FERMI 2 UFSAR

Revision 24

DTE Electric Company

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CHAPTER 1: INTRODUCTION AND GENERAL DESCRIPTION OF PLANT

1.1. INTRODUCTION

The original Final Safety Analysis Report (FSAR) was submitted in support of the Detroit Edison Company's (Edison) application for a license to operate a 3293-MWt (rated) nuclear power plant at the Enrico Fermi Atomic Power Plant site on the western shore of Lake Erie, at Lagoona Beach, Monroe County, Michigan. This Updated Final Safety Analysis Report (UFSAR) was prepared in response to 10 CFR 50.71(e).

The power plant is designated as Fermi 2. The Fermi 2 PSAR (CP Application) was filed in April 1969 and a construction permit CPPR-87 was issued in September 1972. The original FSAR was filed in April 1975. The plant received its license for fuel loading and low-power testing (5 percent power) on March 20, 1985, and its full-power operating license on July 15, 1985.

Fermi 2 uses a General Electric Company (GE) single-cycle, forced-circulation BWR of the BWR 4 Class, with a pressure-suppression Mark I containment. Fermi 2 is similar in design to these nuclear power plants: Browns Ferry Nuclear Plant Units 1, 2, and 3; Cooper Nuclear Station; Edwin I. Hatch Unit No. 1; and Brunswick Steam Electric Plant Units 1 and 2. The design power rating (emergency core cooling system [ECCS] design basis) for Fermi 2 is 3486 MWt, with a turbine-generator design gross electrical output at the generator terminals of 1235 MWe and a net electrical output of 1170 MWe.

On September 9, 1992, the NRC issued Amendment 87 to the Fermi 2 operating license authorizing a change in the thermal power limit from 3293 MWt to 3430 MWt, a 4.2 percent increase in the thermal power and a 5 percent increase in steam flow. This changed the net electrical capacity from 1093 MWe to 1139 MWe, or an increase of 46 MWe.

During RF05 the LP Steam Path was replaced by a GE designed LP Steam Path with a higher efficiency. This changed the designed net electrical capacity from 1139 MWe to 1150 MWe, or an increase of 11 MWe.

During RF07 the HP Steam Path was replaced by a GE designed HP Steam Path with a higher efficiency. However, the gross generator output will not exceed the present 1217 MWe.

During RF11, the Moisture Separator Reheaters (MSRs) were replaced. The gross generator output will not exceed MWe noted above.

The Fermi Power Uprate Program followed the GE Nuclear Energy generic guidelines and evaluations for BWR power plants.[1,2]

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[1] GE Nuclear Energy, "Generic Guidelines for General Electric Boiling Water Reactor Power Uprate," Licensing Topical Report NEDC-31897P-1, Class III, (Proprietary), June 1991

[2] GE Nuclear Energy, "Generic Evaluations of General Electric Boiling Water Reactor Power Uprate," Licensing Topical Report NEDC-31984P, Volumes I and II, Class III, (Proprietary), July 1991.

On February 10, 2014, the NRC issued Amendment 196 to the Fermi 2 operating license authorizing a change in the thermal power limit from 3430 MWt to 3486 MWt, a 1.64 percent increase in thermal power and a 1.88 percent increase in steam flow. This changed the net electrical capacity from 1150 MWe to approximately 1170 MWe. This power uprate was performed in accordance with 10 CFR 50, Appendix K and reflects the improvement in feedwater flow measurement. The Fermi 2 Measurement Uncertainty Recapture (MUR) power uprate followed the GE generic guidelines and evaluations for BWR plants provided in GEH Topical Report NEDC-32938P-A, "Generic Guidelines and Evaluations for General Electric Boiling Water Reactor Thermal Power Optimization," Revision 2, May 2003.

Fermi 2 specific analyses and evaluations were performed, consistent with the generic guidelines, for systems and components that might be affected to ensure their capability to support the increase in power output and steam flow. Since data is described in detail in the UFSAR, revisions were made to this data to reflect the power uprates, as appropriate. The analyses and evaluations resulted in determinations that the systems and components were either not affected by power uprate or had sufficient design capacity to accommodate uprate conditions.

In addition to the above, the effect of the uprates on the environment was assessed to verify that operation of Fermi 2 at uprated power was environmentally acceptable with established NRC requirements and that consistency was maintained with Federal, State, and local regulations. As a result, no changes to the Environmental Protection Plan or to any of the non-NRC permits are required.

The Detroit Edison Company changed its name to DTE Electric Company as of January 1, 2013. The name change to DTE Electric Company was purely administrative in nature; the legal entity remained the same and the name change did not involve a transfer of control or of an interest in the license for Fermi 2. DTE Electric Company continues to be a wholly owned subsidiary of DTE Energy Company. For the purposes of the Fermi 2 UFSAR, except for UFSAR sections of historical context, all DTE Energy Company designations referenced throughout the UFSAR (e.g. DTE Electric, Edison, Detroit Edison, DECo, etc.) are synonymous.

DTE Electric submitted an application for renewal of the operating license for an additional 20 years on April 24, 2014 by letter NRC-14-0028. The application documented the technical and environmental reviews performed to support extension of the license to March 20, 2045. The NRC performed an in-depth review, including audits, an inspection, and multiple requests for additional information. The NRC issued the final Safety Evaluation Report on the License Renewal of Fermi 2 on July 12, 2016. The Safety Evaluation Report was re-issued as NUREG-2210 in October 2016. NUREG-1437, Supplement 56, the Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding Fermi 2 Nuclear Power Plant, was published in September 2016.

Appendix A of the License Renewal Application (LRA) included a supplement to be inserted into the UFSAR following approval of the renewed license. That appendix, including changes submitted in response to NRC requests for additional information, is added to the UFSAR as Appendix B. The appendix addresses the aging management programs that will be implemented per the commitments in the License Renewal Application, a summary of how time limited aging analyses were addressed, and a list of commitments made in the

LRA. Changes to Appendix B may be made per the process for UFSAR revisions under the auspices of 10 CFR 50.59.

The renewed license was issued December 15, 2016.

1.2 GENERAL PLANT DESCRIPTION

1.2.1 General Design Criteria

The general architectural and engineering criteria for the design, construction, and operation of Fermi 2 are summarized in this subsection. For specific NRC General Design Criteria (GDC) conformance description, see Section 3.1.

The discussion of the GDC that follows is divided into three sections. First, the overall requirements criteria are presented for the plant and for the nuclear safety systems and engineered safety features (ESFs). Then the GDC are presented in two ways. First, the criteria are considered in a classification-by-classification approach. Second, the criteria are considered in a system-by-system or system group approach.

1.2.1.1 Overall Requirements Criteria

1.2.1.1.1 Plant Criteria

The plant is designed, fabricated, erected, and operated to generate electricity in a safe and reliable manner. Plant design conforms with applicable codes and regulations and complies with regulatory guides to the extent described in Appendix A.

The plant is also designed, fabricated, erected, and operated in such a way that the release of radioactive materials to the environment is less than the limits of 10 CFR 20 and 10 CFR 50, pertaining to the release of radioactive materials, during normal operation and abnormal events.

Components and structures are provided with appropriate safety factors and adequate strength and stiffness so that a hazardous release of radioactive material will not occur.

Careful consideration is given to all known environmental conditions associated with maintenance, testing, and postulated accidents, including LOCAs, that could result in unplanned releases of radioactive material from the plant. Pollution control equipment and specific design provisions are incorporated in the plant for the specific purpose of protecting public health and safety from the release of radioactive material under both normal and abnormal conditions.

1.2.1.1.2 Nuclear Safety Systems and Engineered Safety Features Criteria

Design margins for the nuclear safety systems and ESFs are conservative.

Nuclear safety systems are designed to respond to abnormal operational transients to limit fuel damage so that, should the freed fission products be released to the environs via the normal discharge paths for radioactive material, the limits of 10 CFR 20 and 10 CFR 50 will not be exceeded.

Nuclear safety systems and ESFs act to preclude damage to the nuclear system process barrier as a result of internal pressures caused by abnormal operational transients or accidents.

When positive and precise action is immediately required in response to accidents, such action is automatic, requiring no decision or manipulation of controls by plant operations personnel.

The reactor core and reactivity control systems are designed so that the control rod action is capable of making the core subcritical and maintaining it so, even when the rod of highest worth is fully withdrawn and unavailable for reinsertion.

Essential safety actions are carried out by equipment in sufficient redundance and independence so that a single failure of active components will not prevent the required actions.

Provision has been made for control of active components of nuclear safety systems and ESFs from the main control room.

Nuclear safety systems and ESFs are designed to permit demonstration of their compliance with functional performance requirements.

Nuclear safety systems and ESFs are designed to maintain operability under all plant-related and site-related events (e.g., earthquakes, tornadoes, floods, fires, etc.).

Features of the plant essential to the mitigation of accident consequences are designed for fabrication and erection to quality standards that reflect the importance of the safety function to be performed. A quality assurance program has been established and implemented.

1.2.1.2 Classification-by-Classification Approach

In this approach, three classifications are considered: (1) power generation; (2) safety; and (3) plant radiation zones. The corresponding GDC are discussed below.

1.2.1.2.1 Power Generation Classification Criteria

The GDC for the power generation classification are further subdivided into criteria for planned operations and for operational transients.

1.2.1.2.1.1 Planned Operations

Power generation design criteria for planned operations are as follows:

a. Fuel cladding is designed to retain integrity as a radioactive material barrier throughout the design power range. The fuel cladding accommodates, without loss of integrity, the pressures generated by fission gases released from fuel material throughout the design life of the fuel

b. Heat removal systems are provided in sufficient capacity and operational adequacy to remove heat generated in the reactor core for the full range of normal operational conditions from plant shutdown to design power. The capacity of such systems is adequate to prevent fuel cladding damage

c. Control equipment is provided to allow the reactor to respond to small load changes

d. Reactor power level is manually controllable

e. Control of the nuclear system is possible from a single location

f. Nuclear system process controls, including alarms, are arranged to allow the operator to rapidly assess the condition of the nuclear system and to locate process system malfunctions

g. Fuel handling and storage facilities are designed to maintain adequate subcriticality, shielding, and cooling for spent fuel

h. Interlocks or other automatic equipment are provided as backup to procedural controls to avoid conditions requiring unnecessary functioning of nuclear safety systems or ESFs

1.2.1.2.1.2 Operational Transients

Power generation design criteria for operational transients are as follows:

a. The fuel cladding, in conjunction with other plant systems, is designed to retain integrity throughout any abnormal operational transient

b. Heat removal systems are provided in sufficient capacity and operational adequacy to remove heat generated in the reactor core for any abnormal operational transient. The capacity of such systems is adequate to prevent fuel cladding damage

c. Control equipment is provided to allow the reactor to respond automatically to normal operational transients, such as major load changes, and to abnormal operational transients, including bringing the reactor to a hot-shutdown condition when appropriate

d. Backup heat removal systems are provided to remove decay heat generated in the core when the normal operational heat removal systems become inoperative. The capacity of such systems is adequate to prevent fuel cladding damage

e. Onsite standby electrical power sources are provided to allow removal of decay heat when normal offsite auxiliary power is not available.

1.2.1.2.2 Safety Classification Criteria

The design criteria for the safety classification are further subdivided into criteria for planned operations, operational transients, and accidents.

1.2.1.2.2.1 Planned Operations

Safety design criteria for planned operations are as follows:

a. The plant is designed, fabricated, erected, and operated in such a way that the normal release of radioactive materials to the environment is within the requirements of 10 CFR 20 and 10 CFR 50

b. The reactor core is designed so that its nuclear characteristics do not contribute to a divergent power transient

c. The nuclear system is designed such that there is no tendency for divergent oscillation of any operating characteristic, considering the interaction of the nuclear system with other appropriate plant systems

d. Gaseous, liquid, and solid waste disposal facilities are designed such that the discharge and offsite shipment of radioactive effluents are in accordance with applicable federal, state, and local regulations

e. The design provides a means by which plant operators are informed when limits on the release of radioactive material are approached

f. Sufficient indication is provided to allow determination that the reactor is operating within the range of conditions considered in the plant safety analysis

g. Radiation shielding and access control procedures are provided to allow a properly trained operating staff to control radiation doses within the limits of applicable regulations in any mode of normal plant operation

h. Procedures for fuel handling and design of fuel storage facilities prevent inadvertent criticality.

1.2.1.2.2.2 Operational Transients

Safety design criteria for operational transients are as follows:

a. The plant is designed, fabricated, erected, and will be operated in such a way that the release of radioactive materials to the environment is within the requirements of 10 CFR 20 and 10 CFR 50

b. Those portions of the nuclear system that form part of the nuclear system process barrier are designed to retain integrity as a radioactive-material barrier following abnormal operational transients

c. Nuclear safety systems act to ensure that no damage to the nuclear system process barrier results from internal pressures caused by abnormal operational transients

d. When positive and precise action is immediately required in response to abnormal operational transients, such action is automatic, requiring no decision or manipulation of controls by plant operations personnel

e. Essential safety actions are carried out by equipment of sufficient redundancy and independence that a single failure of any active component cannot prevent the required actions

f. Provision is made for control of the active components of nuclear safety systems from the main control room

g. Nuclear safety systems are designed to demonstrate their functional performance requirements

h. Nuclear safety systems are designed to maintain their function under all plant-related and site-related events (e.g., earthquakes, floods, tornadoes, and fires)

i. Standby electrical power sources have sufficient capacity to power all nuclear safety systems requiring electrical power

j. Onsite standby electrical power sources are provided to allow prompt reactor shutdown and removal of decay heat under circumstances where normal offsite auxiliary power is not available.

1.2.1.2.2.3 Accidents

Safety design criteria for accidents are as follows:

Fermi 2 has reanalyzed the DBA-LOCA, the control rod drop accident, and the fuel handling accidents in accordance with the methodology in Regulatory Guide 1.183. The release of radioactive materials to the environment is evaluated per the criteria of 10 CFR 50.67 for these accidents only. All other existing accidents are evaluated per the criteria in 10 CFR 100.

a. The plant is designed, fabricated, erected, and will be operated in such a way that the release of radioactive materials to the environment is within the requirements of 10 CFR 100 or 10 CFR 50.67, as applicable

b. Those portions of the nuclear system that form part of the nuclear system process barrier are designed to retain integrity as a radioactive material barrier following accidents. For accidents in which one breach in the nuclear system process barrier is postulated, such a breach does not propagate additional failures in the nuclear system process barrier

c. The ESFs act to ensure that no damage to the nuclear system process barrier results from internal pressures caused by an accident

d. When positive, precise action is immediately required in response to accidents, such action is automatic, requiring no decision or manipulation of controls by plant operating personnel

e. Essential safety actions are carried out by equipment of sufficient redundance and independence that a single failure of any active component cannot prevent the required actions

f. Provision is made for control of active components of the ESFs from the main control room

g. The ESFs are designed to permit demonstration of their functional performance requirements

h. The ESFs are designed to maintain their function under all plant-related and site-related events (e.g., earthquakes, floods, tornadoes, fires, etc.)

i. Onsite standby electrical power sources have sufficient capacity to power the nuclear safety systems and ESFs requiring electrical power during accident conditions

j. Features of the plant essential to the mitigation of accident consequences are designed to be fabricated and erected to quality standards that reflect the importance of the safety actions to be performed

k. The primary containment is designed to retain integrity as a radioactive material barrier during and following accidents that release radioactive material into the primary containment volume

l. The primary containment is designed to permit integrity and leaktightness testing at periodic intervals

m. A secondary barrier (containment) is provided that completely encloses both the primary containment and the fuel storage areas. The secondary barrier design incorporates systems and equipment for controlling the rate of release of radioactive materials from the barrier, and further includes a capability for filtering radioactive materials within the barrier. In the event of a design-basis tornado, the secondary containment barrier above the refueling floor will be breached. See Section 3.3 for additional discussion regarding tornado design

n. The secondary barrier is designed to act as a radioactive material barrier under the same conditions that require the primary containment to act as a radioactive material barrier

o. The secondary barrier is designed to act as a radioactive material barrier, if required, when the primary containment is open for expected operational purposes

p. The primary containment and secondary containment barrier constitute pollution control facilities which, in conjunction with other ESFs, limit radiological effects of accidents resulting in the release of radioactive material to the containment volumes to within the 10 CFR 100 limits or 10 CFR 50.67 limits, as applicable

q. Provisions are made for removing energy from within the primary containment, as necessary, to maintain the integrity of the containment system following accidents that release energy to the primary containment so as to ensure continuing air pollution control functional capability

r. Piping that penetrates the primary containment structure, and which could serve as a path for the uncontrolled release of radioactive material to the environs, is automatically isolated whenever such uncontrolled radioactive material release is threatened. Such isolation is accomplished in time to limit radiological effects to within the 10 CFR l00 limits or 10 CFR 50.67 limits, as applicable

s. The ECCS is provided to limit fuel cladding temperature to 2200 F as a result of a LOCA

t. The ECCS provides for continuity of core cooling over the complete range of postulated break sizes in the nuclear system process barrier in order to minimize the release of radioactive material and to ensure the continuous functional capability of the containment facilities

u. The ECCS is diverse, reliable, and redundant

v. Operation of the ECCS is initiated automatically when required, regardless of the availability of offsite power supplies and the normal generating system of the plant

w. The main control room is shielded against radiation so that occupancy under accident conditions is possible

x. For a special event such as loss of habitability of the main control room, it is possible to bring the reactor from power range operation to a hot-shutdown condition, from outside the main control room, as well as to bring the reactor to a cold-shutdown condition from the hot-shutdown condition

y. For a special event, such as inability to shut down the reactor with control rods, backup reactor shutdown capability is provided, independent of normal reactivity control provisions. This backup system has the capability to shut down the reactor from any normal operating condition and to maintain the shutdown condition.

1.2.1.2.3 Plant Radiation Zone Classification

Radiation zones are identified as a means of classifying the occupancy restrictions on various areas within the plant site boundary. The criteria for each zone are described in Section 12.1.

1.2.1.3 System-by-System Approach

In this approach, the following systems are considered: (1) nuclear system; (2) power conversion systems; (3) electrical power systems; (4) radwaste systems; (5) auxiliary systems; (6) shielding and access control system; (7) nuclear safety and ESFs; and (8) process control systems.

The design criteria are presented below for each one of these systems.

1.2.1.3.1 Nuclear System Criteria

Design criteria for the nuclear system are given below, divided in three groups: mechanical, thermal, and nuclear.

1.2.1.3.1.1 Mechanical

The fuel cladding is designed to retain integrity as a radioactive-material barrier throughout the design power range. The fuel cladding is designed to accommodate, without loss of integrity, the pressures generated by the fission gases released from the fuel material throughout the design life of the fuel.

The fuel cladding, in conjunction with other plant systems, is designed to retain integrity throughout any abnormal operational transient.

Those portions of the nuclear system that form part of the nuclear system process barrier are designed to retain integrity as a radioactive material barrier following operational transients and accidents. For accidents in which one breach in the nuclear system process barrier is postulated, such a breach does not cause additional breaches in the nuclear system process barrier.

1.2.1.3.1.2 Thermal

Heat removal systems are provided in sufficient capacity and operational adequacy to remove heat generated in the reactor core for the full range of normal operational conditions, from plant shutdown to design power, and for any abnormal operational transients. The capacity of such systems is adequate to prevent fuel cladding damage.

Heat removal systems are provided to remove decay heat generated in the core under circumstances wherein the normal operational heat removal systems become inoperative. The capacity of such systems is adequate to prevent fuel cladding damage. Following loss of operation of the normal heat removal systems, the reactor can be automatically shut down fast enough to permit decay heat removal systems to become effective.

1.2.1.3.1.3 Nuclear

The reactor core and the reactivity control system are designed such that the control rod action is capable of bringing the core subcritical, and maintaining it so, even when the rod of highest reactivity worth is fully withdrawn and unavailable for reinsertion.

The reactor core is designed so that its nuclear characteristics do not contribute to a divergent power transient.

The nuclear system is designed so that there is no tendency for divergent oscillation of any operating characteristic, considering the interaction of the nuclear system with other appropriate plant systems.

1.2.1.3.2 Power Conversion Systems Criteria

The power conversion systems are designed to meet the following criteria:

a. Produce electrical power from the steam coming from the reactor, condense the steam into water, and return the water to the reactor as heated feedwater, with the major portion of its gases and particulate impurities removed

b. Ensure that any fission products or radioactivity associated with the steam and condensate during normal operation are safely contained inside the system, or are released under controlled conditions.

1.2.1.3.3 Electrical Power Systems Criteria

The electrical power systems are designed to meet the following criteria:

a. Sufficient normal and standby auxiliary sources of electrical power are provided to attain prompt shutdown and continued maintenance of the plant in a safe condition under all credible circumstances

b. The power sources are adequate to accomplish all required ESF functions under postulated design-basis accident (DBA) conditions.

1.2.1.3.4 Radwaste Systems Criteria

The radwaste systems are designed to meet the following criteria:

a. The radwaste systems are designed to limit release of radioactive materials from the plant during normal operation to within the requirements of 10 CFR 20 and 10 CFR 50

b. Gaseous, liquid, and solid waste disposal systems are designed so that discharge of effluents and offsite shipments are in accordance with applicable regulations, including 10 CFR 50, 10 CFR 71, and 49 CFR 171 through 49 CFR 179, as appropriate.

The design provides a means by which plant operations personnel can be informed whenever operational limits on the release of radioactive material are approached.

1.2.1.3.5 Auxiliary Systems Criteria

Design criteria for each one of the auxiliary systems are presented below. The auxiliary systems considered are: (1) fuel handling and storage systems; (2) water systems; (3) process auxiliaries systems; (4) heating, ventilation, and air conditioning (HVAC) systems; and (5) other auxiliary systems.

1.2.1.3.5.1 Fuel Handling and Storage Facilities

Fuel handling and storage facilities are designed to prevent criticality and maintain adequate shielding and cooling for spent fuel.

1.2.1.3.5.2 Water Systems

The condenser circulating water system is designed to condense the steam discharged from the low-pressure turbines into the condenser.

The general service water (GSW) system is designed to remove heat from the reactor and turbine building closed cooling water (TBCCW) loops and selected equipment to maintain proper equipment temperatures during changing ambient conditions and plant operating modes.

The turbine building closed cooling water system (TBCCWS) is designed to transfer heat from the auxiliary equipment housed in the turbine building to the GSW system to maintain proper equipment temperatures, considering variations in the service water temperatures and plant operating conditions.

The reactor building closed cooling water system (RBCCWS) is designed to transfer heat from reactor auxiliary equipment to the GSW system to maintain proper equipment temperatures, considering variations in service water temperature and plant operating conditions.

The emergency equipment cooling water system (EECWS) provides a backup to the RBCCWS to cool essential equipment by transferring heat to the ultimate heat sink through the emergency equipment service water system (EESWS). It is designed to maintain this function in the event of seismic disturbance, loss of offsite power, or other site- or plant-related events.

The supplemental cooling chilled water system assists the RBCCW system in the RBCCW supplemental cooling mode of operation. RBCCW supplemental cooling is a loop within

RBCCW that provides water cooled by chilled water from SCCW to the EECW loops. The SCCW system and the RBCCW supplemental cooling loops are non-safety-related and are intended to operate during normal plant operation when GSW inlet temperatures are greater than 60°F (nominal).

The demineralized water makeup system is designed to provide water of the required purity in quantities sufficient for plant needs.

The potable water system is designed to provide drinking-quality water, according to state and local standards, in sufficient quantity for the use of plant personnel.

The sanitary wastewater system is designed to dispose of nonradioactive plant sewage liquid waste in accordance with state and local regulations.

The ultimate heat sink (residual heat removal [RHR] complex) is designed to provide cooling to the reactor system and essential auxiliaries under emergency conditions when the normal heat sinks are not available.

The condensate storage facilities are designed to provide retention of condensate to meet the requirements of plant systems, particularly primary system makeup to the condenser and water supply for selected ECCS. The facilities are designed with due regard for radioactive contamination of the condensate.

1.2.1.3.5.3 Process Auxiliary Systems

The compressed air system (instrument and service air) is designed to provide air of required quality at pressures and quantities sufficient to meet plant needs for various operating conditions.

The process sampling system is designed to enable the plant personnel to determine the composition and properties of process fluids in a safe and efficient manner.

The equipment and floor drain systems are designed to conduct drain fluids from general plant areas and equipment to the appropriate radwaste processing facilities.

1.2.1.3.5.4 Heating, Ventilation, and Air Conditioning Systems

The HVAC systems are designed to provide the required ambient environment for plant equipment, to provide a comfortable working environment for plant personnel, and to control airborne radioactivity.

1.2.1.3.5.5 Diesel Generator Auxiliaries

The onsite standby power system (diesel generator) auxiliaries are designed to provide the services required by the diesel generators. Each diesel generator is provided with its own auxiliaries, independent of all other units.

1.2.1.3.5.6 Other Auxiliary Systems

The fire protection system (FPS) is designed to adequately protect the plant from special hazards in accordance with national standards and insurance requirements.

The communications system is designed to provide contact between the main control room and various plant areas. Provisions are made for maintaining communications between essential areas in the event of loss of power.

The lighting systems are designed to provide adequate illumination for work in all plant areas. Provisions are made for emergency lighting in essential areas in the event of loss of power.

1.2.1.3.6 Shielding and Access Control Systems Criteria

The plant radiation shielding is designed to minimize the exposure of plant operating personnel and the general public to radiation due to the reactor, power conversion, auxiliary, and waste processing systems during normal operation, anticipated operational occurrences, postulated accident conditions, and maintenance. Radiation shielding is provided and access control patterns are established to limit radiation doses to the plant staff. The main control room and the technical support center are shielded against radiation so that occupancy is possible under accident conditions.

1.2.1.3.7 Nuclear Safety Systems and Engineered Safety Features Criteria

Design criteria for the nuclear safety systems and ESFs, in the system-by-system approach; have already been listed in various other paragraphs. They are as follows:

a. Design margins for the nuclear safety systems and ESFs are conservative

b. Nuclear safety systems are designed to respond to abnormal operational transients to limit fuel damage so that, should the freed fission products be released to the environs via the normal discharge paths for radioactive material, the limits of 10 CFR 20 and 10 CFR 50 will not be exceeded

c. Nuclear safety systems and ESFs act to preclude damage to the nuclear system process barrier as a result of internal pressures caused by abnormal operational transients or accidents

d. When positive and precise action is immediately required in response to accidents, such action is automatic, requiring no decision or manipulation of controls by plant operating personnel

e. The reactor core and reactivity control systems are designed so that the control rod action is capable of making the core subcritical and maintaining it so, even when the rod of highest reactivity worth is fully withdrawn and unavailable for reinsertion

f. Essential safety actions are carried out by equipment in sufficient redundancy and independence so that a single failure of active components will not prevent the required actions

g. Provision has been made for control of active components of nuclear safety systems and ESFs from the main control room

h. Nuclear safety systems and ESFs are designed to permit demonstration of their compliance with functional performance requirements

i. Nuclear safety systems and ESFs are designed to maintain operability under all plant-related and site-related events (e.g., earthquakes, tornadoes, floods, fires)

j. Features of the plant essential to the mitigation of accident consequences are designed for fabrication and erection to quality standards that reflect the importance of the safety function to be performed. A quality assurance program has been established and implemented

k. Onsite standby electrical power sources are provided to allow prompt reactor shutdown and removal of decay heat under circumstances where normal offsite auxiliary power is not available

l. The plant is designed, fabricated, erected, and will be operated in such a way that under accident conditions the release of radioactive materials to the environment is within the requirements of 10 CFR l00 or 10 CFR 50.67 as applicable

m. Those portions of the nuclear system that form part of the nuclear system process barrier are designed to retain integrity as a radioactive material barrier following accidents. For accidents in which one breach in the nuclear system process barrier is postulated, such a breach does not propagate additional failures in the nuclear system process barrier

n. Onsite standby electrical power sources have sufficient capacity to power the nuclear safety systems and ESFs requiring electrical power during accident conditions

o. The primary containment is designed to retain integrity as a radioactive material barrier during and following accidents that release radioactive material into the primary containment volume

p. The primary containment is designed to permit integrity and leaktightness testing at periodic intervals

q. A secondary barrier (containment) is provided that completely encloses both the primary containment and the fuel storage areas. The secondary barrier design includes a method for controlling the rate of release of radioactive materials from the barrier, and further includes a capability for filtering radioactive materials within the barrier. In the event of a design-basis tornado, the secondary containment barrier above the refueling floor will be breached. See Section 3.3 for additional discussion regarding tornado design

r. The secondary barrier is designed to act as a radioactive material barrier under the same conditions that require the primary containment to act as a radioactive material barrier

s. For a special event such as loss of habitability of the main control room, it is possible to bring the reactor from power range operation to a hot-shutdown condition from outside the main control room, as well as to bring the reactor to a cold-shutdown condition from the hot- shutdown condition

t. For a special event, such as inability to shut down the reactor with control rods, backup reactor shutdown capability is provided, independent of normal reactivity control provisions. This backup system has the capability to shut down the reactor from any normal operating condition and to maintain the shutdown condition.

1.2.1.3.8 Process Control Systems Criteria

Design criteria for the various process control systems are listed below. The systems under consideration are as follows: (l) nuclear systems; (2) power conversion systems; and (3) electrical power systems.

1.2.1.3.8.1 Nuclear System Process Control

Design criteria for nuclear system process control are as follows:

a. Control equipment is provided to allow the reactor to respond to load changes

b. It is possible to control the reactor power level manually

c. Control of the nuclear system is possible from a single location

d. Nuclear system process controls and alarms are arranged to allow the operator to assess the condition of the nuclear system rapidly and locate process system malfunctions

e. Interlocks, or other automatic equipment, are provided as a backup to plant procedural controls to avoid conditions requiring the actuation of nuclear safety systems or ESFs.

1.2.1.3.8.2 Power Conversion Systems Process Control

Design criteria for power conversion systems process control are as follows:

a. Control equipment is provided to control the reactor pressure throughout its operating range

b. The turbine is able to respond automatically to minor changes in load

c. Control equipment in the feedwater system maintains the water level in the reactor pressure vessel (RPV) at the optimum level required by steam separators

d. Control of the power conversion equipment is possible from one location

e. Interlocks or other automatic equipment are provided, in addition to procedural controls, to avoid conditions requiring unnecessary actuation of nuclear safety systems or ESFs.

1.2.1.3.8.3 Electrical Power System Process Control

Design criteria for electrical power system process control are as follows:

a. The electrical power system is designed as a split bus system, with either system being adequate to safely shut down the unit

b. Protective relaying is used to detect and isolate faulted equipment from the system with a minimum of disturbance in the event of equipment failure

c. Undervoltage relays are used on the emergency equipment buses to isolate them from the normal electrical system in the event of loss of offsite power, and to initiate starting the onsite standby power system diesel generators

d. The standby emergency power diesel generators are started by automatically initiated control relays. The generators are also loaded by a programmed control system to meet the existing emergency conditions

e. All 4160-V and 480-V electrically operated breakers are controllable from the main control room

f. Metering for essential generators, transformers, and circuits is monitored in the main control room.

1.2.2 Plant Description

Fermi 2 contains a GE BWR nuclear steam supply system (NSSS) that delivers at rated flow approximately 14,864,000 lb/hr of 991-psia steam to the turbine generator and auxiliary equipment, which produces (at rated steam flow) 1217 MWe of gross electrical output at the generator terminals. The main condenser circulating water is cooled by two wet-type, natural-draft, hyperbolic cooling towers. The plant is equipped with auxiliary systems for control of radioactive contamination, nuclear safety assurance, and operation of the NSSS and turbine generator. The plant is located southwest of Detroit, Michigan and is intended to supply electrical power to the Edison service area.

1.2.2.1 Location and Size of Site

The Fermi 2 site is located on the shore of the western end of Lake Erie, at Lagoona Beach in Frenchtown Township, Monroe County, Michigan. The site is approximately 6 miles northeast of Monroe, Michigan, 30 miles southwest of downtown Detroit, Michigan, and 25 miles northeast of Toledo, Ohio. Reactor centerline coordinates are latitude 41 57'48"N., and longitude 83 15'31"W. The site consists of approximately 1260 acres.

On the same site is Fermi 1, originally a fast breeder reactor, and later also a conventional oil-fired power plant. Both are decommissioned. Also on the site are four oil-fired combustion turbine peaking units rated at 62.4-MWe total capacity. In addition, there is the Independent Spent Fuel Storage Installation for dry storage of Fermi 2 spent fuel. Figures 1.2-1, 1.2-2, and 1.2-3 show the relationship of the site to the surrounding areas. Figure 1.2-4 shows the site boundary and general site location of Fermi 1 and Fermi 2. Figure 1.2-5 is the Fermi site plan.

Transportation facilities are readily available. Interstate Highways 75 and 275 are approximately 5 miles west of the site. More immediate access to the site is available from the Dixie Highway, which runs north and south approximately 2 miles west of the site. From the Dixie Highway, Enrico Fermi Drive (a paved private access road) enters the site on the western boundary where it serves as the main entrance. Rail service to the site is furnished by a spur line from the main line which is 4 miles west of the site.

1.2.2.2 Description of Plant Environs

1.2.2.2.1 General

The site is bounded on the north by Swan Creek, on the east by Lake Erie, on the south by Pointe Aux Peaux Road, and on the west by Toll Road. Entrance to the site is from the west by way of Enrico Fermi Drive, a private road owned by Edison, and from the south via Pointe Aux Peaux Road to Quarry Lake Road, also owned by Edison.

The northern and southern areas of the site are dominated by large lagoons. The western areas are dominated by several woodlots and a series of quarry lakes. Site elevation ranges from approximately 25 ft above the lake level on the western edge of the site to lake level on the eastern edge.

1.2.2.2.2 Population

The area within a 10-mile radius of the site has an estimated total population of 86,214 (1980 data). The only substantially populated community within this radius is the city of Monroe, Michigan, approximately 6 miles southwest, whose 1980 population was 22,995.

Downtown Detroit, Michigan, is located approximately 30 miles northeast of the Fermi site. Downtown Toledo, Ohio, is located about 25 miles southwest.

1.2.2.2.3 Land Use

Approximately 70 percent of Monroe County, in which the plant is located, is farmland. Most of the industrial activity in the county is concentrated in the city of Monroe. Within a 50-mile radius of the site are all, or portions of, eight counties in Michigan, nine counties in Ohio, and two counties in Ontario, Canada. A large number and variety of manufacturing industries are found in this area. However, according to 1974 data, more than 50 percent of the land within the 50-mile radius is farmland, except for the area in the six counties located around metropolitan Detroit and Toledo.

1.2.2.3 Design Bases Dependent On the Site Environs

1.2.2.3.1 Offgas System

A rooftop plant vent is provided for the discharge of gaseous effluent to the atmosphere. Gaseous releases will be in compliance with 10 CFR 20 and 10 CFR 50.

1.2.2.3.2 Liquid Waste Effluents

Liquid waste will be released so that concentrations at the point of discharge will be in compliance with 10 CFR 20 and 10 CFR 50.

1.2.2.3.3 Wind Loading Design

The primary containment, reactor systems, and structures that contain equipment necessary for safe shutdown are designed with a wind load consideration for a sustained high wind (90 mph) and a transient condition imposed by a postulated tornado (300-mph rotation, 60-mph translation, 3-psi external pressure drop at 1 psi/sec).

1.2.2.3.4 Seismic Design

The design of Category I structures is for a maximum horizontal ground acceleration of 0.15g. The maximum vertical ground acceleration is considered to occur simultaneously, and is equal to 0.67 times the horizontal ground acceleration. The combined stresses resulting from functional loadings and a safe-shutdown earthquake (SSE) having a horizontal ground acceleration of 0.15g will be such that a safe shutdown can be achieved.

1.2.2.3.5 Flooding

A comprehensive study has established a maximum stillwater elevation of 586.9 ft (New York Mean Tide, 1935) for the plant site, based on the probable maximum meteorological event (PMME).

The site grade is 583.0 ft (New York Mean Tide, 1935) along the periphery of the power block (reactor/auxiliary building, RHR complex, turbine house, radwaste building, service building, etc.). From this reference elevation, the site has been graded for proper drainage.

Fermi 2 Category I structures and components are conservatively flood protected (waterproofed) to an elevation of 588 ft.

The shoreline of that portion of the site occupied by the plant is protected from erosion resulting from wave action through the use of a specially constructed shore barrier.

1.2.2.3.6 Loss of Normal Heat Sink

The natural-draft cooling towers provide the normal heat sink for the once-through-type main unit condenser and auxiliary systems. Should this heat sink be lost, the reactor can be safely shut down and maintained using the mechanical-draft cooling towers and the RHR reservoir as a heat sink.

1.2.2.3.7 Environmental Radiation Monitoring Program

An environmental monitoring program has been under way at the Fermi site since 1958 when Fermi 1 was being constructed. The present program, which has been specific for Fermi 2 since 1978, is referenced in UFSAR Section 11.6.

1.2.2.4 General Arrangement of Structures and Equipment

The principal structures located on the plant site are the following:

a. The reactor building, which houses the drywell, the suppression pool, the NSSS, the ESFs, some auxiliary systems equipment, and the fuel storage and shipping area

b. The turbine building, which houses the power conversion equipment, the offgas system, and the plant auxiliaries

c. The auxiliary building, which houses the main control room, the computer facility, electrical equipment, and HVAC equipment

d. The radwaste building, which houses the radioactive waste treatment facilities for liquid and solid waste

e. The switchyard

f. The condensate storage tanks and fuel-oil storage tanks

g. The RHR complex, which houses the emergency diesel generators (EDGs), the RHR cooling towers, the RHR service water (RHRSW) reservoir, and the RHRSW, EESWS, and EDG service water pumps

h. Two natural-draft hyperbolic circulating water cooling towers, and corresponding intake conduits, intake structures, and discharge structures

i. The GSW house, and corresponding intake conduits, intake structures, and discharge structures

j. The circulating water pump house, and corresponding intake conduits, intake structures, and discharge structures

k. A reservoir pond

l. The auxiliary boiler house

m. The meteorological towers

n. The office service building and annex

o. The Fermi 1 plant complex

p. The nuclear operations center

q. Technical assistance center

r. Availability improvement center.

s. Hydrogen/Oxygen supply facility for hydrogen water chemistry

t. Nuclear training center

u. The Independent Spent Fuel Storage Installation (ISFSI) Equipment Storage Building

v. The Independent Spent Fuel Storage Installation (ISFSI) Pad

w. ISFSI Fabrication Pad

x. ISFSI Transfer Pad

y. ISFSI Cask Transfer Facility

z. FLEX Storage Facility #1

aa. FLEX Storage Facility #2

The arrangement of these structures on the plant site is shown in Figure 1.2-5. Figures 1.2-6 through 1.2-31 show the equipment arrangement in the principal buildings.

1.2.2.5 Nuclear System (Chapter 4)

The nuclear system includes a single-cycle, forced-circulation GE BWR that produces steam for direct use in the steam turbine. A heat balance showing the major parameters of the nuclear system for the rated power conditions is shown in Figure 1.2-32.

1.2.2.5.1 Reactor Core and Control Rods (Section 4.5)

Fuel for the reactor core consists of enriched uranium dioxide (UO_2) pellets sealed in Zircaloy-2 tubes. These tubes (or fuel rods) are assembled into individual fuel assemblies. Gross control of the core reactivity is achieved by cruciform-shaped, movable, bottom-entry control rods dispersed throughout the lattice of fuel assemblies. These rods are controlled by individual hydraulic systems.

Each fuel assembly has several fuel rods with gadolinia (Gd_2O_3) mixed in solid solution with the UO_2. Gadolinia is a burnable poison that diminishes the reactivity of the fresh fuel and is depleted as the fuel reaches the end of its first cycle.

A conservative limit of plastic strain is used for the design criterion for fuel rod cladding failure. The peak linear heat generation for steady-state operation is well below the damage limit, even late in life. Experience has shown that the control rods are not susceptible to distortion and have an average life expectancy many times greater than the residence time of a fuel loading.

1.2.2.5.2 Reactor Pressure Vessel and Internals (Section 4.5)

The RPV contains the following:

a. Core and supporting structures

b. Steam separators and dryers

c. Jet pumps

d. Control rod guide tubes

e. Distribution lines for the feedwater, core sprays, and standby liquid control

f. In-core instrumentation

g. Other components.

The main connections to the RPV include the steam lines, the coolant recirculation lines, feedwater lines, control rod drive (CRD) housings, and ECCS lines.

The RPV is designed and fabricated in accordance with applicable codes for a pressure of 1250 psig. The nominal rated operating pressure in the steam space above the separators is 1045 psia. The RPV is fabricated of carbon steel and is clad internally (except for the top head) with stainless steel.

The reactor core is cooled by demineralized water that enters the lower portion of the core and boils as it flows upward around the fuel rods. The steam leaving the core is dried by steam separators and dryers located in the upper portion of the RPV. The steam is then directed to the turbine through four 24-in.-diameter main steam lines. Each steam line is provided with three isolation valves in series, one inside the primary containment, and two outside the primary containment.

1.2.2.5.3 Reactor Recirculation System (Subsection 5.5.1)

The reactor recirculation system pumps reactor coolant through the core to remove energy generated in the fuel. This is accomplished by two recirculation loops external to the RPV but inside the primary containment. Each external loop has one motor-driven recirculation pump. Recirculation pump speed can be varied to allow control of reactor power level through the effects of coolant flow rate on moderator void content. The internal portion of the loop consists of the jet pumps, which contain no moving parts, but have high-velocity nozzles to provide a continuous internal circulation path for the core coolant flow. The jet pumps are located in the annular region between the core shroud and the vessel inner wall, and any recirculation line break would still allow core flooding to approximately two-thirds of the core height: the level of the top of the jet pumps.

1.2.2.5.4 Residual Heat Removal System (Subsection 5.5.7)

The RHR system consists of pumps, heat exchangers, and piping that fulfill the following functions:

a. Remove decay heat during and after plant shutdown

b. Remove heat from the primary containment following a LOCA.

1.2.2.5.5 Reactor Water Cleanup System (Subsection 5.5.8)

The reactor water cleanup (RWCU) system recirculates a portion of reactor coolant through a filter-demineralizer to remove particulate and dissolved impurities from the reactor coolant. It also removes excess coolant from the reactor system under controlled conditions.

1.2.2.6 Power Conversion System (Chapter 10)

The megawatt output of the generator is a function of the reactor steam power input to the turbine. Turbine control is achieved by an integrated speed and pressure control system. After the turbine has been brought to the synchronous speed of the power grid system and the generator breakers are closed to lock the machine into the system, the turbine is on pressure control. The turbine acts as a pressure-control device, maintaining the reactor pressure at its particular pressure setpoint level by varying control and/or bypass valve opening. The steam admitted to the turbine is controlled by a pressure regulator that senses the pressure just before the turbine inlet, thus controlling RPV pressure. Figure 1.2-33 shows the turbine-generator heat balance at rated flow.

Feedwater into the reactor is governed by a three-element control system that senses water level, main stream flow rate, and feedwater flow rate. Each of the signals combines in a three-element controller to control the speed of the two turbine-driven reactor feed pumps, thereby regulating feedwater requirements.

1.2.2.7 Electrical Power Systems (Chapter 8)

Power output from the unit is from a nominally rated 1350-MVA turbine generator. Generator output voltage is 22 kV. It is stepped up to 345 kV through two parallel main power transformers, then fed to the 345-kV switchyard and then to the system grid.

Offsite power available for the plant auxiliary system is from both the 345-kV switchyard, just west of the plant, and the 120-kV switchyard located at Fermi 1. Normal auxiliary power is provided from two system service transformers. One transformer is connected to the Fermi 2 345-kV switchyard, which is arranged in a nominal double breaker-double bus design. The remaining system service transformer is energized from the 120-kV switchyard through the 120/13.2-kV transformer 1 with an alternate through 120/13.8/13.8-kV transformer CTG II at the Fermi 1 site.

Onsite standby emergency power is provided from a four-diesel split-bus arrangement that is located in the RHR complex Category I structure near the reactor building. The diesel generators are sized to adequately carry the load necessary to shut down the reactor during a LOCA coincident with a complete loss of offsite power. Battery power is available for loads through two sets of 260/130-V dc Category I station batteries. The batteries furnish power to redundant essential loads. A highly reliable source of 48/24-V dc power is available for neutron monitoring and certain other instrumentation. In addition, a balance-of-plant (BOP) 260/130-V dc battery provides dc power for BOP loads. The batteries are sized to provide adequate power to those loads for a period of not less than 4 hr without battery charger availability. The chargers are full sized and capable of handling the load requirements, while still providing the required float charge for the battery.

1.2.2.8 Radwaste Systems (Chapter 11)

The radioactive waste disposal systems and the radiation monitoring systems (RMS) are designed so that liquid, solid, and gaseous effluents are considerably below those specified in 10 CFR 20.

1.2.2.9 Nuclear Safety Systems and Engineered Safety Features

1.2.2.9.1 Reactor Protection System (Section 7.2)

The reactor protection system (RPS) initiates a rapid, automatic shutdown (scram) of the reactor. It acts in time to prevent fuel cladding damage and any nuclear system process barrier damage following operational transients. The RPS overrides all operator actions and process controls and is based on a fail-safe design philosophy that allows appropriate protective action even if a single failure occurs.

1.2.2.9.2 Neutron Monitoring System (Subsection 7.6.l)

Those portions of the neutron monitoring system (NMS) that provide high neutron flux signals to the RPS qualify as a nuclear safety system. The intermediate range monitors (IRMs) and average power range monitors (APRMs), which monitor neutron flux via in-core detectors, signal the RPS to scram in time to prevent fuel cladding damage as a result of overpower transients.

1.2.2.9.3 Control Rod Drive System (Subsection 4.5.2)

When a scram is initiated by the RPS, the CRD system inserts the negative reactivity necessary to shut down the reactor. Each rod is individually controlled by a hydraulic control unit (HCU). When a scram signal is received, high-pressure water, stored in an accumulator in the HCU, forces its control rod into the core.

1.2.2.9.4 Nuclear System Pressure Relief System (Subsection 5.2.2)

A pressure relief system, consisting of safety/relief valves mounted on the main steam lines, prevents excessive pressure inside the nuclear system following either abnormal operational transients or accidents.

1.2.2.9.5 Reactor Core Isolation Cooling System (Subsection 5.5.6)

The reactor core isolation cooling (RCIC) system provides makeup water to the RPV when the vessel is isolated. The RCIC system uses a steam-driven turbine pump unit and operates automatically, with sufficient coolant flow in time to maintain adequate water levels in the RPV.

1.2.2.9.6 Primary Containment (Section 6.2)

The primary containment (Mark I containment) is a steel plate pressure vessel consisting of a light bulb-shaped drywell and a torus-shaped pressure suppression chamber. The primary containment is designed in accordance with the 1968 ASME Boiler and Pressure Vessel Code, Class B Vessel, including the 1969 summer addenda. The basic objective of the primary containment is to provide the capability, in the event of a postulated LOCA, of limiting the release of fission products within the values specified in 10 CFR 50.67 or 10 CFR 100.

1.2.2.9.7 Primary Containment and Reactor Isolation System (Subsection 6.2.4)

The containment isolation system consists of the isolation valves and controls required for the timely isolation of the containment in the event of incidents when the free release of containment contents cannot be permitted. The reactor isolation system consists of the isolation valves and controls required for the timely isolation of the RPV in the event of incidents when the fuel must be prevented from failing.

1.2.2.9.8 Secondary Containment (Section 6.2)

The reactor building, in conjunction with the reactor building heating and ventilation system and the standby gas treatment system (SGTS), constitutes the secondary containment. The primary purpose of the secondary containment is to minimize the ground-level release of airborne radioactive materials and provide means for a controlled release of the building atmosphere.

The reactor building is a cast-in-place reinforced-concrete structure enclosing the primary containment. The superstructure of the reactor building is composed of structural steel and steel siding.

1.2.2.9.9 Main Steam Line Isolation Valves (Subsection 5.5.5)

All pipelines that penetrate the primary containment, offering a potential release path for radioactive material, are provided with redundant isolation capabilities. The main steam lines, because of their large size and large mass flow rates, are given special isolation consideration. The automatic isolation valves in each main steam line, immediately inside and outside the primary containment, are powered by both pneumatic pressure and spring force. These valves fulfill the following objectives:

a. Prevent excessive damage to the fuel barrier by limiting the loss of reactor coolant from the RPV as a result of (1) a major leak in the steam piping outside the primary containment, or (2) a malfunction of the pressure control system causing excessive steam flow from the RPV

b. Limit the release of radioactive materials by closing the nuclear system process barrier in the event of a gross release of radioactive materials from the fuel to the reactor cooling water and steam

c. Limit the release of radioactive materials by closing the primary containment barrier in the event of a major leak from the nuclear system inside the primary containment.

A third, motor-operated, main steam isolation valve (MSIV) is provided in each main steam line to limit postulated leakage. See Subsection 6.2.6.

1.2.2.9.10 Main Steam Line Flow Restrictors (Subsection 5.5.4)

A venturi-type flow restrictor is installed in each steam line. These devices limit the loss of coolant from the RPV before the MSIVs are closed, in case of a main steam line break outside the primary containment.

1.2.2.9.11 Emergency Core Cooling System (Section 6.3)

A number of functions of the ECCS are provided to limit fuel cladding temperatures to minimize the release of radioactive material and to ensure the continued functional capability of the containment facility if a breach in the nuclear system process barrier results in a loss of reactor coolant. The four functions of the ECCS are presented in the following paragraphs.

1.2.2.9.11.1 High Pressure Coolant Injection System

The high pressure coolant injection (HPCI) system provides and maintains an adequate coolant inventory inside the RPV. This limits fuel cladding temperature, which may result from postulated small breaks in the nuclear system process barrier. A high-pressure system is needed for small breaks because the RPV depressurizes slowly, preventing low-pressure systems from injecting coolant. Also, the HPCI system reduces RPV pressure rapidly, permitting operation of the low-pressure systems. The HPCI system includes a turbine-driven pump powered by reactor steam. The system is designed to accomplish its function on a short-term basis, without reliance on plant auxiliary power supplies other than the dc power supply.

1.2.2.9.11.2 Automatic Depressurization System

The automatic depressurization system (ADS) rapidly reduces RPV pressure in a LOCA situation in which the HPCI system fails to maintain the RPV water level. The depressurization provided by the system enables the low-pressure ECCS to deliver cooling water to the RPV. The ADS uses some of the relief valves that are part of the nuclear system pressure relief system. The automatic relief valves are arranged to open on conditions indicating that a break in the nuclear system process barrier has occurred, and that the HPCI system is not delivering sufficient cooling water to the RPV to maintain the water level above a preselected value. The ADS will not be activated unless either the core spray or low pressure coolant injection (LPCI) system pumps are operating. This ensures that adequate cooling will be available so that boiling will not occur at the reduced pressure.

1.2.2.9.11.3 Core Spray System

The core spray system consists of two independent pump loops that deliver cooling water to independent spray spargers over the core. The system is actuated by conditions indicating that a breach exists in the nuclear system process barrier. Water is delivered to the core after RPV pressure is reduced. This system provides the capability of cooling the fuel by spraying water onto the core. Either of the core spray loops is capable of limiting fuel cladding temperature to less than 2200°F following a LOCA.

1.2.2.9.11.4 Residual Heat Removal - Low Pressure Coolant Injection Mode

The LPCI is an operating mode of the RHR system, but is discussed here because the LPCI mode acts as an ESF in conjunction with the other functions of the ECCS. The LPCI system uses the pump loops of the RHR system to inject cooling water at low pressure into an undamaged reactor recirculation loop. The LPCI is actuated by conditions indicating a breach in the nuclear system process barrier. Water is delivered to the core after RPV pressure is reduced. The LPCI operation, together with the core shroud and jet pump arrangement, provides the capability of core reflooding, following a LOCA, in time to prevent fuel cladding temperature from exceeding 2200°F.

1.2.2.9.12 Residual Heat Removal System - Containment Cooling Mode (Section 6.3)

The containment cooling subsystem is placed in operation to limit the temperature of the water in the suppression pool following a design-basis LOCA. In the containment cooling mode of operation, the RHR pumps take suction from the suppression pool and pump the water through the RHR system heat exchangers. Cooling takes place by transferring heat to the RHRSW system. The primary coolant is then discharged back to the suppression pool.

Another portion of the RHR system sprays water into the primary containment as an augmented means of removing energy from the containment following a LOCA. This capability is in excess of the required emergency heat removal capability and can be placed in service at the discretion of the operator.

1.2.2.9.13 Control Rod Velocity Limiter (Subsection 4.5.2.1)

A control rod velocity limiter is attached to each control rod to limit the velocity at which it can fall out of the core should it become detached from its CRD. This action limits the rate of reactivity insertion resulting from a control rod drop accident. The limiters contain no moving parts.

1.2.2.9.14 Control Rod Drive Housing Supports (Subsection 4.5.3)

The CRD housing supports are located underneath the RPV near the control rod housings. The supports limit the travel of a control rod should a control rod housing become ruptured. The supports prevent a nuclear excursion as a result of a housing failure and thus protect the fuel barrier.

1.2.2.9.15 Standby Gas Treatment System (Subsection 6.2.3)

The SGTS consists of two identical 100 percent equipment and filter trains for the plant. On detection of radioactivity or conditions that could lead to a release of radioactivity, the SGTS functions to minimize the release-related offsite dose rates by permitting the venting and purging of both the primary and secondary containment atmospheres under accident or abnormal conditions, and at the same time containing any airborne particulate or halogen contamination that might be present. Either train may be considered as an installed spare, with the other train being capable of passing the required amount of air. Either train alone is capable of exchanging the total reactor building air volume once in a 24-hr period.

Each equipment train contains an electric heater, a prefilter, a high-efficiency particulate filter (water and fire resistant), an iodine filter (fire resistant), a fan, and associated instrumentation.

The primary containment can be purged through the SGTS.

1.2.2.9.16 Onsite AC Power Supply (Subsection 8.3.1)

The onsite ac power supply provides sufficient power to those devices necessary to produce a safe shutdown with subsequent reactor decay heat removal should normal offsite power not be available. Power is derived from four EDGs housed in a Category I structure (RHR complex) located near the reactor building. The EDGs are installed in division pairs. Either division pair is capable of completely maintaining itself and the safety loads it supplies for 7 days. The entire standby power supply system is independent of offsite power.

1.2.2.9.17 DC Power Supply (Subsection 8.3.2)

The dc power supply provides power to those safety devices receiving their motive and/or control power from the station battery systems. The batteries are redundant and each has a battery charger capable of providing the full load capacity and maintaining the float charge on the battery.

1.2.2.9.18 Ultimate Heat Sink (Residual Heat Removal Complex) Section 6.3 and Subsection 9.2.5)

The RHR complex provides cooling for the RHR system, EESW, and EDGs. The RHR complex consists of mechanical-draft cooling towers, cooling water reservoirs, RHR, and emergency equipment cooling and EDG cooling service water pumps. The RHR complex also contains the EDGs. (See Figures 1.2-25 through 1.2-31.)

1.2.2.9.19 Main Steam Line Radiation Monitor System (Subsection 11.4.3.8.2.3)

The main steam line radiation monitor system consists of four gamma radiation channels located external to the main steam lines just outside the primary containment. The monitors are designed to detect a gross release of fission products from the fuel. On detection of high radiation, the trip signals generated by the monitors are used to isolate the reactor water sample system, trip condenser mechanical vacuum pumps, and trip glad seal exhausters.

1.2.2.9.20 Fuel Pool Ventilation Exhaust Radiation Monitor System (Subsection 11.4.3.8.2.11)

The fuel pool ventilation exhaust radiation monitor system consists of four radiation monitors arranged to monitor the activity level of the ventilation exhaust from the fuel pool area. On detection of high radiation, the SGTS is automatically started, the primary containment vent valves are closed, the reactor building vent system is isolated, the control center is isolated, and control center emergency recirculation is initiated.

1.2.2.9.21 Emergency Equipment Cooling Water System (Subsection 9.2.2)

Equipment required for a safe shutdown of the reactor is cooled by the EECWS, which is cross connected to the RBCCWS for normal operation. The EECW is isolated and is cooled by the ultimate heat sink (RHR complex) for emergency operation. The EECWS is designed to Category I requirements.

1.2.2.9.22 Combustible Gas Control (Subsections 6.2.5 and 9.3.6)

The NRC amended 10 CFR 50.44, “Standards for combustible gas control system in light-water-cooled power reactors” on October 16, 2003 to eliminate the requirements for hydrogen recombiners. The hydrogen recombiner Technical Specification requirements were subsequently removed by License Amendment 159, dated March 15, 2004. Regulatory Guide 1.7 was revised in March 2007 to reflect the amended 10 CFR 50.44. The Combustible Gas Control System (CGCS) has been retired in place with its electrical circuits de-energized and fluid process piping isolated from primary containment with redundant locked-closed isolation valves. Combustible gas control of the primary containment is provided by inerting the primary containment with nitrogen.

1.2.2.9.23 Instrumentation and Control Power Supply System Subsection 8.3.1)

The purpose of the instrumentation and control power supply system is to provide a reliable source of 120-V ac regulated power where necessary, for analog instrumentation, solenoid valves, and logic relaying for certain specific systems. These systems include: core spray, RHR, radwaste control, and NSSS process instrumentation.

1.2.2.9.24 Main Control Room Emergency Ventilation System (Section 6.4)

A main control room emergency ventilation system is provided to protect the main control room operators against radiation, smoke, or any noxious chemical release. It consists of an emergency makeup (pressurizing) and a control center recirculation filter train with 100 percent redundant active components.

1.2.2.9.25 Engineered Safety Features Ventilation Cooling System (Subsection 6.2.l.2)

All ESF equipment is provided with ventilation fans and/or cooling units to maintain design temperatures if the normal ventilation system is isolated. Redundant divisional ESF equipment is supplied with its own independent ventilation equipment powered by the corresponding division of the ESF bus.

1.2.2.10 Special Safety Systems

1.2.2.10.1 Standby Liquid Control System (Subsection 4.5.2.4)

Although not intended to provide prompt reactor shutdown, like the control rods, the standby liquid control system (SLCS) provides a redundant, independent, and different way to bring the nuclear fission reaction to subcriticality and maintain subcriticality as the reactor cools. The system permits an orderly and safe shutdown in the event that control rods cannot be inserted into the reactor core in sufficient number to accomplish shutdown in the normal manner. The system is sized to counteract the positive reactivity effect in decreasing power from rated power to the cold-shutdown condition.

The SLCS is also credited for injecting sodium pentaborate into the reactor coolant system after a design basis LOCA in order to control ECCS water pH to prevent iodine re-evolution. The SLCS can be manually initiated to provide this function.

1.2.2.10.2 Plant Equipment Outside the Main Control Room To Effect Reactor Shutdown (Section 7.5)

Instrumentation and controls necessary to meet the requirements of 10 CFR 50, Appendix A, Criterion 19, have been provided on a remote shutdown panel located outside the main control room. Details of the instruments and controls provided on the shutdown panels and the procedures required for carrying out a safe and orderly shutdown are described fully in Subsection 7.5.1.5.

Additionally, local shutdown panels are provided to meet the requirements of 10 CFR 50, Appendix R. These panels are provided in the event a fire causes a loss of control from the main control room. Details on achieving reactor shutdown in this event are provided in Subsection 7.5.2.5.

1.2.2.11 Nuclear System Process Control and Instrumentation

1.2.2.11.1 Reactor Manual Control System (Subsection 7.7.1.1)

The reactor manual control system (RMCS) provides the means by which control rods are positioned from the main control room for gross power control. The system operates valves in each HCU to change control rod position. Only one control rod can be manipulated at a time. The RMCS includes the logic that restricts control rod movement (rod block), under certain conditions, as a secondary control.

1.2.2.11.2 Recirculation Flow Control System (Subsection 7.7.1.2)

The recirculation flow control system (RFCS) controls the speed of the reactor recirculation pumps. Adjusting the pump speed changes the coolant flow rate through the core, thereby changing the core power level.

1.2.2.11.3 Neutron Monitoring System (Subsection 7.6.1.13)

The NMS is a system of in-core neutron detectors and out-of-core electronic monitoring equipment. The system provides indication of neutron flux, which can be correlated to thermal power level, for the entire range of flux conditions that can exist in the core. The source range monitors SRMs and the IRMs provide flux level indications during reactor startup and low power operation. The local power range monitors (LPRMs) and APRMs allow assessment of local and overall flux conditions during power range operation. Rod block monitors (RBMs) are provided to prevent rod withdrawal when reactor power should not be increased at the existing reactor coolant flow rate and also function to prevent local fuel damage. The flux mapping and calibration subsystem provides a means to calibrate individual monitors with traveling in-core probes.

1.2.2.11.4 Refueling Interlocks (Section 7.6.1.1 and Subsection 9.1.4)

A system of interlocks that restricts movement of refueling equipment and control rods when the reactor is in the refueling mode prevents an inadvertent criticality during refueling operations. The interlocks back up procedural controls that have the same objective. The interlocks affect the refueling bridge, refueling bridge hoists, fuel grapple, and control rods.

1.2.2.11.5 Reactor Pressure Vessel Instrumentation (Section 5.6)

In addition to instrumentation for the nuclear safety systems and ESFs, instrumentation is provided to monitor and transmit information that can be used to assess both the condition existing inside the RPV and the physical condition of the vessel itself. This instrumentation monitors RPV parameters such as pressure, water level, surface temperature, internal differential pressures, coolant flow rates, and top head flange leakage.

1.2.2.11.6 Integrated Plant Computer System (Subsection 7.6.1.9)

The Integrated Plant Computer System (IPCS) includes the following process monitoring functions:

a. Scan, Log and Alarm (SLA)

b. Man-Machine Interface (MMI)

c. Data Archival

d. Nuclear Steam Supply System (NSSS)

e. Balance of Plant (BOP)

f. Emergency Response

   1. Safety Parameter Display System (SPDS)

   2. Emergency Response Data System (ERDS)

g. Meteorological (MET)

h. Transient Recording and Analysis (TRA)

i. External System Interfaces

1.2.2.11.7 Reactor Coolant Pressure Boundary Leakage Detection System (Subsection 5.2.7)

The nuclear leak detection system consists of temperature, pressure, flow, and fission product sensors with associated instrumentation and alarms. This system detects and annunciates leakage in the following systems:

a. Main steam lines

b. Reactor water cleanup

c. Residual heat removal

d. Reactor core isolation cooling

e. High pressure coolant injection

f. Instrument lines.

Small leaks are generally detected by temperature and pressure changes, fillup rate of drain sumps, and fission product concentration inside the primary containment. Large leaks are also detected by changes in reactor water level and changes in process lines.

1.2.2.11.8 Emergency Core Cooling System Suction Piping Leakage Detection (Subsections 6.3.2.2.7and 7.6.1.8.12)

The ECCS leak detection system (LDS) uses the sump level and torus water level monitors to identify any failed line in the reactor building subbasement area and, thereby, prevents a loss of ECCS pump suction head.

1.2.2.11.9 Primary Containment Monitor System (Subsections 6.2.1.5 and 7.6.1.12)

The NRC amended 10 CFR 50.44, “Standards for combustible gas control system in light-water-cooled power reactors” on October 16, 2003 to eliminate the requirements for hydrogen recombiners. The hydrogen recombiner Technical Specification requirements were subsequently removed by License Amendment 159, dated March 15, 2004. Regulatory

Guide 1.7 was revised in March 2007 to reflect the amended 10 CFR 50.44. The Combustible Gas Control System (CGCS) has been retired in place with its electrical circuits de-energized and fluid process piping isolated from primary containment with redundant locked-closed isolation valves.

The primary containment monitor system (PCMS) is an advisory system only, which consists of measurements of hydrogen and oxygen concentration, particulate and gaseous radiation level, pressure, temperature, and water level in the drywell and suppression chamber. Hydrogen and oxygen monitors provide an operator with necessary information for the effective control of the nitrogen inerting system. The radiation monitor supplies information necessary for effective control of the SGTS as a primary containment atmospheric cleanup system and is a part of a redundant leak detection system, operating in conjunction with the drywell floor drain sump level indicating system. Hydrogen and radiation monitors also yield vital information regarding personnel access to the primary containment. The remaining instruments supply information on the overall conditions of the atmosphere in the drywell and suppression chamber and on water level and temperature in the suppression chamber.

1.2.2.11.10 Rodworth Minimizer Computer (Subsection 7.6.1.20)

The rodworth minimizer microcomputer system is a stand alone microcomputer-based system with an RWM operator display and a continuously operating self-test feature that enforces adherence to established startup, shutdown, and low power control rod procedures. The RWM prevents rod motion under low power conditions if the rod being moved is not moved in accordance with a preplanned pattern. The effect of the RWM is to limit the reactivity worth of the control rods by enforcing adherence to the preplanned rod pattern.

1.2.2.12 Power Conversion System Process Control and Instrumentation

1.2.2.12.1 Pressure Regulator and Turbine Generator Control (Subsection 10.4.4)

The pressure regulator maintains control of the turbine control and bypass valves to allow proper generator and reactor response to system load demand changes while also maintaining the nuclear system pressure essentially constant.

The turbine-generator speed-load controls act to maintain the turbine (generator frequency) at constant speed.

1.2.2.12.2 Feedwater Control System (Subsection 7.7.1.3)

A three-element controller is used to regulate the feedwater system so that the proper water level is maintained in the RPV. The control system uses main steam flow rate, RPV water level, and feedwater flow rate signals. The feedwater control signals are used to control the two turbine-driven feedwater pumps.

1.2.2.12.3 Turbine Generator Overspeed Trip System (Subsection 10.2.2)

The turbine generator overspeed trip system protects the turbine generator on overspeed. The system has overspeed trip mechanisms (four magnetic speed pickups and two overspeed trip rings), which will shut down the turbine, closing all valves (turbine high-pressure stop valves, control valves, low-pressure intercept valves, and low-pressure stop valves), on detection of the overspeed condition.

1.2.2.13 Electrical Power System Control and Instrumentation (Chapter 8)

The electrical power system is monitored by indicating and/or recording devices to account for the power generated at the plant, and to determine the auxiliary power usage required to achieve this level of generation. System requirements will govern the generator excitation level needed for the desired megavar output from the generator at the required terminal voltage. Wattmeters, ammeters, varmeters, etc., will be used to indicate electrical conditions. Selected inputs to the IPCS will record conditions for later comparison or record purposes.

1.2.2.14 Radiation Monitoring and Control (Chapters 11 and 12)

1.2.2.14.1 Process and Effluent Radiological Monitoring System (Section 11.4)

Radiation monitors are provided on various lines to monitor for either radioactive materials, released to the environs via process liquids and gases, or process system malfunctions. Subsection 11.4.1 provides the complete listing of all radiation monitoring systems.

1.2.2.14.2 Area Radiation Monitoring (Subsection 12.1.4)

The area radiation monitoring system (ARMS) provides indication in the relay room and recording and alarm in the main control room of abnormal radiation levels in plant work areas where radioactive material may be stored, handled, or inadvertently introduced. In addition, selected local areas have local alarm and/or indication, where necessary, to warn personnel of a substantial rapid increase in radiation levels.

1.2.2.14.3 Site Environs Radiation Monitoring (Section 11.6)

The site environs radiation monitoring program includes the use of passive dosimeters for direct radiation measurement and the orderly collection of samples for laboratory analyses. These analyses include airborne, aquatic, and terrestrial radiological measurements.

The program is designed to document: (1) background levels of direct radiation and concentrations of radionuclides that exist in aquatic and terrestrial ecosystems before and during plant operation; and (2) the concentrations of radionuclides that could be attributable to the operation of Fermi 2.

1.2.2.14.4 Liquid Radwaste Control (Section 11.2)

The liquid radwaste system is designed to segregate, collect, and process waste generated throughout the plant. Processing of the waste is normally sufficient to allow recycling of the wastewater. Ties exist among all of the liquid radwaste subsystems to provide backup processing in the event of failure of one subsystem.

1.2.2.14.5 Solid Radwaste Control (Section 11.5)

The solid radwaste system is designed to handle and package solid waste produced by the plant. The waste, depending on its radioactivity and type, will be packaged for offsite shipment in accordance with applicable regulations.

1.2.2.14.6 Gaseous Radwaste Control (Section 11.3)

The gaseous radwaste system processes and controls the release of gaseous radioactive wastes to the site environs so that the total radiation exposure to persons outside the controlled area does not exceed the limits of 10 CFR 20 and 10 CFR 50.

Continuous radiation monitors provide indications of radioactive release from the reactor by monitoring the offgas equipment trains. The offgas system radiation monitors are used to monitor and alarm on indication of high radioactivity.

1.2.2.15 Auxiliary Systems

1.2.2.15.1 New and Spent-Fuel Storage (Subsections 9.1.1 and 9.1.2)

New fuel may be stored in a dry vault in the reactor building subject to the restrictions discussed in Section 9.1.1.2.1. Irradiated (spent) fuel is stored underwater in the reactor building in the spent fuel pool or in dry storage casks at the Independent Spent Fuel Storage Installation.

1.2.2.15.2 Fuel Pool Cooling and Cleanup System (Subsection 9.1.3)

A fuel pool cooling and cleanup system (FPCCS) removes decay heat from spent fuel stored in the fuel pool and maintains a specified water temperature, purity, clarity, and level.

1.2.2.15.3 Nitrogen Inerting System (Containment) (Subsection 9.3.6)

The nitrogen inerting system is provided primarily to maintain a nitrogen atmosphere (inerted) inside the primary containment, and also to supply pressurized nitrogen for pneumatic service inside the primary containment and distribution throughout the plant.

1.2.2.15.4 Heating, Ventilation, and Air Conditioning Systems (Sections 6.4 and 9.4)

The objective of the plant HVAC systems is to provide a thermal environment and air quality to ensure personnel comfort, health, and safety and efficient equipment operation and integrity. In addition, the HVAC system for the main control room and the RHR ventilation systems and the fan-coil cooling units located in the reactor/auxiliary building have the further objective to operate under postulated accident conditions.

The HVAC systems provide individual air supply and exhaust systems as described in Section 9.4 for each system. Normally airflow will be routed from areas of lesser to areas of progressively greater potential contamination prior to being exhausted from the building. The ventilation arrangement will protect personnel and equipment from airborne contaminants and temperature extremes. The ventilation air exhaust from each ventilation system is located in such a manner as to minimize the possibility of the same air as was exhausted being drawn into a fresh air intake. Exhaust of potentially radioactive gases will be monitored. If the radioactivity in the exhaust systems exceeds a predetermined level, the ventilation system is shut down and the system intake and exhaust dampers are closed.

1.2.2.15.5 Normal Auxiliary AC Power (Section 8.3)

Normal auxiliary power is provided from two system service transformers. One transformer is connected to the Fermi 2 345-kV switchyard, which is arranged as a highly reliable double breaker-double bus design. The remaining system service transformer is energized from the 120-kV switchyard through the 120/13.2-kV transformer at the Fermi 1 site.

1.2.2.15.6 Reactor Building Closed Cooling Water System (Subsection 9.2.2)

The RBCCWS is a closed-loop system that provides parallel flow cooling to auxiliary equipment in the drywell and the reactor building. The closed loop provides a barrier between contaminated systems and the GSW discharged to the circulating water reservoir. Heat is removed from the closed loop by the GSW system.

1.2.2.15.6.1 RBCCW Supplemental Cooling (Subsection 9.2.2)

RBCCW is designed with two RBCCW supplemental cooling loops. These loops operate using separate pumps and heat exchangers using chilled water from the supplemental cooling chilled water system to cool the RBCCW supplied to the EECW loops during normal plant operation. RBCCW supplemental cooling operation is optional, intended for use when the GSW supply temperature exceeds approximately 60°F.

1.2.2.15.6.2 Supplemental Cooling Chilled Water (Subsection 9.2.9)

The supplemental cooling chilled water (SCCW) system is a chilled water closed loop system designed to cool the water that is supplied to EECW by the RBCCW supplemental cooling loops.

The SCCW system transfers the heat it has removed from the RBCCW via the supplemental RBCCW system to the GSW system via mechanical chillers. The chillers are designed to operate using GSW supply water at 60°F or greater.

1.2.2.15.7 Turbine Building Closed Cooling Water System (Subsection 9.2.7)

The TBCCWS is designed to cool the auxiliary plant equipment associated with the power conversion systems over the full range of normal plant operation.

1.2.2.15.8 Water Systems

1.2.2.15.8.1 Circulating Water System (Subsection 10.4.5)

The circulating water system is a closed-loop system designed to condense steam exhausting into the main condenser from the main turbine. The system consists of five circulating water pumps, two vertical natural-draft cooling towers, piping, and a cooling reservoir. The circulating water pumps are located in a circulating-water pump house adjacent to the reservoir.

1.2.2.15.8.2 General Service Water (Subsection 9.2.1)

The GSW system is designed to cool various non-safety-related plant auxiliary systems such as the RBCCW and the TBCCW during all normal plant operating modes. The GSW system also provides the source of makeup water for the plant FPS and serves as a source of makeup water for the RHR complex. The once-through GSW discharges into the station's circulating water system where its heat load is rejected in the two natural-draft cooling towers. The GSW thus serves as cooling tower makeup.

1.2.2.15.9 Compressed Air Systems (Subsection 9.3.1)

The service and instrument air systems provide a continuous supply of compressed air of suitable quality and pressure for instrument control and general plant use. The service air compressor and the instrument air compressors discharge into their respective air receivers. The air is then distributed throughout the plant. Instrument air is additionally filtered and dried prior to distribution throughout the plant.

1.2.2.15.10 Makeup Demineralized Water System(Subsection 9.2.3)

Potable water is demineralized by the makeup demineralizer system and is stored in the demineralized water storage tank.

1.2.2.15.11 Potable Water System (Subsection 9.2.4)

The potable water system provides the necessary supply of domestic water for the plant. The potable water is supplied by the Frenchtown Township Water Supply System to meet drinking water standards.

1.2.2.15.12 Plant Equipment and Floor Drainage(Subsection 9.3.3)

The equipment and floor drainage system is designed to collect liquid waste throughout the plant and discharge the radioactive waste to the radwaste system for processing. Separate drainage facilities are provided for nonradioactive waste.

The drainage system is also used to detect abnormal leakage in the ESF rooms.

1.2.2.15.13 Process Sampling Systems (Subsection 9.3.2)

The process sampling system provides process information that is required to monitor plant conditions and equipment performance. Representative liquid and gas samples are taken automatically and/or manually during normal plant operation for laboratory or on-line analyses.

1.2.2.15.14 Plant Communication Systems (Subsection 9.5.2)

Plant communications consist of a Hi-Comm system of loudspeakers and hand sets, two-way radio units on a unique wavelength, and main control room phones (hard-wired units) that use local phone jack connections at instrument panels and other selected areas.

1.2.2.15.15 Fire Protection System (Subsection 9.5.1 and Appendix 9A)

The FPS is designed to provide an adequate supply of water, CO_2, Halon, or chemicals to points throughout the plant area where fire protection may be required. Diversified fire alarm and fire suppression types are selected to suit the particular areas or hazards being protected. The water for the system is taken from Lake Erie, and constant pressure is provided by the FPS jockey pump. One electrically driven pump, one diesel-engine-driven pump, and the associated piping, valves, and hydrants are provided.

Chemical fire-fighting systems (portable extinguishers) are also provided as additions to, or in lieu of, the water fire-fighting system and the CO_2 and Halon flooding systems. The necessary instrumentation and controls are provided for the proper operation of the fire-fighting systems and for fire detection and annunciation.

1.2.2.15.16 Auxiliary Steam Boilers (Subsection 9.4.8)

The two auxiliary steam boilers are designed to provide low pressure steam for plant heating and to the radwaste evaporators. The boilers and their associated auxiliary equipment are located in the auxiliary boiler house. The boilers may be operated from the main control room.

Each boiler is designed to provide 50,000 lb/hr of l20-psia steam. Combined capacity of the two boilers will provide sufficient heating and radwaste evaporator steam during a shutdown for refueling.

1.2.2.15.17 Condensate Storage and Transfer System (Subsection 9.2.6)

The condensate storage and transfer system (CSTS) is designed to store and distribute condensate and demineralized water throughout the plant during normal and shutdown plant conditions. The condensate storage and return tanks are arranged to permit gravity feed to the condensate supply pumps and to the HPCI, RCIC, CRD, standby feedwater (SBFW), and core spray systems. During normal station operation, hotwell level is raised as necessary by vacuum dragging water to the hotwell from the CST or CRT. When the plant is shutdown, or when a greater flow is required, the normal, or if necessary the emergency, hotwell supply pumps will start and stop automatically depending on hotwell level.

The makeup demineralized storage tank feeds demineralized water transfer pumps, which supply water to the demineralized water service risers and the condensate storage tank.

1.2.2.15.18 Primary Containment Air Cooling and Handling System (Subsection 9.4.5)

The drywell cooling system's primary function is to maintain the temperature of the drywell atmosphere within design conditions. The system uses air-to-water cooling coils with water being supplied by the RBCCW system during normal operating conditions and by the EECW system during abnormal conditions. However, high drywell pressure will automatically close the EECW supply line outboard containment isolation valves.

1.2.2.16 Shielding (Section 12.1)

Shielding is designed so that the dose to personnel manning the main control room and the technical support center during the course of a postulated LOCA is less than 5 rem to the whole body, or its equivalent to any part of the body. For those Design Basis Accidents that are reanalyzed in accordance with Regulatory Guide 1.183, the shielding is shown to limit dose to the Control Room and TSC personnel to less than 5 rem TEDE. In addition, the shielding ensures that, during normal operation and plant shutdown for refueling and maintenance, the dose to personnel and the dose at the site boundary will be as low as reasonably achievable (ALARA) and within the limits specified in 10 CFR 20.

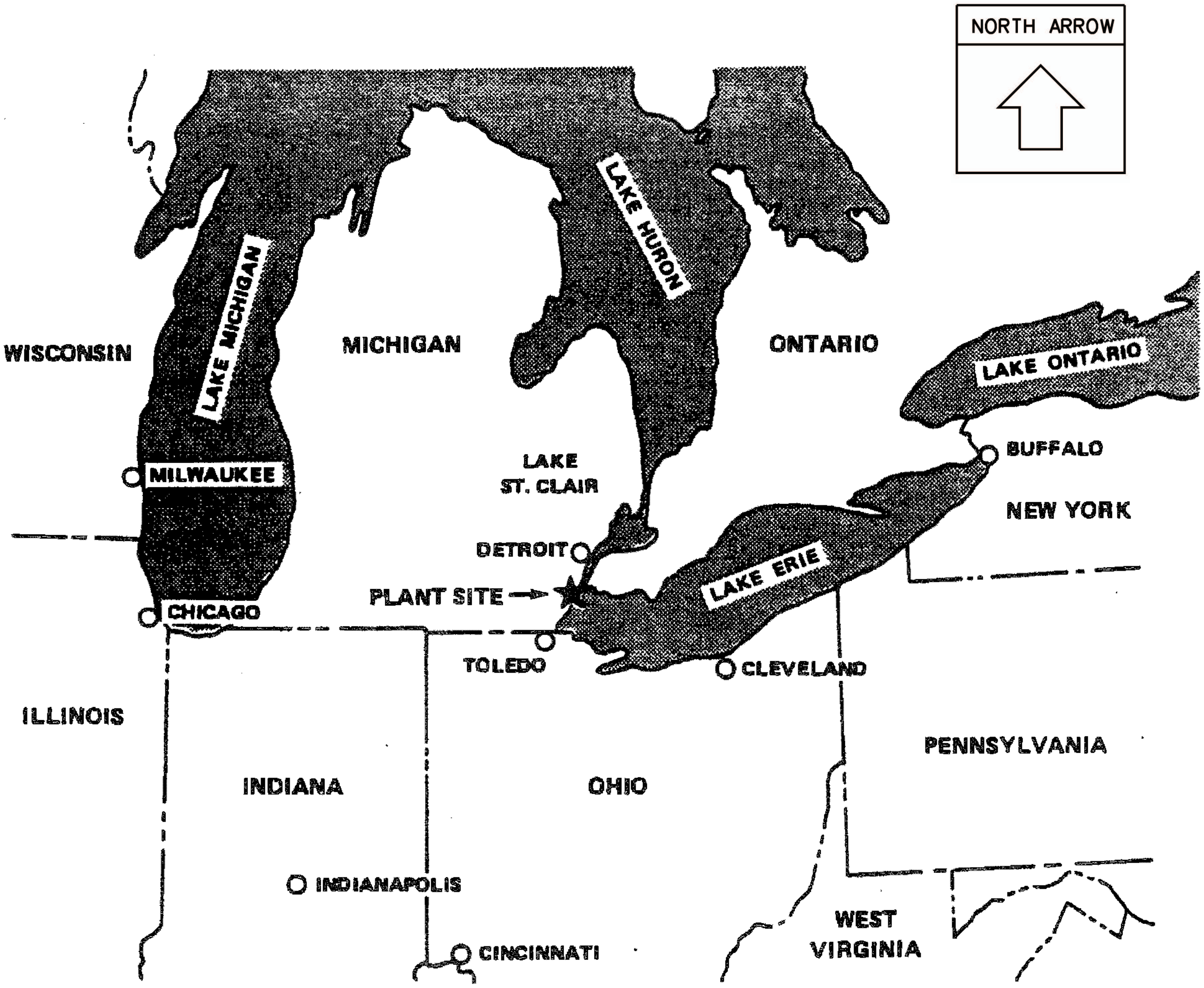

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FIGURE 1.2-1

PLANT SITE LOCATION

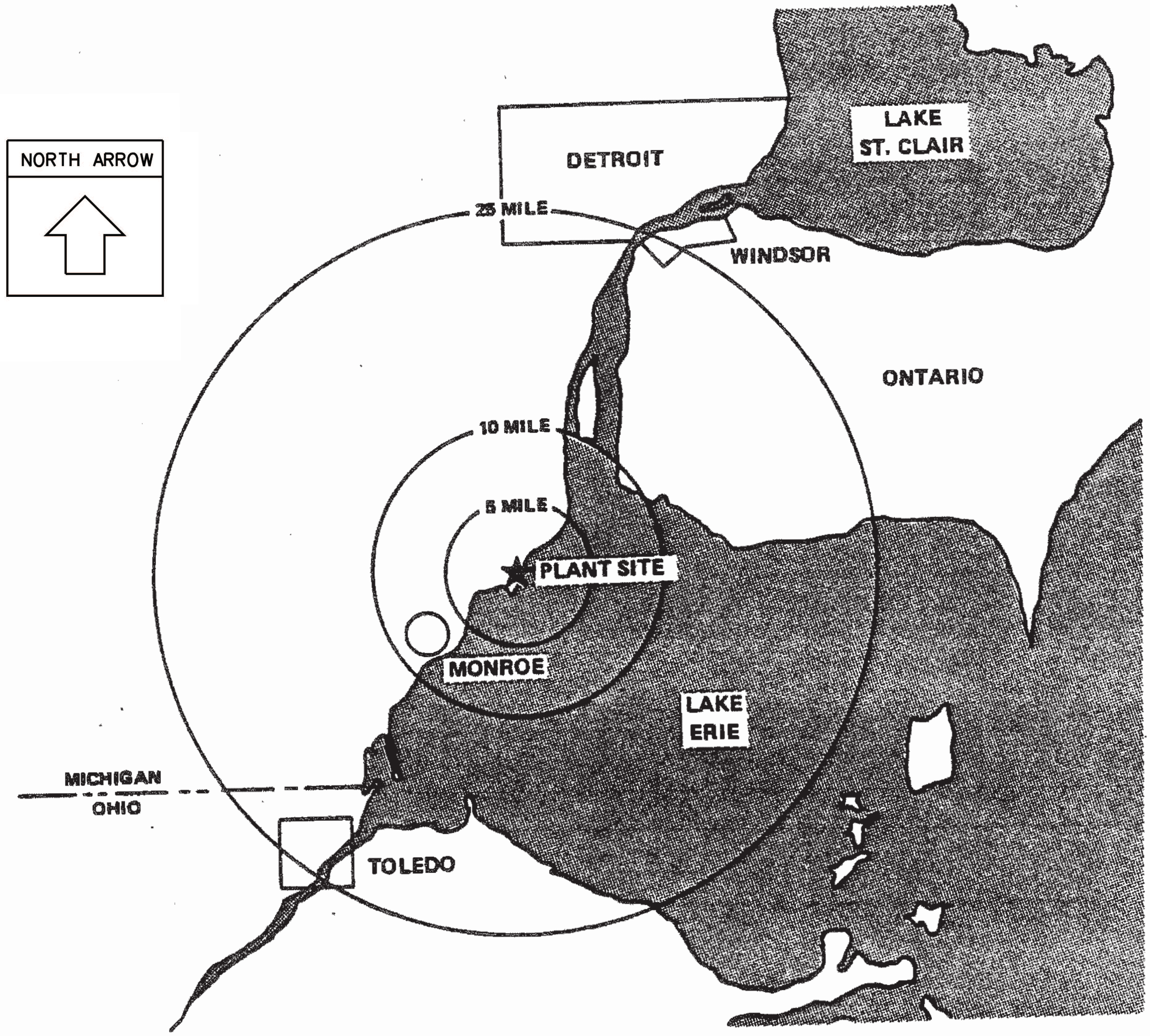

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FIGURE 1.2-2

GENERAL REGION OF THE FERMI SITE

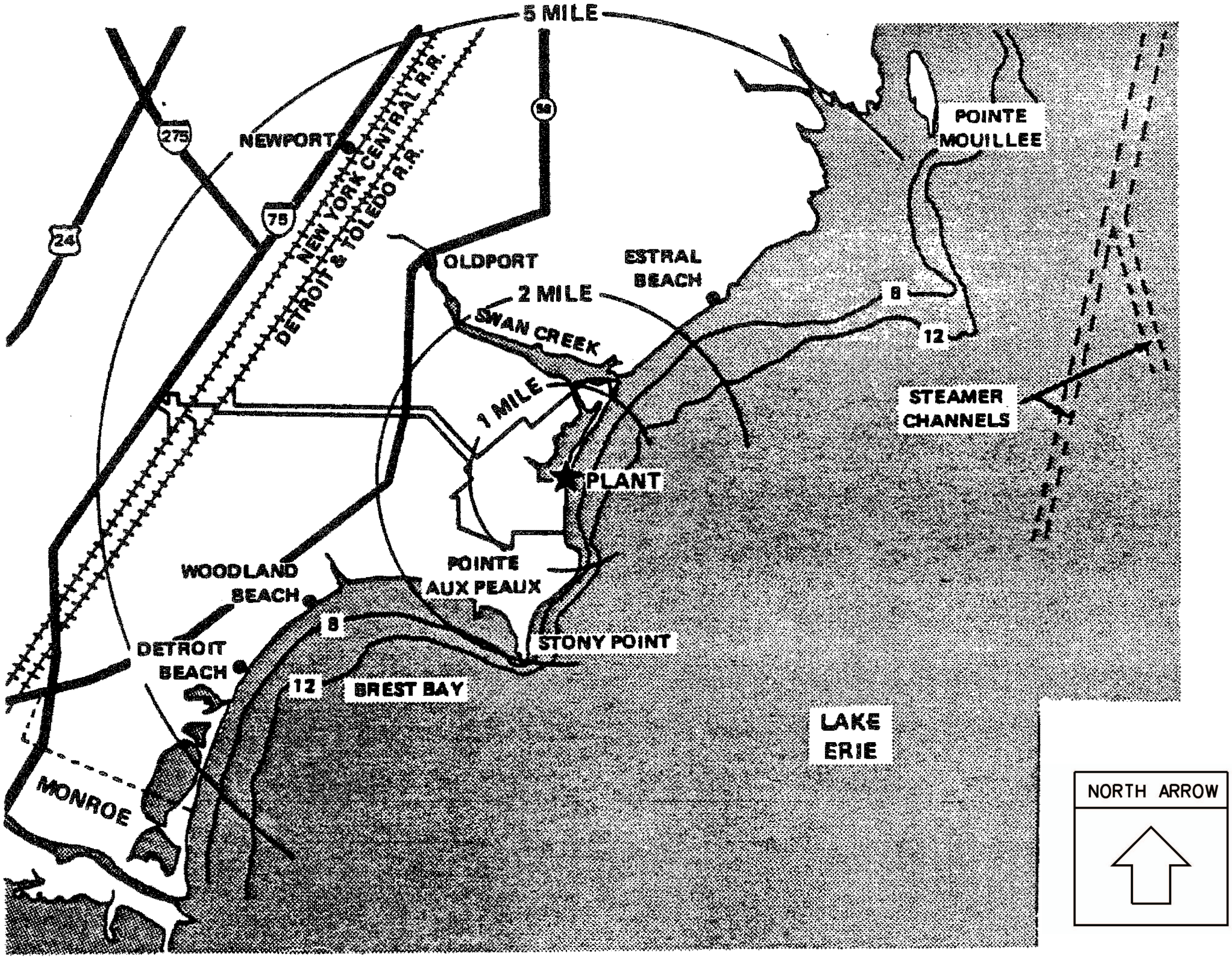

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FIGURE 1.2-3

IMMEDIATE SITE AREA

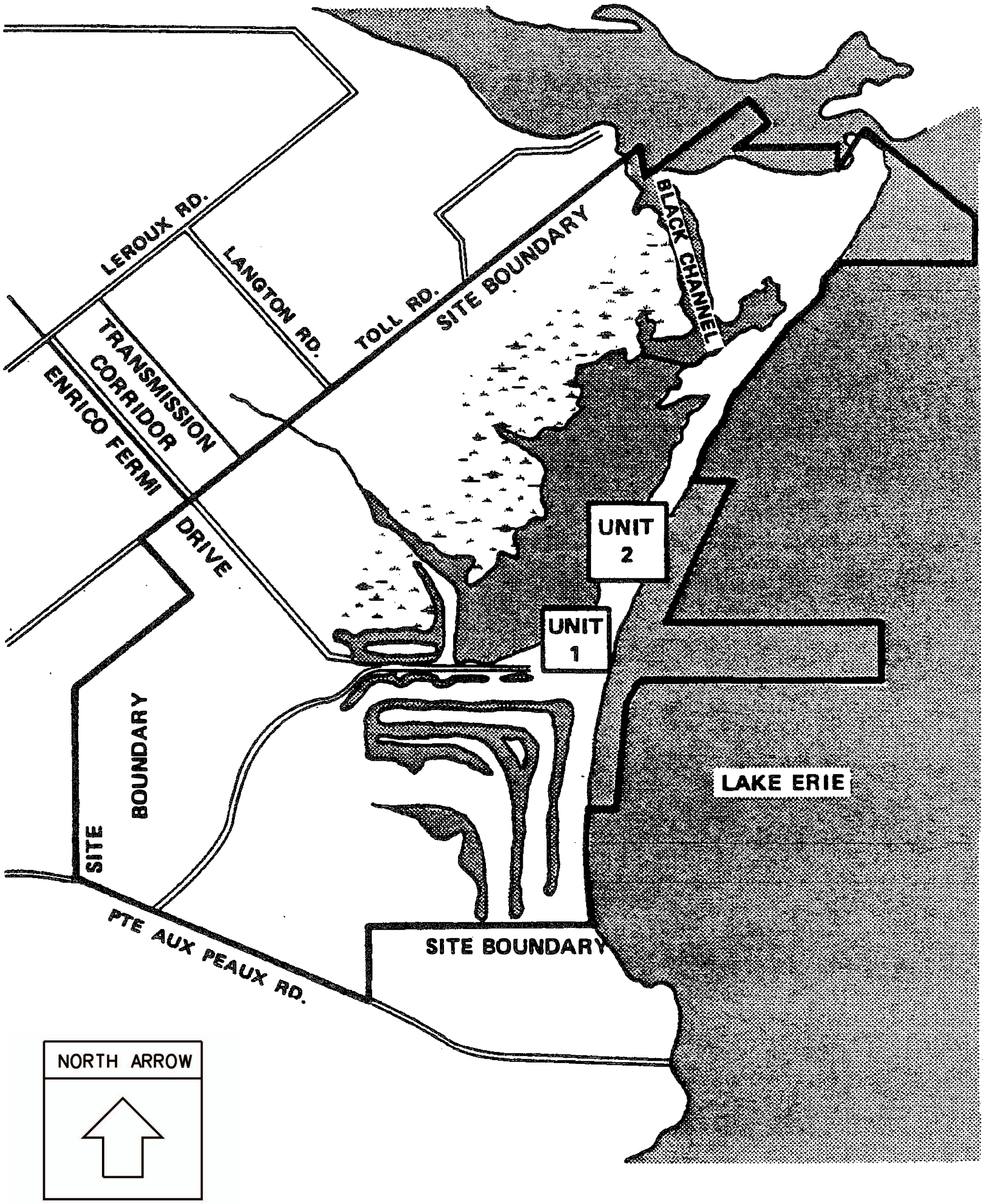

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FIGURE 1.2-4

SITE BOUNDARY

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Refer to Plant Drawing A-2102

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FIGURE 1.2-5

SITE PLOT PLAN

Figure Intentionally Removed
Refer to Plant Drawing A-2080

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FIGURE 1.2-6

GENERAL ARRANGEMENT DRAWING
SUBBASEMENT, REACTOR BUILDING, AND
HIGH-PRESSURE COOLANT INJECTION ROOM
ELEVATION 540.0 FT

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Refer to Plant Drawing A-2080

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FIGURE 1.2-7

GENERAL ARRANGEMENT DRAWING - BASEMENT REACTOR BUILDING ELEVATION 562.0 FT, TURBINE BUILDING ELEVATION 564.0 FT, AND RADWASTE BUILDING ELEVATION 557.5 FT

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Refer to Plant Drawing A-2081

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FIGURE 1.2-8

GENERAL ARRANGEMENT DRAWIING
FIRST FLOOR, REACTOR BUILDING

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Refer to Plant Drawing A-2081

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FIGURE 1.2-9

GENERAL ARRANGEMENT DRAWING
FIRST FLOOR, TURBINE BUILDING
FLOOR ELEVATION 583.5 FT

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Refer to Plant Drawing A-2082

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FIGURE 1.2-10

GENERAL ARRANGEMENT DRAWING
SECOND AND MEZZANINE LEVELS
REACTOR AND TURBINE BUILDING

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Refer to Plant Drawing A-2082

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FIGURE 1.2-11

GENERAL ARRANGEMENT DRAWING
SECOND FLOOR, TURBINE BUILDING

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Refer to Plant Drawing A-2082

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FIGURE 1.2-12

GENERAL ARRANGEMENT DRAWING
SECOND FLOOR, MEZZANINES
RADWASTE BUILDING

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Refer to Plant Drawing A-2083

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FIGURE 1.2-13

GENERAL ARRANGEMENT DRAWING
THIRD FLOOR, REACTOR BUILDING
FLOOR ELEVATION 643.5 FT

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Refer to Plant Drawing A-2083

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FIGURE 1.2-44
GENERAL ARRANGEMENT DRAWING
THIRD FLOOR, TURBINE BUILDING

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Refer to Plant Drawing A-2084

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FIGURE 1.2-15

GENERAL ARRANGEMENT DRAWING
FOURTH FLOOR, REACTOR BUILDING
FLOOR ELEVATION 659.5 FT

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Refer to Plant Drawing A-2084

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FIGURE 1.2-16

GENERAL ARRANGEMENT DRAWING
FOURTH FLOOR, TURBINE BUILDING
FLOOR ELEVATION 659.5 FT

Figure Intentionally Removed
Refer to Plant Drawing A-2085

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FIGURE 1.2-17

GENERAL ARRANGEMENT DRAWING
FIFTH FLOOR, REACTOR BUILDING
ELEVATION 677.5 FT AND 684.5 FT

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Refer to Plant Drawing A-2085

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FIGURE 1.2-18

GENERAL ARRANGEMENT DRAWING
FIFTH FLOOR, TURBINE BUILDING
ELEVATION 677.5 AND 684.5 FT

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Refer to Plant Drawing A-2086

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FIGURE 1.2-19

GENERAL ARRANGEMENT DRAWING
ROOF PLANS, TURBINE BUILDING

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Refer to Plant Drawing A-2042

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FIGURE 1.2-20

GENERAL ARRANGEMENT DRAWING
TRANSVERSE SECTION

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Refer to Plant Drawing A-2043

FIGURE 1.2-21

GENERAL ARRANGEMENT DRAWING
LONGITUDINAL SECTION

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Refer to Plant Drawing A-2035

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FIGURE 1.2-22

GENERAL ARRANGEMENT DRAWING
RADWASTE BUILDING, SECTION "A-A"

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Refer to Plant Drawing A-2034

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FIGURE 1.2-23

GENERAL ARRANGEMENT DRAWING
RADWASTE BUILDING. SECTION "B-B"

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Refer to Plant Drawing A-2034

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FIGURE 1.2-24

GENERAL ARRANGEMENT DRAWING
RADWASTE BUILDING
SECTIONS "C-C AND D-D"

Figure Intentionally Removed
Refer to Plant Drawing M-N-2026

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FIGURE 1.2-25

GENERAL ARRANGEMENT DRAWING
RESIDUAL HEAT REMOVAL COMPLEX
BASEMENT FLOOR ELEVATION 562.0 FT

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Refer to Plant Drawing M-N-2027

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FIGURE 1.2-26

GENERAL ARRANGEMENT DRAWING
RESIDUAL HEAT REMOVAL COMPLEX, GRADE FLOOR PLAN

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Refer to Plant Drawing M-N-2028

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FIGURE 1.2-27

GENERAL ARRANGEMENT DRAWING
RESIDUAL HEAT REMOVAL COMPLEX
UPPER FLOOR ROOF ELEVATION 617.0 FT

Figure Intentionally Removed
Refer to Plant Drawing M-N-2029

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FIGURE 1.2-28

GENERAL ARRANGEMENT DRAWING
RESIDUAL HEAT REMOVAL COMPLEX
ROOF PLAN

Figure Intentionally Removed
Refer to Plant Drawing M-N-2030

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FIGURE 1.2-29

GENERAL ARRANGEMENT DRAWING
RESIDUAL HEAT REMOVAL COMPLEX
SECTIONS "A-A" AND "B-B"

Figure Intentionally Removed
Refer to Plant Drawing M-N-2031

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FIGURE 1.2-30

GENERAL ARRANGEMENT DRAWING
RESIDUAL HEAT REMOVAL COMPLEX
SECTION "C-C"

Figure Intentionally Removed
Refer to Plant Drawing M-N-2032

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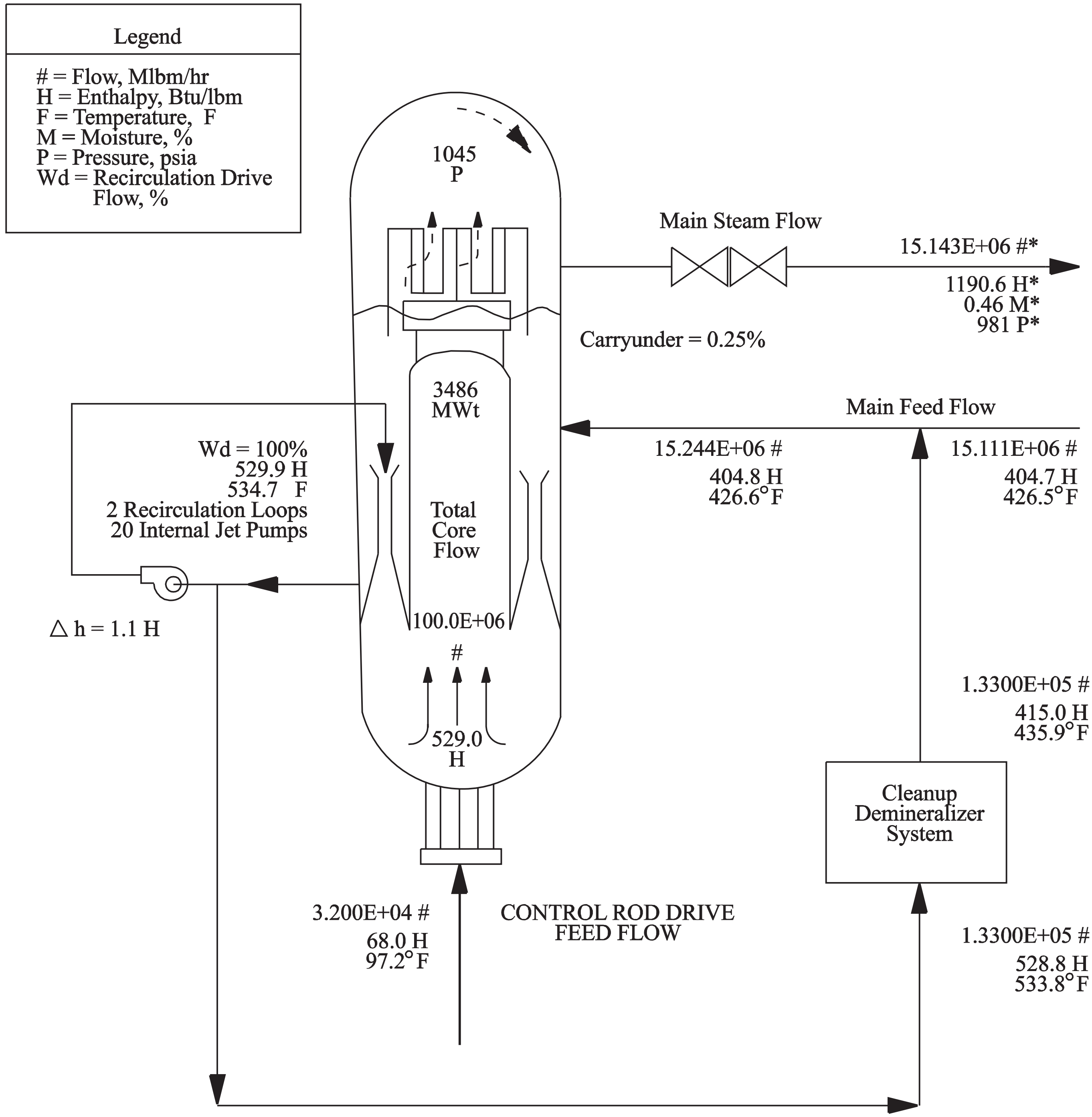
FIGURE 1.2-31

GENERAL ARRANGEMENT DRAWING
RESIDUAL HEAT REMOVAL COMPLEX
SECTION "D-D"



*Conditons at upsteam side of TSV

Core Thermal Power	3486.0
Pump Heating	10.6
Cleanup Losses	-4.4
Other System Losses	-1.2
Turbine Cycle Use	3491.0 MWt

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FIGURE 1.2-32

GE REACTOR SYSTEM HEAT BALANCE
RATED PERFORMANCE

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Refer to Plant Drawing C1C OUT

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FIGURE 1.2-33

GEC TURBINE - GENERATOR HEAT BALANCE
AT 100 PERCENT DESIGN FLOW

1.3 COMPARISON TABLES

This section highlights the principal design features of Fermi 2, and provides a comparison of its major features with other BWR facilities for which license applications had been made under 10 CFR 50 at the time of submittal of the original Fermi 2 FSAR.

The design of this facility was based on proven technology attained during the development, design, construction, and operation of BWRs of similar types. The data, performance characteristics, and other information presented herein are subject to revisions as the design of the referenced facilities evolves. However, the information presented is adequate for general comparison purposes and thus will not be subsequently revised.

1.3.1. Comparisons With Similar Facilities Designs

The similar facilities used for comparison are: (l) Brunswick Steam Electric Plant Units 1 and 2; (2) Browns Ferry Nuclear Plant Units 1, 2, and 3; (3) Cooper Nuclear Station; and (4) Edwin I. Hatch Unit No. 1. Of these facilities, Browns Ferry 1, 2, and 3 received operating permits on June 26, 1973, June 28, 1974, and July 2, 1976, respectively. Cooper received an operating permit on January 18, 1974. Hatch received an operating permit on August 6, 1974.

1.3.2. Nuclear System Design Characteristics

Table 1.3-1 summarizes the original design and operating characteristics of Fermi 2, as well as those of the similar facilities discussed in Subsection 1.3.1.

1.3.3. Power Conversion Systems Design Characteristics

Table 1.3-2 compares the original power conversion systems design characteristics of Fermi 2 with those of the similar facilities discussed in Subsection 1.3.1.

TABLE 1.3-1 NUCLEAR PLANTS PRINCIPAL PLANT DESIGN FEATURES COMPARISON[a]

	Fermi 2	Brunswick Units 1 & 2	Browns Ferry Units 1, 2, & 3	Cooper	Edwin I. Hatch Unit 1
Site					
Location	Monroe County, Michigan	Brunswick County, N. Carolina	Limestone County, Alabama	Nemaha County, Nebraska	Appling County, Georgia
Size of site, acres	1120	1200	840	1090	2100
Site ownership	Edison	CP&L	U.S. Government	CPPD	GPC
Plant ownership	Edison	CP&L	TVA	CPPD	GPC
Number of units on site	1	2	3	1	1
Plant-reactor warranted conditions					
Net electrical output, MWe	1093	821/unit	1075/unit	770	786
Gross electrical output, MWe	1154	847/unit	1098/unit	801	813
Turbine heat rate, Btu/kWh	(proprietary)	9816	10,231	10,142	10,218
Gross plant heat rate, Btu/kWh	10,296 net	10,120	10,243	10,187	10,227
Feedwater temperature, °F	420	420	376.1	367	387.4
Reactor pressure vessel					
Inside diameter, in.	251	218	251	218	218
Overall length inside, ft-in.	72-0	69-4	72-0	69-4	69-4
Design pressure, psig	1250	1250	1250	1250	1250
Wall thickness, in. (including clad)	6-7/16	5-17/32	6-5/16	5-17/32	5-17/32
Reactor coolant recirculation loops					
Location of recirculation loops	Primary containment system drywell structure	Primary containment system drywell structure	Primary containment system drywell structure	Primary containment system drywell structure	Primary containment system drywell structure
Number of recirculation loops	2	2	2	2	2
Pipe size, in.	28	28	28	28	28
Pump capacity (each), gpm	45,200	45,200	45,000	45,200	45,200
Number of jet pumps	20	20	20	20	20
Location of jet pumps	Inside reactor primary vessel	Inside reactor primary vessel	Inside reactor primary vessel	Inside reactor primary vessel	Inside reactor primary vessel
Reactor					

TABLE 1.3-1 NUCLEAR PLANTS PRINCIPAL PLANT DESIGN FEATURES COMPARISON[a]

	Fermi 2	Brunswick Units 1 & 2	Browns Ferry Units 1, 2, & 3	Cooper	Edwin I. Hatch Unit 1
Reactor warranted conditions					
Thermal output, MWt	3292	2436	3293	2381	2436
Reactor operating pressure, psig (steam dome)	1005	1005	1005	1005	1005
Total reactor core flow rate, lbs/hr	100.0×10^6	77×10^6	102.5×10^6	73.5×10^6	78.5×10^6
Main steam flow rate, lb/hr (warranted)	14.156×10^6	10.47×10^6	13.36×10^6	9.551×10^6	10.03×10^6
Reactor core description					
Lattice	8 x 8	7 x 7	7 x 7	7 x 7	7 x 7
Pitch of movable control rods, in.	12.0	12.0	12.0	12.0	12.0
Number of fuel assemblies	764	560	764	548	560
Number of movable control rods	185	137	185	137	137
Effective active fuel length, in	150	144	144	146	144
Equivalent reactor core diameter, in.	187.1	160.2	187.1	158.5	160.2
Circumscribed reactor core diameter, in.	198	169.7	197.8	169.7	169.7
Total weight UO_2, lb	348,904	272,850	372,373	267,095	272,850
Reactor fuel description					
Fuel material	UO_2	UO_2	UO_2	UO_2	UO_2
Fuel density, percent of theoretical	95	95	95	95	95
Fuel pellet diameter, in.	0.410	0.487	0.487	0.487	0.487
Fuel rod cladding material	Zircaloy-2	Zircaloy-2	Zircaloy-2	Zircaloy-2	Zircaloy-2
Fuel rod cladding thickness, in.	0.032	0.037	0.032/0.037	0.032/0.037	0.037
Fuel rod cladding process	Freestanding loaded tubes	Freestanding loaded tubes	Freestanding loaded tubes	Freestanding loaded tubes	Freestanding loaded tubes
Fuel rod outside diameter, in.	0.483	0.563	0.563	0.563	0.563
Length of gas plenum, in.	10.0	16.0	16.0	16.0	16.0

TABLE 1.3-1 NUCLEAR PLANTS PRINCIPAL PLANT DESIGN FEATURES COMPARISON[a]

	Fermi 2	Brunswick Units 1 & 2	Browns Ferry Units 1, 2, & 3	Cooper	Edwin I. Hatch Unit 1
Fuel rod pitch, in.	0.640	0.738	0.738	0.738	0.738
Fuel assembly channel material	Zircaloy-4	Zircaloy-4	Zircaloy-4	Zircaloy-4	Zircaloy-4
Reactor control					
Control rods					
Number	185	137	185	137	137
Shape	Cruciform	Cruciform	Cruciform	Cruciform	Cruciform
Material	B_4C granules compacted in SS tubes	B_4C granules compacted in SS tubes	B_4C granules compacted in SS tubes	B_4C granules compacted in SS tubes	B_4C granules compacted in SS tubes
Pitch, in.	12.0	12.0	12.0	12.0	12.0
Poison length, in.	143.0	143.0	143.0	143.0	143.0
Blade span, in.	9.75	9.75	9.75	9.75	9.75
Number of control material tubes for rod	76	76	76	76	76
Tube dimensions, in.	0.188 O.D. x 0.025-wall	0.188 O.D. x 0.025-wall	0.188 O.D. x 0.025-wall	0.188 O.D. x 0.025-wall	0.188 O.D. x 0.025-wall
Stroke, in.	144.0	144.0	144.0	144.0	144.0
Thermal-hydraulic data					
Heat transfer area per assembly, ft^2	97.998	86.513	86.513	86.513	86.513
Reactor core heat transfer area, ft^2	74,871	48,447	66,096	47,409	48,447
Maximum heat flux[b] Btu/hr ft^2	361,590	428,400	428,400	428,400	428,400
Average heat flux[b] Btu/hr ft^2	143,700	164,700	163,310	164,470	164,700
Maximum power per fuel rod unit length[b], kW/ft	13.4	18.5	18.5	18.5	18.5
Average power per fuel rod unit length[b], kW/ft	5.3	7.10	7.04	7.09	7.10
Maximum fuel temperature, °F	3435	4380	4380	4380	4380
Total heat generated in fuel	96	96	96	96	96
Core average exit quality	14.1	13.5	12.9	12.9	12.7
Power distribution - peaking factors (peak/average)					

TABLE 1.3-1 NUCLEAR PLANTS PRINCIPAL PLANT DESIGN FEATURES COMPARISON[a]

	Fermi 2	Brunswick Units 1 & 2	Browns Ferry Units 1, 2, & 3	Cooper	Edwin I. Hatch Unit 1
Axial	1.40	1.50	1.50	1.50	1.50
Radial assembly	1.40	1.40	1.40	1.40	1.40
Local (within assembly)	1.24	1.24	1.24	1.24	1.24
Total peaking factor	2.43	2.6	2.6	2.6	2.6
Nuclear design data					
Average discharge exposure - 1st core, Mwd/ST	16,204	19,000	19,000	19,000	19,000
Moderator to fuel volume ratio at total core H_2O/UO_2 cold	2.74	2.41	2.45	2.41	2.41
In-core neutron instrumentation					
Number of in-core neutron detectors (LPRM)[c]	172	124	172	124	124
Number of in-core detector strings (LPRM)[c]	43	31	43	31	31
Number of detectors per string	4	4	4	4	4
Number of traversing in-core probe detectors	5	4	5	4	4
Range (and number) of detectors					
Source range monitor	Source to 10^{-3}% power (4)	Source to 10^{-3}% power (4)	Source to 10^{-3}% power (4)	Source to 10^{-3}% power (4)	Source to 10^{-3}% power (4)
Intermediate range monitor	10^{-4}% to 10% power (8)	10^{-4}% to 10% power (8)	10^{-4}% to 10% power (8)	10^{-4}% to 10% power (8)	10^{-4}% to 10% power (8)
Local power range monitor	2.5% to 125% power (172)	2.5% to 125% power (124)	2.5% to 125% power (172)	2.5% to 125% power (124)	2.5% to 125% power (124)
Average power range monitor	2.5% to 125% power (6)[d]	2.5% to 125% power (6)[d]	2.5% to 125% power (6)[d]	2.5% to 125% power (6)[d]	2.5% to 125% power (6)[d]
Number and type of in-core neutron sources	7-Sb-Be	5-Sb-Be	7-Sb-Be	5-Sb-Be	5-Sb-Be
Reactivity control					
Approximate effective reactivity of core with all control rods in (cold)	~0.975k	0.96k	0.96k	0.96k	0.96k

TABLE 1.3-1 NUCLEAR PLANTS PRINCIPAL PLANT DESIGN FEATURES COMPARISON[a]

	Fermi 2	Brunswick Units 1 & 2	Browns Ferry Units 1, 2, & 3	Cooper	Edwin I. Hatch Unit 1
Effective reactivity of core with strongest control rod out (cold)	<0.99k	<0.99k	<0.99k	<0.99k	<0.99k
Typical moderator temperature coefficient (Δk/k°F)[e]					
Cold (at 68°F)	-5.0×10^{-5}	-5.0×10^{-5}	-5.0×10^{-5}	-5.0×10^{-5}	-5.0×10^{-5}
Hot (no voids)	-39.0×10^{-5}	-39.0×10^{-5}	-39.0×10^{-5}	-39.0×10^{-5}	-39.0×10^{-5}
Typical moderator void coefficient (Δk/k% void)					
Hot (no voids)	-1.0×10^{-3}	-1.0×10^{-3}	-1.0×10^{-3}	-1.0×10^{-3}	-1.0×10^{-3}
At rated output	-1.6×10^{-3}	-1.6×10^{-3}	-1.6×10^{-3}	-1.6×10^{-3}	-1.6×10^{-3}
Typical fuel temperature (Doppler) coefficient (k/k°F)[e]					
Cold (at 68°F)	-1.3×10^{-5}	-1.3×10^{-5}	-1.3×10^{-5}	-1.3×10^{-5}	-1.3×10^{-5}
Hot (no voids)	-1.2×10^{-5}	-1.2×10^{-5}	-1.2×10^{-5}	-1.2×10^{-5}	-1.2×10^{-5}
At rated output	$\leq -1.3 \times 10^{-5}$	$\leq -1.3 \times 10^{-5}$	$\leq -1.3 \times 10^{-5}$	$\leq -1.3 \times 10^{-5}$	$\leq -1.3 \times 10^{-5}$
<u>Containment systems</u>					
Primary containment					
Type	Pressure suppression	Pressure suppression	Pressure suppression	Pressure suppression	Pressure suppression
Construction					
Drywell	Light bulb/ steel vessel	Light bulb/ reinforced concrete with steel liner	Light bulb/ steel vessel	Light bulb/ steel vessel	Light bulb/ steel vessel
Pressure suppression chamber	Torus/steel vessel	Torus/reinforced concrete with steel liner	Torus/steel vessel	Torus/steel vessel	Torus/steel vessel
Pressure suppression chamber-internal design pressure, psig	+56	+62	+56	+56	+56
Pressure suppression chamber-external design pressure, psig	+2	+2	+1	+2	+2
Drywell-internal design pressure, psi	+56	+62	+56	+56	+56
Drywell-external design pressure, psig	+2	+2	+1	+2	+2
Drywell free volume, ft^3	163,730	164,100	159,000	145,430	146,240

TABLE 1.3-1 NUCLEAR PLANTS PRINCIPAL PLANT DESIGN FEATURES COMPARISON[a]

	Fermi 2	Brunswick Units 1 & 2	Browns Ferry Units 1, 2, & 3	Cooper	Edwin I. Hatch Unit 1
Pressure suppression chamber free volume, ft^3	127,760 (min)	124,000	119,000	109,810	110,950
Pressure suppression pool water volume, ft^3	121,080 (min)	87,600	85,000	87,660	87,660
Submergence of vent pipe below pressure pool surface, ft-in	4-0	4-0	4-0	4-0	3-8
Design temperature of drywell, °F	340	300	281	281	281
Design temperature of pressure suppression chamber, °F	281	220	281	281	281
Downcomer vent pressure loss factor	6.21	6.21	6.21	6.21	6.21
Break area/gross vent area	0.019	0.02	0.019	0.019	0.019
Drywell free volume/pressure suppression chamber free volume	1.25	1.32	1.33	1.4	1.3
Calculated maximum drywell pressure after blowdown with no pre-purge, psig	56.5	49.4	40.0	46.0	46.5
Leakage rate, percent free volume per day	0.5	0.5	0.5	0.5	1.2
Secondary containment					
Type	Controlled leakage, rooftop release	Controlled leakage, elevated release	Controlled leakage, elevated release	Controlled leakage, elevated release	Controlled leakage, elevated release
Construction					
Lower levels	Reinforced concrete	Reinforced concrete	Reinforced concrete	Reinforced concrete	Reinforced concrete
Upper levels	Steel super-structure and siding	Steel super-structure and siding	Steel super- structure and siding	Steel super-structure and siding	Steel super- structure and siding
Roof	Metal decking with built-up roofing	Metal decking with built-up roofing	Steel sheeting	Steel sheeting	Steel sheeting
Internal design pressure, psig	0.25	0.25	0.25	0.25	0.25

TABLE 1.3-1 NUCLEAR PLANTS PRINCIPAL PLANT DESIGN FEATURES COMPARISON[a]

	Fermi 2	Brunswick Units 1 & 2	Browns Ferry Units 1, 2, & 3	Cooper	Edwin I. Hatch Unit 1
Design in leakage rate, percent free volume/day at 0.25 in. H_20	100.0	100.0	100.0	100.0	100.0
Elevated release point					
Type	Rooftop	Stack	Stack	Stack	Stack
Construction	Steel	Reinforced concrete	Steel	Steel	Reinforced concrete
Height (above ground), meters	54.1	100.0	200.0	100.0	150.0
Plant auxiliary systems					
Emergency core cooling systems					
Reactor core spray cooling system	2 loops	2 loops	2 loops	2 loops	2 loops
High pressure coolant injection system	1 pump	1 pump	1 pump	1 pump	1 pump
Auto-relief system	1	1	1	1	1
Residual heat removal system					
Low pressure coolant injection subsystem	4 pumps	4 pumps	4 pumps	4 pumps	4 pumps
Primary containment spray/cooling subsystem	2 redundant loops	2 redundant loops	2 redundant loops	2 redundant loops	2 redundant loops
Reactor shutdown cooling subsystem	1	1	1	1	1
Reactor auxiliary systems					
Spent fuel pool cooling and demineralizing system	1	1	1	1	1
Reactor cleanup demineralizer system	1	1	1	1	1
Reactor core isolation cooling system	1	1	1	1	1
Plant electrical power systems					
Transmission system					
Outgoing lines (number-rating)	2-345 kV	8-230 kV	4-500 kV	4-345 kV	5-230 kV
Auxiliary power systems					

TABLE 1.3-1 NUCLEAR PLANTS PRINCIPAL PLANT DESIGN FEATURES COMPARISON[a]

	Fermi 2	Brunswick Units 1 & 2	Browns Ferry Units 1, 2, & 3	Cooper	Edwin I. Hatch Unit 1
Incoming lines (number-rating)	3-120 kV 4-345 kV	8-230 kV	2-161 kV	1-69 kV 1-115 kV	5-230 kV
Onsite Sources					
Auxiliary transformers	2	2	3	1	1
Startup transformers	0	2	2	2	2
Shutdown transformers	0	0	0	1	1
Emergency diesel generator system					
Number of diesel generators	4	4	4	4	3

[a] Original design information provided for comparison purposes only. Not intended to be updated. For current Fermi 2 information, refer to main body of UFSAR.
[b] Items are shown at design limits rather than design points.
[c] Local power range monitor.
[d] Represents six channels.
[e] Beginning of core life.

TABLE 1.3-2 COMPARISON OF POWER CONVERSION SYSTEMS DESIGN CHARACTERISTICS[a]

	Fermi 2	Brunswick Units 1 & 2	Browns Ferry Units 1, 2, & 3	Cooper	Edwin I. Hatch Unit 1
Turbine generator					
Rated generator output, MWe	1154 Tandem compound 6-flow/46 1 high pressure, 3 low pressure	849 Tandem compound 4-flow/43 1 high pressure, 2 low pressure	1152 Tandem compound 6-flow/43 1 high pressure, 3 low pressure	836 Tandem compound 2-flow/44 1 high pressure, 2 low pressure	819 Tandem compound 2-flow/43 1 high pressure, 2 low pressure
Steam conditions at throttle valve					
Flow, lb/hr	14.156×10^6	10.46×10^6	13.38×10^6	9.81×10^6	10.03×10^6
Pressure, psia	965	965	965	970	970
Temperature, °F	540.3	540.3	540.3	540.9	540.9
Moisture content, percent	0.41	0.41	0.28	0.32	0.32
Turbine cylinder arrangement					
Steam reheat stages, no.	1	2	0	0	1
Feedwater heating stages, no.	6	5	5	5	5
Strings of feedwater heaters, no.	2/3	2	2	2	2
Heaters in condenser necks, no.	2	2	2	2	2
Heater drain system	Pumped forward	Pumped forward	Pressure differential	Pumped forward	Pressure differential
Condensate pumps, no.	3	3	3	3	3
Heater feed pumps, no.	3	3	3	3	3
Header drain pumps, no	3	2	0	3	0
Reactor feed pumps, no.	2	2	3	2	2
Main Steam Lines					
Steam lines, no.	4	4	4	4	4
Design pressure, psig	1250	1146	1146	1146	1146
Design Temperature, °F	575	563	563	563	563
Pipe Diameter, in.	24	24	26	24	24
Pipe material	Carbon steel	Carbon steel	Carbon steel	Carbon steel	Carbon steel
Main steam line bypass capacity, percent	25	25 (unit 1) 105 (unit 2)	25	25	25
Final feedwater temperature, °F	420	420	376.1	367	387.4
Condenser					
Type	Single pressure	Single pressure	Single pressure	Single pressure	Single pressure
Condenser shells, no.	2	2	3	2	2
Design pressure, in. Hg abs	1.5	1.5	2.0	2.0	3.37
Total condenser duty, Btu/hr	7.547×10^9	5.6×10^9	7.77×10^9	5.6×10^9	5.8×10^9
Circulating water system					
Type	Closed/ND cooling towers (2)	Open	Open	Open	Closed/ND cooling Towers (2)
Flow, gpm	9×10^5	6.24×10^5	6.3×10^5		5.55×10^5
Circulating water pumps, no.	5	4	3	4	3

[a] Original design information provided for comparison purposes only. Not intended to be updated. For current Fermi 2 information, refer to main body of UFSAR.

1.4 IDENTIFICATION OF AGENTS AND CONTRACTORS

1.4.1 The Detroit Edison Company

The Detroit Edison Company changed its name to DTE Electric Company as of January 1, 2013. The name change to DTE Electric Company was purely administrative in nature; the legal entity remained the same and the name change did not involve a transfer of control or of an interest in the license for Fermi 2. DTE Electric Company continues to be a wholly owned subsidiary of DTE Energy Company. For the purposes of the Fermi 2 UFSAR, except for UFSAR sections of historical context, all DTE Energy Company designations referenced throughout the UFSAR (e.g. DTE Electric, Edison, Detroit Edison, DECo, etc.) are synonymous.

Edison is the sole owner of Fermi 2 and, as such, is responsible for the design, construction, and operation of the facility. Edison is the architect-engineer for Fermi 2.

Edison employed an engineering, design, and construction supervision staff. Many of the key engineering personnel had had previous nuclear experience, primarily on the design, construction, and operation of fast breeder reactor Fermi 1, and, subsequently, in the design and construction of Fermi 2.

Edison has extensive power plant design and development experience, having acted as architect-engineer on the majority of its own power generating facilities.

To ensure competence in all areas of Fermi 2 design and construction, Edison retained various principal agents and contractors.

1.4.2 Sargent & Lundy

Sargent & Lundy (S&L) was retained for the civil, structural, and architectural design of the reactor building and other areas of the plant where that firm's experience was especially appropriate. These include preparation of the specifications for the primary containment vessel, certain electrical design tools, and piping system analyses. By a separate contract, S&L was responsible for the design of the residual heat removal (RHR) complex.

Sargent & Lundy had specialized in consulting and design engineering for the generation, transmission, and distribution of electric power for three-quarters of a century. They had provided engineering services for l5 percent of the nation's investor-owned electric generating capacity. More than 650 turbine generator units with a total capacity of more than 70,000 MWe had been put in operation or were on order; of this total more than 21,800 MWe was nuclear generating capacity, the majority of which was of the water reactor type. Sargent & Lundy had been actively engaged in the nuclear power plant field since its inception.

1.4.3 Stone & Webster Engineering Corporation

Stone & Webster Michigan, Incorporated (S&W), a wholly-owned subsidiary of Stone & Webster, Incorporated, was retained and assigned responsibility for completion of certain engineering and design tasks commencing in January 1978. Some of the major tasks included design of the plant security system, high density fuel racks, pipe hanger design assistance, nonnuclear steam supply, integrated leak-rate testing, and review of seismic requirements. Stone

& Webster also provided assistance in the general areas of licensing requirements, advisory operations, and various electrical, mechanical, and instrument and control activities.

Stone & Webster is an engineering and construction firm serving the electric utility industry in the design and construction of all types of power stations. Stone & Webster had provided engineering services related to generating capacity in excess of 70,000,000 kW. Stone & Webster had been actively engaged in engineering and construction of nuclear power plants since 1954. Over 26,000,000 kW of generating capacity had been associated with S&W's nuclear engineering services.

1.4.4 General Electric Company

General Electric (GE) was contracted to design, fabricate, and deliver the single-cycle boiling water nuclear steam supply system (NSSS), fabricate the first core of nuclear fuel, and provide technical direction for installation and startup of this equipment. General Electric had been engaged in the development, design, construction, and operation of BWRs since l955. Thus, GE had substantial experience, knowledge, and capability to design, manufacture, and furnish technical advice for the installation and startup of the reactor.

GE was later contracted to design, fabricate and deliver a replacement for the LP Turbine Steam Path installed during RF05 and the HP Turbine System Path installed during RF07.

1.4.5 General Electric Company Turbine-Generator, Ltd.

General Electric Company (GEC) Turbine-Generator, Ltd. of Rugby, England, was responsible for the design, fabrication, and delivery of the turbine generator as well as for providing technical assistance for installation and startup of this equipment. General Electric Company Turbine-Generator, Ltd. had had a long history of fabrication and application of turbine generators in electrical power production facilities.

The LP Turbine Steam Path was replaced during RF05 with GE designed components. The major components replaced were the rotors, diaphragms, associated seals and steam flow guides, including the internal exhaust hood spray piping and nozzles.

The HP Turbine Steam Path was replaced during RF07 with GE designed components. The major components replaced were the rotor, diaphragms, associated seals, and coupling spacers. An inlet snout was added to provide the steam flow path into the first stage diaphragm nozzles.

1.4.6 Other Consultants

1.4.6.1 Dames & Moore

The independent consulting firm of Dames & Moore (D&M) was retained to do hydrology, geology, and seismology studies for Fermi 2. Having performed environmental studies for approximately 50 nuclear power plant sites, D&M was active in the field of environmental engineering related to nuclear power plant construction.

1.4.6.2 NUS Corporation

NUS Corporation was retained to provide software for startup and operation of Fermi 2, and to prepare the environmental report and other environmental and licensing consulting services.

Software for Fermi 2 included administrative documents to govern startup, system descriptions, and preoperational test procedures. NUS was also responsible for preparation of the plant operating manual. NUS also provided environmental consulting services in the areas of aquatic ecology, land and water use, thermal and chemical effects, alternatives, radiological effects, and miscellaneous licensing consulting services as required.

NUS had provided consulting services throughout the world for a wide range of utilities, industries, and governmental organization.

1.4.6.3 Ralph M. Parsons Company

Ralph M. Parsons Company of Michigan (Parsons) was engaged as the general contractor for Fermi 2 with responsibility for overall construction management of the entire facility, and with direct contractual responsibility for field fabrication of small diameter piping, and installation of the plant piping systems and mechanical equipment. Parsons was terminated as general contractor in November 1974.

Under a separate contract, Ralph M. Parsons of Los Angeles was engaged to help establish the initial Quality Assurance (QA) and Quality Control (QC) Organization at the site to work in conjunction with Edison to provide work surveillance, inspection, and documentation services which ensure conformance to the codes and standards applicable to nuclear construction and the design specifications. In addition, Ralph M. Parsons of Los Angeles provided support in seismic and pipe structure analyses and specific engineering assignments.

Parsons was one of the world's largest architectural, engineering, and construction firms. Its world headquarters were located in Los Angeles, California, with principal offices in several foreign countries. The company had demonstrated its total engineering and construction capability in a variety of foreign and domestic industrial, technical, and scientific projects completed for the petroleum refining, metallurgical processing, power generation, aerospace, chemical processing, shipbuilding, commercial transportation, and nuclear industries.

Projects included engineering and construction of rapid transit facilities, transportation systems, water and sewage treatment, desalination plant, petroleum and petrochemical plants, gas processing facilities, marine and port complex, automated shipyard, airports and air terminals, mining and metallurgical facilities, environmental process development, fast breeder nuclear reactor installation, nuclear power plant installation, and many others.

1.4.6.4 Daniel Construction Company

Daniel Construction Company was retained and assigned responsibility for site construction management commencing in November 1974. It maintained that responsibility throughout construction until systems and structures nearing completion were transferred to Edison. Commencing in January 1984, Daniel assisted the Fermi 2 Project Management Organization as needed and was responsible for the day-to-day management of Wismer & Becker, API, and Chicago Bridge and Iron Company. Daniel Construction Company, a division of Daniel International Corporation, of Greenville, S.C., had a wide variety of engineering and construction assignments being completed in many parts of the world. A recent survey of the nation's 400 largest contractors rates Daniel fourth in contract awards, twelfth in international contract awards, and thirty-second in design awards.

Daniel had acquired extensive construction and project management experience in major industrial complexes for the chemical, paper, rubber, textile, aluminum, and power generation industries. These construction services involved the ability to meet precise tolerances and specifications on erection, fabrication, and equipment installation, and required a thorough knowledge of heavy construction, mechanical, electrical, and instrumentation techniques and methods. This experience and the developed capabilities were applicable to the construction of nuclear power facilities.

The Daniel Construction Company Quality Assurance Program for ASME nuclear code construction was evaluated and accepted by an ASME survey team, and the certificate of authorization to perform code construction ("N" stamp) was awarded Daniel following the ASME team audit of field implementation and enforcement.

Daniel's experience included construction of nuclear and fossil fueled power plants. Daniel's first project of this nature was construction of the nuclear power Carolina-Virginia Tube Reactor at Parr, South Carolina. This facility operated several years as a prototype plant. Nuclear power plant construction projects included the following:

a. Joseph M. Farley Nuclear Plant, Unit No. 1 and Unit No. 2, 829-MW PWR each, for Alabama Power Company

b. Virgil Summer Nuclear Power Plant, a 920-MW nuclear power generating plant of the Westinghouse pressurized-water type, for South Carolina Electric and Gas Company

c. Shearon Harris Nuclear Power Plant for Carolina Power & Light Company.

1.4.6.5 EG&G, Inc.

EG&G was engaged to provide site meteorological programs. EG&G has performed a variety of marine, meteorological, biological, hydrological, and climatological analyses, instrumentation selection and application, and a full range of services including field installation, maintenance, data gathering and processing, diffusion modeling, and report preparation for many clients.

1.4.6.6 Bechtel Power Corporation

Bechtel Power Corporation was the general services contractor for the Fermi 2 power plant. Bechtel provided engineering, construction, maintenance, startup assistance, and plant operational support services as mutually agreed to by Edison and Bechtel. The work was performed on Quality Assurance Level 1 or non-quality-related systems within the plant. The governing quality assurance program, either Edison's or Bechtel's, was adhered to depending on the kind and nature of the work for which the services are rendered.

Bechtel had demonstrated its ability in successfully performing construction management, engineering, and other functions in accordance with quality assurance programs under the jurisdiction of the NRC over past years. As such, Bechtel was deemed fully qualified to perform any safety-related work that may be assigned to it by Edison.

1.4.6.7 L. K. Comstock

L. K. Comstock was responsible for furnishing labor, tools, equipment, and materials as required to complete the electrical installation at Fermi 2. Comstock's work included electrical installation at Fermi 2. Comstock's work also included receiving, storing, installing, connecting, and readying for service all electrical equipment as well as providing electrical QA/QC services and design engineering services.

Comstock had extensive experience in the nuclear power field and understood the QA requirements. It had provided construction services on the BWR units at Dresden and Quad Cities and had completed the electrical erection contracts at the Kewaunee, Prairie Island, Cook, and FitzPatrick nuclear projects.

1.4.6.8 Commonwealth Associates, Inc., of Gilbert Commonwealth

Commonwealth Associates, Inc., of Gilbert Commonwealth, was retained in 1981 to provide technical personnel to assist during the construction of Fermi 2 in the Field Engineering, Startup, Nuclear Production, and Quality Assurance Departments.

The personnel provided by Commonwealth had the expertise, gained from work at other utilities, required during Fermi 2 construction and the startup operations.

1.4.6.9 NUTECH Engineers

NUTECH was retained to provide technical assistance to Edison's Engineering Department, on an as-required basis. Subsequently, it provided services to the Nuclear Production Department as well as other areas.

Areas of service provided included (a) In-Service Inspection Program development, (b) In-Service Inspection staff augmentation, (c) Computer Program development, (d) Radiation Emergency Preparedness Program development, and (e) Plant Unique Analysis Program addressing hydrodynamic loads in the containment.

1.4.6.10 Wismer & Becker

Wismer & Becker was responsible for furnishing labor, materials, tools, equipment, and technical and professional services as necessary for the installation of piping and mechanical equipment at Fermi 2. Support provided included QA/QC work and pressure testing on piping systems and equipment as required by the applicable codes and specifications.

For over 30 years, Wismer & Becker had been involved in all phases of power plant construction. Previous nuclear experience from the Council Bluffs and Diablo Canyon nuclear power plants had proved that Wismer & Becker had a thorough understanding of ASME Code Section III work and QA requirements

1.5 REQUIREMENTS FOR FURTHER TECHNICAL INFORMATION

This section is included for historical purposes and will not be further updated. It includes a discussion of Advisory Committee on Reactor Safeguards (ACRS) and AEC staff concerns regarding BWRs, Fermi 2 in particular. These concerns were expressed prior to and during the Fermi 2 Construction Permit period and were required to be resolved prior to or during construction.

1.5.1 Resolved Concerns

The ACRS has voiced various concerns about the development of BWRs. Specific concerns resolved during the development of the BWR, and specific Fermi 2 ACRS concerns and the documents in which each specific concern is resolved, were presented in Appendix B of the original Fermi 2 FSAR.

Although some of the concerns expressed by the ACRS did not directly apply to Fermi 2, they were included in Appendix B as evidence of the refinements and degree of analysis included in the design of the Fermi 2 BWR.

Specific GE development programs to improve the safety and performance of the BWR, and the status as applicable to Fermi 2, are discussed in Subsection 1.5.2.

Additionally, the AEC staff enumerated a number of concerns during the Fermi 2 Construction Permit review that were documented in Appendix D to the original FSAR. Appendix D also included the status of the NRC review and resolution of these Fermi 2 specific items.

1.5.2 General Electric Development Programs

1.5.2.1 Instrumentation for Vibration and Loose Parts Detection

System has been abandoned.

1.5.2.2 Core Spray Distribution

Because of the slight changes in core dimensions and spray sparger geometry from plant to plant, a series of tests was conducted. The purpose of these tests was to ensure that the core spray flow distribution for the Fermi 2 header design would supply adequate cooling water from the core spray system to each fuel assembly within the reactor core in the event of a LOCA. The tests demonstrated that each fuel assembly receives adequate cooling water flow for required spray flow rates between rated flow and runout flow conditions. Details of this test program were very similar to those described in Amendment 30 (December 1967) to the Oyster Creek FSAR, NRC Docket No. 50-219.

1.5.2.3 Vibration Testing of Reactor Internals

The major reactor components within the reactor pressure vessel have been subjected to extensive testing and dynamic analysis to properly describe any flow-induced vibration incurred during normal reactor operation and anticipated operational transients. Extensive prototype testing on BWR 4 plants has been reported in GE Topical Report NEDO-24057. Testing provisions for Fermi 2 invoke this prototype test program as stipulated by Regulatory Guide

1.20, Revision 2. An approved preoperational test was conducted prior to fuel load for flow-induced vibration of reactor internals. Refer to Subsection 3.9.1 for details.

1.5.2.4 Pipe Whip Inside Containment

Dynamic restraint tests have been performed on the plastic design restraints to demonstrate the adequacy of the piping restraint concept. The concept provides clearances that allow for normal thermal movements of the pipe but limit motion in the event of a postulated rupture.

Edison has extensively analyzed the dynamic effects of pipe ruptures inside containment and has installed design provisions including pipe whip restraints to prevent damage caused by pipe whip. Refer to Section 3.6 for details.

1.5.2.5 Recirculation Pump-Motor Missiles

An analysis has been performed on the generation of missiles as a result of a recirculation line break. Based on GE analyses, postulated recirculation pump missiles, which may be generated during a design-basis LOCA overspeed condition, are safely contained within the pump casing. Analyses of pump missiles ejected from the open end of the broken pipe have also been performed. Piping restraints were added to prevent the potential missile exit points in the pipe from developing. Further details and references to GE topical reports are provided in Subsections 3.5.1.2 and 5.5.1.4.

1.5.2.6 Standby Gas Treatment System Filter Efficiency Test

A test program to demonstrate the efficiency of the new gasket-less carbon filter was successfully completed by Edison in 1974. NEDC-12431 (Reference 1) concluded that tests on the filter, simulating the Fermi 2 standby gas treatment system (SGTS) carbon filter, successfully demonstrated the ability of the filter to remove greater than 99.99 percent of the iodine processed through the filter. Thus, the Fermi 2 SGTS can be credited (with adequate conservatism) with an iodine removal efficiency of 95 percent. For additional information on this subject, refer to Subsection 6.2.3.

1.5.2.7 Hydrogen Flammability Tests

The NRC amended 10 CFR 50.44, “Standards for combustible gas control system in light-water-cooled power reactors” on October 16, 2003 to eliminate the requirements for hydrogen recombiners. The hydrogen recombiner Technical Specification requirements were subsequently removed by License Amendment 159, dated March 15, 2004. Regulatory Guide 1.7 was revised in March 2007 to reflect the amended 10 CFR 50.44. The Combustible Gas Control System (CGCS) has been retired in place with its electrical circuits de-energized and fluid process piping isolated from primary containment with redundant locked-closed isolation valves. Measures against hydrogen-oxygen combustion are provided by inerting of the primary containment atmosphere during plant operation. Refer to Subsections 6.2.5 and 9.3.6 for details.

1.5.2.8 Water Chemistry Program

Edison has participated extensively in water chemistry development programs and in the application of operating BWR water chemistry findings to the Fermi 2 plant. A water chemistry program with applicable Technical Requirements Manual and operating procedures has been developed in conformance with Regulatory Guide 1.56. General Electric Water Quality Document No. 22A2747 has served as a basis for this program. Refer to Subsections 9.3.2 and 10.4.6 for details.

1.5 REQUIREMENTS FOR FURTHER TECHNICAL INFORMATION

REFERENCES

1. NEDC-12431 Class I, January 30, 1974, Subject: Detroit Edison Standby Gas Treatment System Gasketless Filter Test Series, D. P. Siegwarth and M. Siegler, General Electric Company.

1.6 MATERIAL INCORPORATED BY REFERENCE

Table 1.6-1 lists topical reports that are incorporated in whole or in part by reference in this Updated Final Safety Analysis Report (UFSAR); these references are on file with the U.S. Nuclear Regulatory Commission (NRC).

UFSAR Figures that are derived from Edison controlled drawings contain a reference to the Edison drawing number. These figures will be regularly updated or have been removed. Drawings that are not expected to require revision fall into one or more of the following classes:

a. Figures that are typical (e.g., generic) sketches not showing design detail

b. Figures that will not change throughout the life of Fermi 2 (e.g., site geology, site geography, population distribution, and design criteria used during construction)

c. The portion of the drawing referenced from the UFSAR text that is not likely to change.

UFSAR Figures that are based on vendor drawings contain a reference to the vendor drawing number. These drawings may or may not be updated regularly or have been removed.

The Technical Requirements Manual (TRM) Volume 1 provides a central location for requirements relocated from the Fermi Operating License, Appendix A, Technical Specifications. The TRM Volume 1 (except for the Core Operating Limits Report) is incorporated by reference into the UFSAR.

TABLE 1.6-1 REFERENCED REPORTS

General Electric Company Reports

Report Number	Title	UFSAR Sections Where Referenced
APED-555	Impact Testing on Collet Assembly for Control Rod Drive Mechanism 7RDB144A (November 1967)	4.5
APED-5458	Effectiveness of Core Standby Cooling Systems for General Electric Boiling Water Reactors (March 1968)	5.5
APED-5460	Design and Performance of GE BWR Jet Pumps (July 1968)	4.5
APED-5652	Stability and Dynamic Performance of the General Electric Boiling Water Reactor (April 1969)	4.1
APED-5696	Tornado Protection for the Spent Fuel Storage Pool (November 1968)	3.3, 3.5
APED-5706	In-Core Neutron Monitoring System for General Electric Boiling Water Reactors (November 1968; revised April 1969)	7.6
APED-5750	Design and Performance of General Electric Boiling Water Reactor Main Steam Line Isolation Valves (March 1969)	5.5
NEDO-10029	An Analytical Study on Brittle Fracture of GE-BWR Vessel Subject to the Design Basis Accident (July 1969)	App. A
NEDO-10139	Compliance of Protection Systems to Industry Criteria: General Electric BWR Nuclear Steam Supply System (June 1970)	3.12, 7.1, 7.2, 7.3, 7.6
NEDO-10173	Current State of Knowledge, High Performance BWR Zircaloy-Clad UO_2 Fuel (May 1970)	11.1
NEDO-10299	Core Flow Distribution in a Modern Boiling Water Reactor as Measured in Monticello (January 1971)	4.4
NEDO-10320	The General Electric Pressure Suppression Containment Analytical Model (April 1971), Supplement 1 (May 1971)	6.2
NEDO-10329	Loss-of-Coolant Accident and Emergency Core Cooling Models for General Electric Boiling Water Reactors (April 1971), Supplement 1 (April 1971), Addenda (May 1971)	6.2

TABLE 1.6-1 REFERENCED REPORTS

General Electric Company Reports

Report Number	Title	UFSAR Sections Where Referenced
NEDO-10505	Experience with BWR Fuel Through September 1971 (May 1972)	11.1
NEDO-10527	Rod Drop Accident Analysis for Large Boiling Water Reactors (March 1972), Supplement 1 (July 1972) and Supplement 2 (January 1973)	4.5, 7.6, 15.4.9
NEDO-10602	Testing of Improved Jet Pump for the BWR/6 Nuclear System (June 1972)	4.5
NEDO-10677	Analysis of Recirculation Pump Overspeed in a Typical GE BWR (October, 1972)	5.5
NEDO-10678	Seismic Qualification of Class I Electric Equipment (November 1972)	3.10, 7.1, 7.3, 7.4, 7.6
NEDO-10698	Environmental Qualification of Class 1 Control and Instrumentation Equipment (November 1972)	3.11, 7.1, 7.2, 7.3, 7.4, 7.6
NEDO-10722A	Core Flow Distribution in a General Electric Boiling Water Reactor as Measured in Quad Cities Unit 1 (August 1976)	4.4
NEDO-10802 NEDO-10802-1	Analytical Methods of Plant Transient Evaluations for the General Electric Boiling Water Reactor (February 1973), Supplement 1 (April 1973)	4.4
NEDE-10811	Pipe Restraint Testing Program Conducted in Conjunction with the Design of the Enrico Fermi Power Plant Unit No. 1 (April 1973)	3.6
NEDO-10812	Hydrogen Flammability and Burning Characteristics in BWR Containments (July 1973)	1.5
NEDE-10813	PDA - Pipe Dynamic Analysis Program for Pipe Rupture Movement (March 1973)	3.6
NEDO-10871	Technical Derivation of BWR 1971 Design Basis Radioactive Source Terms (March 1973)	11.1
NEDO-10899	Chloride Control in BWR Coolants (June 1973)	5.2

TABLE 1.6-1 REFERENCED REPORTS

General Electric Company Reports

Report Number	Title	UFSAR Sections Where Referenced
NEDO-10958 NEDE-10958	General Electric Company BWR Thermal Analysis Basis (GETAB): Data, Correlation and Design Application (November 1973)	4.4, 15.1.2
NEDO-10958A	GETAB Data, Correlation, and Design Application (January 1977)	4.4
NEDO-12037	Summary of Gamma and Beta Energy and Intensity Data (January 1970)	15A
NEDC-12431	Detroit Edison SGTS Gasketless Filter Test (July 1973)	1.5, 6.2
NEDE-13296	Pipe Whip Restraint Dynamic Evaluation (August 1972)	3.6
NEDE-13298	Deformation of Piping Due to Combined Bending and Lateral Load Under Pipe Whip Loading (August 1972)	3.6
NEDE-13331	Deformation of Piping Due to Combined Bending and Restraint Lateral Load – Additional Tests of Stainless Steel Pipes (March 1973)	3.6
NEDO-20360	General Electric BWR Generic Reload Application for 8 x8 Fuel	15.4.9
NEDO-20566, NEDE-20566-P	Analytical Model for Loss-of-Coolant Analysis in Accordance with 10 CFR Part 50, Appendix K (December 1975)	4.2, 6.3
NEDO-20566A	General Electric Company Analytical Model for Loss-of-Coolant Analysis in Accordance with 10 CFR 50, Appendix K (September 1986)	6.3
NEDO-20944, NEDE-20944-P, NEDE-20944-1P	BWR 4 and BWR 5 Fuel Design (October 1976) Proprietary Version (January 1977)	4.1, 4.2, 4.3, 4.4
NEDO-20946-A	BWR Simulator Methods Verification (July 1976)	4.3
NEDC-20994	Peach Bottom Atomic Power Station Units 2 and 3 Safety Analysis Report for Plant Modifications To Eliminate Significant In-Core Vibration (September 1975)	4.4, 4.5

TABLE 1.6-1 REFERENCED REPORTS

General Electric Company Reports

Report Number	Title	UFSAR Sections Where Referenced
NEDO-21143	Conservative Radiological Accident Evaluation – The CONACO1 Code	15.6.7, 15.7.4
NEDE-21156	Supplemental Information for Plant Modification To Eliminate Significant In-Core Vibration (January 1976)	4.4
NEDE-21175P-3	BWR Fuel Assembly Evaluation of Combined SSE and LOCA Loadings (July 1982)	3.9, 4.2, 4.5
NEDO-21291	Group Notch Mode of the Rod Sequence Control System for Cooper Nuclear Station (June 1976)	4.3, 15.4.1
NEDO-21506	Stability and Dynamic Performance of the General Electric Boiling Water Reactor (January 1977)	4.4
NEDO-21617 NEDO-21617-A	Analog Transmitter/Trip Unit System for Engineered Safeguard Sensor Trip Inputs (December 1978)	7.1, 7.2, 7.3, 7.4
NEDO-21778-A	Transient Pressure Rises Affecting Fracture Toughness Requirements for Boiling Water Reactors (January 1978)	5.2
NEDE-21821	Boiling Water Reactor Feedwater Nozzle Sparger (March 1978)	5.2
NEDO-21888-2	Mark I Containment Program Load Definition Report (November 1981)	3.8, 6.2
NEDO-22209	Analysis of Scram Discharge Volume System Piping Integrity (August 1982)	3.6
NEDE-23785-PA	The GESTR-LOCA and SAFER Models for the Evaluation of the Loss-of-Coolant Accident – SAFER/GESTR Application (October 1984)	6.3
NEDO-23786-1 NEDO-23786-P	Fuel and Rod Prepressurization (May 1978)	4.2
NEDO-24048	Evaluation of Acoustic Pressure Loads on BWR/6 Internal Components (September 1978)	3.9
NEDO-24057 NEDO-24057-P	Assessment of Reactor Internals Vibration in BWR/4 and BWR/5 Plants (November 1977)	1.5, 3.9

TABLE 1.6-1 REFERENCED REPORTS

General Electric Company Reports

Report Number	Title	UFSAR Sections Where Referenced
NEDO-24154	Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors (October 1978)	5.2, 2.3
NEDO-24342	GE Evaluation in Response to NRC Request Regarding BWR Scram System Pipe Break (April 1981)	3.6
NEDC-24388-P	Enrico Fermi Atomic Power Plant Unit 2 Suppression Pool Temperature Response (December 1981)	6.2
NEDO-24568-3	Mark I Containment Program Plant Unique Load Definition – Enrico Fermi Atomic Power Plant Unit 2 (April 1982)	3.8, 6.2
NEDO-24708-A	Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors	3.6
GEAP 13197	Emergency Cooling in BWRs Under Simulated Loss-of-Coolant (BWR FLECHT Final Report) (June 1971)	6.2
NEDE-24011-P-A-10	General Electric Standard Application for Reactor Fuel (March 1991)	4.1, 4.2, 4.3, 4.4, 15.0, 15.1, 15.2, 15.4, 15.5
NEDE-24011-P-A-10-US	General Electric Standard Application for Reactor Fuel, United States Supplement (March 1991)	4.1, 4.2, 4.3, 4.4, 15.0, 15.1, 15.2, 15.4, 15.5
NEDE-31096	Anticipated Transients Without Scram Response to NRC ATWS Rule 10 CFR 50.62 (February1987)	15.8
NEDC-33865P	DTE Energy Enrico Fermi 2 SAFER/PRIME-LOCA Loss-of-Coolant Accident Analysis (March 2015)	6.3

1.7 ABBREVIATIONS AND SYMBOLS USED IN THE UFSAR

Abbreviations and symbols used in the UFSAR are contained in this section. Figure 1.7-1 contains the symbols used on Edison and GEC drawings. Figure l.7-2 contains the piping and instrumentation symbols used on GE drawings and figures. Figure 1.7-3 contains the logic symbols used on GE/Edison Functional Control Diagrams. Figure 1.7-4 contains the piping and instrumentation symbols used on Sargent & Lundy drawings and figures.

1.7.1. Abbreviations

A	
Advisory Committee on Reactor Safeguards	ACRS
Alternative Source Term	AST
alternating current	ac
American Concrete Institute	ACI
American Institute of Steel Construction	AISC
American Iron and Steel Institute	AISI
American National Standards Institute	ANSI
American Nuclear Society	ANS
American Petroleum Institute	API
American Society for Testing and Materials	ASTM
American Society of Agricultural Engineers	ASAE
American Society of Civil Engineers	ASCE
American Society of Heating, Refrigerating, and Air-Conditioning Engineers	ASHRAE
American Society of Mechanical Engineers	ASME
American Standards Association	ASA
American Water Works Association	AWWA
American Welding Society	AWS
Ampere	A
as low as reasonably achievable	ALARA
Atomic Energy Commission (see also NRC)	AEC
Atomic Safety and Licensing Board	ASLB
B	
Battelle Memorial Institute	BMI
Branch Technical Position	BTP

C	
Canadian Standards Association	CSA
Charpy V-notch	CVN
Chicago Bridge and Iron (Company)	CBI
Code of Federal Regulations	CFR
critical heat flux	CHF
cubic centimeter	cm^3
cubic feet per minute	cfm
cubic feet per second	cfs
cubic foot	ft^3
cubic meter	m^3
cubic meters per second	m^3/sec
cubic yard	yd^3
curie	Ci
cycles per second	Hz
D	
decibel	dB
degree (plane angle)	---
degree - Centigrade	C
degree - Fahrenheit	F
degree Rankine	R
Department of Transportation	DOT
Diesel Engine Manufacturers Association	DEMA
dioctyl phthalate penetration test	DOP
direct current	dc
Director, Reactor Licensing	DRL
The Detroit Edison Company	Edison
E	
2.7l8 ---, base of Naperian log system	e
Electric Power Research Institute	EPRI
electron volt	eV

electronic data processing	EDP
end of life	EOL
Environmental Protection Agency	EPA
erg	erg
effective neutron multiplication factor of the reactor	k_{eff}
F	
failure modes and effects analysis	FMEA
Federal Power Commission	FPC
Federal Water Pollution Control Act	FWPCA
feet per hour	ft/hr
feet per minute	fpm
feet per second	fps
foot (feet)	ft
foot of water (conventional)	ft H_2O
foot-pound	ft-lb
G	
gallon	gal
gallons per minute	gpm
gallons per second	gps
General Design Criterion (Criteria)	GDC
General Electric - Boiling Water Reactor	GE-BWR
General Electric Company Turbine - Generator, Ltd.	GEC
Geological Society of America	GSA
gigacycles per second	GHz
gigaelectron volt (10^9)	GeV
gram	g
grams per cubic centimeter	g/cm^3
gravitational acceleration factor, (32 ft per sec^2)	g
The General Electric Company	GE
H	
Heat Exchange Institute	HEI
henry	H

hertz	Hz
horsepower	hp
hour	hr
hydrogen-ion concentration	pH
I	
inch	in.
inch per second	in./sec
inch-pound	in.-lb
inches of mercury absolute	in. Hg abs
inches of water (pressure)	in. H_2O
inservice inspection	ISI
inside diameter	I.D.
Institute of Electrical and Electronics Engineers	IEEE
Institute of Nuclear Power Operations	INPO
Instrument Society of America	ISA
Interim Acceptance Criteria (AEC)	IAC
Interstate Commerce Commission	ICC
K	
kilo	k
kilocalorie	kcal
kilocycle per second	kHz
kiloelectron volt	keV
kilogram	kg
kilogram per square centimeter	kg/cm^2
kilojoule	kJ
kilometer	km
kilovolt, 10^3	kV
kilovolt-ampere	kVA
kilowatt	kW
kilowatt-hour	kWh
L	
least significant bit	LSB

licensee event report	LER
linear heat generation rate	LHGR
liter	l
low-population zone	LPZ
M	
maximum permissible concentration	mpc
mean low water datum	MLD
mega (10^6)	M
megacycles per second	MHz
megaelectron volt (10^6)	MeV
megahertz	MHz
megavolt-ampere	MVA
megawatt	MW
megawatt electric	MWe
megawatt thermal	MWt
megawatt-days per metric ton	MWd/t
megawatt-days per short ton	MWd/ST
meter	m
mho	mho
micro (10^{-6})	μ
microampere	μA
microcurie	μCi
microgram	μg
microhenry	μH
micrometer	μm
micromho	μmho
microsecond	μsec
microwatt	μW
mil	mil
miles per hour	mph
Military Specification	MIL
milli (10^{-3})	m

milliampere	mA
millicurie	mCi
milligram	mg
millihenry	mH
millimeter	mm
millimeter of mercury absolute	mm Hg abs
million electron volts	MeV
millirem	mrem
milliroentgen	mR
millisecond	msec
millivolt	mV
milliwatt	mW
Mine Safety Appliance	MSA
minute (time)	minute
molecular power supply unit	MPSU
N	
National Electrical Manufacturers Association	NEMA
National Fire Protection Association	NFPA
National Fire Protection Organization	NFPO
National Institute of Occupational Safety and Health	NIOSH
National Society of Professional Engineers	NSPE
National Weather Records Center	NWRC
neutron density, neutrons per cubic centimeter	n
neutron flux, neutrons per cubic centimeter per second	nv
neutron velocity time	nvt
nil ductility transition temperature	NDTT
nondestructive examination	NDE
nondestructive testing	NDT
Nuclear Energy Property Insurance Association	NEPIA
Nuclear Regulatory Commission (see also AEC)	NRC
O	
Occupational Safety and Health Administration	OSHA
Operating License	OL

P	
parts per billion	ppb
parts per million	ppm
percent	percent
piping and instrumentation drawing	P&ID
Plant Operations Manual	POM
pound	lb
pound mass per second	lbm/sec
pound-foot	lb-ft
pounds per cubic foot	lb/ft^3
pounds per hour	lb/hr
pounds per second	lb/sec
pounds per square inch	psi
pounds per square inch, absolute	psia
pounds per square inch, differential	psid
pounds per square inch, gage	psig
preservice inspection	PSI
probable maximum flood	PMF
probable maximum meteorological event	PMME
probable maximum precipitation	PMP
Q	
quality assurance	QA
quality control	QC
R	
rad, unit of absorbed radiation	rad
radian	radian
Radiological Emergency Response Preparedness	RERP
Radiologically Controlled Area	RCA
revolutions per minute	rpm
revolutions per second	rps
Rock Quality Designation	RQD

Rockwell hardness number	RHN
roentgen equivalent, man	rem
roentgen, unit of radiation exposure	R
root mean square	rms
S	
safe-shutdown earthquake	SSE
Safety Evaluation Report	SER
second (time)	sec
Seismic Qualification Review Team	SQRT
Southeast Michigan Council of Governments	SEMCOG
square centimeter	cm^2
square foot	ft^2
square inch	$in.^2$
square root of the sum of the squares	SRSS
square yard	yd^2
standard cubic feet per minute	scfm
Standard Review Plan	SRP
T	
thousand electron volts	keV
total effective dose equivalent	TEDE
Transient Reactor Analysis Code (GE)	TRACG
Tubular Exchanger Manufacturers Association	TEMA
U	
United States Bureau of Mines	USBM
United States Coast and Geodetic Survey	USC&GS
United States Geological Survey	USGS
V	
volt	V
volt-ampere	VA
volts, alternating current	V ac
volts, direct current	V dc
W	

watt	W
watt-hour	Wh

1.7.2. System, Component, and Process Abbreviations

anticipated transient without scram	ATWS
area radiation monitoring system	ARMS
automatic depressurization system	ADS
automatic gain control	AGC
average power range monitor	APRM
balance of plant	BOP
boiling water reactor	BWR
cathode ray tube	CRT
closed cooling water	CCW
combustible gas control system	CGCS
combustion turbine generator	CTG
condensate storage and transfer system	CSTS
containment and reactor vessel isolation control system	CRVICS
continuous air monitor	CAM
control center air conditioning system	CCACS
control rod drive	CRD
control rod drive return line	CRDRL
core cooling and containment system	CCCS
critical power ratio	CPR
design-basis accident	DBA
dosimeter of legal record	DLR
electro-hydraulic control	EHC
emergency core cooling system	ECCS
emergency diesel generator	EDG
emergency diesel generator service water system	EDGSW
emergency equipment cooling water system	EECWS
emergency equipment service water system	EESWS
emergency response data system	ERDS
engineered safety feature	ESF

excess flow check valve	EFCV
fire protection system	FPS
fuel pool cooling and cleanup system	FPCCS
full length emergency cooling heat transfer	FLECHT
functional control diagram	FCD
GE type of relay	HFA
Geiger-Mueller tubes	G-M tubes
general service water	GSW
heat affected zone	HAZ
heating, ventilation, and air conditioning	HVAC
high pressure coolant injection	HPCI
high-efficiency particulate air	HEPA
hydraulic control unit	HCU
hydrogen water chemistry	HWC
Independent Spent Fuel Storage Installation	ISFSI
induction heating stress improvement	IHSI
integrated plant computer system	IPCS
intergranular stress corrosion cracking	IGSCC
intermediate range monitor	IRM
intermediate-break accident	IBA
leak detection system	LDS
local power range monitor	LPRM
loose parts monitoring system	LPMS
loss-of-coolant accident	LOCA
low pressure coolant injection	LPCI
main steam isolation valve	MSIV
main steam isolation valve leakage control system	MSIVLCS
maximum average planar linear heat generation rate	MAPLHGR
maximum linear heat generation rate	MLHGR
mechanical equipment qualification	MEQ
minimum critical power ratio	MCPR
motor control center	MCC
motor-generator sets	M-G sets

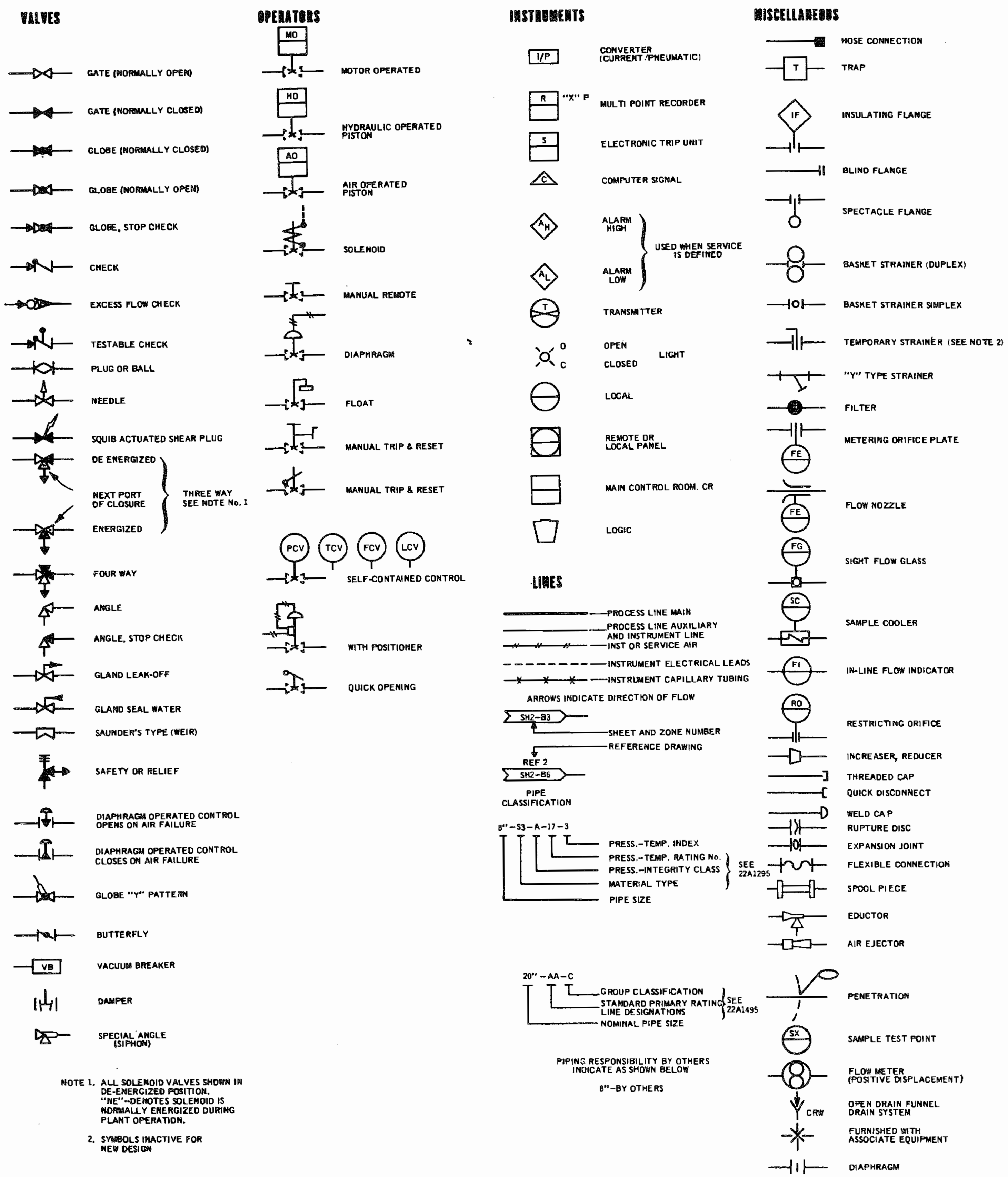
net positive suction head	NPSH
neutron monitoring system	NMS
noninterruptible air supply	NIAS
nuclear boiler system	NBS
nuclear pressure relief system	NPRS
nuclear steam supply system	NSSS
Onsite Review Organization	OSRO
operating-basis earthquake	OBE
oscillation power range monitor	OPRM
pipe whip restraint support system	PWRSS
power range monitor	PRM
pressure control valve	PCV
primary containment monitoring system	PCMS
process and effluent radiation monitor system	PERMS
radiation area protective (clothing)	RAP
radiation monitoring system	RMS
reactor building closed cooling water system	RBCCW
reactor coolant leak detection system	RCLDS
reactor coolant pressure boundary	RCPB
reactor core isolation cooling (system)	RCIC
reactor feed pump	RFP
reactor manual control system	RMCS
reactor pressure vessel	RPV
reactor protection system	RPS
reactor recirculation system	RRS
reactor water cleanup	RWCU
recirculation flow control system	RFCS
recirculation pump trip	RPT
residual heat removal	RHR
residual heat removal service water	RHRSW
rod block monitor	RBM
rod sequence control system	RSCS
rod worth minimizer	RWM

safe-shutdown earthquake	SSE
safety parameter display system	SPDS
safety/relief valve	SRV
scram discharge volume	SDV
small-break accident	SBA
sequence of events	SOE
source range monitor	SRM
standby gas treatment system	SGTS
standby liquid control system	SLCS
steam generation system	SGS
stuck open relief valve	SORV
supplemental cooling chilled water	SCCW
torus water management system	TWMS
traversing in-core probe	TIP
turbine building closed cooling water system	TBCCWS

Figure Intentionally Removed
Refer to Plant Drawing M-2001

FIGURE 1.7-1

SYMBOLS APPLICABLE TO
EDISON AND GEC FIGURES



NOTE 1. ALL SOLENOID VALVES SHOWN IN DE-ENERGIZED POSITION. "NE"–DENOTES SOLENOID IS NORMALLY ENERGIZED DURING PLANT OPERATION.

2. SYMBOLS INACTIVE FOR NEW DESIGN

GENERAL ELECTRIC

PARTS LIST FOR 197R567 CONT ON SHEET F SH NO. 1

REV NO. ∅ 1

PARTS LIST FOR Rev.1 1-30-70

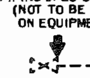
CONT ON SHEET SH NO.

TITLE PIPING AND INSTRUMENT SYMBOLS

FIRST MADE FOR

INSTRUMENT FUNTION / MEASURED VARIABLE (FIRST LETTER)		CONTROLLING (SECOND and THIRD LETTER) RECORDING	INDICATING	NON-INDICATING	CONTROL VALVE	SUMMER	FUNCTION GENERATOR	MEASURING (SECOND and THIRD LETTER) RECORDER	INDICATOR	OBSERVATION GLASS	PRIMARY ELEMENT	TEST POINT	TRANSMITTER OR PREAMP	INTEGRATOR	AMPLIFIER	SAMPLER	INDICATING SWITCH	NON INDICATING SWITCH	ALARMS	
		–RC	–IC	–C	–CV	–Σ	–f	–R	–I	–G	–E	–X	–T	–Q	Am	Sm	IS	–S	–A	
AIR	A	–	–	–	–	–	–	–	–	–	–	–	–	–	–	ASm	–	–	–	
CONDUCTIVITY	C	CRC	CIC	–	CCV	–	–	CR	CI	–	CE	CX	CT	–	–	CSm	CIS	CS	CA	
DENSITY	D	DRC	DIC	DC	DCV	–	–	DR	DI	–	–	DX	DT	–	–	–	DIS	DS	DA	
DIFF. PRESS.	dP	dPRC	dPIC	dPC	dPCV	–	–	dPR	dPI	–	–	–	dPT	–	–	–	dPIS	dPS	dPA	
FLOW	F	FRC	FIC	FC	FCV	FΣ	Ff	FR	FI	FG	FE	FX	FT	FQ	–	–	FIS	FS	FA	
HYDROGEN ION CONC.	pH	pHRC	pHIC	pHC	pHCV	–	–	pHR	pHI	–	pHE	pHX	–	–	pHAm	pHSm	–	–	–	
LEVEL	L	LRC	LIC	LC	LCV	–	–	LR	LI	LG	–	–	LT	–	–	–	LIS	LS	LA	
MOISTURE	M	MRC	MIC	–	–	–	–	MR	MI	–	ME	–	–	–	–	–	–	–	–	
NEUTRON FLUX	N	NRC	NIC	NC	–	–	–	NR	NI	–	NE	NX	NT	NQ	NAm	–	–	–	NA	
OXYGEN	O_2	–	–	–	–	–	–	O_2R	O_2I	–	O_2E	–	–	–	–	–	–	–	–	
PRESSURE	P	PRC	PIC	PC	PCV	–	–	PR	PI	–	–	PX	PT	–	–	–	PIS	PS	PA	
POSITION	Po	–	–	–	–	–	–	PoR	PoI	–	–	–	PoT	–	–	–	–	PoS	PoA	
RADIATION	R	–	–	–	–	–	–	RR	RI	–	RE	RX	–	–	RAm	RSm	–	RS	RA	
SPEED	S	SRC	SIC	SC	–	–	–	SR	SI	–	SE	–	–	–	–	–	–	–	–	
TEMPERATURE	T	TRC	TIC	TC	TCV	–	–	TR	TI	–	TE	TX	TT	–	–	–	TIS	TS	TA	
TIME	t	–	–	tC	–	–	–	–	tI	–	–	–	–	–	–	–	tIS	tS	–	
VIBRATION	Vb	–	–	–	–	–	–	VbR	VbI	–	–	–	–	–	–	–	–	VbS	VbA	
WEIGHT FACTOR	Wf	WfRC	WfIC	–	WfV	–	–	–	–	–	–	–	–	–	–	–	–	–	–	

PIPING SPEC CHANGE (NOT TO BE USED ON EQUIPMENT)



MISCELLANEOUS ABBREVIATIONS:

A/S	AIR SUPPLY
AW	ACID WASTE (CORROSIVE. CAUSTIC)
CIT	CONDUCTIVITY INDICATOR TRANSMITTER
CRD	CONTROL ROD DRIVE
CRDHS	CONTROL ROD DRIVE HYDRAULIC SYSTEM
CRS	CONDUCTIVITY RECORDING SWITCH
CRW	CLEAN RADWASTE
DRW	DIRTY RADWASTE
dTS	DIFFERENTIAL TEMPERATURE SWITCH
E/P	CONVERTER (VOLTAGE PNEUMATIC)
E/S	SPECIAL ELECTRIC POWER SUPPLY REQUIRED
FAI	FAIL AS IS (SEE NOTE 2)
FC	INDICATES CLOSES ON AIR OR ELECTRICAL FAILURE
FIT	FLOW INDICATOR TRANSMITTER
FO	INDICATES OPENS ON AIR OR ELECTRICAL FAILURE
FRCS	FLOW RECORDING CONTROLLER SWITCH
HCU	HYDRAULIC CONTROL UNIT
HS	HAND SWITCH (SEE NOTE 2)
IP	CONVERTER (CURRENT PNEUMATIC)
LC	LOCK CLOSED
L/DRS	LEVEL & DENSITY RECORDER SWITCH
LIM SW	LIMIT SWITCH
LIRS	LEVEL INDICATOR RECORDING SWITCH
LO	LOCK OPEN
LRS	LEVEL RECORDING SWITCH
MV/I	MILLIVOLT TO CURRENT CONVERTER
NC	NORMALLY CLOSED
ND	NORMALLY DE-ENERGIZED
NE	NORMALLY ENERGIZED
NO	NORMALLY OPEN
NW	NORMAL WASTE (CONVENTIONAL)
RBCCW	REACTOR BUILDING CLOSED COOLING WATER
RBEDT	REACTOR BUILDING EQUIPMENT DRAIN TANK
RM	REMOTE MANUAL
RMC	REMOTE MANUAL CONTROL
RMS	REMOTE MANUAL SWITCH
RPS	REACTOR PROTECTION SYSTEM
RPV	REACTOR PRESSURE VESSEL
SS	SELECTOR SWITCH
SSa	SELECTIVE SWITCH AUTOMATIC
SQ RT or √	SQUARE ROOT CONVERTOR
TBCCW	TURBINE BUILDING CLOSED COOLING WATER
tC	CYCLE TIMER
tdS	TIME DELAY SWITCH
TQOS	TORQUE OVERLOAD SWITCH
TQRS	TORQUE RECORDER SWITCH
TQT	TORQUE TRANSMITTER
TRS	TEMPERATURE RECORDER SWITCH

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UPDATED FINAL SAFETY ANALYSIS REPORT

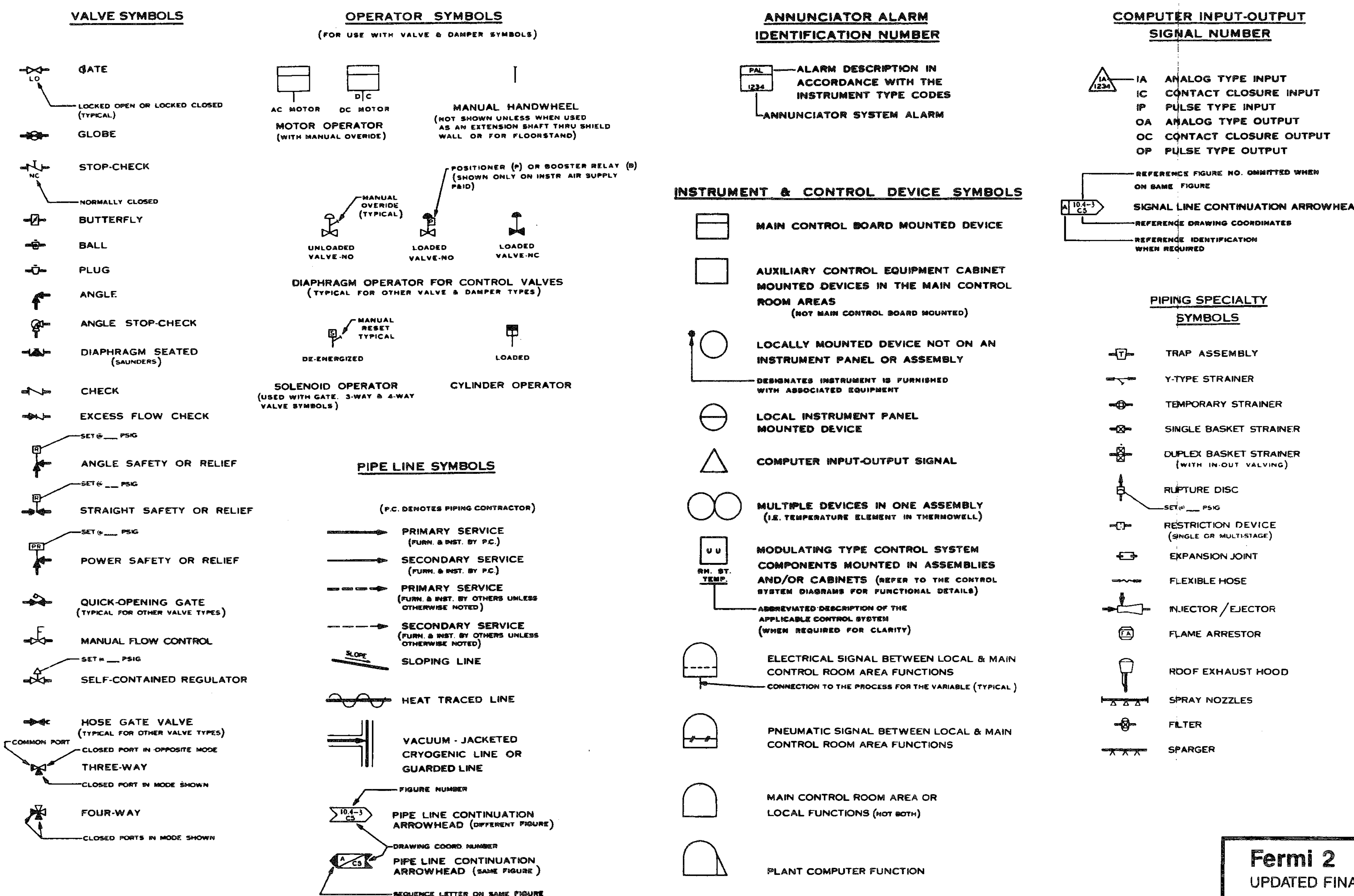
FIGURE 1.7-2

PIPING AND INSTRUMENTATION SYMBOLS APPLICABLE TO GE FIGURES

Figure Intentionally Removed
Refer to Plant Drawing 209A4756

FIGURE 1.7-3

LOGIC SYMBOLS USED ON GE/EDISON
FUNCTIONAL CONTROL DIAGRAMS



Fermi 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 1.7-4, SHEET 1

SYMBOLS APPLICABLE TO SARGENT & LUNDY FIGURES

INSTRUMENT TYPE CODES

FIRST LETTER

VARIABLE

(MEASURED OR INITIATING)

A	ANALYSIS
B	BURNER-FLAME
C	CONDUCTIVITY
D	DENSITY
E	VOLTAGE
F	FLOW
H	HAND (MANUAL)
I	CURRENT (ELEC.)
J	POWER (KW)
K	TIME
L	LEVEL (LIQUID OR SOLID)
M	MOISTURE (HUMIDITY)
N	NEUTRON FLUX
P	PRESSURE
R	RADIOACTIVITY
S	SPEED OR FREQUENCY
T	TEMPERATURE
U	MULTIVARIABLE
V	VIBRATION
W	WEIGHT
X	SPECIAL
Y	STRAIN
Z	POSITION

SECOND OR SUCCEEDING LETTERS

INSTRUMENT FUNCTION

A	ALARM
AC	ALARM CLOSED
AH	ALARM HIGH
AL	ALARM LOW
AO	ALARM OPEN
C	CONTROLLER (BLIND)
CD	CONTROL DAMPER
CK	CONTROLLER & HAND/AUTO
CV	CONTROL VALVE
D	DAMPER
DC	DIFFERENTIAL CONTROLLER
DI	DIFFERENTIAL INDICATOR
DK	DIFFERENTIAL CONTROL STATION
DR	DIFFERENTIAL RECORDER
DS	DIFFERENTIAL SWITCH
DT	DIFFERENTIAL TRANSMITTER
DY	DIFFERENTIAL RELAY
E	PRIMARY ELEMENT
EW	PRIMARY ELEMENT THERMOWELL
G	GLASS
I	INDICATOR
IC	INDICATING CONTROLLER
IR	INDICATING RECORDER
IS	INDICATING SWITCH
IT	INDICATING TRANSMITTER
IY	INDICATING RELAY
K	CONTROL STATION -VARIABLE TYPE-HAND. HAND-AUTO
L	LIGHT (PILOT)
Q	INTEGRATOR
R	RECORDER
RC	RECORDER CONTROLLER
S	SWITCH
SC	SWITCH - CLOSED DEVICE POSITION
SH	SWITCH HIGH
SI	SWITCH - INTERMEDIATE DEVICE POSITION
SL	SWITCH LOW
SO	SWITCH - OPEN DEVICE POSITION
SV	SOLENOID VALVE
T	TRANSMITTER
U	MULTIFUNCTION
V	VALVE - ON-OFF POWER-OPERATED TYPE
W	THERMOWELL
X	SPECIAL
Y	RELAY - SIGNAL CONVERTER, COMPUTING, ETC.
Z	POWER POSITIONER (EXCEPT VALVE MOUNTED)

CLARIFYING SYMBOL LIST

A	ANALOG SIGNAL	MAX	MAXIMUM
AVG	AVERAGE	MIN	MINIMUM
D	DIGITAL	N_2	NITROGEN
DIFF	SUBTRACT	N_2H_4	HYDRAZINE
DIR	DIRECT ACTING	O_2	OXYGEN
FC	FAIL CLOSED	pH	pH ANALYSIS
FI	FAIL INTERMEDIATE	REV	REVERSE ACTING
FL	FAIL LOCKED	SI	SILICA
FO	FAIL OPEN	SM	SMOKE OR IONIZATION
H_2	HYDROGEN	SP	SET POINT
HL	HIGH LIMIT	SQ. RT	SQUARE ROOT
HP	HIGH PASS	TURB	TURBIDITY
LL	LOW LIMIT	X	MULTIPLY
LP	LOW PASS		

PIPE LINE INSTRUMENT SYMBOLS

FE

FLOW NOZZLE OR VENTURI

FLOW NOZZLE OR VENTURI PIPE SECTION

FLOW ORIFICE (ORIFICE FLANGES BY P. C., UNLESS OTHERWISE NOTED)

FE — UNCLASSIFIED FLOW ELEMENT (MAGNETIC, TARGET, AIR FOIL, LAMINAR, ETC.)

SIGHT FLOW INDICATOR

ROTAMETER

PITOT TUBE

TURBINE METER

FLOW STRAIGHTENING VANES

AIR FILTER-PRV SET

PROCESS RADIATION MONITOR

TW — THERMOWELL

FS — FLOW SWITCH

AE — SAMPLE ELEMENT (ANALYSIS - CELL, PROBE, ETC.)

TEST CONNECTIONS

PRESSURE

GRAB SAMPLE

TEMPERATURE WHEN THERMOWELL IS NOT USED

FLOW

HVAC DUCT TEST FOR PRESSURE, TEMPERATURE AND / OR FLOW

PIPE LINE COMPONENT SYMBOLS

END CLOSURE (WELDED CAP)

END CLOSURE (SCREWED CAP)

END CLOSURE (BLIND FLANGE)

END CLOSURE (HOSE CONN)

REDUCER

OPEN FUNNEL DRAIN

CLOSED FUNNEL DRAIN

FLOOR DRAIN

ATMOSPHERIC VENT (WITH SCREEN)

THERMAL SLEEVE

RELIEF VALVE VENT PIPE SLIP JOINT

PENETRATION OF PRIMARY CONTAINMENT

HOT SIDE

PENETRATION OF OUTER SHIELD WALL

PENETRATION OF INNER SHIELD WALL

HVAC SYMBOLS

DUCTS

DUCTED AIR FLOW (FURN. & INST. BY HVAC CONTRACTOR)

NON-DUCTED AIR FLOW

DAMPERS

OPPOSED BLADE

NO / FO — NORMALLY OPEN / FAIL OPEN — TYPICAL

PARALLEL BLADE

NC / FC — NORMALLY CLOSED / FAIL CLOSED — TYPICAL

FAN INLET VANES

BUTTERFLY — NORMALLY CLOSED — NORMALLY OPEN

GRAVITY SHUTTER

FIRE DAMPER WITH FUSIBLE LINK

EQUIPMENT

CV — CONSTANT VOLUME BOX

RH — TERMINAL REHEAT ATTENUATOR

MB — MIXING BOX

ABBREVIATIONS

SA	SUPPLY AIR
RA	RETURN AIR
EA	EXHAUST AIR
OA	OUTSIDE AIR
MB	MIXING BOX
CV	CONSTANT VOLUME BOX
RH	TERMINAL REHEAT ATTENUATOR
H	HOT DUCT
C	COLD DUCT

FILTERS

PRE-FILTER

HEPA FILTER

MED EFF FILTER

CHARCOAL FILTER

INSTRUMENT & CONTROL SIGNAL SYMBOLS

INSTRUMENT TRANSMITTED PNEUMATIC SIGNAL NOT INSTRUMENT AIR SUPPLY (FURN. & INST. BY P.C.)

LINES NOT CONNECTED

LINES CONNECTED

INSTRUMENT TRANSMITTED PNEUMATIC SIGNAL (FURN. & INST. BY OTHERS UNLESS OTHERWISE NOTED)

LINES NOT CONNECTED

LINES CONNECTED

ELECTRICAL CONTROL & INTERLOCKING SIGNAL

LINES NOT CONNECTED

LINES CONNECTED

HYDRAULIC SIGNAL

LINES NOT CONNECTED

LINES CONNECTED

Fermi 2

UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 1.7-4, SHEET 2

SYMBOLS APPLICABLE TO SARGENT & LUNDY FIGURES

CHAPTER 2: SITE CHARACTERISTICS

2.1 GEOGRAPHY AND DEMOGRAPHY

Section 2.1 was prepared circa 1974 at the time of preparation of the original FSAR. It has not been updated in the area of geography and demography since it represents the area at the time the Construction Permit was issued. Minor changes were made in Subsection 2.1.3.5 in response to questions from the NRC in 1979.

2.1.1 Site Location

The Fermi 2 power plant is located at the Fermi site on the western shore of Lake Erie at Lagoona Beach, Frenchtown Township, Monroe County, Michigan (see Figures 2.1-1 through 2.1-3). The plant is approximately 8 miles east-northeast of Monroe, Michigan; 30 miles southwest of downtown Detroit, Michigan; and 25 miles northeast of downtown Toledo, Ohio.

The coordinates of the Fermi 2 reactor containment structure are latitude 41°57'48"N, and longitude 83°15'31"W. The Universal Transverse Mercator coordinates are 4,647,950 m north and 312,930 m east, Zone 17T.

2.1.2 Site Description

The Fermi site comprises approximately 1260 acres of land solely owned by The Detroit Edison Company (Edison). The site is bounded on the north by Swan Creek, on the east by Lake Erie, on the south by Pointe Aux Peaux Road, and on the west by Toll Road. Entrance to the site is from the west by way of Enrico Fermi Drive, a private road owned by Edison, and from the south via Pointe Aux Peaux Road to another private road also owned by Edison.

The northern and southern areas of the site are dominated by large lagoons. The western areas are dominated by several woodlots and quarry lakes. Site elevation ranges from the level of Lake Erie, on the eastern edge of the site, to approximately 25 ft above the lake level, on the western edge of the site.

An aerial photograph of the site taken May 5, 1983, is presented in Figure 2.1-4. A plot plan of the Fermi site showing the plant, its natural draft cooling towers, and other major structures is presented in Figure 2.1-5.

In accordance with 10 CFR l00, the exclusion area for Fermi 2 has been defined as that area within 915 m of the reactor containment structure. As indicated in Figure 2.1-5, this area encompasses a portion of adjoining Lake Erie.

2.1.2.1 Exclusion Area Control

The land portion of the exclusion area for Fermi 2 is entirely within the Fermi site. Consequently, Edison has the authority to determine all activities within the land portion of the exclusion area, including authority for the exclusion of personnel and property. No public roads, waterways, or railroads traverse the land portion of the exclusion area.

The Lake Erie shoreline of the plant site is unsuitable for beach activities. The limited beach area available is inaccessible to the public from the land side and is posted as private property. Few plant-unrelated activities are expected to take place on Lake Erie adjacent to the plant site. These will be primarily fishing from boats and pleasure craft; however, due to poor fishing and the shallow characteristics of the lake in this area, boating activities are not carried out in proximity to the shoreline. Past experience at the site has indicated the public has made little or no attempt to use the shoreline area or to approach the site from the lake. The emergency plans are described in Section 13.3.

2.1.2.2 Boundaries for Establishing Effluent Release Limits

The boundary used to establish Technical Specifications limits for the release of gaseous effluents from Fermi 2, in accordance with 10 CFR 20.106(a) and other related as-low-as-reasonably-achievable provisions, is based on the boundary of the Fermi site. The site boundaries for gaseous effluents and for liquid effluents shall be as shown in Figure 2.1-5. As shown in Figure 2.1-5, the closest on-land boundary line is approximately 915 m from the center line of the reactor building. This closest on-land boundary line corresponds to the maximum site boundary value of the meteorological dispersion parameter (c/Q) calculated for the baseline year 1974-1975.

Virtually all of the 1120-acre site is enclosed by a perimeter fence, restricting casual access to the property. Additionally, a fenced-in area surrounds the immediate plant area within the Fermi site, shown in Figure 2.1-5. Access to the plant area will be continually and actively controlled by Edison. Only those persons specifically authorized will have access to this area.

In those areas of the southern portion of the Fermi site outside the plant fenced-in area, the public will be permitted to use only those facilities specifically designated by Edison. Normal surveillance of these areas will be maintained by Edison, which, as sole owner of the entire Fermi site, has the authority to exclude personnel and property from the designated areas.

2.1.3 Population and Population Distribution

Figure 2.1-3 shows the locations of the municipalities and other cultural features surrounding the plant within 10 miles. Towns and cities in the region surrounding the plant within 50 miles are shown in Figure 2.1-2. These centers of population are listed in Table 2.1-1, along with their 1970 resident populations and their distances and directions from the plant.

2.1.3.1 Population Within 10 Miles

Within 10 miles of the plant, the estimated 1970 population was 63,963 persons; within 5 miles, it was 11,135 persons. The following communities, as identified by the 1970 Census of Population, and indicated in Figure 2.1-3, are within 10 miles of the plant:

	1973 Population	Distance (miles) and Direction from Plant
Stony Point	1,370	1 SSW
Estral Beach	419	2 NE
Woodland Beach	2,249	3 WSW
Detroit Beech	2,053	4 WSW
Monroe (closest point)	23,894	5.5 SW
South Monroe	3,012	6 SW
South Rockwood	1,477	8 N
Rockwood	3,119	9 N
Carleton	1,503	9 NW
Patterson Gardens	2,169	9 W

The City of Monroe and the villages of Estral Beach, South Rockwood, and Carleton are the only incorporated communities.

Estimates of the 1970 resident population within 5 miles of the plant were determined from house counts and 1970 census data. The house counts were determined from June 1970 aerial photographs obtained from the Southeast Michigan Council of Governments (SEMCOG) (Reference 1). House counts were converted to population by applying the ratios of persons to housing units obtained from 1970 census data (Reference 2). For the townships concerned (all in Monroe County), these ratios are

Berlin	3.53
Frenchtown	3.62
Ash	3.71

The resultant population data were assumed to be applicable, without adjustments, to April 1970.

Beyond the 5-mile radius, population estimates were based on 1970 census data (Reference 3) and the corresponding state map, account being taken of the population estimated to be within 5 miles of the plant. Use was made of data for the smallest applicable census unit (e.g., village, town, city, or township). From this state map, census units within each segment of the population wheel were identified, and their fractions within each segment determined. It was assumed that the population within each census unit was uniformly distributed.

Population projections for areas within 10 miles for the years 1980, 1990, 2000, 2010, and 2020 were based on corresponding projections for the individual counties concerned. There were no population projections available for census units smaller than counties. It was assumed that each component (or fraction) of a county had the same decennial rate of growth as that for the county as a whole.

Monroe and Wayne are the only counties with areas within 10 miles of the plant. Projections by SEMCOG were available for both counties for 1970, 1980, and 1990 (Reference 1). The

1970-1980 and 1980-1990 decennial rates of growth derived from these projections were applied to the 1970 census data to obtain the projected 1980 and 1990 populations. The projected 2000, 2010, and 2020 populations of the counties were derived by assuming their decennial rate of growth from 1990 to 2020 to be constant and equal to the average of the 1970-1980 and 1980-1990 rates of growth.

Figure 2.1-6 shows the estimated 1970 population distribution within 10 miles of the plant. Figures 2.1-7 through 2.1-11 show corresponding projected populations for the years 1980, 1990, 2000, 2010, and 2020. These projected population data are the unrounded mathematical results of the methods described above.

2.1.3.2 Population Between 10 and 50 Miles

The 1970 population and projections between 10 and 50 miles were determined in accordance with the method used for the area between 5 and 10 miles from the plant. For the areas within Canada, use was made of the June 1, 1971, Canadian census data (Reference 4) and corresponding provincial map. Using data from the previous Canadian census of June 1, 1966 (Reference 5), and assuming linearity, the 1971 Canadian census data were adjusted to April 1, 1970, so they would coincide with the 1970 U.S. census data.

For population projection purposes, counties between 10 and 50 miles of the plant were divided into four groups:

a. SEMCOG counties

b. Other Michigan counties

c. Ohio counties

d. Canadian counties.

The SEMCOG counties are Monroe, Wayne, Oakland, Macomb, Livingston, and Washtenaw. Wayne County was separated into two parts consisting of Detroit, and Wayne County minus Detroit. Projected populations for these counties for the years 1980-2020 were obtained as explained in Subsection 2.1.3.1 for Monroe and Wayne County projections at 5 to 10 miles. The projected 1980 and 1990 populations for Detroit were similarly derived; however, its population was assumed to remain unchanged (rather than to continue decreasing) from 1990 to 2020.

Other Michigan counties consist of Jackson and Lenawee. The projected populations for each of these counties were derived by assuming their decennial rates of growth from 1970 to 2020 to be constant and equal to the average of their 1960-1970 rates of growth, obtained from census data, and their 1970-1980 rates of growth, derived from 1970 census data and their 1978 population estimated by the State of Michigan (Reference 6).

The Ohio counties consist of Seneca, Sandusky, Ottawa, Lucas, Huron, Henry, Fulton, Erie, and Wood. The projected populations for each of these counties were derived by assuming their decennial rates of growth from 1970 to 2020 to be constant and equal to the 1970 to 1980 rates of growth obtained from 1970 to 1975 to 1980 to 1985 projections by the State of Ohio (Reference 7).

Official projections for Essex and Kent, the two Canadian counties, were not available. Projected 1980-2020 populations of these counties were based on their adjusted April 1, 1970, populations and were derived by assuming their decennial rates of growth from 1970 and 2020 to be constant and equal to their 1961-1971 rates of growth determined from Canadian census data.

Figure 2.1-6 shows the estimated 1970 population distribution between 10 and 50 miles from the plant. Figures 2.1-7 through 2.1-11 show corresponding projected populations for the years 1980, 1990, 2000, 2010, and 2020. These projected population data are the unrounded mathematical results of the methods described above.

2.1.3.3 Low-Population Zone

In accordance with criteria specified in 10 CFR 100, the outer boundary of the low-population zone (LPZ) for Fermi 2 will be 3 miles (4827 m) from the containment structure. The estimated resident population distribution within this distance for the years 1970 through 2020 is shown in Table 2.1-2. Population distribution for distances up to 50 miles from the plant is shown in Figures 2.1-6 through 2.1-11; a detailed map of the LPZ is shown in Figure 2.1-12.

The area within the LPZ does not contain either agricultural or industrial activities that would create a daily transient population of any magnitude. Therefore, other than the recreational activities that draw daily users, the daily population is relatively stable. As stated in Subsection 2.1.4.2.3, the population in the communities within the LPZ that have beach and boating facilities is predominantly permanent, and the facilities are for resident use. The schools, hospitals, institutions, and recreational areas are shown in Tables 2.1-3 through 2.1-5.

Sterling State Park and Point Mouillee State Game Area are approximately 5 miles from the Fermi 2 site and annually attract about 385,000 and 180,000 visitors, respectively, as shown in Table 2.1-5. Approximately 70 percent of use occurs between April and November.

2.1.3.4 Transient Population

2.1.3.4.1 Seasonal Agricultural and Horticultural Labor

Needs for seasonal agricultural and horticultural labor (including migrant workers) in Monroe County are listed in Table 2.1-6. Peak requirements, which occur in the month of October, are for a total of about 2335 seasonal workers, 34 percent of whom are expected to be migrant workers. Needs for such seasonal labor are at a minimum during the winter months, down to a total of about 230 workers, 12 percent of whom would be migrant workers. Following are 1972 data on migrant workers within 10 miles of Fermi 2 (Reference 8):

Employers	Number of Migrant Workers	Distance (miles) and Direction From Plant
Smith and Son	75	8 NW
J. F. Ilgenfritz	30	10 WSW

Employers	Number of Migrant Workers	Distance (miles) and Direction From Plant
Tracy Gaynier	12	11 SW
Don Wolmer	20	12 WSW
Walter Iott	20	12 WSW

2.1.3.4.2 Historical Attractions

There are two facilities in the City of Monroe that draw large numbers of visitors each year: the Custer Museum, 8 miles west-southwest of the plant; and the Monroe County Historical Museum, 8 miles west-southwest of the plant. In 1972, the former had approximately 12,000 visitors and the latter about 45,000 (Reference 9).

2.1.3.4.3 Commuters

Monroe and Wayne are the only two counties with areas within 10 miles of the plant site. Monroe County has an inflow of 1500 commuters and an outflow of 19,292 commuters, a net loss of 17,792 individuals per day. Wayne County, with an inflow of 139,305 and an outflow of 165,754 commuters, has a net loss of 26,449 individuals per day (Reference 10).

2.1.3.4.4 Seasonal Homes

Within 10 miles of the plant, according to the 1970 census data, there were 51 seasonal homes in Monroe County and 26 in Wayne County (Reference 11).

Many of the houses that had been used in the past as summer cottages are currently used as permanent homes.

2.1.3.5 Population Center

The nearest population center, as defined in 10 CFR 100, is the City of Monroe, which had a 1970 population of 23,894. Its nearest corporate boundary is approximately 5.5 miles southwest of Fermi 2.

The residential population distribution of the city and the surrounding jurisdiction (Frenchtown Township) shows this distance to be a valid, conservative figure for use as the population center distance. The concentrated residential section of the city is farther distant from the plant site, with the closest portion of the city along the northeastern boundary being predominantly open for industrial development (Reference 12).

Frenchtown Township in 1977 was composed of scattered, small residential clusters and a few small communities along the shore of Lake Erie (Reference 13). The 1975 total population was estimated to be 15,900 over a land area of 27,000 acres an average density of about 0.6 person/acre (Reference 13). Future land use and residential population distribution for the city and township were also examined to determine the potential influence of proposed growth on the population center distance. The Monroe land use plan did not propose further expansion on the northeast edge of the city. Some annexation had taken place on the west, but further annexation was not considered likely in 1979 (Reference 14).

The land area within the city boundary was slated to remain predominantly open or industrial. One small tract (approximately 39 acres) was proposed for potential residential development (Reference 12). The future growth of Monroe based on data available in 1979 would not create any densely populated residential land closer than 5.5 miles from Fermi 2.

Land use plans for Frenchtown Township indicated that future residential growth will take place in the vicinity of Fermi 2. Land use plans call for development of the corridor between Monroe and Fermi 2 and along the Lake Erie shore (Reference 13). A mixture of land uses was proposed; however, it was mainly recreational and low density (average of one dwelling unit per acre) and medium density (1 to 4 dwelling units per acre) residential. A 450-acre tract on the northeastern corner of the growth area had been rezoned from agricultural to residential use. This land, like most of the area, had severe soil limitations based on high water table, fair-to-poor bearing capacity, and moderate volume change. For this reason, the staff of the Monroe County Planning Commission had reservations about the residential rezoning of the site and suggested rezoning only for low density (Reference 15) (one dwelling unit per acre).

Based on the distribution and density of the proposed future land use, Frenchtown Township was not expected to form a contiguous extension of the population center of Monroe or develop into a separate densely populated center. From these facts it was apparent that the 5.5-mile population center distance would remain valid in the future.

2.1.3.6 Public Facilities and Institutions

A survey was conducted to locate public facilities and institutions, such as schools, hospitals, prisons, and parks, within 10 miles of the plant.

2.1.3.6.1 Schools

Schools within 10 miles of the plant are listed in Table 2.1-3 and indicated in Figure 2.1-13 (References 16 through 20). Closest to the plant is the Brest School at Woodland Beach (2.5 miles west-southwest) with a 1972 enrollment of 163. The Monroe County Community College, a 2-year college, is located 11 miles west-southwest of the plant and had a 1972 enrollment of 1676 students.

2.1.3.6.2 Hospitals

Data on hospitals and nursing facilities are contained in Table 2.1-4 (References 21 through 26). The closest facility to the plant is the Frenchtown Convalescent Center, 6 miles west, with 226 beds.

2.1.3.6.3 Prisons

The only jail within 10 miles of the plant is the Monroe County Jail, located in the City of Monroe. It has an average of 50 inmates per day (Reference 27).

2.1.3.6.4 Recreational Areas

Recreational areas within 10 miles of the plant are listed in Table 2.1-5 and indicated in Figure 2.1-14 (References 9 and 28 through 30). The recreational facilities closest to the plant are Stony Point Beach, about 2 miles south, and Estral Beach, 2 miles northeast. Swimming is reported to take place there. The largest facility in the area is Sterling State Park, 5 miles southwest of the plant.

2.1.4 Uses of Adjacent Lands and Waters

2.1.4.1 Agricultural Activities

Approximately 95 percent of the land area within 10 miles of Fermi 2 is within Monroe County, with the remaining 5 percent in Wayne County. About 71 percent of the land in Monroe County was used for farming; however, only 55 percent of the land within 10 miles of the plant consisted of farms. Farmland use within 10 miles of the plant in 1973 was as follows (Reference 31):

Crop	Percentage of Farmland
Soybeans	50
Corn	22
Wheat	7
Miscellaneous (vegetables, hay, oats, and grazing and pastureland)	7
Idle Cropland	14
Total	100

Data on the principal crops grown within 10 miles of the plant site in 1973 (Reference 31) were as follows:

Crop	Acreage	Annual Production (bushels)	Value
Soybeans	21,000	840,000	$2,940,000
Corn	9,500	902,500	$1,173,250
Wheat	3,150	126,000	$252,000

All soybeans and wheat were sold as cash crops. Approximately 75 percent of the corn was sold as a cash crop; the remaining 25 percent was used for feed.

The large livestock, poultry, and crop farms located within the environs of the Fermi site in 1973 are listed below:

Owner	Farm Type and Information	Distance (miles) and Direction From Plant
Ronald Welb	Poultry – 2,500 laying hens	5 NW
Del Chapman	Livestock – 1,500 sheep	7 N
Smith and Sons	Vegetables and greenhouse products	8 NW
Butler Farms	Livestock – 500 beef cattle	10 W
St. Mary's Farm	Livestock – 200 beef cattle	10 W
Clayton Dick	Poultry – 15,000 to 20,000 laying hens	16 WSW
Lennard and Sons	Potato farm - 2,000 acres	16 WSW

The Lennard and Sons farm was the largest potato farm in the State of Michigan, with a gross annual income of approximately $1.8 million. The Smith and Sons farm was one of the largest vegetable and greenhouse-product producers in the State of Michigan, with a gross annual income exceeding $500,000.

Table 2.1-7 contains data on the 29 dairy farms within l8 miles of the plant in 1971, and Figure 2.1-15 indicates their locations. Ten of these dairy farms were within 10 miles. The closest, owned by John Reiger and containing about 30 milking cows, was approximately 4 miles west of the plant. The only other dairy farm within 5 miles was that of Henry Noel. This dairy farm was approximately 5 miles northwest of the plant and had approximately 25 milking cows in 1973 (References 32, 33, and 34). The productive cows nearest the plant were located 3 miles north-northwest. Milk from these four cows was used for home consumption.

Livestock and dairy operations within 10 miles of the plant had been going out of business. Tax increases over the past years (an increase of $40 per acre in 1972) and attractive offers for farmland ($1000 to $1500 per acre) resulted in many farmers selling their grazing and pastureland and accepting employment with local industries (Reference 31). Agricultural statistics for Monroe County indicated that in 1964 there were approximately 3549 dairy cattle. In 1972 there were only 2100 dairy cattle. The County Agricultural Cooperative Extension Service was then discouraging new livestock and dairy operations within the county; however, it was assisting established farms to remain in operation. Crop farmers in the county were able to continue their operations due to the high productivity of the land, which compensated for the large tax increases (Reference 31).

In 1967, approximately 10 percent (approximately 37,700 acres) of the county's land was developed. However, agricultural land was being rapidly developed for nonagricultural purposes as the county became more urbanized. The comprehensive development plan of 1967 (Reference 35) for Monroe County called for the retention of agricultural land to serve as buffers between recommended major development corridors. Accordingly, this plan specified that the majority of land located west of U.S. Route 23 and U.S. Route 24, and west of Interstate 75 in the northeast quadrant of the county, be reserved primarily for agricultural use (Figure 2.1-16).

Economic projections showed that as the county grew and became more urbanized, some farmlands would be lost to urban development and farm employment would decrease. Farm employees would continue to be attracted to high-paying nonagricultural occupations, and farms would adopt additional labor-saving methods and machinery. It was estimated that by 1980 farm employment in the county would decrease to about 2 percent of the labor force as compared to 5.8 percent in 1960 (Reference 35).

The small portion of Wayne County within 10 miles of the plant was predominantly a residential area and had only a limited amount of agricultural activity: small crops of field corn, soybeans, hay, and some fresh market vegetables. There were no dairy farms in this area in 1973 (Reference 36).

Agricultural statistics of all counties within 50 miles of the plant site are presented in Tables 2.1-8 through 2.1-11 for the 1969 to 1971 time period (References 37 and 38).

2.1.4.2 Water Uses

The most prominent body of water in the environs of the Fermi site is Lake Erie. Rivers and streams entering Lake Erie within 10 miles of the site are shown in Figure 2.1-17. The five drainage basins within a 10-mile radius of the site are as follows (Reference 39):

Drainage Basin	Drainage Area (square miles)
Area between the Huron and Rouge Basins	120
Huron River	923
Stony and Swan Creeks	290
River Raisin	1,043
Southeast Monroe County	189

A detailed description of the hydrology of the region is presented in Section 2.4.

2.1.4.2.1 Potable Water Supplies

As shown in Figure 2.1-18, privately owned wells and four municipal water systems served the area within 10 miles of the Fermi site in the 1970 time period. The four municipal systems are those of Detroit, Monroe, Flat Rock, and Toledo (Ohio).

The Detroit system served most of Wayne County. In the area within 10 miles of the plant, this water system served portions of Brownstown Township, Rockwood, South Rockwood, the City of Carleton, and Berlin Township. The Flat Rock system served portions of Brownstown Township and Rockwood. The Monroe system, which has its intake on Lake Erie, served most of Frenchtown Township, the City of Monroe, and Monroe Township. The service area of the Toledo system included portions of La Salle and Erie Townships. Although these municipal water systems provided services in these areas, homeowners who had wells prior to the construction of the municipal water services were not obligated to use them. Consequently, about 15 percent of the homeowners in the service areas of these municipal systems were still obtaining their potable water from individually owned wells.

Owners of newly constructed dwellings in these service areas, however, were obligated to obtain their potable water from the municipal system.

Within 10 miles of the plant, homeowners outside the service areas of the municipal systems obtained their potable water from individually owned wells. These wells ranged in depth from 50 to 120 ft; however, well depths generally do not exceed 70 ft (Subsection 2.4.13.2). Throughout Monroe County there were approximately 6000 active wells in 1972, mostly in the western half of the county. The number of wells drilled from 1964 to 1972 in each of the townships wholly or partially within a 10-mile radius of the Fermi site was reported (Reference 40) to be as follows:

Frenchtown	336
Ash	216
Raisinville	324
Berlin	207
Monroe	115
Exeter	132
La Salle	288

Figure 2.1-19 shows the approximate number of wells in use in 1972 and their distribution within 10 miles of the currently unused quarry at the Fermi site (Reference 41).

The quality of well-water in Monroe County is generally poor. Efforts were being made for expanded use of municipal water services from the Detroit, Monroe, and Toledo systems. Plans in 1973 showed that Toledo would eventually serve not only La Salle and Erie Townships, but Bedford and Whiteford Townships as well (Reference 40). The Monroe system was planning a new treatment facility in the same region as the 1973 facility to increase the intake capacity to 4.5 billion gal per year, an increase of approximately 125 percent over the 1973 capacity. Future plans called for the servicing of the entire Frenchtown region, Raisinville, Dundee, and parts of London Township. No data on initial construction were available in 1972 (Reference 42). The Monroe water system has its intake on Lake Erie, in the Pointe Aux Peaux region, approximately 1 mile south of the Fermi site. The intake is 5260 ft long and 2.5 ft in diameter (Reference 43).

The 1973 plans for the Detroit water system showed that Ash Township was considering the use of Detroit water, while Exeter and London Townships were negotiating for service (Reference 40).

At one time, bottled water was being used as potable water by the communities along the Lake Erie shoreline because of the poor quality of the well-water. This condition has since been alleviated as a result of the services provided by the municipal water systems (Reference 40).

The following 1973 data on other municipal water systems in Monroe County (Reference 43) are provided for reference:

System	Source	Distance (miles) and Direction From Plant	Yearly Production (millions of gallons)	Area Served
Village of Dundee	River Raisin	19 W	70.8	Village of Dundee
Village of Petersburg	2 wells	21 WSW	53.0	Village of Petersburg

The Flat Rock water intake is located on the Huron River at a point about 10 miles north of the plant. Its average withdrawal is about 750,000 gal per day (Reference 44).

Data on municipal water intakes (including those of Toledo and Monroe) from Lake Erie are presented in Table 2.1-12 (1969-1972 data). The locations of the intakes for these municipal water systems are shown in Figure 2.1-20 (References 31, 45, and 46).

2.1.4.2.2 Agricultural Water Supplies

Within 10 miles of the plant in 1973, the Smith and Sons farm was the only agricultural user of surface water. The intake of this farm was on Swan Creek, at a point about 8 miles northwest of the plant. Water from this intake was used for irrigation and cattle watering. Within 50 miles of the plant, there were no known withdrawals of water from Lake Erie for agricultural irrigation or livestock watering. Previously existing withdrawals for agricultural purposes had been discontinued in this area. This was primarily a result of the residential development along the lakeshore (Reference 31).

2.1.4.2.3 Recreational Water Uses

Along the shoreline of Lake Erie in Monroe County there are numerous communities with beach and boating facilities.

Recreational activities at these places include swimming, water-skiing, motorboating, and sportfishing. The following are the principal recreational areas in the environs of the Fermi site:

Community	Distance (miles) and Direction From Plant
Pointe Aux Peaux	1 S
Stony Point	1 SSW
Estral Beach	2 NE
Woodland Beach	3 WSW
Detroit Beach	4 WSW
Avalon Beach	9 SW
Toledo Beach	11 SW
Luna Pier	15 SW

The majority of the homes in these communities were at one time used as summer cottages; however, most of them were being used as permanent homes in 1973. The water quality along the beaches of these communities was below that required by applicable standards for sports involving body contact with the water. Sterling State Park, located along the Lake

Erie shoreline 5 miles southwest of the plant site, was closed for swimming because of poor water quality. However, in spite of water quality and water-quality standards, water-sport activities continued to take place on the shoreline area in 1973 (Reference 40).

2.1.4.2.4 Fishing

Sportfishing activities in the general environs of the Fermi site are conducted off the shores of Lake Erie and along the shores of the River Raisin, and Stony and Swan Creeks. Lake Erie fish include carp, sheepshead, bullheads, suckers, channel catfish, white bass, yellow perch, and walleye. Fish in the River Raisin and Stony and Swan Creeks include panfish, suckers, catfish, perch, and bass (Reference 47).

There were approximately six commercial fishermen in 1973 who used the shores of Lake Erie in the Monroe County area. In 1971, the fish catch was approximately 172,736 lb, representing an estimated value of $24,343 (Reference 47). Commercial fishing in this area slackened over the 2-year period of 1972 and 1973 because of low availability of fish. However, as a result of improving conditions, it was predicted that commercial fishing would increase.

A summary of commercial fish landings taken from Lake Erie statistical districts in 1971 is presented in Table 2.1-13 for the Province of Ontario, and Table 2.1-14 for the State of Ohio (References 48 and 49). The respective districts are illustrated in Figure 2.1-21.

2.1.4.2.5 Industrial Water Use

Within 10 miles of the plant site, 1974 industrial users of Lake Erie water included the Fermi l Power Plant, the Monroe Power Plant, Union Camp Corporation, and Consolidated Packaging Corporation. The Fermi 1 plant, an oil-fired peaking unit located on the Fermi site, drew both potable and cooling water from Lake Erie. Potable water usage during 1971 and 1972 was 25 million gal per year and 19 million gal per year, respectively. It should be noted that the potable water system for Fermi 1 was the source of demineralized water for the construction of Fermi 2. Cooling water use averaged approximately 72 million gal per day when Fermi 1 was in operation. The Fermi 1 breeder reactor and oil-fired power plant have been permanently decommissioned. Four combustion turbine peakers are still in use on the site. The Monroe Power Plant, which is approximately 6 miles south-southwest of the Fermi site, obtains the major portion of its cooling water from Lake Erie at an intake located about 1300 ft from Lake Erie on the River Raisin. Monroe Unit 1 began operating in 1971, Unit 2 in 1972, Unit 3 in 1973, and Unit 4 in 1974. Each of these four units requires an average of 350,000 gpm for cooling purposes. Discharge is through a canal to Lake Erie. Their potable water supply is obtained from the City of Monroe (Reference 50).

The Union Camp Corporation (Reference 51) and the Consolidated Packaging Corporation (Reference 52), both located in the City of Monroe, have their Lake Erie intakes in the Sterling State Park region, which is approximately 5 miles southwest of the Fermi site. The water is piped approximately 3 miles overland to the corporate sites. After usage, it is discharged into the River Raisin at a point approximately 2 miles inland from Lake Erie. Both of these industries share the same pumping and discharging facilities. Their average daily withdrawals are approximately 3 million and 2.6 million gal, respectively. Both facilities obtain their potable water supplies from the Monroe municipal water system.

In Monroe, the Ford Motor Company has a large manufacturing plant (2700 employees) that has a water intake on the River Raisin at a point approximately 1.2 miles upriver from Lake Erie. From this intake, the Ford plant draws an average of approximately 12 million gal per day. This water is used for industrial purposes only. The potable water required for the plant is obtained from the City of Monroe at the rate of 200,000 gal per day (Reference 53).

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27. Louise Moore, NUS Corporation, and Lieutenant Brown, Monroe County Sheriff's Office, Monroe, Michigan, Meeting, February 1, 1973.
28. Gerald Edgley, NUS Corporation, and Mr. James Akers, Director of Environmental Health, Monroe County, Monroe, Michigan, Telephone Conversation, February 17, 1973.
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Water Systems	Name	Title
Ashtabula	Mr. Smith	Administrative Assistant
Conneaut	Mr. Coates	Chief Operator
Vermilion	Mr. Strittrather	Superintendant of Water
Lorain	Mr. Emerick	Superintendant of Water
Cleveland	Mr. Mash	Duty Project Engineer
Fairport	Mr. Killimen	Superintendant of Water
Erie	Mr. Prazer	Bureau Chief
Buffalo	Mr. Martin	Senior Administrative Assistant
Dunkirk	Mr. Smagner	Assistant Operator
Port Colborne	Mr. Farbiak	Area Foreman
Port Maitland	Mr. Sakamopo	Project Service Manager
Port Stanley	Mrs. Taylor	Secretary-Treasurer
Blenheim	Mr. Gawley	Secretary-Treasurer
Leamington	Mr. Sanger	Secretary-Treasurer
Kingsville	Mr. Sanger	Secretary-Treasurer
Detroit	Mr. Janeczko	Public Information
Monroe	Mr. J. D. D’Haene	Supervisor of Filtration
Toledo	Mr. Hixson	Chief Engineer for Water
Port Clinton	Mr. Held	Chief Operator
Sandusky	Mr. Showalter	Assistant Superintendant
Huron	Mr. Hetrick	Director of Utilities
Port Dover	Mr. Barry	Foreman
Wheatly	Mr. Thompson	Secretary-Treasurer

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TABLE 2.1-1 TOWNS AND CITIES WITHIN 50 MILES OF THE FERMI SITE

Town/City[a]	1970 Population	Distance (miles) and Direction From Site
0-10 Miles		
Stony Point	1,370	1 SSW
Estral Beach	419	2 NE
Woodland Beach	2,249	3 WSW
Detroit Beach	2,053	4 WSW
Monroe (closest point)	23,894	5.5 SW
South Monroe	3,012	6 SW
South Rockwood	1,477	8 N
Patterson Gardens	2,169	9 W
Rockwood	3,119	9 N
Carleton	1,503	9 NW
10-20 Miles		
Flat Rock	5,643	11 N
Gibralter	3,325	11 NNE
Amherstburg, Ontario (Canada)	5,045	12 NE
Luna Pier	1,418	12 SW
Woodhaven	3,330	13 N
Trenton	24,127	13 NNE
Maybee	485	14 WNW
Grosse Ile	7,799	15 NNE
Riverview	11,342	17 NNE
Harrow, Ontario (Canada)	1,964	18 ENE
Southgate	33,909	18 N
Harbor View, Ohio	238	19 SSW
Reno Beach, Ohio	1,049	19 S
Wyandotte	41,061	19 NNE
20-30 Miles		
Dundee	2,472	20 W
Taylor	70,020	20 N
Belleville	2,406	21 NNW
Allen Park	40,747	22 N
Ecorse	17,515	22 NNE

TABLE 2.1-1 TOWNS AND CITIES WITHIN 50 MILES OF THE FERMI SITE

Town/City[a]	1970 Population	Distance (miles) and Direction From Site
Lambertville	5,721	22 SW
Lincoln Park	52,984	22 NNE
Melvindale	13,862	23 NNE
Petersburg	1,227	23 W
River Rouge	15,947	23 NNE
Milan	4,533	24 WNW
Dearborn	109,358	25 N
Inkster	38,420	25N
Norwood	30,420	25 SSW
Toledo, Ohio	383,818	25 SW
Wayne	21,054	25 NNW
Clay Center	370	26 S
Essex, Ontario (Canada)	3,941	26 NE
Deerfield	834	27 W
Detroit	1,511,482	27 NE
Garden City	41,864	27 N
Kingsville, Ontario (Canada)	3,952	27 ENE
Ottawa Hills, Ohio	4,270	27 SW
Dearborn Heights	80,069	28 N
Milbury, Ohio	771	28 SSW
Sylvania, Ohio	12,031	28 SW
Windsor, Ontario (Canada)	200,790	28 NNE
Westland	86,749	28 NNW
Ypsilanti	29,538	28 NW
Britton	697	29 W
Genoa, Ohio	2,139	29 S
Rocky Ridge, Ohio	385	29 S
Rossford, Ohio	5,302	29 SSW
Walbridge, Ohio	3,208	29 SSW
30-40 Miles		
Highland Park	35,444	31 NNE
Oak Harbor, Ohio	2,807	31 SSE
Put-In-Bay, Ohio	135	31 SE
Saline	4,811	31 WNW
Tecumseh, Ontario (Canada)	124	31 NE
Blissfield	2,758	32 WSW

TABLE 2.1-1 TOWNS AND CITIES WITHIN 50 MILES OF THE FERMI SITE

Town/City[a]	1970 Population	Distance (miles) and Direction From Site
Elmore, Ohio	1,316	32 S
Holland, Ohio	1,108	32 SW
Maumee, Ohio	15,937	32 SW
Perrysbury, Ohio	7,693	32 SW
Plymouth	11,758	32 NNW
St. Clair Beach, Ontario (Canada)	1,931	32 NE
Ann Arbor	99,797	33 WSW
Berkey, Ohio	294	33 S
Woodville, Ohio	1,834	33 S
Hamtramck	27,245	34 NNE
Hazel Park	23,784	34 NNE
Leamington, Ontario (Canada)	10,229	34 E
Port Clinton, Ohio	7,202	34 SSE
Grosse Pointe Park	15,585	35 NNE
Grosse Pointe	6,637	36 NNE
Luckey, Ohio	996	36 SSW
Oak Park	36,762	36 N
Tecumseh	7,120	36 W
Farmington	13,337	37 N
Belle River, Ontario (Canada)	2,739	37 NE
Metamora, Ohio	594	37 WSW
Northville	5,400	37 NNW
Clinton	1,677	37 WNW
Ferndale	30,850	38 NNE
Gibsonbury, Ohio	2,585	38 S
Grosse Pointe Farms	11,701	38 NNE
Huntington Woods	8,536	38 N
Lathrup Village	1,429	38 N
Novi	9,668	38 NNW
Pemberville, Ohio	1,301	38 SSW
Quaker Town	837	38 N
Pleasant Ridge	3,989	38 N
Berkley	22,618	39 N
Center Line	10,379	39 NNE
Grosse Pointe Shores	3,042	39 NNE
Grosse Pointe Woods	21,878	39 NE
Harper Woods	20,186	39 N
Marblehead, Ohio	726	39 SE

TABLE 2.1-1 TOWNS AND CITIES WITHIN 50 MILES OF THE FERMI SITE

Town/City[a]	1970 Population	Distance (miles) and Direction From Site
Wood Creek Farms	1,090	39 N
40-50 Miles		
Adrian	20,382	40 W
Franklin	10,075	40 N
Haskins, Ohio	549	40 SW
Quaker Town North	7,101	40 N
Royal Oak	85,499	40 N
Bay View	798	41 SE
Beverly Hills	13,598	41 N
Bingham Farms	566	41 N
East Detroit	45,920	41 NNE
Helena, Ohio	298	41 S
Madison Heights	38,599	41 NNE
Southfield	69,285	41 N
South Lyon	2,675	41 NNW
Warren	179,260	41 NNE
Waterville, Ohio	2,940	41 SW
Wheatley, Ontario (Canada)	1,631	41 ENE
Ballville, Ohio	1,652	42 S
Birmingham	26,170	42 N
Clawson	17,617	42 N
Dexter	1,729	42 NW
Fremont, Ohio	18,490	42 SSE
Manchester	1,650	42 WNW
St. Clair Shores	88,093	42 NNE
Stoney Prairie, Ohio	1,913	42 S
Witmore Lake	2,763	42 NW
Wixom	2,010	42 NNW
Bowling Green, Ohio	21,760	43 SSW
Bradner, Ohio	1,140	43 S
Roseville	60,529	43 NNE
Tontogany, Ohio	395	43 SW
Walled Lake	3,759	43 NNW
Bloomfield Hills	3,672	44 N
Castalia, Ohio	1,045	44 SSE
Fraser	11,868	44 NNE

TABLE 2.1-1 TOWNS AND CITIES WITHIN 50 MILES OF THE FERMI SITE

Town/City[a]	1970 Population	Distance (miles) and Direction From Site
Sandusky, Ohio	32,674	45 SE
Lyons, Ohio	630	45 WSW
Troy	39,419	45 N
Wayne, Ohio	921	45 SSW
Wolverine Lake	4,301	45 NNW
Delta, Ohio	2,544	46 WSW
Orchard Lake Village	1,487	46 N
Sterling Heights	61,365	46 NNE
Burgoon, Ohio	221	47 S
Clyde, Ohio	5,503	47 SSE
Portage, Ohio	494	47 SSW
Chelsea	3,858	48 NW
Bettsville, Ohio	833	48 S
Brighton	2,457	48 NNW
Grand Rapids, Ohio	976	48 SW
Keego Harbor	3,092	48 N
Milford	4,699	48 NNW
Onsted	555	48 W
Rising Sun, Ohio	730	48 S
Sandusky South, Ohio	8,501	48 SE
Sylvan Lake	2,219	48 N
Tilbury, Ontario (Canada)	2,572	48 ENE
Green Springs, Ohio	1,279	49 SSE
Pontiac	85,279	49 N
Utica	3,504	49 NNE
West Milgrove, Ohio	215	49 SSW
Weston, Ohio	1,269	49 SSW
Clair Haven West	1,367	50 NNE
Clayton	773	50 W
Mt. Clemens	20,476	50 NNE
Jerry City, Ohio	470	50 SSW
Pinckney	921	50 NW

a. Towns and cities identified by the 1970 Census of Population.

TABLE 2.1-2 POPULATION DISTRIBUTION WITHIN THE LOW-POPULATION ZONE

Direction	1970	1980	1990	2000	2010	2020
N	387	504	612	771	970	1,021
NNE	267	348	422	532	669	842
NE	428	557	678	863	1,073	1,350
ENE	0	0	0	0	0	0
E	0	0	0	0	0	0
ESE	0	0	0	0	0	0
SE	0	0	0	0	0	0
SSE	0	0	0	0	0	0
S	445	579	705	886	1,116	1,404
SSW	1,682	2,191	2,662	3,349	4,216	5,307
SW	225	293	356	448	564	710
WSW	940	1,224	1,487	1,872	2,356	2,966
W	144	167	128	287	361	455
WNW	91	118	144	182	228	287
NW	184	240	291	367	462	581
NNW	603	785	954	1,201	1,512	1,902
TOTAL	5,396	7,006	8,439	10,748	13,527	16,825

TABLE 2.1-3 SCHOOLS WITHIN 10 MILES OF THE FERMI SITE

	School[a]	1972 Enrollment	Distance (miles) and Direction From Plant Site
1.	Brest	163	2.5 WSW
2.	Jefferson High	848	2.8 W
3.	Jefferson Jr. High	928	2.8 W
	Jefferson Elementary	155	
4.	St. Charles Schools	257	3 NNW
5.	St. Anne School	205	4 WSW
6.	Henry Niedermeir Elementary	230	4 NW
7.	Hurd Road Elementary	752	5 WSW
8.	Pt. Moulier School	57	5 NNE
9.	Airport Elementary	340	6 NW
10.	Golden Elementary	166	7 W
11.	Zion Lutheran School	174	7 WSW
12.	Cantrick Jr. High	1,437	7 WSW
13.	Hollywood Elementary	455	7 WSW
14.	Fred W. Riter Elementary	396	7 N
15.	Christiancy Elementary	406	7 WSW
16.	St. Mary Parish School	357	7 WSW
17.	Orchard Elementary	137	8 WSW
18.	Lincoln Elementary	700	8 WSW
19.	Monroe Catholic Central	454	8 WSW
20.	Riverside Elementary	298	8 WSW
21.	Trinity Lutheran School	275	8 WSW
22.	Monroe High	2,842	8 WSW
23.	St. Mary Academy	526	8 WSW
24.	Hall of the Divine Child	218	8 WSW
25.	St. John School	230	8 WSW
26.	St. Michael's School	350	8 WSW
27.	Manor Elementary	339	8 WSW
28.	Chapman Elementary	378	8 N
29.	Rockwood Elementary	286	8 N
30.	Borrow Elementary	170	9 N
31.	Airport Community High	1,417	9 NW
32.	South Monroe Townsite Elementary	357	9 WSW
33.	Waterloo Elementary	257	9 WSW
34.	Holy Ghost Lutheran School	101	9 WNW
35.	Parsons Elementary	748	9 NW
36.	Church Street Elementary	345	9 NW
37.	St. Mary	345	9 NW
38.	Carleton High and Jr. High	1,782	9 NW
39.	Raisinville Elementary	654	10 W
40.	St. Patrick School	240	10WNW
41.	Carleton Elementary	227	10 NW
42.	Custer Elementary I	949	10 WSW

TABLE 2.1-3 SCHOOLS WITHIN 10 MILES OF THE FERMI SITE

	School[a]	1972 Enrollment	Distance (miles) and Direction From Plant Site
43.	Custer Elementary II	428	10 WSW
44.	Monroe County Community College	1,676	11 WSW
TOTAL (within 10 miles)		23,183	

[a] Numbers refer to Figure 2.1-13.

TABLE 2.1-4 HOSPITALS AND NURSING FACILITIES WITHIN 10 MILES OF THE FERMI SITE

Hospital/Nursing Home	Number of Beds	Distance (miles) and Direction From Plant Site
Frenchtown Convalescent Center	226	6 W
Memorial Hospital of Monroe	78	7 W
Mercy Hospital	126	7 WSW
Monroe Convalescent Center	85	7 WSW
Rockwood Children's Home	8	8 N
Monroe County Shelter	17	8 WSW
Beech Nursing Home	123	8 WSW
Lutheran Home for the Aged	102	9 WSW
Monroe Care Center (a nursing facility)	103	9 WSW
TOTAL	868	

TABLE 2.1-5 RECREATIONAL AREAS WITHIN 10 MILES OF THE FERMI SITE

Park/Recreational Facility /Museum[a]	Distance (miles) and Direction
1. Estral Beach	2 NNE
2. Stony Point Beach	2 S
3. Woodland Beach	3 WSW
4. Frenchtown Park[b]	4 W
5. Willow Beach	4 WSW
6. Detroit Beach	4 WSW
7. Sterling State Park[b]	5 SW
8. Point Mouillee State Game Area[b]	5 NE
9. Point Mouillee State Game Area[b]	6 NE
10. Custer Park	6 WSW
11. Lake Erie Marshes	7 WSW
12. Heck Park	7 WSW
13. Soldiers and Sailors Park	8 WSW
14. Custer Museum[b]	8 WSW
15. Monroe County Historical Museum[b]	8 WSW
16. Bolles Harbor Public Boat Ramp	9 SW
17. Plum Creek Park	9 WSW
18. Waterloo Park	9 WSW
19. Avalon Beach	10 SW
20. Monroe County Fairgrounds[b]	10 W
21. Huron River (canoeing)	12 WNW

[a] Numbers refer to Figure 2.1-14.

[b] Attendance data were available for the following six facilities:

	Number of Visitors Annually
Sterling State Park	385,394
Custer Museum	12,000
Monroe County Historical Museum	45,000
Monroe County Fairgrounds	110,000
Frenchtown Park	20,000-30,000 (1974 estimates)
Point Mouillee State Game Area	180,000 User Days*

*A User Day is defined as one person using the facility for at least several hours at a time.

TABLE 2.1-6 NEEDS FOR SEASONAL AGRICULTURAL AND HORTICULTURAL LABOR IN MONROE COUNTY[a]

	Peak	Winter Only	March	April	May	June	July	August	September	October	November
Nursery and Landscape											
Number of Workers	300	-	200	300	300	200	175	175	300	300	200
Percent Migrants	15	-	0	5	15	20	20	10	10	10	10
Commercial Fruits											
Number of Workers	140	10	20	40	40	120	40	40	140	140	60
Percent Migrants	40	0	0	10	10	40	10	10	40	40	20
Greenhouse Produce											
Number of Workers	120	120	60	60	50	30	10	10	10	20	20
Percent Migrants	20	20	25	25	25	10	10	10	10	10	10
Commercial Vegetables, Tomatoes											
Number of Workers	1200	30	40	250	300	300	500	1000	1200	1200	150
Percent Migrants	50	0	0	10	10	10	30	45	45	50	10
General Farm Produce											
Number of Workers	500	50	50	250	300	200	250	250	450	500	250
Percent Migrants	5	0	0	0	5	10	10	5	5	5	0
Potatoes											
Number of Workers	75	20	10	20	25	25	40	60	75	75	40
Percent Migrants	60	20	0	10	10	10	20	50	60	60	20

TABLE 2.1-6 NEEDS FOR SEASONAL AGRICULTURAL AND HORTICULTURAL LABOR IN MONROE COUNTY[a]

	Peak	Winter Only	March	April	May	June	July	August	September	October	November
						Totals					
Number of Workers	2335	230	380	920	1015	875	1015	1535	2165	2335	720
Percent Migrants	34	12	4	7	11	17	11	30	32	34	8
Average Number Migrants	795	28	15	61	110	144	223	515	695	795	57

[a] "Seasonal worker" does not include farm manager, year-round hired labor, paid or unpaid year-round workers of the immediate farm family, or pick-your-own consumers. "Seasonal worker" includes migrant laborers, students, neighbors, trade-off time efforts, and others who work for 1 week or more during the year, at one location.

TABLE 2.1-7 DAIRIES WITHIN 18 MILES OF THE FERMI SITE

	Number and Owner[a]	Number of Cows	Distance (miles) and Direction From Plant Site
1.	Fred Kemp	35	10 NW
2.	Henry Noel	25	5 NW
3.	William King	12	7 NNW
4.	Robert Reaume	25	6 NW
5.	Irving Langton	25	10 NW
6.	F. Hawley and J. Van Buskirk	50	8 NW
7.	Laurence Mieden	25	10 NW
8.	John Reiger	30	4 W
9.	Fred Falkenberg	35	9 WNW
10.	Frank Kominek	25	11 WNW
11.	William McGowan	30	12 WNW
12.	Earl and Robert Nowitzke	40	10 NW
13.	William Barnaby, Jr.	15	16 W
14.	George and Ruth Doty	49	13 W
15.	Wilbert Knapp	20	15 W
16.	Rolland Lemerand	30	16 W
17.	Stella Opferman	30	14 W
18.	Alvin Parron	44	14 W
19.	Lloyd Schafer	29	15 W
20.	M. Knapp and W. Young	50	17 W
21.	Glenn Lassey	45	13 WSW
22.	Arnold Hotchkiss	40	15 W
23.	Donald Doty	35	12 W
24.	Jerome Verhille	6	13 WNW
25.	Robert Doty	20	13 WNW
26.	St. Mary's Farm	93	11 W
27.	Glen Johnson	49	11 WSW
28.	Reuhs Bros.	149	18 W
29.	Julius Jaworski	71	18 W

[a] Numbers refer to Figure 2.1-15.

TABLE 2.1-8 FARM SIZE, FARMLAND USE, AND FARM SALES OF COUNTIES WITHIN 50 MILES OF THE FERMI SITE (1969)

COUNTY	Land Area of County (Acres)	Land in Farms (Acres)	Percent of Land in Farms	Number of Farms	Average Farm Size (Acres)	FARMLAND USE (ACRES)							FARM SALES (THOUSANDS OF DOLLARS)				
						CROPLAND				Woodland	All Other Land[b]	Irrigated Land	Value of All Agricultural Products Sold[c]		Crops Including Nursery Products and Hay	Forest Products	Livestock, Poultry, and their Products
						Total	Harvested	Pasture or Grazing	All Other Cropland[a]				Total	Average Per Farm			
MICHIGAN																	
Monroe	356,544	253,927	71.2	2,000	126.9	221,396	162,585	4,001	54,810	15,292	17,239	726	20,052	10.0	2	40	6,317
Wayne	387,200	49,527	12.8	597	82.9	38,887	25,562	2,378	10,947	4,567	6,073	326	5,865	9.8	4,866	6	993
Macomb	307,328	96,934	31.5	997	97.2	77,368	47,335	6,901	23,132	9,029	10,537	1,248	13,382	13.4	9,122	22	4,237
Oakland	554,560	101,820	18.4	863	117.9	68,085	33,362	14,182	20,541	13,706	20,029	499	8,852	10.2	4,387	43	4,421
Livingston	366,080	174,047	47.5	1,099	158.3	119,832	71,810	16,496	31,526	21,125	33,090	702	11,228	10.2	2,855	56	8,317
Washtenaw	464,720	260,283	57.2	1,699	153.1	196,810	126,019	24,074	46,717	26,136	37,337	490	18,439	10.8	5,293	50	13,097
Jackson	446,848	258,094	57.8	1,577	163.6	175,259	100,751	25,618	48,890	27,559	55,276	573	16,923	10.7	3,516	62	13,346
Lenawee	481,856	403,602	83.8	2,558	157.7	335,283	241,044	12,293	81,946	30,913	37,406	640	31,912	12.5	13,427	33	18,453
OHIO																	
Fulton	260,288	239,839	92.1	1,738	137.9	207,129	166,959	4,477	35,693	15,942	16,768	119	35,663	20.5	10,302	35	25,327
Lucas	219,776	98,521	44.8	785	125.5	88,640	74,932	1,726	11,982	4,264	5,617	279	12,386	15.8	9,646	6	2,739
Henry	265,920	266,064	100.1	1,695	156.9	238,297	200,319	5,062	32,916	11,632	16,135	13	25,876	15.3	15,088	12	10,776
Wood	396,288	371,279	93.7	2,181	170.2	333,725	280,223	7,411	46,091	16,998	20,556	326	28,256	12.9	18,202	1	10,053
Putman	311,040	306,085	98.4	1,975	154.9	272,049	231,113	9,436	31,500	16,129	17,979	123	30,056	15.2	15,738	21	14,297
Seneca	352,640	329,755	93.5	1,887	174.7	271,501	207,941	13,167	50,393	31,816	26,438	112	20,873	11.1	11,562	33	9,277
Ottawa	167,296	130,272	77.9	976	133.0	115,093	87,620	1,910	25,563	5,493	9,686	302	9,254	9.4	6,212	7	3,035
Sandusky	261,888	240,924	92.0	1,488	161.9	208,239	160,598	6,939	40,702	13,852	18,903	566	21,225	14.2	13,188	17	8,020
Erie	168,832	106,733	63.2	702	152.0	87,830	64,461	3,434	19,935	7,869	11,034	207	9,026	12.8	4,863	15	4,143
ONTARIO CANADA																	
Kent	616,320	559,811	d	3,748	d	484,482	d	21,229	11,076	16,296	32,911	d	d	d	d	d	d
Essex	460,160	353,203	d	3,768	d	318,138	d	5,573	9,978	9,279	8,248	d	d	d	d	d	d

[a] Includes cropland used for soil-improvement crops, crops failure, cultivated summer fallow and idle cropland.

[b] Includes pastureland other than cropland and woodland pasture, rangeland, and land in house lots, barn lots, ponds, roads, etc.

[c] Represents market value, before taxes and expenses, of all agricultural products sold by all farms in the census areas.

[d] Data not available.

TABLE 2.1-9 CROPS HARVESTED IN U.S. COUNTIES WITHIN 50 MILES OF THE FERMI SITE (1969)

	Field Corn			Sorghum					Other Small Grains									Green House Products Under Glass
	Grain		Silage	Grain		Silage	Wheat			Soy Beans		Hay	Potatoes	Veg. and Melons	Berries	Land in Orchards	Other Crops	
County	Acres	Bushels	Acres	Acres	Bushels	Acres	Acres	Bushels	Acres	Acres	Bushels	Tons	Acres	Acres	Acres	Acres	Acres	Square feet
MICHIGAN																		
Lenawee	77,037	7,069,410	12,682	104	4,492	96	31,343	1,379,556	15,532	78,292	2,213,558	61,216	276	1,340	5	719	3,932	128,400
Jackson	31,384	2,389,527	9,211	-	-	114	9,963	577,637	10,287	1,431	25,999	87,817	184	961	64	1,126	2,443	36,000
Washtenaw	37,167	3,058,604	7,423	159	4,208	265	15,489	596,895	14,486	11,439	287,359	89,833	340	1,929	66	773	1,991	357,921
Livingston	19,418	1,479,003	8,061	-	-	134	6,418	233,206	5,688	723	16,108	77,040	23	475	19	763	2,324	21,136
Oakland	7,862	603,518	1,792	3	180	23	3,540	130,298	2,907	355	7,351	33,208	96	615	52	1,232	607	984,360
Macomb	10,188	796,486	3,789	25	800	24	4,837	176,756	4,514	3,021	76,976	29,855	482	5,480	28	1,458	1,962	1,770,327
Wayne	4,275	295,448	448	-	-	-	2,177	74,820	1,258	11,537	237,768	5,597	8	2,174	39	469	716	1,196,462
Monroe	39,262	3,518,839	3,524	66	4,030	48	22,684	902,666	9,283	70,220	1,826,878	16,125	2,670	4,899	70	503	4,694	630,306
OHIO																		
Erie	17,754	1,396,548	2,097	112	3,770	20	10,810	393,438	4,636	17,174	422,382	14,742	114	3,946	28	1,305	2,378	645,000
Sandusky	43,863	3,451,504	3,449	1,341	80,513	45	20,595	769,702	8,237	54,651	1,481,979	33,877	357	7,254	46	1,409	8,159	86,840
Ottawa	10,124	670,171	1,285	270	18,250	18	13,109	429,732	5,939	37,348	791,278	28,920	2	2,827	9	1,741	4,112	33,480
Seneca	57,490	4,801,680	2,959	22	1,650	48	31,221	1,443,581	13,710	81,916	2,269,753	40,243	181	1,694	16	24	4,183	111,600
Putman	64,934	5,575,890	2,789	223	14,763	28	27,129	1,091,547	11,314	96,768	2,650,298	33,322	261	5,236	9	14	10,995	-
Wood	85,879	6,313,301	3,445	30	2,975	80	40,787	1,688,582	20,604	103,803	2,749,362	48,286	13	3,336	36	69	6,513	431,796
Henry	64,190	5,627,260	2,947	12	550	6	26,306	1,141,355	10,060	78,233	2,336,747	27,171	57	3,888	5	22	7,067	3,000
Lucas	22,048	1,878,614	877	-	-	-	7,628	323,785	2,760	31,038	787,416	9,631	771	3,653	23	612	2,844	3,203,755
Fulton	69,122	6,330,547	10,556	50	1,000	46	17,326	742,313	6,529	50,984	1,454,446	24,669	839	2,834	21	124	695	40,148

TABLE 2.1-10 CROPS HARVESTED IN CANADIAN COUNTIES WITHIN 50 MILES OF THE FERMI SITE (1971)

	Ontario Province County[a]	
	Kent	Essex
Corn		
Grain	233,745	81,002
Silage	18,013	6,479
Wheat	43,299	48,724
Oats		
Grain	18,453	12,719
Silage	267	350
Barley	4,962	2,068
Mixed grain	2,226	516
Rye	340	158
Field beans	11,719	492
Tame hay	10,537	13,521
Soy beans	115,119	118,703
Potatoes	505	3,186
Tobacco	2,005	963
Other field crops	1,322	661

[a] All figures are in acres.

TABLE 2.1-11 LIVESTOCK AND POULTRY OF COUNTIES WITHIN 50 MILES OF THE FERMI SITE (1969)

						Chickens	
County	Cattle	Milk Cows	Hogs	Sheep	Horses	Total	Hens
Monroe	13,984	2,190	15,408	4,441	942	106,870	104,781
Wayne	2,328	537	1,584	500	669	32,362	31,758
Macomb	12,574	4,966	2,649	1,683	737	62,489	61,306
Oakland	12,008	2,820	3,009	2,584	2,442	58,162	57,779
Livingston	27,660	9,508	5,812	7,497	1,426	10,550	8,721
Washtenaw	33,588	10,550	23,890	53,361	1,961	126,700	111,633
Jackson	40,794	9,566	15,283	17,327	1,616	64,048	59,572
Lenawee	46,691	10,822	39,036	12,765	1,523	284,342	258,350
Fulton[a]	39,548	6,340	71,393	2,922	670	566,494	436,571
Lucas[a]	3,968	499	10,470	421	250	113,068	112,861
Henry[a]	13,744	3,686	23,026	4,103	412	513,142	416,951
Wood[a]	23,376	1,622	23,093	7,160	812	109,996	108,852
Putnam[a]	20,686	6,348	57,715	6,713	285	571,304	478,747
Seneca[a]	19,352	7,587	38,744	22,911	680	106,832	99,468
Ottawa[a]	5,645	1,876	5,643	1,040	200	140,324	123,916
Sandusky[a]	18,801	3,973	21,959	6,465	566	137,632	110,883
Erie[a]	8,212	3,604	7,108	2,489	437	71,477	31,808
Kent[b]	47,883	1,500	113,070	3,934	1,132	452,558	286,199
Essex[b]	16,162	6,505	27,520	865	1,133	381,461	199,870

[a] Counties located in Ohio.

[b] Counties located in Canada.

TABLE 2.1-12 MUNICIPAL WATER INTAKES FROM LAKE ERIE

Intake Point	Year	Withdrawal (10^6 gal/year)	Number of People Served	Percent to Industry	Percent to Residents	Distance (miles) From Plant Site[a]
Monroe	1972	2,000	40,000	35	65	6
Toledo	1972	29,200	500,000	40	60	28
Kingsville	1972	156	1,400	10	90	28
Leamington	1972	450	10,000	50	50	32
Port Clinton	1971	577	12,000	10	90	37
Wheatley	1972	114	1,059	54	46	42
Sandusky	1972	3,960	47,000	60	40	48
Huron	1972	450-500	7,500	33	67	53
Vermilion	1972	33	9,000	-	-	62
Lorain	1972	5,027	85,000	39	61	70
Blenheim	1972	90	4,000	5	95	70
Cleveland	1972	130,875	2,000,000	52	48	93
Fairport	1971	274	36,000	66	34	108
Port Stanley	1971	88	(summer residents only)	0	100	112
Ashtabula	1972	1,900	34,000-36,000	45	55	130
Conneaut	1969	477	15,000	52	48	140
Erie	1972	16,700	180,000	35	65	167
Port Dover	1972	165	4,000-7,000	10	90	170
Port Maitland	1972	4,100	1,000	90	10	197
Dunkirk	1972	1,487	30,000	51	49	207
Port Colborne	1972	1,191	20,000	5	95	212
Buffalo	1972	47,950	500,000	30	70	233

[a] See Figure 2.1-20 for locations.

TABLE 2.1-13 SUMMARY OF COMMERCIAL FISH LANDINGS (POUNDS) BY STATISTICAL DISTRICT FOR 1971 FOR THE PROVINCE OF ONTARIO[a]

Species	S.D. 1	S.D. 2	S.D. 3	S.D. 4	S.D. 5	Totals Pounds	Totals Dollars
Bowfin	-	-	-	19,640	-	19,640	589
Bullhead	-	-	-	34,259	383	34,642	5,307
Carp	27,052	522	-	23,233	1,793	52,600	3,548
Catfish	38,514	40,949	11,159	9,207	1,207	101,036	24,474
Northern Pike	-	-	15	1,642	410	2,067	323
Yellow Perch	3,770,391	6,383,547	2,880,354	360,175	523,144	13,917,611	3,563,039
Suckers	4,536	262	65	5,488	2,192	12,543	1,248
Rock Bass	-	284	-	18,439	8,271	26,994	5,987
Freshwater Drum	355	65,946	9,460	8,424	8,788	92,973	2,953
Smelt	12,324	958,481	1,117,242	11,041,802	526	13,130,375	571,461
Sunfish	-	-	-	84,271	-	84,271	23,664
White Bass	3,210	9,274	44,006	23,869	11,668	92,027	22,182
Lake Whitefish	630	21	-	179	2	832	312
Yellow Pickerel	5,300	1,703	6	117	23,049	30,175	15,272
Others	371,153	985,503	16,451	25,900	78,766	1,477,773	14,333
Total Catch (lb)	4,233,465	8,446,492	4,078,758	11,656,645	660,199	29,075,559	
Total Value ($)	896,694	1,719,527	852,174	613,199	173,098		4,254,692

[a] See Figure 2.1-21 for district areas.

TABLE 2.1-14 SUMMARY OF COMMERCIAL FISH LANDINGS (POUNDS) BY STATISTICAL DISTRICT FOR 1971 FOR THE STATE OF OHIO[a]

Species	S.D. 6	S.D. 7	S.D. 8	S.D. 9	Totals
Buffalo	6,628	35	100	2,347	9,110
Bullhead	14,753	55	4	21,657	36,469
Carp	2,237,111	10,058	44	912,211	3,159,424
Catfish	423,822	9,882	78	193,518	627,300
Freshwater Drum	245,313	138,085	856	441,982	826,236
Goldfish	2,754	1	-	76,821	79,576
Quillback	27,644	412	-	-	28,056
Smelt	230	183	-	-	413
Suckers	67,675	19,636	138	31,020	118,469
White Bass	676,287	62,989	4,687	184,949	928,912
Yellow Perch	691,726	937,868	531,917	27,395	2,188,906
Total Catch	4,393,943	2,358,408	537,824	1,891,900	8,002,871

[a] See Figure 2.1-21 for district areas.

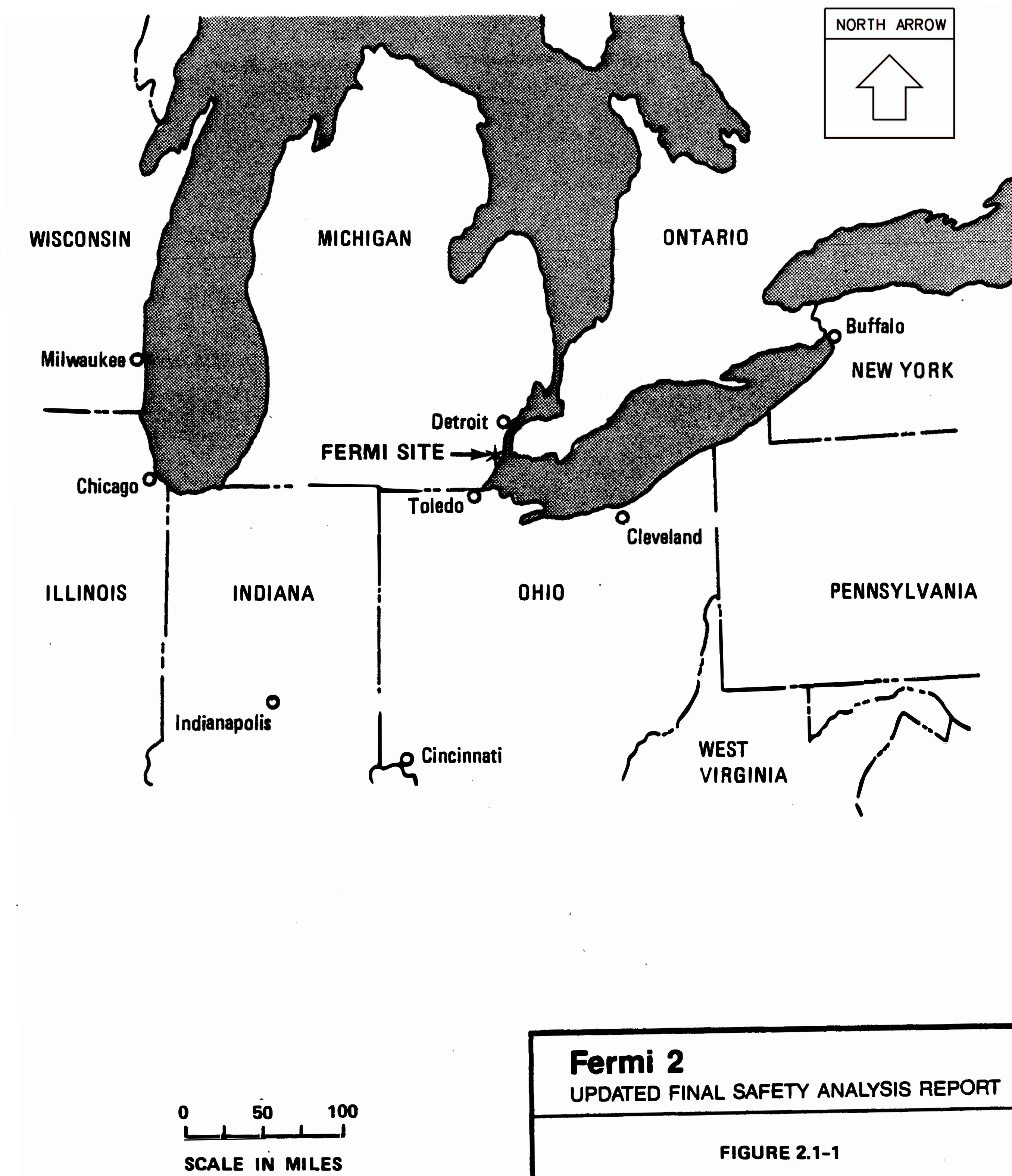

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FIGURE 2.1-1

SITE LOCATION

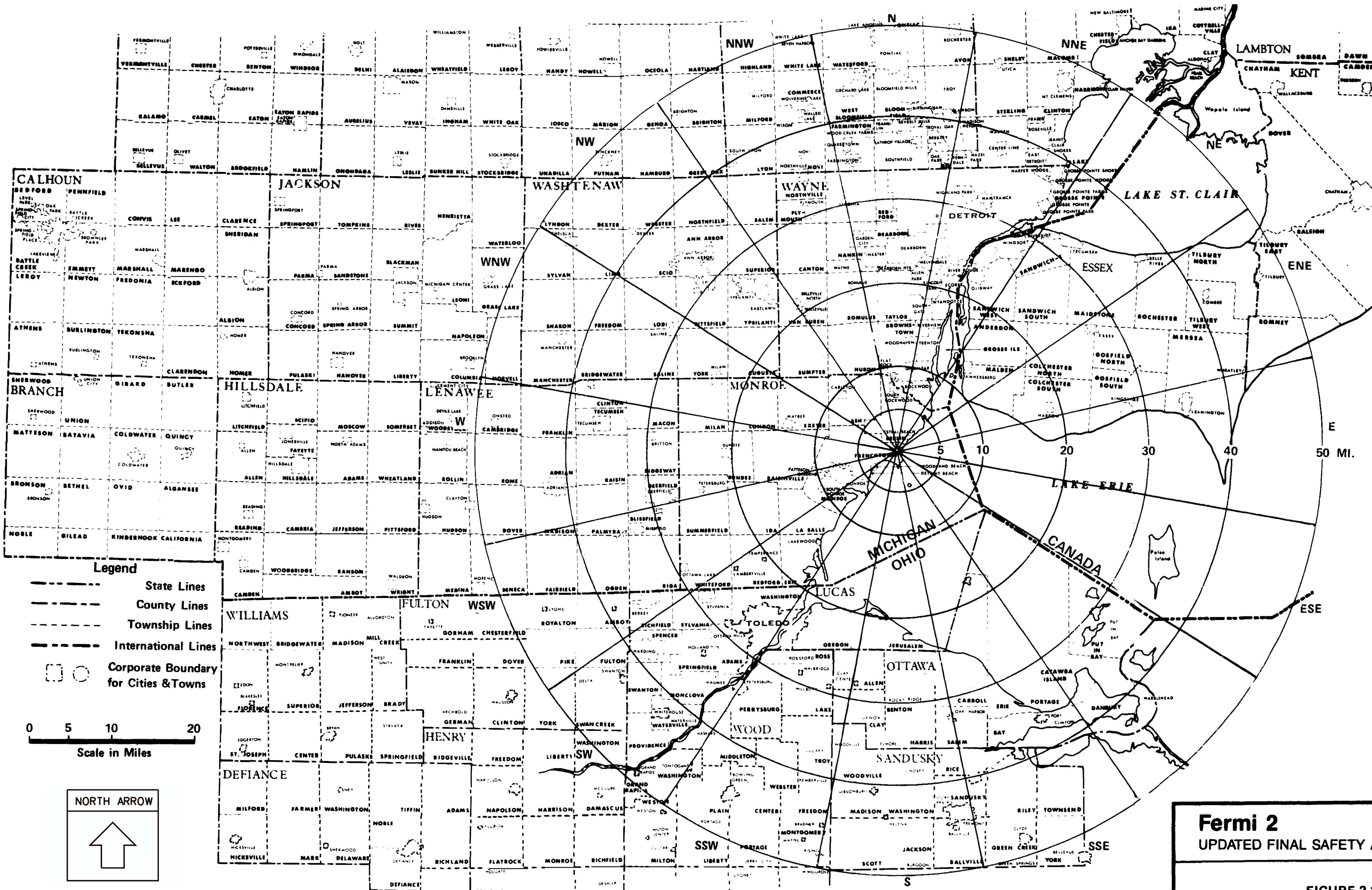

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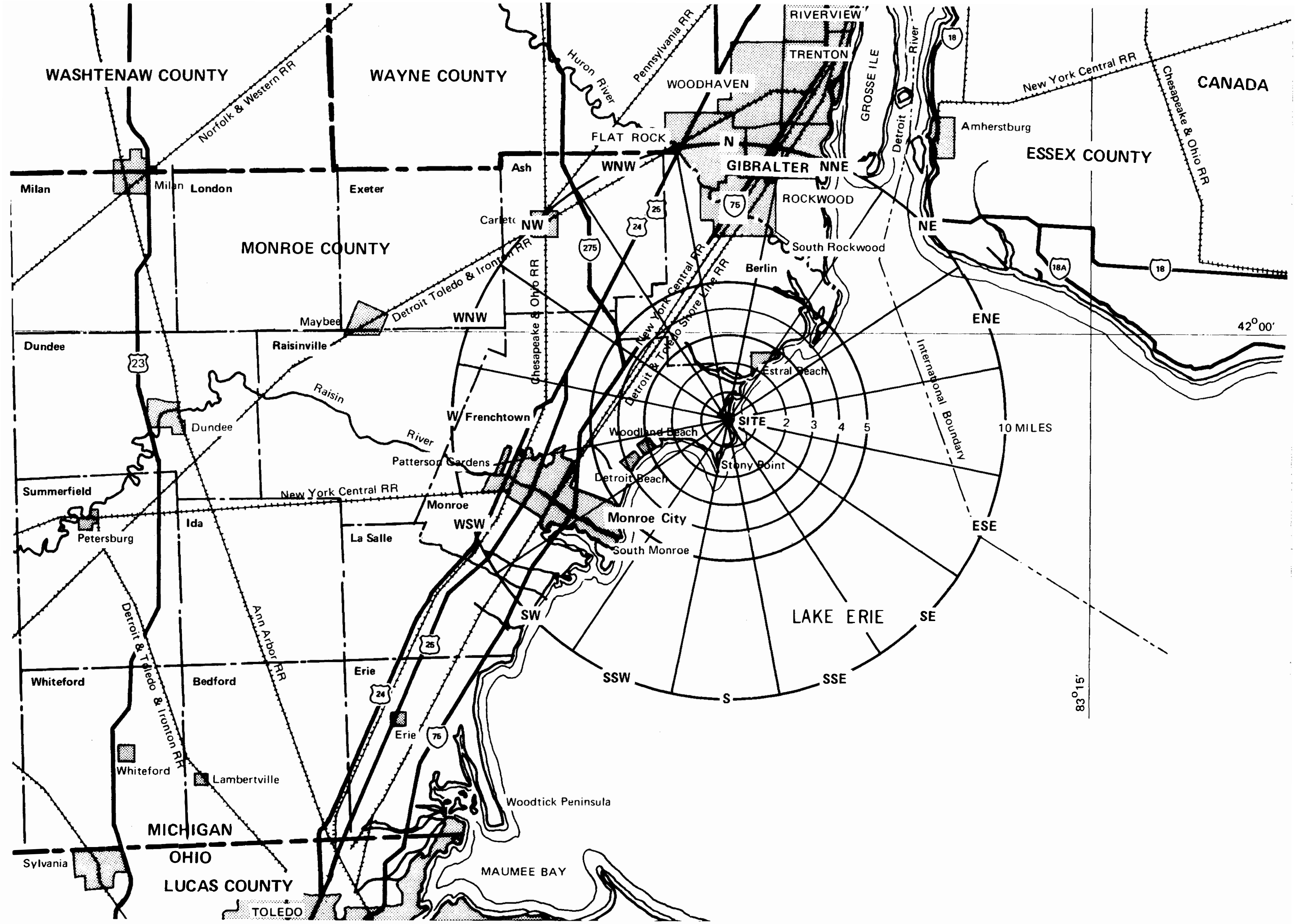
FIGURE 2.1-2

SITE – SURROUNDING REGION



NORTH ARROW

LEGEND

County Lines

Towns & Cities

Interstate & U.S. Highway Numbers

Latitude Lines

Railroads

Township Lines

0 4 8 12

SCALE IN MILES

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FIGURE 2.1-3

SITE – IMMEDIATE ENVIRONS

REFERENCE:
ADAPTED FROM DETROIT EDISON COMPANY
SERVICE AREA GENERAL MAP, 1971

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FIGURE 2.1-4

SITE AERIAL VIEW

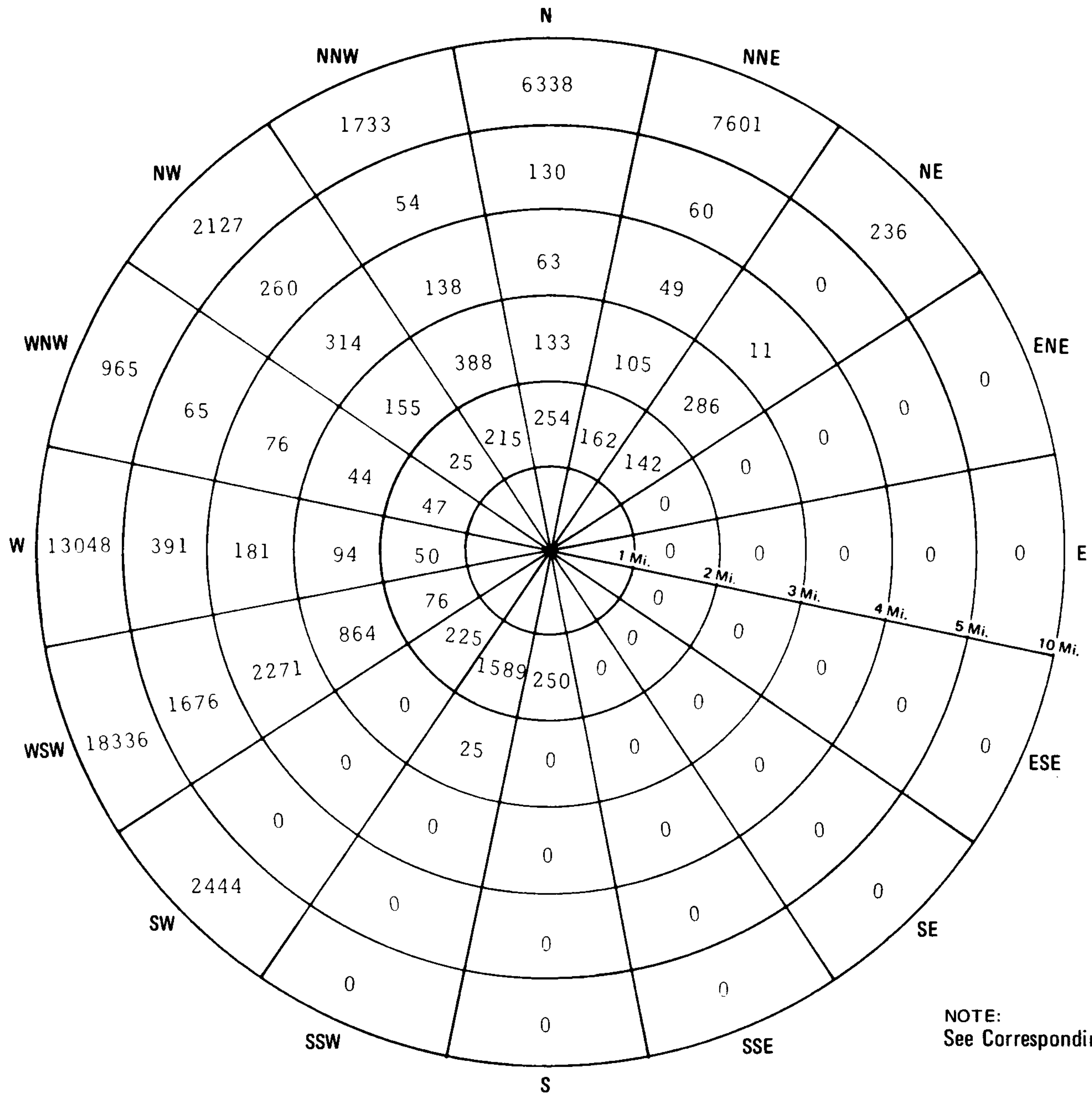
Figure Intentionally Removed
Refer to Plant Drawing A-2102

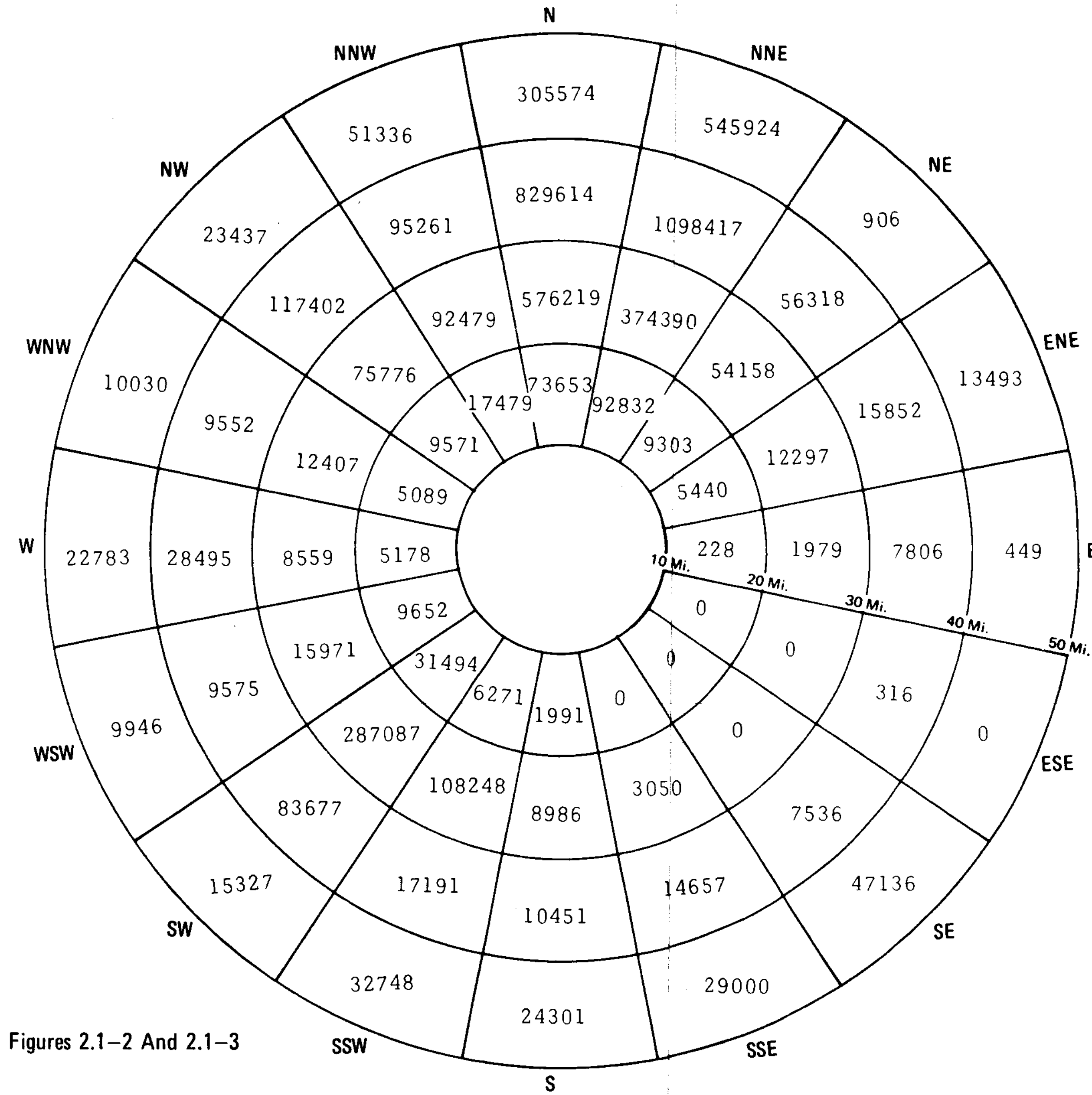
FIGURE 2.1-5

SITE PLOT PLAN

Annulus	0–1 Mi.	1–2 Mi.	2–3 Mi.	3–4 Mi.	4–5 Mi.	5–10 Mi.	Total 0–10 Mi.
Population	267	3035	2094	3103	2636	52828	63963

Annulus	10–20 Mi.	20–30 Mi.	30–40 Mi.	40–50 Mi.	Total 10–50 Mi.	Total 0–50 Mi.
Population	268181	1631606	2402120	1132390	5434297	5498260





NOTE:
See Corresponding Maps, Figures 2.1–2 And 2.1–3

Values For 0–1 Mile Annulus

N	NNE	NE	ENE	E	ESE	SE	SSE
0	0	0	0	0	0	0	0
195	68	0	0	0	0	4	0
S	SSW	SW	WSW	W	WNW	NW	NNW

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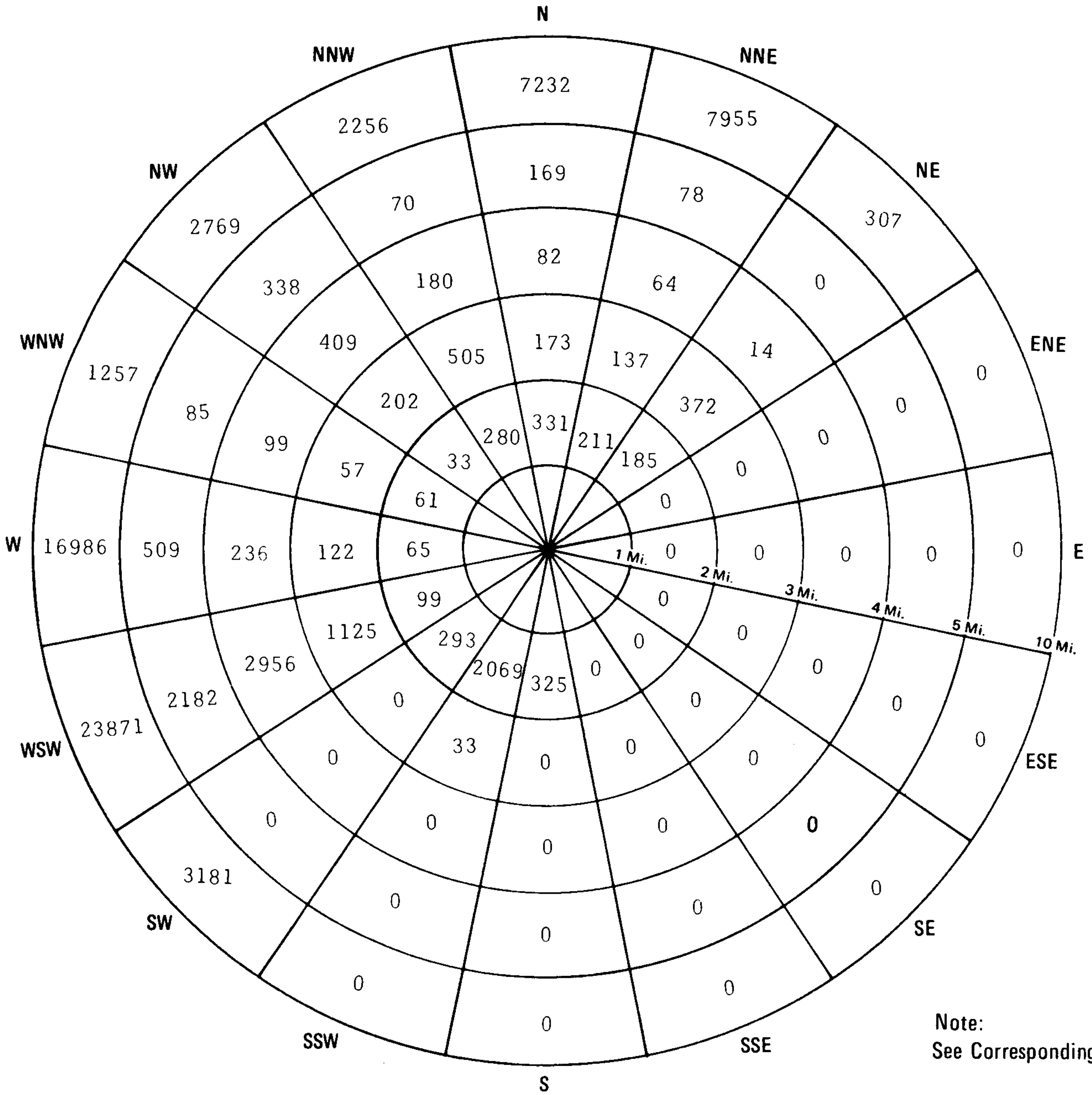
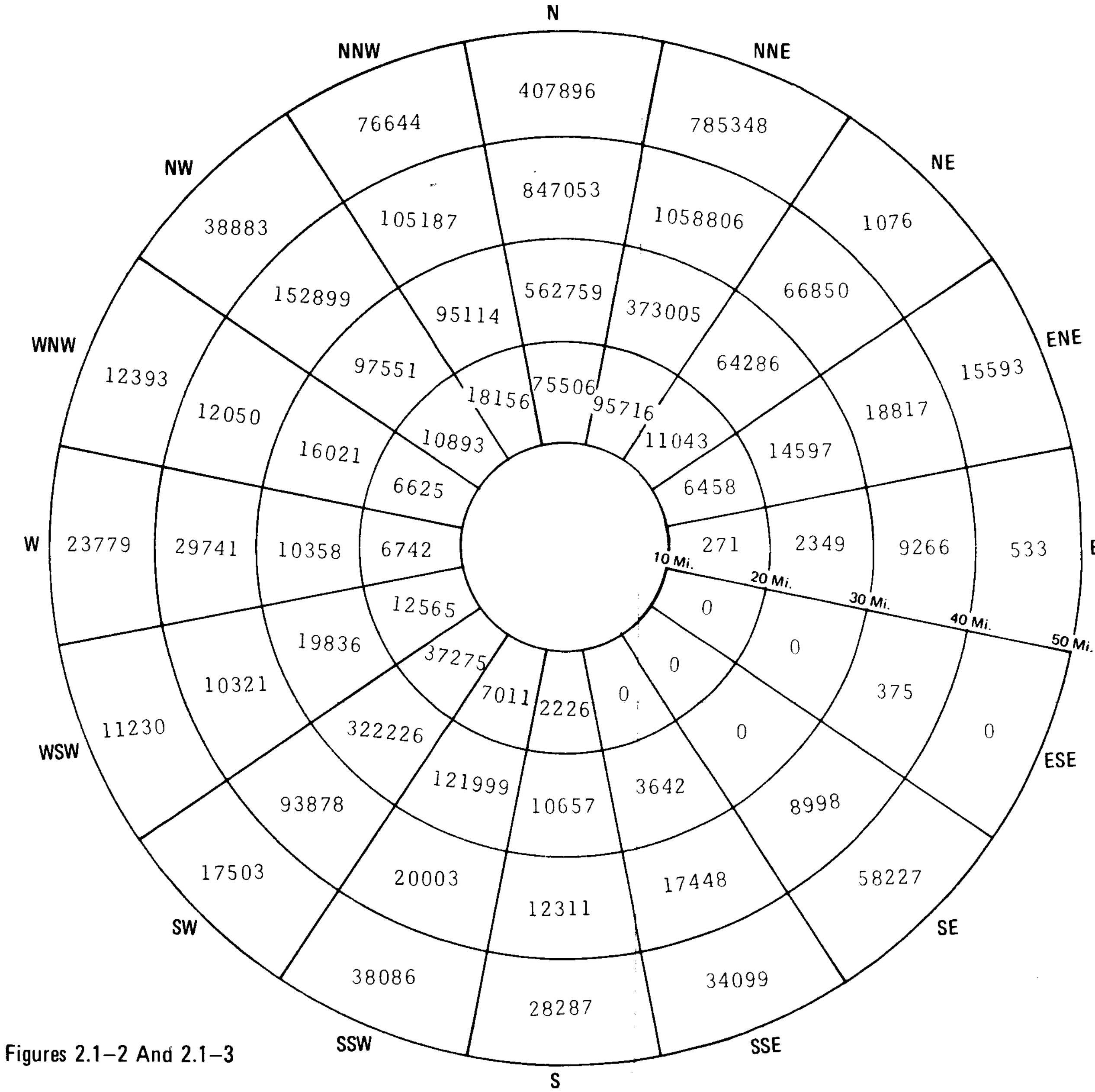
FIGURE 2.1-6

POPULATION DISTRIBUTION – 1970
0-10 MILES AND 10-50 MILES

Annulus	0–1 Mi.	1–2 Mi.	2–3 Mi.	3–4 Mi.	4–5 Mi.	5–10 Mi.	Total 0–10 Mi.
Population	348	3952	2726	4040	3431	65814	80311

Annulus	10–20 Mi.	20–30 Mi.	30–40 Mi.	40–50 Mi.	Total 10–50 Mi.	Total 0–50 Mi.
Population	290487	1714400	2464003	1549577	6018467	6098778





Note:
See Corresponding Maps, Figures 2.1–2 And 2.1–3

Values For 0–1 Mile Annulus

N	NNE	NE	ENE	E	ESE	SE	SSE
0	0	0	0	0	0	0	0
254	89	0	0	0	0	5	0
S	SSW	SW	WSW	W	WNW	NW	NNW

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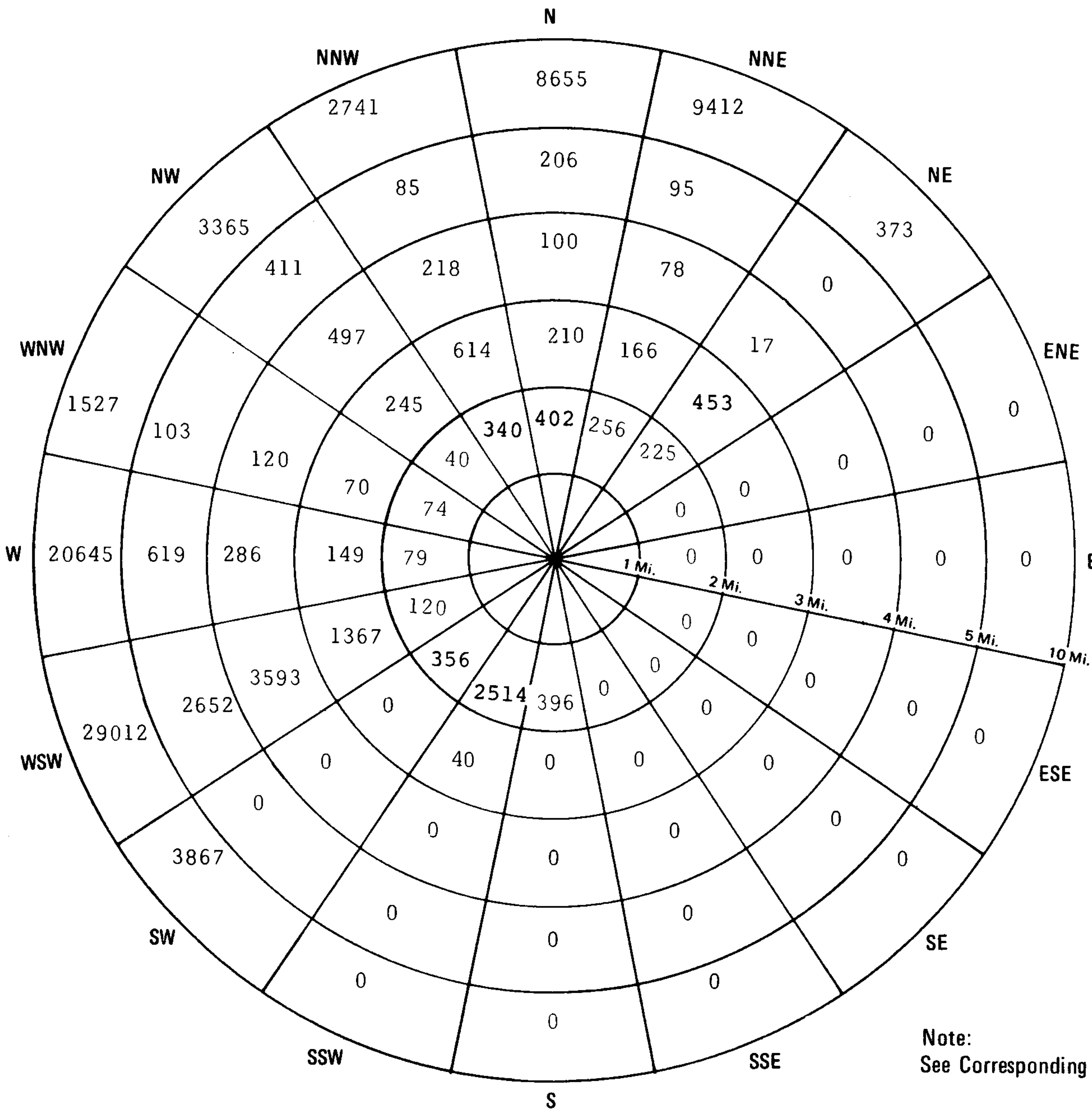
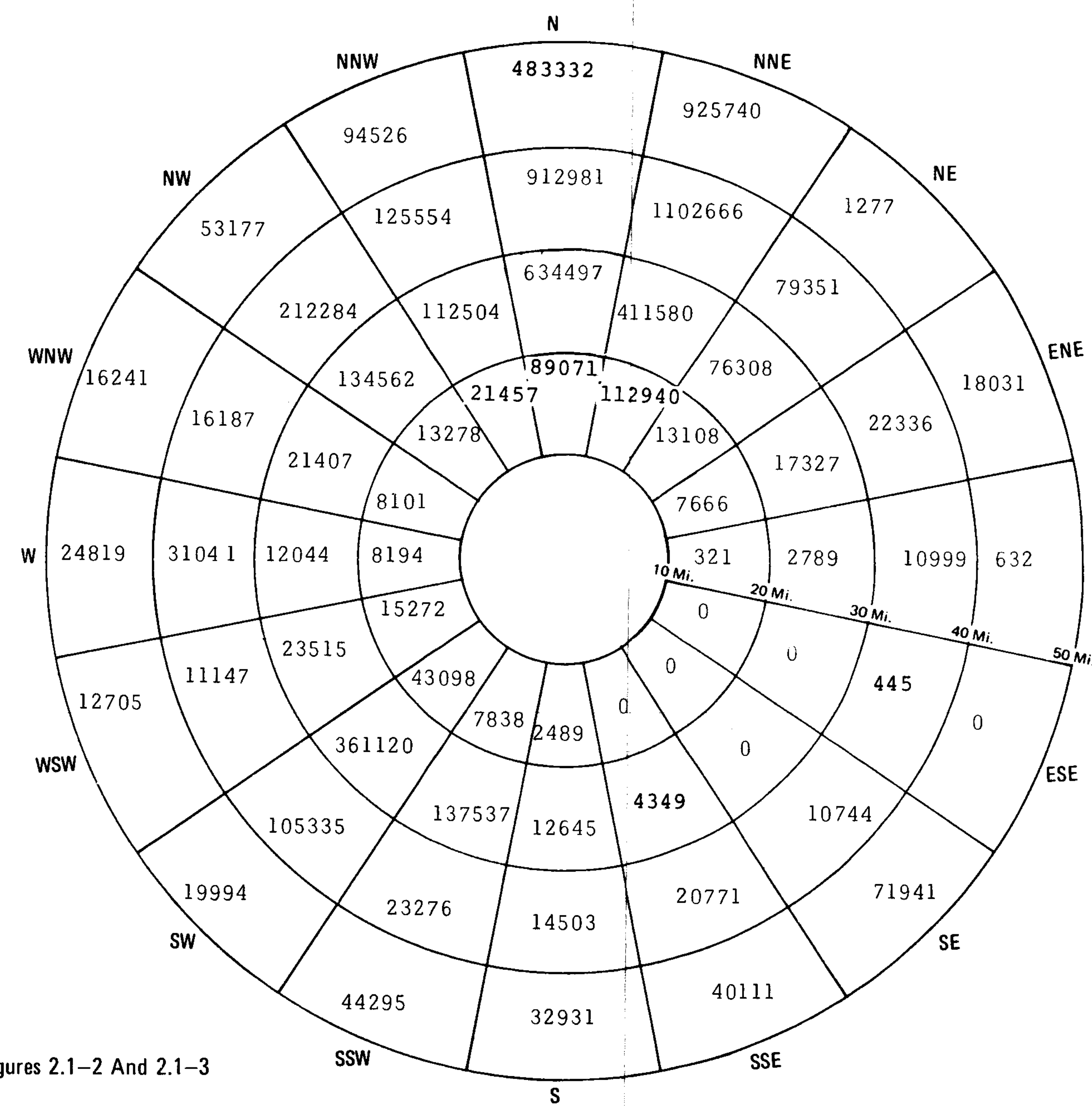
FIGURE 2.1-7

POPULATION DISTRIBUTION – 1980
0-10 MILES AND 10-50 MILES

Annulus	0–1 Mi.	1–2 Mi.	2–3 Mi.	3–4 Mi.	4–5 Mi.	5–10 Mi.	Total 0–10 Mi.
Population	423	4802	3314	4909	4171	79597	97216

Annulus	10–20 Mi.	20–30 Mi.	30–40 Mi.	40–50 Mi.	Total 10–50 Mi.	Total 0–50 Mi.
Population	342833	1962184	2699620	1839752	6844389	6941605





Note:
See Corresponding Maps, Figures 2.1–2 And 2.1–3

Values For 0–1 Mile Annulus

N	NNE	NE	ENE	E	ESE	SE	SSE
0	0	0	0	0	0	0	0
309	108	0	0	0	0	6	0
S	SSW	SW	WSW	W	WNW	NW	NNW

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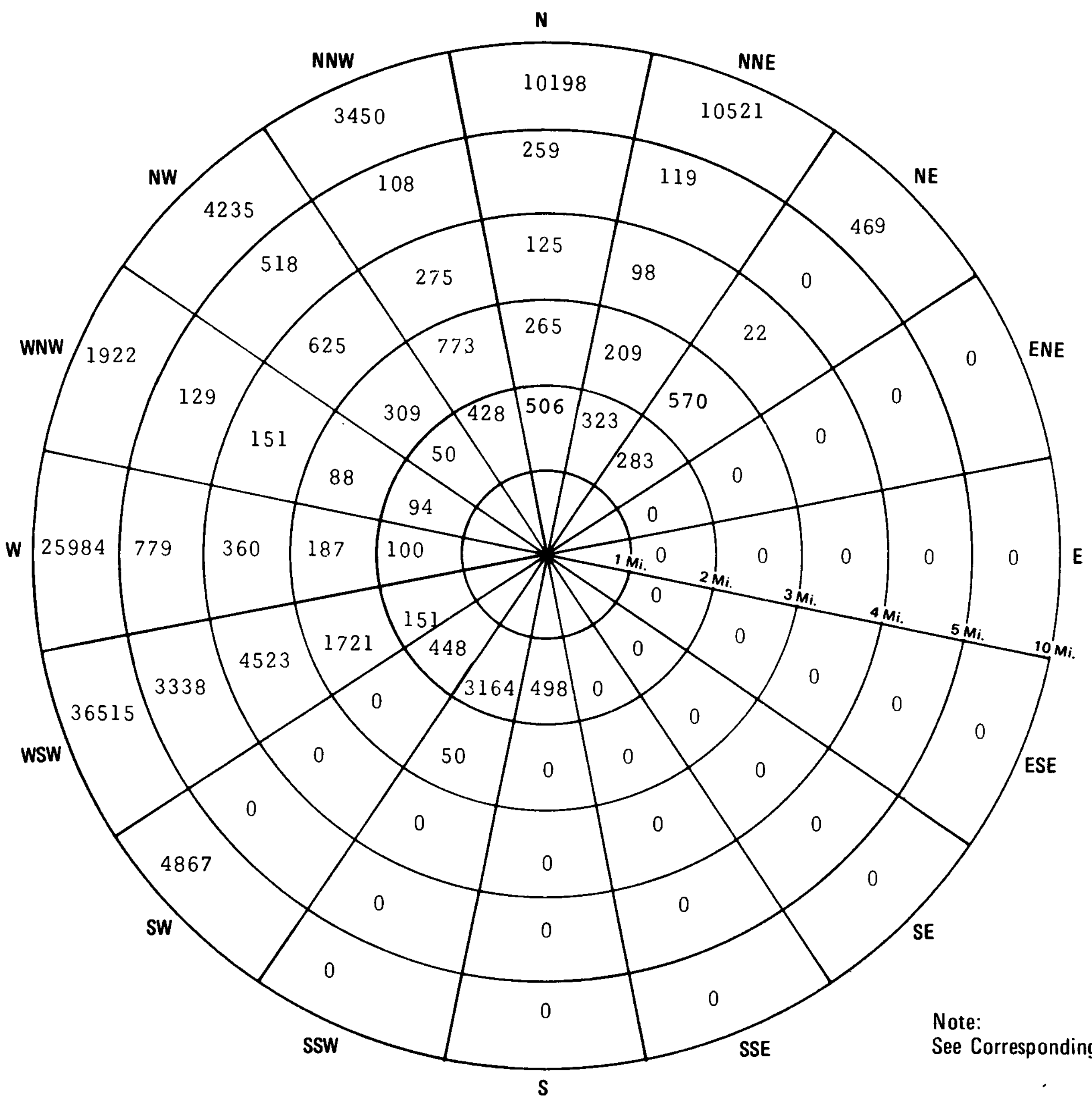
FIGURE 2.1-8

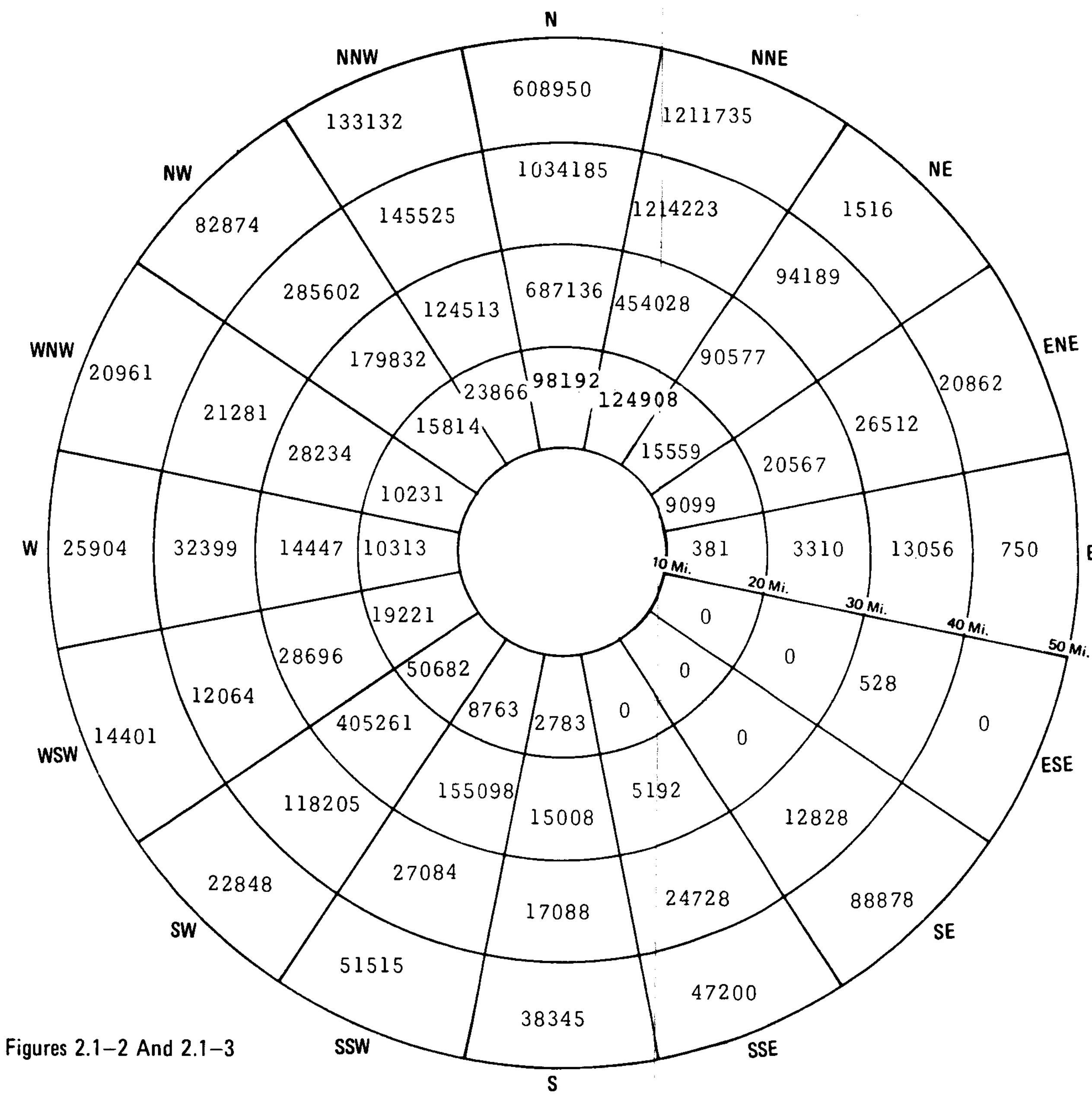
POPULATION DISTRIBUTION – 1990
0-10 MILES AND 10-50 MILES

Annulus	0–1 Mi.	1–2 Mi.	2–3 Mi.	3–4 Mi.	4–5 Mi.	5–10 Mi.	Total 0–10 Mi.
Population	531	6045	4172	6179	5250	98161	120338

Annulus	10–20 Mi.	20–30 Mi.	30–40 Mi.	40–50 Mi.	Total 10–50 Mi.	Total 0–50 Mi.
Population	389812	2211899	3079497	2369871	8051079	8171417



Note:
See Corresponding Maps, Figures 2.1–2 And 2.1–3



Values For 0–1 Mile Annulus

N	NNE	NE	ENE	E	ESE	SE	SSE
0	0	0	0	0	0	0	0
388	135	0	0	0	0	8	0
S	SSW	SW	WSW	W	WNW	NW	NNW

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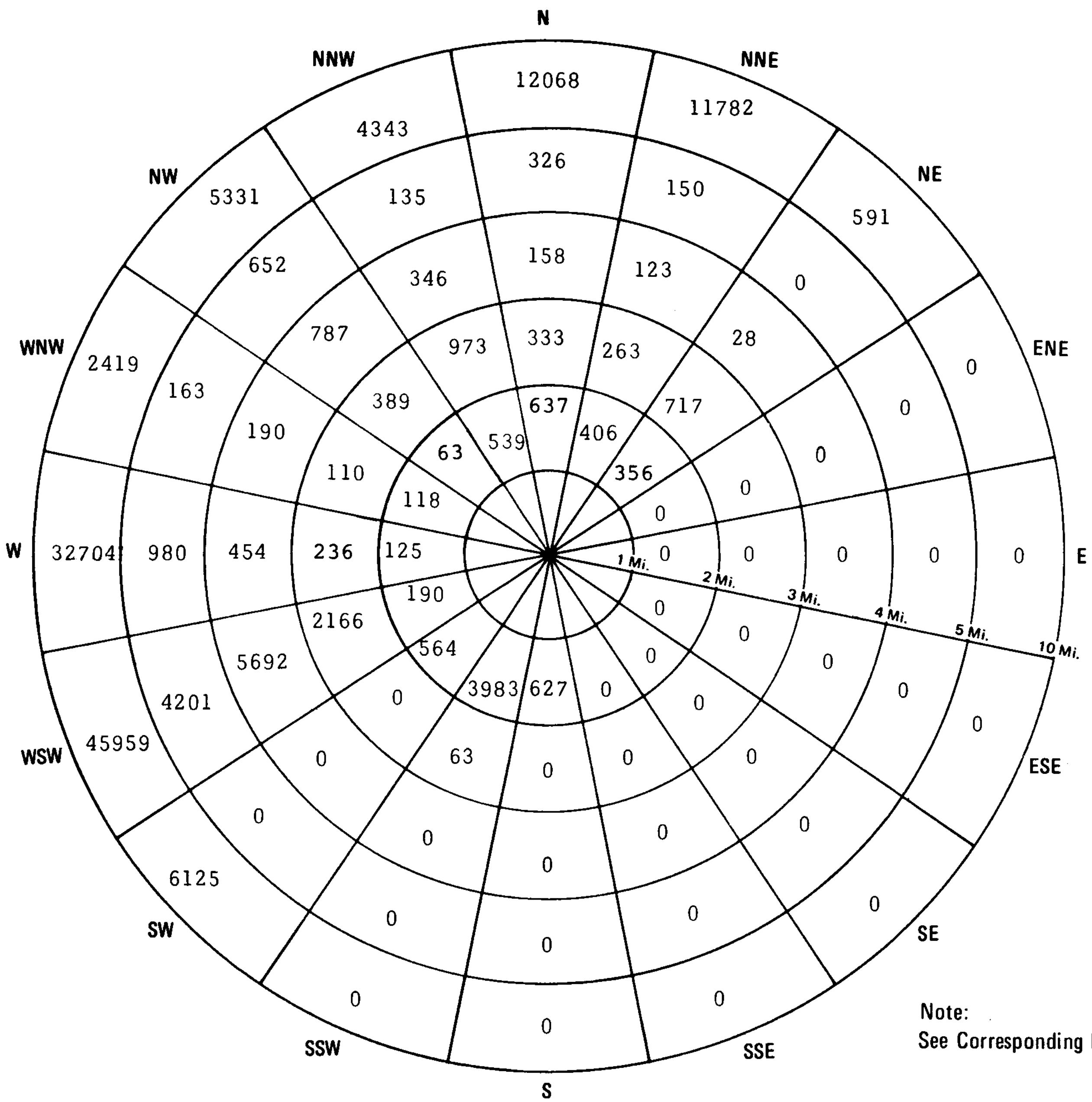
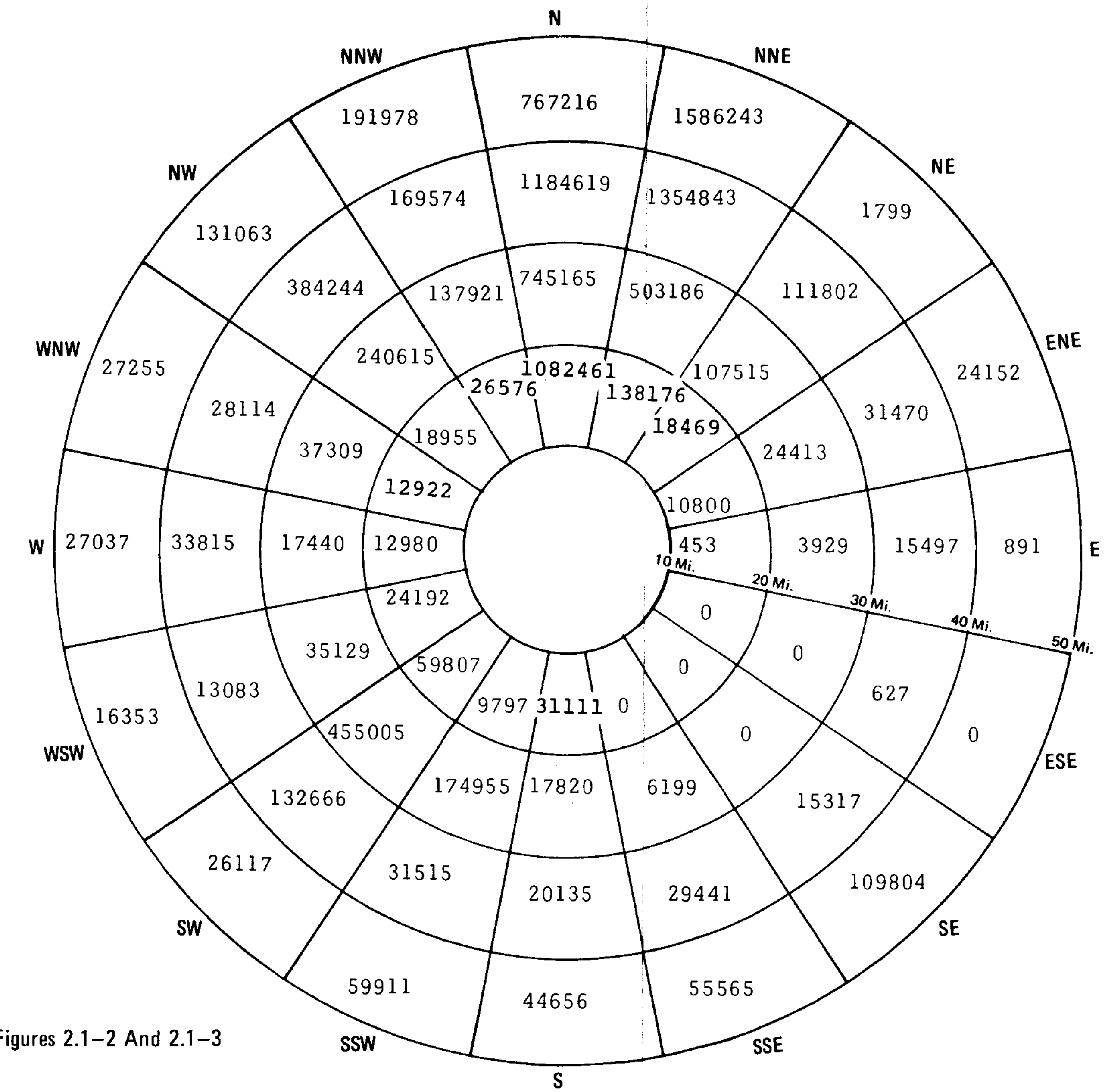
FIGURE 2.1-9

**POPULATION DISTRIBUTION – 2000
0-10 MILES AND 10-50 MILES**

Annulus	0–1 Mi.	1–2 Mi.	2–3 Mi.	3–4 Mi.	4–5 Mi.	5–10 Mi.	Total 0–10 Mi.
Population	669	7608	5250	7778	6607	121322	149234

Annulus	10–20 Mi.	20–30 Mi.	30–40 Mi.	40–50Mi.	Total 10–50 Mi.	Total 0–50 Mi.
Population	444484	250601	3556762	3070040	9577887	9727121





Note:
See Corresponding Maps, Figures 2.1–2 And 2.1–3

Values For 0–1 Mile Annulus

N	NNE	NE	ENE	E	ESE	SE	SSE
0	0	0	0	0	0	0	0
489	170	0	0	0	0	10	0
S	SSW	SW	WSW	W	WNW	NW	NNW

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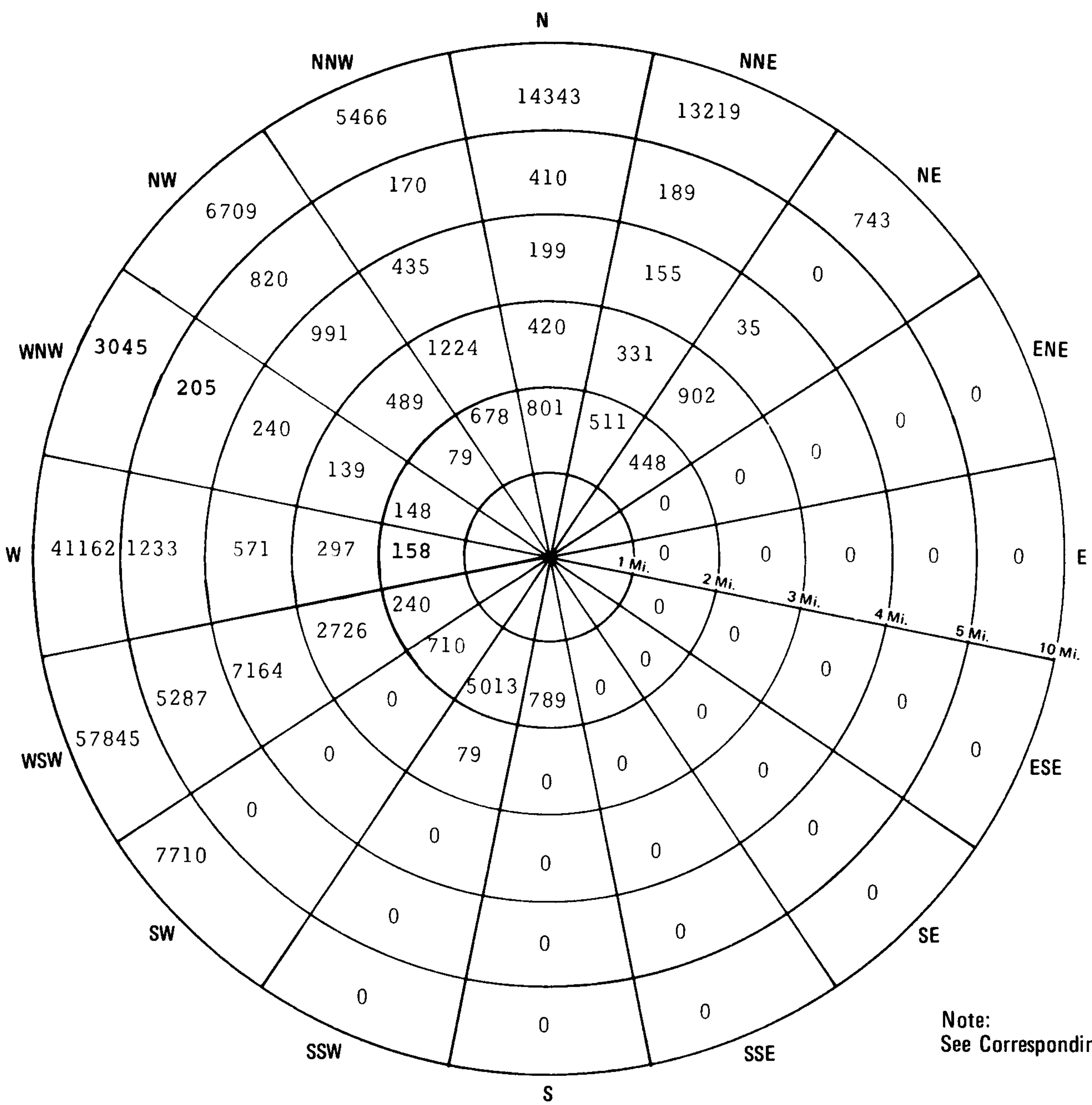
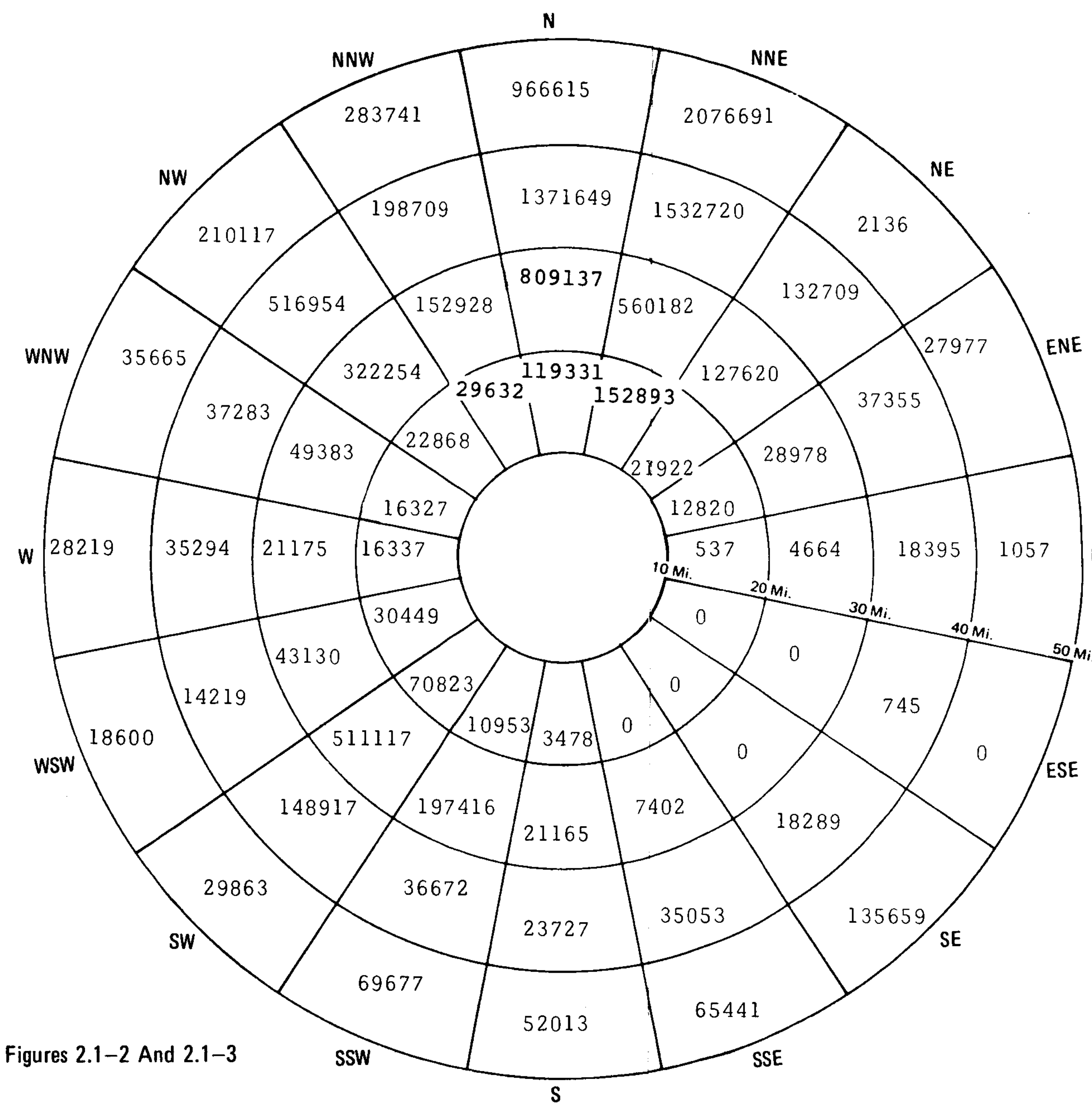
FIGURE 2.1-10

POPULATION DISTRIBUTION – 2010
0-10 MILES AND 10-50 MILES

Annulus	0–1 Mi.	1–2 Mi.	2–3 Mi.	3–4 Mi.	4–5 Mi.	5–10 Mi.	Total 0–10 Mi.
Population	843	9575	6607	9790	8314	150242	185371

Annulus	10–20 Mi.	20–30 Mi.	30–40 Mi.	40–50 Mi.	Total 10–50 Mi.	Total 0–50 Mi.
Population	508370	2856551	4158690	4003471	11527082	11712453





Note:
See Corresponding Maps, Figures 2.1–2 And 2.1–3

Values For 0–1 Mile Annulus

N	NNE	NE	ENE	E	ESE	SE	SSE
0	0	0	0	0	0	0	0
615	215	0	0	0	0	13	0
S	SSW	SW	WSW	W	WNW	NW	NNW

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FIGURE 2.1-11

POPULATION DISTRIBUTION – 2020
0-10 MILES AND 10-50 MILES

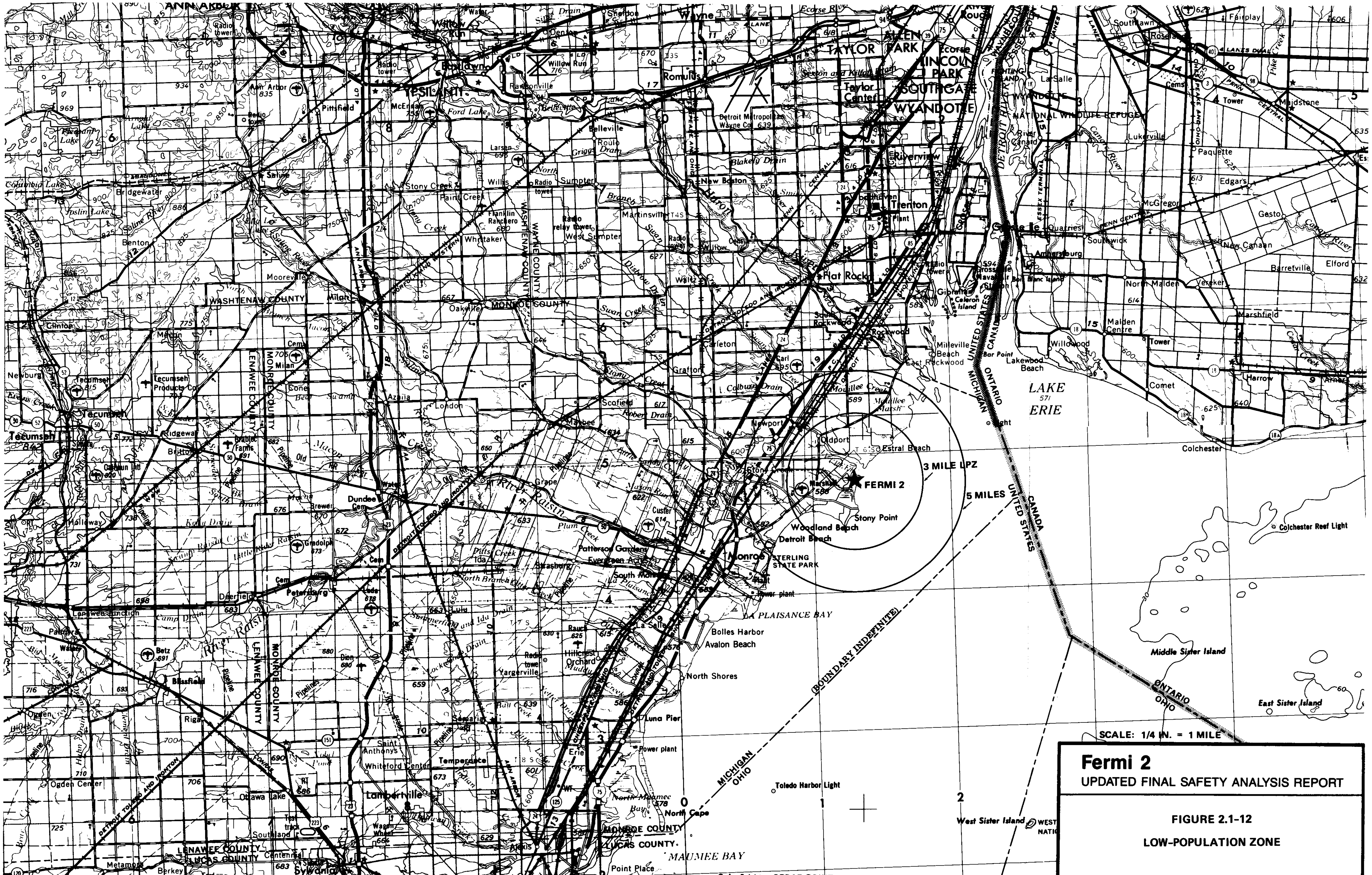

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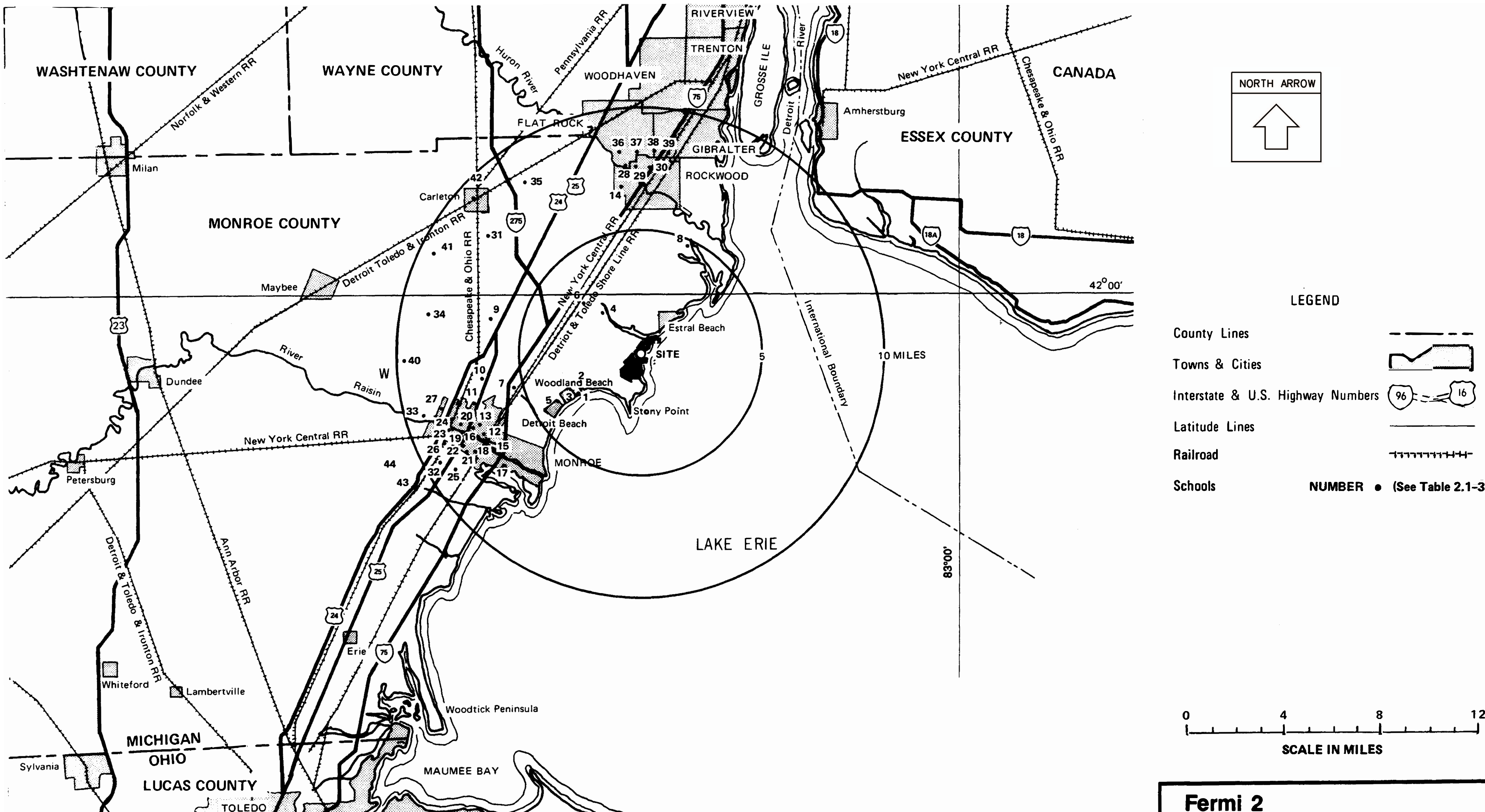
FIGURE 2.1-12

LOW-POPULATION ZONE



REFERENCE:
ADAPTED FROM DETROIT EDISON COMPANY
SERVICE AREA GENERAL MAP, 1971

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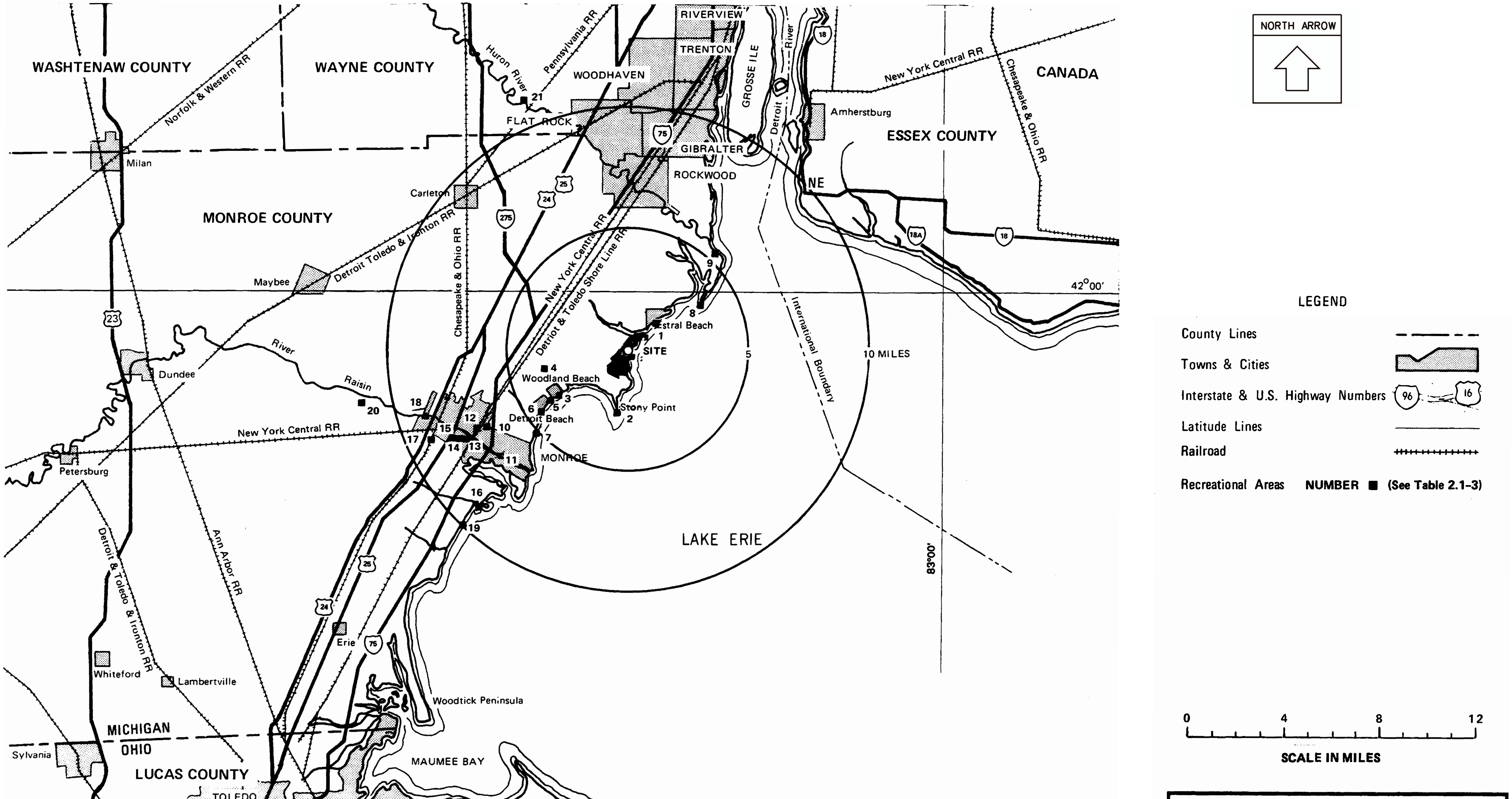
FIGURE 2.1-13

SCHOOLS IN THE VICINITY



REFERENCE:
ADAPTED FROM DETROIT EDISON COMPANY
SERVICE AREA GENERAL MAP, 1971

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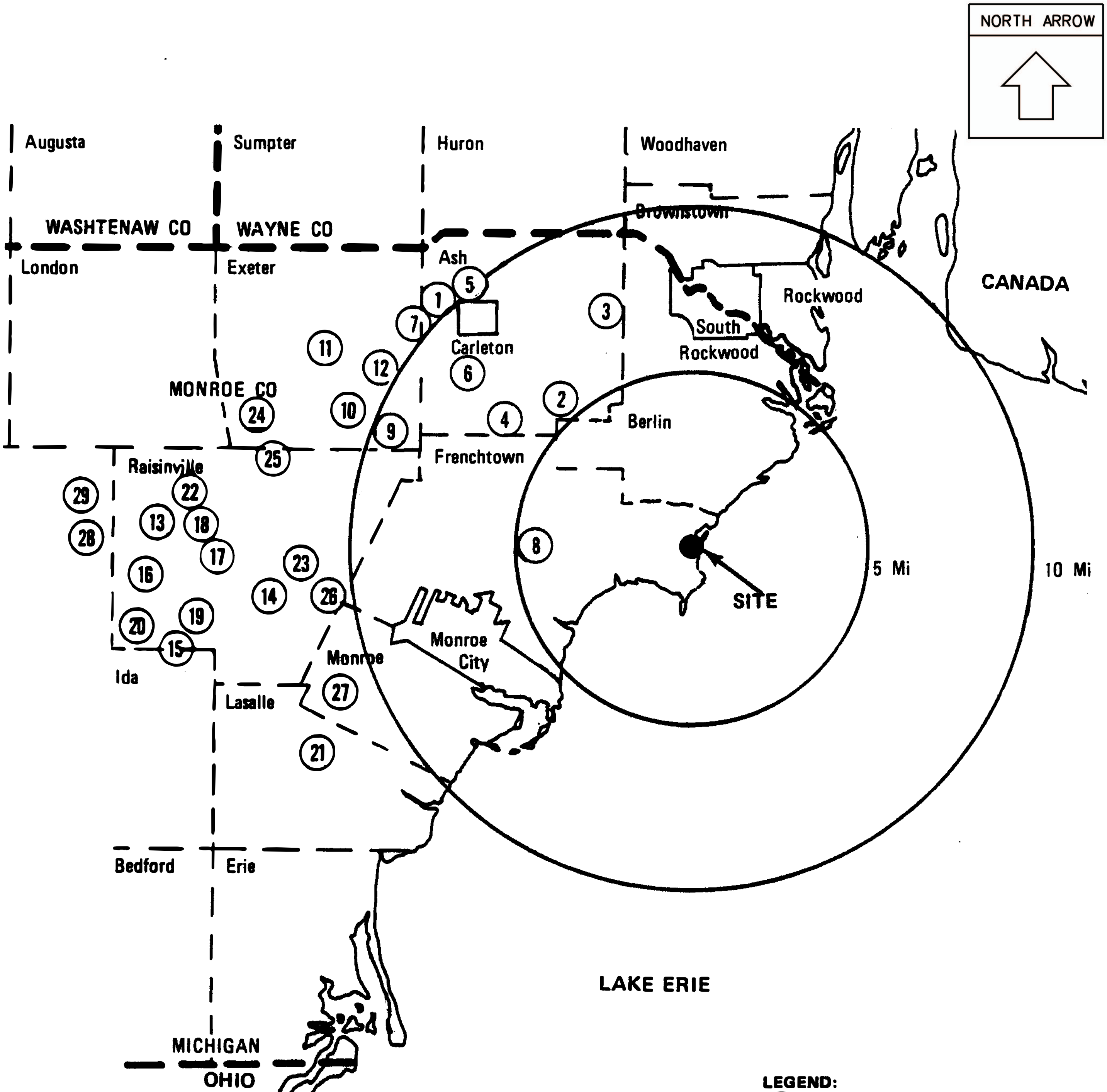
FIGURE 2.1-14

RECREATION AREAS IN THE VICINITY



REFERENCE:
ADAPTED FROM SOUTHEAST MICHIGAN COUNCIL OF GOVERNMENTS – COUNTY-TOWNSHIP-CITY-VILLAGE MAP, 1971

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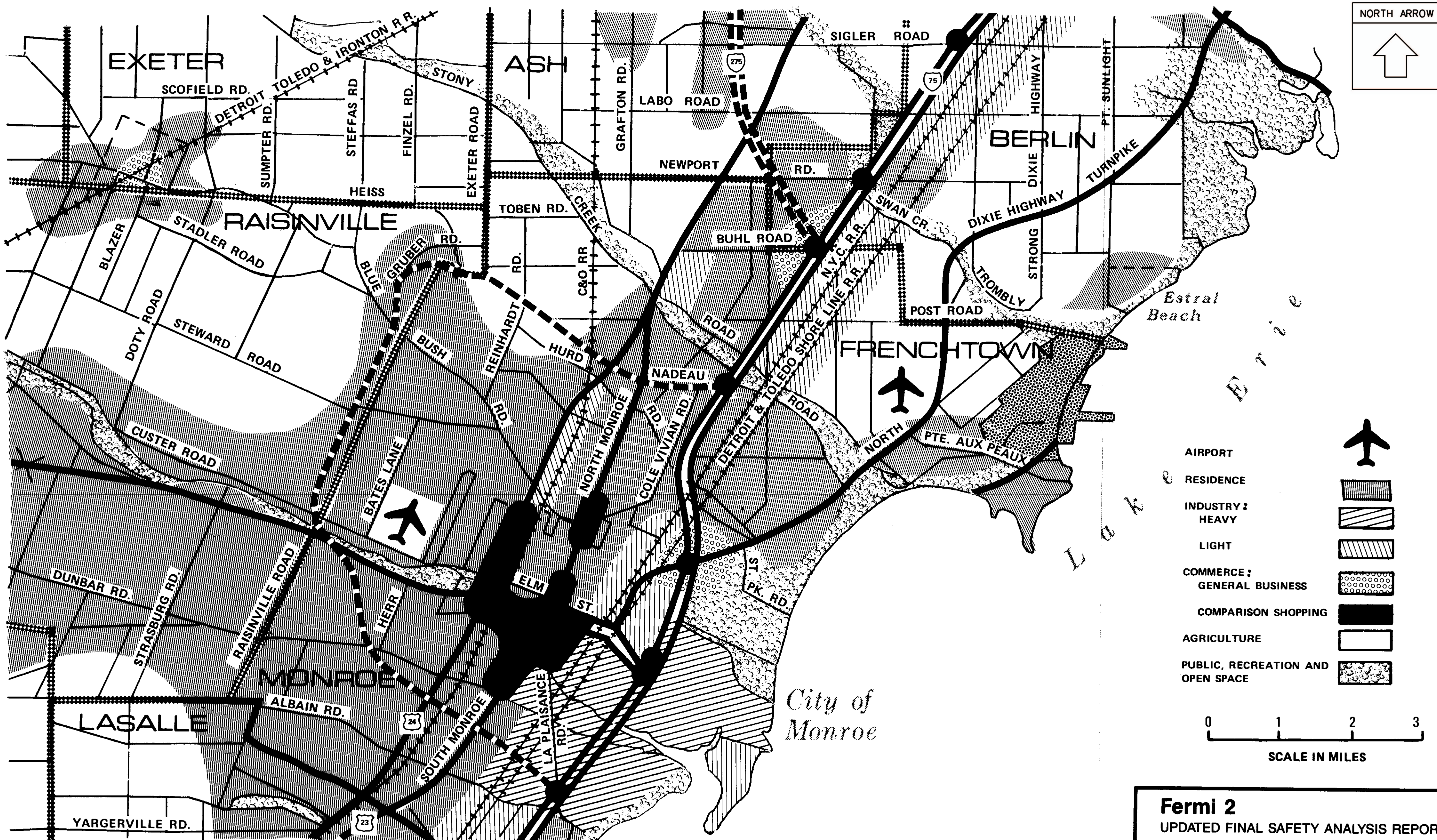
FIGURE 2.1-15

DAIRY FARMS IN THE VICINITY



REFERENCE:
ADAPTED FROM MONROE COUNTY COMPLAN, 2000, 1967

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FIGURE 2.1-16

MONROE COUNTY LAND USE PLAN

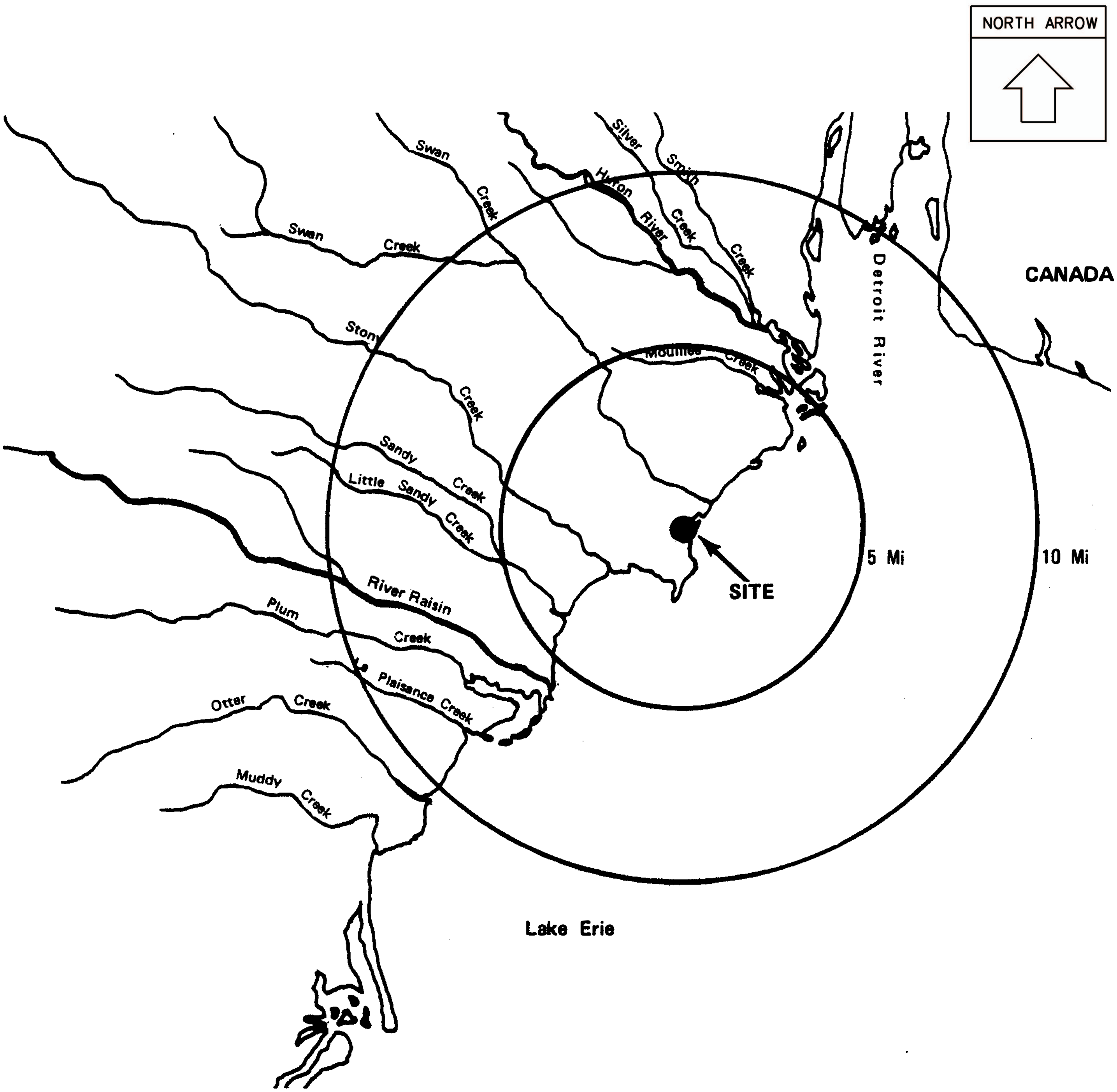

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FIGURE 2.1-17

LAKES, RIVERS, AND STREAMS IN THE VICINITY

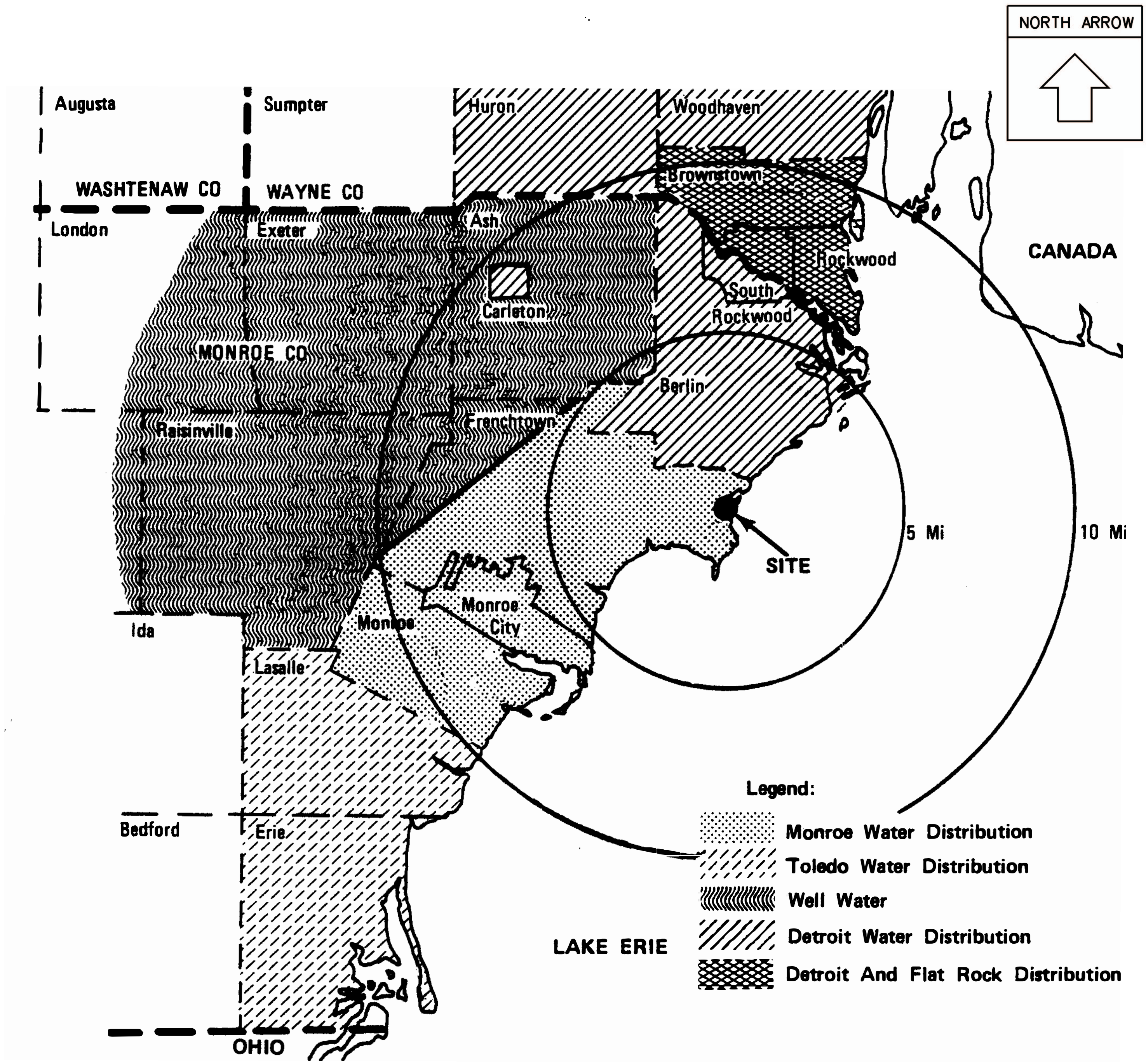

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FIGURE 2.1-18

POTABLE WATER SUPPLIES IN THE VICINITY

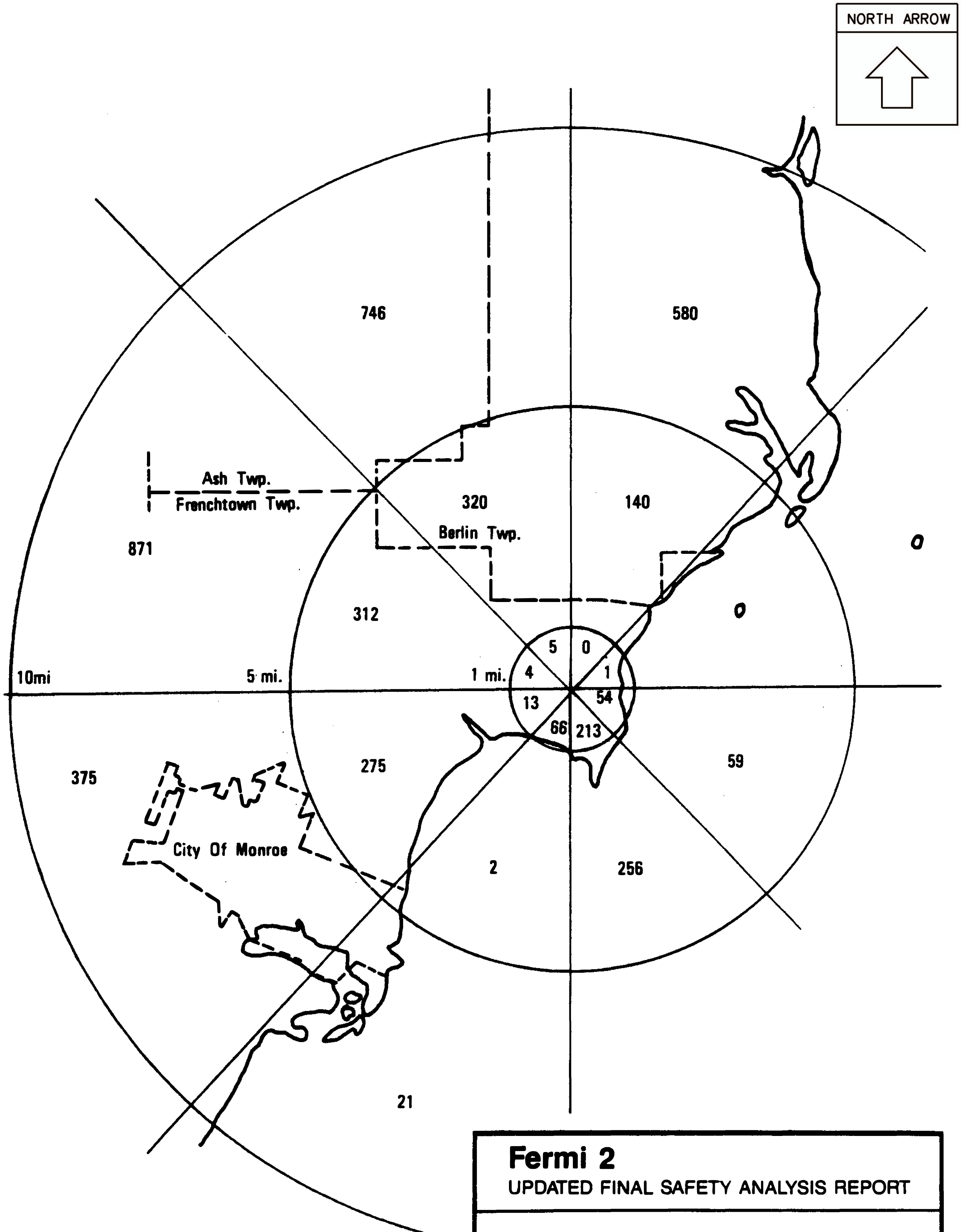

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FIGURE 2.1-19

DISTRIBUTION OF WATER WELLS WITHIN A 10 MILE RADIUS OF THE SITE

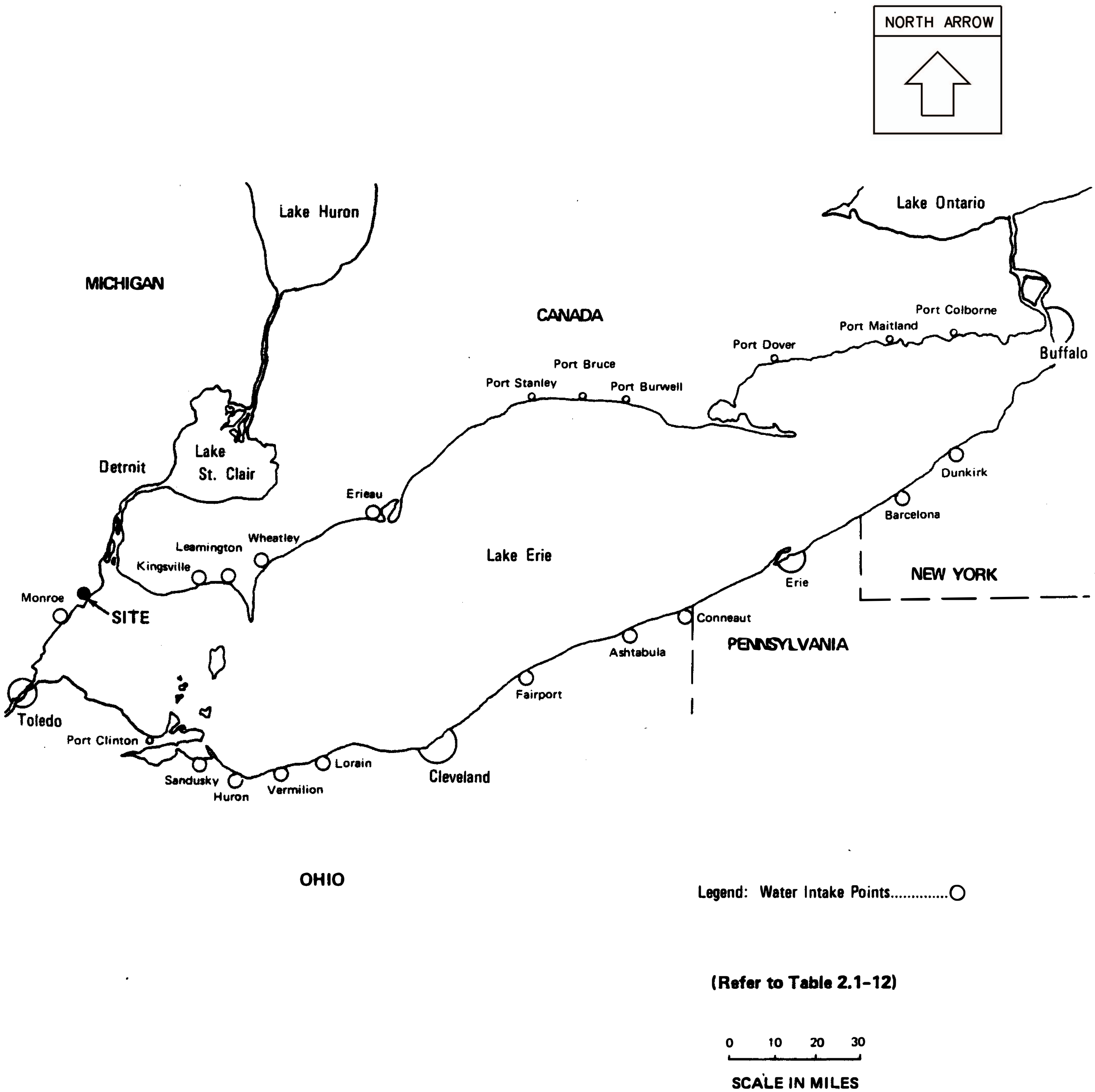

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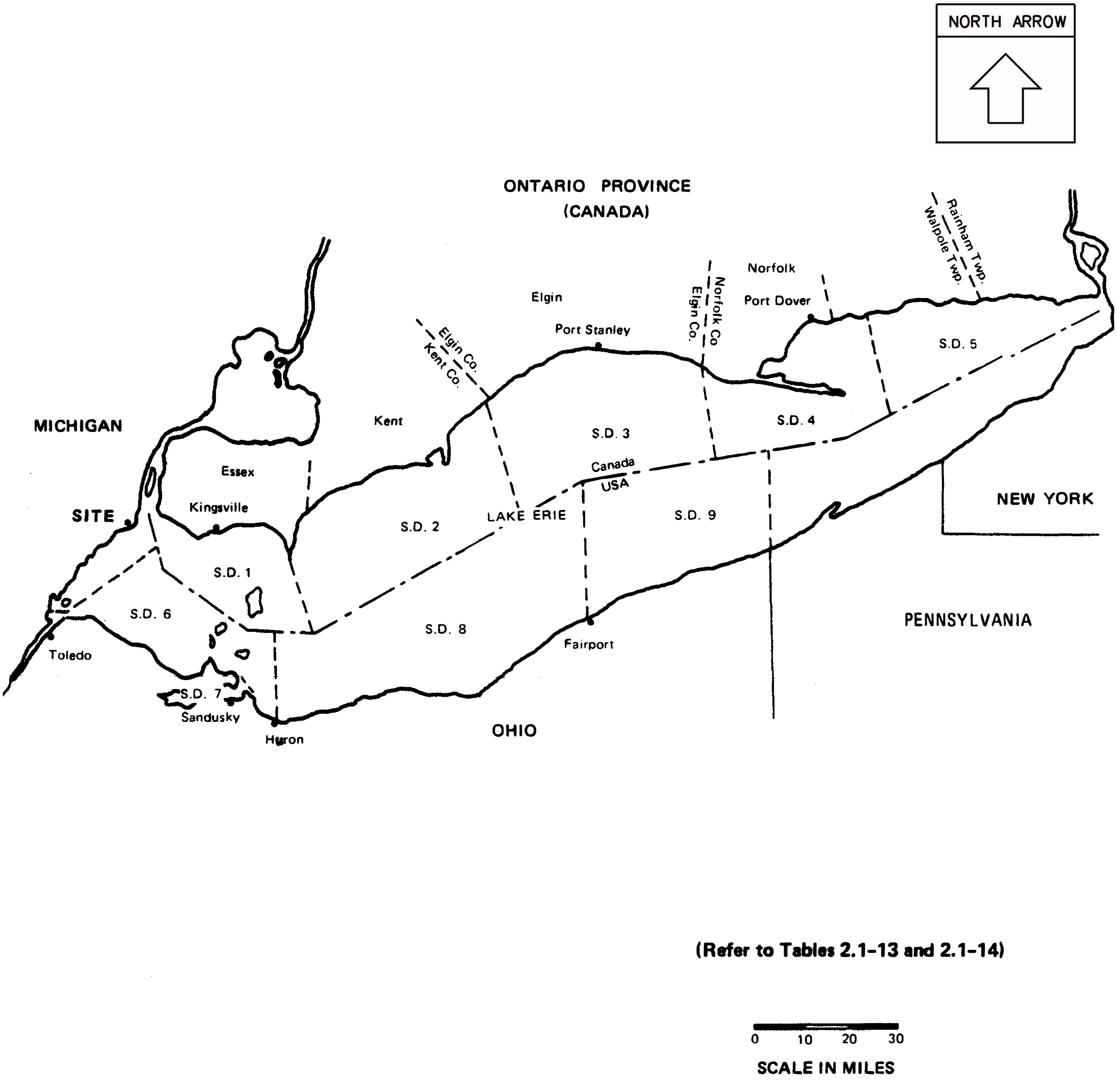
FIGURE 2.1-20

POTABLE WATER INTAKES ON LAKE ERIE



(Refer to Tables 2.1-13 and 2.1-14)

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FIGURE 2.1-21

COMMERCIAL FISHING STATISTICAL DISTRICTS IN LAKE ERIE

2.2 NEARBY INDUSTRIAL, TRANSPORTATION, AND MILITARY FACILITIES

Section 2.2 was prepared circa 1974 at the time of preparation of the original FSAR. It has not generally been updated in the area of nearby industrial, transportation, and military facilities since it represents the area at the time the Construction Permit was issued. However, changes have been made based on additions/modifications of facilities in the area.

2.2.1 Locations and Routes

2.2.1.1 Industrial Facilities

Industrial (and commercial) facilities within 5 miles of Fermi 2 are listed in Table 2.2-1, along with their products and number of employees (Reference 1).

The Fermi 1 breeder reactor, also on the Fermi site, is not operating and has been permanently shut down. The Fermi 1 plant is located on the site with Fermi 2. The Fermi 1 oil-fired plant has also been decommissioned, and it has been demolished. The 800,000-gal oil storage tank, which supplied the oil-fired boiler, has been abandoned. There is an additional nuclear power plant site within 30 miles of the Fermi site (Reference 2). This is Toledo Edison Company's Davis-Besse Nuclear Power Station, approximately 26 miles to the south-southeast.

There are three extractive industries within 10 miles of the site. The France Stone Company of Monroe, Michigan, is located 9.4 miles southwest of the Fermi site; the maximum quantity of explosives (mainly ammonium nitrate) stored at this quarry is between 25,000 and 35,000 lb (Reference 3). The Halloway Construction Company operates a quarry about 8 miles north of the site. A maximum of about 25,000 lb of explosives is stored at this quarry (Reference 4). Rockwood Stone, Inc., operates a quarry 3 miles north-northeast of the site. As reported to the NRC in July 1986, the maximum quantity of explosives located at this quarry is between 50,000 and 80,000 lb.

The Monroe Branch of the Austin Powder Company maintains a maximum storage of approximately 25,000 lb of dynamite at a site 6.7 miles west-southwest of the Fermi site. These explosives are used for agriculture and for highway construction, as well as for quarrying activities (Reference 5).

The Frenchtown Township water treatment facility is located approximately 2.5 miles south of the site. There are no explosives stored at this facility. The facility has a 1,000 gallon underground fuel oil storage tank for an onsite emergency generator. (Reference 5a).

2.2.1.2 Transportation Facilities

There are two major roads within 10 miles of the plant, Interstate 75 and U.S. Routes 24/25, shown in Figure 2.1-3. Their closest approach to the plant is 4.1 miles and 5.8 miles north-west of the plant site, respectively, with average 24-hr traffic flows of 27,300 and 9200 vehicles, respectively (Reference 6).

Within 10 miles of the plant, there are four Class I railroads. The Detroit and Toledo Shore Line Railroad, 4 miles northwest of the site, passes closest to and serves the Fermi site through the use of a single spur track. This company operates a freight service only between Detroit, Michigan, and Toledo, Ohio. At their closest approach to the plant, the other three lines (the Penn Central Railroad, the Chesapeake and Ohio Railroad, and the Detroit Toledo and Ironton Railroad) come to within 4 miles northwest, 7 miles west-northwest, and 9 miles northwest, respectively. The railroad yard in Monroe is the nearest yard to the plant. It is operated by the Penn Central Railroad and has a capacity of 230 cars (Reference 7).

Airports within 25 miles of the plant are listed in Table 2.2-2 and indicated in Figure 2.2-1. There are no major airports within 15 miles of the site. Three smaller airports are located about 9 miles from the site (Custer), 5 miles (Carl), and 2 miles (Marshall). The closest airport, Marshall Field, is 2 miles west of the plant. This is a small airfield with two sod runways, the longer being 1962 ft. This runway is oriented about northeast-southwest, approximately 30 degrees offset from the reactor site. Only light aircraft use this field. The weight of the heaviest aircraft using this field is about 3400 lb.

The closest major airports are Detroit Metropolitan and Willow Run, which are 19 miles north-northwest and 24 miles northwest of the plant, respectively (Reference 8). Figure 2.2-2 illustrates the approach patterns for Custer, Grosse Ile, and Detroit Metropolitan Airports. None of these approach patterns lie within 5 miles of the Fermi site.

There are three low level federal airways within 5 miles of the plant: V297, V96, and V10-188. The center line of airway V297 passes directly over the Fermi 2 plant and follows a southeast-northwest path. The center lines of airways V96 and V10-188 are 6.5 miles to the southeast and 4.0 miles north of the plant, respectively (Reference 8). (Airways are 4 miles wide.)

The shipping port nearest the plant is the Port of Monroe. Shipping traffic to this port is through an unobstructed channel, approximately 4.5 miles long, east-southeast of the site and extending from the head of navigation of River Raisin to the deep water in Lake Erie. As shown in Figure 2.2-3, the nearest approach of this channel to the Fermi site is approximately 6 miles south of the plant. Shipping traffic to the Port of Monroe is minimal in comparison to the traffic through the Detroit River. In 1964 there were only six commercial vessel trips inbound to the Port of Monroe, as compared to 10,999 upbound and 9693 downbound through the Detroit River (Reference 7). As shown in Figure 2.2-3, the Detroit River navigation channel connects to the West Outer Channel and the East Outer Channel in Lake Erie at a point approximately 7 miles northeast of the plant. The majority of the Detroit River traffic utilizes the East Outer Channel. Traffic on the West Outer Channel has a 5-mile nearest approach to the plant.

Oil and natural gas pipelines in the environs of the Fermi site are shown in Figure 2.2-4 and are described in Subsection 2.2.2.2.

2.2.1.3 Military Facilities

There are currently no military facilities within 10 miles of the plant. However, there are two restricted areas in Lake Erie, identified as Zone 1 and Zone 2. These zones are 20 miles and 27 miles from the plant, respectively, and are used as impact areas for small arms, ground artillery, and antiaircraft artillery from Camp Perry and from the test firing range at Erie

Industrial Park. Restrictions on weapon horizontal firing range and direction, as well as the nature of the projectiles, preclude a threat to the plant (Reference 9).

2.2.2 Descriptions

2.2.2.1 Industrial Facilities

The Fermi 1 power plant and the storage tank supporting the combustion turbine peakers of that plant are described in Subsection 2.2.1.1. The industrial facilities within 5 miles of the plant, including a description of their products and/or services and number of employees, are listed in Table 2.2-1.

The Frenchtown Township water treatment facility is a water processing plant for Frenchtown Township. The water treatment plant has the capacity to process 4,000,000 gallons of water per day. The chemicals used for water processing are not a hazard to Fermi 2 (Reference 5a).

2.2.2.2 Transportation Facilities

As shown in Figure 2.2-4, the natural gas distribution lines that pass nearest to the plant are those of the Michigan Gas Utilities Company. Their closest approaches are approximately 1.5 miles south and 2 miles west of the plant, with pipeline diameter sizes of 6 and 4 in., respectively. The natural gas transmission line of the Panhandle Eastern Pipeline Company passes approximately 10 miles northwest of the plant. There are currently no other gas pipelines within 10 miles of the plant.

The oil-products line of the Sinclair Pipeline Company, which passes 5 miles west of the plant, is the closest oil pipeline. Four other oil pipelines pass between 6 and 8 miles northwest of the plant. Of these, three are 6-in. to 12-in. oil products pipelines of the Pure Transportation Company, Sun Pipeline Company, and the Buckeye Pipeline Company; the fourth one is a 6-in. to 22-in.-diameter crude oil pipeline of the Buckeye Pipeline Company.

2.2.3 Evaluations

2.2.3.1 Cooling Water Intake Structure

The cooling water intake structure for Fermi 2 is a shoreline structure located adjacent to the existing Fermi 1 intake channel. This channel is protected by two rock jetties that extend into the lake. This intake provides cooling water and makeup water to the 5.5-acre pond, which is part of the closed-loop source of cooling water to operate the plant; the lake level at the mouth of the intake varies from 3 ft to 10 ft, depending on the status of the sandbar that continually forms at the end of the jetties and the prevailing level of Lake Erie. (Refer to Figure 2.4-9.)

Navigation by large ships and barges in the Western Basin does not normally approach within approximately 5 miles of the Fermi site. As a result of the very shallow water in the vicinity of the site, no large vessel could be expected to reach the site and damage the intake structure, even if this were attempted.

In addition, assuming that the intake structure is damaged sufficiently to prevent normal cooling water intake for an extended period of time, the 5.5-acre closed-cycle circulating water reservoir is of sufficient size to allow limited periods of normal plant operation with sufficient reserve to accomplish normal shutdown. If it were ascertained that the intake structure were to be inoperable for an extended period of time, reduction in load and shutdown would be initiated in a timely manner. In addition to the circulating water reservoir, the ultimate heat sink [residual heat removal (RHR) complex] provides cooling for 7 days in conformance with Regulatory Guide 1.27.

2.2.3.2 Industrial Facilities

The industrial facilities within 5 miles of the site (Table 2.2-1) do not present any potential danger to the safe operation of Fermi 2.

The Rockwood Stone, Inc., quarry located 3 miles from the site stores a maximum of 80,000 lb of ammonium nitrate fuel oil (ANFO) explosive in the delivery trailers on the quarry property at the ground surface level. ANFO has a TNT equivalence of 1.08. Edison has evaluated the effects on Fermi 2 of the explosion of this maximum inventory of explosives on the quarry site and of the explosion of a maximum shipment of 40,000 lb of the explosive at the closest approach to Fermi 2 (2 miles). Regulatory Guide 1.91 was used as a basis to evaluate overpressure effects. The U.S. Navy Design Manual Number 7.2, Foundations and Earth Structures, 1982, was used to estimate the ground motion effects due to blasting. It was concluded that the operation of the Rockwood Stone, Inc., quarry and the blast-induced overpressure, hydrostatic pressure, and ground motion effects due to accidental explosions do not pose a hazard to the Fermi 2 plant. The NRC Staff performed an independent evaluation of the blast-generated displacements, velocities, and accelerations of the ground using the empirical relationships in A. J. Hendron's paper titled Engineering of Rock Blasting on Civil Projects. Based on a review of Edison's analysis and on their independent evaluation, the NRC Staff concluded that the hazards due to blast-induced overpressure, ground motion, and hydrostatic pressure changes are insignificant with respect to Fermi 2 (Reference 10).

The Frenchtown Township water treatment plant is located approximately 2.5 miles south of the site. No chemicals with a potential to cause an explosion are used at this facility. Sodium hypochlorite is used for water treatment. This is not considered a hazard to Fermi 2 and it does not impact the chlorine release accident analysis as described in Section 6.4.

2.2.3.3 Offsite Transportation Facilities

As described in Subsections 2.2.1.2 and 2.2.2, no roads, railroads, or pipelines cross or pass close to the plant except for the site access road and railroad spur. No conceivable event associated with offsite highways, railroads, and pipelines in the area could be expected to influence normal operation of the plant.

The two principal shipping channels (described in Subsection 2.2.1.2) are 5 and 6 miles away from the Fermi 2 site. There is no potential for fire or explosion from any ship in one of these lanes to interfere with normal plant operation.

A 6-in.-diameter natural gas distribution pipeline passes 1.5 miles south of the plant. Potential explosions cannot endanger safe operation of the plant due to the size and distance of the line.

Table 2.2-2 and Figures 2.2-1 and 2.2-2 indicate the nearest airports to the Fermi site and the approach patterns for Custer, Grosse Ile, and Detroit Metropolitan airports.

The annual aircraft flights along the three low level federal airways V297, V96, and Vl0-l88, described in Subsection 2.2.1.2, are provided in Table 2.2-3, along with the aircraft types using these airways and an estimate of the probability of a crash at the Fermi site involving one of these aircraft. Also provided in Table 2.2-3 are estimates of the probabilities of crashes of private and corporate aircraft into the Fermi 2 spent fuel pool.

The Detroit Flight Service Center, which handles air traffic along 15 airways, including V297, V96, and V10-188, makes an average of about 34,000 radio contacts per year (References 11, 12, and 13). Between one-third and one-half of all flights along these airways make at least one radio contact with the Detroit Flight Service Center; thus a conservative estimate of the total flights per year along these 15 airways is about 100,000 or about 7000 per airway. About 40 percent of these flights are by commercial aircraft.

Aircraft crash data for the years 1970 through 1972 indicate that the probability of a crash during level or near-level flight is about 0.2 per million miles of operation for private and corporate aircraft (References 12, 14, and 15) and about 0.003 per million miles of operation for commercial air carriers (Reference 16).

Aircraft crash probabilities provided in Table 2.2-3 are based on crash bands of 13 miles for V96, 8 miles for V10-188, and 2 miles for V297. The target area for the plant was conservatively assumed to be 0.015 square miles (References 17, 18, 19, 20, and 21). The conservatively estimated probability of a commercial aircraft crash into the Fermi 2 plant is 8.9×10^{-8} per year and for a private aircraft 8.9×10^{-6} per year.

The target area for the spent fuel pool was taken to be 0.0001 square miles. A conservatively estimated probability of a private aircraft crash into the spent fuel pool is 5.9×10^{-8} per year. The exterior walls of the Category I reactor/auxiliary building were analyzed for the crash of the largest private aircraft capable of using Marshall Field and were found able to withstand such a postulated event.

2.2.3.4 Onsite Storage of Fuels and Explosives

The site access rail spurs are not used for the transportation of explosives or fuel oil. Fuel oil is transported by truck to the fuel-oil storage tanks onsite. A winter blend of #2 and #1 fuel oil is required for operation of the 62.2 MWe combustion turbine peakers south of Fermi 1.

The 300,000-gal fuel-oil storage tank for the combustion turbine peaker units is located approximately 1/3 mile south from the plant and safety-related plant structures. The results of any event related to the transportation and storage of fuel oil at this tank would have no effect on the normal operation of Fermi 2 or endanger safety-related plant structures or equipment. The tank is surrounded by a conservatively sized clay-lined dike with a polyethylene geomembrane inner dike liner and is equipped with piping to a foam distribution manifold on the tank. In the event of a fire involving the tank, a foam-generating fire truck can be connected to a nearby hydrant (furnished for the purpose). The foam discharge lines from the truck can be connected to the tank manifold piping using the provided fire department connection, and foam distributed within the tank. Should the tank rupture, the tank contents will be contained within the dike, and any fire extinguished using conventional fire fighting methodologies as well as the manifold. The fuel storage facility has been designed in accordance with applicable fire codes.

A 20,000 gallon liquid hydrogen storage tank is located at the HWC gas supply facility. The gas supply facility is approximately 1100 feet northwest of the RHR Complex. The tank location has been chosen to ensure that the results of any event related to transportation or storage of hydrogen at this tank would have no effect on the safe operation of Fermi 2 or endanger safety-related plant structures or equipment. The gas supply facility has been designed in accordance with applicable fire codes and the nuclear industry guidelines for permanent HWC installations.

Other onsite fuel storage facilities are identified and evaluated in Subsection 9.5.1 and Appendix 9A.

The only storage of explosives in the vicinity of the unit will be in quantities sufficiently small and at such a distance that no postulated accident can endanger the safe operation of the unit.

2.2.3.5 Onsite Storage of Toxic Chemicals

Sodium hypochlorite and a small quantity of acids are stored onsite.

Sulfuric acid for circulating water is transported in accordance with all applicable regulations. Safety measures are taken near handling and storage facilities. Any spills during transfer operations will soak into the ground and be neutralized or will drain to a chemical sump for neutralization.

Sodium hypochlorite used to treat the circulating water is stored at the circulating water pumphouse in a tank located within a nominal 150 percent tank capacity retention dike and pad.

Sodium hypochlorite used to treat the GSW System is stored at the GSW pumphouse in a tank located within a nominal 150 percent tank capacity retention dike and pad.

2.2.3.6 Cooling Tower Collapse

The cooling towers are hyperbolic in design and any postulated failure of this tower would cause it to collapse inwardly. This failure would in no way endanger the safe shutdown of the unit.

2.2 NEARBY INDUSTRIAL, TRANSPORTATION, AND MILITARY FACILITIES

REFERENCES

1. Monroe County Manufacturers Directory, Monroe County Library System and the Greater Monroe Chamber of Commerce, Monroe, Michigan.

2. Electricity from Nuclear Power, Central Station Nuclear Power Plants in the U.S., Atomic Industrial Forum, Inc.

3. G. Edgley, NUS Corporation, and Mr. Elson, Plant Supervisor, France Stone Company, Monroe, Michigan, Telephone Conversation, February 28, 1973.

4. G. Edgley, NUS Corporation, and W. Jarvi, Research and Development, Dow Chemical Company, Telephone Conversation, May 1, 1974.

5. G. Edgley, NUS Corporation, and G. Dridalt, Austin Powder Company, Monroe, Michigan, Telephone Conversation, February 28, 1973.

5a. Letter from M. P. Faeth, P.E., McNamee, Porter & Seeley, Inc., to E. F. Madsen, Detroit Edison, Subject: Frenchtown Charter Township WTP, dated April 25, 1994.

6. 1971 Average 24 Hour Traffic Flow Map, Report No. 223, Michigan Department of State Highways.

7. Inventory of Airports, Harbors, Railroads, Pipelines, and Truck Terminals; Detroit Regional Transportation and Land Use Study, January 1968.

8. Sectional Aeronautical Chart (Scale 1:500,000) - Detroit - 4th Edition; U.S. Department of Commerce, National Oceanic and Atmospheric Administration, National Ocean Survey, Washington, D.C., May 25, 1972.

9. Preliminary Safety Analysis Report for the Davis-Besse Nuclear Power Station, Appendix 2A, pp. 2A-1 through 2A-14 and Amendment No. 6, pp. 2A-13 through 2A-15, Docket No. 50-346, The Toledo Edison Company and Cleveland Electric Illuminating Company.

10. Letter from J. J. Stefano, NRC, to B. R. Sylvia, Detroit Edison, Subject: Fermi 2 Site Potential Hazards Due to Operation of the Nearby Rockwood Stone, Inc., Quarry, dated October 15, 1987.

11. Telephone conversations with G. Brainerd, Supervisor, Detroit Center, Flight Service Station, FAA, 11499 Conner Avenue, Detroit, Michigan 482l3. February 22 to February 28, 1975.

12. FAA Statistical Handbook of Aviation, Department of Transportation, 1972 Edition (Stock Number 5007-0l88).

13. Detroit Sectional Aeronautical Chart, Lambert Conformal Projection Standard Parallels 41°20' and 45°40', 9th Edition, U.S. Department of Commerce, National Oceanic and Atmospheric Administration, Washington, D.C.

14. K. A. Solomon, et al., Airplane Crash Risk to Ground Population, UCLA-ENG 7424, March l974.

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15. Annual Review of Aircraft Accident Data, U.S. General Aviation, Adopted May 29, 1974, NTSB-74-2.

16. U.S. Nuclear Regulatory Commission, Standard Review Plan, Section 3.5.1.6, Aircraft Hazards, June 1975.

17. Darrell G. Eisenhut, " A Review of Testimony by the Division of Reactor Licensing, Long Island Lighting Company, Unit 1," May 3, 1971.

18. Shoreham Nuclear Power Station, Amendment 3, USAEC Docket No. 150-322, February 5, 1969.

19. "Zion Station Amendment," USAEC 18-Docket 50-295, December 1971.

20. Karl Hornyik, "Airplane Strike Probability Near a Flight Target," ANS Annual Meeting, Chicago, Illinois, June 10-15, 1973.

21. "Probability of an Airplane Strike," Appendix D and Appendix E, USAEC 5-Docket-50-289, February 23, 1968.

TABLE 2.2-1 INDUSTRIAL FACILITIES WITHIN 5 MILES OF THE FERMI SITE

Company[a]	Products and/or Services	Number of Employees
B&M Industry, Inc.	Metal stamping	50
Lisowski Brothers, Inc.	Plating equipment and supplies	9
Marshall (Olen) Hardware and Airport	Hardware, paint, pumps; plumbing and electrical supplies; airport-flight instruction, tie down, gas and oil	2
Neidermeier Oil Company	Distribution of Union 76 fuel oil	4
Newport State Bank	General banking services	16
Ohio China Company	Retail and wholesale china	28
Rockwood Stone, Inc.	Limestone quarry	30
Frenchtown Township Water Treatment Plant	Potable water	4

[a] All of these facilities, except Rockwood Stone, Inc., are in Frenchtown Township, Monroe County, Michigan. Rockwood Stone is in Berlin Township, Monroe County, Michigan.

TABLE 2.2-2 AIRPORTS WITHIN 25 MILES OF THE FERMI SITE

Airport	Distance (miles) and Direction From Site	Number and Type of Aircraft Based at the Airport	Largest Type of Aircraft Likely to Land at Airport	Runway Direction/and Length (ft)	Runway Composition	Hours Attended	Average Weekly Flight Operations
Marshall	2 W	6 single-engine	Piper Aztec	50°-230°/1962	Sod	0800-dusk	10
Carl	6 NNW	21 single-engine	Cessna 310	180°-360°/2400 90°-270°/2300	Turf	0800-dusk	10
Wickenheiser	7 NW	3 single-engine	Cessna 172	90°-270°/1900 80°-360°/2600	Turf	-	2
Custer	9 W	53 single-engine 3 multi-engine	DC-3	20°-200°/3500	Blacktop	0800-2000	150
Grosse Ile	11 NNE	142 single-engine 6 multi-engine 2 helicopters	Convair 440	30°-210°/4980 170°-350°/5480	Blacktop Blacktop	0700-2400	1000
Detroit Metro	19 NNW	90 single-engine 60 multi-engine	Boeing 747	30°L-210°R/ 10500 30°L-210°L/ 8500 90°-270°/ 8700 150°-330°/ 4331	Concrete Concrete Concrete Concrete	24hrs	5544
Bielec	21 WNW	Information not available		180°-3600°/ 1900 50°-1750°/ 1750	Turf Turf	-	-
Frankman Ranchero	21 NW	3 single-engine	Piper-Apache	60°-240°/ 1930 90°-270°/ 1340	Turf Turf	-	12
Larsen	21 NW	48 single-engine	Twin Beach 45	180°-360°/ 1752	Turf	Not Given	300
Lada	22 W	1 single-engine	Piper Navajo	180°-3600°/2600	Sod	Daylight	1
Willow Run	24 NW	69 single-engine 105 multi-engine	DC-8	90°L-270°R/ 7294 90°R-270°L/ 7294 50°L-230°R/ 6656 50°L-230°L/ 7526 140°-320°/ 6911	Concrete-asphalt Concrete Concrete-asphalt Concrete-asphalt	24hrs	3800
Chippewa	25 S	Information not available	-	90°-270°/ 2600	Turf	None	-
Gradolph	25 W	10 single-engine 1 multi-engine	-	90°-270°/ 2600	Turf	Jan-Dec/ Mon-Sat 0800-1800	18

TABLE 2.2-3 AIRCRAFT CRASH PROBABILITY FOR THE FERMI SITE

Airway	Aircraft Type[a]	Estimated Flights Per Year	Target	Estimated Crash Probability Per Year
V297	U.S. Air Carrier	2800	Plant	6.3×10^{-8}
	General Aviation	4200	Plant	6.3×10^{-6}
	General Aviation	4200	Spent Fuel Pool	4.2×10^{-8}
V96	U.S. Air Carrier	2800	Plant	9.7×10^{-9}
	General Aviation	4200	Plant	9.7×10^{-7}
	General Aviation	4200	Spent Fuel Pool	6.5×10^{-9}
V10-188	U.S. Air Carrier	2800	Plant	1.6×10^{-8}
	General Aviation	4200	Plant	1.6×10^{-6}
	General Aviation	4200	Spent Fuel Pool	1.1×10^{-8}

[a] U.S. Air Carrier flights include such planes as the C-747, B-707, B-720, B-727, DC-8, DC-9, DC-10, L-1011, and others. General Aviation includes flights by U.S. Civil Aircraft owned and operated by persons, corporations, etc., other than those engaged in air carrier operations authorized by a Certificate of Public Convenience and Necessity.

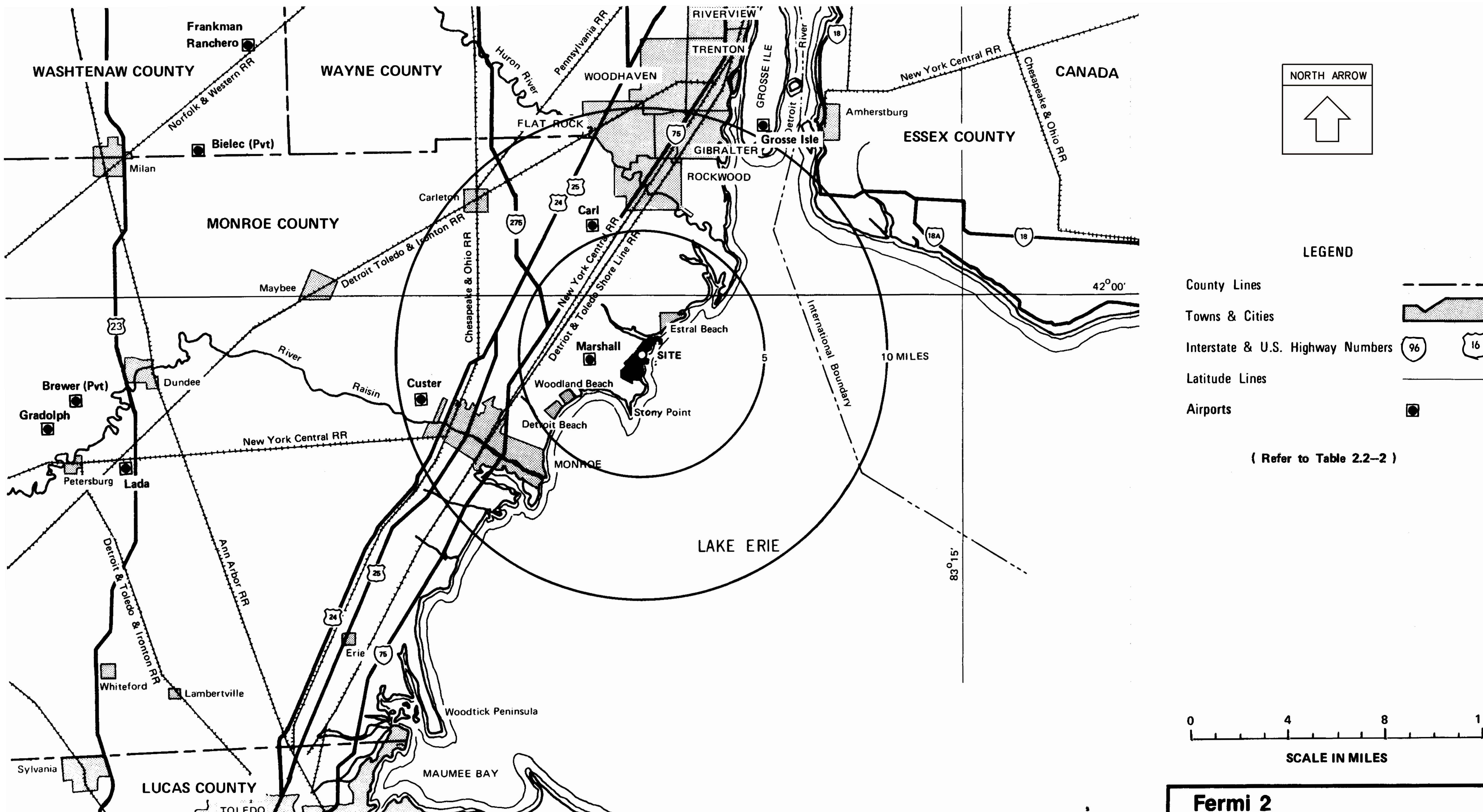

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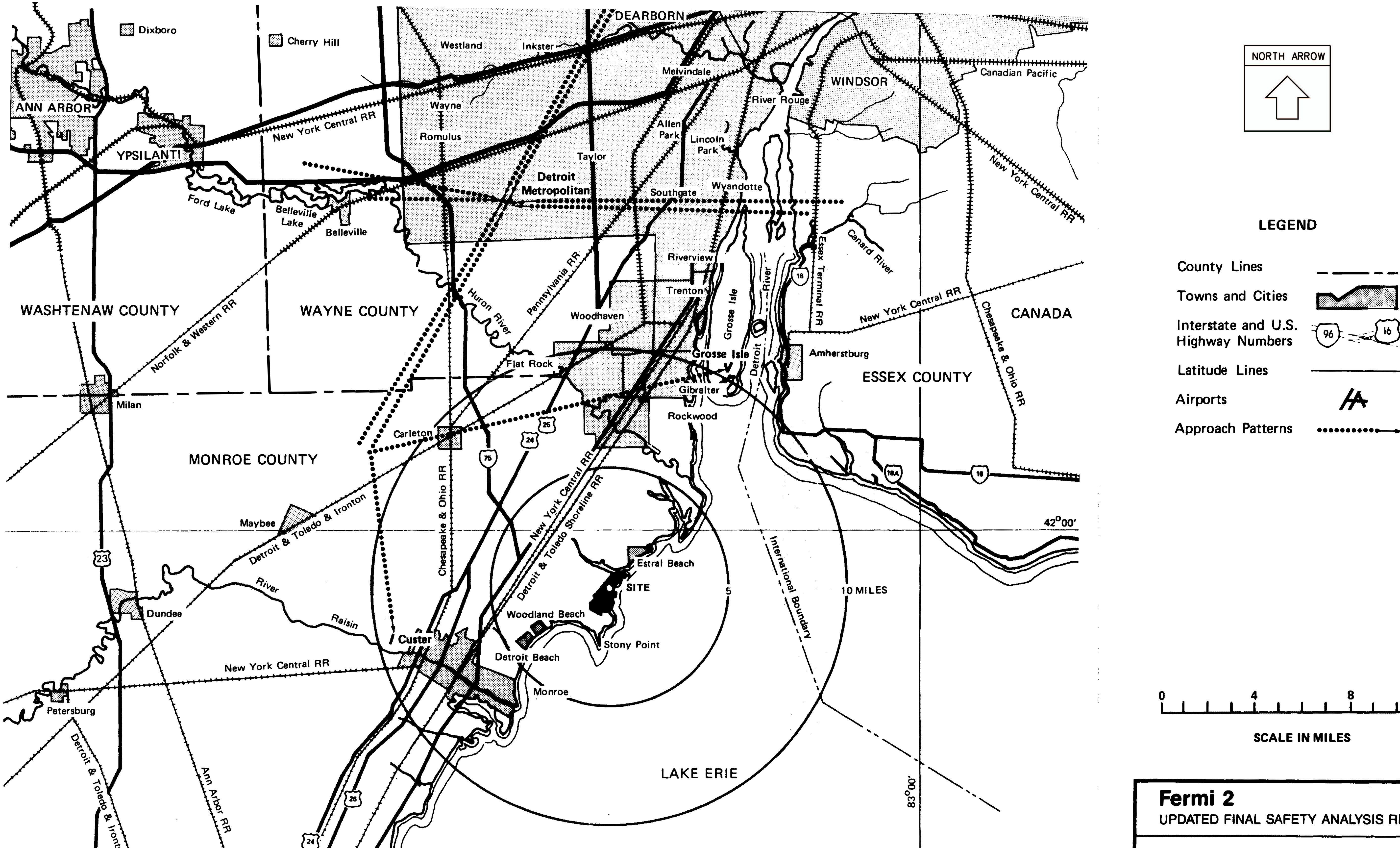
FIGURE 2.2-1
AIRPORTS IN THE VICINITY



0 4 8 12

SCALE IN MILES

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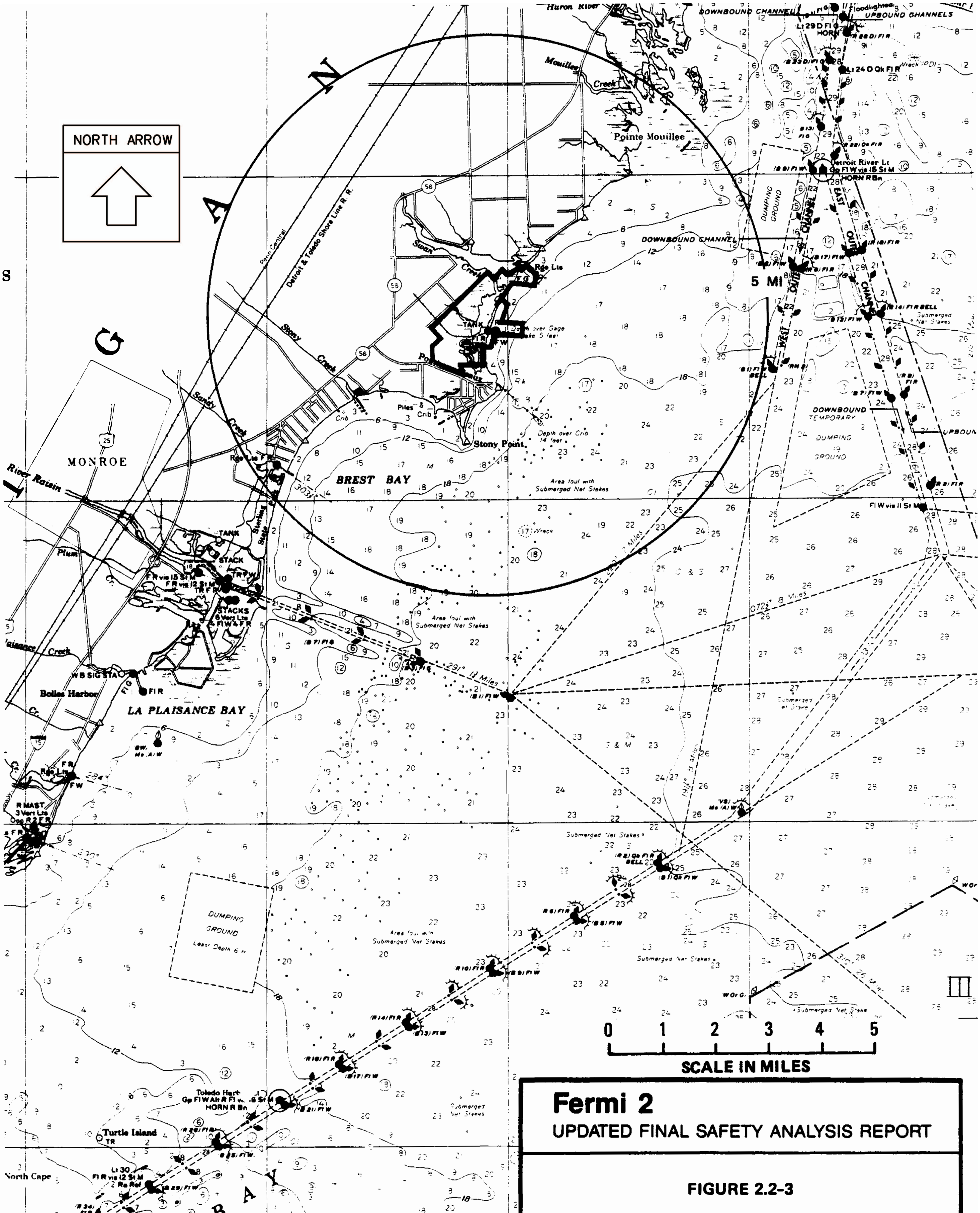
FIGURE 2.2-2

SELECTED AIRPORTS AND APPROACH PATTERNS IN THE VICINITY



REFERENCE:
U.S. LAKE SURVEY
CHART NO. 39, 1968

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FIGURE 2.2-3

LAKE ERIE NAVIGATION CHANNELS IN THE VICINITY

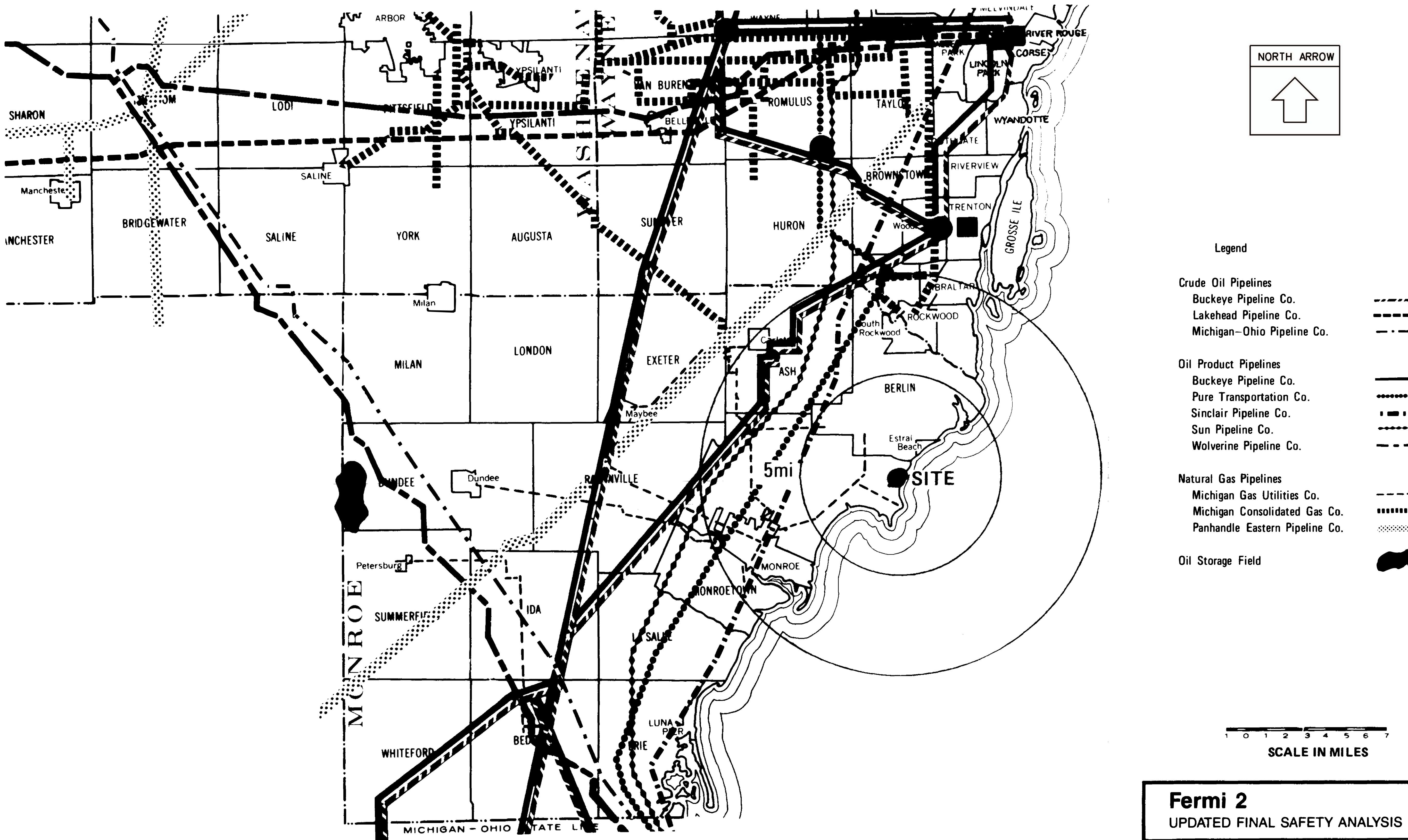

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FIGURE 2.2-4

OIL AND NATURAL GAS PIPELINES IN THE VICINITY

2.3 METEOROLOGY

2.3.1. Regional Climatology

2.3.1.1. Data Sources

The regional climatology pertinent to the Fermi site was determined from data acquired by the National Weather Service and summarized by the Environmental Data Service. The 1971 through 1974 local climatological data were obtained for the Detroit Metropolitan Airport (Reference 1), Detroit City Airport (Reference 2), and for Toledo, Ohio (Reference 3). The climatological summary was obtained for the cities of Monroe (Reference 4) and Willis (Reference 5), Michigan. These data provided sufficient information to determine the climatological characteristics of the area surrounding the Fermi site.

Extreme wind data were obtained from studies by Thom (Reference 6). Severe storm and tornado data were obtained from monthly storm data (Reference 7), climatological data national summary (Reference 8), the tornadoes of western Canada (Reference 9), and tornado probabilities (Reference 10).

The data for meteorological extremes were obtained for Detroit Metropolitan Airport, Detroit City Airport, and for Toledo Express Airport from the local climatological data for each station. Extremes for Monroe and Willis, Michigan, were obtained from the climatological summary for each station.

Monthly storm data were used to determine the number of occurrences of hailstorms and ice storms.

Climatological data for restrictive dilution conditions were obtained from a variety of sources concerned with stagnating conditions in the United States (References 11 and 12).

2.3.1.2. General Climate

The Fermi site is located in the southeast lower climatic district of Michigan on the western shore of Lake Erie. The lake smooths out most climatic extremes, with the most pronounced lake effect occurring in the coldest part of the winter when there is an excess of cloudiness and very little sunshine. Prevailing winds are from the western sectors in winter. Periods of easterly winds (off Lake Erie) and local lake breezes modify temperatures during the summer months. The climate in the area alternates between semi-marine and continental (Reference 4).

The predominant wind in the area is from the southwest, averaging approximately 10 mph (Reference 1). The average afternoon (1:00 p.m.) relative humidity for the Fermi site area is 58 percent, and varies from 52 percent in May to 71 percent in December (Reference 1). The highest temperature recorded in the area was 105°F (Reference 2) and the lowest was -19°F (References 1 through 5).

Precipitation is well distributed throughout the year. The Fermi site area receives an average of 31.15 in. of precipitation per year, with 56 percent occurring between the months of May and October. Minimum amounts of precipitation generally occur during the winter months (December, January, and February) and average approximately 2.0 in. per month. Maximum amounts of precipitation generally occur during the summer months (June, July, and August) and average approximately 3.0 in. per month (References 1 through 3). The mean annual snowfall in the area is 33.7 in. (References 1 through 5).

2.3.1.3. Severe Weather

2.3.1.3.1. Extreme Winds

According to a compilation by Thom (Reference 6) for characterizing extreme winds, the extreme mile wind speed at 30 ft above the ground, which is predicted to occur once in 100 years, is approximately 90 mph. The approximate values for other recurrence intervals are listed in Table 2.3-1, with the extrapolated value of 117 mph for the 1000-year recurrence interval (Reference 6). The extreme mile wind speed is defined as being the 1-mile passage of wind with the highest speed for the day. Based on the gustiness factor of 1.3, the highest instantaneous gust expected in 100 years is 117 mph. The highest mile wind recorded at Detroit City Airport, based on the 1934 through 1965 period of record, was 77 mph from the northwest (Reference 2). Based on the 1956 through 1972 period of record, the highest mile wind recorded at Toledo, Ohio, was a 72-mph wind from the southwest (Reference 3).

The Category I structures of Fermi 2 are designed to withstand a 90 mph fastest mile sustained wind velocity, 30 ft above ground level. This wind velocity has a 100-year recurrence interval.

The relationships to determine the vertical velocity distribution of the wind are obtained from Page 1139 of ASCE Paper No. 3269 for coastal areas and are as follows:

for $V_{30} \leq 60$ mph

$$V_z = V_{30}\left(\frac{z}{30}\right)^{0.3}$$

for $V_{30} > 60$ mph

$$V_Z = V_{30}\left(\frac{z}{30}\right)^{x}$$

where

V_{30} = basic wind velocity (mph) at a height 30 ft above ground level (grade)

x = factor which varies from 0.3 when V_{30} = 60 mph to 0.143 when V_{30}= 130 mph (Reference 3)

V_z = wind velocity (mph) at a height (z) above grade

Z = distance above grade in ft

Thus, at heights between 100 and 150 ft above grade, the height of the upper portion of the reactor building, the wind velocity is calculated to be 123.5 mph. Gust factors have also been determined by the methods given on pages 1124 through 1198 in ASCE Paper No. 3269. For all Category I structures, the gust factor varies linearly from 1.1 at grade level to 1.0 at 400 ft. However, a gust factor of 1.1 was used for the full height of both the reactor/auxiliary building and the residual heat removal complex except for the blow-away siding design during the design tornado, where a factor of 1.0 was used.

2.3.1.3.2. Tornadoes

2.3.1.3.2.1. Frequency

During the period January 1951 through December 1974, a total of 51 tornadoes were reported within a 50-mile radius of the Fermi site (References 8 and 9). These 51 tornadoes occurred within the United States. This is an average of two tornadoes per year within this radius. There were no tornadoes reported within 50 miles of the site in Canada for the period 1951 through 1960 (Reference 9). Canadian tornado data were not available for the period 1961 to 1974. There was one tornado reported at Tecumseh, Ontario, on August 1, 1973. This tornado was not included in this analysis.

According to the statistical methods proposed by Thom (Reference 10), the probability of a tornado striking a point within a given area may be estimated as follows:

$$P = \frac{\bar{z}\bar{t}}{A}$$

where

P	=	mean probability per year
$\bar{z}$	=	geometric mean tornado path area
$\bar{t}$	=	mean number of tornadoes per year
A	=	area of concern

For the region surrounding the Fermi site, the geometric mean path length computed was approximately 2.15 miles, and the geometric mean path width computed was approximately 75 yd (References 7 and 10), yielding a mean path area ($\bar{z}$) of 0.092 square mile, based on the January 1951 through December 1974 period of record. The use of a 50-mile radius to compute A (excluding the water area of Lake St. Clair and Lake Erie and the land area in Canada) and a value of 2.125 for $\bar{t}$ yields a tornado probability of 4.075 x 10^{-5} per year, or a recurrence interval of 24,500 years.

It should be noted that the June 8, 1953, tornado in northern Ohio had a reported path length of 100 miles and a path width of 440 to 1760 yd. These data were not used in the computation of $\bar{z}$, as recommended by Thom (Reference 10), who states that tornadoes with reported paths longer than 100 miles and paths wider than 1000 yd are considered doubtful observations. However, including this tornado, this yields a probability of 4.7 x 10^{-5}, or a recurrence interval of 21,200 years.

During the period of record studied, three tornadoes occurred within 5.5 miles of the Fermi site, but it is difficult to determine which occurred closest to the site. These were (1) on June 28, 1973, a tornado was observed 3 miles south of Estral Beach; no data on path length or width were given; (2) on June 12, 1973, a tornado occurred 3 miles west of South Rockwood with a path length of 0.1 mile and width of 40 yd; and (3) another nearby tornado occurred on June 11, 1968, at Monroe, Michigan. The path length reported was "short" and no path width was given. No persons were reported killed or injured, and the damage was estimated at from $500 to $5000 (References 7 and 8).

Not included in the above tornado discussion were water spouts and funnel clouds sighted in the area that did not touch the ground. Only one water spout was sighted within 50 miles of the site during the period 1965 through 1974. This occurred on August 1, 1965, 13 miles southeast of Mt. Clemens; there was no damage reported.

2.3.1.3.2.2. Parameters

Category I structures housing the systems required for a safe shutdown of the plant in the event of a tornado are designed to withstand the effects of a tornado by providing either sufficiently strong structures or appropriate venting. The design parameters of the Fermi 2 design-basis tornado are

a. A rotational wind velocity of 300 mph

b. A translational wind velocity of 60 mph

c. An external pressure drop of 3 psi at the rate of 1 psi/sec.

2.3.1.3.3. Precipitation Extremes

Tables 2.3-2 through 2.3-6 list extremes of precipitation and other meteorological parameters for several stations that surround the Fermi site. The maximum amount of precipitation recorded for a 24-hr period was 4.39 in. at Toledo, Ohio, in July 1969. The maximum monthly snowfall measured in the region was 28.5 in. at Monroe, Michigan, in March 1954 (Reference 1 through Reference 5). A December 1 and 2, 1974, snowstorm deposited 19.3 in. of snow at the Detroit Metropolitan Airport.

The 100-year recurrence snowpack and 100-year recurrence daily snowfall were computed using data from the Detroit Metropolitan Airport for the years 1971-1974 inclusive (see Figures 2.3-1 and 2.3-2). Each of these had the data ranked according to the amount and number of occurrences in the 4-year period. From these ranked amounts, a cumulative distribution table was generated. This cumulative percentage was graphed as a function of amount and the curve visually extrapolated to the value occurring in 100 years.

Snowpack

Number of Occurrences	Maximum Snowpack (in.)	Cumulative Number of Occurrences	Cumulative Percentage
10	Trace	36	100.00
8	1	21	72.22
3	2	18	50.00
5	3	15	41.67
3	4	10	27.78
1	5	7	19.41
2	7	6	16.67
1	8	4	11.11
1	9	3	8.33
2	11	2	5.56

The average number of observations per year is nine for this calculation, so that 100 years would provide 900 samples. The 100-year recurrence percentage would therefore be 0.11 percent. Referring to the graph of the cumulative frequency of snowpack versus amount, the extrapolated 100-year recurrence value is 27.8 in.

Daily Snowfall

Number of Occurrences	Maximum Daily Snowfall (in.)	Cumulative Number of Occurrences	Cumulative Percentage
4	Trace	28	100.00
2	0.1	24	85.71
1	0.5	22	78.57
1	0.6	21	75.00
2	1.0	20	71.43
1	1.3	18	64.29
1	1.5	17	60.71
1	1.6	15	57.14
1	1.7	15	53.14
1	2.5	14	50.00
2	2.7	13	46.43
1	2.8	11	39.29
1	2.9	10	35.71
1	3.1	9	32.14
1	3.2	8	28.57
1	3.7	7	25.00
1	3.8	6	21.43
1	4.7	5	17.86
1	5.2	4	14.29
1	8.4	3	10.71
1	8.7	2	7.14
1	19.3	1	3.75

The average number of observations per year is seven for this calculation, so that 100 years would provide 700 samples. The 100-year recurrence percentage would therefore be 0.15 percent. Referring to the graph of the cumulative frequency of maximum daily snowfall versus amount, the extrapolated 100-year recurrence value is 28.2 in.

2.3.1.3.4. Hailstorms

A review of hailstorm data for the period of 1962 through 1974 is reported in storm data for Monroe County and the immediately surrounding counties of Lenawee, Washtenaw, Wayne, Lucas (Ohio), and Ottawa (Ohio). This review indicates that there were 93 days with hailstorms in this area. Generally, these hailstorms occurred with scattered thunderstorms which covered a wide area (i.e., northern Ohio or southern Michigan). One of the most severe storms in the area occurred on July 19, 1967, in Wayne and Monroe Counties. Hailstones varying in size from "small peas to larger than golf balls" were reported to have accumulated to depths of 6 to 7 in. in spots. Damage to both crops and property ranged from $5000 to $50,000 (Reference 7).

2.3.1.3.5. Ice Storms

A study of ice storm data for the 1962 through 1974 period for Monroe County and the immediately surrounding counties indicates that there were 26 storms in this region. The storms were rarely limited to a small area, but were widespread over the state. The greatest accumulation of ice in the region came from the January 26 and 27, 1967, storm, which deposited up to 3 in. of ice in northern Ohio (Reference 7).

2.3.1.3.6. Thunderstorms

Thunderstorms occur on an average of 35 days per year, approximately 80 percent occurring in the months of June, July, and August (References 1 through 3). Generally, these thunderstorms encompass a large area (on the order of several hundred square kilometers each) and are associated with strong winds, intense precipitation for short time intervals, and lightning. Lightning incidence is estimated at about 10 flashes per year per square kilometer.

Each thunderstorm produces an average of about 120 independent flashes to ground (an average of one every 20 sec. for an interval of about 40 minutes). Each thunderstorm (isolated) encompasses an area of about 400 km^2 (20 km on a side). With 35 days per year associated with thunderstorms, these estimates give

$$\frac{35\ \text{Storms}}{400\ \text{km}^2} \text{ x } 120\ \frac{\text{flashes}}{\text{storm}} = 10\,\frac{\text{flashes}}{\text{Km}^2} \text{ per year.}$$

2.3.1.3.7. Restrictive Dilution Conditions

The frequency of occurrence of low-level inversions or isothermal layers based at or below a 500-ft elevation in the site region is approximately 28 percent of the total hours on an annual basis, according to Hosler (Reference 11), who takes into account lake and ocean effects on inversion frequencies. Seasonally, the greatest frequencies of inversions based on percent of total hours are 30 percent during the summer and fall. The inversion frequencies are 25 percent in the spring and 20 percent in the winter. The majority of these inversions are nocturnal in nature.

The mean mixing depth is another restriction to atmospheric dilution. The mixing depth is the thickness of the atmospheric layer, measured from the surface upward, in which convective overturning is taking place, caused by the daytime heating at the surface. The mixing depth is usually at its shallowest during the early morning hours, just after sunrise, when the nocturnal inversion is being modified by solar heating at the surface. The mixing depth is at its greatest during the later part of the afternoon, 3:00 p.m. to 4:00 p.m., when the maximum surface temperature of the day is reached. The monthly mean daily mixing depths, based on Flint, Michigan, upper air data for the period January 1960 through December

1964, are presented in Table 2.3-7 (Reference 12). Shallow mixing depths have a greater frequency of occurrence during the fall and winter months.

Periods of high air pollution potential are usually related to a stagnating anticyclone, with the average wind speed less than or equal to 9.0 mph (4.0 m/sec), no precipitation, and a mixing depth of less than 1600 ft (Reference 14).

The greatest air pollution potential in the site region occurs during the months of August, September, and October, when the tendency is greatest for a quasi-stationary anticyclone to develop in the region (Reference 15).

According to Korshover (Reference 15), there were approximately 19 anticyclone stagnation cases, each 4 days or more, reported in the site region during the period 1936-1967.

2.3.1.3.8. Maximum Roof Loadings

The following data itemize the maximum snow and ice load in inches of water that the roofs of safety-related structures are capable of withstanding during plant operation. The operating- basis conditions are based on the service conditions allowable stresses or strengths. The design-basis conditions are based on the strength of the structure at yield stresses with a load factor of 1.0.

Safety-Related Structure	Operating-Basis Snow and Ice Load (psf)	Water Equivalent (in.)	Design-Basis Snow and Ice Load (psf)	Water Equivalent (in.)
Reactor / auxiliary building	30	5.8	87	16.7
RHR Complex	70	13.5	276	53.0*

*This depth exceeds parapet height

2.3.2. Local Meteorology

2.3.2.1. Data Sources

The original Fermi 2 FSAR was filed with 12 months (June 1, 1974, to May 31, 1975) of onsite data obtained from a 60-m tower equipped with sensors that meet the requirements of Regulatory Guide 1.23 (Reference 16). Data from previous site meteorological systems and offsite National Weather Service sources were included as appropriate.

Offsite wind, stability, precipitation, temperature, relative humidity, and fog data were based on meteorological observations from Detroit Metropolitan Airport and Toledo Express Airport, both first-order National Weather Service stations (References 1 and 3). Additional temperature and precipitation data were obtained from National Weather Service cooperative stations at Monroe and Willis, Michigan (References 4 and 5). The 1956 to 1959 period site wind, stability, and precipitation data were obtained and summarized by the University of Michigan from the Fermi 1 100-ft meteorological tower (Subsection 2.3.3.1.1) (References 17 and 18). Additional onsite data from a low-level 33-ft tower at Langton Road are presented in this section, based on data obtained and reduced by the University of Michigan for the period January 1, 1972, to December 31, 1972. These data include ambient temperature and relative humidity; however, the low-level wind data are only briefly discussed because of unfavorable (42 percent) data recovery.

Wind stability and fog data summaries for Detroit Metropolitan Airport and Toledo Express Airport were also obtained.

2.3.2.2. Normal and Extreme Values of Local Meteorological Parameters

The distribution of wind direction and speed is an important factor when considering transport conditions relevant to site diffusion climatology. The monthly, seasonal, and annual distributions of wind direction and speed from the 60-m tower at the Fermi site (June 1, 1974, to May 31, 1975) are presented in Figures 2.3-3 through 2.3-19. For comparative purposes, data from Detroit City Airport (81-ft level, 1951 to 1960) and Toledo Express Airport (20-ft level, 1950 to 1955) are presented in Figures 2.3-20 through 2.3-31; each month presented represents averaged data for the years reported. These data are summarized and presented in annual wind roses in Figure 2.3-32. Average wind directions for all locations show a predominance of winds from the southwest through west-southwest. Limited site data from the Langton Road Tower (33-ft level) for the January 1, 1972, to December 31, 1972, period indicate a predominance of winds from the south through west-southwest.

Atmospheric dilution is directly proportional to the wind speed, with other factors remaining constant. Table 2.3-8 presents the average wind speeds and frequencies of calms for the Fermi site, the Detroit Metropolitan Airport, and the Toledo Express Airport. A calm is defined as a wind speed of $\leq$1.0 mph for the Fermi site 60-m and 150-m tower data and $\leq$1.2 mph for data recorded at National Weather Service stations and the Fermi site 100-ft tower. The threshold of the anemometer was used as the determining value of calm conditions. The highest average speed of the four stations, summarized in Table 2.3-8, is at the Fermi site at the 60-m level. This can be attributed to the higher exposure height of the wind sensors at the Fermi site and the shoreline location of the site, since wind speeds during onshore wind flows may be greater, and a lake breeze situation can develop during periods when light winds or calms are recorded at inland meteorological stations. Variations in speed can also be attributed to differences in instrumentation, data reduction techniques, and periods of record.

2.3.2.2.1. Wind Direction Persistence

Wind direction persistence is important when considering potential effects from a contaminant release. Wind direction persistence is defined as a continuous flow from a given direction or range of directions. Figure 2.3-33 shows the probability of occurrence of a 22-1/2° sector wind flow persistence as a function of duration, based on data from the 60-m tower (June 1, 1974, to May 31, 1975) and offsite data from the Detroit Metropolitan Airport (1959 to 1962 data period) and the Toledo Express Airport (1959 to 1963 data period). The wind persistence summary from onsite data (60-m tower) is shown in Table 2.3-9 in increments of 1 hr.

Based on the onsite observation time (12 months), the 10-m level data indicate a 5 percent probability of continuous wind direction persistence of about 7 hr and a 1 percent probability of 11-hr duration. At the 60-m level, these same percentages are 7 hr and 13 hr, respectively.

The 5 and 1 percent probabilities of continuous wind direction persistences at the 60-m level were greater than those observed at the 10-m level, as should be expected. The Detroit Metropolitan Airport data at 58 ft indicate a 5 percent probability of continuous wind direction persistence periods greater than 9 hr and a 1 percent probability of continuous wind direction persistence periods greater than 15.5 hr. The Toledo Express Airport data at 20 ft indicate a 5 percent probability of continuous wind direction persistence for periods greater than about 16 hr.

The maximum wind persistence at the Fermi site within a 22-1/2° sector, recorded on the 60-m tower during the June 1, 1974, to May 31, 1975, period, was one period lasting for 32 hr at the 10-m level from the south, associated with an average speed of 21 mph. The maximum wind persistence at the Detroit Metropolitan Airport within a 22-1/2° sector, recorded during the 1959 to 1963 period, was a 37-hr wind from the east-southeast, associated with an average speed of 17 mph. The maximum wind persistence at the Toledo Express Airport within a 22-1/2° sector, recorded during the 1959 to 1963 period, was a 37-hr wind from the east-northeast associated with an average wind speed of 17.0 mph. Episodes of maximum wind persistence within a 22-1/2° sector for the Fermi site 10-m level (60-m tower) data, Detroit Metropolitan Airport, and the Toledo Express Airport are presented in Figure 2.3-34.

2.3.2.2.2. <u>Atmospheric Stability</u>

Stability is a measure of the degree of atmospheric turbulence. A low degree of wind turbulence can be expected for stable conditions, resulting in relatively suppressed diffusion conditions. Conversely, during periods of instability, a high degree of wind turbulence can be associated with relatively enhanced diffusion conditions.

The seasonal and annual frequencies of stability indices for the Detroit Metropolitan Airport, Toledo Express Airport, and the Fermi site 60-m tower are presented in Tables 2.3-10 and 2.3-11. The stability data for the two airports were classified according to the Pasquill-Turner approach (Reference 19). This method is an indirect approach and involves the utilization of factors such as cloud cover, solar insulation, time of day, and wind speed to classify data that are generally available at National Weather Service observation stations. The onsite stability data were determined for the 60-m tower for the June 1, 1974, to May 31, 1975, period. The stabilities were classified from $\Delta T_{(60\ m\text{-}10\ m)}$ data, using the procedure outlined in Regulatory Guide 1.23 (Reference 16). Examination of Tables 2.3-10 and 2.3-11 indicates the predominance of neutral conditions. The frequency of stable (E, F, and G) conditions for both Detroit Metropolitan Airport and Toledo Express Airport is similar to the frequency of inversions based on Fermi site $\Delta T_{(100\ ft\text{-}25\ ft)}$ data from the 100-ft tower on a seasonal and annual basis (Table 2.3-12). The onsite data from the 60-m tower show a larger spread in the stability data.

Onsite stability data for the 1956 to 1959 period were compiled on a seasonal and annual basis and summarized in reports by the University of Michigan (References 17 and 18). The data were based on a $\Delta T_{(100\ ft\text{-}25\ ft)}$ and were obtained from the 100-ft tower described in Subsection 2.3.3.1. The data were classified into the following three groups:

a. Strong vertical temperature gradients ($\Delta T_{(100\ ft\text{-}25\ ft)} < 0.98°C/100$ m or -5.4°F/1000 ft)

b. Weak vertical temperature gradients ($\Delta T_{(100\ ft\text{-}25\ ft)}$ >0.98°C/100 m or 5.4°F/1000 ft, and ≤0)

c. Inversions (temperature increases with height).

In addition, $\Delta T_{(300\ ft\text{-}20\ ft)}$ data are available from the WJBK-TV tower located in the northwest suburbs of Detroit, approximately 35 miles north of the Fermi site. Data from this tower were analyzed for the 1956 to 1959 period for inversion conditions only.

Fermi site $\Delta T_{(60\ m\text{-}10\ m)}$ data from the 60-m tower are presented on an hourly basis over the June 1, 1974, to May 31, 1975, period in Tables 2.3-13 and 2.3-14. Additional Fermi site $\Delta T_{(100\ ft\text{-}25\ ft)}$ data from the 100-ft tower are presented on a seasonal and annual basis in Table 2.3-12. WJBK-TV $\Delta T_{(300\ ft\text{-}20\ ft)}$ data for inversion conditions only are presented in Table 2.3-15 for comparative purposes. These two locations compare favorably as to frequency of occurrence of inversion conditions. Both have a maximum during the summer and a minimum during the spring. The diurnal distribution of frequency of inversions at the WJBK-TV tower compares well with that at the Fermi site using data from the 60-m tower. The maximum frequency of inversions occurs in the midmorning hours (5:00 a.m. to 8:00 a.m.), while the maximum frequency of unstable conditions occurs in the early afternoon hours (1:00 p.m. to 3:00 p.m.).

Table 2.3-16 shows the inversion persistence derived from the 60-m tower measurements over the June 1, 1974, to May 31, 1975, period.

The stability classes were determined from $\Delta T_{(60\ m\text{-}10\ m)}$ 60-m tower data using the classification scheme outlined in Regulatory Guide 1.23. For Table 2.3-16, an inversion was defined as the existence of a temperature difference between the 60-m level and the 10-m level of greater than -0.0°C (i.e., temperature change with height (°C/100 m) >-0.0).

Figure 2.3-35 presents the probability of inversion persistence for durations greater than 6 hr, based on the frequency of occurrence with respect to surface-based inversions only. These data are based on Fermi ΔT site data from the 100-ft tower for the 1956 to 1959 period and ΔT site data from the 60-m tower for the June 1, 1974, to May 31, 1975, period. Figure 2.3-35 shows a 5 percent probability of an inversion lasting longer than 25 hr and a 1 percent probability of an inversion lasting longer than 43 hr, using the 100-ft tower data. For the 60-m tower data, these same percentages produce inversions of 18 hr and 30 hr, respectively.

Joint frequency tables of wind directions and speed by stability class are presented in Appendix 2A of the original FSAR for onsite Fermi data from the 60-m tower from June 1, 1974, to May 31, 1975. Current data for the 10-m level and 60-m level are provided by the operational meteorological system (Subsection 2.3.3.2). Annual summaries of meteorological data are prepared as required by the Technical Specifications.

2.3.2.2.3. Distribution and Frequency of Precipitation

Distribution of precipitation as a function of wind direction is presented in Table 2.3-17 for the Fermi site, using data from 1956-1959 from the 100-ft tower and from June 1, 1974, to May 31, 1975, from the 60-m tower. The 100-ft tower data show that the highest frequency of precipitation occurs when associated with winds from the southwest through west-northwest. The average wind speeds (100-ft level) during precipitation are 11.0 mph for all directions. The frequency of precipitation during calm conditions is 0.2 percent of the total hours of precipitation (Reference 18). The 60-m tower data show a larger spread, which may be due to the smaller sample size (12 months). A wind rose showing the distribution of wind speed versus wind direction with respect to precipitation only is presented in Figure 2.3-36.

2.3.2.2.4. Natural Fog Occurrences

Fog is essentially a cloud that has developed on the ground. Therefore, the processes leading to fog formation are similar to those for cloud formation. In general, the conditions that promote water-vapor condensation in ground-level air may lead to fog conditions. Aside from the interrelated thermodynamics of the ambient air and the ground surface, a number of other factors may influence the formation of fog. These factors include the size, character, and number of condensation nuclei; the extent of cloud cover; the wind speed and direction; the time of day; and the atmospheric turbulence.

The surface air may generally be treated as a mixture of dry air and water vapor. The most frequent and effective cause of fog is the cooling of humid surface air to a point where vapor condensation occurs. The condensation generally takes place on larger and more active condensation nuclei, and may occur somewhat before the dewpoint temperature (saturation) is reached. However, as long as the moisture content is sufficiently below the saturation value, condensation does not occur and fog conditions do not exist.

According to Byers, there are three types of fog which predominate in the Great Lakes area (Reference 20). Spring and early summer conditions (warm atmosphere and cold lake) contribute to the formation of land and lake breeze fogs. In the fall, advection-radiation fogs form over the land. During the fall and winter, steam fogs form over the lakes.

In the formation of a land and lake breeze fog, warm moist air from the land is transported out over the cold lake and, if the winds are light, a dense surface fog may develop over the lake. The fog may then be carried out over the land by a lake breeze during the day and may recede at night during a land breeze flow. These fogs rarely penetrate very far inland (i.e., 2 or 3 miles).

An advection-radiation fog is formed by nighttime radiational cooling of air of high humidity that has been advected inland from the lake during the day. This advection of lake air with a high relative humidity makes possible the formation of fog with normal nocturnal cooling.

Steam fog will form when cold air with a low vapor pressure passes over warm water. Steam fog is generally shallow in depth (i.e., 50 ft to 100 ft thick). According to Rondy, the western end of Lake Erie will have 70 percent to 90 percent ice coverage out to 35 miles by January 15 during a normal winter. The extreme western shoreline, where the Fermi site is located, will have 100 percent coverage out to 5 miles from the shore by January 15 (Reference 21). Therefore, steam fog in the Fermi site area will occur mostly during the fall.

Fog occurs predominantly during the early morning hours when the moisture-bearing air is cooled to the lowest temperature and the vapor saturation of the air is most closely approached. This effect is illustrated in Figure 2.3-37 where the probability of fog occurrence at the Detroit Metropolitan Airport, for the December 1, 1958, to September 1, 1962, period, is plotted versus the hour of the day for the annual average. Over the year, the peak frequency of fog occurrence is about 32.1 percent of the total hours of fog and occurs between 5:00 a.m. and 7:00 a.m. There is a notably higher frequency of fog between the hours of 11:00 p.m. and 10:00 a.m. Fog (other than frontal fog) is normally expected to dissipate during the late morning hours, particularly on clear, sunny days. However, cloud cover can extend the period of fog well into the daytime hours.

The monthly percentage occurrences of fog based on Detroit Metropolitan Airport data are presented in Figure 2.3-38. As can be seen in Figure 2.3-38, the monthly distribution of fog at the Detroit Metropolitan Airport does not show the distribution of fog for a Great Lakes area station predicted by Byers. Great Lakes area fogs have peak occurrences in the spring, early summer, and fall. The Detroit Metropolitan Airport shows peaks in the fall and winter. The major cause of the difference between occurrences observed at the Detroit Metropolitan Airport and those predicted by Byers is the location of the airport with respect to Lake Erie. Detroit Metropolitan Airport is located approximately 20 miles from Lake Erie. Because of this, lake- land breeze-type fogs, which rarely penetrate more than 2 to 3 miles inland, will not be evident at the airport. Because the Toledo Express Airport is 20 miles from Lake Erie, these types of fogs will not be evident there either. However, in a location such as the Fermi site, the lake will have a greater effect on natural fog occurrences, and the types and frequencies of fog should be the same as outlined by Byers.

The presence of fog onsite (at the shoreline) is associated with, for the most part, calm wind conditions. The ability of the natural draft cooling tower plume to rise to considerable heights is a significant factor in reducing the potential of adverse ground-level environmental effects. For example, under calm wind conditions, a typical plume penetration height for the Fermi 2 cooling towers is about 1000 ft above the top of the towers. In addition, the major roadways in the vicinity of the site are Interstate 75 and U.S. 24/25, whose closest approaches are 5.1 and 5.8 miles to the northwest, respectively. Dixie Highway, Pointe Aux Peaux Road, and Toll Road are closer, but are not considered major highways (Reference 22).

2.3.2.2.5. Meteorological Parameters

The extremes and means of meteorological parameters have been tabulated in Tables 2.3-2 through 2.3-6 for the Detroit City Airport, Detroit Metropolitan Airport, Toledo Express Airport, and Monroe and Willis, Michigan.

Table 2.3-18 presents the average temperature and relative humidity by month during the January 1, 1972, through December 31, 1972, period at the Fermi site (Langton Road Tower), the Detroit City Airport, and the Toledo Express Airport, for comparative purposes. However, the average relative humidity values by month for Fermi site data seem somewhat high and may, to some extent, be attributed to instrumentation and calibration inaccuracies. (Prevailing winds for the period were from the south through west-southwest.)

Figures 2.3-39 and 2.3-40 show the means of the daily averages and extremes of ambient air temperature and relative humidity, respectively. Relative humidity data were derived from ambient air temperature and dewpoint temperature data collected at the 10-m level of the 60-m tower from June 1, 1974, through May 31, 1975.

A comparison of monthly average temperatures and monthly high and low temperatures between the Fermi site data and National Weather Service data nearby, for the June 1, 1974, through May 31, 1975, period, is shown in Table 2.3-19.

2.3.2.3. Potential Influence of the Plant and the Facilities on Local Meteorology

The physical structures of the plant, especially the large natural draft cooling towers, are expected to locally increase atmospheric turbulence. There is also a potential for somewhat decreased low-level wind speeds in the immediate vicinity of the physical structures of the plant due to a wind-shielding effect. A study has shown that a cooling tower has an extended downwind wake upward to at least one and one-half times the tower height and downwind approximately two to three times the tower diameter. This will occur for wind speeds greater than 5 to 8 mph. Analysis has shown that any increase in precipitation due to the natural draft system will be minimal. Maximum precipitation from drift is predicted to occur at a distance of 3 km (1.8 miles) both northeast and west-southwest of the cooling towers at a total rate of approximately 0.008 in. annually. The increase in surface relative humidity is insignificant. The greatest relative humidity increase (nearly 21 percent at 1500 m downwind) will occur on winter mornings at an approximate height of 470 m (1542 ft). This 21 percent increase is ample to cause a visible plume from the natural draft cooling tower to extend downwind approximately 1000 m during the winter. There will be no significant fogging problems offsite on an annual basis. The offsite ground-level visibility reduction (to <1000 m) is predicted to occur only about 1 hr per year (Reference 22).

The cited cooling tower studies were conducted specifically for the Fermi 2 cooling towers by the NUS Corporation. The parameters used and the results of these studies are presented in the Fermi 2 Environmental Report in Section 5.1. The models used are described in Section 6.1 and were filed with the NRC on August 30, 1974, as the reports listed below as supporting documents to Docket Nos. 50-500 and 50-501.

a. Langrangian Vapor Plume Model - Version 3 (LVPM-3), NUS-TM-S-184
b. FOG Model Description, NUS-TM-S-185
c. ICE Model Description, NUS-TM-S-186.

2.3.2.4. Topographic Description

2.3.2.4.1. General Description

The terrain in the region of the Fermi site is characterized by flat plains, with the relief varying from 0 to 100 ft. More than 80 percent of the area is gently sloping. However, the actual site area is relatively flat and characterized by marshlands. Figures 2.3-41 and 2.3-42 are topographic maps of the area within 5- and 50-mile radii, respectively. Figure 2.3-43 is a topographic cross section of the Fermi site area out to 5 miles from the plant site and Figure 2.3-44 is a topographic cross section of the Fermi site out to 50 miles.

2.3.2.4.2. Topographic Influences on Meteorological Diffusion Estimates

The major local topographic effect on site meteorology is the presence of Lake Erie and the resultant occurrences of lake and land breeze circulations. Lake and land breeze circulations are driven by horizontal pressure gradients across the shoreline. These pressure gradients are the result of the temperature variation between water and land. This temperature differential between water and land can be most readily explained by the turbulent mixing and transport of surface heat by wave action and currents in a lake. This turbulent mixing process within the lake effects a continuous downward transport of surface heat through the water, thus lowering the surface water temperature (and also lowering the temperature of the overlying air), in contrast with the strong surface heating of the air over the shoreline region. This contrast is also intensified because the lake water has a higher thermal capacity than that of the soil. The temperature differential across the shoreline is enhanced under clear skies and light geostrophic winds.

Because the land is heated faster than the lake, the air above the land becomes warmer than the air above the lake. The warmer air over the land begins to rise as it expands and becomes less dense. At an average height aloft of 700 m, a pressure gradient from the land to the lake is formed (Reference 23). Because of this pressure gradient, air begins to flow from the land toward the lake. This offshore flow aloft is known as the return flow. Typical return flows extend above 1500 m and have velocities that can exceed 5 m/sec.

Because air is advected from the land to over the lake aloft, a surface low is formed over the land and a surface high is formed over the water. With a surface pressure gradient thus formed, an onshore wind flow at the surface (the lake breeze) is started. To complete the circulation cell of the lake breeze, there is strong upward motion (with average updrafts of over 1 mph) over the land and subsiding air over the lake. Figure 2.3-45 is a schematic representation of the streamlines during a well-developed lake breeze cell (Reference 23). Although formation of the lake breeze circulation is usually perpendicular to the shoreline, Coriolis forces become significant as the system matures. During the later afternoon, the lake breeze can be expected to have a major component parallel to the shore (i.e., to the right of the original trajectory).

In the middle latitudes, lake breezes can occur during 30 to 60 percent of the days in the spring and summer months of the year. Lake breezes can also occur during the fall and winter seasons, although less frequently than during the spring and summer. Land breezes are the converse of lake breezes and may develop when lake temperatures are warmer than land temperatures, such as during the fall and early winter, or during the night in the summer. However, land breezes are generally weaker and less frequent than lake breezes. Once the lake becomes covered by ice, the temperature differential between lake and land becomes minimal, and the lake effect becomes nonexistent.

The front edge of the lake breeze flow has the basic characteristics of a cold front with cool, moist lake air behind the front advancing inland. This lake breeze front may advance 30 km or more inland (Reference 24).

During onshore wind flow, such as a lake breeze, cool air flowing off the lake is modified by thermal surface heating and by surface roughness effects as the air flows over the land. The air from the lake is modified significantly as it flows over the land, especially during the spring and early summer. The air is heated from below, resulting in an unstable vertical temperature gradient and hence enhanced diffusion conditions. Surface roughness effects over the land increase atmospheric turbulence (also resulting in enhanced diffusion conditions), although low-level wind speeds will decrease. The thermal and roughness effects occur at the shoreline and form a "boundary layer" which increases vertically with distance inland. Within this boundary layer is unstable air, with stable air and an intense elevated inversion (suppressed diffusion) above the boundary layer. During the late fall and winter seasons, especially when there is not as large a temperature differential between the lake and the land as during the spring and early summer, the boundary layer is more shallow and the surface-based inversion (suppressed diffusion), normally formed right at the lakeshore, penetrates further inland.

Offshore wind flows generally result in somewhat suppressed diffusion conditions. The warm air advected from over the land is cooled from below, resulting in a stable vertical temperature gradient (inversion) and less diffusion for the over-water flow than for an overland flow. There is also a decrease in wind turbulence, although wind speeds will increase as the air flows from the relatively rough land surface over the smooth water surface. In addition to lake land breezes near a shoreline, there are also downwash and upwash effects. The primary cause of a downwash or upwash condition is the difference in surface roughness between the land and the lake (Reference 24). The upwash situation occurs with the winds blowing off the lake. The air flows from the relatively frictionless lake surface over the rough land, and a reduction in low-level wind speed occurs. This reduction in wind speed enhances plume rise to the extent that the plume can more easily escape the dynamic downwash effects of the plant structure. Downwash effects occur primarily with an offshore wind. The low-level winds coming off the relatively rough land over the smooth lake increase in speed. This increase in wind speed enhances plume downwash toward the lake surface.

A qualitative study of the surface characteristics of lake breezes at and in the near vicinity of the Fermi 2 site has been reported in Reference 25. The preliminary results of this study confirm the aforementioned factors. During the summer months, about one-third of the days were determined to give rise to a lake breeze situation. The inland penetration of these airflows averaged about 4 miles with a mean temperature decrease at the site of about 2°F and a relative humidity increase at the site of about 10 percent. The mean wind speed change due to a lake breeze situation was small (1 to 2 mph) when the lake breeze was in a direction so as to enhance the wind speed. Under conditions when the lake breeze occurred in opposition to a gradient wind, some wind direction changes were found. However, the infrequency of these situations makes it doubtful that the lake breeze could significantly change the atmospheric dispersion of effluents on an annual basis.

Edison performed a short-term meteorological study, specifically for emergency planning application, during the lake breeze seasons of 1983 and 1984 to determine the effect of Lake Erie on plume transport characteristics at the Fermi 2 site.

2.3.3. Onsite Meteorological Programs

2.3.3.1. Preoperational Onsite Meteorological Program

2.3.3.1.1. Meteorological Facility Operations

Onsite data presented in this report were collected from three different locations within the site boundary: from a 60-m tower approximately 2400 ft southwest of the Fermi 2 reactor building (since June 1, 1974) (Data from the 60-m tower were used for the diffusion estimate modeling); from the Fermi 1 100-ft tower located approximately 500 ft south-southeast of the Fermi 1 turbine building (December 1, 1956, to November 30, 1959); and from a 10-m (33-ft) tower located near Langton Road (January 1, 1972, to December 31, 1972).

Data were also collected from a 150-m tower that was located approximately 2400 ft south of Fermi 2 on the Lake Erie shoreline. One year of data (June 1, 1974, to May 31, 1975) from the 150-m tower and the 60-m tower were compared (Reference 26). The results of that study show that the 60-m tower data are representative of the Fermi 2 onsite meteorological conditions. When the Fermi 2 preoperational meteorological program was completed May 31, 1976, the 150-m tower was decommissioned. At that time, the 60-m tower operations were also discontinued until approximately 18 months prior to Fermi 2 fuel load (Reference 27). Following this, meteorological data have been collected only from the 60-m tower; thus the 60-m tower data are presented in this section. The 60-m tower data were collected, developed, and analyzed according to Regulatory Guides 1.23 and 1.111, Revision 1 (Reference 26).

The bases for decommissioning the 150-m tower, which was approved by the NRC (Reference 27), were as follows:

a. The analysis of the meteorological data collected shows the 60-m tower data are, for most parameters including χ/Q values, a more conservative characterization of the Fermi 2 conditions
b. The inland location of the 60-m tower is more representative of the air layer into which the plant effluent will be released since the gaseous release point is approximately 250 m from the shoreline on the west side (inland) of the building complex
c. Gas turbine peaking units located north of the 150-m tower affect the temperature measurements at the 10-m and 60-m levels, and consequently ΔT values, when the winds are from the north-northwest sector. During these periods, the data have to be rejected, which can seriously jeopardize the 90 percent data-recovery requirement of Regulatory Guide 1.23
d. The Fermi 1 plant structures are located such that building wake may bias the wind data for the 150-m tower for northerly directions
e. The 60-m tower is less susceptible to the icing conditions and localized lake shoreline effects experienced at the 150-m tower
f. The 2 years of data collected on the 150-m tower compare favorably, indicating only minor variations between seasons that are considered to be within the expected statistical variations between years. Thus 1 year of data at either tower, since it can be assumed the 60-m tower correlations would be valid for any year period, can be considered representative of site meteorology.

Data and discussions for the 100-ft and Langton Road towers are presented to provide supplementary site information. Data reduction on the 100-ft tower covered only the period from 1956 to 1959 to obtain data for the Fermi 1 plant; therefore, neither the instruments, data collection methods, nor data-reduction methods meet Regulatory Guide 1.23 requirements. The 33-ft Langton Road tower was originally installed as a satellite to the 150-m tower and was not instrumented to meet Regulatory Guide 1.23 requirements. A brief description of the 100-ft and 33-ft towers is presented in the following paragraphs.

On the 100-ft tower, wind speed and direction were measured at the 24-ft (7 m) level, 56-ft (17 m) level, and the 100-ft (30 m) level. Temperature sensing elements were located at 5 ft (1.5 m), 25 ft (7.6 m), 57 ft (17 m), and 100 ft (30 m). A standard National Weather Service rain gage was located near the base of the tower. Specifically, the instrumentation of the 100-ft tower included

a. Wind instrumentation - three Bendix aerovanes
b. Temperature instrumentation - four ventilated and shielded iron-constantan thermojunctions
c. Precipitation instrumentation - one standard National Weather Service rain gage located at the base of the tower.

Data analyses are available from the above station for the December 1, 1956, to November 30, 1959, period and include only the 100-ft wind and temperature measurements ΔT(100 ft-25 ft).

The Langton Road tower (33 ft) was onsite in an open field, approximately 3500 ft west of the plant. This 10-m tower was maintained and operated by the University of Michigan. Wind data at Langton Road were collected at the 10-m level; temperature and relative humidity were recorded on a hygrothermograph housed in a conventional instrument shelter at a height of approximately 5 ft (1.5 m). Specifically, the instrumentation at the Langton Road tower included

a. Wind instrumentation - Gill propeller vane direction and speed sensors at the 10-m level
b. Temperature and humidity instrumentation - Belfort hygrothermograph housed in a conventional instrument shelter.

The specifications for the above equipment are summarized in Table 2.3-20. Data have been collected and reduced from this station for the January 1, 1972, to December 31, 1972, period.

2.3.3.1.2. Preoperational 60-Meter Tower Meteorological Data System

All the preoperational meteorological data systems that have been used during the Fermi 2 program are described in this section. The data are available from the 150-m tower (Reference 26), but are not reported herein.

2.3.3.1.2.1. Instrumentation

A revised Fermi 2 site meteorological program was initiated in November 1973 that more adequately measured meteorological conditions at the Fermi site and met the requirements of Regulatory Guide 1.23. The revised program included the reinstrumentation of the 150-m tower on January 23, 1974, and the installation of a 60-m tower with identical instrumentation. The two-tower program monitored most meteorological conditions, with the 150-m tower measuring undisturbed onshore flow off Lake Erie, and the 60-m tower measuring the perturbed onshore flow characteristic of conditions that could affect gaseous effluent releases during overland flow conditions. Figure 2.3-46 is a map of the Fermi site area with the meteorological tower locations.

Instrumentation on the 60-m tower measured wind speed, wind direction, and temperature at the 10-m level and the 60-m level. In addition, dewpoint was measured at the 10-m level, and precipitation was measured at ground level.

The interface electronics and backup analog recorders were located at the base of the 60-m tower in an environmentally controlled instrument shelter. The primary recording was accomplished using a digital system with teletype printout in engineering units and a computer-compatible paper tape. A minicomputer, located in the instrument shelter at the base of the 150-m tower, provided continuous automatic sensor polling every 15 sec and printed out averages of the data collected from the last 15 minutes once every hour. During periods when data might be desired more often than once an hour, the operator could call for a printout at any desired time interval. The 60-m tower instrumentation was interconnected to the 150-m tower system by a 2500-ft data-transmission line. Thus, the tower was controlled by the minicomputer. The 2500-ft data-transmission line was protected at each end by optical isolators designed to withstand 10 kV. This minimized the interface effects of all but the closest lightning flashes.

The revised meteorological program instrumentation specifications are shown in Table 2.3-21. The revised site meteorological program was fully operational in May 1974. Onsite data from the preoperational test program were acquired and analyzed from the 60-m tower from June 1, 1974, to May 31, 1975, from the digital printouts and the computer-compatible paper tape. AST operational onsite program data were also selected and analyzed from the 60-m tower for the period January 1, 1995 through December 31, 1999.

2.3.3.1.2.2.Calibration

Analog. Every 6 months, all sensors, electronics, and recording equipment were calibrated. Additional onsite calibrations were performed during the service visits. Any necessary adjustments were made onsite and equipment that malfunctioned was either corrected onsite or replaced with similar spare equipment. After any adjustments or repairs, the calibration was repeated. Electronics calibrations were performed by simulating the output of each of the sensors with precision test equipment and monitoring the recorded values for each parameter. Wind speed sensors were replaced by a square wave frequency generator (with its output monitored by a frequency counter) that was adjusted to provide frequencies corresponding to known wind speeds. Wind direction sensors were replaced by a stable voltage source (with its output monitored by a digital voltmeter), which was adjusted to provide an output corresponding to known wind vane orientations. Temperature sensors were replaced with a stable decade resistance box, which was adjusted to provide accurate resistances corresponding to known temperatures. In all cases, the test instrument settings used were those for which the sensor manufacturer published calibration equivalents. Sensor calibrations are performed by the manufacturer. All results of both electronics and sensor calibrations are kept and filed onsite.

Digital. The complete instrumentation system was calibrated every 6 months. Electronics calibrations were virtually the same as were performed on the analog system. Dewpoint electronics calibrations were performed in the same manner as those for air temperature electronics. With the exception of precipitation, sensor calibrations were performed by the manufacturer. The precipitation sensor and electronics were calibrated by placing known weights in the emptied weighing bucket corresponding to a known amount of rainfall. All results of both electronics and sensor calibration were kept and filed onsite.

2.3.3.1.2.3.Service and Maintenance

Analog. Visits were made twice a week to the 150-m tower to change chart paper, fill inkwells and pens, and change ribbons. A visual inspection of the sensors was made to see if they had been damaged. Using the same precision test equipment used for calibration, all instrumentation was checked to ensure reliable operation.

Digital. Daily operational checks and service were performed by a resident technician. These checks included inspection of the data to determine that all sensors were functioning correctly and of the strip charts to ensure accurate recording. In addition, the technician marked the correct time to the nearest minute on the strip chart and verified the correct time of the digital system. Visual inspections of sensors were also performed to ensure that they had not been physically damaged.

2.3.3.1.3. Data Analysis Procedures

The data analysis procedures discussed in this subsection were those used for the data reported herein, which includes data from the 60-m tower, 100-ft tower, and Langton Road tower. The total preoperational meteorological program also included the 150-m tower from which data were collected and analyzed over the period from July 3, 1973, to May 31, 1975. However, approximately 170 m north of the 150-m tower, four peaking units were located that were operated during periods of high electrical demand. When the peaking units were in operation and the wind was from the north, it was occasionally noticed that significant increases in temperature at the 60-m and 150-m levels occurred. Because of this, it was deemed necessary to delete periods during which peaking unit operation influenced the determination of the lapse rate. This influence was apparent several times during the course of the annual data collection. Because of the problems associated with the 150-m tower's location, the 60-m tower was installed. An analysis of 1 year of simultaneous meteorological data from the 150-m tower and 60-m tower (Reference 26) showed that the 60-m tower data were representative of the onsite meteorology. Thus, after the Fermi 2 preoperational onsite meteorological data collection was completed, the 150-m tower was decommissioned. Future data will be collected using the 60-m tower only (Reference 26).

2.3.3.1.3.1.60-Meter Tower Data Reduction

The meteorological monitoring systems for the Fermi site are described in Subsection 2.3.3.1.2. The data acquisition system utilized two levels of instrumentation (10-m and 60-m) on the 60-m tower located approximately 2400 ft southwest of the Fermi 2 plant. The atmospheric stability conditions were determined from the temperature differences (ΔT) between the 10-m and 60-m temperature measurements, in accordance with the Pasquill Stability Criteria, Conditions A through G. Data from the 60-m tower were read by computer from paper tape to an IBM computer-compatible disk pack and magnetic tape for further use in modeling the site meteorological conditions and χ/Q calculations for various time periods. Strip charts were used only for backup. The strip- chart data, when needed, were read manually and the data put on IBM cards. Data from the charts were recovered by averaging the 15-minute period immediately preceding the hour. As long as 90 percent of the time span (13.5 minutes) was available for averaging, the data were deemed valid.

As a continuing operational verification of data validity, comparisons for all sensors at all levels on the tower between analog and digital averages were made on a random basis during the preoperational phase. The results of these comparisons for all parameters at the 10-m level and the air temperature at the 60-m level of the 60-m tower are shown in Table 2.3-22. For all checks the correlations are excellent. Differences can be attributed to strip-chart-reading error combined with the greater resolution of the digital system.

Precipitation at ground level was recorded onsite starting December 7, 1973. With the digital system operational, the strip charts were used only for backup, thus eliminating the strip-chart-reading task. Digital data were verified periodically against strip charts.

2.3.3.1.3.2. Langton Road Tower and 100-Ft Tower Data Reduction

Data from the 10-m Langton Road tower were recorded on strip charts and manually reduced. One 10-minute sample for each 1-hr available-data period was obtained for values of the wind direction range (i.e., the extremes of the direction trace peaks). Average values of wind direction and wind speed were obtained by visually estimating a median for the 1-hr sample of the analog traces. One reading was taken for each 1 hr of data available to obtain instantaneous values of temperature and relative humidity. The manually reduced data were transcribed on cards and were used as computer input for data analysis and summary.

Data from the 100-ft tower were also recorded on strip charts and manually reduced. Hourly averages of wind direction, wind speed, and temperature were obtained by estimating a median for the analog trace.

2.3.3.1.4. Meteorological Data Recovery

2.3.3.1.4.1. 60-Meter Tower Data Recovery

The meteorological data recovery rates for the 60-m tower data for the June 1, 1974 through May 31, 1975 period are listed in Table 2.3-23. The joint data recovery (ΔT, wind speed, wind direction) for the June 1, 1974, to May 31, 1975, period of 91.16 percent meets the 90 percent required by Regulatory Guide 1.23

The joint data recovery of wind speed and direction and ΔT for the January 1, 1995 through December 31, 1999 10-meter tower data that was utilized in the PAVAN model for accidental releases at offsite locations is 96.2 percent, also meeting the NRC 90 percent criterion.

For the calculations presented herein, only 10-m wind speed and direction, and temperature differences between 60-m and 10-m were used to calculate the short-term postulated accidental release diffusion estimates based on the 1995-1999 data. The 10-m and 60-m wind speeds were used to calculate the long-term mixed-mode annual average X/Q and D/Q values based on the June 1974 through May 1975 period.

2.3.3.1.4.2. Langton Tower and 100-Ft Tower Data Recovery

The meteorological data-recovery rates for the 33-ft Langton Tower data are listed in Table 2.3-24. Wind data for the January 1, 1972, to December 31, 1972, period have not been included in this report due to a low data-recovery rate. The recovery was 94 percent for the temperature and relative humidity data for the report period. The data-recovery rate for the 100-ft tower was 77 percent for temperature data, and 96 percent for the 100-ft- level wind data for the December 1, 1956, to November 30, 1959, period. Data-recovery information for other levels of the 100-ft tower are not readily available.

2.3.3.2. Operational Meteorological Monitoring System

The previously described preoperational meteorological program was upgraded for plant operation. The upgraded program is composed of two independent meteorological trains of instrumentation – a primary train and a secondary train – mounted on the 60-m tower. Both trains feed the data acquisition equipment of the Integrated Plant Computer System (IPCS) located in the Fermi 2 control center. The IPCS has the capability to share the meteorological data with other plant computers, display the data on IPCS terminals at various plant locations, and perform plume dispersion analysis in support of Emergency Plan activities. The NRC can also receive selected meteorological data through the Emergency Response Data System (ERDS). The operational meteorological monitoring system is described in further detail in the following subsections and is illustrated in Figure 2.3-47.

2.3.3.2.1. Instrumentation

Table 2.3-25 lists the meteorological parameters monitored, the sampling height(s), and the sensing technique for the primary and secondary systems.

To minimize data loss due to ice storms, external heaters are installed on all primary wind sensors. The heaters are thermostatically controlled and are of the slip-on/slip-off design for easy attachment. The wind sensor specifications are not affected by these heaters.

A windscreen is mounted around the precipitation gage to minimize the amount of windblown snow and debris deposited in the gage.

Electrical power is supplied to the primary and secondary systems by independent power supplies. One source of power is Fermi 2; the other is an offsite source. If one supply fails, the other automatically supplies the necessary power for both systems. Two precautions are taken to minimize lightning damage to the system. Two of the three legs are grounded and the signal cables are routed through a lightning protection panel. Each signal line is protected by transient protection diodes specifically designed to stay below the individual line voltage breakdown point.

2.3.3.2.2. Signal Conditioning

Inside the environmentally controlled instrument shelter, sensor signals are conditioned. Each sensor signal requires a single printed-circuit board to perform the necessary conversion, amplification, and scaling to provide a pair of analog outputs for each parameter. Zero and full-scale test switches are front-panel mounted on each printed-circuit board to facilitate parameter testing.

After conditioning through their respective printed-circuit boards, the 10-m horizontal wind direction and vertical wind speed signals pass into the Climatronics Standard Deviation Computer boards to compute the 15-minute average sigma theta and sigma phi.

The primary and secondary signal conditioner and standard deviation computer boards are completely independent of each other.

2.3.3.2.3. Data Transmission

The outputs of the instrument signal conditioning equipment is transmitted to the control center via two independent transmission lines. The one line incorporates a phone line between the shelter and the nuclear operations center, where information is microwaved to the Office Service Building. From the Office Service Building, the signals are transmitted to the control center. The second line uses a separate phone line from the shelter to the nuclear operations center, where the data are transmitted to the office service building via a phone line. From the office service building, the signals are transmitted to the control center. The two signals are electrically separated from one another from the 60-m tower to the control center. The instrumentation at the 60-m tower is electrically isolated from the equipment in the control center computer room.

2.3.3.2.4. Data Acquisition

The dual IPCS data acquisition multiplexors accept two trains of data from the Meteorological system primary and secondary data acquisition equipment. This data is provided to the IPCS computers to perform meteorological calculations, update the data archive, display the information on the man-machine interface, and output the data to communication devices. The IPCS provides redundant computers that provide a main (Master) and backup (Slave) capability. The redundant computers in conjunction with the two trains of data acquisition provide two independent paths of data. The IPCS system monitors available error signals to determine equipment status. If an instrument input malfunctions, if data are suspect, or an instrument input is manually removed from service, the IPCS will substitute the reading from the next level of redundancy as listed in Table 2.3-26 and indicate the substitution on the IPCS computers.

Meteorological data are available in five different formats: instantaneous values, 1-minute blocked averages, 15-minute rolling averages, 15-minute blocked averages, and 1-hour blocked averages.

In the event that a data path to IPCS is unavailable, a recorder is available on each train of instrumentation at the meteorological instrument building to archive the raw data.

2.3.4. Short-Term (Accident) Diffusion Estimates

2.3.4.1. Calculation of Offsite Atmospheric Diffusion Coefficients

2.3.4.1.1. Objective

To evaluate the dispersion potential of the atmosphere in the Fermi site area, calculations were made of concentrations of effluents normalized by the source strength of the power plant release. These atmospheric dilution factors were calculated using the meteorological data collected onsite from January 1, 1995 - December 31, 1999.

Short-term offsite transport was modeled using the PAVAN software (Reference 28), which is based on the NRC design-basis-accident methodology in Regulatory Guide 1.145

(Reference 31). PAVAN is a commercial software package applicable to nuclear safety-related analyses as well as non-safety related studies and evaluations. Its use is applicable for determining normalized offsite concentrations as required for the Exclusion Area Boundary (EAB) and the Low Population Zone (LPZ). These locations are defined in UFSAR Sections 2.1.2 and 2.1.3.3 as radial distances of 915 m and 4827 m, respectively, from the containment building.

Six different χ/Q values, corresponding to six different time periods following an accident, were calculated. The time periods postulated to follow an accident are those specified by the NRC in Regulatory Guide 1.145. These are 0-2 hr, 0-8 hr, 8-24 hr, 1-4 days, 4-30 days and the annual period.

2.3.4.1.2. Dispersion Equations

This section describes the governing atmospheric dispersion modeling equations and assumptions in accordance with Regulatory Guide 1.145.

Ground-levelχ/Q values were calculated for the 2 hours following the accident for the EAB and LPZ, and for the annual period for the LPZ. Calculations were based on the following equations:

$$\chi/Q = \frac{1}{\bar{U}_{10}(\pi\sigma_y\sigma_z + A/2)} \quad (2.3\text{-}1)$$

$$\chi/Q = \frac{1}{\bar{U}_{10}(3\pi\sigma_y\sigma_z)} \quad (2.3\text{-}2)$$

$$\chi/Q = \frac{1}{\bar{U}_{10}\pi\Sigma_y\sigma_z} \quad (2.3\text{-}3)$$

Where:

- χ/Q is relative concentration, in sec/m^3
- π is 3.14159
- $\bar{U}_{10}$ is wind speed at 10 meters above plant grade, in m/sec
- σ_y is lateral plume spread, in m, a function of atmospheric stability and distance
- σ_z is vertical plume spread, in m, a function of atmospheric stability and distance
- Σ_y is lateral plume spread with meander and building wake effects (in meters), a function of atmospheric stability, wind speed, and distance [for distances of 800 m or less, Σ_y=Mσ_y, where M is determined from Regulatory Guide 1.145 Figure 3; for distances greater than 800 m, Σ_y=(M-1)σ_{y800m}+σ_y
- A is the smallest vertical-plane cross-sectional area of the reactor building, in m^2 (other structures or a directional consideration may be justified when appropriate). Offsite χ/Qs are calculated assuming a minimum cross-sectional area, A, of the combined reactor/auxiliary building of 2300 m^2, as shown in Figure 2.3-48

Plume meander is only considered during neutral (D) or stable (E, F, or G) atmospheric stability conditions where the highest χ/Q values resulting from equations 2.3-1, 2.3-2 and

2.3-3 is selected. For all other conditions (stability classes A, B, or C), meander is not considered and the highest χ/Q value of equations 2.3-1 and 2.3-2 is selected.

The χ/Q values calculated at the EAB based on meteorological data representing a 1-hour average is assumed to apply for the entire 2-hour period.

2.3.4.1.3. Determination of Max Sector and Overall 5 Percent Site χ/Q Values

2.3.4.1.3.1. Maximum Sector χ/Q

To determine the maximum sector χ/Q value at the EAB, a cumulative frequency probability distribution (probabilities of a given χ/Q value being exceeded in that sector during the total time) is constructed for each of the 16 sectors using the χ/Q values calculated for each hour of data. This probability is then plotted versus the χ/Q values and a smooth curve is drawn to form an upper bound of the computed points. For each of the 16 curves, the χ/Q value that is exceeded 0.5 percent of the total hours is selected and designated as the sector χ/Q value. The highest of the 16 sector χ/Q values is the maximum sector χ/Q.

Determination of the LPZ maximum sector χ/Q is based on a logarithmic interpolation between the 2-hour sector χ/Q and the annual average χ/Q for the same sector. For each time period, the highest of these 16 sector χ/Q values is identified as the maximum sector χ/Q value. The maximum sector χ/Q values will, in most cases, occur in the same sector. If they do not occur in the same sector, all 16 sets of values will be used in dose assessment requiring time-integrated concentration considerations. The set that results in the highest time-integrated dose within a sector is considered the maximum sector χ/Q.

2.3.4.1.3.2. 5 Percent Overall Site χ/Q

The 5 percent overall site χ/Q value for the EAB and LPZ is determined by constructing an overall cumulative probability distribution for all directions. χ/Q versus the probability of being exceeded is then plotted and an upper bound curve is drawn. From this curve, the 2-hour χ/Q value that is exceeded 5 percent of the time is found. The 5 percent overall site χ/Q at the LPZ for intermediate time periods is determined by logarithmic interpolation of the maximum of the 16 annual average χ/Q values and the 5 percent 2-hour χ/Q values.

2.3.4.1.4. Wind Speed Categorization

The meteorological database was prepared for use in PAVAN by transforming the five years (i.e., 1995-1999) of hourly meteorological tower data observations into a joint wind speed-wind direction-stability class occurrence frequency distribution. Seven (7) wind speed categories were defined according to Regulatory Guide 1.23 (Reference 16) with the first category identified as "calm". The higher of the starting speeds of the wind vane and anemometer (i.e., 0.75 mph) was used as the threshold for calm winds, per Regulatory Guide 1.145, Section 1.1. A midpoint was also assumed between each of the Regulatory Guide 1.23 wind speed categories, Nos. 2-6, as to be inclusive of all wind speeds. The wind speed categories have therefore been defined as follows:

Category No.	Regulatory Guide 1.23 Speed Interval (mph)	PAVAN-Assumed Speed Interval (mph)
1 (Calm)	0 to < 1	0 to < 0.75
2	1 to 3	≥ 0.75 to < 3.5
3	4 to 7	≥ 3.5 to < 7.5
4	8 to 12	≥ 7.5 to < 12.5
5	13 to 18	≥ 12.5 to < 18.5
6	19 to 24	≥ 18.5 to < 24
7	>24	≥24

In the equations shown in Section 2.3.4.1.2, it should be noted that wind speed appears as a factor in the denominator. This causes difficulties in making calculations for periods of calm. The procedures used by PAVAN to assign a direction to each calm period according to the directional distribution for the lowest wind-speed class. This is done separately for the calms in each stability class.

2.3.4.1.5. Short-Term X/Q Modeling Results

Atmospheric diffusion estimates developed for use in evaluating accidents are summarized in Table 2.3-27 for the above-mentioned periods following the accident. This table includes estimates for the maximum sector and overall 5 percent site χ/Q.

2.3.4.2. Calculation of Onsite (Control Room) χ/Q Values

2.3.4.2.1. Objective

To evaluate the dispersion potential of the atmosphere in the Fermi site area, calculations were made of concentrations of effluents normalized by the source strength of the power plant release. These atmospheric dilution factors were calculated using the meteorological data collected onsite from January 1, 1995-December 31, 1999.

Short-term onsite transport was modeled using the ARCON96 software, which is a commercially available general code for assessing atmospheric relative concentrations in the presence building wakes that is based on the NRC design-basis-accident methodology in Regulatory Guide 1.194 (Reference 32). The code user documentation and calculation methodology is documented in Revision 1 of NUREG/CR-6331, “Atmospheric Relative Concentrations in Building Wakes” (Reference 33).

ARCON calculates relative concentrations for a specified source-to-receptor configuration with the user supplied hourly meteorological data. It then combines the hourly averages to estimate concentrations for periods ranging in duration from 2 hours to 30 days. Wind direction is considered as the averages are formed. As a result, the averages account for persistence in both diffusion conditions and wind direction. Cumulative frequency distributions are prepared from the average relative concentrations. Relative concentrations that are exceeded no more than five percent of the time (95^{th} percentile relative concentrations) are determined from the cumulative frequency distributions for each averaging period. Finally, the relative concentrations for five standard averaging periods (0-2 hr, 2-8 hr, 1-4 days and 4-30 days) are calculated from the 95^{th} percentile relative concentrations.

2.3.4.2.2. Dispersion Equations

This section describes the governing atmospheric dispersion modeling equations and assumptions (with noted exceptions) in accordance with Regulatory Guide 1.194.

The basic diffusion model implemented in the ARCON96 is a straight-line Gaussian model that assumes the release rate is constant for the entire period of release. This assumption is made to permit evaluation of potential effects of accidental releases without having to specify a complete release sequence.

$$\frac{\chi}{Q} = \frac{1}{\pi \sigma_y \sigma_z U} \exp\left[-0.5\left(\frac{y}{\sigma_y}\right)^2\right] \qquad (2.3\text{-}4)$$

where:

$\frac{\chi}{Q}$	is relative concentration, in sec/m^3
π	is 3.14159
U	is wind speed at 10 meters above plant grade, in m/sec.
σ_y	is lateral diffusion coefficient (m)
σ_z	is vertical diffusion coefficient (m), and
y	is distance from the center of the plume (m)

This equation represents a ground level release that is assumed to be continuous, constant, and of sufficient duration to establish a relative mean concentration. It also assumes that the material being released is reflected by the ground. Diffusion coefficients are typically determined from atmospheric stability and distance from the release point using empirical relationships. ARCON96 uses the same diffusion coefficient (σ_z and σ_y) parameterizations utilized in the NRC PAVAN code for calculating the short-term post-accident offsite atmospheric dispersion.

Calculation of the onsite χ/Q values associated with stack releases (i.e., SGTS, RBHVAC, and the TBHVAC), the “vent release” option was specified in conjunction with a zero-vent velocity. According to Regulatory Guide 1.194, the NRC specifies a ground release as the acceptable release mode for performing atmospheric dispersion calculations, consistent with this philosophy, the NRC does not accept the ARCON96 vent release calculation methodology. However, ARCON96 is coded to use the ground release equations when the vent exiting velocity is less than the wind-speed. Thus, in specifying a zero vent exiting velocity for cases where the vent release option was selected, the ground release equations were implemented and the intent of Regulatory Guide 1.194 was met. The purpose for specifying the zero-velocity vent release option was to allow for consideration of the 60-meter meteorological data in the calculation of the atmospheric relative concentration. Alternatively, the ground release option could have been specified with same inputs for the release and receptor elevations with the same result. In addition, in specifying the vent release, no credit was assumed for pre-dilution of the relative source term concentration inside the secondary containment or turbine building free air volumes or in the volumetric flows of the HVAC system associated with a particular vent location.

ARCON 96 includes the effects of low wind speed and building wake by replacing σ_z and σ_y above by composite wake diffusion coefficients of the following form:

$$\Sigma_y = \left(\sigma_y^2 + \Delta\sigma_{y1}^2 + \Delta\sigma_{y2}^2\right)^{1/2} \text{ and } \Sigma_z = \left(\sigma_z^2 + \Delta\sigma_{z1}^2 + \Delta\sigma_{z2}^2\right)^{1/2} \qquad (2.3\text{-}5)$$

where σ_Z and σ_y are the normal diffusion coefficients and $\Delta\sigma_{z1}$ and $\Delta\sigma_{y1}$ are the low wind speed corrections and $\Delta\sigma_{z2}$ and $\Delta\sigma_{y2}$ correct for building wake. The building wake correction is calculated based on a 2300 m^2 building area cross-section.

ARCON96 was run assuming the default surface roughness factor of 0.1 meters. This value is representative of a terrain having low-lying vegetation; i.e., farmland, wetland, etc.

2.3.4.2.3. Wind Speed Categorization

The meteorological database was prepared for use in ARCON96 by transforming the five years (i.e., 1995-1999) of hourly meteorological tower data observations into the format required by ARCON96. The required input consists of the Julian day, hour, 10-meter wind direction, 10-meter wind speed, stability class, 60-meter wind direction, and 60-meter wind speed for each of these years. ARCON96 requires the specification of the calm threshold. χ/Q values calculated using wind velocities below the calm threshold are automatically included in the statistical evaluation of a specific χ/Q regardless of the associated wind direction. Regulatory Guide 1.194 suggests a minimum calm threshold of 0.5 m/s; however, the ARCON96 performed in support of Alternate Source Term implementation were reviewed and approved with a calm threshold of 0.33 m/s. Based on NRC endorsement of the regulatory guide and endorsement of the original AST submittal, both values are acceptable.

2.3.4.2.4. Physical Orientation of Source-Receptor Combinations and Dual Inlet Credit

Consistent with Regulatory Guide 1.194, Position 3.4, the source-to-receptor distances used to calculate the atmospheric dispersion coefficients were calculated as the slant distance or direct line-of-site distances. Conservatively, the values of relative air concentrations used to evaluate vital area doses do not credit the additional distance incurred in circumventing intervening plant structures. However, such credit is permitted in accordance with the NRC methodology and was considered in evaluating the relative importance of postulated potential MSIV and secondary containment bypass leak release locations against the Turbine Building exhaust stack as a single representative release point.

2.3.4.2.4.1. DBA LOCA

Post LOCA atmospheric dispersion of ECCS and primary containment leakage was evaluated based on an assumed release via the SGTS stack to the control room north and south emergency air intakes. The TBHVAC stack was the assumed release point for Main Steam Line Leakage, also having the main control room north and south emergency air intakes as receptors. The table below identifies the horizontal and vertical separation distances between the postulated source and receptor locations. The RBHVAC stack and secondary containment wall were not assumed release locations evaluated in support of the LOCA analysis performed using the Alternate Source term. Nevertheless, their physical locations with respect to the control center emergency air intakes are included for historical purposes.

Source Release Location	Intake Separation Distance, meters [Horizontal/Vertical]	
	South Emergency/Normal*	North Emergency
SGTS Stack	39.4/24.9	17.2/35.8
TBHVAC Stack	69.1/10.7	111.1/21.6
RBHVAC Stack	11.6/24.9	48.8/35.8
Secondary Containment Wall	13.9/0	13.9/0

*Note that the vertical distance used to calculate the atmospheric dispersion coefficients for transport to the south emergency air intake for the LOCA analysis credits only the upper, missile-proof portion of the inlet plenum. The south emergency air intake also includes a safety-related sided enclosure that extends the intake down an additional 10.9 meters.

The Fermi 2 Control Center HVAC system is designed with dual emergency makeup air inlets located on the North and South sides of the Auxiliary Building. With the exception of the TBHVAC exhaust stack, the emergency air inlets have a separation distance that is sufficient to place them outside of a 90° wind direction window centered on the line-of-sight from any of the stack locations above to the opposite emergency air intakes. Thus, consistent with Regulatory Guide 1.194, Position 3.3.2, they are configured such that neither release point is capable of simultaneously impacting both air inlets. Furthermore, the Control Room Emergency Filtration System associated with CCHVAC is capable of automatically selecting the inlet with the lowest dose. However, the operators are procedurally instructed to take manual control of the inlet selection. On this basis, consistent with Regulatory Guides 6.4 and 1.194, Position 3.3.2.3, the χ/Q associated with the most favorable intake is assumed and divided by a factor of four. Fermi differs from the Regulatory Guide 1.194, Position 3.3.2.3 in that the factor of four is applied from the start of the accident rather than from the time the manual action is assumed to occur.

The TBHVAC stack is the assumed release point for the source term associated with Main Steam Isolation Valve leakage. This stack location does not have sufficient separation relative to the two inlets to allow dual inlet credit. The value of χ/Q calculated by ARCON96 is used directly (i.e., with no correction or reduction) to represent MSIV leakage transport to the control center with only credit for the ability of the operator to select the most favorable inlet. In this manner, the transport to the control center occurs instantaneously as the leakage occurs as if TBHVAC were in operation with no credit for any dilution in the TBHVAC airflow or the very large volume above the turbine deck. Each of the thirteen smoke vents on the Turbine Building roof and the external doors associated with the turbine and auxiliary buildings were also considered in selecting an appropriate release location. While the χ/Qs calculated for these locations were potentially larger than that associated with the TBHVAC stack value, the conservatism in the application of the stack value with no credit taken for mixing or deposition was considered adequately compensating.

2.3.4.2.4.2.Fuel Handling Accident

Fermi considers two types of fuel handling accidents, one that occurs 24 hours post-scram that involves a drop of recently irradiated fuel and credits only secondary containment and the operation of the SGTS for mitigation. The second type of fuel handling accident involving fuel that is no longer "recently irradiated," which occurs following a post-scram delay period sufficient such that credit for secondary containment and SGTS operation is not required.

Although not specifically required in Regulatory Guides 1.183 and 1.194, the FHA analyses submitted in support of Amendments 144 and 160, conservatively applied the 0-2 hr control room χ/Q values calculated by ARCON96 to the entire 30-day duration of accident.

Neither type of fuel handling accident assumes credit for the operation of the Control Room Emergency Filtration System. Consequently, the factor associated with the dual inlet configuration is not credited for reducing the value of χ/Q calculated by the ARCON96 software. Adequate separation is credited, however, to ensure that only the single most limiting air intake is specified.

The release and receptor locations used to evaluate the radiological consequences of the fuel handling accident differ from those associated with the DBA LOCA and depend on which of the two types of fuel handling accidents is to be evaluated.

2.3.4.2.4.2.1. 24-Hour Fuel Handling Accident Involving Recently Irradiated Fuel

This accident postulates an initial brief period of unfiltered release via the RBHVAC stack prior to secondary containment isolation and operation of the SGTS. ARCON96 was used to calculate the atmospheric dispersion coefficient representing transport from these stacks to each emergency air intake. The source-to-receptor distances are as specified in the table in Section 2.3.4.2.4.1 except the additional vertical distance of 10.9 meters associated with the full length of the south emergency air intake is credited.

2.3.4.2.4.2.2. Fuel Handling Accident Involving Fuel No Longer Considered Recently Irradiated

This accident assumes no credit for secondary containment isolation or operation of the SGTS. Consequently, the most likely release path would be via the RBHVAC stack as a consequence of continued RBHVAC operation. Several source-to-receptor locations were considered in establishing the limiting plant configuration, these included the SGTS and RBHVAC stacks as well as the reactor building railroad bay and first floor personnel air-lock (via the Outage Building front) doors.

While RBHVAC was identified and the most credible release point, the outage building front doors were conservatively selected as a bounding release location. Due to the location of the outage doors on the south side of the reactor building, the corresponding limiting receptor location is the south emergency air intake. The horizontal and vertical distances between these source and receptor locations are 29.3 m and 18.6 m for an overall slant distance of 34.7 m. The overall slant distance was input to ARCON96 in evaluating the associated atmospheric dispersion as a ground release.

This source-to-receptor pathway presumes the source term is removed from the building and is transported to the control room via the normal/emergency makeup air intakes. Thus, the control room envelope is effectively assumed to be intact and any maintenance that involves breaches of the control room envelope must include the controls necessary to preserve this assumption.

2.3.4.2.4.3. Control Rod Drop Accident

This accident considers two release paths: delayed release from the main condenser and a forced release from the offgas system due to the continued operation of the steam-jet air ejectors. The main condenser activity is released to the environment via the TBHVAC stack and is modeled as a zero-velocity vent release. The steam-jet air ejector activity is released to the environment through the RBHVAC stack and is also modeled as a zero-velocity vent release. ARCON96 was used to calculate the atmospheric dispersion coefficients representing transport from these stacks to each emergency air intake. The source-to-receptor distances are as specified in the table in Section 2.3.4.2.4.1. The analysis assumes no credit for the operation of the Control Room Emergency Filtration System. Consequently, the factor associated with the dual inlet configuration is not credited for reducing the value of χ/Q calculated by the ARCON96 software. Although the χ/Q values are calculated for both emergency air intakes, the analysis conservatively uses the values associated with the south emergency air intake.

2.3.4.2.5. Short-Term Onsite χ/Q Modeling Results

Atmospheric diffusion estimates developed for use in evaluating accidents are summarized in Table 2.3-28.

2.3.5. Long-Term Diffusion and Deposition Calculations

To evaluate the long-term dispersion potential of the atmosphere in the Fermi site area, calculations were made of effluent concentrations normalized by source strength of the power plant release and relative deposition rate. These atmospheric dilution and deposition factors were calculated using meteorological data collected onsite at the 60-m tower over the period June 1, 1974, to May 31, 1975. The long-term calculations are based on the straight line trajectory airflow model where a mixed-mode release, depending on wind speed, is assumed as described in Regulatory Guide 1.111, Revision 1 (Reference 30).

The models used to evaluate the long-term (annual) estimates of χ/Q and D/Q are described in Annex B of Appendix 11A. The analyses reported herein were performed for three separate sources at the Fermi 2 site: the containment building vent, the turbine building vent, and the radwaste building vent. Since the calculations were performed assuming a mixed-mode release based on wind speed, the release characteristics of each source are given in Table 2.3-28.

It should be noted that the results of the calculations performed for χ/Q (undecayed and undepleted, and decayed and depleted for radioiodines) and D/Q for radioiodines and particulates are presented in Appendix 2A.

2.3.5.1. Undecayed and Undepleted χ/Q Estimates

Values of χ/Q assuming no decay or depletion were calculated for the three air effluent releases using the mixed-mode techniques referenced in Annex B to Appendix 11A and

Regulatory Guide 1.111, Revision 1, July 1977. The calculations were performed for all 22-1/2° sectors at distances of

a. 0.4 to 1.6 km in 0.4-km increments
b. 1.6 to 16 km in 0.8-km increments
c. 16 to 80 km in 8-km increments.

These values of undecayed and undepleted χ/Q in units of seconds per cubic meter are presented in "wheel diagrams" for each source in Figures 2.3-52 through 2.3-54. Note that each figure provides values for the three distances for each release point. The numerical χ/Q values are presented by distance and sector in Appendix 2A.

2.3.5.2. Decayed and Depleted χ/Q Estimates

Values of χ/Q, assuming a radioactive effluent with a half-life of 8 days and using the plume depletion effect curves in Regulatory Guide 1.111, Revision 1, July 1977, in conjunction with the mixed-mode techniques, were calculated for the distances noted in Subsection 2.3.5.1.

These values of decayed and depleted χ/Q in units of seconds per cubic meter are presented for each of the three sources in Figures 2.3-55 through 2.3-57. The numerical values are presented by distance and sector in Appendix 2A.

2.3.5.3. Relative Deposition Estimates

Values of relative deposition (D/Q) per unit area were calculated for the three sources also using the mixed-mode techniques. The relative deposition-rate curves in Figures 6 through 9 of Regulatory Guide 1.111, Revision 1, July 1977, were used for the same distances as described above.

These values of relative deposition per unit area (square meters) are presented for each of the three sources in Figures 2.3-58 through 2.3-60. The numerical values are presented by distance and sector in Appendix 2A.

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TABLE 2.3-1 EXTREME WIND SPEED OCCURRENCE PROBABILITIES (AT 30 FT ABOVE GROUND)

Probability	Recurrence Interval (years)	Extreme Wind Speed (mph)
0.500	2	50
0.100	10	62
0.040	25	70
0.020	50	82
0.010	100	90
0.001	1000	117

TABLE 2.3-2 DETROIT, MICHIGAN METROPOLITAN AIRPORT NORMALS, MEANS, AND EXTREMES

Month	Temperature – Normal – Daily maximum	Temperature – Normal – Daily minimum	Temperature – Normal – Monthly	Temperature – Extremes – Record highest	Temperature – Extremes – Year	Temperature – Extremes – Record lowest	Temperature – Extremes – Year	Normal heating degree days (base 65°)	Precipitation – Normal total	Precipitation – Maximum monthly	Precipitation – Year	Precipitation – Minimum monthly	Precipitation – Year	Precipitation – Maximum in 24 hr	Precipitation – Year
(a)	(b)	(b)	(b)	14		14		(b)	(b)	14		14		14	
J	33.3	19.0	26.2	62	1965	-14	1972	1203	1.93	3.63	1965	0.27	1961	1.72	1967
F	34.4	18.9	26.7	58	1966	-9	1971	1072	1.95	2.68	1971	0.15	1969	1.23	1965
M	42.8	25.9	34.4	77	1963	1	1963	949	2.41	3.59	1965	0.92	1960	1.18	1972
A	56.7	36.2	46.5	85	1970[d]	17	1964	555	3.05	5.40	1961	0.92	1971	1.97	1965
M	68.8	46.4	57.6	92	1962	25	1966	259	3.54	5.88	1968	1.15	1965	2.87	1968
J	79.0	56.8	67.9	99	1971	36	1972[d]	61	3.31	6.60	1960	2.12	1959	2.62	1960
J	83.9	60.9	72.4	98	1966	41	1965	0	2.69	6.02	1969	1.11	1964	3.19	1966
A	82.1	59.4	70.8	97	1964	40	1964	11	2.84	7.70	1964	1.06	1969	3.21	1964
S	74.5	52.0	63.3	94	1971[d]	33	1970[d]	111	2.32	5.83	1961	0.43	1960	2.07	1961
O	63.1	41.3	52.2	91	1963	18	1965	405	2.57	4.87	1967	0.35	1964	2.11	1959
N	47.3	31.2	39.3	77	1968	9	1969[d]	771	2.27	3.31	1968	0.80	1964	1.52	1968
D	35.8	21.9	28.9	66	1966	-9	1960	1119	1.92	6.00	1965	0.46	1960	3.71	1965
					June		Jan.				Aug.		Feb.		Dec.
YR	58.5	39.2	48.9	99	1971	-14	1972	6516	30.80	7.70	1964	0.15	1969	3.71	1965

Month	Snow, Ice Pellets – Mean total	Snow, Ice Pellets – Maximum monthly	Snow, Ice Pellets – Year	Snow, Ice Pellets – Maximum in 24 hr	Snow, Ice Pellets – Year	Relative Humidity – hr 01 (Local time)	Relative Humidity – hr 07 (Local time)	Relative Humidity – hr 13 (Local time)	Relative Humidity – hr 19 (Local time)	Wind[g] – Mean speed	Wind[g] – Prevailing direction	Wind[g] – Fastest Mile[h] – Speed	Wind[g] – Fastest Mile[h] – Direction[i]	Wind[g] – Fastest Mile[h] – Year	Percent possible sunshine	Mean sky cover sunrise to sunset	Mean number of days – Sunrise to Sunset – Clear	Mean number of days – Sunrise to Sunset – Partly cloudy	Mean number of days – Sunrise to Sunset – Cloudy	Mean number of days – Precipitation 0.01 in. or more	Mean number of days – Snow, ice pellets 1.0 in. or more	Mean number of days – Thunderstorms	Mean number of days – Heavy Fog	Mean number of days – Temperatures – Maximum – 90° and above[f]	Mean number of days – Temperatures – Maximum – 32° and below	Mean number of days – Temperatures – Minimum – 32° and below	Mean number of days – Temperatures – Minimum – 0° and below	Average daily solar radiation (langleys)
(a)	14	14		14		14	14	14	14	14	5	6	6		7	14	14	14	14	14	14	14	14	14	14	14	14	
J	8.1	13.4	1959	6.6	1968	77	78	69	73	11.3	WSW	50	W	1971	38	7.5	4	7	20	13	3	(c)	3	0	17	30	4	
F	8.3	17.4	1962	10.3	1965	75	77	64	69	11.3	WSW	52	SW	1967	45	7.2	5	6	17	11	3	(c)	2	0	12	27	2	
M	6.3	16.1	1965	6.5	1968	76	78	61	65	11.2	WSW	36	SW	1969	52	7.2	5	8	18	13	2	1	2	0	5	25	0	
A	1.6	7.4	1961	4.2	1961	75	79	55	59	11.2	WSW	45	SW	1968	54	6.8	6	7	17	13	1	4	1	0	(c)	10	0	
M	(e)	(e)	1970[d]	(e)	1970[d]	75	78	53	56	10.1	WSW	40	SW	1970	61	6.3	7	10	14	10	0	4	(c)	(c)	0	1	0	
J	0.0	0.0		0.0		80	80	54	59	8.8	SW	39	W	1970	62	5.9	8	10	12	11	0	6	1	3	0	0	0	
J	0.0	0.0		0.0		81	82	53	58	8.3	SW	50	SW	1968	65	5.7	8	13	10	10	0	6	1	4	0	0	0	
A	0.0	0.0		0.0		84	87	56	64	8.2	SW	36	NW	1971	71	5.4	10	11	10	9	0	6	2	3	0	0	0	
S	0.0	0.0		0.0		84	87	57	68	8.6	SW	34	W	1970	58	6.4	8	9	13	10	0	4	2	1	0	0	0	
O	(e)	(e)	1972[d]	(e)	1972[d]	81	84	56	68	9.2	WSW	33	SW	1968[d]	52	6.1	8	10	13	9	0	1	3	(c)	0	5	0	
N	3.2	11.8	1966	5.2	1966[d]	80	83	66	74	10.6	SW	37	SW	1968	28	7.8	3	7	20	11	1	(c)	2	0	1	17	0	
D	8.0	17.3	1962	5.7	1966	79	81	71	76	10.8	SW	50	W	1972	25	7.9	3	7	21	13	3	(c)	3	0	13	26	1	
			Feb.		Feb.									Feb.														
YR	35.5	17.4	1962	10.3	1965	79	81	60	66	10.0	SW	52	SW	1967	53	6.7	75	105	185	131	13	33	23	11	48	140	7	

[a] Length of record, years, based on January data. Other months may be for more or fewer years if there have been breaks in the record.
[b] Climatological standard normals (1931-1960)
[c] Less than one half.
[d] Also on earlier dates, months, or years.
[e] Trace, an amount too small to measure.
[f] at Alaskan stations.
[g] Figures instead of letters in a direction column indicate direction in tens of degrees from true North; i.e., 09 - East, 18 - South, 27 - West, 36 - North, and 00 - Calm. Resultant wind is the vector sum of wind directions and speeds divided by the number of observations. If figures appear in the direction column under "Fastest Mile" the corresponding speeds are fastest observed 1-minute values.
[h] For period May 1966 through current year.
[i] To eight compass points only.

Below zero temperatures are preceded by a minus sign.

The prevailing direction for wind in the Normals, Means, and Extremes table is from records through 1963.

Unless otherwise indicated, dimensional units used in this bulletin are: temperature in ºF; precipitation, including snowfall in in.; wind movement in mph; and relative humidity in percent. Heating degree day totals are the sums of negative departures of average daily temperatures from 65ºF. Sleet was included in snowfall totals beginning with July 1948. The term "Ice Pellets" includes solid grains of ice (sleet) and particles consisting of snow pellets encased in a thin layer of ice. Heavy fog reduces visibility to 1/4 mile or less.

Sky cover is expressed in a range of 0 for no clouds or obscuring phenomena to 10 for complete sky cover. The number of clear days is based on averaqe cloudiness 0-3, partly cloudy days 4-7, and cloudy days 8-10 tenths.

Solar radiation data are the averages of direct and diffuse radiation on a horizontal surface. The langley denotes 1 g/cal/cm^2.

TABLE 2.3-3 DETROIT, MICHIGAN CITY AIRPORT NORMALS, MEANS, AND EXTREMES

Month	Temperature – Normal – Daily maximum	Temperature – Normal – Daily minimum	Temperature – Normal – Monthly	Temperature – Extremes – Record highest	Temperature – Extremes – Year	Temperature – Extremes – Record lowest	Temperature – Extremes – Year	Normal heating degree days (base 65°)	Precipitation – Normal total	Precipitation – Maximum monthly	Precipitation – Year	Precipitation – Minimum monthly	Precipitation – Year	Precipitation – Maximum in 24 hr	Precipitation – Year	Precipitation – Snow, Ice Pellets – Mean total	Precipitation – Snow, Ice Pellets – Maximum monthly	Precipitation – Snow, Ice Pellets – Year	Precipitation – Snow, Ice Pellets – Maximum in 24 hr	Precipitation – Snow, Ice Pellets – Year	Relative Humidity – hr 01	Relative Humidity – hr 07	Relative Humidity – hr 13	Relative Humidity – hr 19	Wind[g] – Mean speed	Wind[g] – Prevailing direction	Wind[g] – Fastest Mile – Speed	Wind[g] – Fastest Mile – Direction	Wind[g] – Fastest Mile – Year	Percent possible sunshine[h]	Mean sky cover sunrise to sunset[h]	Mean number of days – Sunrise to Sunset[h] – Clear	Mean number of days – Sunrise to Sunset[h] – Partly cloudy	Mean number of days – Sunrise to Sunset[h] – Cloudy	Mean number of days – Precipitation .01 in. or more	Mean number of days – Snow, ice pellets 1.0 in or more	Mean number of days – Thunderstorms	Mean number of days – Heavy Fog	Mean number of days – Temperatures – Maximum – 90° and above[f]	Mean number of days – Temperatures – Maximum – 32° and below	Mean number of days – Temperatures – Minimum – 32° and below	Mean number of days – Temperatures – Minimum – 0° and below	Average daily solar radiation (langleys)
																					(Local time)																						
(a)	(b)	(b)	(b)	39		39		(b	(b)	35		35		35		37	37		32		35	39	35	39	39	14	6	6		32	32	32	32	32	35	35	39	39	39	39	39	39	
J	33.0	20.7	26.9	67	1950	-13	1963	1181	2.05	4.38	1950	0.23	1961	1.63	1960	8.1	21.1	1939	8.4	1957	75	79	69	74	11.5	W	40	26	1971	32	7.8	4	6	21	13	3	(c)	2	0	16	28	1	
F	33.9	20.4	27.2	68	1944	-16	1934	1058	2.08	4.95	1938	0.10	1969	2.43	1950	7.6	15.8	1965	10.0	1965	76	79	65	71	11.5	NW	40	23	1971[d]	43	7.3	4	7	17	12	3	1	1	0	13	26	1	
M	42.3	27.3	34.8	82	1945	-1	1943	936	2.42	4.40	1938	0.47	1958	1.85	1949	5.4	15.5	1954	9.8	1934	74	78	60	66	11.5	NW	40	23	1972	49	7.0	5	8	18	13	2	1	1	0	5	22	(c)	
A	56.4	38.8	47.6	87	1942[d]	14	1954	522	3.00	6.89	1947	0.74	1946	2.94	1947	1.2	6.8	1943	4.2	1942	71	74	53	58	11.1	NW	37	29	1967	52	6.8	6	8	16	12	(c)	3	1	0	(c)	8	0	
M	68.6	49.4	59.0	93	1962[d]	30	1966[d]	220	3.53	8.05	1943	0.58	1934	2.53	1948	(e)	0.1	1954	0.1	1954	71	71	51	56	9.8	S	33	35	1972[d]	59	6.4	7	10	14	12	0	4	(c)	1	0	(c)	0	
J	79.1	60.3	69.7	104	1934	38	1969[d]	42	2.83	6.58	1960	1.01	1959	3.53	1968	0.0	0.0		0.0		75	74	53	57	9.0	S	40	28	1971[d]	65	6.0	7	12	11	11	0	6	(c)	4	0	0	0	
J	83.9	64.8	74.4	105	1934	42	1972	0	2.82	7.05	1969	0.81	1936	2.80	1957	0.0	0.0		0.0		75	75	51	55	8.2	S	40	28	1966	70	5.3	9	13	9	9	0	6	(c)	6	0	0	0	
A	81.9	63.6	72.8	101	1936	43	1934	0	2.86	7.51	1940	1.07	1936	3.65	1956	0.0	0.0		0.0		78	80	53	60	8.1	N	46	30	1968	65	5.4	10	12	9	9	0	5	1	4	0	0	0	
S	74.2	56.0	65.1	100	1953[d]	32	1942	87	2.44	5.90	1936	0.53	1969	2.56	1959	0.0	0.0		0.0		79	83	54	64	8.9	S	36	14	1971[d]	61	5.4	10	10	10	9	0	3	1	1	0	(c)	0	
O	62.8	44.7	53.8	92	1963	24	1972[d]	360	2.63	7.80	1954	0.50	1964	3.72	1954	(e)	1.0	1943	1.0	1943	77	71	55	66	9.5	S	25	29	1969	56	5.6	10	9	12	9	0	1	1	(c)	0	2	0	
N	47.1	33.7	40.4	81	1950	5	1958	738	2.21	4.14	1948	0.57	1939	2.18	1951	2.5	9.2	1950	5.6	1951	76	79	64	70	11.3	SW	30	24	1970	35	7.5	4	7	19	11	1	(c)	1	0	2	13	0	
D	35.7	24.1	29.9	66	1971	-5	1960	1088	2.08	4.60	1957	0.43	1943	2.45	1965	6.8	24.0	1951	6.8	1951	77	79	70	74	11.3	SW	43	21	1971	32	7.7	4	6	21	13	2	(c)	2	0	12	25	(c)	
					July		Feb.				May		Feb.		Oct.			Dec.		Feb.									Aug.														
YR	58.2	42.0	50.1	105	1934	-16	1934	6232	30.95	8.05	1943	0.10	1969	3.72	1954	31.6	24.0	1951	10.0	1965	75	78	58	64	10.1	S	46	30	1968	54	6.5	80	108	177	131	11	32	11	15	48	125	2	

[a] Length of record, years, based on January data. Other months may be for more or fewer years if there have been breaks in the record.
[b] Climatological standard normals (1931-1960).
[c] Less than one half.
[d] Also on earlier dates, months, or years.
[e] Trace, an amount too small to measure.
[f] at Alaskan stations.
[g] Figures instead of letters in a direction column indicate direction in tens of degrees from true North; i.e., 09 - East, 18 - South, 27 - West, 36 - North, and 00 - Calm. Resultant wind is the vector sum of wind directions and speeds divided by the number of observations. If figures appear in the direction column under "Fastest Mile" the corresponding speeds are fastest observed 1-minute values.
[h] Data accumulated through 1965.
[i] To eight compass points only.

Means and extremes above are from existing and comparable exposures. Annual extremes have been exceeded at other sites in the locality as follows: Lowest temperature -24 in December 1872; maximum monthly precipitation 8.76 in July 1878; minimum monthly precipitation 0.04 in February 1887; maximum precipitation in 24 hours 4.75 in July 1925; maximum monthly snowfall 38.4 in February 1908; maximum snowfall in 24 hours 24.5 in April 1886; fastest mile of wind 95 from Northwest in June 1890.
Below zero temperatures are preceded by a minus sign.
The prevailing direction for wind in the Normals, Means, and Extremes table is from records through 1963.
Unless otherwise indicated, dimensional units used in this bulletin are: temperature in ºF; precipitation, including snowfall, in in.; wind movement in mph; and relative humidity in percent. Heating degree day totals are the sums of negative departures of average daily temperatures from 65ºF.Cooling degree day totals are the sums of positive departures of average daily temperatures from from 65°F. Sleet was included in snowfall totals beginning with July 1948. The term "Ice Pellets" includes solid grains of ice (sleet) and particles consisting of snow pellets encased in a thin layer of ice. Heavy fog reduces visibility to 1/4 mile or less.
Sky cover is expressed in a range of 0 for no clouds or obscuring phenomena to 10 for complete sky cover. The number of clear days is based on average cloudiness 0-3, partly cloudy days 4-7, and cloudy days 8-10 tenths.
Solar radiation data are the averages of direct and diffuse radiation on a horizontal surface. The langley denotes 1 g/cal/cm^2.

TABLE 2.3-4 TOLEDO, OHIO NORMALS, MEANS, AND EXTREMES

Month	Temperature							Normal heating degree days (base 65°)	Precipitation												Relative Humidity				Wind[g]					Percent possible sunshine	Mean sky cover sunrise to sunset	Mean number of days											Average daily solar radiation (langleys)
	Normal			Extremes												Snow, Ice Pellets											Fastest Mile					Sunrise to Sunset							Temperatures				
																																							Maximum		Minimum		
	Daily maximum	Daily minimum	Monthly	Record highest	Year	Record lowest	Year		Normal total	Maximum monthly	Year	Minimum monthly	Year	Maximum in 24 hr	Year	Mean total	Maximum monthly	Year	Maximum in 24 hr	Year	hr 01	hr 07	hr 13	hr 19	Mean speed	Prevailing direction	Speed	Direction[h]	Year			Clear	Partly cloudy	Cloudy	Precipitation .01 in. or more	Snow, ice pellets 1.0 in or more	Thunderstorms	Heavy Fog	90° and above[f]	32° and below	32° and below	0° and below	
																					(Local time)																						
(a)	(b)	(b)	(b)	17		17		(b)	(b)	17		17		17		17	17		17		17	17	17	17	17	8	17	17		17	17	17	17	17	17	17	17	17	17	17	17	17	
J	34.1	18.4	26.3	62	1967[d]	-17	1972[d]	1200	2.33	4.61	1965	0.27	1961	1.78	1959	8.8	14.2	1970	6.6	1957	72	78	69	73	10.9	WSW	47	W	1972[d]	45	7.4	5	7	19	13	3	(c)	2	0	17	29	4	
F	35.7	18.8	27.3	68	1957	-14	1967	1056	1.88	3.13	1960	0.27	1969	1.35	1959	7.8	14.4	1967	7.4	1967	72	78	65	70	10.9	WSW	56	SW	1967	47	7.3	4	7	17	11	2	(c)	2	0	12	27	2	
M	44.7	25.6	35.2	80	1963	-1	1960	924	2.26	4.88	1964	0.58	1958	1.56	1964	6.9	11.6	1964	7.5	1962	73	81	61	66	11.0	WSW	56	W	1957[d]	50	7.4	5	7	19	14	2	2	2	0	5	25	(c)	
A	58.4	35.4	46.9	87	1960	11	1964	543	2.77	4.94	1961	0.88	1962	2.39	1956	1.9	12.0	1957	9.8	1957	76	80	55	59	10.9	E	72	SW	1956	54	6.9	6	7	17	13	1	5	1	0	(c)	11	0	
M	70.4	46.1	58.3	95	1962	26	1968	242	3.04	5.13	1968	0.96	1964	1.96	1970	(e)	(e)	1966[d]	(e)	1966[d]	76	79	51	56	10.0	WSW	45	W	1957	63	6.3	6	11	14	12	0	3	1	1	0	2	0	
J	80.3	56.3	68.3	99	1971	32	1972	60	3.79	4.86	1960	1.89	1964	2.50	1956	0.0	0.0		0.0		82	82	54	58	8.4	SW	50	W	1969	65	6.0	7	11	12	10	0	7	1	4	0	(c)	0	
J	85.1	60.2	72.7	96	1966[d]	43	1972[d]	0	2.59	6.75	1969	1.58	1964	4.39	1969	0.0	0.0		0.0		84	86	55	61	7.5	WSW	54	NW	1970	68	5.8	7	14	10	10	0	8	1	4	0	0	0	
A	83.0	58.8	70.9	98	1964	37	1965	16	3.33	8.47	1965	0.81	1967	2.42	1972	0.0	0.0		0.0		86	89	57	65	7.3	SW	47	W	1965	68	5.5	9	12	10	8	0	6	2	4	0	0	0	
S	75.5	51.3	63.4	95	1960	29	1961	117	2.13	8.10	1972	0.58	1963	3.97	1972	(e)	(e)	1967	(e)	1967	86	90	57	70	7.8	SSW	47	NW	1969	62	5.9	8	10	12	10	0	4	2	1	0	(c)	0	
O	63.8	40.3	52.1	91	1963	16	1965	406	2.39	3.72	1959	0.28	1964	1.71	1957	(e)	0.2	1972[d]	0.2	1972[d]	81	85	55	68	8.7	WSW	40	SW	1956	59	5.8	9	10	12	8	0	1	2	(c)	0	6	0	
N	47.3	29.8	38.6	78	1968	2	1958	792	2.04	4.63	1966	0.77	1964	2.06	1969	3.6	17.9	1966	8.3	1966	81	83	67	74	10.3	WSW	65	SW	1957	39	7.7	4	7	19	11	1	(c)	2	0	3	18	0	
D	35.8	20.8	28.3	67	1971	-11	1960	1138	1.95	6.81	1967	0.54	1958	3.53	1967	7.7	19.0	1969	8.0	1969	82	83	73	78	10.5	SW	45	SW	1971[d]	36	7.8	3	7	21	14	3	(c)	2	0	12	27	2	
YR	59.5	38.5	49.0	99	Jun. 1971	-17	Jan. 1972[d]	6494	30.50	8.47	Aug 1965	0.27	Feb. 1969[d]	4.39	Jul. 1969	36.7	19.0	Dec. 1969	9.8	Apr. 1957	79	83	60	67	9.5	WSW	72	SW	Apr. 1956	56	6.7	73	110	182	134	12	40	19	4	49	146	8	

[a] Length of record, years, based on January data. Other months may be for more or fewer years if there have been breaks in the record.

[b] Climatological standard normals (1931-1960).

[c] Less than one half.

[d] Also on earlier dates, months, or years.

[e] Trace, an amount too small to measure.

[f] at Alaskan stations.

[g] Figures instead of letters in a direction column indicate direction in tens of degrees from true North; i.e., 09 - East, 18 - South, 27 - West, 36. - North, and 00 - Calm. Resultant wind is the vector sum of wind directions and speeds divided by the number of observations. If figures appear in the direction column under "Fastest Mile" the corresponding speeds are fastest observed 1-minute values.

[h] To eight compass points only.

Means and extremes above are from existing and comparable exposures. Annual extremes have been exceeded at other sites in the locality as follows: Highest temperature 105° in July 1936; maximum monthly precipitation 8.49 in October 1881; minimum monthly precipitation 0.04 in November 1904; maximum precipitation in 24 hr 5.98 in September 1818; maximum monthly snowfall 26.2 in January 1918; maximum snowfall in 24 hr 19.0 in February 1900; fastest mile 87 in March 1948.

Below zero temperatures are preceded by a minus sign.

The prevailing direction for wind in the Normals, Means, and Extremes table is from records through 1963.

Unless otherwise indicated, dimensional units used in this bulletin are: temperature in ºF; precipitation, including snowfall, in in.; wind movement in mph; and relative humidity in percent. Heating degree day totals are the sums of negative departures of average daily temperatures from 65ºF.Cooling degree day totals are the sums of positive departures of daily temperatures from 65°F. Sleet was included in snowfall totals beginning with July 1948. The term "Ice Pellets" includes solid grains of ice (sleet) and particles consisting of snow pellets encased in a thin layer of ice. Heavy fog reduces visibility to 1/4 mile or less.

Sky cover is expressed in a range of 0 for no clouds or obscuring phenomena to 10 for complete sky cover. The number of clear days is based on average cloudiness 0-3, partly cloudy days 4-7, and cloudy days 8-10 tenths.

Solar radiation data are the averages of direct and diffuse radiation on a horizontal surface. The langley denotes 1 $g/cal/cm^2$.

TABLE 2.3-5 CLIMATOLOGICAL SUMMARY MONROE, MICHIGAN (MEANS AND EXTREMES FOR PERIOD 1940-1969)

Latitude 41° 54'
Longitude 83° 22'
Elev. (Ground) 582 feet

Station Monroe, Michigan, Monroe County

Month	Temperature (°F) Means: Daily maximum	Temperature (°F) Means: Daily minimum	Temperature (°F) Means: Monthly	Temperature (°F) Extremes: Record highest	Temperature (°F) Extremes: Year	Temperature (°F) Extremes: Record lowest	Temperature (°F) Extremes: Year	Mean degree days**	Precipitation Totals (inches): Mean	Precipitation Totals (inches): Greatest daily	Precipitation Totals (inches): Year	Snow, Ice Pellets: Mean	Snow, Ice Pellets: Maximum monthly	Snow, Ice Pellets: Year	Snow, Ice Pellets: Greatest daily	Snow, Ice Pellets: Year	Mean number of days: Precip. .10 inch or more	Mean number of days: Temperatures Max.: 90° and above	Mean number of days: Temperatures Max.: 32° and below	Mean number of days: Temperatures Min.: 32° and below	Mean number of days: Temperatures Min.: 0° and below	Month
(a)	30	30	30	30		30		30	30	30		30	30		30		30	30	30	30	33	
JANUARY	32.9	18.5	25.7	70	1950	-16	1953	1218	1.95	1.74	1959	6.6	17.8	1943	7.0	1957	5	0	15	29	2	JANUARY
FEBRUARY	35.3	19.8	27.6	70	1944	- 8	1951	1057	1.73	1.74	1950	7.5	20.3	1962	12.8	1965	5	0	11	26	1	FEBRUARY
MARCH	44.1	27.1	35.6	81	1945	- 2	1943	911	2.39	1.99	1954	6.0	23.5	1954	9.0	1954	6	0	4	23	*	MARCH
APRIL	58.0	38.2	48.1	91	1942	16	1954	507	3.13	2.25	1965	. 9	12.0	1957	8.5	1957	7	*	*	8	0	APRIL
MAY	69.0	48.7	53.9	95	1952+	29	1966	233	3.41	2.52	1968	T	.3	1954	.3	1954	7	1	0	1	0	MAY
JUNE	79.9	69.2	69.6	100	1944	39	1949	42	3.47	2.74	1944	0	0		0		7	4	0	0	0	JUNE
JULY	83.9	62.9	73.4	102	1941+	43	1945	3	2.80	2.57	1948	0	0		0		5	6	0	0	0	JULY
AUGUST	82.3	61.1	71.7	101	1964	42	1965	12	3.16	2.12	1964	0	0		0		6	4	0	0	0	AUGUST
SEPTEMBER	75.6	54.2	64.9	100	1954	30	1942	72	2.40	2.20	1959	0	0		0		5	2	0	*	0	SEPTEMBER
OCTOBER	64.9	43.6	54.4	91	1951	23	1952	344	2.58	2.67	1949	T	T	1969	T	1969	5	*	0	3	0	OCTOBER
NOVEMBER	48.9	33.3	41.1	81	1950	1	1958	717	2.11	1.66	1968	2.5	10.4	1966	4.0	1966	5	0	1	14	0	NOVEMBER
DECEMBER	36.5	22.7	29.5	64	1966+	- 8	1960	1097	2.08	2.75	1957	7.2	27.0	1951	8.0	1951	5	0	11	26	1	DECEMBER
Year	59.3	40.8	50.1	102	July 1941+	-16	Jan. 1963	6213	31.29	2.75	Dec. 1967	30.7	28.5	Mar. 1954	12.8	Feb. 1965	68	17	42	130	4	Year

(a) Average length of record, years.

T Trace, an amount too small to measure.

** Base 65°F (H. C. S. Thom, Monthly Weather Review, January 1954)

\+ Also on earlier dates, months, or years.

* Less than one half.

TABLE 2.3-6 CLIMATOLOGICAL SUMMARY WILLIS, MICHIGAN (MEANS AND EXTREMES FOR PERIOD 1940-1969)

Latitude 41° 05'

Longitude 83° 35' Station WILLIS, MICHIGAN, WASHTENAW COUNTY

Elev. (Ground) 660 feet

Month	Temperature (°F) Means Daily maximum	Temperature (°F) Means Daily minimum	Temperature (°F) Means Monthly	Temperature (°F) Extremes Record highest	Year	Record lowest	Year	Mean degree days**	Precipitation Totals (inches) Mean	Greatest daily	Year	Snow, Ice Pellets Mean	Maximum monthly	Year	Greatest daily	Year	Mean number of days Precip. .10 inch or more	Temperatures Max. 90° and above	Max. 32 and below	Min. 32° and below	Min. 0° and below	Month
(a)	33	30	30	30		30		30	30	30		30	30		30		30	30	30	30	33	
JANUARY	31.4	15.6	23.5	69	1950	-18	1957	1287	1.95	1.52	1960	7.9	19.5	1943	5.0	1968+	5	0	17	30	4	JANUARY
FEBRUARY	34.0	17.2	25.6	67	1944	-14	1963	1113	1.71	1.35	1949	7.5	19.5	1962	7.5	1950	5	0	12	27	2	FEBRUARY
MARCH	43.5	25.1	34.3	80	1915	-13	1943	952	2.46	1.84	1954	6.4	21.5	1954	9.0	1956	6	0	5	25	1	MARCH
APRIL	54.0	35.5	46.8	85	1942	12	1964	546	3.22	2.48	1956	1.3	8.3	1957	4.0	1947	8	0	*	13	0	APRIL
MAY	69.0	45.6	57.3	92	1962	22	1966	267	3.41	2.03	1968	T	.3	1940	.3	1940	7	*	0	2	0	MAY
JUNE	79.2	55.6	67.4	99	1952	35	1965+	65	3.53	3.05	1967	0	0		0		7	3	0	0	0	JUNE
JULY	83.2	63.7	71.0	100	1941	38	1965	12	2.97	2.74	1951	0	0		0		6	4	0	0	0	JULY
AUGUST	81.6	66.8	69.2	93	1948	35	1965	31	3.45	3.95	1949	0	0		0		6	4	0	0	0	AUGUST
SEPTEMBER	74.5	49.4	62.0	101	1953	25	1942	144	2.27	2.22	1945	T	T	1967	T	1957	5	1	0	1	0	SEPTEMBER
OCTOBER	64.1	33.6	51.9	91	1963+	15	1965+	400	2.62	2.42	1945	T	.7	1943	.7	1943	5	*	0	8	0	OCTOBER
NOVEMBER	47.7	30.1	39.0	81	1950	- 4	1969	780	2.39	1.76	1958	3.7	14.0	1966	8.0	1951	6	0	2	19	*	NOVEMBER
DECEMBER	35.1	19.7	27.4	65	1966	-19	1960+	1165	2.21	2.85	1957	7.1	21.0	1951	7.0	1951	5	0	13	27	2	DECEMBER
Year	58.5	37.4	48.0	101	Sep. 1953	-19	Dec. 1950+	6773	32.19	3.55	Aug. 1943	33.9	21.5	March 1954	9.0	March 1956	71	12	49	152	9	Year

(a) Average length of record, years.

T Trace, an amount too small to measure.

** Base 65°F

\+ Also on earlier dates, months, or years.

* Less than one half.

(H. C. S. Thom, Monthly Weather Review, January 1954)

TABLE 2.3-7 MONTHLY MEANS OF DAILY AFTERNOON ATMOSPHERIC MIXING DEPTHS (FLINT, MICHIGAN, 1960-1964)

Month	Depth (m)	Depth (ft)
January	700	2300
February	780	2560
March	1110	3650
April	1680	5500
May	1640	5380
June	1680	5510
July	1820	5970
August	1580	5180
September	1350	4430
October	1340	4400
November	910	2990
December	800	2620

TABLE 2.3-8 AVERAGE WIND SPEEDS AND FREQUENCY OF CALMS FOR THE FERMI SITE, 100-FT TOWER; DETROIT CITY AIRPORT; TOLEDO EXPRESS AIRPORT; AND FERMI SITE 60-M TOWER

Sensor Height	Data Period	Average Speed (mph)	Frequency of Calms (percent)
Fermi site - 10 m 60-m	1 June 1974 - 31 May 1975	8.85	0.4[a]
Fermi site - 60 m tower	1 June 1974 - 31 May 1975	14.64	0.6[a]
Fermi site - 100 ft	1 December 1956 - 30 November 1959	12.4	0.30[b]
Detroit City Airport - 58 ft	1956 - 1959	10.3	1.10[b]
Toledo Express Airport - 20 ft	1950 - 1955	11.01	1.38[b]

[a] Calms defined as wind speeds ≤ 1.0 mph.

[b] Calms defined as wind speeds ≤ 1.2mph.

TABLE 2.3-9 WIND DIRECTION PERSISTENCE, 60-METER TOWER

(Instrument Height – 10 M)

1 June 1974 to 31 May 1975

Number of Occurrences by Direction

Hours of Persistence	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	Total Cumulative Percentage
1	105	94	79	85	85	92	120	122	129	137	138	150	142	125	123	127	100.000
2	47	40	29	38	30	26	61	57	55	62	57	70	53	56	61	36	48.168
3	19	10	22	13	16	29	25	26	24	30	32	38	21	26	31	20	26.406
4	9	9	12	12	9	11	12	12	13	22	20	22	16	15	14	7	15.720
5	3	1	7	7	3	3	3	3	10	16	16	13	11	5	7	4	9.706
6	1	2	2	4	5	6	8	4	4	7	7	8	6	7	4	1	6.573
7	1	1	3	4	4	2	5	3	5	6	2	6	3	4	2	3	4.448
8	0	0	1	1	0	4	3	1	3	4	2	1	1	0	4	1	2.937
9	1	0	2	3	1	0	0	2	0	4	0	2	2	4	1	1	2.210
10	0	0	2	2	0	1	3	1	0	2	5	2	0	3	1	0	1.566
11	0	0	0	0	0	1	0	0	0	2	3	1	0	1	0	0	0.951
12	0	0	0	0	0	0	0	0	0	1	1	1	0	0	0	0	0.727
13	0	1	0	0	1	0	0	0	0	0	1	1	0	0	0	0	0.643
14	0	0	0	0	0	1	0	0	0	1	0	0	1	0	0	0	0.531
15	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0.448
16	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0.392
17	0	0	1	0	0	0	0	0	0	0	0	0	0	0	1	0	0.364
18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0.308
19	0	0	0	0	0	0	0	0	0	2	0	0	1	0	0	0	0.280
20	0	0	0	0	0	0	0	0	1	0	1	0	1	0	0	0	0.196
21	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0.112
22	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0.084
23	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.056
24	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.056
25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.056
26	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.056
27	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.056
28	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.056
29	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.056
30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.056
31	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0.056
32	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0.028

(Instrument Height – 60 M)

TABLE 2.3-9 WIND DIRECTION PERSISTENCE, 60-METER TOWER

1 June 1974 to 31 May 1975

Number of Occurrences by Direction

Hours of Persistence	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	Total Cumulative Percentage
1	68	72	66	81	84	100	111	126	112	129	156	150	124	101	89	66	100.000
2	26	25	39	43	37	35	39	71	62	79	65	52	52	55	42	28	52.011
3	8	15	23	16	16	21	26	31	25	35	36	28	33	26	18	22	29.997
4	11	4	14	8	17	12	9	14	14	33	26	21	11	19	20	10	18.873
5	3	5	7	9	3	3	5	4	6	16	12	12	5	10	4	1	11.741
6	1	7	6	3	3	5	2	3	9	12	15	10	9	7	4	2	8.659
7	1	2	5	5	5	2	4	4	5	7	9	6	6	3	3	4	5.782
8	2	1	2	2	1	0	1	3	1	3	7	3	4	2	1	1	3.698
9	0	0	3	0	0	1	0	2	2	3	2	3	0	0	2	1	2.700
10	0	1	3	0	1	0	1	1	3	2	5	3	0	2	2	0	2.143
11	0	0	0	0	0	0	0	0	0	2	0	3	1	2	0	0	1.438
12	0	0	2	0	0	2	1	0	0	4	2	2	2	1	0	1	1.203
13	0	0	1	0	2	0	0	0	1	0	2	0	0	0	0	0	0.704
14	0	0	0	0	1	0	0	0	0	1	0	1	0	0	0	0	0.528
15	0	0	1	0	1	0	0	0	1	0	1	0	0	0	0	0	0.440
16	0	0	0	0	0	0	0	0	0	1	1	0	0	0	1	0	0.323
17	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0	0	0.235
18	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0.176
19	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0.147
20	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0.117
21	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.088
22	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.088
23	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0.088
24	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	1	0.059

TABLE 2.3-10 SEASONAL AND ANNUAL FREQUENCES OF STABILITY CATEGORIES AND ASSOCIATED WIND SPEEDS FOR DETROIT METROPOLITAN AIRPORT AND TOLEDO EXPRESS AIRPORT

Detroit Metropolitan Airport (1958 – 1962)

		A	B	C	D	E	F	G
Spring[a]	%	0.23	3.39	11.70	61.81	12.42	8.50	1.95
	mph	5.40	7.00	10.40	13.60	9.10	5.90	3.30
Summer[a]	%	1.39	8.89	18.56	39.95	11.89	14.48	4.84
	mph	5.10	7.00	10.00	11.20	8.40	5.80	3.30
Fall[a]	%	0.11	3.24	9.67	55.90	13.03	13.48	4.56
	mph	0.00	5.90	8.40	11.80	8.60	5.80	3.50
Winter[a]	%	0.02	0.92	4.11	74.41	10.89	7.42	2.23
	mph	0.00	4.00	7.80	12.90	9.20	5.60	2.90
Annual	%	0.44	4.13	11.05	57.95	12.06	10.98	3.39
	mph	5.20	6.80	9.60	12.50	8.90	5.80	3.30

TOLEDO EXPRESS AIRPORT (1959 – 1963)

		A	B	C	D	E	F	G
Spring[a]	%	0.41	4.26	11.52	58.04	9.34	10.85	5.59
	mph	5.00	6.60	9.70	12.60	8.30	5.50	3.00
Summer[a]	%	2.34	12.80	20.34	30.34	6.85	15.20	12.13
	mph	5.00	6.60	8.50	9.70	7.10	5.20	3.06
Fall[a]	%	0.06	4.05	11.56	50.29	10.23	14.52	9.20
	mph	0.00	5.60	7.80	10.90	8.10	5.40	3.04
Winter[a]	%	0.00	0.37	5.46	72.06	9.81	8.47	3.84
	mph	-	4.30	7.60	11.80	8.90	5.50	3.07
Annual[a]	%	0.71	5.40	12.26	52.58	9.05	12.27	7.76
	mph	5.00	6.30	8.50	11.40	8.20	5.40	3.01

[a] Seasons

Spring = March, April, May;

Summer = June, July, August;

Fall = September, October, November;

Winter = December, January, February.

TABLE 2.3-11 MONTHLY AND ANNUAL FREQUENCIES OF STABILITY CATEGORIES AND ASSOCIATED WIND SPEEDS FOR 10-METER LEVEL FERMI SITE DATA

Stabilities are determined from ΔT (10 - 60 M)

1 June 1974 to 31 May 1975

		A	B	C	D	E	F	G	Total
June 74	%	8.93	2.38	2.68	21.13	51.04	11.16	2.68	100
	mph	18.97	8.28	9.53	9.09	9.41	6.54	4.39	8.82
July 74	%	12.05	0.57	1.29	19.23	46.92	11.48	8.46	100
	mph	8.17	6.46	9.32	8.51	8.86	5.43	4.10	7.91
Aug 74	%	25.96	2.61	2.47	23.08	35.71	6.87	3.30	100
	mph	7.74	8.10	8.01	8.22	7.75	5.01	4.74	7.58
Sept 74	%	2.46	0.49	0.66	20.85	55.50	9.03	11.00	100
	mph	11.39	7.76	7.53	10.33	8.78	6.05	5.83	8.58
Oct 74	%	40.18	4.68	2.34	10.45	15.68	15.14	11.53	100
	mph	9.83	8.79	9.25	9.01	7.69	6.37	5.63	8.34
Nov 74	%	0.42	0.00	0.14	7.38	75.77	11.00	5.29	100
	mph	7.08	0.00	12.20	10.41	9.70	6.87	4.21	9.14
Dec 74	%	1.43	0.57	0.86	7.73	76.82	10.01	2.58	100
	mph	9.95	13.08	7.25	7.59	8.57	6.32	3.96	8.18
Jan 75	%	2.86	0.82	1.77	61.04	25.20	7.08	1.23	100
	mph	8.27	8.14	14.09	10.48	9.85	9.71	7.32	10.21
Feb 75	%	0.34	1.52	3.21	63.79	24.53	5.08	1.52	100
	mph	4.24	9.16	9.28	10.38	7.77	5.89	7.04	9.39
Mar 75	%	4.73	4.43	4.73	54.36	22.90	5.76	3.10	100
	mph	11.10	12.85	11.34	12.00	8.71	8.32	8.26	10.88
Apr 75	%	3.81	3.02	4.29	46.19	21.75	14.76	6.19	100
	mph	11.68	11.90	11.71	10.23	9.27	9.12	5.83	9.76
May 75	%	10.24	4.45	4.75	29.38	25.52	17.21	8.46	100
	mph	8.16	9.68	9.11	8.37	6.84	6.30	5.96	7.49
Annual	%	9.17	2.08	2.40	30.29	40.46	10.31	5.30	100
	mph	8.95	9.94	10.08	10.04	8.79	6.82	5.41	8.86

TABLE 2.3-12 THREE YEAR SUMMARY OF TEMPERATURE LAPSE RATE DATA FOR THE FERMI SITE (1956-1959)

Fermi Site Data ($\Delta T_{100\ ft - 25\ ft}$)

Season	Strong Vertical Temperature Gradients $\Delta T < -0.98°C/100m$ or $-5.4°F/1000$ ft (%)	Weak Vertical Temperature Gradients $\Delta T > -0.98°C/100m$ or $-5.4°F/1000$ ft (%) ≤ 0	Inversion (Temperature Increases with Height) (%)
Spring (March, April, May)	61.3	15.5	23.1
Summer (June, July, August)	38.0	27.3	34.8
Fall (September, October, November)	42.9	26.2	30.9
Winter (December, January, February)	40.6	35.5	23.8
ANNUAL	45.4	26.7	27.9

TABLE 2.3-13 METEOROLOGICAL DATA ANALYSIS HOURLY TEMPERATURE[a] AVERAGE OVER A 24-HR INTERVAL

Hours of Missing Data	10 - Meter	282
	60 - Meter	211
Total No. of Observations	10 - Meter	8478
	60 - Meter	8549

Hour	10-M	60-M
1	8.88	9.10
2	8.50	8.77
3	8.25	8.54
4	7.96	8.28
5	7.64	8.05
6	7.44	7.95
7	7.35	7.79
8	7.32	7.63
9	7.95	7.86
10	8.69	8.36
11	9.55	8.97
12	10.19	9.60
13	10.75	10.20
14	11.00	10.38
15	11.40	10.80
16	11.51	11.00
17	11.56	11.15
18	11.55	11.22
19	11.22	10.98
20	10.84	10.74
21	10.26	10.32
22	9.85	10.02
23	9.53	9.66
24	9.22	9.37
Minimum	-19.30	-19.30
Maximum	34.89	34.80
Annual Average	9.52	9.45

[a] All units in °C

TABLE 2.3-14 PASQUILL CATEGORIES HOURLY STABILITY INDEX DISTRIBUTION

1 June 1974 to 31 May 1975

	In Percent of Total Obs							In Percent of Hourly Obs						
Hour	A	B	C	D	E	F	G	A	B	C	D	E	F	G
1	0.27	0.04	0.01	0.93	1.94	0.65	0.35	6.53	0.85	0.28	22.16	46.31	15.62	8.24
2	0.19	0.04	0.04	1.04	1.92	0.56	0.40	4.56	0.85	0.85	24.79	45.87	13.39	9.69
3	0.14	0.06	0.02	0.95	2.01	0.60	0.39	3.42	1.42	0.57	22.79	48.15	14.25	9.40
4	0.14	0.02	0.05	0.99	1.80	0.67	0.49	3.44	0.57	1.15	23.78	43.27	16.05	11.75
5	0.18	0.02	0.06	0.90	1.76	0.75	0.48	4.30	0.57	1.43	21.78	42.41	18.05	11.46
6	0.13	0.02	0.02	1.02	1.79	0.62	0.52	3.17	0.58	0.58	24.78	43.23	14.99	12.68
7	0.17	0.06	0.02	1.04	1.79	0.52	0.56	4.01	1.43	0.57	24.93	42.98	12.61	13.47
8	0.21	0.02	0.08	1.08	1.89	0.50	0.30	5.23	0.58	2.03	26.45	46.22	12.21	7.27
9	0.44	0.10	0.07	1.30	1.83	0.23	0.17	10.66	2.31	1.73	31.41	44.38	5.48	4.03
10	0.67	0.06	0.10	1.51	1.60	0.12	0.11	16.05	1.43	2.29	36.39	38.40	2.87	2.58
11	0.64	0.15	0.20	1.58	1.39	0.11	0.07	15.47	3.72	4.87	38.11	33.52	2.58	1.72
12	0.81	0.13	0.14	1.61	1.23	0.12	0.05	19.83	3.21	3.50	39.36	30.03	2.92	1.17
13	0.82	0.25	0.27	1.36	1.21	0.12	0.04	20.12	6.12	6.71	33.53	29.74	2.92	0.87
14	0.81	0.26	0.24	1.44	1.26	0.08	0.06	19.48	6.30	5.73	34.67	30.37	2.01	1.43
15	0.79	0.14	0.33	1.46	1.18	0.18	0.05	19.02	3.46	8.07	35.45	28.53	4.32	1.15
16	0.73	0.18	0.18	1.57	1.21	0.19	0.08	17.53	4.31	4.31	37.93	29.31	4.60	2.01
17	0.61	0.10	0.17	1.64	1.38	0.20	0.11	14.45	2.27	3.97	39.09	32.86	4.82	2.55
18	0.48	0.08	0.15	1.58	1.50	0.26	0.13	11.36	1.99	3.69	37.78	35.80	6.25	3.12
19	0.38	0.06	0.05	1.38	1.89	0.33	0.12	9.04	1.41	1.13	32.77	44.92	7.91	2.82
20	0.27	0.10	0.04	1.21	1.89	0.56	0.14	6.50	2.26	0.85	28.81	44.92	13.28	3.39
21	0.27	0.05	0.05	1.13	1.83	0.75	0.15	6.46	1.12	1.12	26.69	43.26	17.70	3.65
22	0.29	0.06	0.02	1.08	1.77	0.77	0.24	6.74	1.40	0.56	25.56	41.85	18.26	5.62
23	0.23	0.06	0.06	1.17	1.75	0.67	0.29	5.37	1.41	1.41	27.68	41.53	15.82	6.78
24	0.25	0.02	0.05	1.06	1.92	0.61	0.32	5.92	0.56	1.13	25.07	45.35	14.37	7.61

TABLE 2.3-15 THREE YEAR SUMMARY OF TEMPERATURE LAPSE RATE ($\Delta T_{300\ FT - 20\ FT}$) DATA FOR THE WJBK-TV TOWER (1956-1959)

Season	Inversions (Temperature increasing with height) (percent)
Spring (March, April, May)	23.0
Summer (June, July, August)	35.5
Fall (September, October, November)	33.1
Winter (December, January, February)	23.0
ANNUAL	28.6

TABLE 2.3-16 PROBABILITY OF OCCURRENCE OF INVERSIONS[a] FOR A GIVEN LENGTH OF TIME AT FERMI SITE

Number of Hours of Persistence t	Probability (percent) That Inversion Persisted for Periods Greater Than t
1	100.00
2	65.21
3	51.52
4	45.06
5	40.30
6	36.50
7	32.51
8	29.47
9	25.67
10	23.76
11	21.48
12	19.01
13	15.97
14	13.49
15	11.03
16	8.555
17	6.844
18	4.753
19	3.992
20	3.612
21	3.042
23	2.281
25	2.091
26	1.711
27	1.331
28	1.141
33	0.951
41	0.760
43	0.570
44	0.380
46	0.190

[a] From data from 60-m tower, 1 June 1974 through 31 May 1975.

TABLE 2.3-17 THE DISTRIBUTION AND FREQUENCY OF PRECIPITATION BY WIND DIRECTION AND SPEED FOR THE FERMI SITE

	(1956 -1959) 100 – Ft Tower		(June 74 – May 75) 60-M Tower	
Wind Direction	Average Wind Speed (100 ft Level) During Precipitation (mph)	Frequency With Respect to Precipitation Only (percent)	Average Wind Speed (10-m Level) During Precipitation (mph)	Frequency With Respect to Precipitation Only (percent)
NNE	12.5	4.1	7.5	7.6
NE	16.0	6.1	9.7	5.9
ENE	16.8	5.3	10.4	6.7
E	17.9	5.3	11.8	10.9
ESE	15.3	3.4	10.3	11.8
SE	14.4	3.2	10.2	5.0
SSE	13.3	3.9	9.5	8.4
S	12.5	5.3	11.7	5.9
SSW	12.6	7.3	13.6	5.0
SW	14.1	9.6	9.9	5.0
WSW	14.7	13.8	11.2	5.0
W	16.6	11.1	9.1	2.5
WNW	14.0	8.3	12.2	9.2
NW	12.5	6.4	7.4	5.9
NNW	12.9	5.1	4.2	1.7
N	11.2	3.4	8.3	3.4
CALM	----	0.2	----	----

TABLE 2.3-18 AVERAGE TEMPERATURE AND RELATIVE HUMIDITY SUMMARY FOR THE FERMI SITE, DETROIT CITY AIRPORT, AND TOLEDO EXPRESS AIRPORT

(1 January 1972 to 31 December 1972)

	Fermi Site (Langton Rd)		Detroit		Toledo	
Month	Temperature (°F)	Relative Humidity (percent)	Temperature (°F)	Relative Humidity (percent)	Temperature (°F)	Relative Humidity (percent)
January	26	85	26	66	23	69
February	25	86	25	64	24	69
March	29	83	33	62	34	57
April	42	80	45	48	46	51
May	58	82	61	58	60	61
June	63	78	65	62	64	70
July	69	80	73	62	71	73
August	67	90	70	74	68	79
September	62	88	64	75	62	78
October	48	78	49	70	47	71
November	37	84	39	74	37	74
December	29	84	31	76	30	76
Annual	47	83	48	66	47	69

TABLE 2.3-19 COMPARISON OF MONTHLY TEMPERATURE HIGH, LOW, AND AVERAGE BETWEEN FERMI 2 SITE DATA AND NATIONAL WEATHER BUREAU DATA COLLECTED AT THE NEAREST LOCATIONS FOR THE PERIOD JUNE 1974 THROUGH MAY 1975

		June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May
Fermi 2	High	84.8	94.2	89.5	81.0	74.4	72.7	42.9	52.9	44.7	60.8	62.9	84.7
	Avg.	68.4	76.3	74.2	61.5	50.5	41.9	30.4	29.5	27.3	32.5	39.6	62.5
	Low	47.0	52.0	55.0	34.5	24.3	15.9	11.3	8.6	-2.7	16.8	20.4	44.3
Monroe Sewage Plant 6.6 miles NW	High	88.0	100.0	93.0	89.0	81.0	76.0	44.0	57.0	53.0	68.0	70.0	93.0
	Avg.	68.4	76.3	74.2	63.8	51.6	42.8	30.1	28.9	28.2	33.5	42.5	63.8
	Low	47.0	52.0	55.0	34.0	24.0	15.0	11.0	7.0	-5.0	12.0	17.0	38.0
Willis 21.6 miles NW	High	85.0	95.0	88.0	85.0	77.0	75.0	40.0	57.0	49.0	64.0	69.0	88.0
	Avg.	65.0	70.7	69.1	57.7	48.2	39.2	26.9	27.5	26.7	32.3	40.7	62.2
	Low	45.0	43.0	45.0	26.0	13.0	11.0	-2.0	4.0	-11.0	8.0	18.0	36.0
Detroit Metro Airport 20 miles North	High	86.0	97.0	90.0	87.0	77.0	74.0	41.0	53.0	46.0	63.0	69.0	88.0
	Avg.	65.9	72.5	72.3	59.7	48.8	40.6	28.6	28.3	27.5	32.5	40.9	62.8
	Low	47.0	50.0	50.0	29.0	17.0	14.0	6.0	6.0	-6.0	10.0	19.0	40.0
Detroit City Airport 33.7 miles NNE	High	89.0	97.0	89.0	87.0	79.0	75.0	44.0	57.0	50.0	66.0	70.0	91.0
	Avg.	57.6	75.1	73.8	62.9	52.2	43.0	32.3	31.1	29.7	33.9	43.3	66.1
	Low	48.0	52.0	58.0	34.0	28.0	19.0	21.0	10.0	4.0	15.0	21.0	42.0

TABLE 2.3-20 METEOROLOGICAL SYSTEM EQUIPMENT SPECIFICATIONS (33-FT TOWER)

Instrument	Manufacturer	Model	Level	Specifications
Wind speed and direction	Gill	Model 35001 propeller vane	33 ft (10 m)	Wind Direction Range: 360°, mechanical 342°, electrical Wind Speed Range: variable 0-15 mph, 0-30 mph, 0-50 mph Threshold: Vane - 0.3-0.5 mph Propeller - 0.4-0.7 mph
Temperature and relative humidity	Belfort	Model 5-592 hygrothermograph	Shelter (Base approximately 4-1/2 ft above ground level)	Accuracy: Temperature: +1°F between -20°F to +100°F Humidity: ±3% RH between 20% and 95%, ±5% at extremes

TABLE 2.3-21 60-M TOWER ANALOG/DIGITAL METEOROLOGICAL SYSTEM INSTRUMENTATION (PREOPERATIONAL PROGRAM)

WIND SPEED SENSORS: All Levels

Sensor: Climet Instruments model #WS-011-1. Wind speed transmitter and cup assembly.

Distance constant:	5 ft maximum
Threshold wind:	0.6 mph
Accuracy:	± 0.1% or 0.15 mph, whichever is greater

Electronics: Analog signal conditioner constructed by EG&G, Albuquerque..

Accuracy:	± 0.1% full scale

Recorder: Digital representation of Datel Systems, Inc. model #ADC-E 3-digit (BCD) analog to digital converter.

OVERALL SYSTEM ACCURACY:	± 1% or 0.15 mph

Recorder: (Backup) Esterline Angus Model #EAL1102S dual analog recorder

Accuracy:	± 0.25% full scale
OVERALL SYSTEM ACCURACY:	± 1.04% or 0.38 mph, whichever is greater

WIND DIRECTION SENSORS: All Levels

Sensor: Climet Instruments model #WD-012-03 wind direction transmitter and wind vane assembly.

Distance constant:	1 m maximum
Damping ratio:	0.4 standard
Threshold:	0.75 mph
Accuracy:	± 3°

Electronics: Analog signal conditioner constructed by EG&G, Albuquerque

Accuracy:	± 0.10% full scale

Recorder: Digital representation of Datel Systems, Inc. model #ADC-E 3-digit (BCD) analog to digital converter.

Accuracy:	± ½ LSB

TABLE 2.3-21 60-M TOWER ANALOG/DIGITAL METEOROLOGICAL SYSTEM INSTRUMENTATION (PREOPERATIONAL PROGRAM)

Recorder: (Backup) Esterline Angus Model #EAL1102S dual analog recorder.

Accuracy:	± 0.25% full scale
OVERALL SYSTEM ACCURACY:	± 3.2°

TEMPERATURE SENSORS: All Levels

Sensors: Rosemount Engineering model #171BM platinum resistance thermometer.

Linearity:	0.01% full scale
Stability:	0.01°C per year
Aspiration rate:	24 ft/sec flow over sensor

Electronics: Analog signal conditioner constructed by EG&G, Albuquerque.

Accuracy:	± 0.10% full scale

Recorder: Digital representation of Datel Systems, Inc. model #ADC-E 3-digit (BCD) analog to digital converter.

Accuracy:	± ½ LSB

Recorder: (Backup) Esterline Angus Model #EAL1102S dual analog recorder.

Accuracy:	± 0.25% full scale
OVERALL SYSTEM ABSOLUTE ACCURACY:	± 0.2°C
OVERALL SYSTEM DIFFERENCE ACCURACY:	± 0.1°C

DEWPOINT SENSOR:

Sensor: Environmental Equipment Division of EG&G, model #110S-M dewpoint measuring set.

Range:	-80°F to +120°F
Accuracy:	± 0.5°F maximum

Electronics: Analog signal conditioner constructed by EG&G, Albuquerque.

Accuracy:	± 0.1% full scale

TABLE 2.3-21 60-M TOWER ANALOG/DIGITAL METEOROLOGICAL SYSTEM INSTRUMENTATION (PREOPERATIONAL PROGRAM)

Recorder: Digital representation of Datel Systems, Inc. model #ADC-E 3-digit (BCD) analog to digital converter.

Recorder: (Backup) Esterline Angus Model #EAL1102S dual analog recorder

Accuracy:	± 0.25% full scale
OVERALL SYSTEM ACCURACY:	± 0.35°C

PRECIPITATION SENSOR:

Sensor: Fisher & Porter Company model #35-1559 EA10, precipitation gage recorder.

Range:	0 to 19.5 in. precipitation
Accuracy:	± 0.015 in. of range span
Sensitivity:	0.025 in. response
OVERALL SYSTEM ACCURACY:	± 0.1 in.

TABLE 2.3-22 COMPARISON BETWEEN MANUALLY READ ANALOG AVERAGES AND DIGITAL AVERAGES FOR ALL PARAMETERS AT THE 10-METER LEVEL AND THE TEMPERATURE AT THE 60-METER LEVEL ON THE 60-METER TOWER

		Temperature at 10-m level		Dewpoint		Temperature at 60-m level		Wind Speed at 10-m Level		Wind Direction at 10-m Level	
Date	Time	Digital	Analog	Digital	Analog	Digital	Analog	Digital	Analog	Digital	Analog
1974											
June 15	04:00	18.46	18.42	15.71	15.74	18.41	18.45	12.6	12.7	198.4	198.4
June 15	14:00	18.83	18.84	16.33	16.31	18.93	18.96	12.5	12.5	191.8	192.4
June 25	03:00	11.45	11.46	6.23	6.25	11.98	11.93	6.7	6.8	341.3	341.5
June 29	09:00	19.92	19.96	14.44	14.40	20.20	20.28	5.7	5.7	231.6	230.9
July 10	16:00	23.40	23.41	21.12	21.19	23.20	23.22	12.2	12.2	042.3	042.6
July 14	03:00	25.35	25.31	16.37	16.37	25.62	25.69	7.4	7.4	244.4	244.0
July 24	06:00	14.06	14.05	13.86	13.83	17.20	17.25	2.1	2.1	319.5	319.3
July 29	09:00	24.06	24.00	19.46	19.46	23.52	23.51	6.9	6.8	274.6	274.7
August 8	13:00	23.35	23.39	18.23	18.22	22.63	22.68	8.8	8.8	137.3	136.4
August 11	02:00	23.08	23.07	19.38	19.31	23.01	23.04	11.7	11.7	159.8	160.9
August 22	02:00	20.53	20.53	16.06	16.01	20.45	20.46	7.7	7.8	057.4	056.2
August 25	02:00	16.85	16.86	14.14	14.12	18.45	18.42	5.8	5.7	027.6	027.2
September 11[a]	13:00	25.51	25.88	18.98	19.22	26.12	26.07	9.9	10.1	207.3	204.6
September 11	15:00	26.28	26.21	19.35	19.24	25.99	25.75	11.9	11.7	211.9	208.7
October 26	14:00	15.95	16.43	-03.15	-02.97	15.75	15.62	13.2	12.8	279.7	280.6
October 28	12:00	03.64	03.53	06.90	06.88	16.12	16.10	7.3	7.1	127.7	127.4
November 6	04:00	04.09	03.86	02.51	02.40	04.13	04.22	5.5	5.2	287.2	282.8
November 10	14:00	09.51	09.28	06.54	06.59	09.24	09.21	9.4	9.3	127.3	122.8
November 22	20:00	04.14	04.13	01.28	01.33	04.5	04.5	5.9	5.6	244.7	239.9
November 24	10:00	12.23	12.14	11.20	11.18	11.89	11.89	11.2	10.9	255.2	249.9
December 4	17:00	03.79	-03.58	-08.95	-08.58	-03.45	-03.72	3.5	3.1	281.3	279.2
December 9	11:00	-05.20	-05.20	-09.68	-09.22	-05.18	-05.37	12.3	11.9	285.1	282.6
December 19	11:00	0.61	00.64	-00.91	00.90	00.31	0.18	12.0	12.1	253.2	248.8
December 23	12:00	04.80	04.57	00.53	00.86	05.30	05.10	9.1	8.8	249.3	245.7

TABLE 2.3-22 COMPARISON BETWEEN MANUALLY READ ANALOG AVERAGES AND DIGITAL AVERAGES FOR ALL PARAMETERS AT THE 10-METER LEVEL AND THE TEMPERATURE AT THE 60-METER LEVEL ON THE 60-METER TOWER

		Temperature at 10-m level		Dewpoint		Temperature at 60-m level		Wind Speed at 10-m Level		Wind Direction at 10-m Level	
Date	Time	Digital	Analog	Digital	Analog	Digital	Analog	Digital	Analog	Digital	Analog
1975											
January 3	10:00	1.48	1.58	0.25	0.32	1.04	1.01	13.3	13.0	226.7	222.7
January 6	14:00	0.48	0.53	0.23	0.25	0.18	0.21	10.7	10.9	180.0	177.8
January 12	16:00	-6.15	-6.17	-16.66	-16.76	-6.83	-6.86	9.0	8.8	246.0	243.7
January 17	03:00	-7.60	-7.36	-14.26	-14.56	-7.96	-7.76	1.4	1.4	299.1	297.1
February 5	16:00	0.23	-0.15	-0.09	0.05	-0.22	-1.03	6.6	6.1	042.9	038.7
February 10	03:00	-17.25	-16.87	-22.99	-22.61	-17.22	-16.89	4.9	4.5	248.6	249.2
February 14	23:00	-4.21	-4.52	-08.9	-9.13	-4.62	-4.74	6.5	6.0	115.5	110.3
February 15	01:00	-4.11	-4.40	-8.38	-8.36	-4.48	-4.61	7.7	7.2	118.6	117.0
March 13	23:00	-2.49	-2.62	-9.76	-9.63	-2.97	-3.14	14.3	13.8	050.9	047.3
March 14	01:00	-2.55	2.73	-12.77	-12.26	-3.07	-3.41	16.8	16.3	065.7	063.1
March 17	10:00	0.02	0.08	-1.79	-1.92	-0.73	0.94	5.8	6.0	046.4	042.0
March 24	03:00	3.39	4.22	1.38	1.71	2.73	3.10	18.8	18.5	079.6	081.0
April 4	22:00	-1.91	-2.11	-11.72	-11.32	N/A	N/A	N/A	N/A	N/A	N/A
April 5	04:00	-6.14	-6.13	-11.84	-11.43	N/A	N/A	N/A	N/A	N/A	N/A
April 10	18:00	N/A	N/A	N/A	N/A	3.48	3.61[b]	12.5	12.4	060.2	056.7
April 11	13:00	N/A	N/A	N/A	N/A	2.86	3.02[b]	7.2	7.8	159.1	156.2
April 25	19:00	8.07	8.01	2.19	2.40	7.75	7.90	8.3	7.5	358.3	355.0
April 26	01:00	5.13	4.72	0.60	0.71	5.92	6.44	3.2	3.4	062.5	061.2
May 17	09:00	11.13[c]	11.01	9.99	9.73[c]	12.33	12.32	8.1	8.0	080.9	074.3
May 19	23:00	22.48	22.83	14.31	14.56	19.39	19.00[d]	10.4	10.4	201.6	197.6
May 27	21:00	20.97	21.04	8.36	8.24	21.96	21.87	4.0	3.6	314.9	312.3
May 28	07:00	16.02	16.51	7.05	6.67	15.44	15.86	9.5	9.4	069.7	064.7

[a] Digital system of the 60-meter tower was down from 9/17/74 to 10/26/74. Comparison checks for this time period are not available.
[b] Reading 1 hr later than indicated time.
[c] Reading 2 hr prior to indicated time.
[d] Reading 16 hr prior to indicated time.

TABLE 2.3-23 PERCENTAGE OF DATA RECOVERY FOR THE 60-M METEOROLOGICAL TOWER AT THE SITE

1 June 1974 through May 1975

	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Jan.	Feb.	March	April	May	Annual
Regulatory Guide 1.23[a]	93.47	93.95	98.79	87.36	74.73	100.00	94.22	98.92	97.77	82.39	87.50	90.73	91.16
10-m wind speed	96.53	94.62	99.87	97.36	95.30	99.86	94.89	98.92	87.80	96.10	99.72	99.33	96.87
10-m wind direction	97.08	94.22	98.25	86.39	78.23	99.86	96.64	99.60	96.73	94.76	99.44	99.19	95.15
10-m air temperature	93.33	96.77	99.60	99.03	99.60	99.72	95.97	99.19	97.47	92.47	87.78	98.66	96.78
10-m dewpoint temp.	93.33	96.64	99.33	97.92	95.83	99.72	95.03	96.37	97.47	92.34	98.47	89.52	96.11
60-m wind speed	99.58	96.24	99.73	97.64	98.66	99.72	96.64	99.60	91.82	96.10	97.92	97.58	97.77
60-m wind direction	98.33	96.37	99.33	90.14	95.03	99.58	96.64	99.60	97.32	95.70	97.92	99.19	97.24
60-m air temperature	99.58	96.10	99.60	98.89	99.46	99.72	95.70	99.60	97.47	92.74	99.58	91.26	97.59

[a] Joint recovery between 10-m wind speed, 10-m wind direction, 10-m temperature, 60-m temperature.

TABLE 2.3-24 METEOROLOGICAL DATA RECOVERY (PERCENT) FOR 33-FT TOWER

(January 1, 1972 – December 31, 1972)

	Temperature Data	Relative Humidity Data
Spring (March, April, May)	94	93
Summer (June, July, August)	96	96
Fall (September, October, November)	96	96
Winter (December, January, February)	90	90
ANNUAL	94	94

TABLE 2.3-25 METEOROLOGICAL MONITORING NETWORK (OPERATIONAL PROGRAM)

Parameter	Sampling Height (m)	Sensing Technique
Primary Monitoring System		
Wind speed	10 and 60	Cups/light chopper
Wind direction	10 and 60	Vane/potentiometer
Vertical wind speed	10	Propeller
Differential temperature	10 to 60	Matched thermistors
Ambient temperature	10	Thermistor
Dewpoint	10	Lithium Chloride Type
Precipitation	1.5	Tipping bucket
Secondary Monitoring System		
Wind speed	10 and 60	Cups/light chopper
Wind direction	10 and 60	Vane/potentiometer
Vertical wind speed	10	Propeller/light chopper
Differential temperature	10 to 60	Matched thermistors
Ambient temperature	10	Thermistor

TABLE 2.3-26 METHOD FOR SUBSTITUTING REDUNDANT PARAMETERS FOR THE CRITICAL METEOROLOGICAL MEASUREMENTS

Level of Redundancy	10-Meter Level Wind Speed	10-Meter Level Wind Direction	Stability Indicator
0	Primary WS10	Primary WD10	Primary delta T
1	Secondary WS10	Secondary WD10	Secondary delta T
2			Primary sigma theta
3			Secondary sigma theta

TABLE 2.3-27 SUMMARY OF MAXIMUM SECTOR AND 5 PERCENT OVERALL SITE LIMIT χ/Q VALUES AT THE EAB AND LPZ FOR REGULATORY POST-ACCIDENT TIME PERIODS

EAB* (915 m)		LPZ* (4827 m)						
0-2 Hours		0-2 Hours		0-8 Hours	8-24 Hours	1-4 Days	4-30 Days	Annual Average
Max Sector	Site Limit	Max Sector	Site Limit	Max Sector	Max Sector	Max Sector	Max Sector	Max Sector
2.09 E-04	1.54 E-04	4.86 E-05	2.98 E-05	2.17 E-05	1.45 E-05	6.02 E-06	1.71 E-06	3.66 E-07
(ESE)		(ESE)		(ESE)	(ESE)	(ESE)	(ESE)	(ESE)

* For the EAB and LPZ, the 0-2 hour maximum sector χ/Q value is based on the highest sector-specific 0.5% χ/Q sector value; and the 0-2 hour site limit is based on the 5 percent overall site χ/Q value. In accordance with Regulatory Guide 1.145, the higher of these is selected as the controlling 0-2 hour χ/Q. Also, for the LPZ, per Regulatory Guide 1.145, logarithmic interpolation between the controlling 0-2 hour value and the maximum annual average χ/Q in any sector is performed to derive the approximate LPZ χ/Q value for each of the post-accident time periods.

TABLE 2.3-28 SUMMARY OF χ/Q (s/m^3) VALUES AT THE CONTROL CENTER COMPLEX FOR REGULATORY POST-ACCIDENT TIME PERIODS

Accident (source-to-receptor)	Time Interval				
LOCA					
	0-2 Hours	2-8 Hours	8-24 Hours	1-4 Days	4-30 Days
SGTS and ECCS leakage (SGTS stack-to-South control center intake)	6.18E-4	4.53E-4	1.88E-4	1.26E-4	8.70E-5
MSIV Leakage (TBHVAC Stack-to-North control center intake)	4.75E-4	3.78E-4	1.45E-4	9.80E-5	7.19E-5
Fuel Handling Accident					
	0-2 Hours	2-8 Hours	8-24 Hours	1-4 Days	4-30 Days
24-hr Drop of Recently Irradiated Fuel (SGTS-to-North Emergency Intake)	4.03E-3* 3.65E-3	The two-hour value is conservatively applied for the duration of accident.			
Fuel No Longer Recently Irradiated without SGTS (Outage Building-to-South Emergency Intake)	4.25E-3	The two-hour value is conservatively applied for the duration of accident.			
Control Rod Drop Accident					
	0-2 Hours	2-8 Hours	8-24 Hours	1-4 Days	4-30 Days
Condenser Release (TBHVAC stack-to-South Emergency Intake**)	1.17E-3	9.09E-4	3.41E-4	2.29E-4	1.73E-4
SJAE Release (RBHVAC stack-to-South Emergency Intake**)	7.33E-3	5.59E-3	2.35E-3	1.66E-3	1.26E-3

* This value applies during the initial unfiltered release via RBHVAC.
** CREF and dual inlet configuration not credited for control rod drop accident analyses.

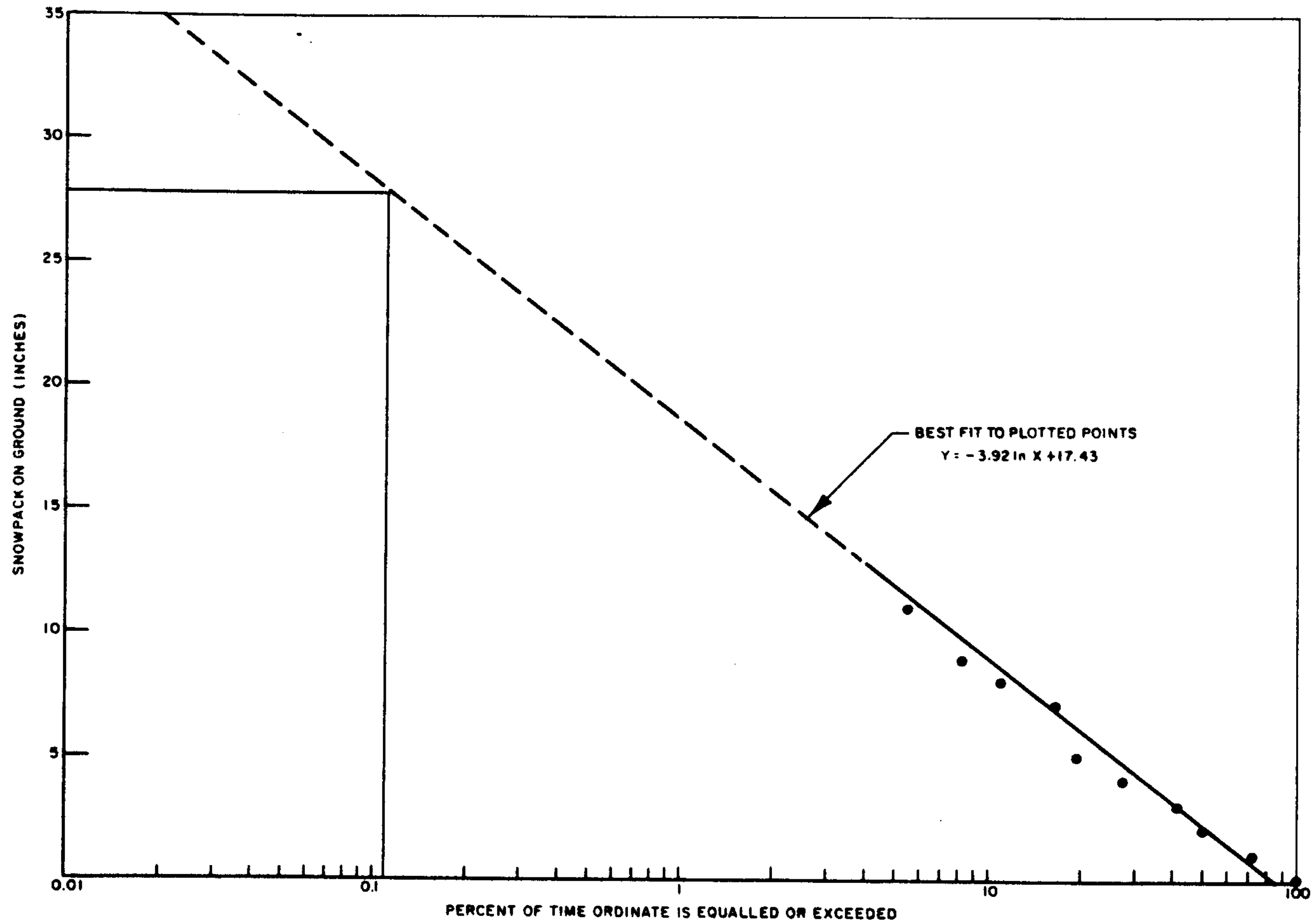

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FIGURE 2.3-1

CUMULATIVE FREQUENCY OF SNOWPACK

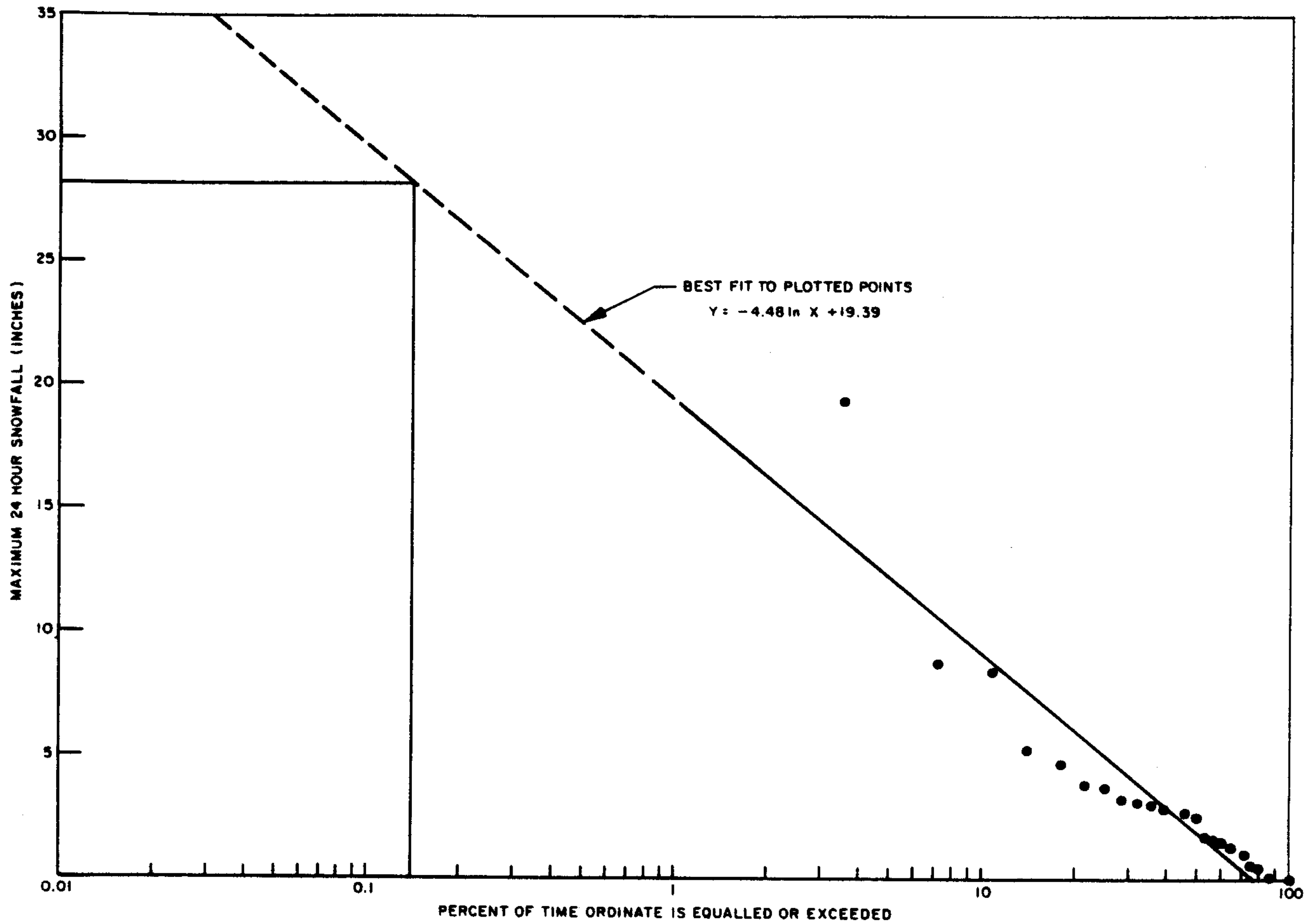

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FIGURE 2.3-2

CUMULATIVE FREQUENCY OF SNOWFALL

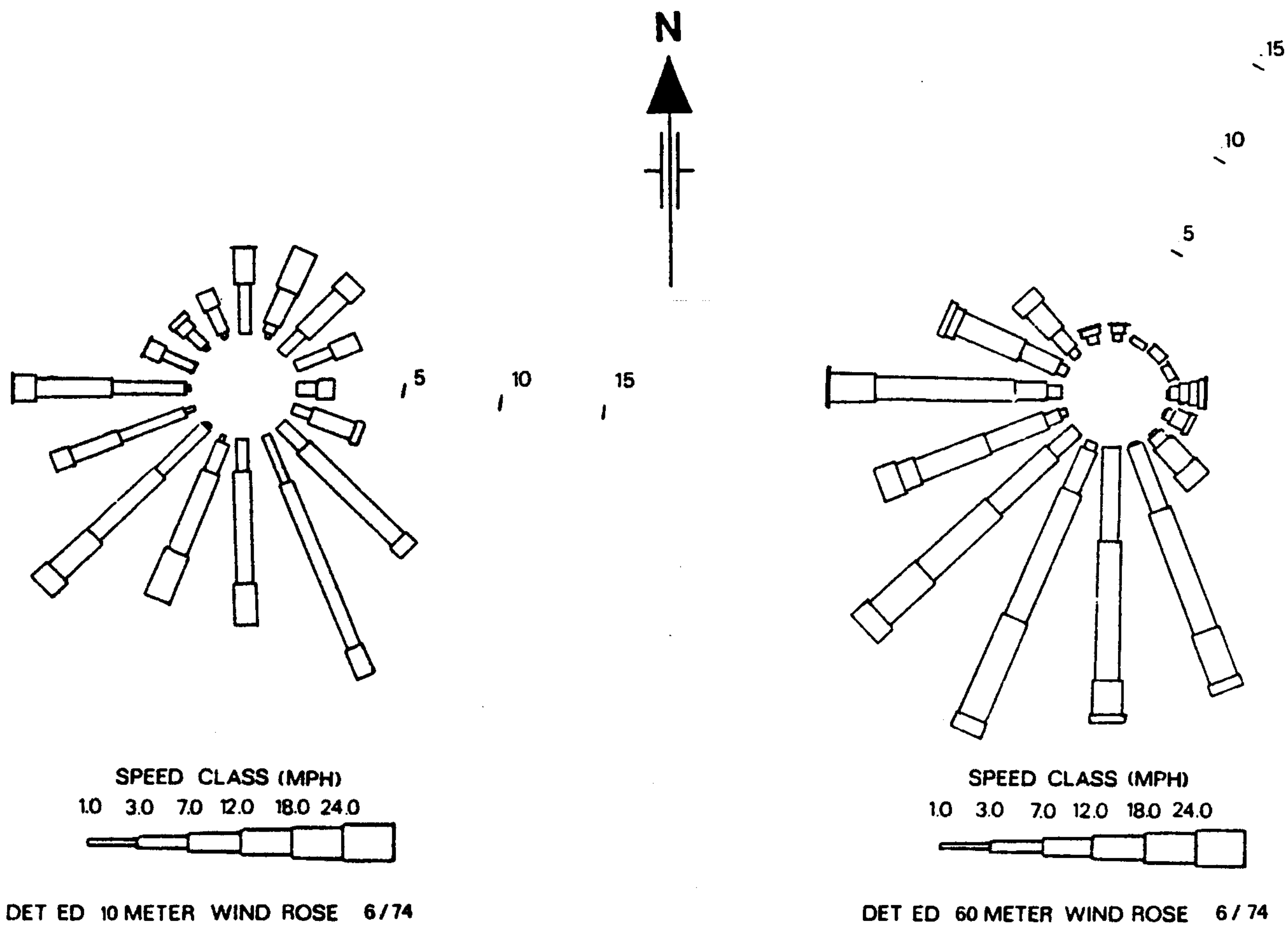

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FIGURE 2.3-3

WIND ROSE DATA FOR JUNE 1974

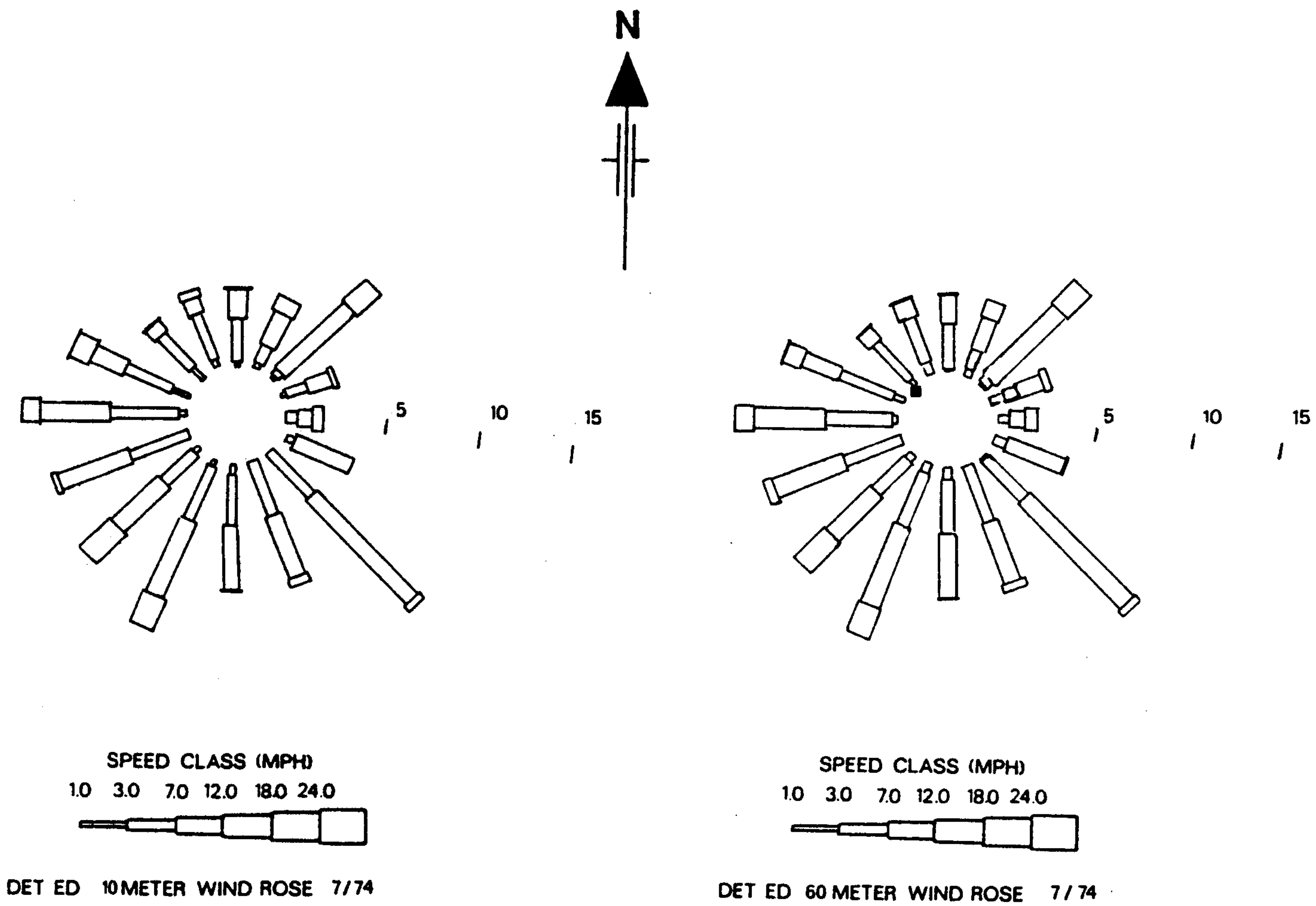

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FIGURE 2.3-4

WIND ROSE DATA FOR JULY 1974

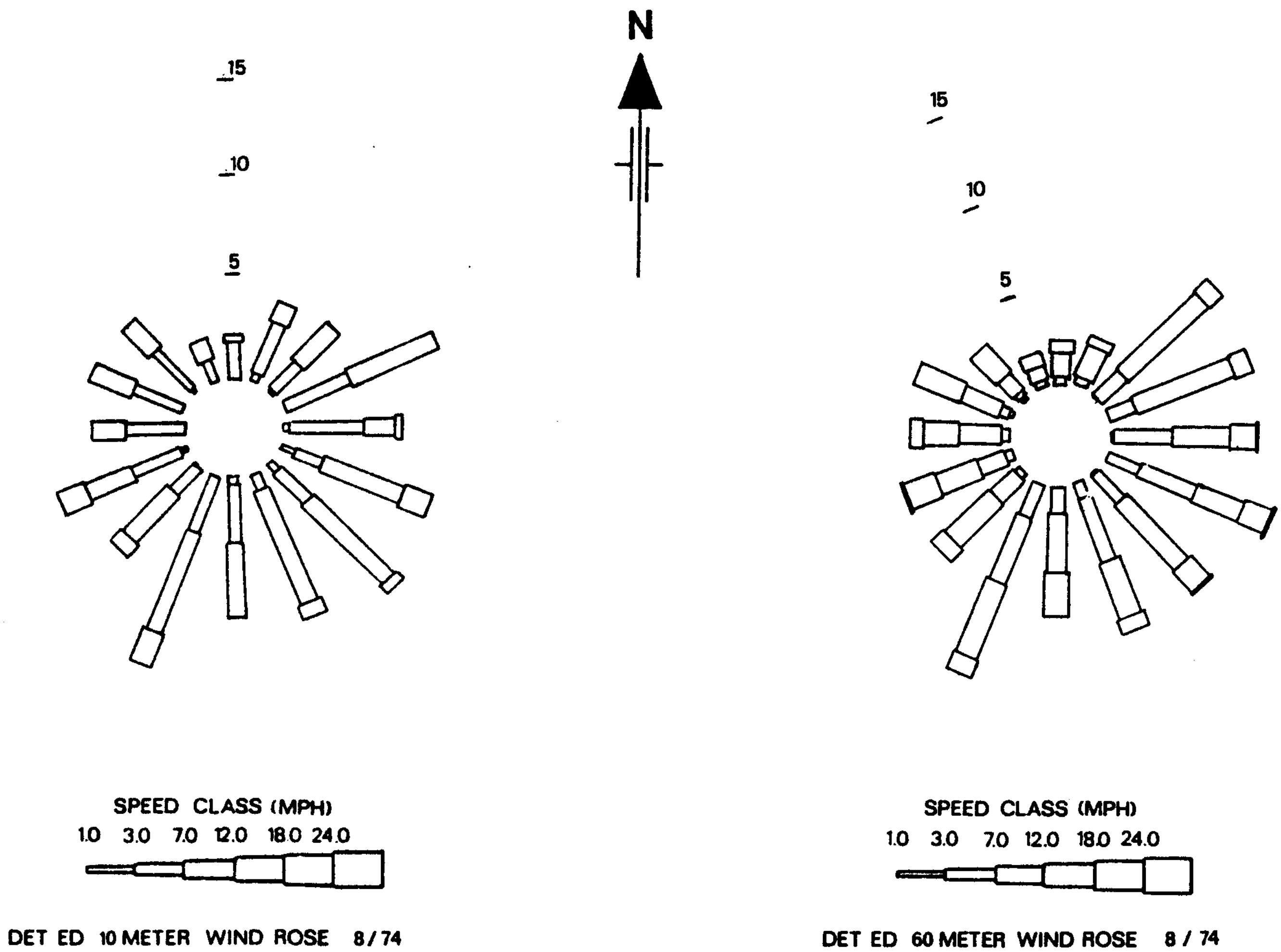

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FIGURE 2.3-5

WIND ROSE DATA FOR AUGUST 1974

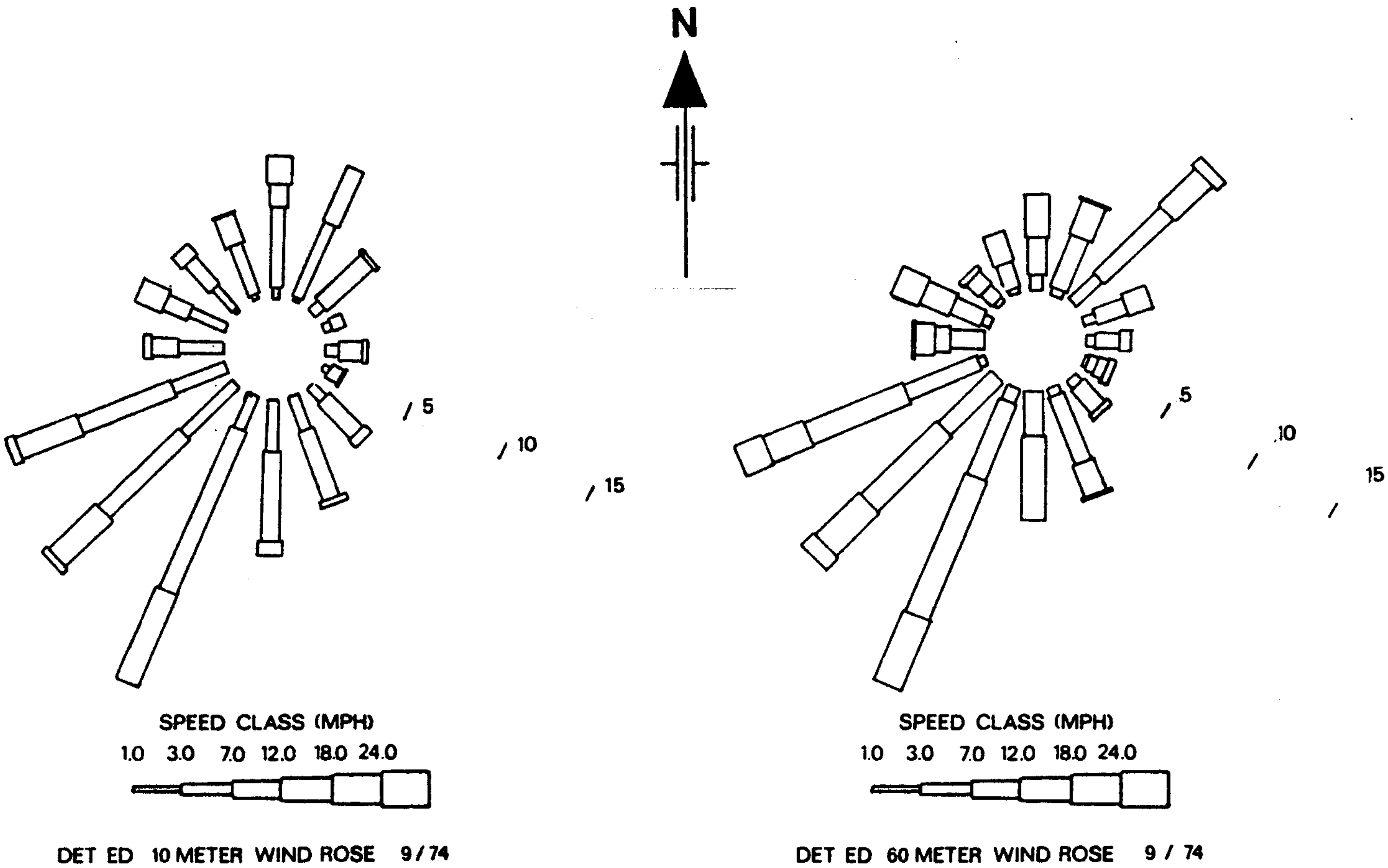

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FIGURE 2.3-6

WIND ROSE DATA FOR SEPTEMBER 1974

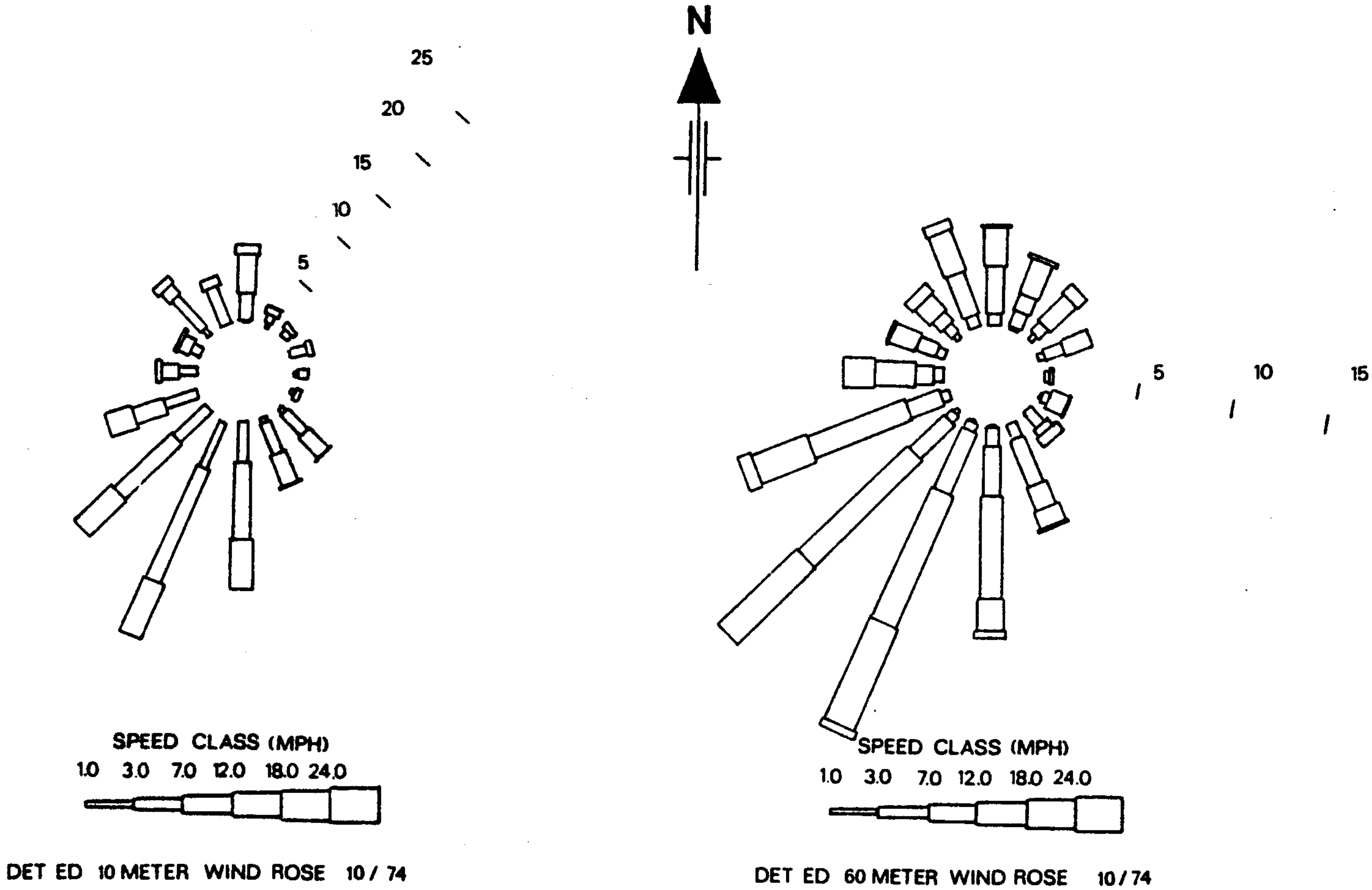

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FIGURE 2.3-7

WIND ROSE DATA FOR OCTOBER 1974

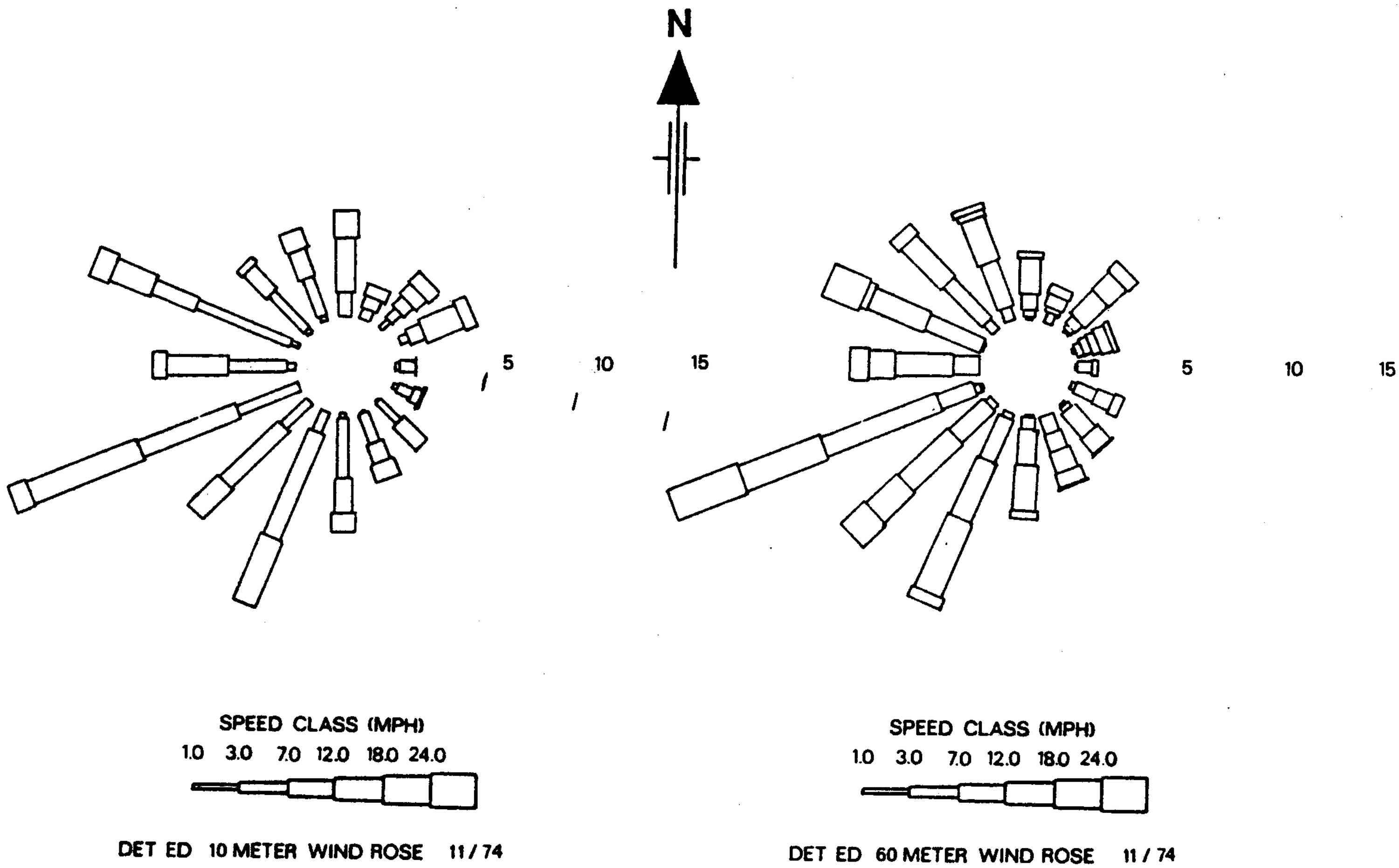

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FIGURE 2.3-8

WIND ROSE DATA FOR NOVEMBER 1974

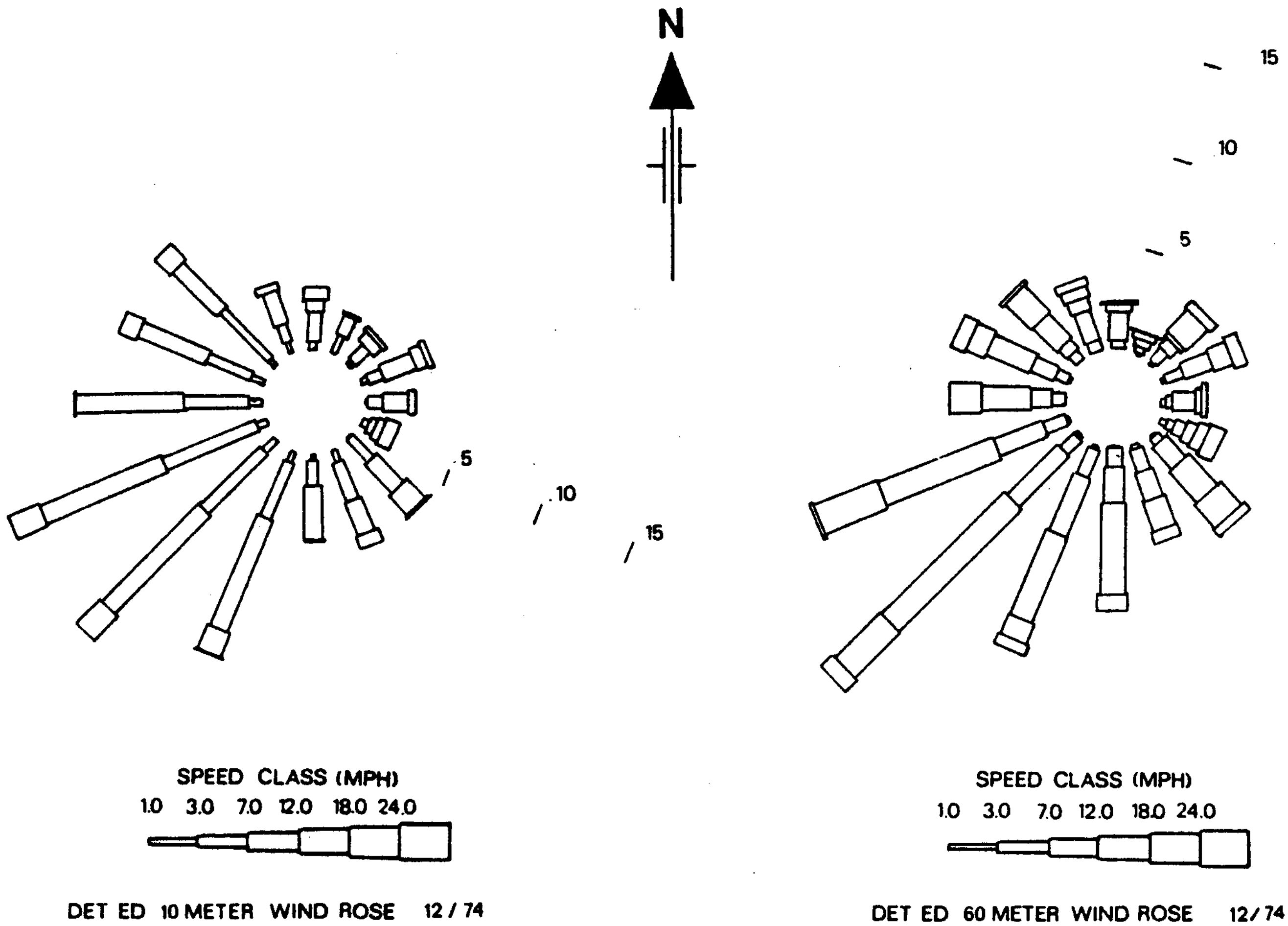

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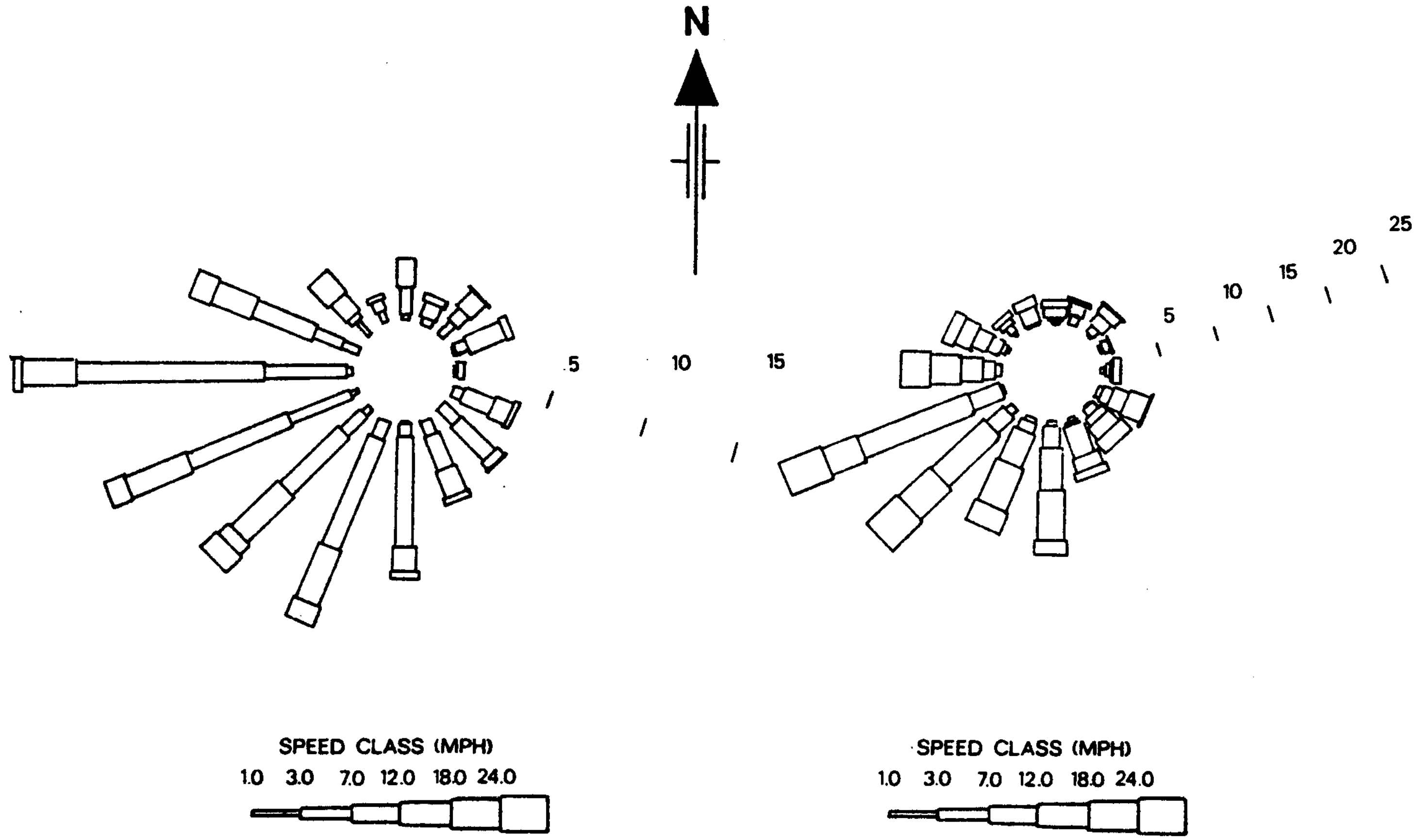
FIGURE 2.3-9

WIND ROSE DATA FOR DECEMBER 1974



DET ED 10 METER WIND ROSE 1/75

DET ED 60 METER WIND ROSE 1/75

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FIGURE 2.3-10

WIND ROSE DATA FOR JANUARY 1975

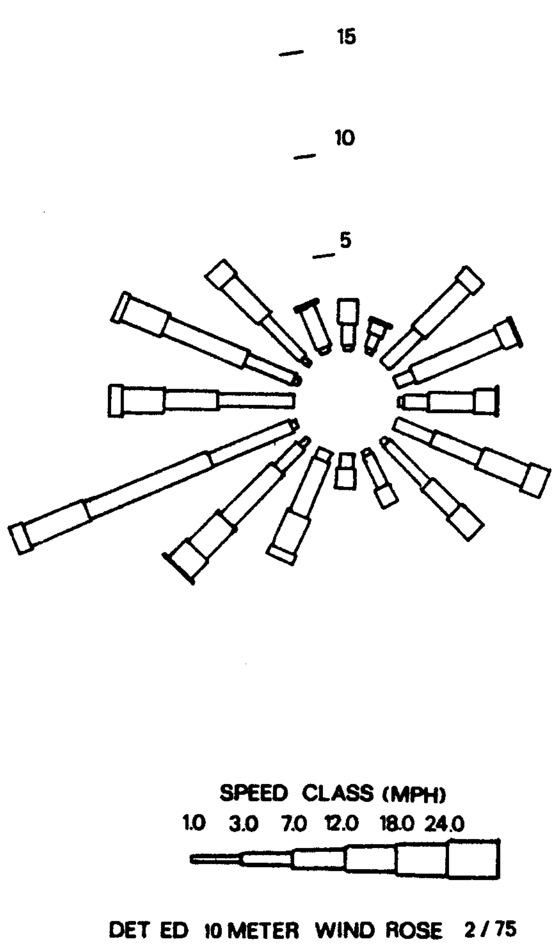

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FIGURE 2.3-11

WIND ROSE DATA FOR FEBRUARY 1975

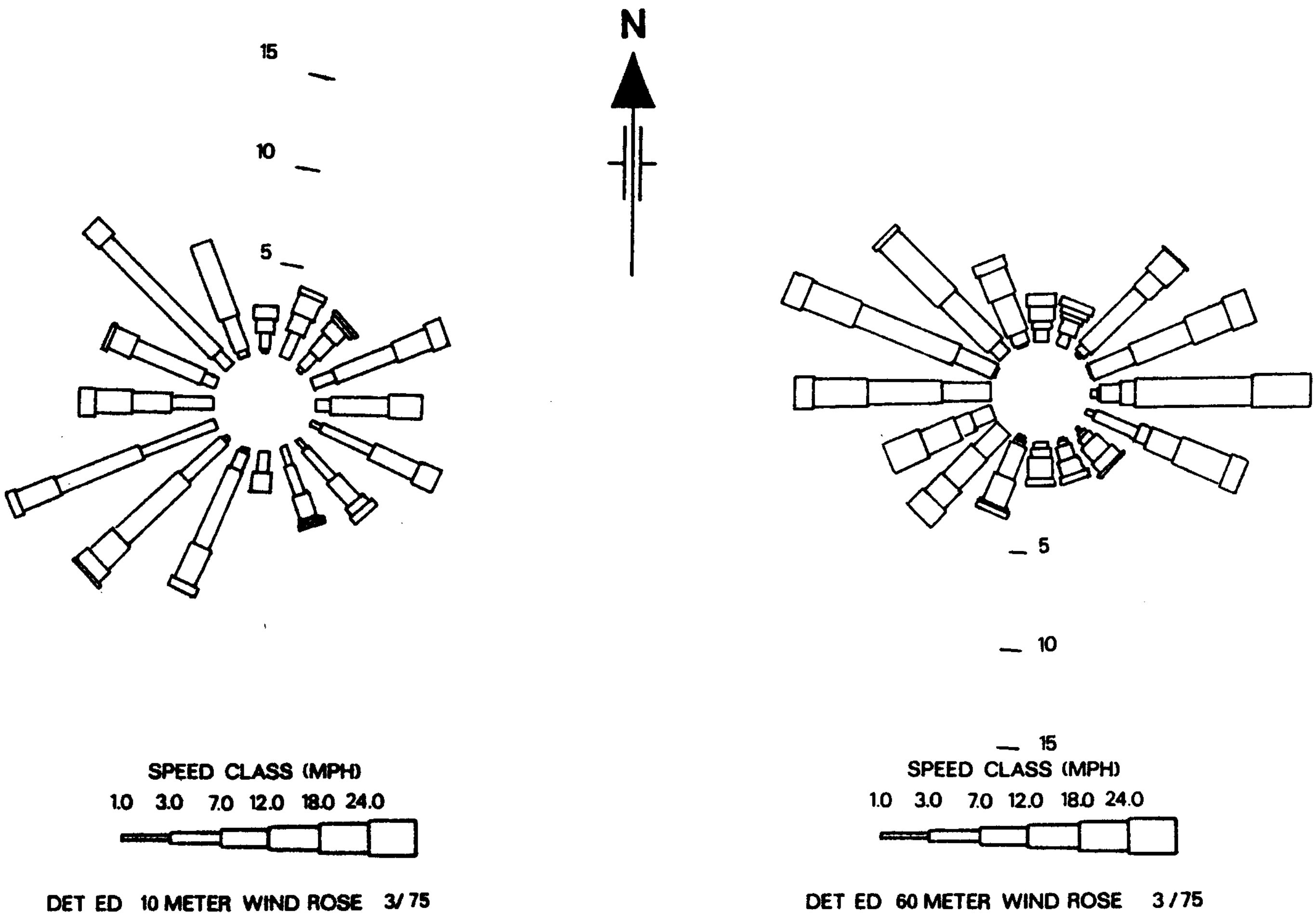

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FIGURE 2.3-12

WIND ROSE DATA FOR MARCH 1975

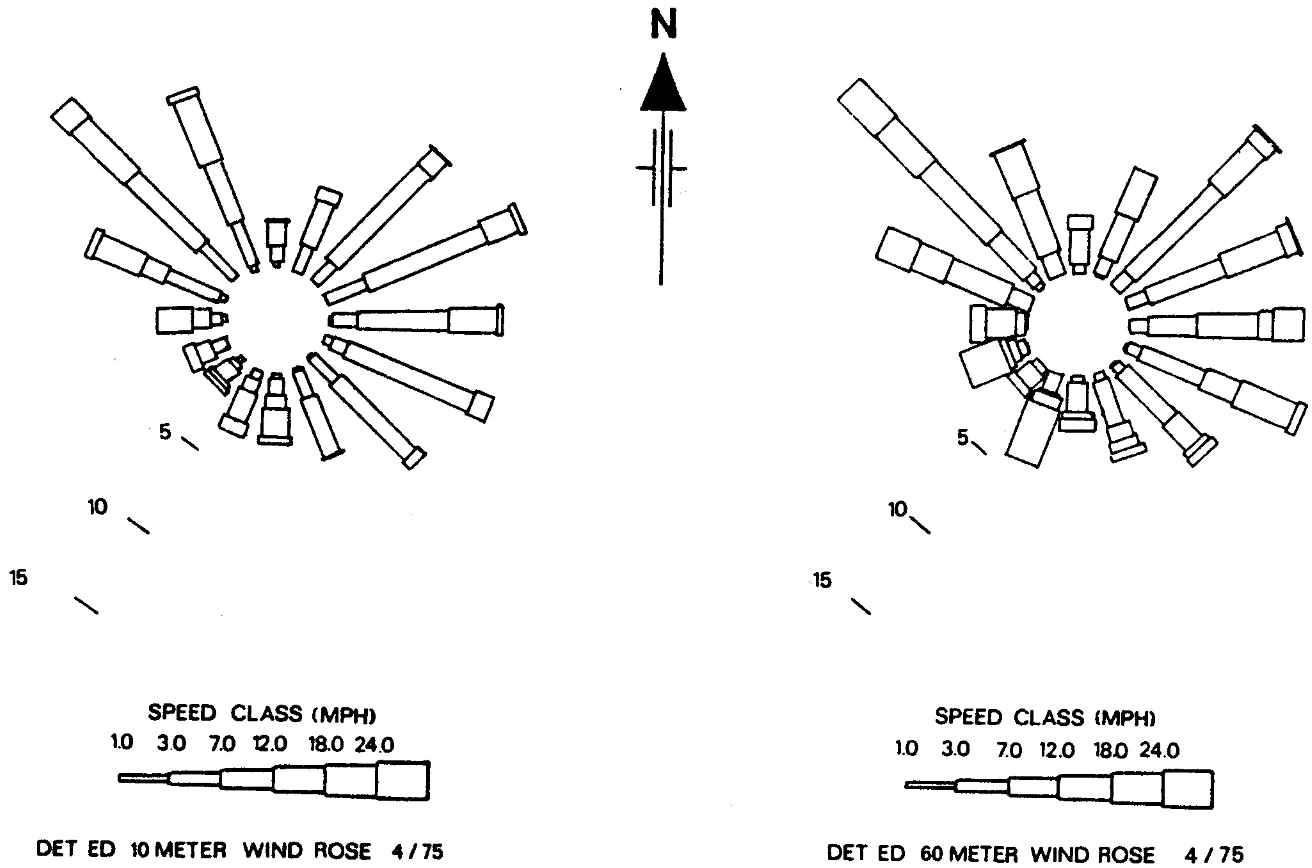

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FIGURE 2.3-13

WIND ROSE DATA FOR APRIL 1975

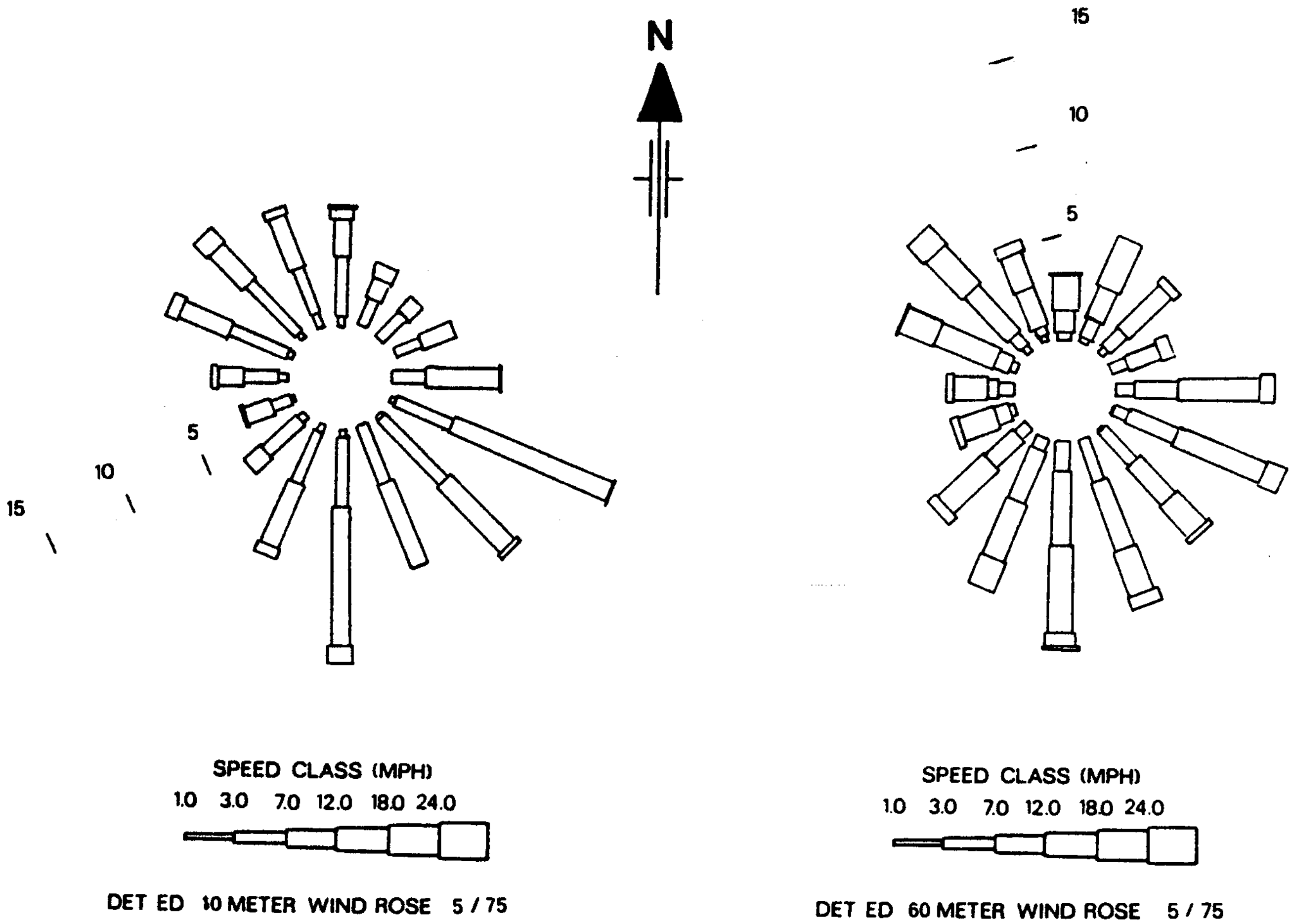

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FIGURE 2.3-14

WIND ROSE DATA FOR MAY 1975

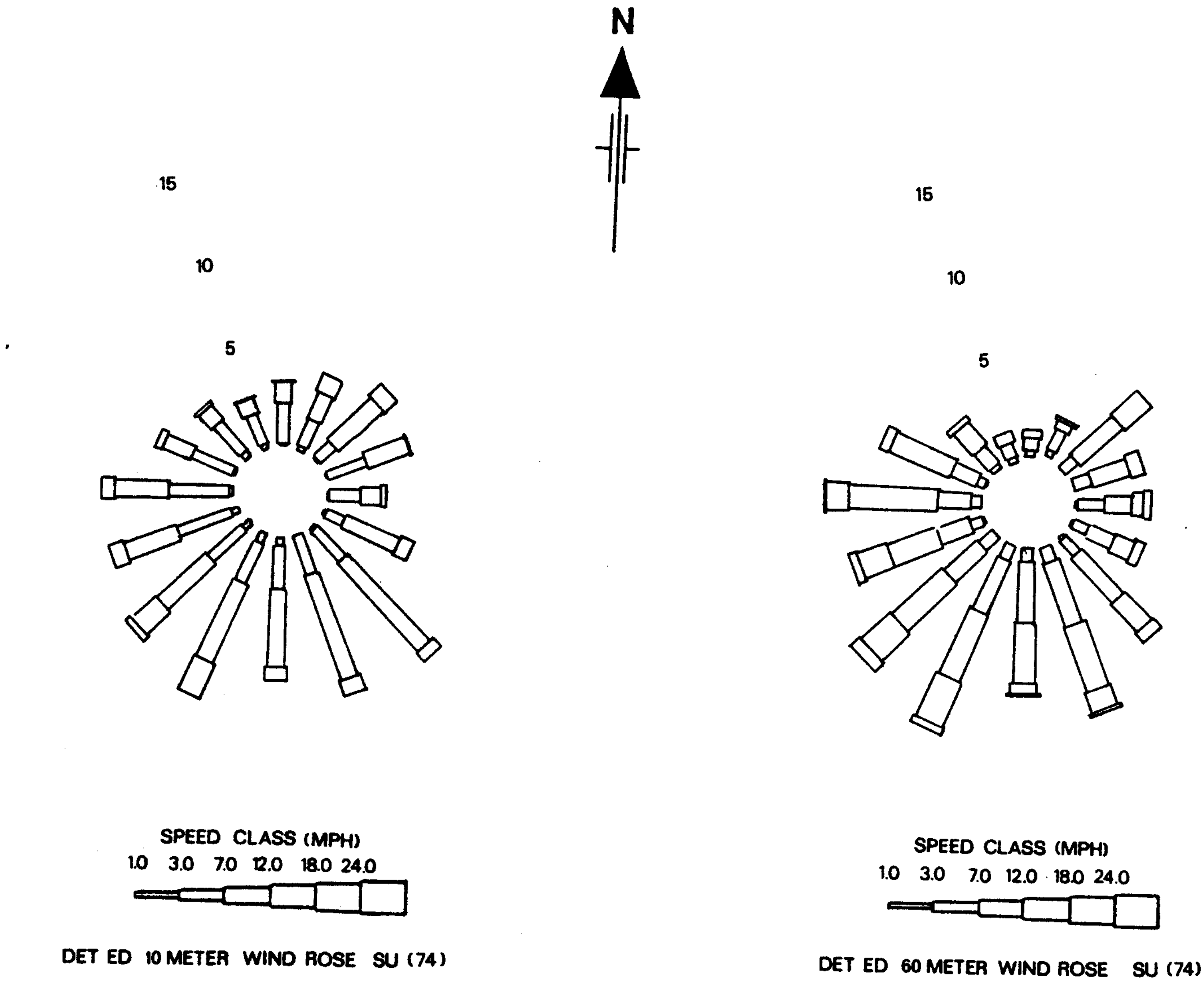

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FIGURE 2.3-15

FERMI SITE WIND ROSE DATA FOR SUMMER 1974

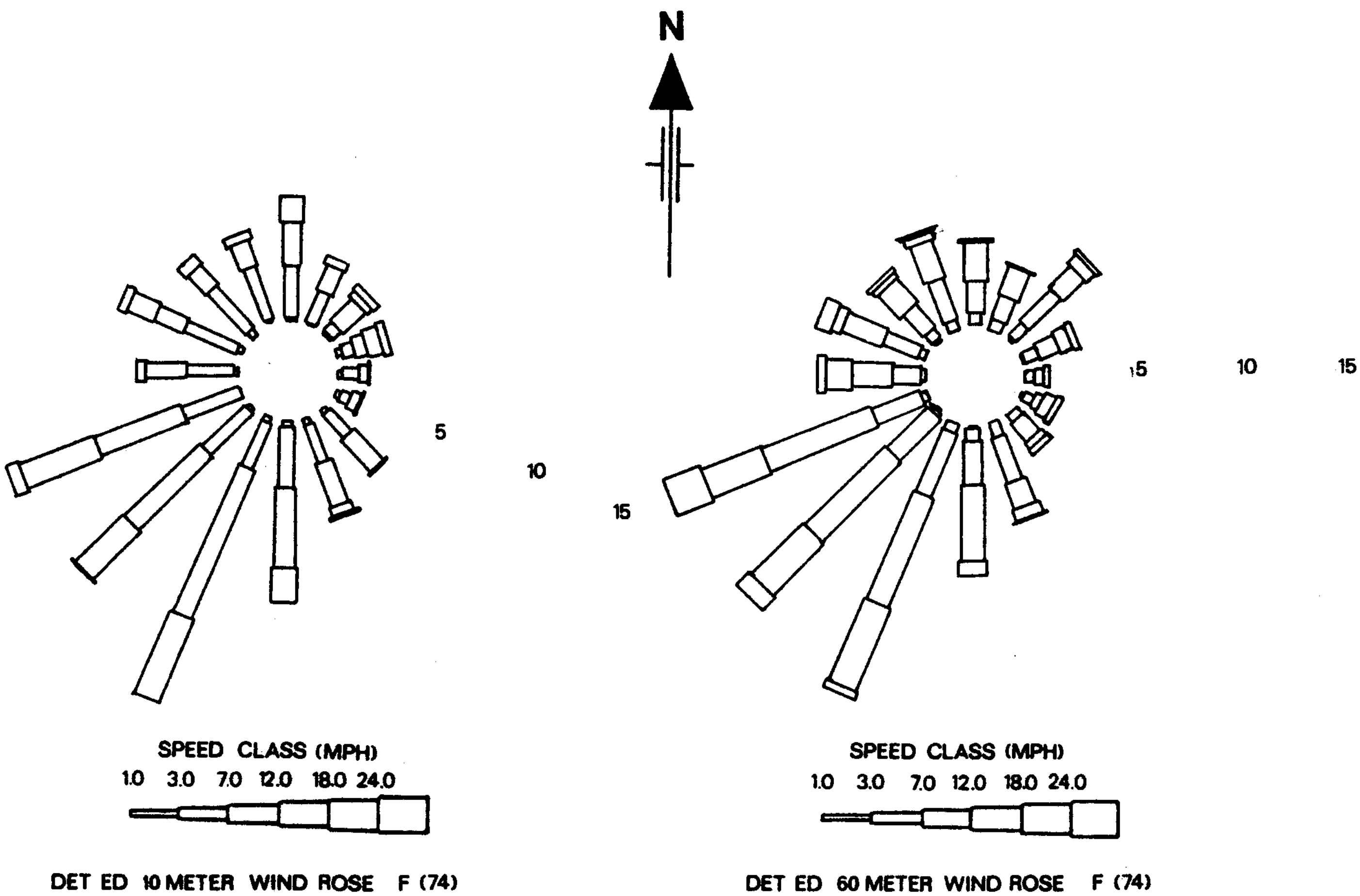

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FIGURE 2.3-16

FERMI SITE WIND ROSE DATA FOR FALL 1974/75

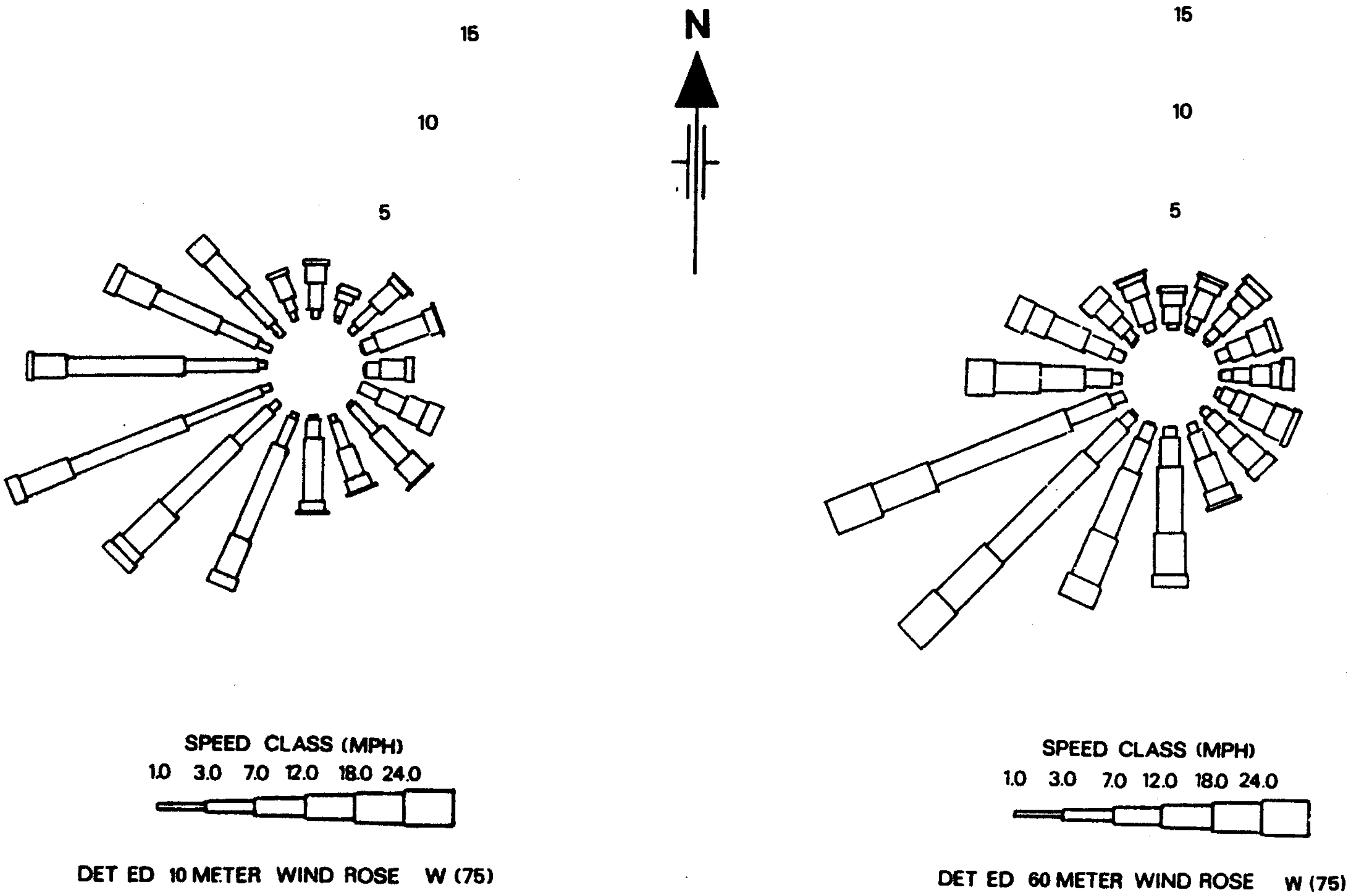

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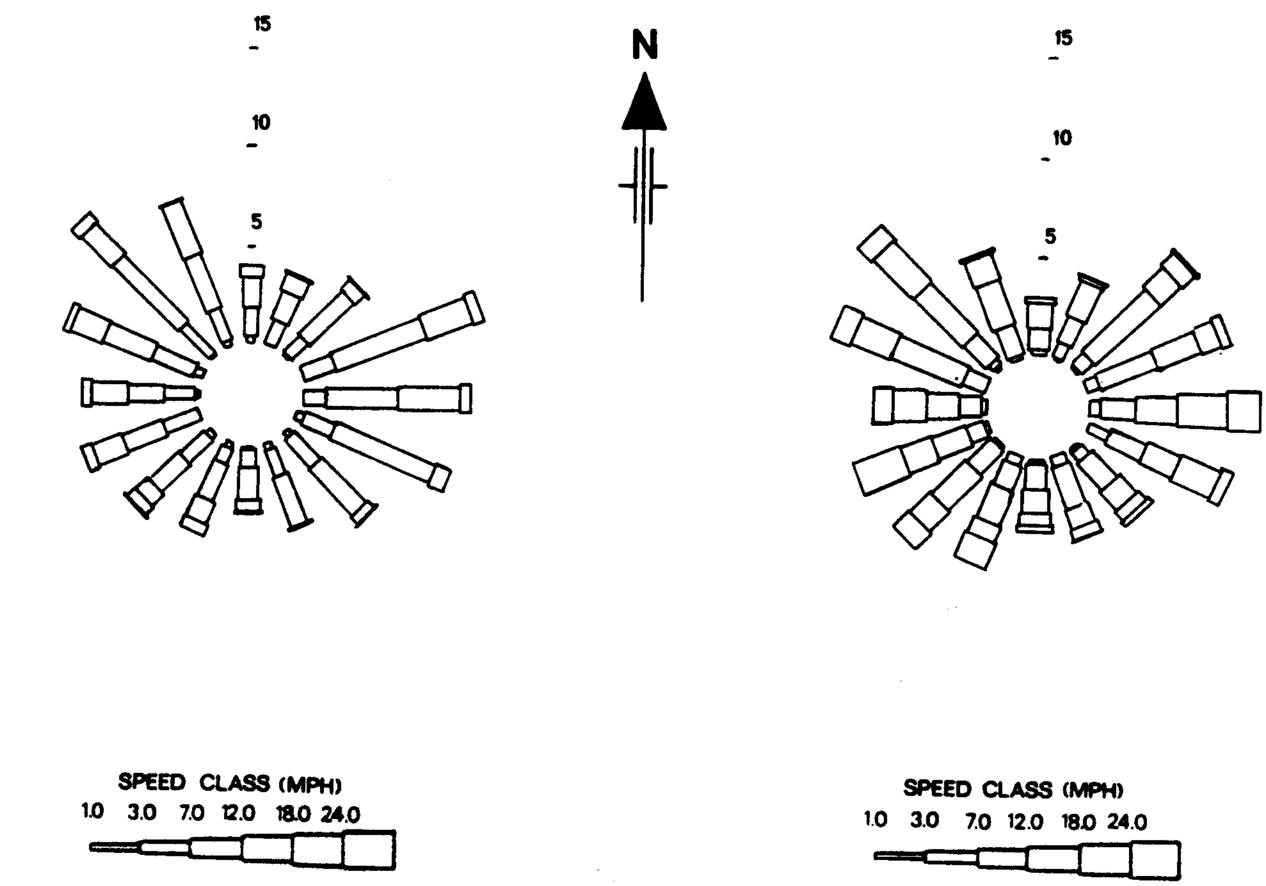
FIGURE 2.3-17

FERMI SITE WIND ROSE DATA FOR WINTER 1975



DET ED 10 METER WIND ROSE SP 75

DET ED 60 METER WIND ROSE SP 75

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FIGURE 2.3-18

FERMI SITE WIND ROSE DATA FOR SPRING 1975

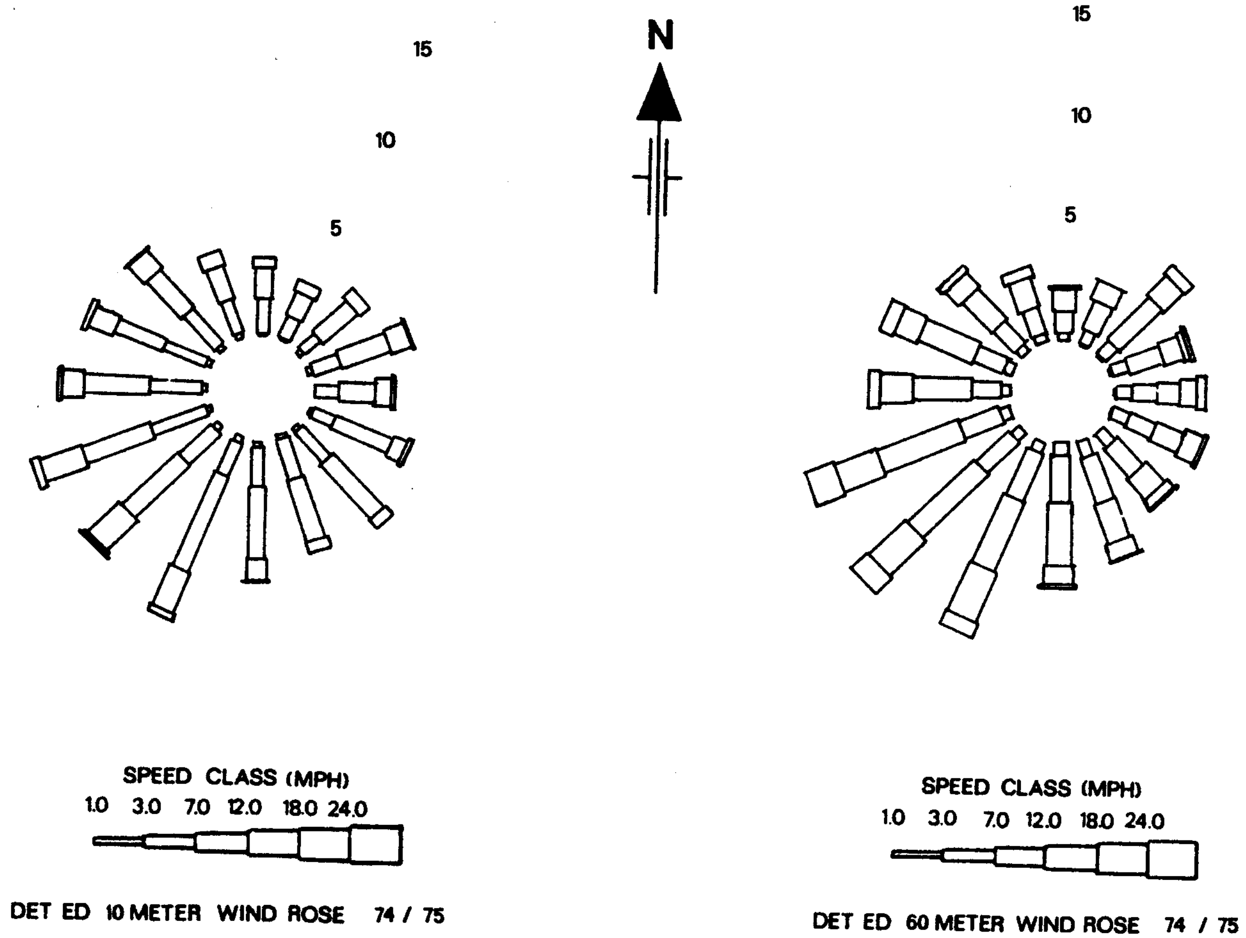

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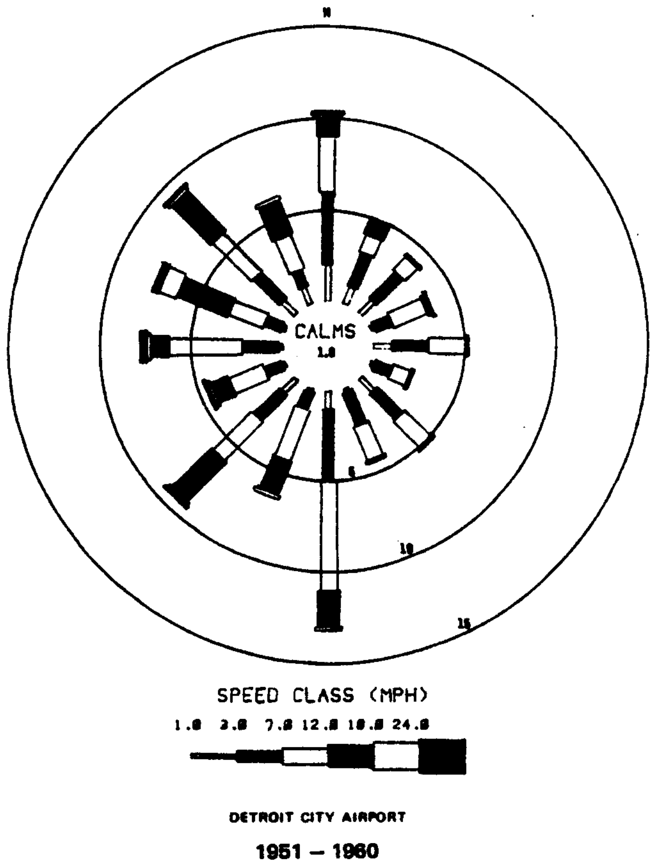
FIGURE 2.3-19

FERMI SITE WIND ROSE DATA FOR ANNUAL PERIOD 1 JUNE 1974 – 31 MAY 1975



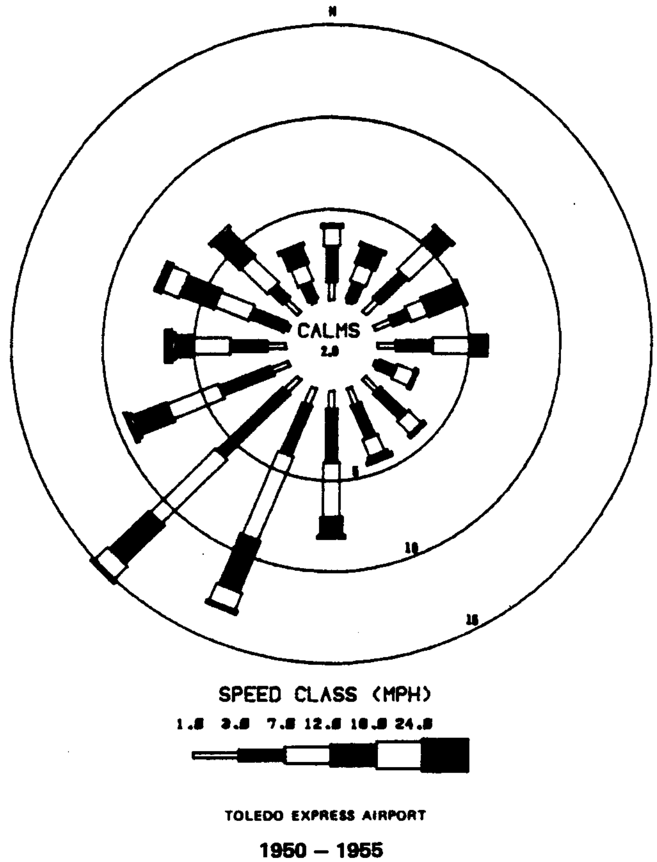


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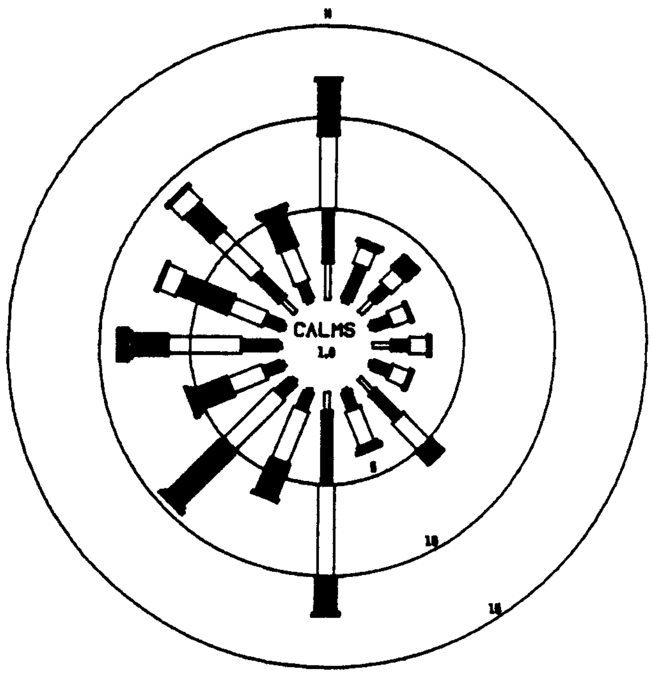
FIGURE 2.3-20

WIND ROSE DATA FOR SEPTEMBER

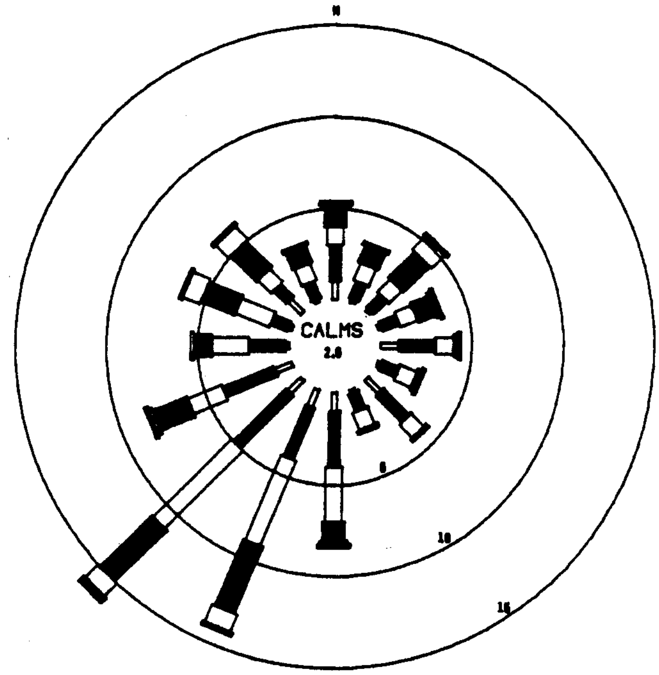


SPEED CLASS (MPH)

1.0 3.0 7.0 12.0 18.0 24.0

DETROIT CITY AIRPORT

1951 – 1960



SPEED CLASS (MPH)

1.0 3.0 7.0 12.0 18.0 24.0

TOLEDO EXPRESS AIRPORT

1950 – 1955

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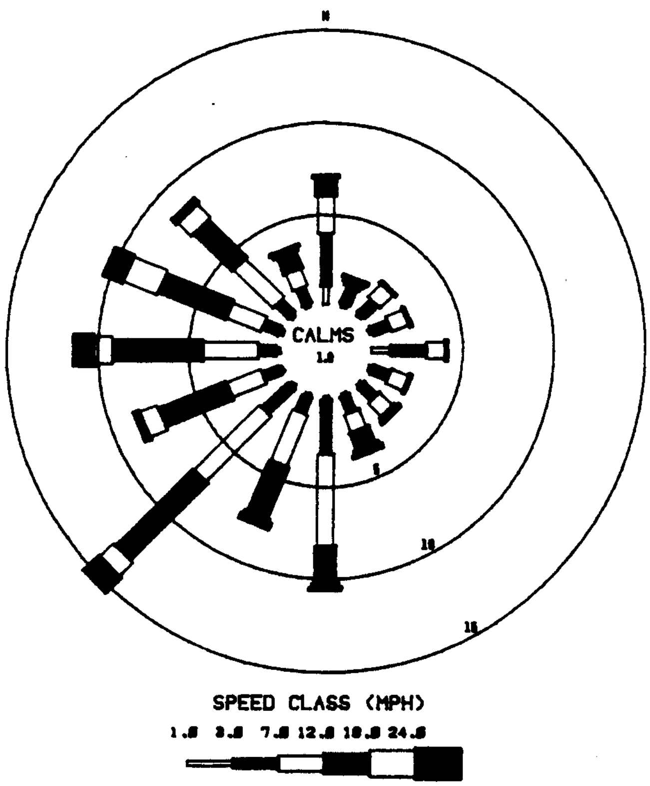
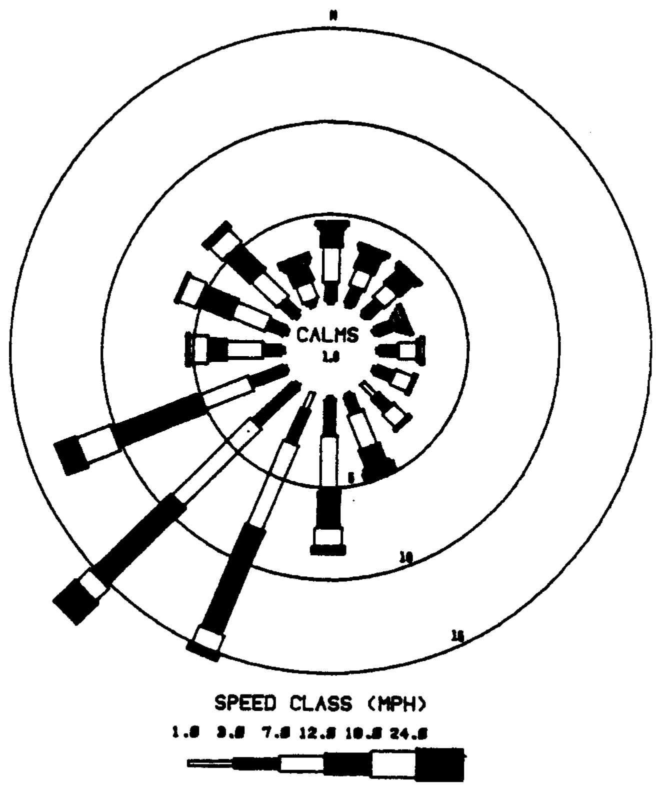
FIGURE 2.3-21

WIND ROSE DATA FOR OCTOBER



DETROIT CITY AIRPORT

1951 – 1960



TOLEDO EXPRESS AIRPORT

1950 – 1955

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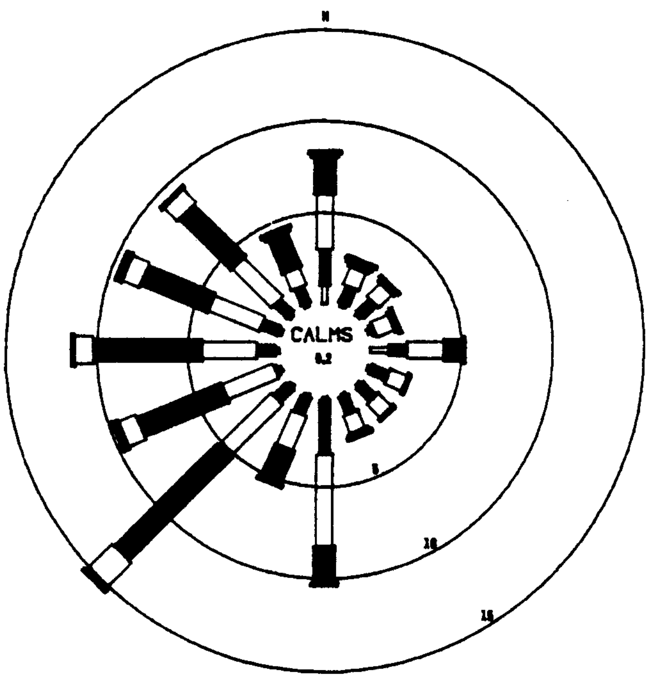
FIGURE 2.3-22

WIND ROSE DATA FOR NOVEMBER

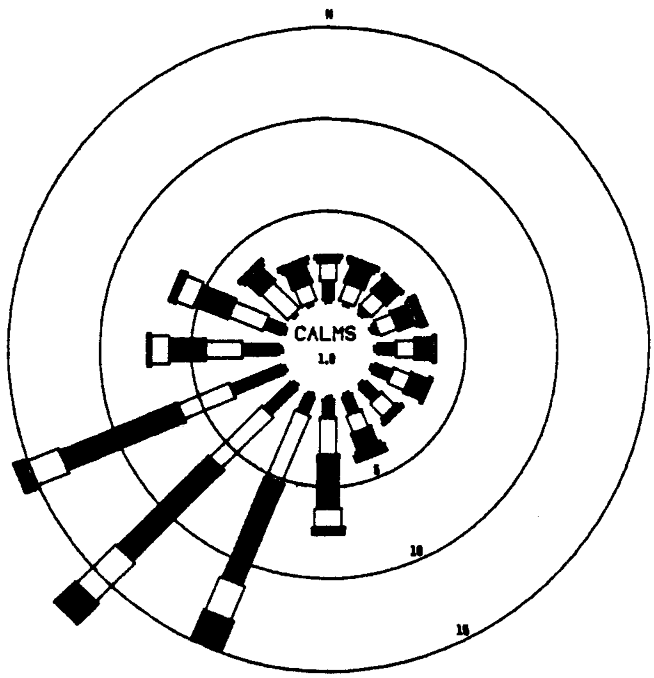


SPEED CLASS (MPH)

1.0 3.0 7.0 12.0 18.0 24.0

DETROIT CITY AIRPORT

1951 – 1960



SPEED CLASS (MPH)

1.0 3.0 7.0 12.0 18.0 24.0

TOLEDO EXPRESS AIRPORT

1950 – 1955

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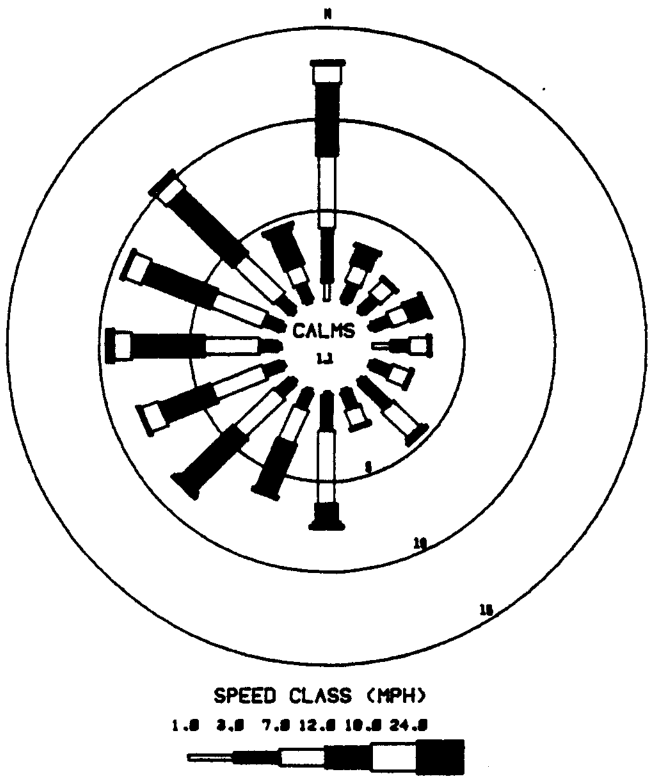
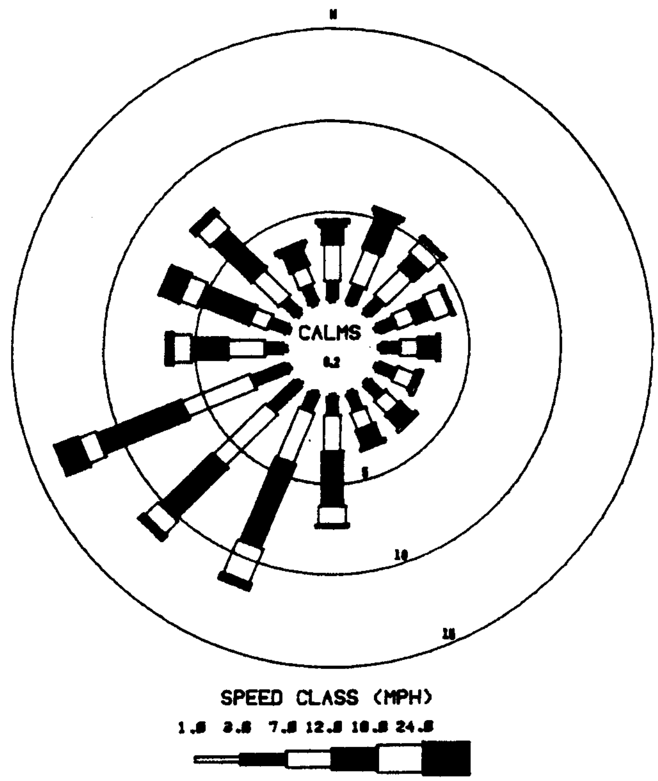
FIGURE 2.3-23

WIND ROSE DATA FOR DECEMBER



DETROIT CITY AIRPORT

1951 – 1960



TOLEDO EXPRESS AIRPORT

1950 – 1955

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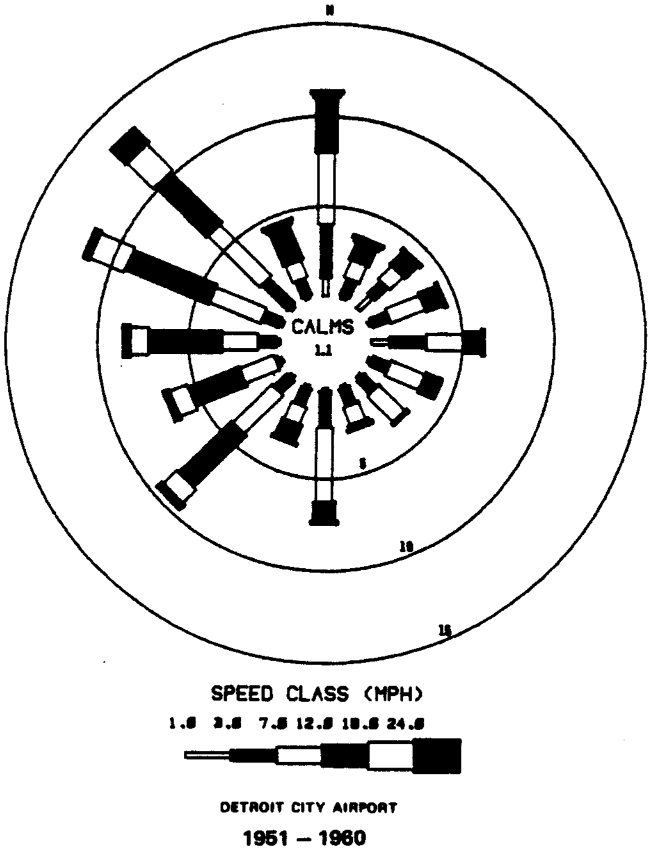
FIGURE 2.3-24

WIND ROSE DATA FOR JANUARY



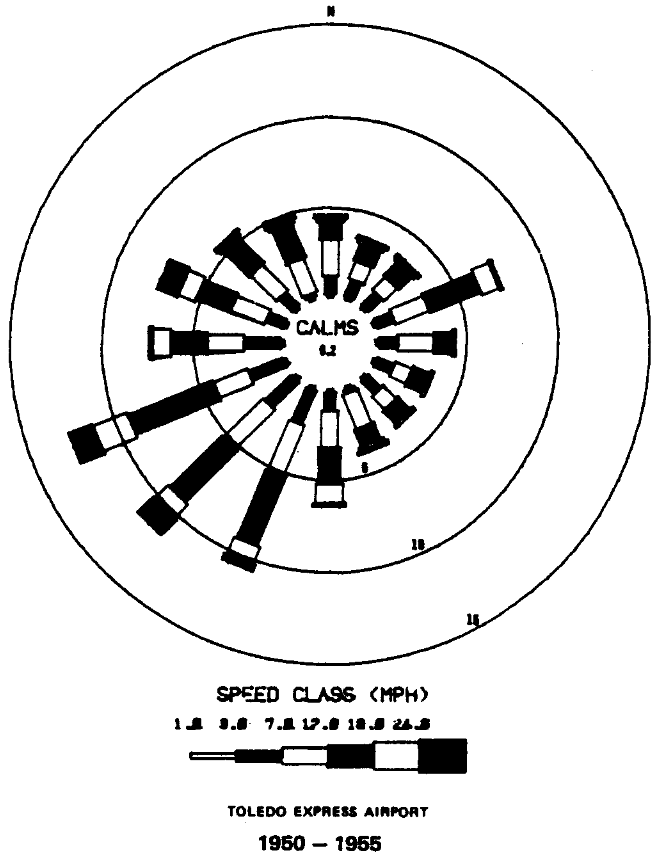


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FIGURE 2.3-25

WIND ROSE DATA FOR FEBRUARY

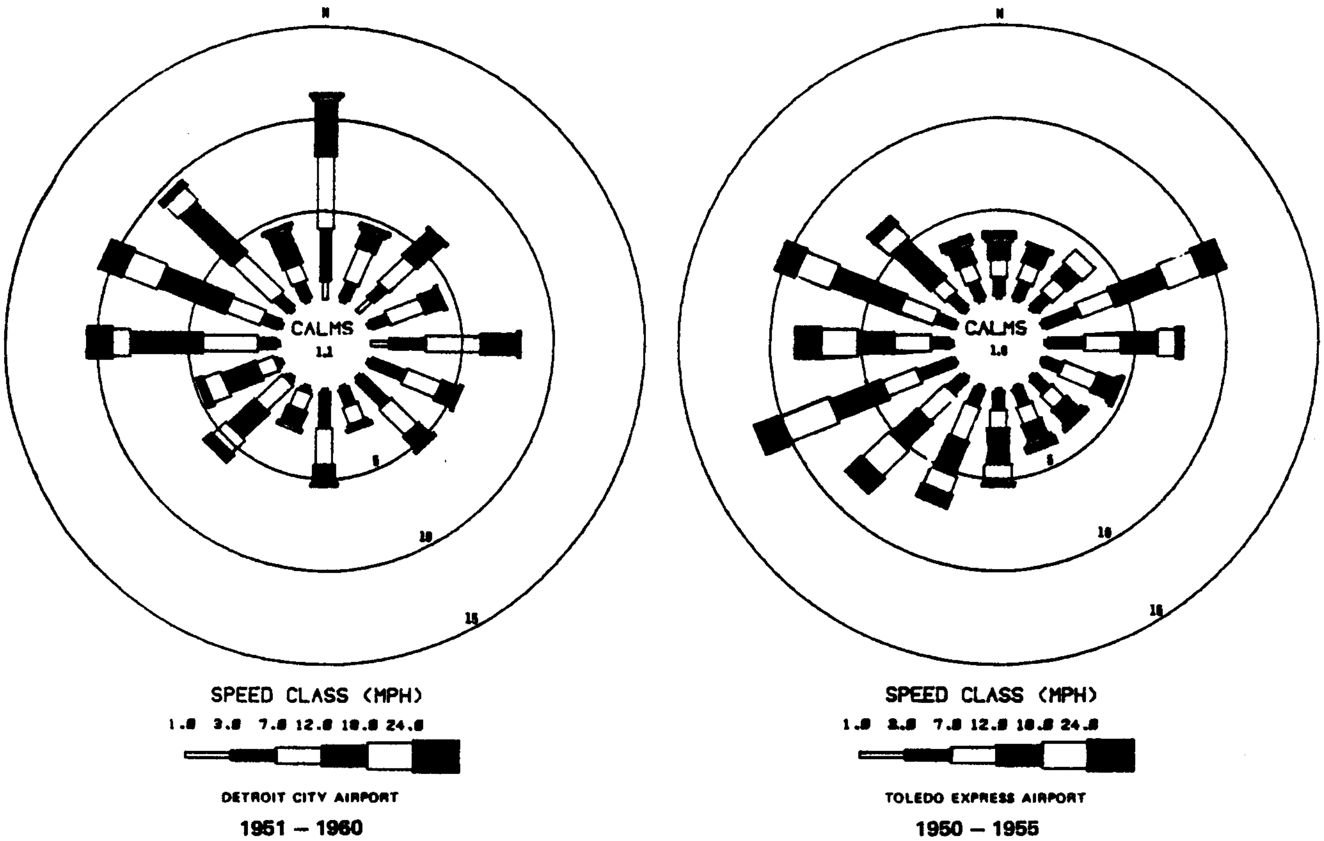

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FIGURE 2.3-26

WIND ROSE DATA FOR MARCH

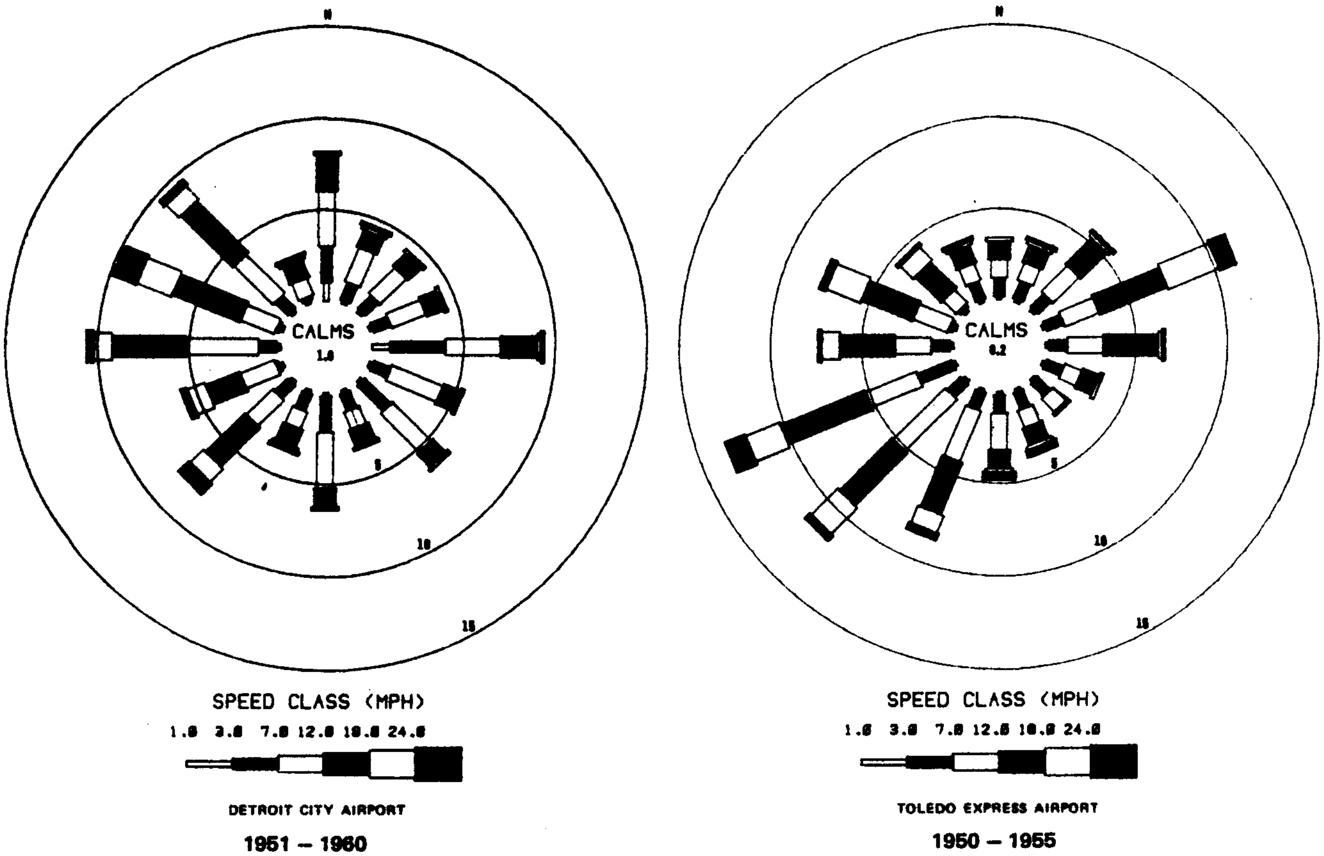

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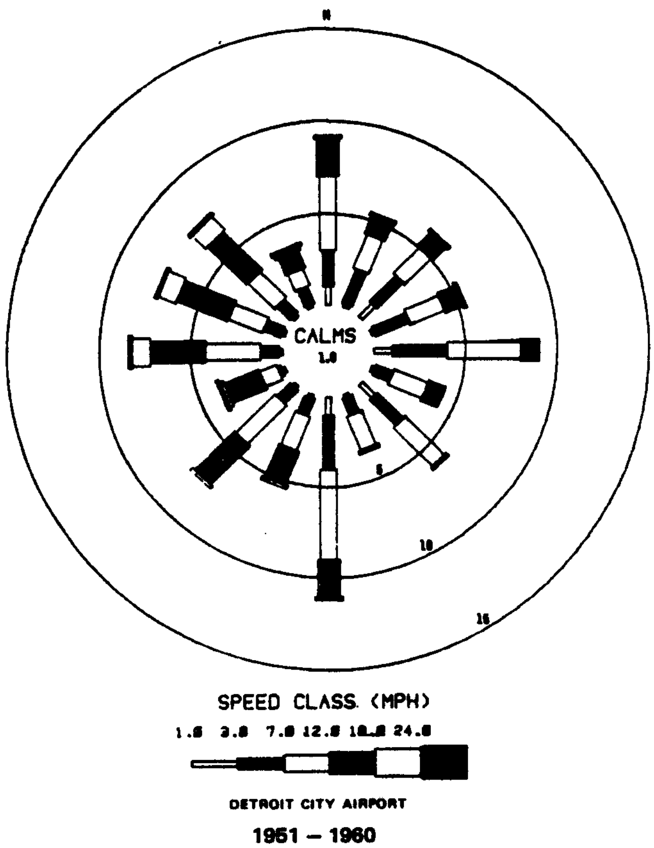
FIGURE 2.3-27

WIND ROSE DATA FOR APRIL



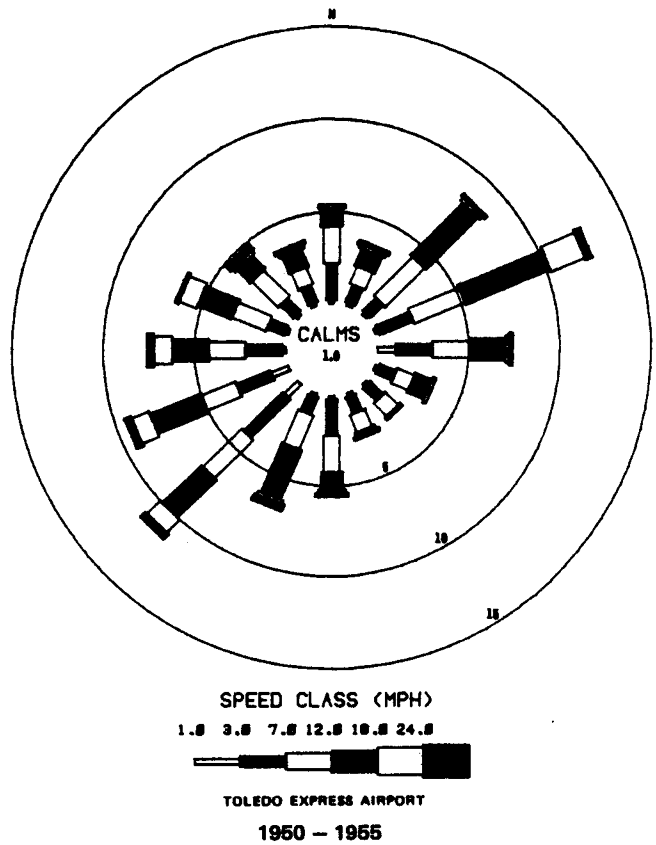


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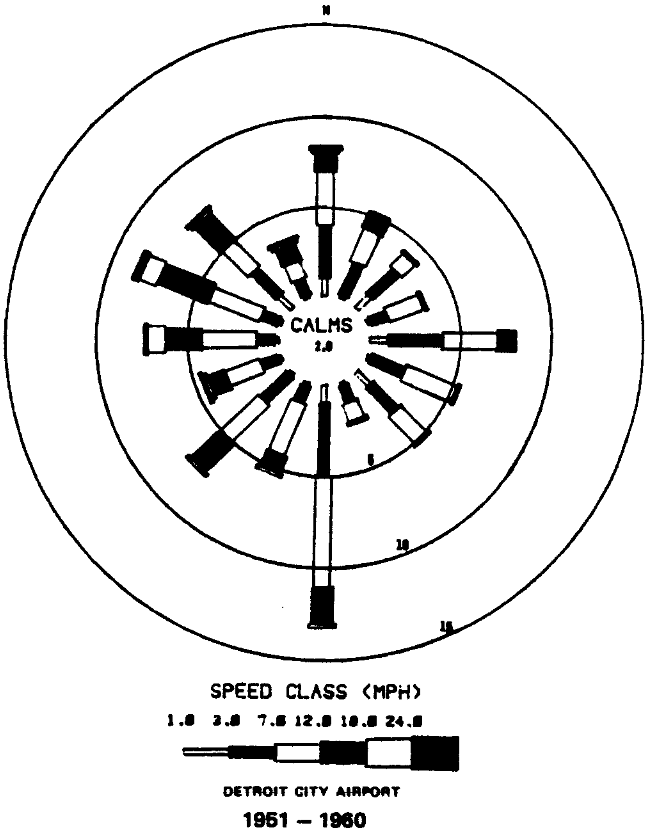
FIGURE 2.3-28

WIND ROSE DATA FOR MAY



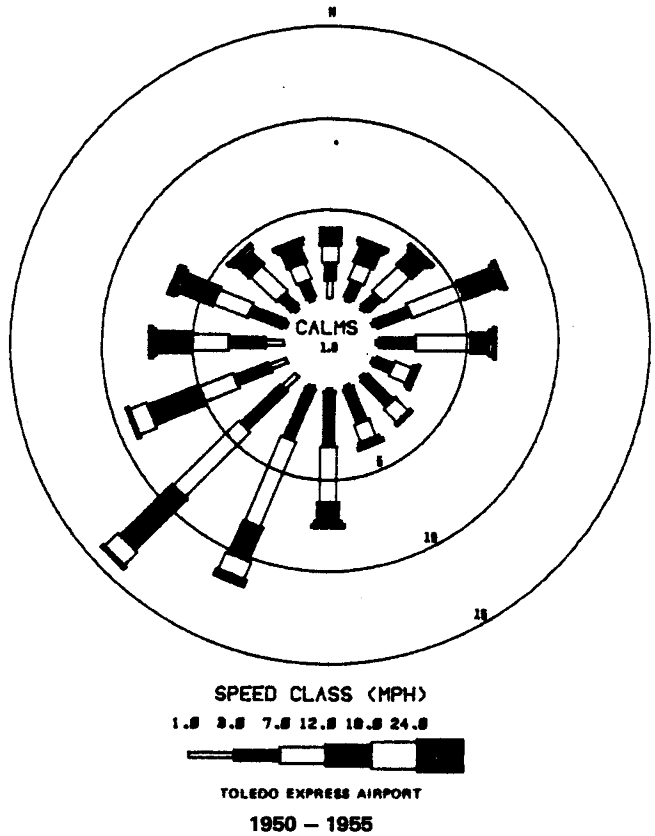


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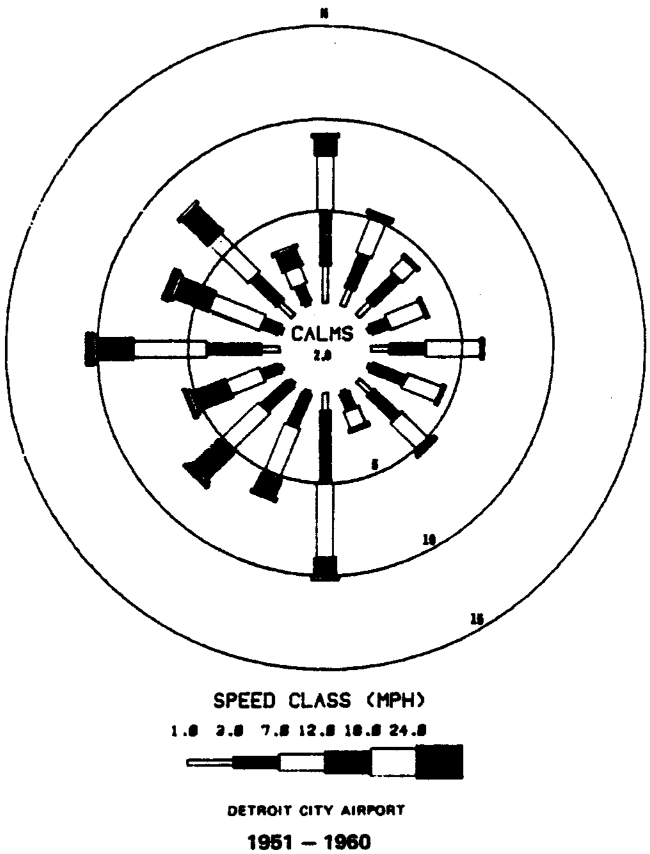
FIGURE 2.3-29

WIND ROSE DATA FOR JUNE



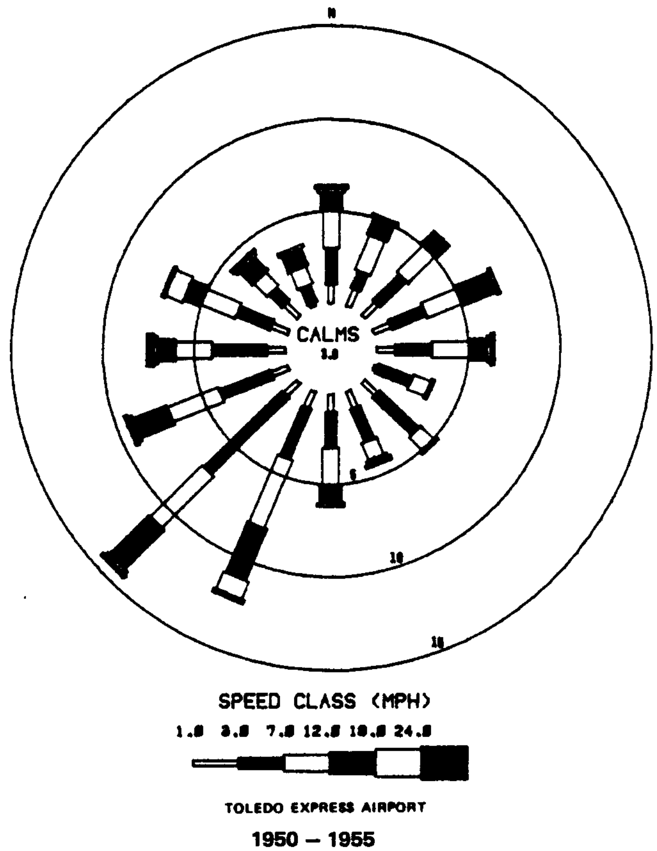


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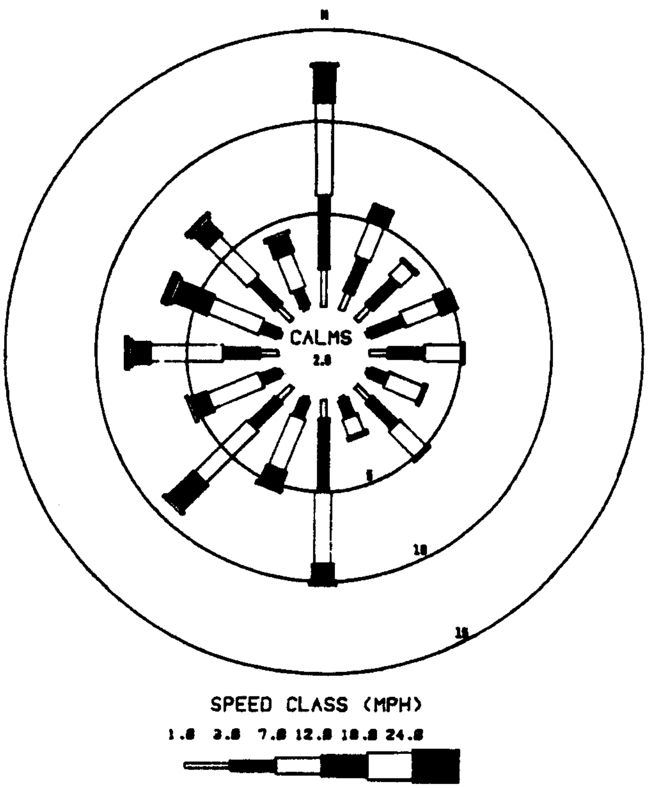
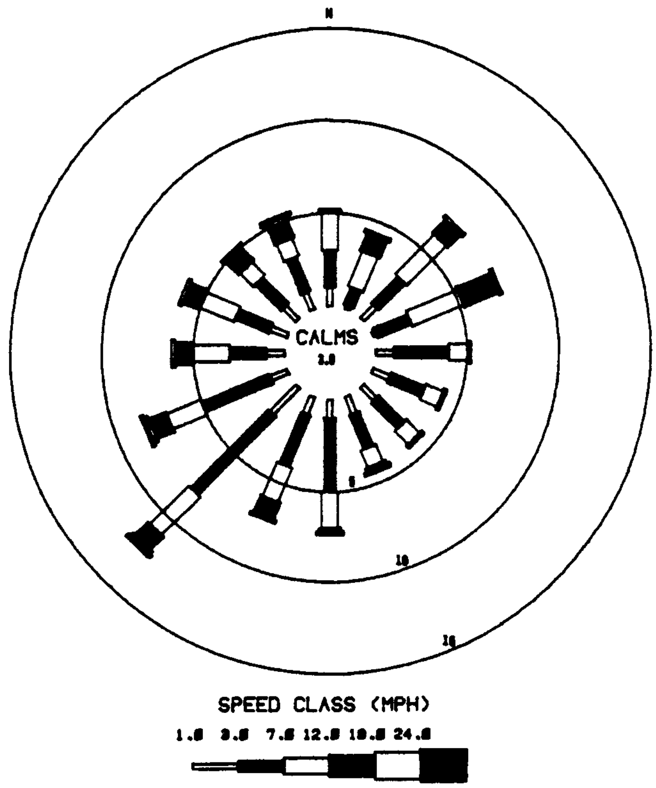
FIGURE 2.3-30

WIND ROSE DATA FOR JULY



DETROIT CITY AIRPORT

1951 – 1960



TOLEDO EXPRESS AIRPORT

1950 – 1955

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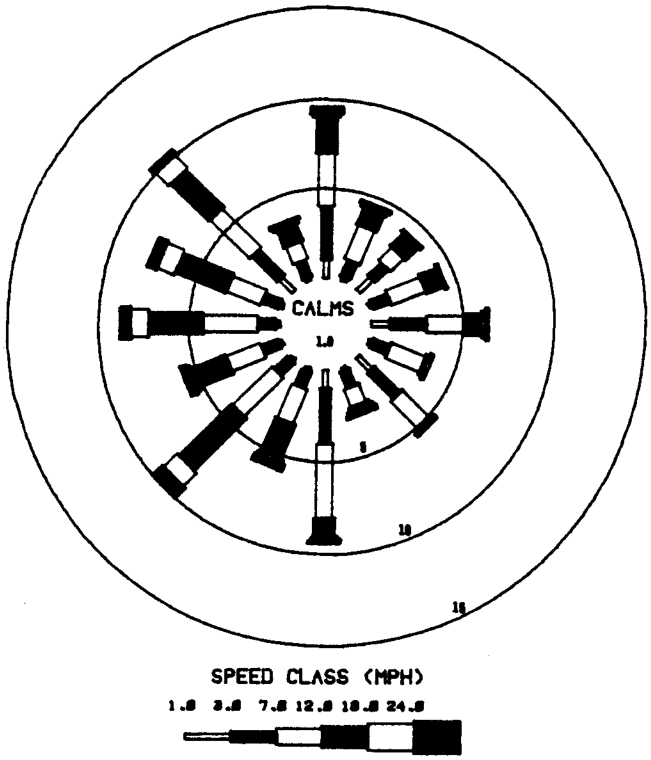
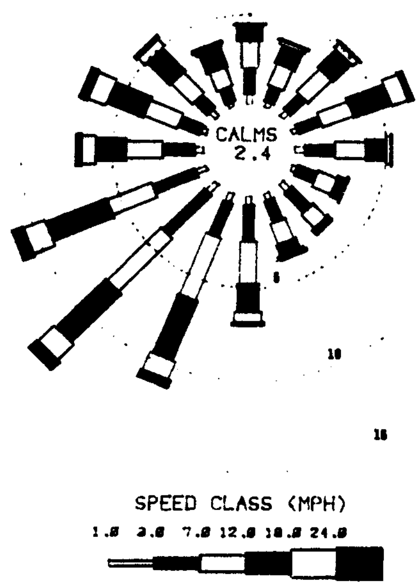
FIGURE 2.3-31

WIND ROSE DATA FOR AUGUST



DETROIT CITY AIRPORT
1951 – 1960



TOLEDO EXPRESS AIRPORT
1950 – 1955

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FIGURE 2.3-32

ANNUAL WIND ROSE DATA

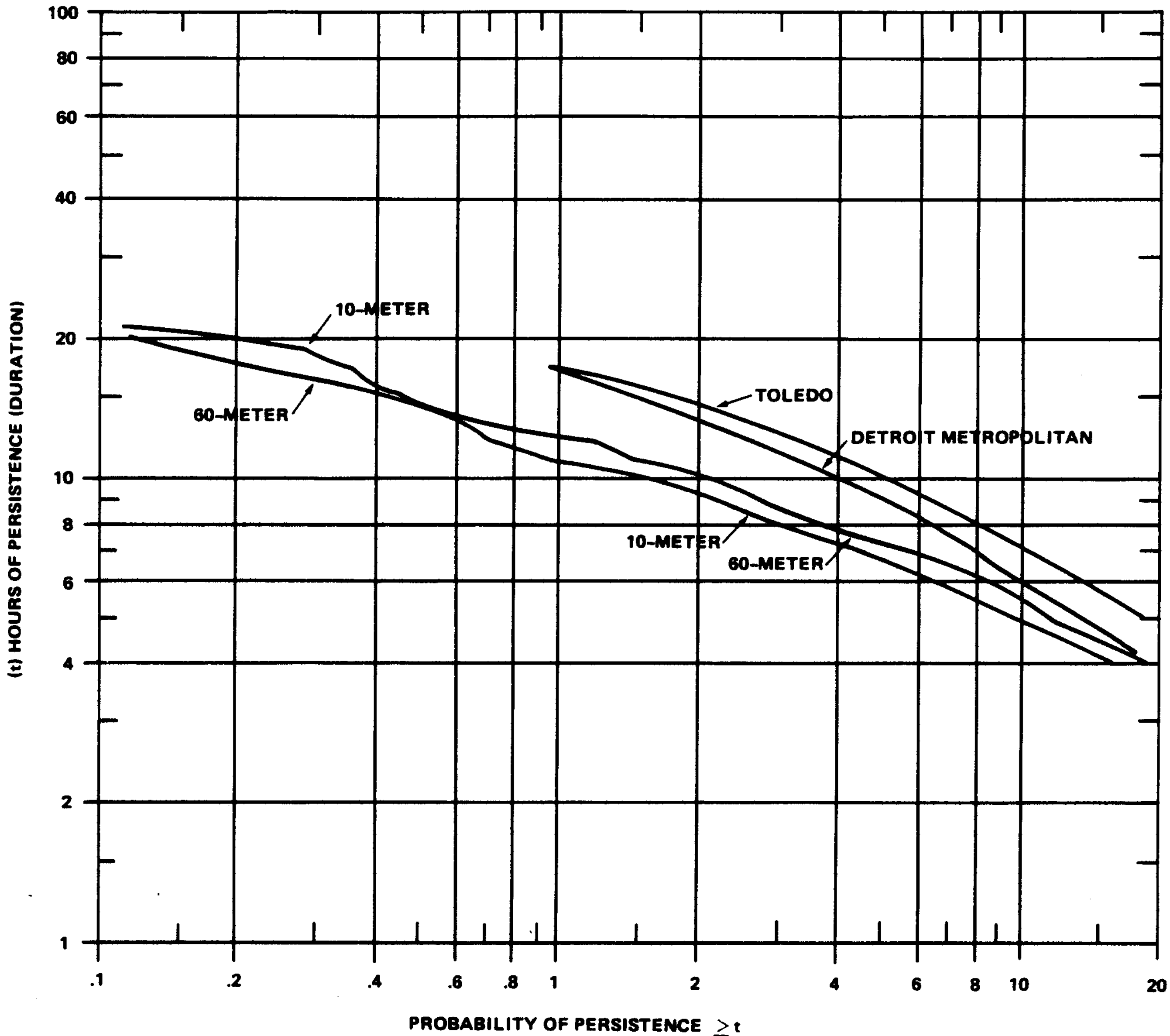

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FIGURE 2.3-33

ONE SECTOR (22½°) WIND DIRECTION PERSISTENCE PROBABILITY

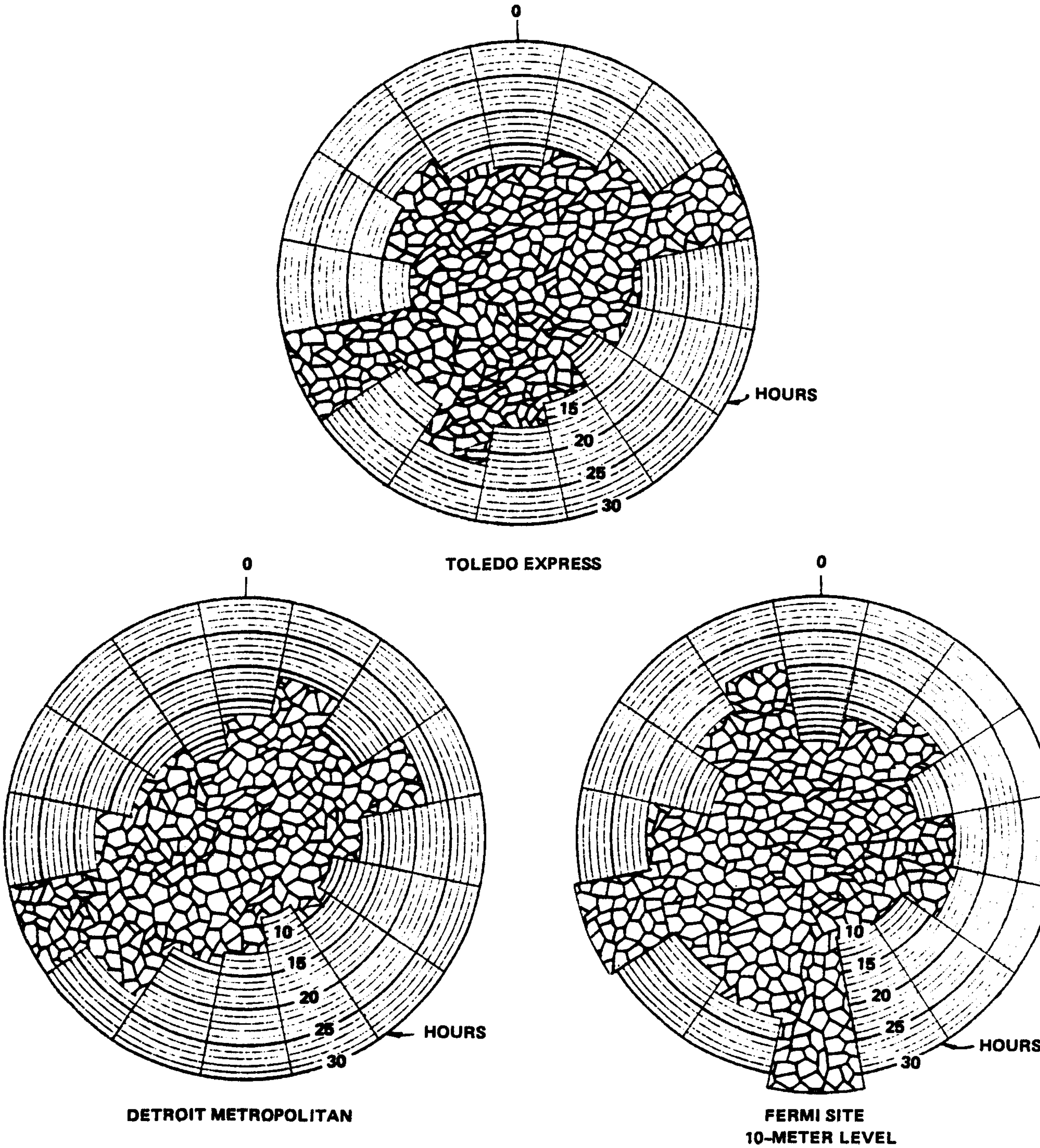

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FIGURE 2.3-34

MAXIMUM WIND PERSISTENCE ROSE

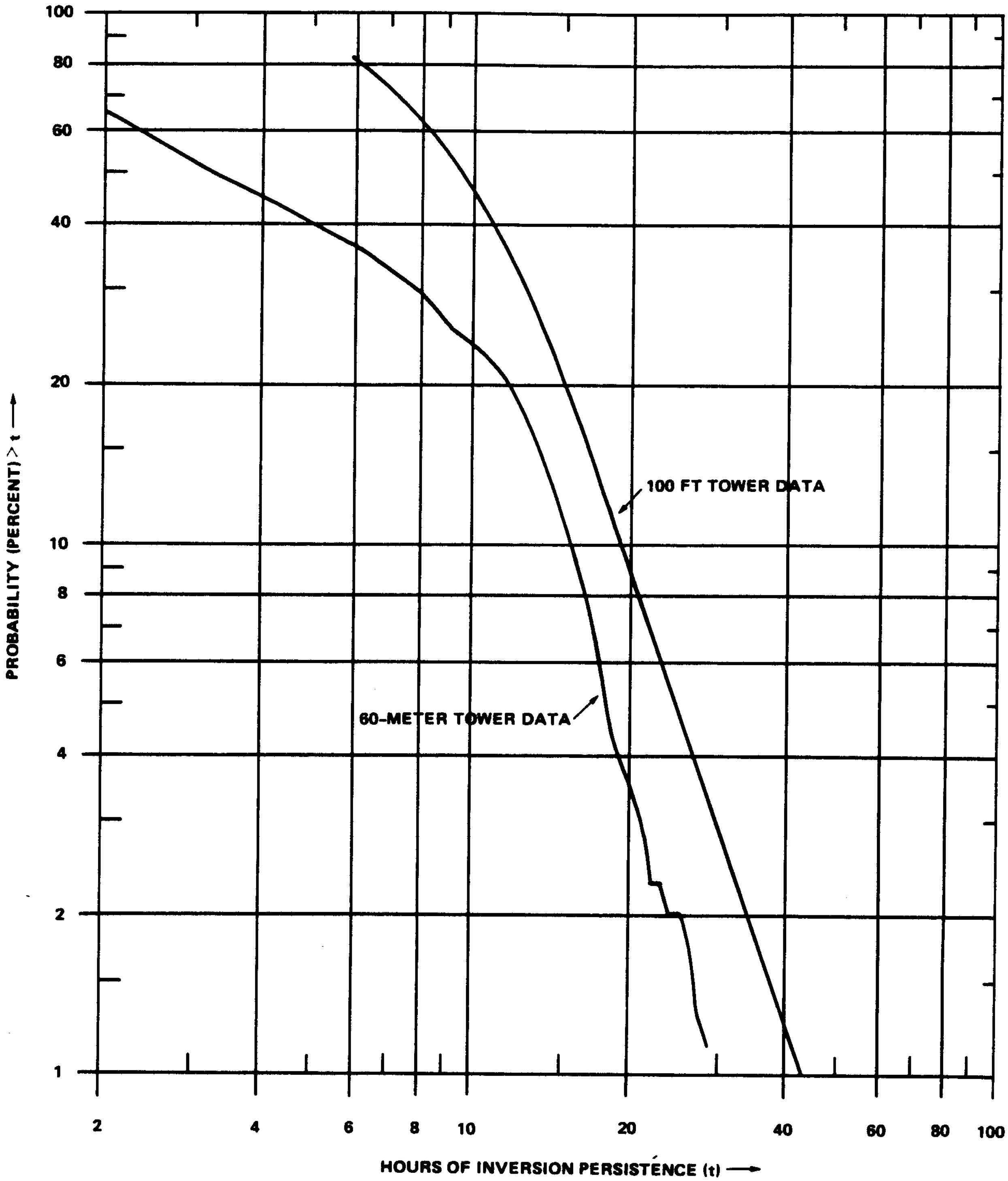

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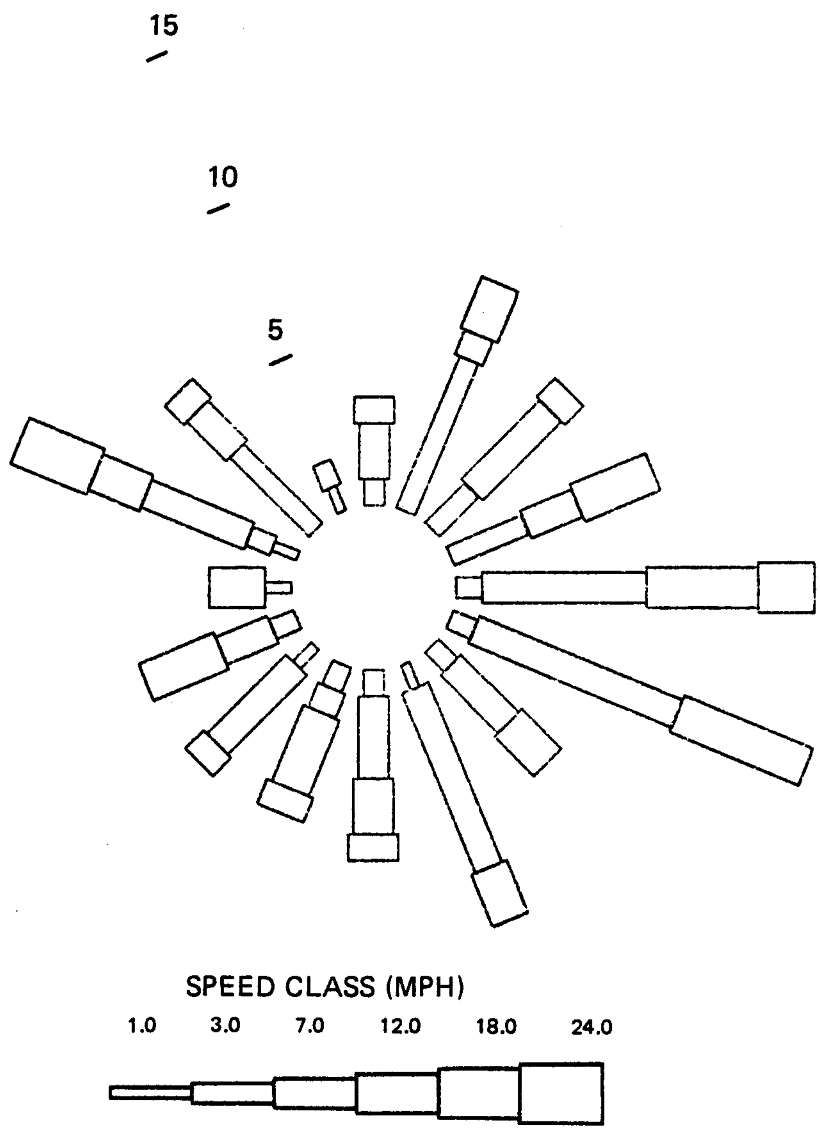
FIGURE 2.3-35

INVERSION PERSISTENCE PROBABILITY



DETROIT EDISON 60-METER TOWER 10-METER WIND ROSE
PRECIPITATION 1974-1975

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FIGURE 2.3-36

DISTRIBUTION OF WIND SPEED VERSUS WIND DIRECTION (PRECIPITATION ONLY)

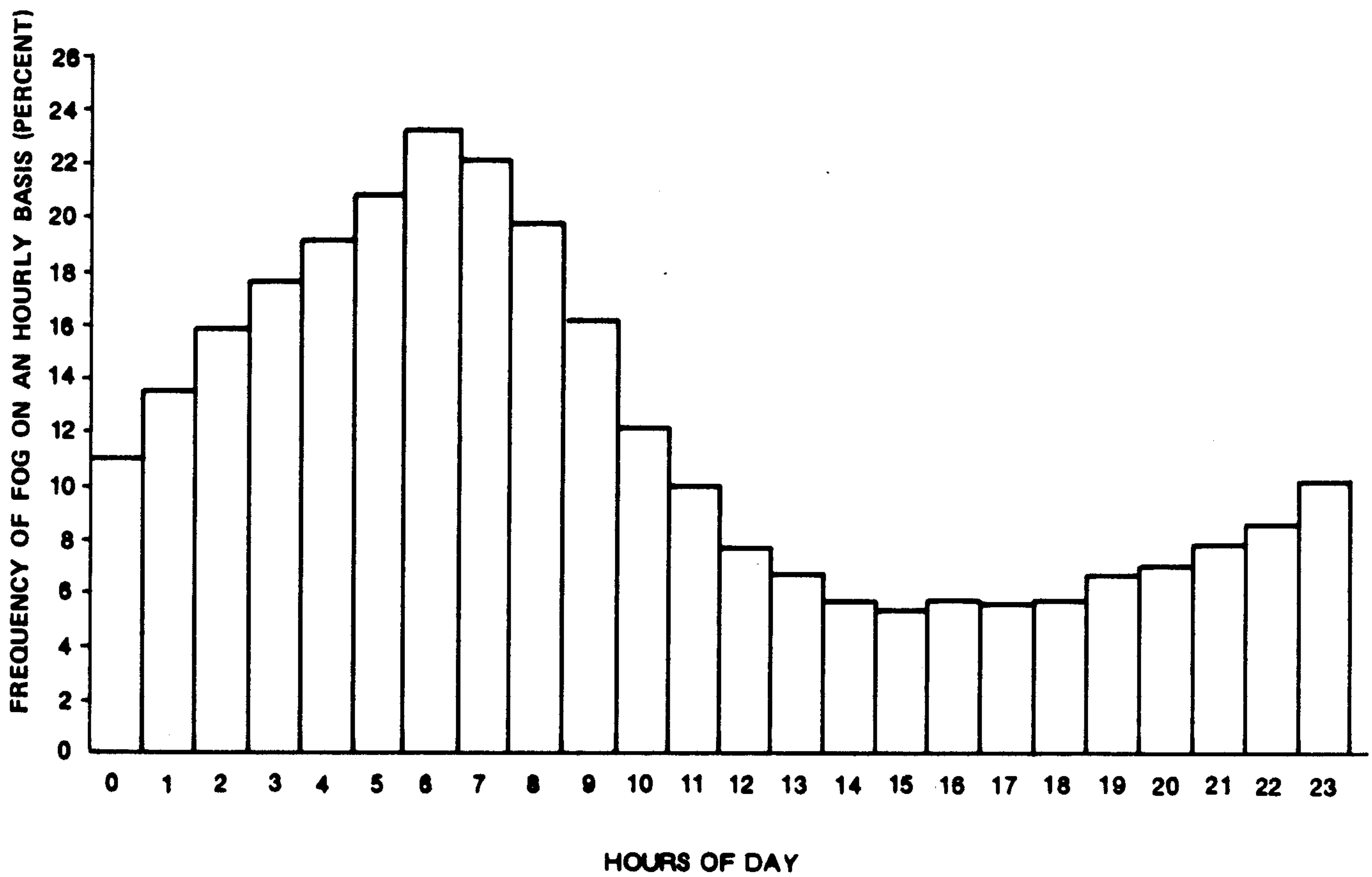

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FIGURE 2.3-37

FOG – OCCURANCE BY HOUR OF DAY
(DETROIT METROPOLITAN AIRPORT
1958-1962)

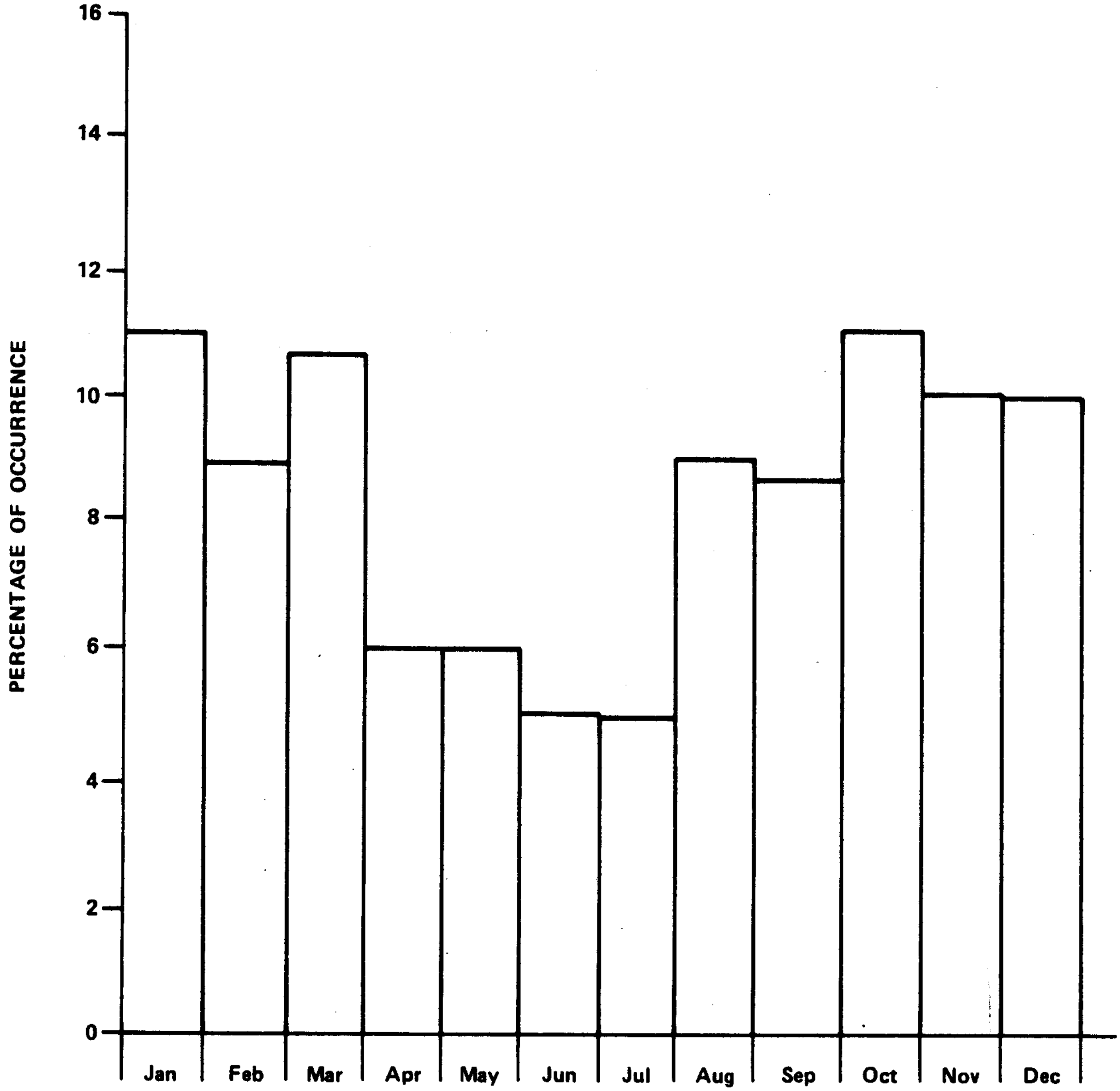

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FIGURE 2.3-38

FOG – MONTHLY PERCENTAGE OCCURANCE (DETROIT METROPOLITAN AIRPORT 1958-1962)

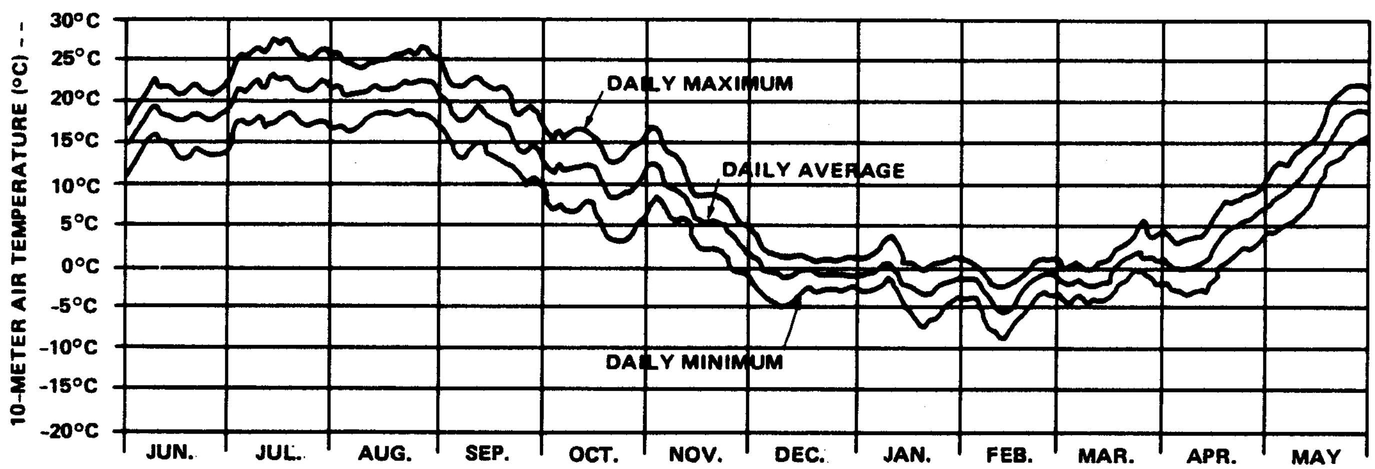

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FIGURE 2.3-39

MINIMUM, AVERAGE, AND MAXIMUM DAILY AIR TEMPERATURE AT THE FERMI SITE FROM 10-METER LEVEL DATA FROM JUNE 1974 THROUGH MAY 1975

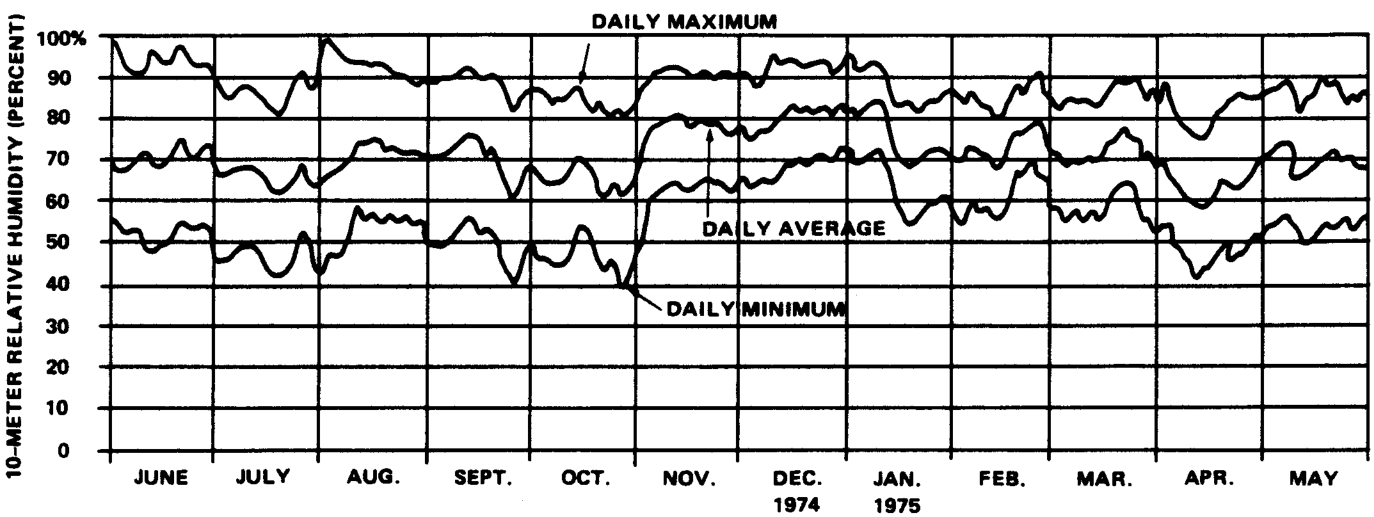

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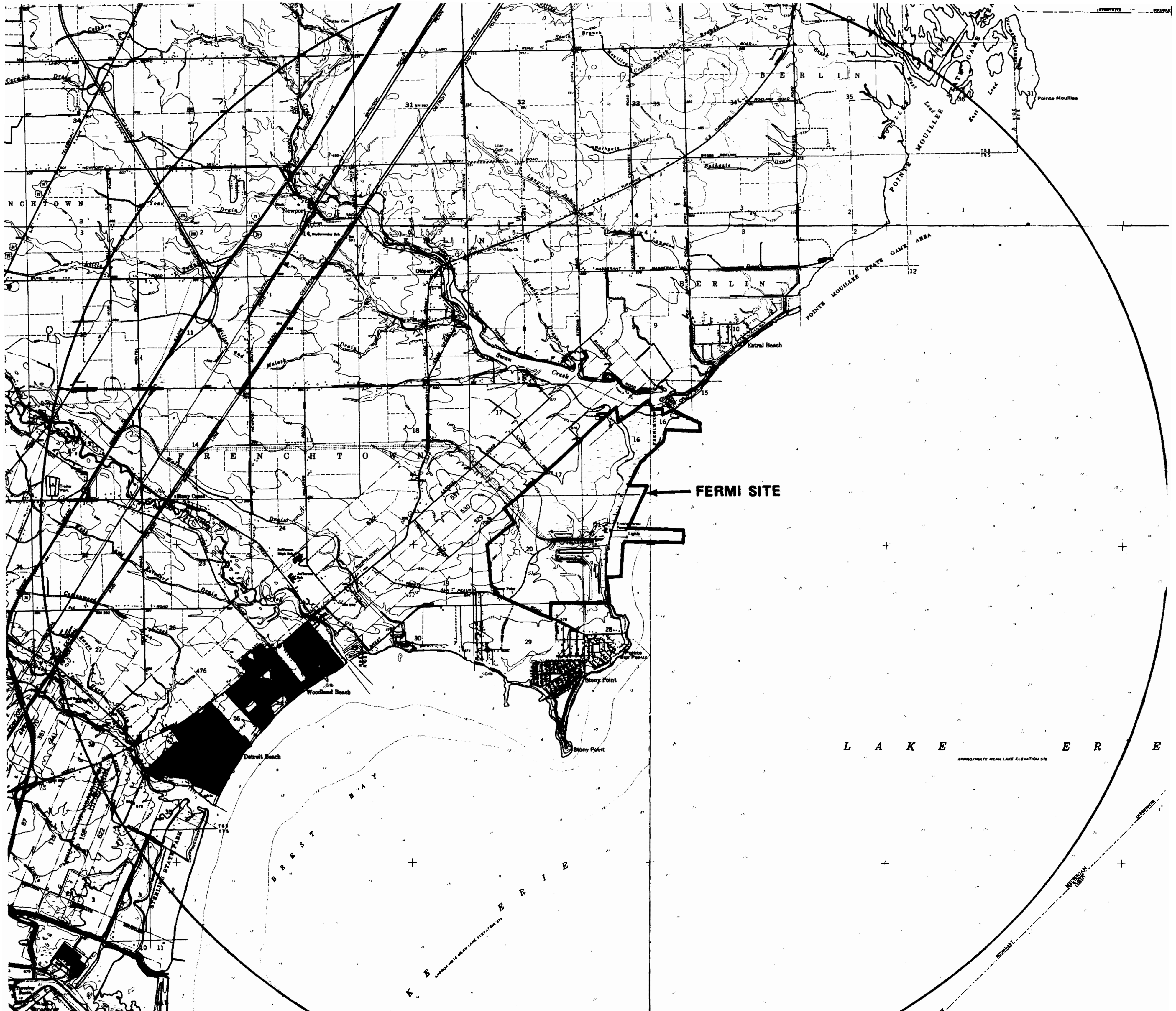
FIGURE 2.3-40

MINIMUM, AVERAGE, AND MAXIMUM DAILY RELATIVE HUMIDITY FROM JUNE 1974 THROUGH MAY 1975



NORTH ARROW

SCALE 1:24000

CONTOUR INTERVAL 5 FEET
DATUM IS MEAN SEA LEVEL

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FIGURE 2.3-41

TOPOGRAPHIC MAP OF THE AREA WITHIN A 5-MILE VICINITY

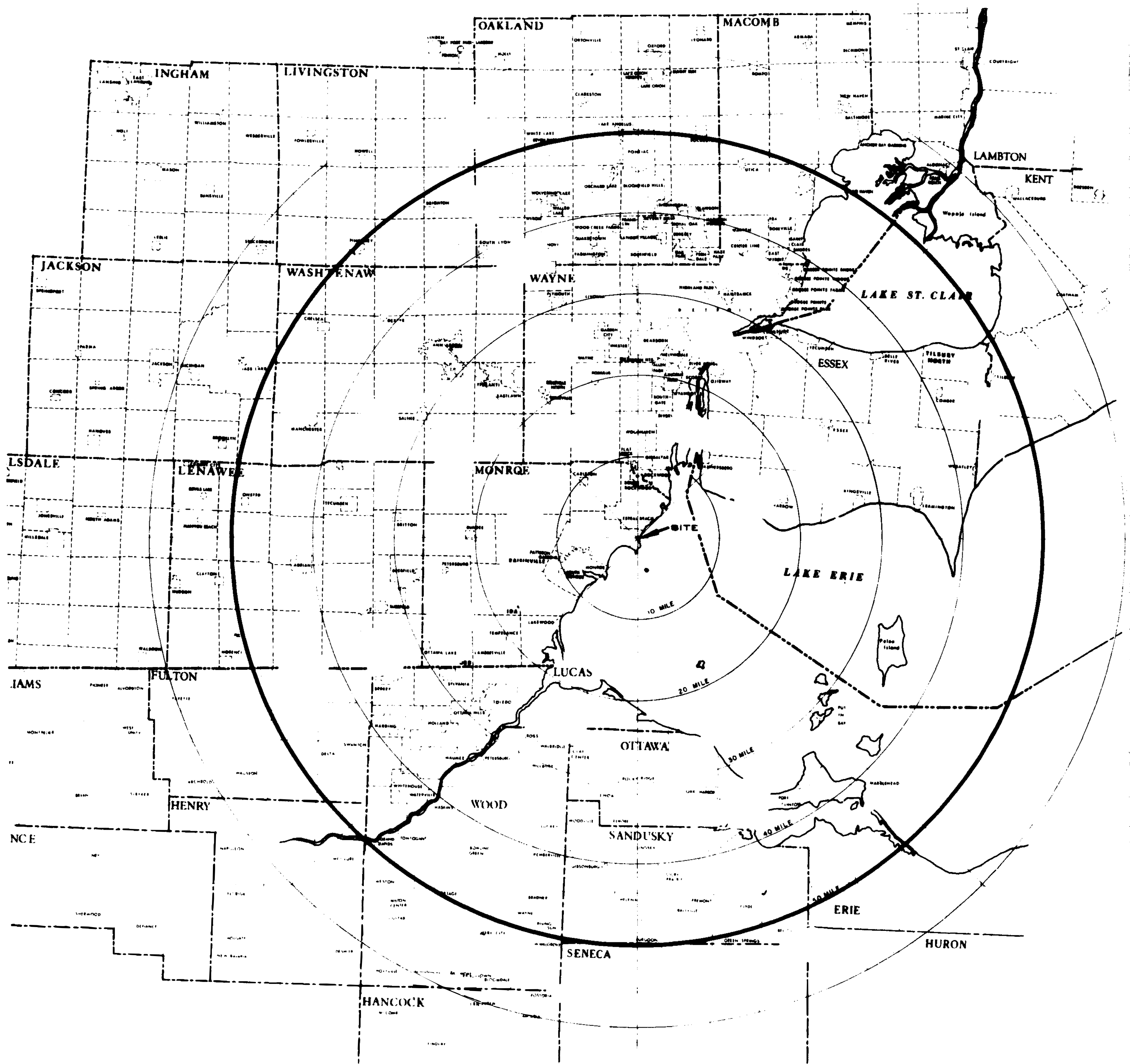

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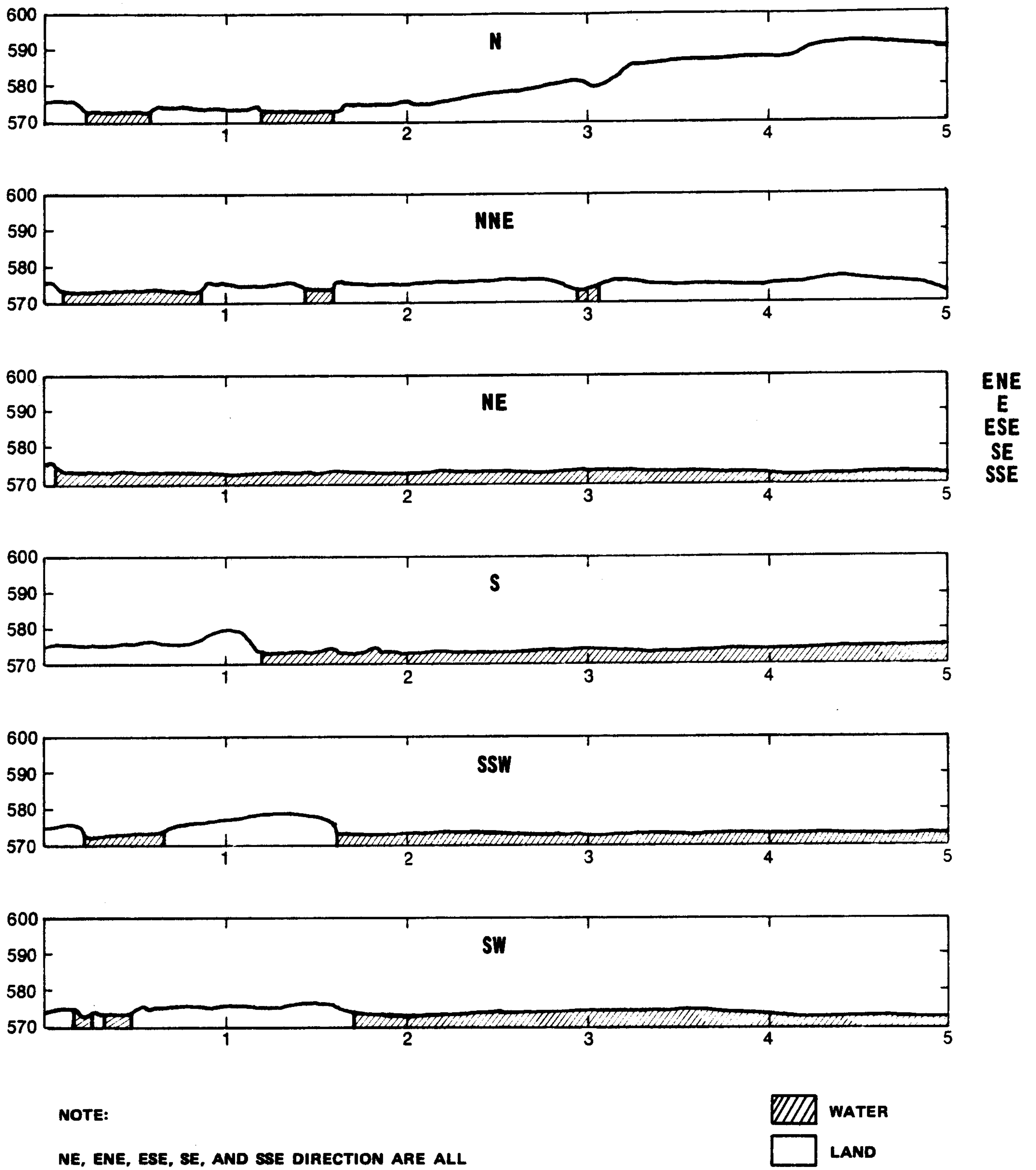
FIGURE 2.3-42

MAP OF THE AREA WITHIN A 50-MILE VICINITY



NOTE:

NE, ENE, ESE, SE, AND SSE DIRECTION ARE ALL IDENTICAL. ELEVATIONS IN FEET ABOVE SEA LEVEL (NEW YORK MEAN TIDE, 1935). SECTION TAKEN IN DIRECTION INDICATED.

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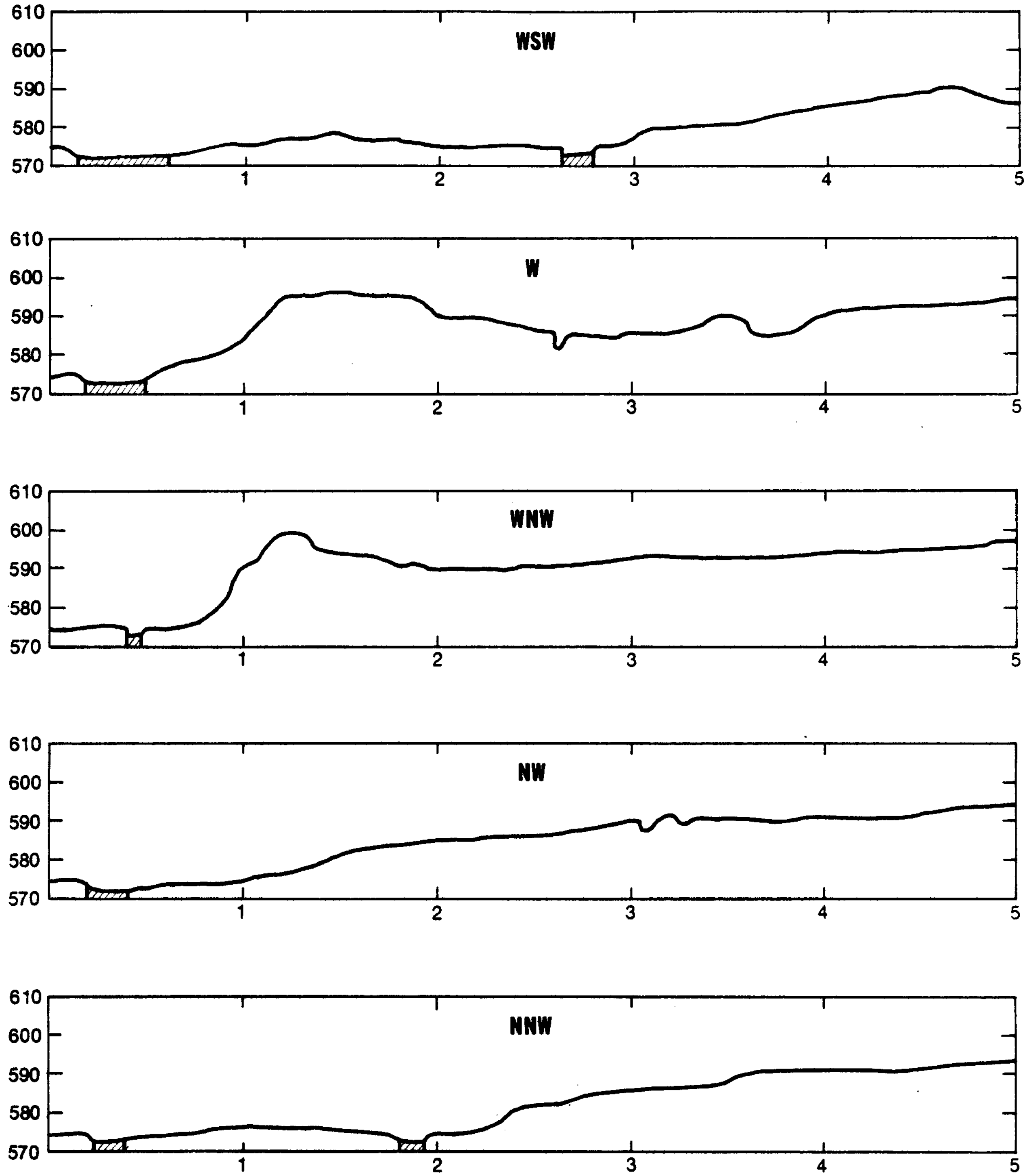
FIGURE 2.3-43, SHEET 1

TOPOGRAPHIC CROSS SECTION OUT TO 5 MILES



NOTE:

NE, ENE, ESE, SE, AND SSE DIRECTION ARE ALL IDENTICAL. ELEVATIONS IN FEET ABOVE SEA LEVEL (NEW YORK MEAN TIDE, 1935). SECTION TAKEN IN DIRECTION INDICATED.

WATER

LAND

Fermi 2

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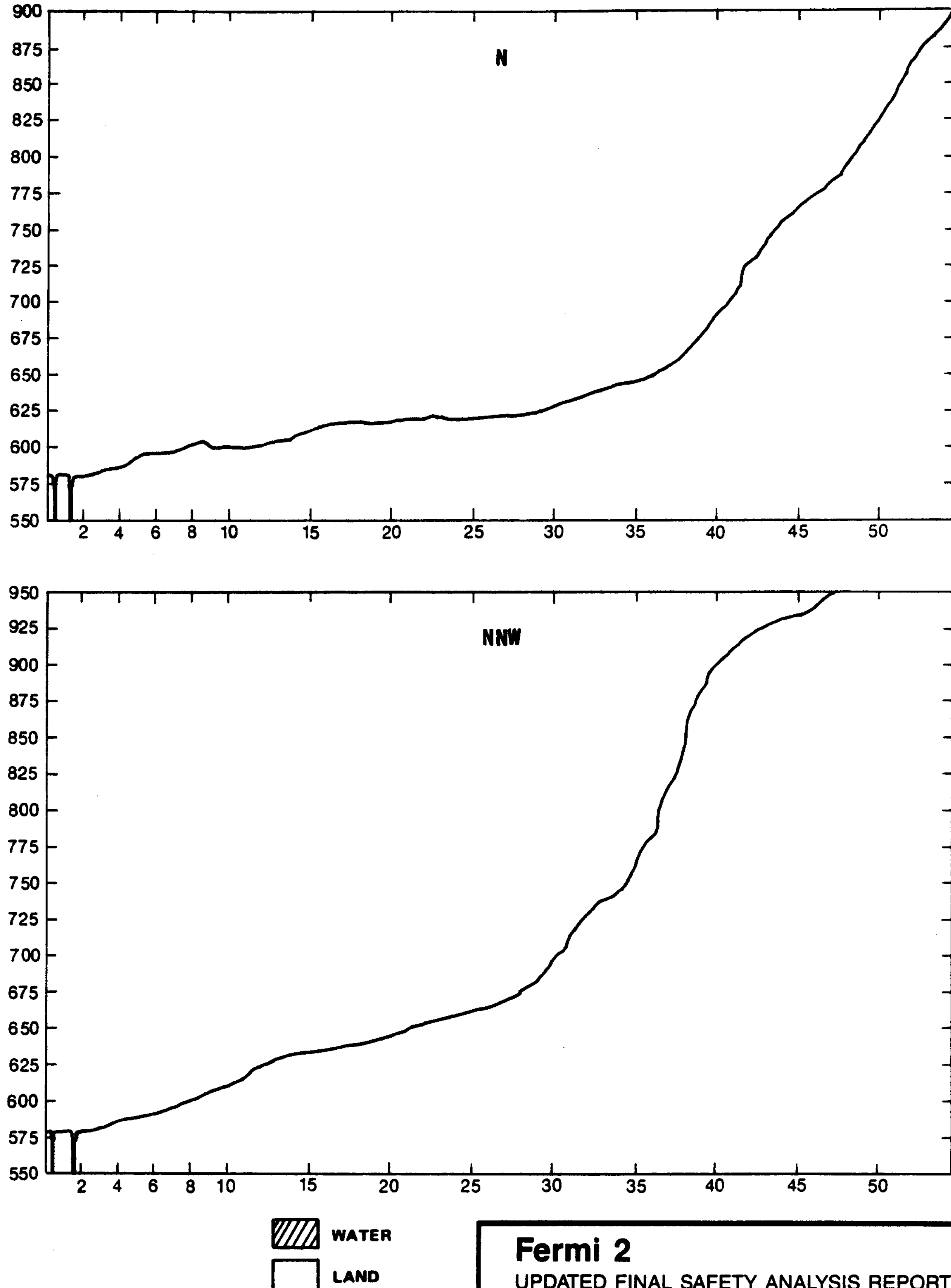
FIGURE 2.3-43, SHEET 2

TOPOGRAPHIC CROSS SECTION OUT TO 5 MILES



NOTE:

ELEVATION IS IN FEET ABOVE SEA LEVEL. (N.Y, MEAN TIDE, 1935). SECTION TAKEN IN DIRECTION INDICATED.

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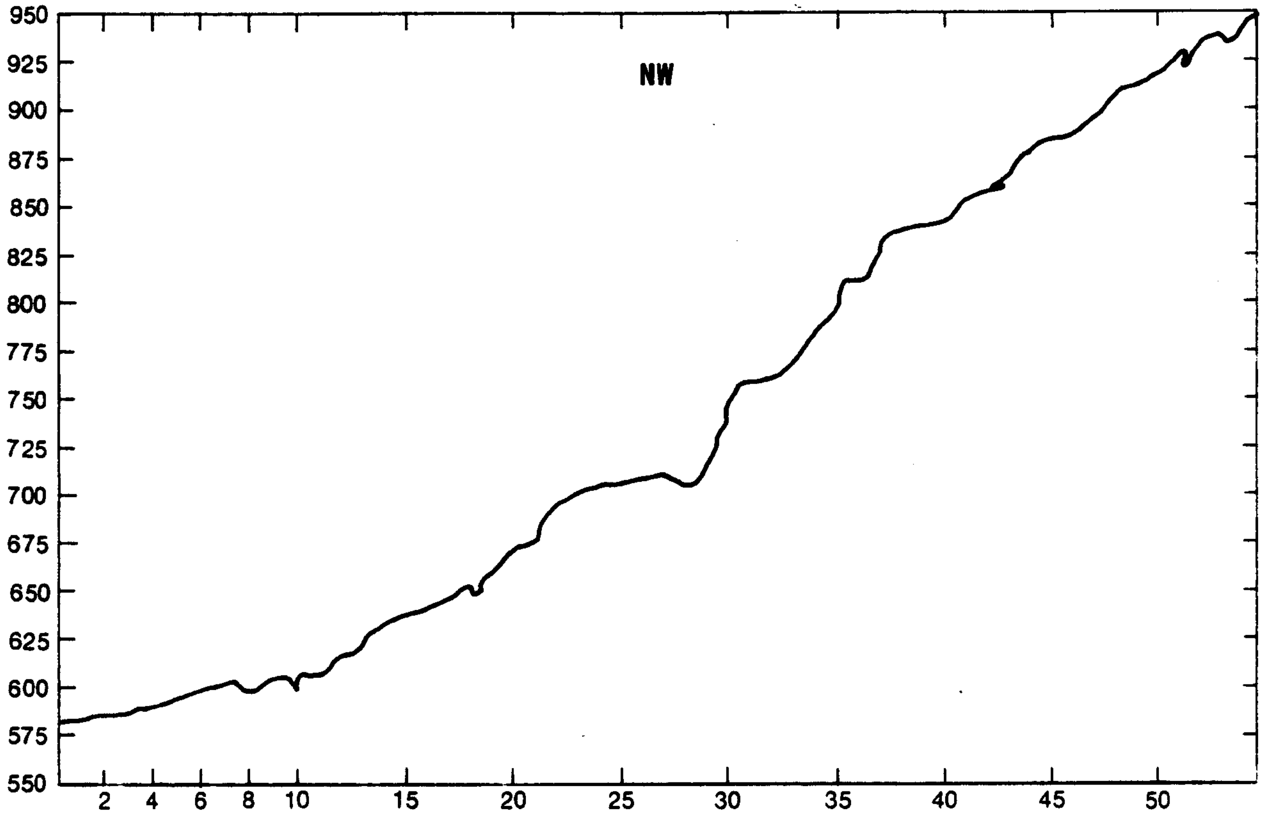
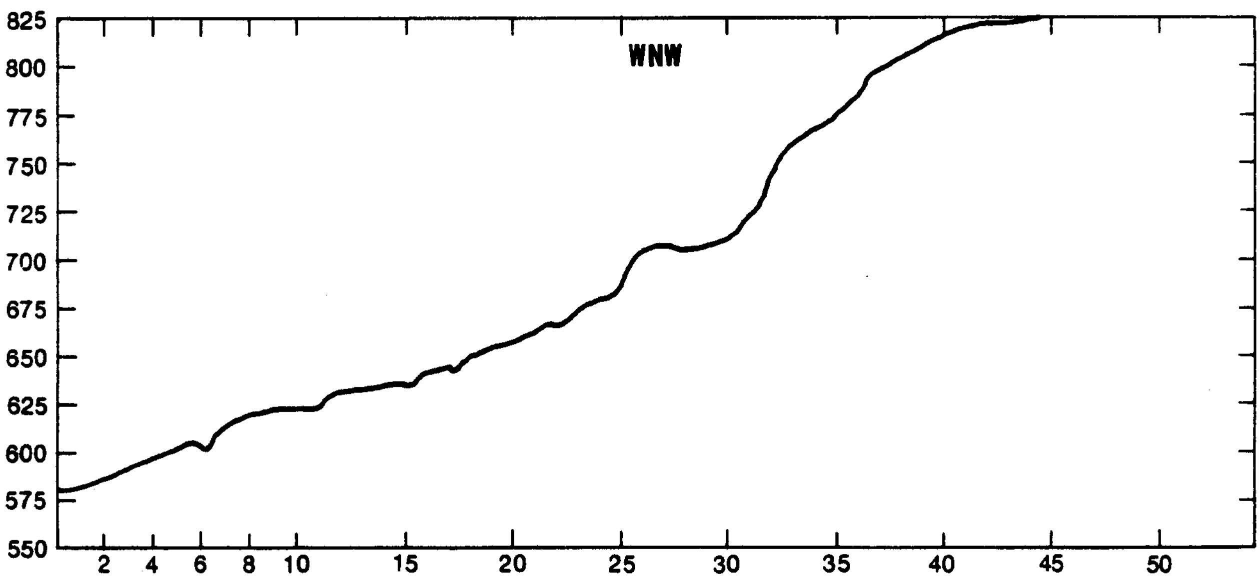
FIGURE 2.3-44, SHEET 1

TOPOGRAPHIC CROSS SECTION OUT TO 50 MILES





WATER

LAND

NOTE:

ELEVATION IS IN FEET ABOVE SEA LEVEL. (N.Y. MEAN TIDE, 1935). SECTION TAKEN IN DIRECTION INDICATED.

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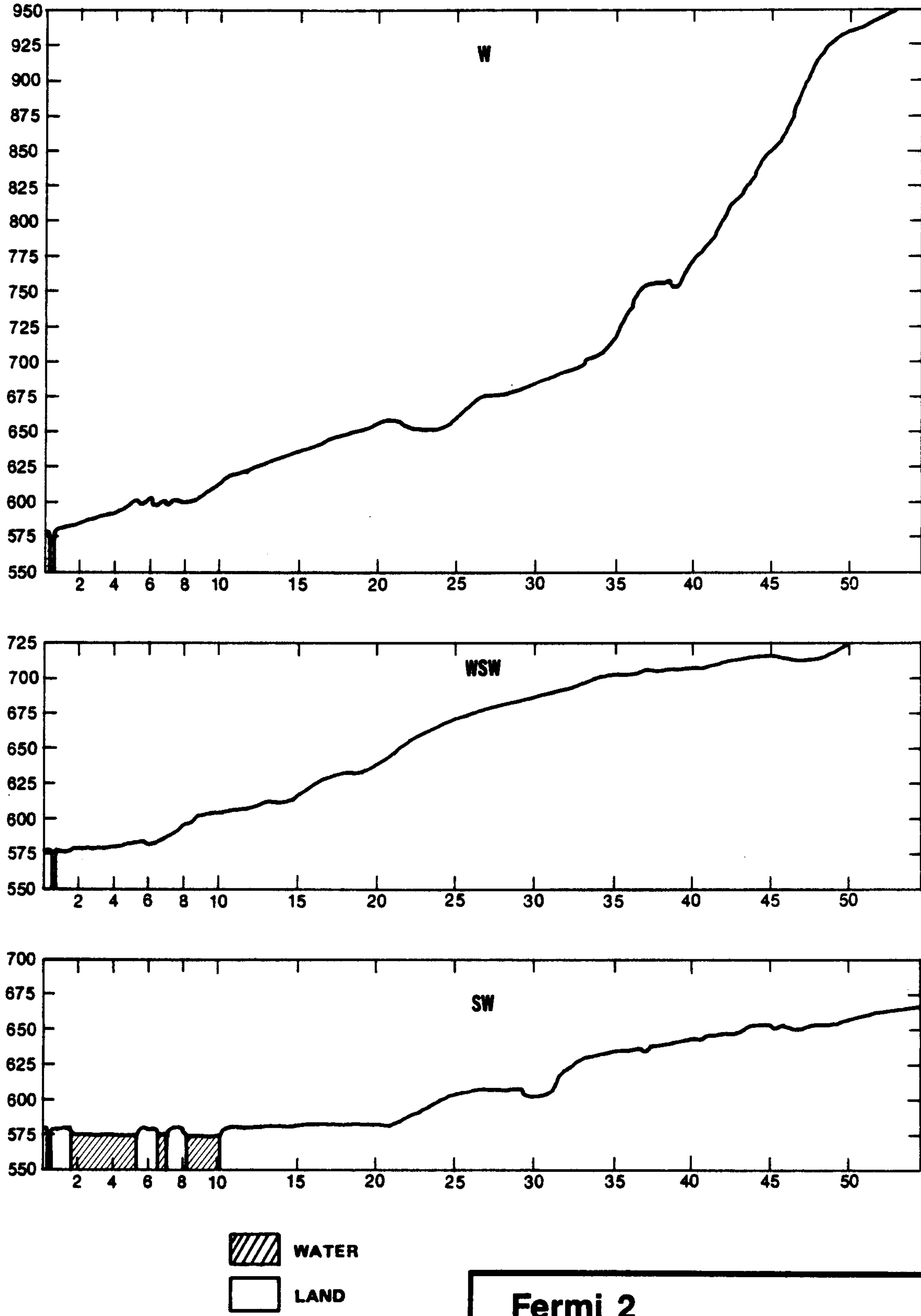
FIGURE 2.3-44, SHEET 2

TOPOGRAPHIC CROSS SECTION OUT TO 50 MILES



NOTE:

ELEVATION IS IN FEET ABOVE SEA LEVEL. (N.Y, MEAN TIDE, 1935). SECTION TAKEN IN DIRECTION INDICATED.

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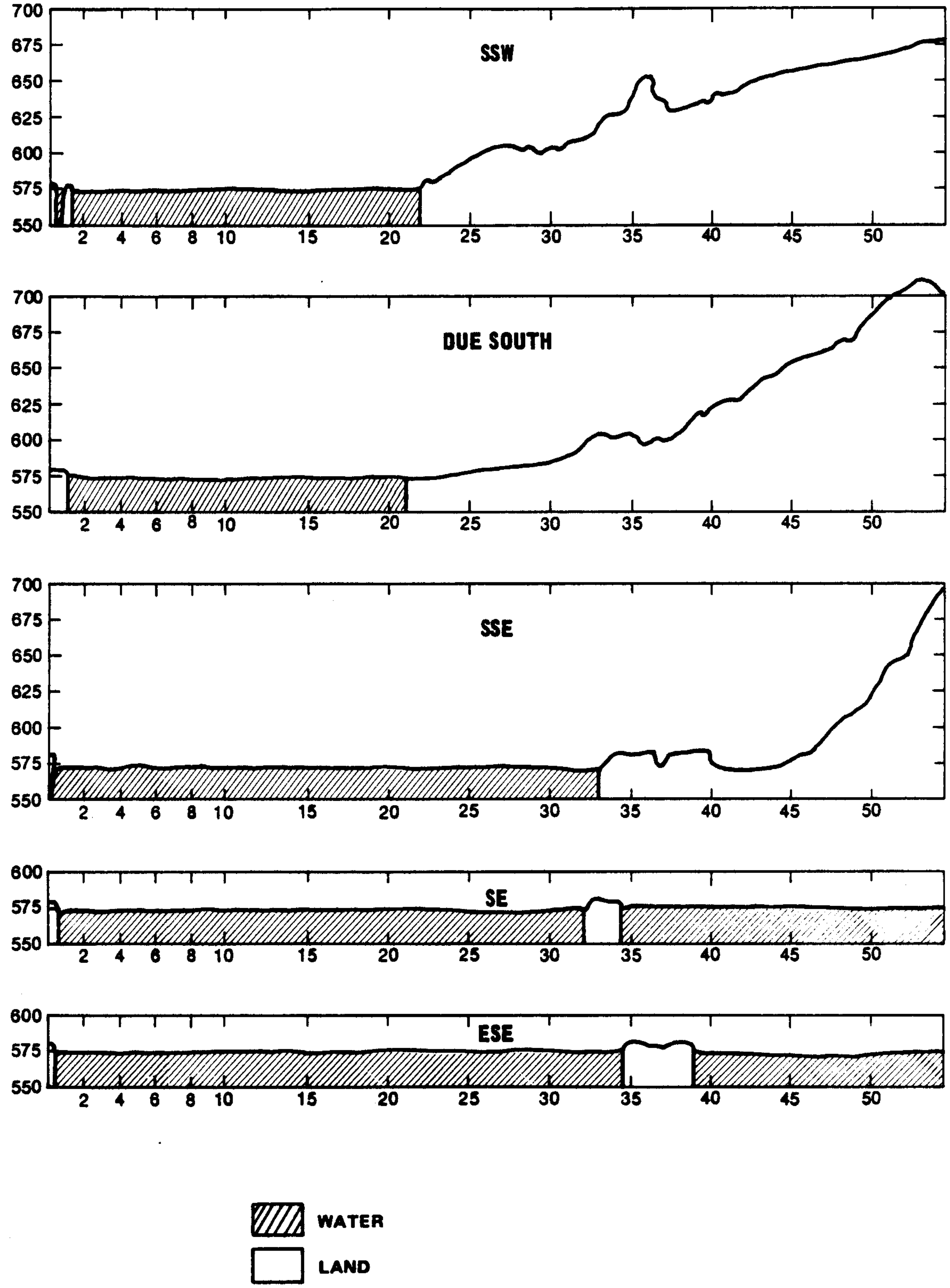
FIGURE 2.3-44, SHEET 3

TOPOGRAPHIC CROSS SECTION OUT TO 50 MILES



NOTE:

ELEVATION IS IN FEET ABOVE SEA LEVEL. (N.Y, MEAN TIDE, 1935). SECTION TAKEN IN DIRECTION INDICATED.

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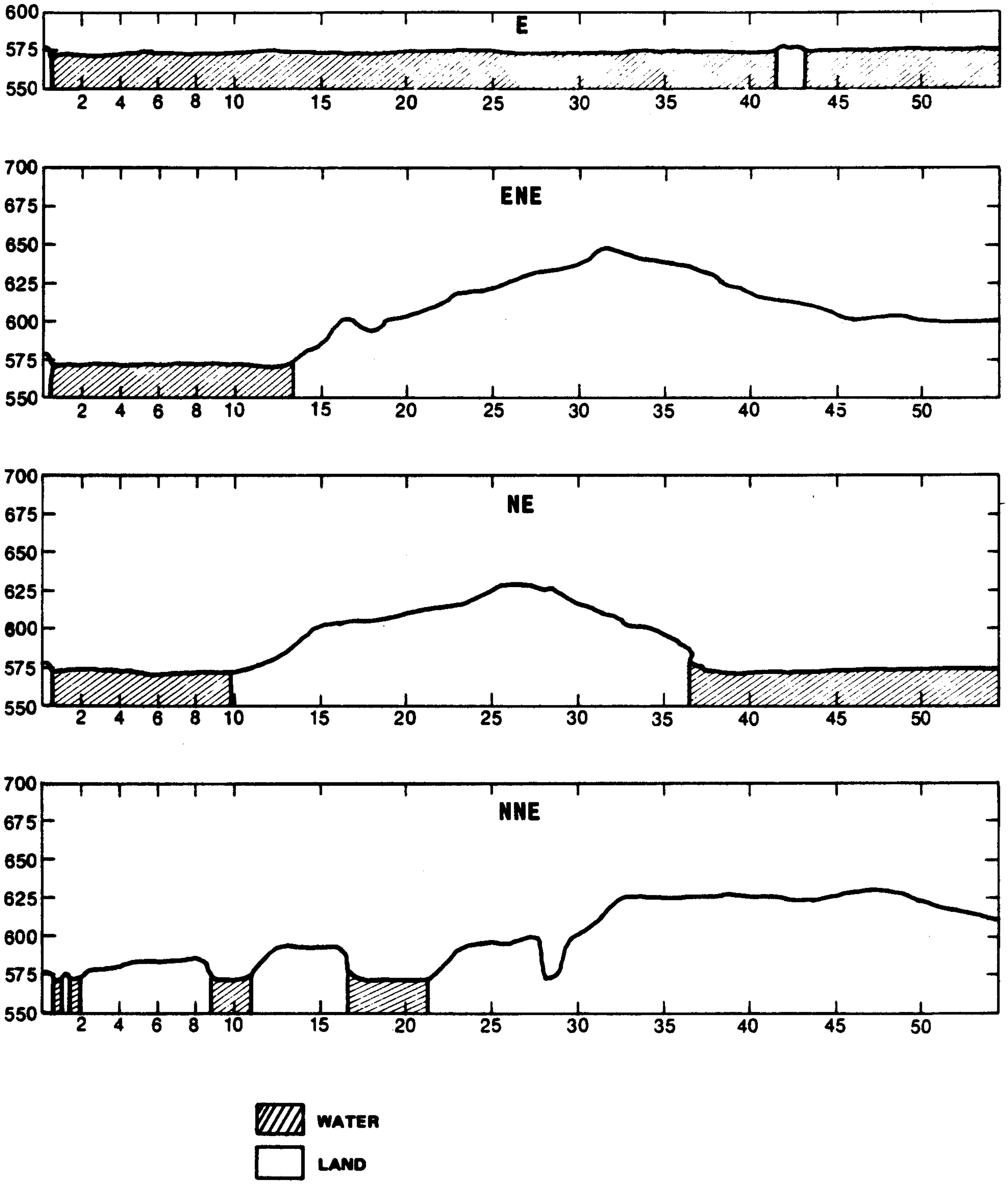
FIGURE 2.3-44, SHEET 4

TOPOGRAPHIC CROSS SECTION OUT TO 50 MILES



NOTE:

ELEVATION IS IN FEET ABOVE SEA LEVEL. (N.Y, MEAN TIDE, 1935). SECTION TAKEN IN DIRECTION INDICATED.

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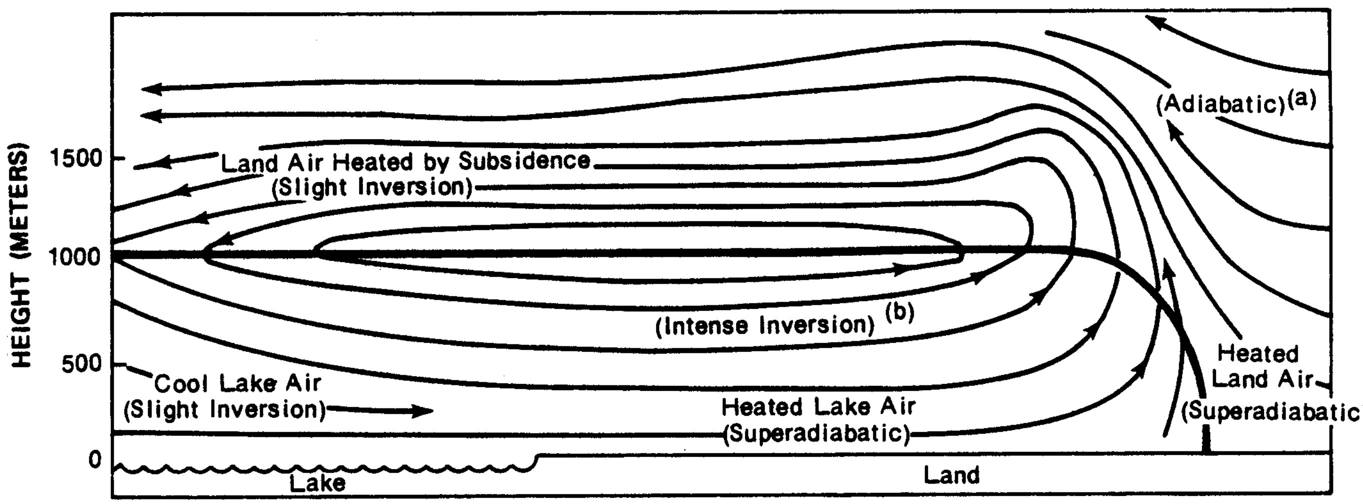
FIGURE 2.3-44, SHEET 5

TOPOGRAPHIC CROSS SECTION OUT TO 50 MILES



(a) Adiabatic Temperature Gradient = -.98 C 100m or -5.4 F 1000 ft

(b) Inversion = Temperature Increasing With Height

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FIGURE 2.3-45

STREAMLINES DURING A LAKE BREEZE SITUATION

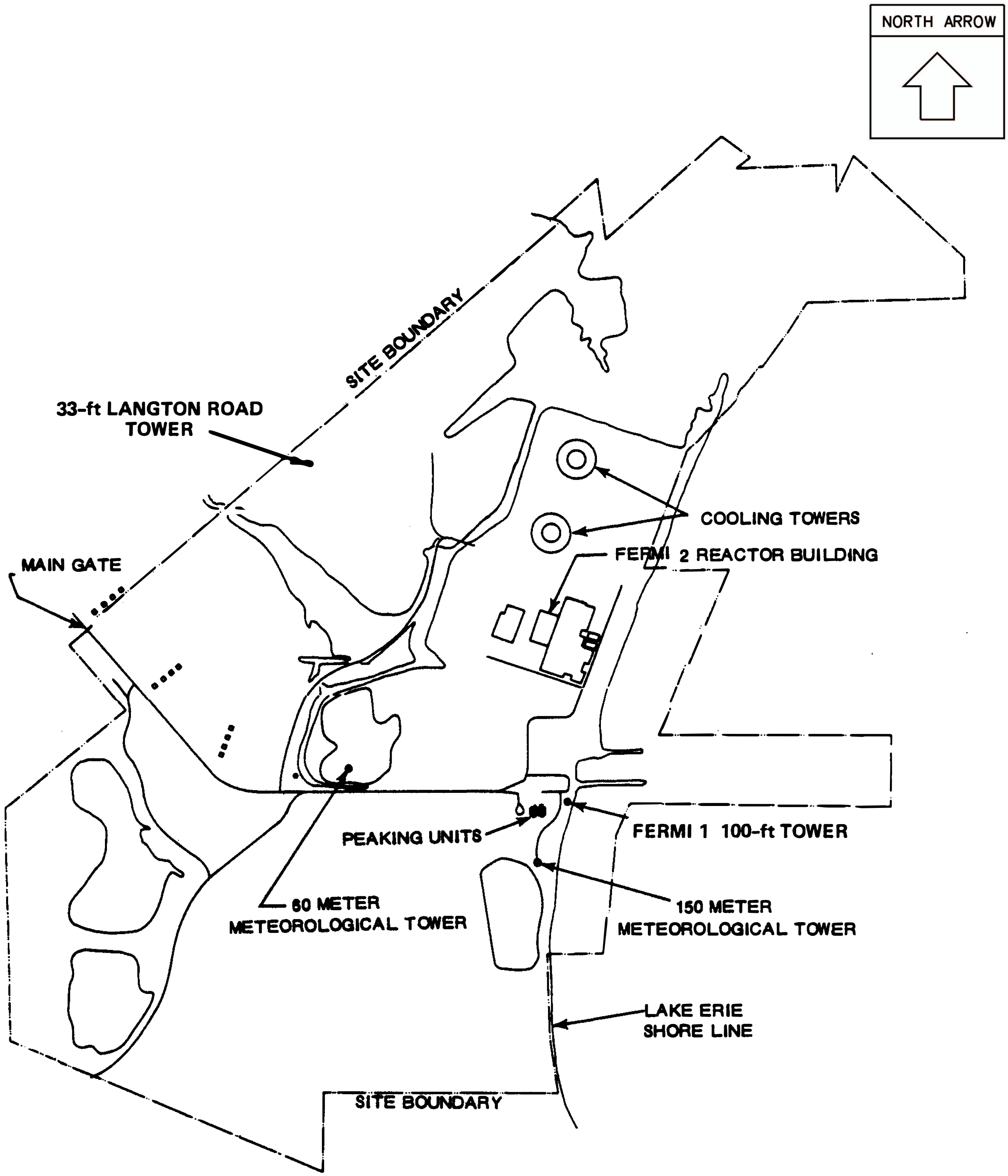

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FIGURE 2.3-46

MAP OF SITE INCLUDING TOWER LOCATIONS

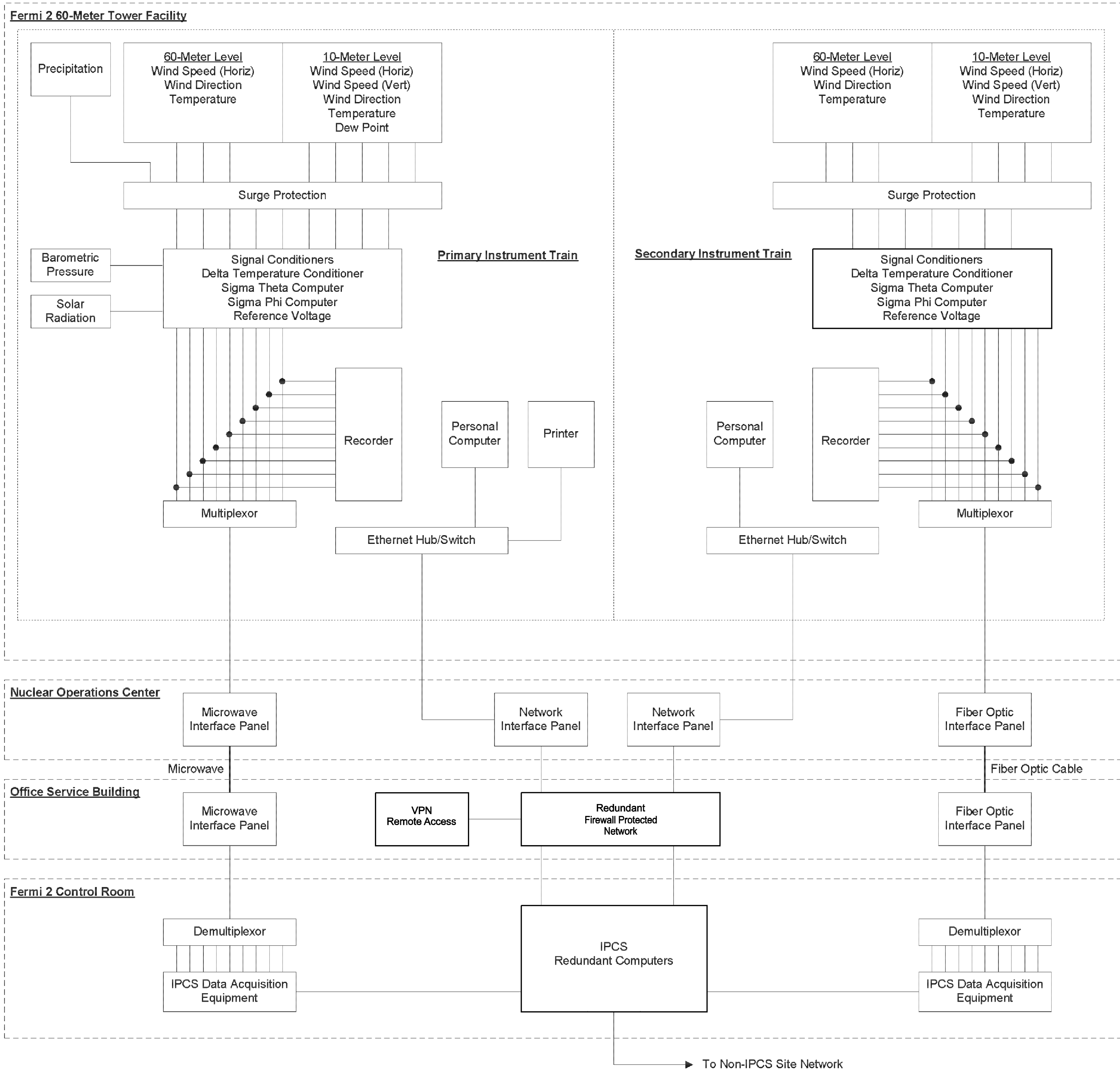

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FIGURE 2.3-47

BLOCK DIAGRAM OF DETROIT EDISON METEOROLOGICAL DATA ACQUISITION SYSTEM

Figure Intentionally Removed
Refer to Plant Drawing A-2042

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FIGURE 2.3-48

CROSS SECTIONAL AREAS OF REACTOR BUILDING AND AUXILIARY BUILDING

FIGURES 2.3-49 THROUGH 2.3-51 HAVE BEEN DELETED

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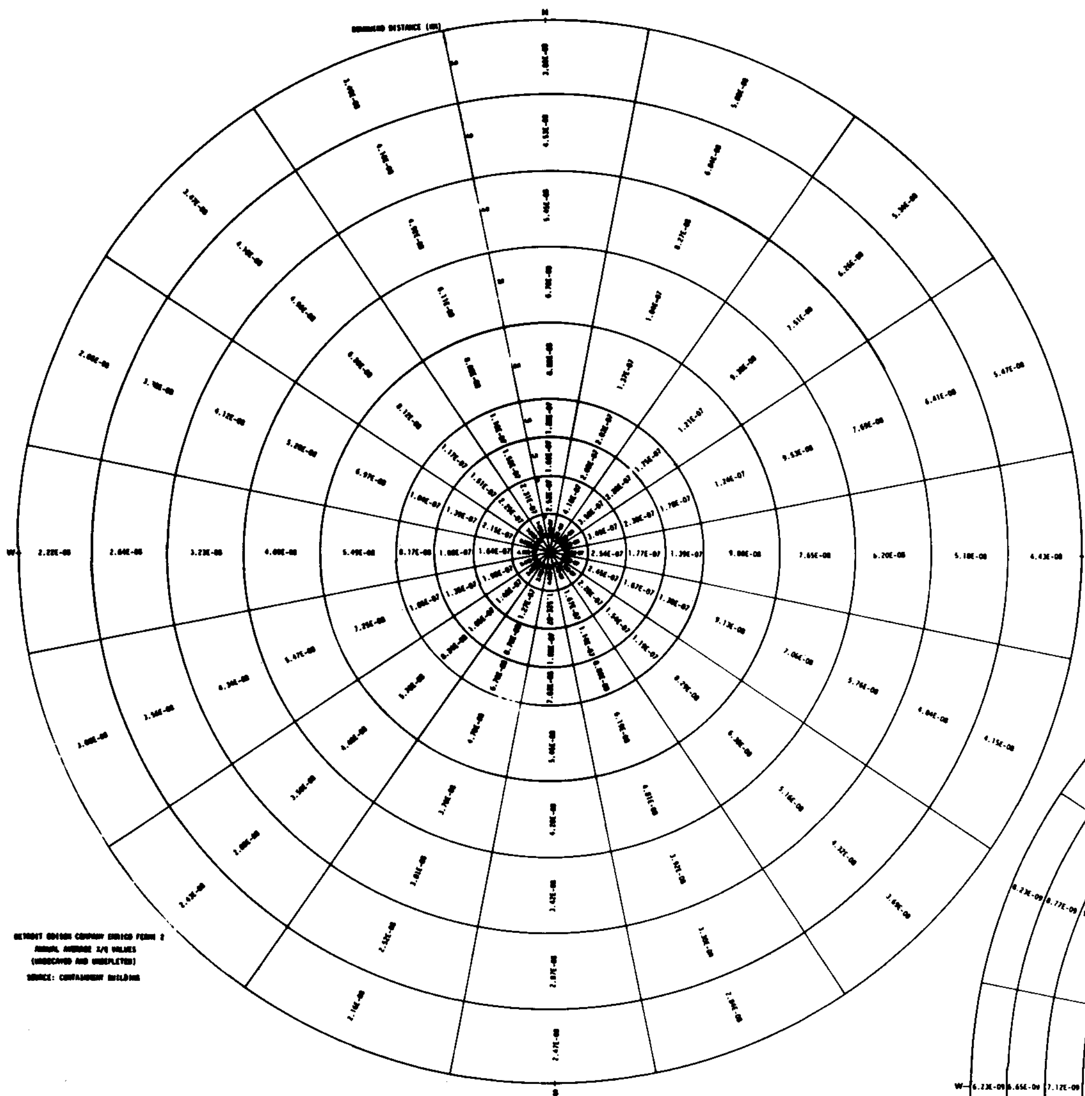

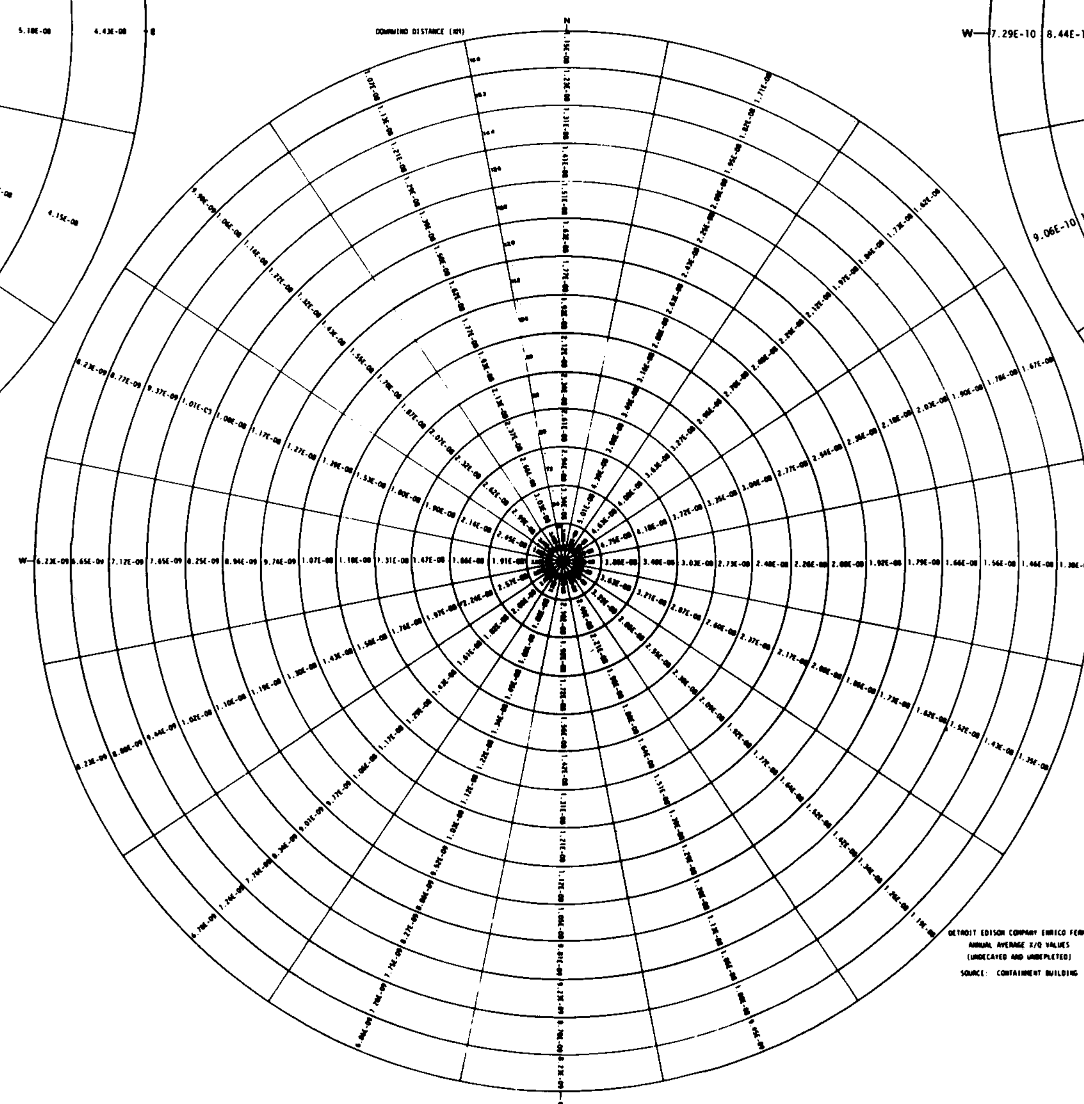

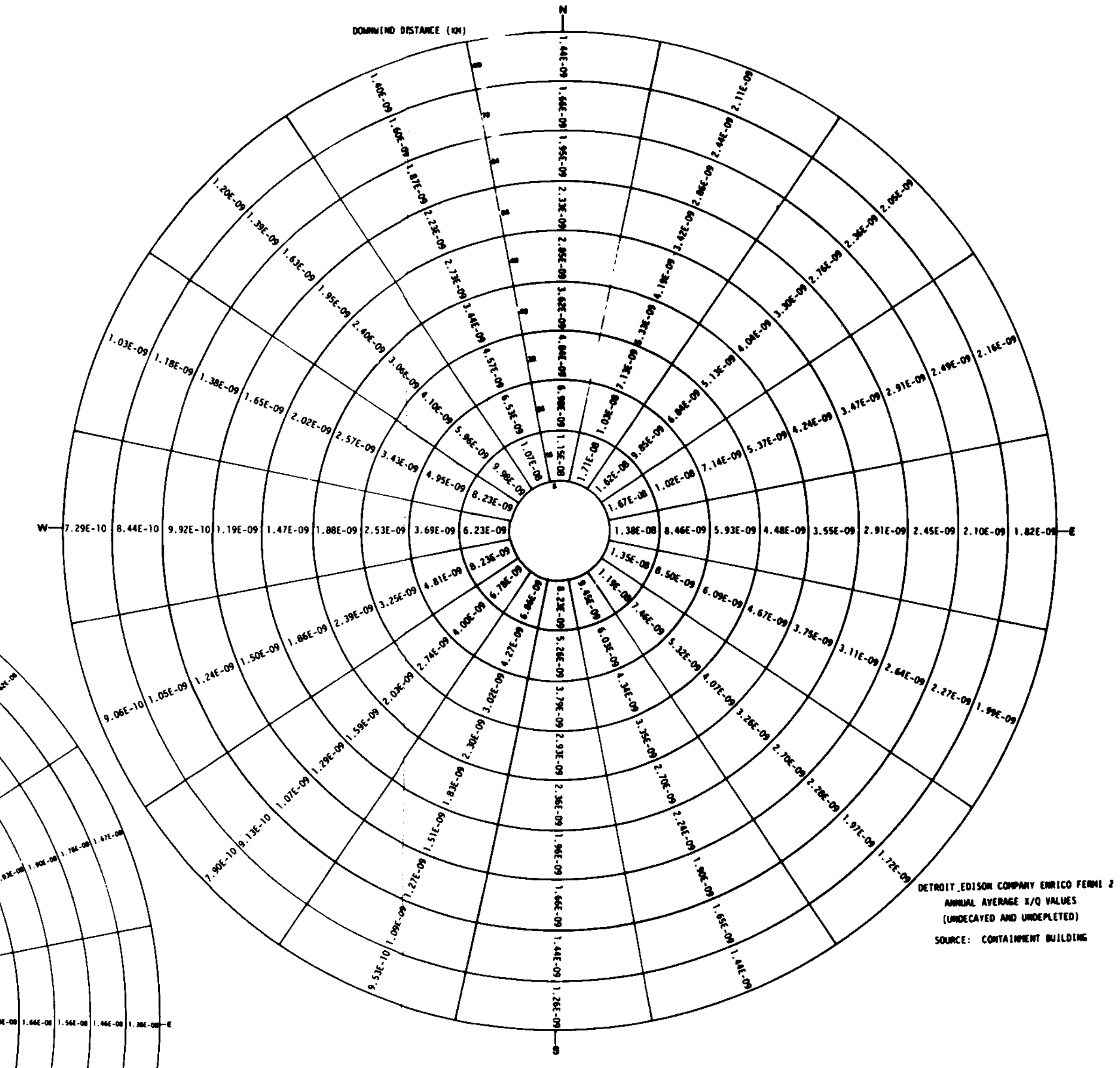

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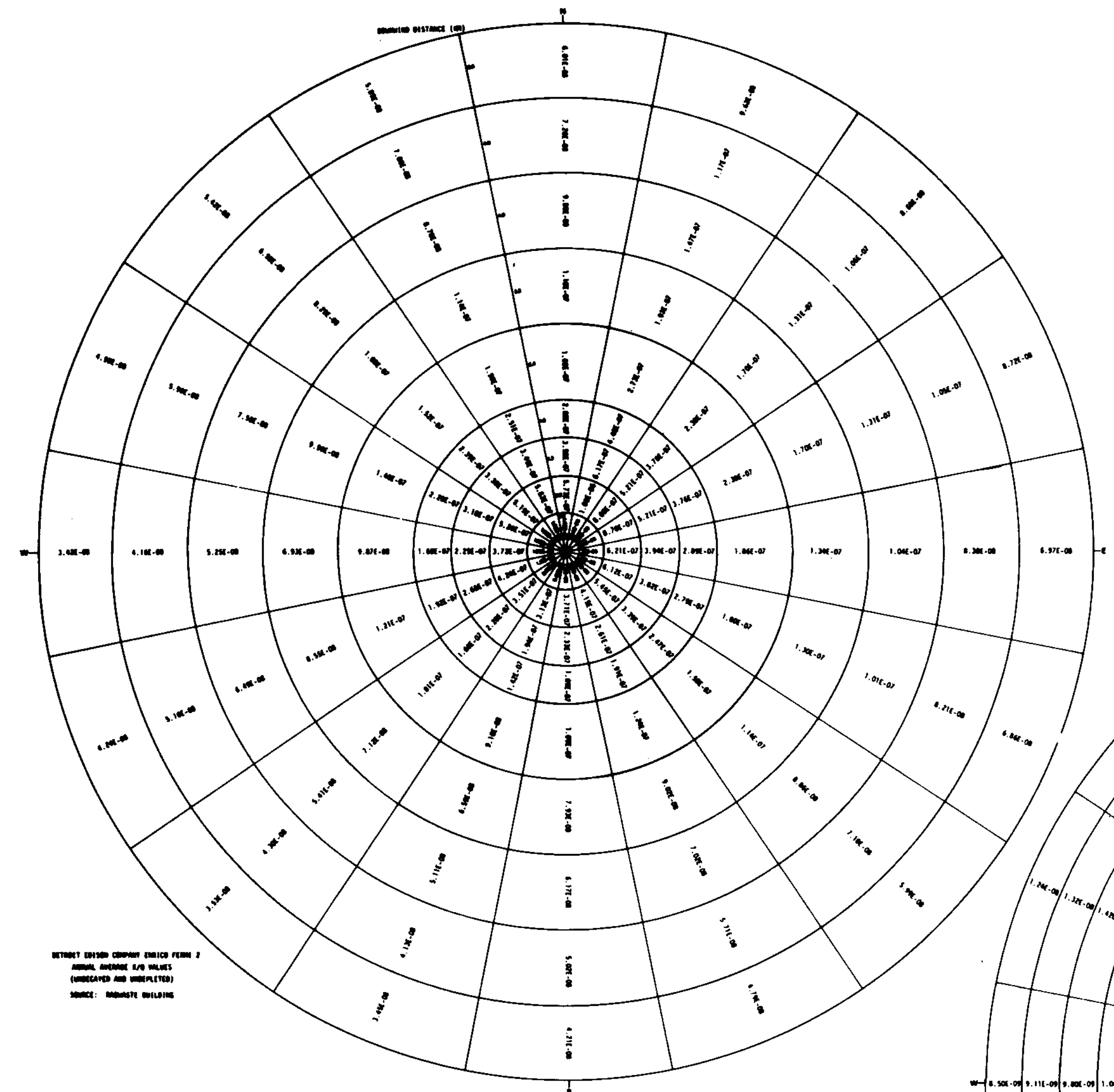
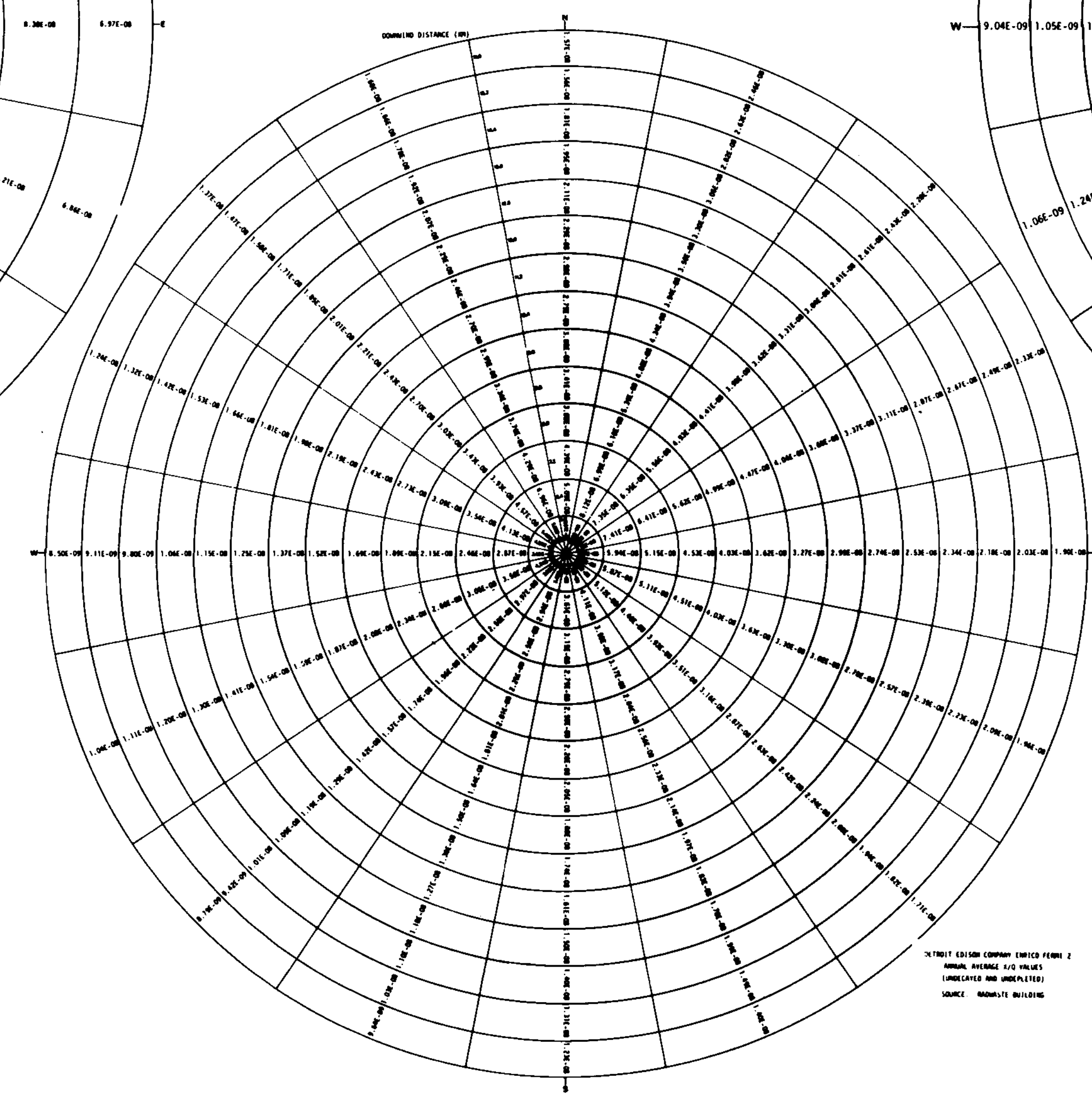
FIGURE 2.3-52

ANNUAL AVERAGE X/Q VALUES
CONTAINMENT BUILDING SOURCE
(UNDECAYED AND UNDEPLETED)





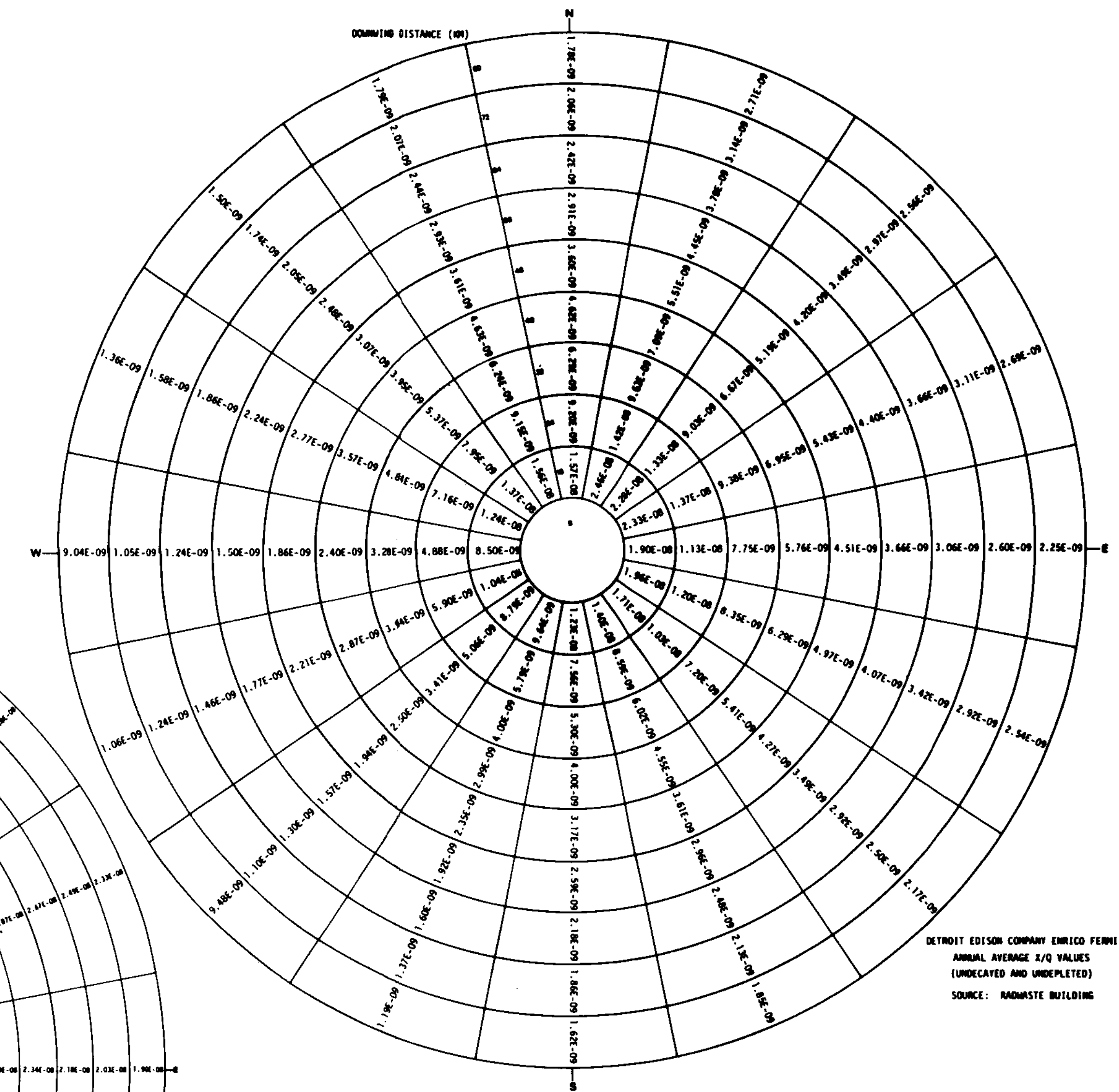


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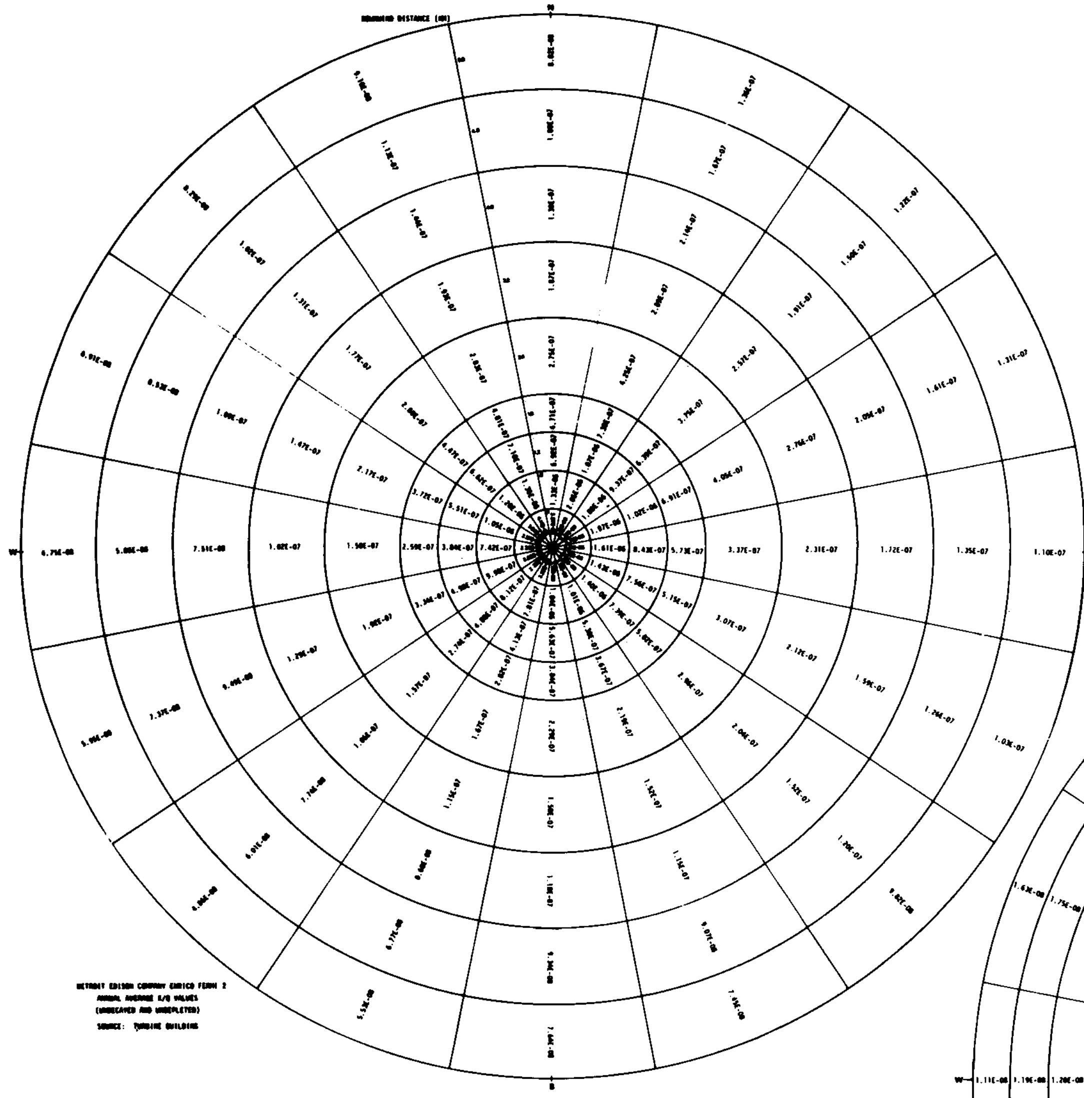
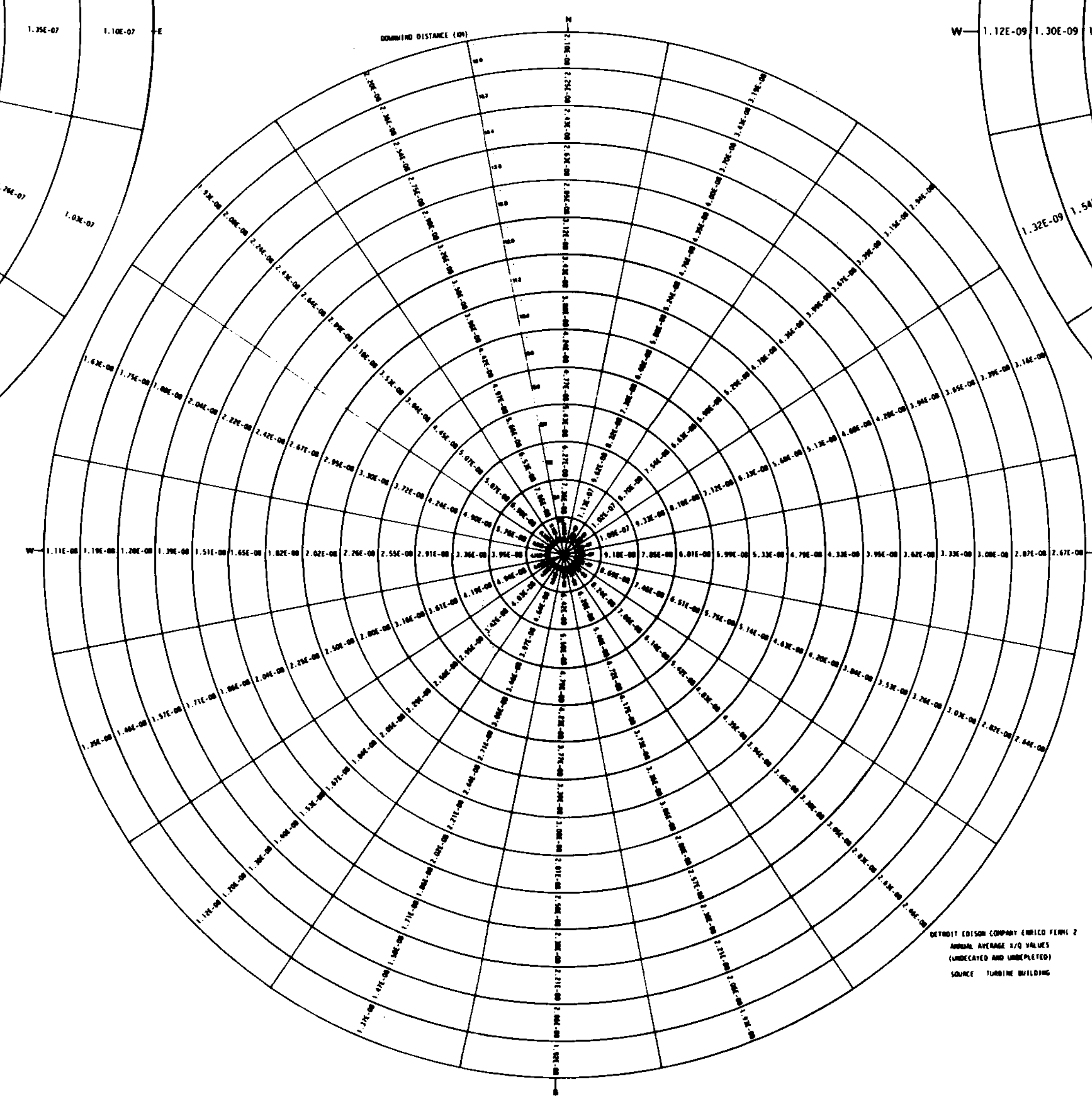
FIGURE 2.3-53

ANNUAL AVERAGE X/Q VALUES
RADWASTE BUILDING SOURCE
(UNDECAYED AND UNDEPLETED)





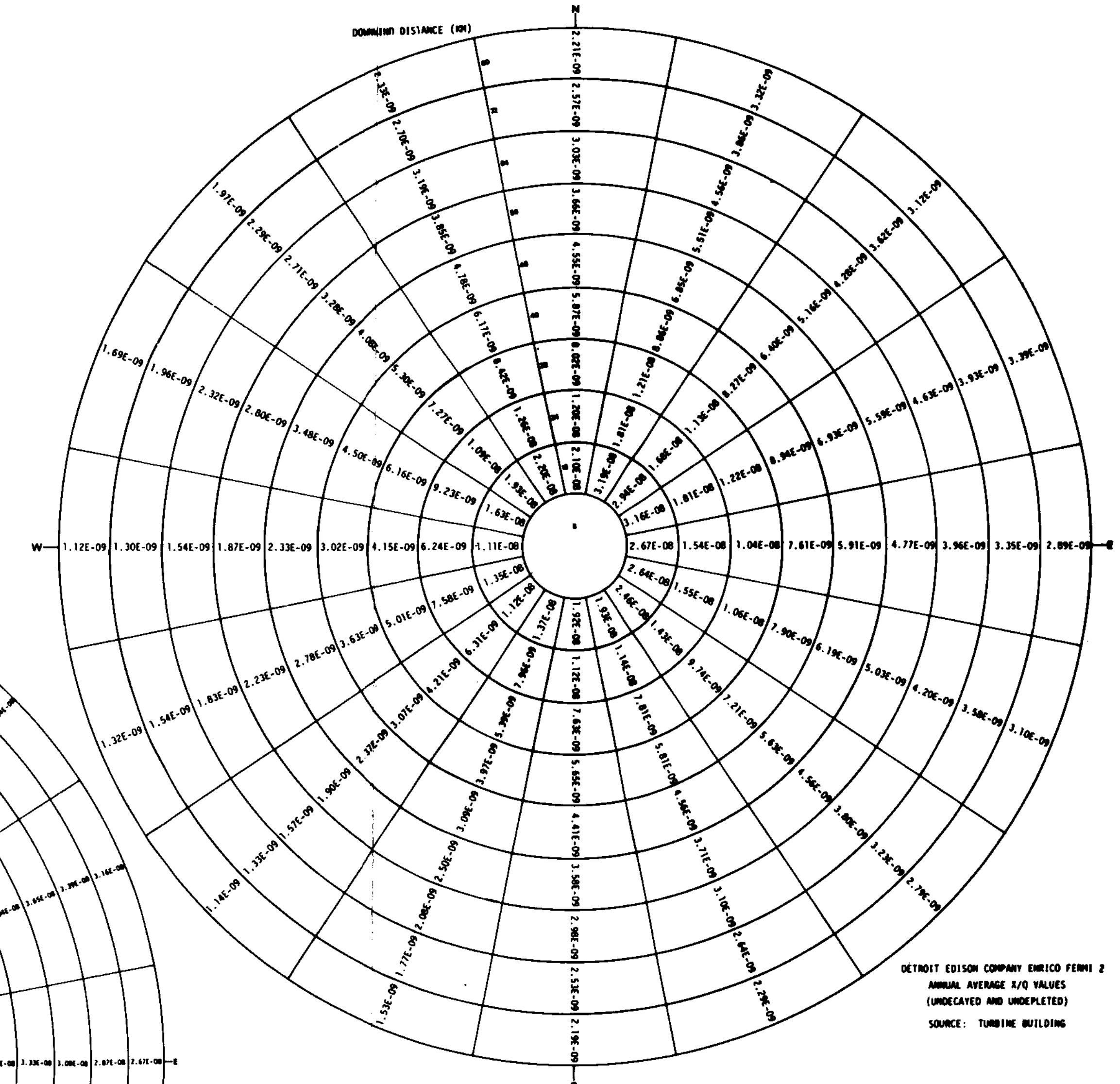


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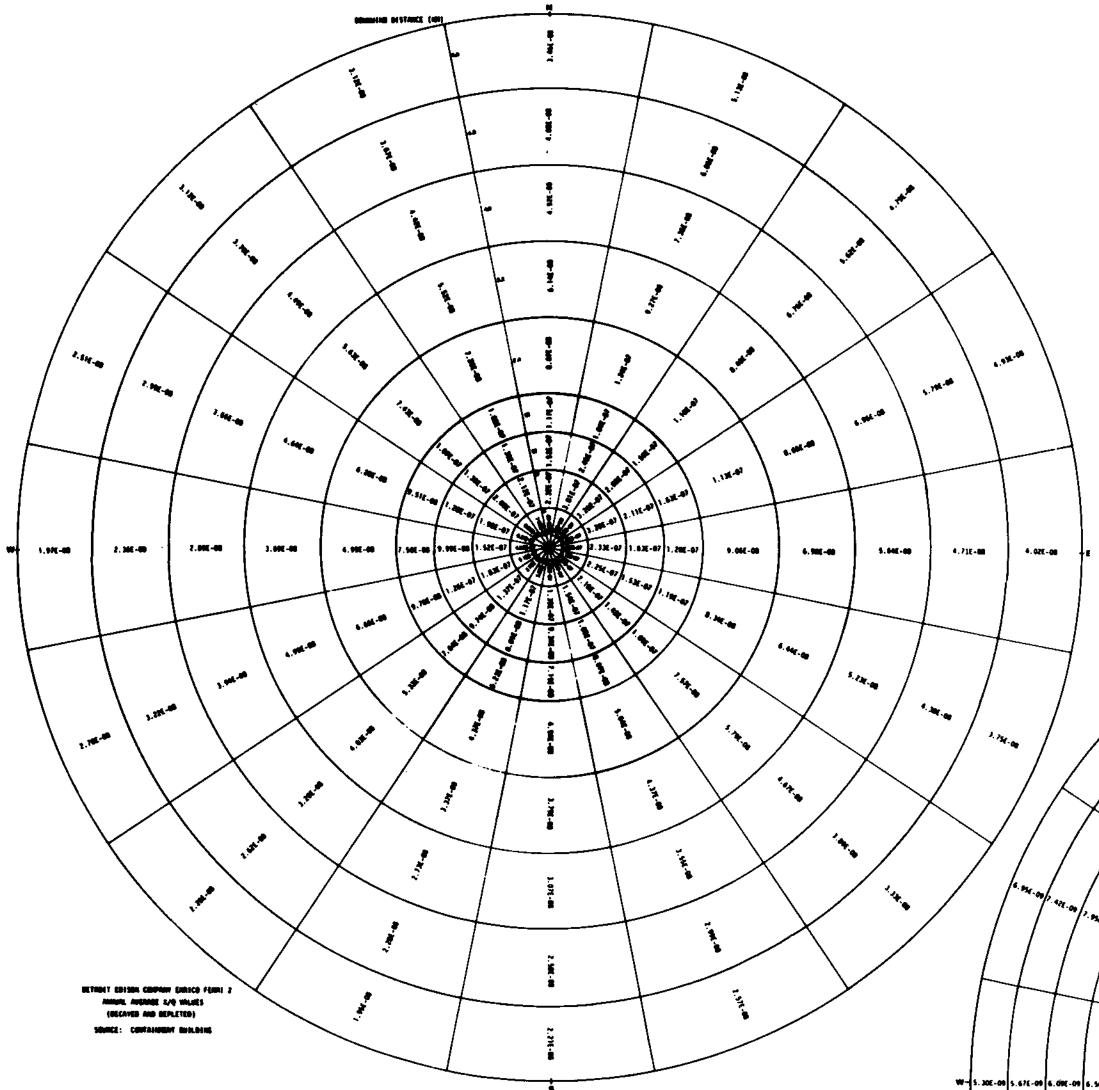
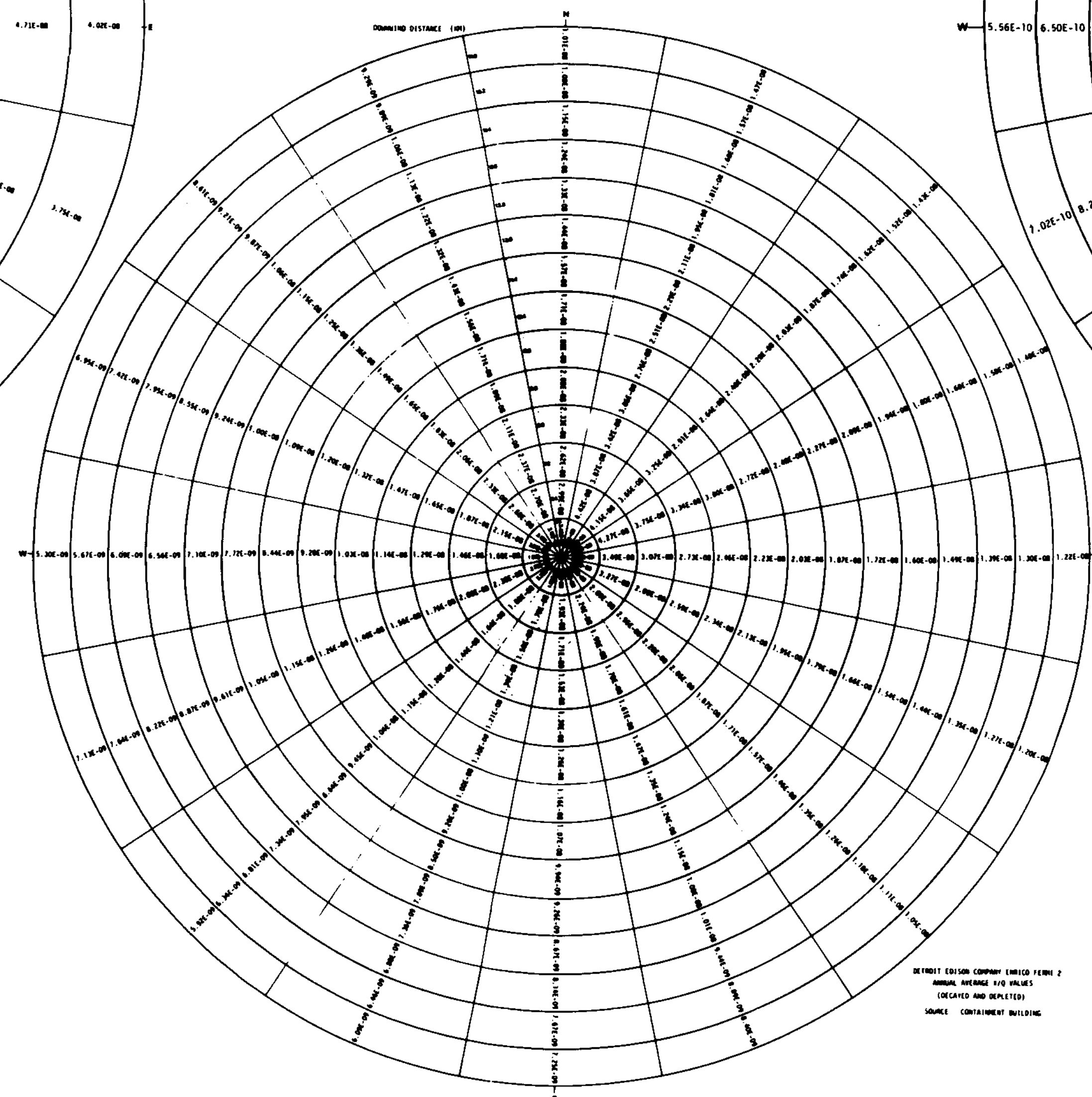
FIGURE 2.3-54

ANNUAL AVERAGE χ/Q VALUES
TURBINE BUILDING SOURCE
(UNDECAYED AND UNDEPLETED)





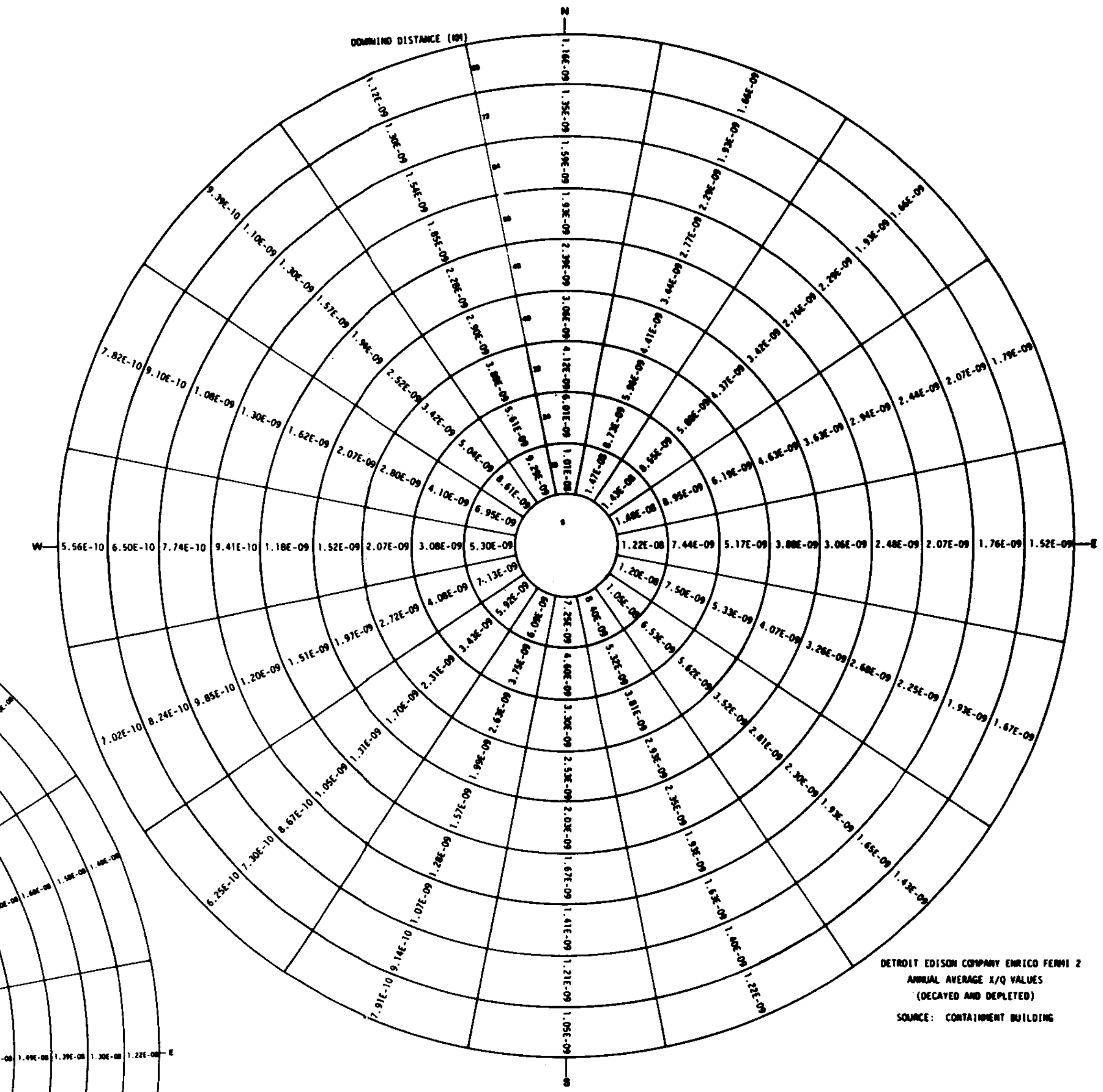


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FIGURE 2.3-55

ANNUAL AVERAGE X/Q VALUES
CONTAINMENT BUILDING SOURCE
(DECAYED AND DEPLETED)

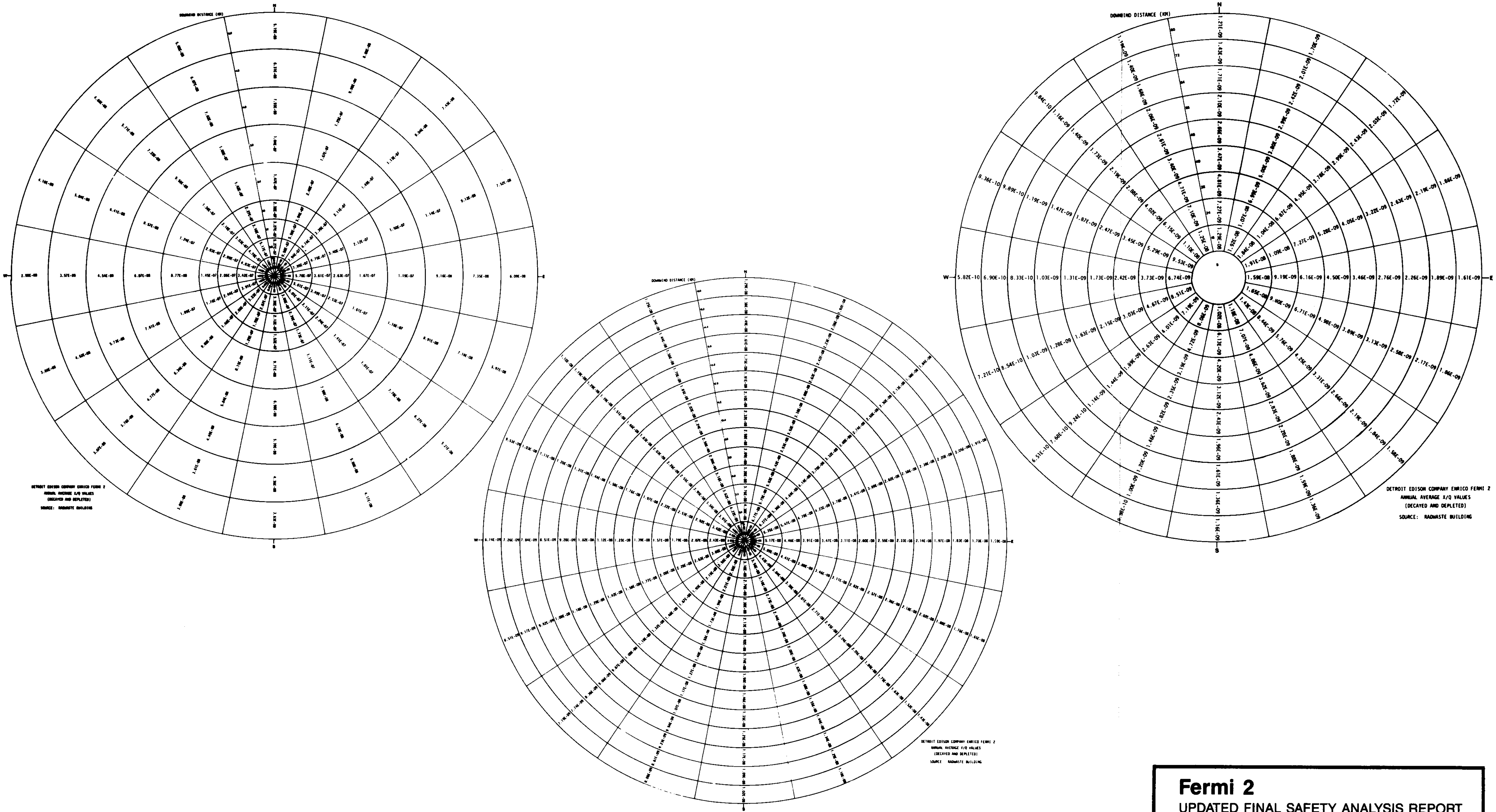

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FIGURE 2.3-56

ANNUAL AVERAGE X/Q VALUES RADWASTE BUILDING SOURCE (DECAYED AND DEPLETED)

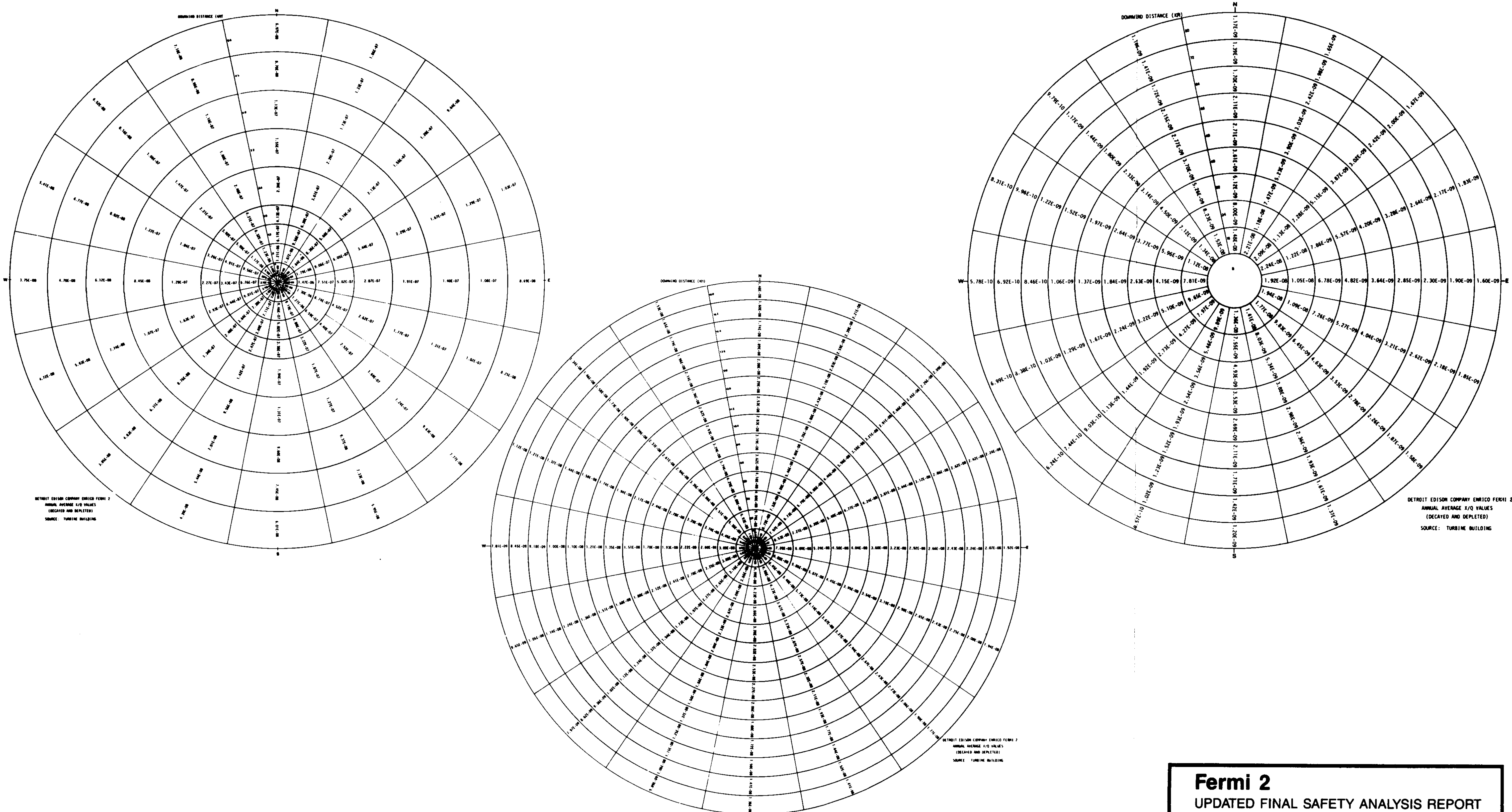

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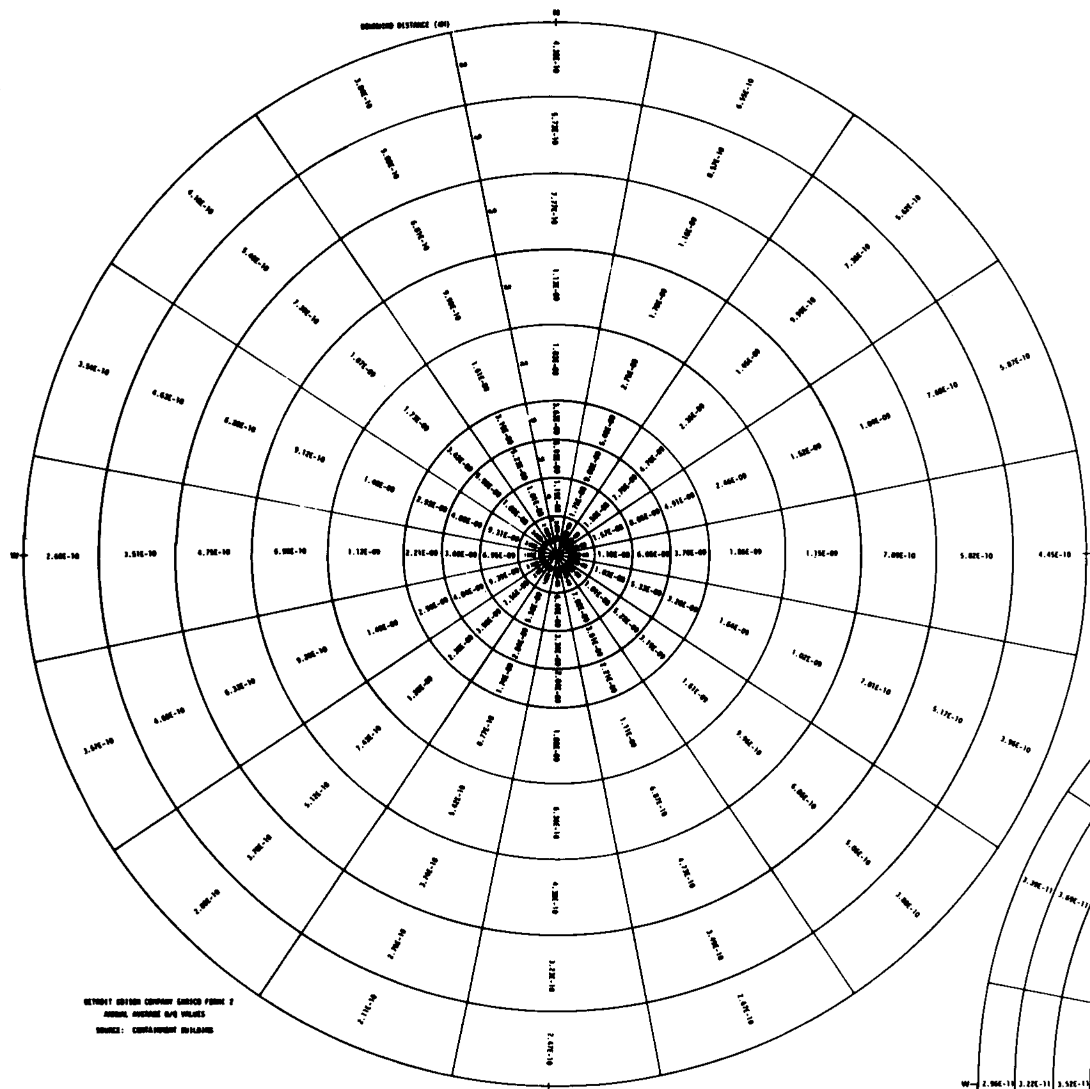
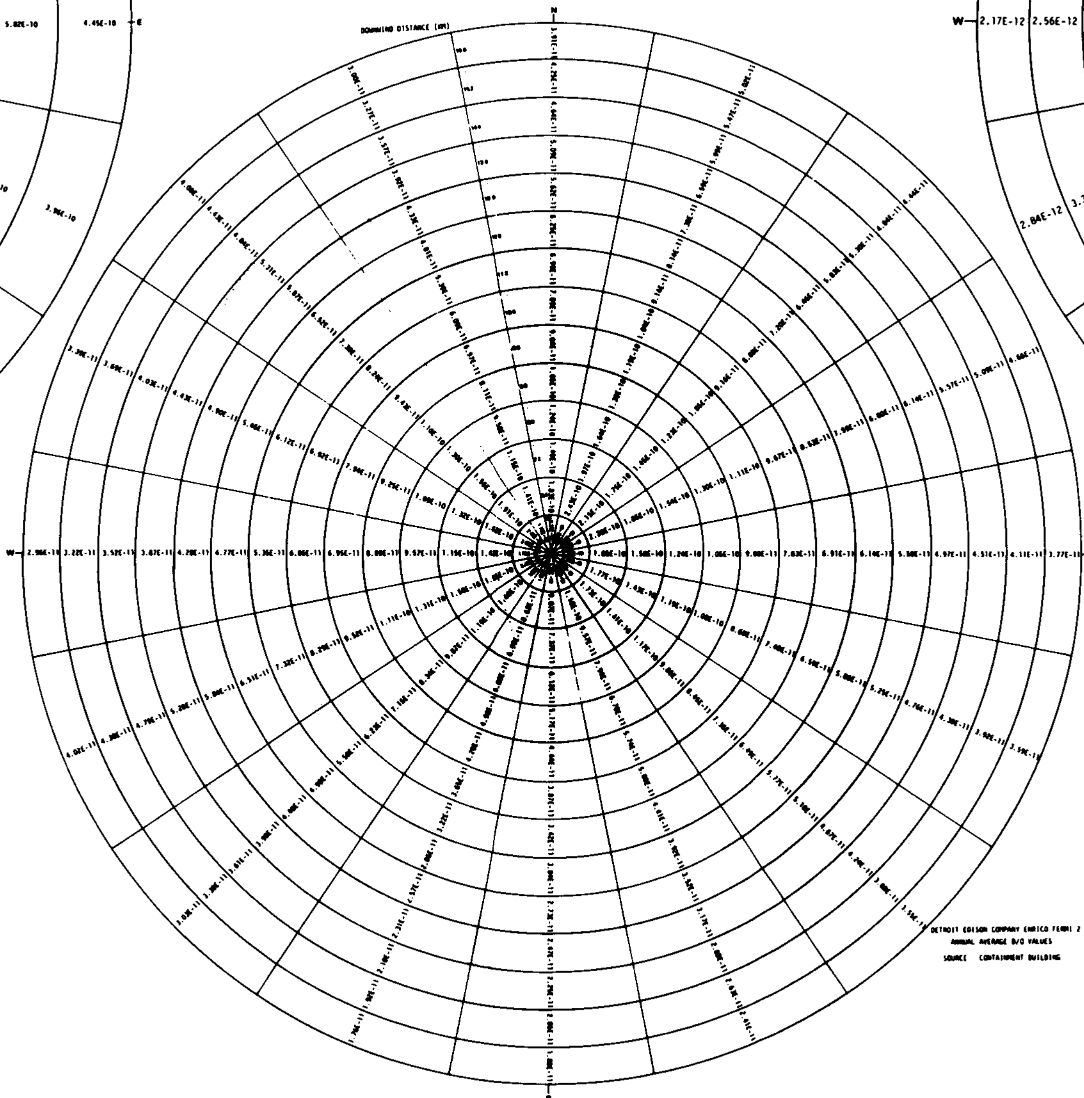
FIGURE 2.3-57

ANNUAL AVERAGE χ/Q VALUES TURBINE BUILDING SOURCE (DECAYED AND DEPLETED)





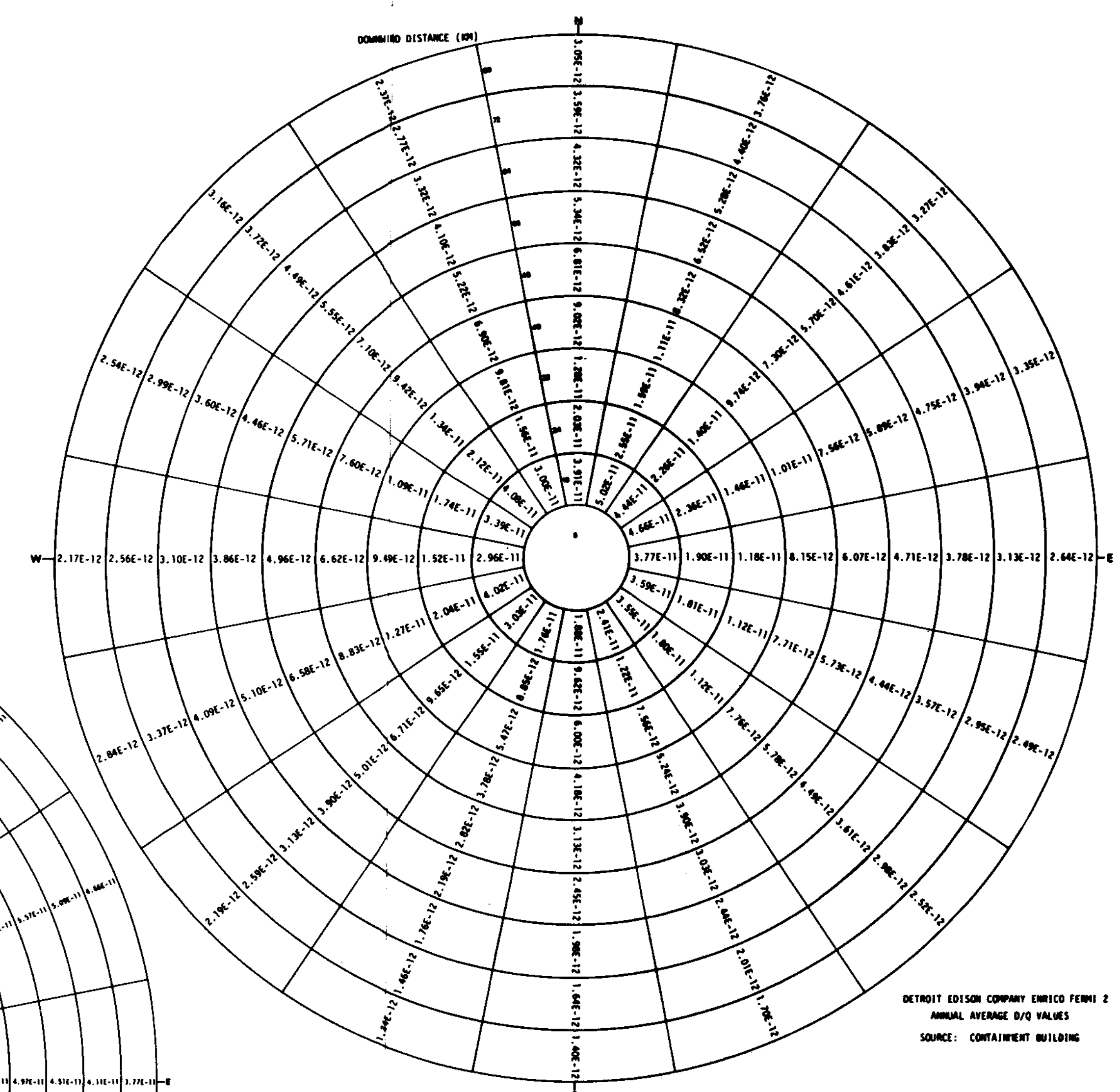


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FIGURE 2.3-58

RELATIVE DEPOSITION D/Q VALUES CONTAINMENT BUILDING SOURCE

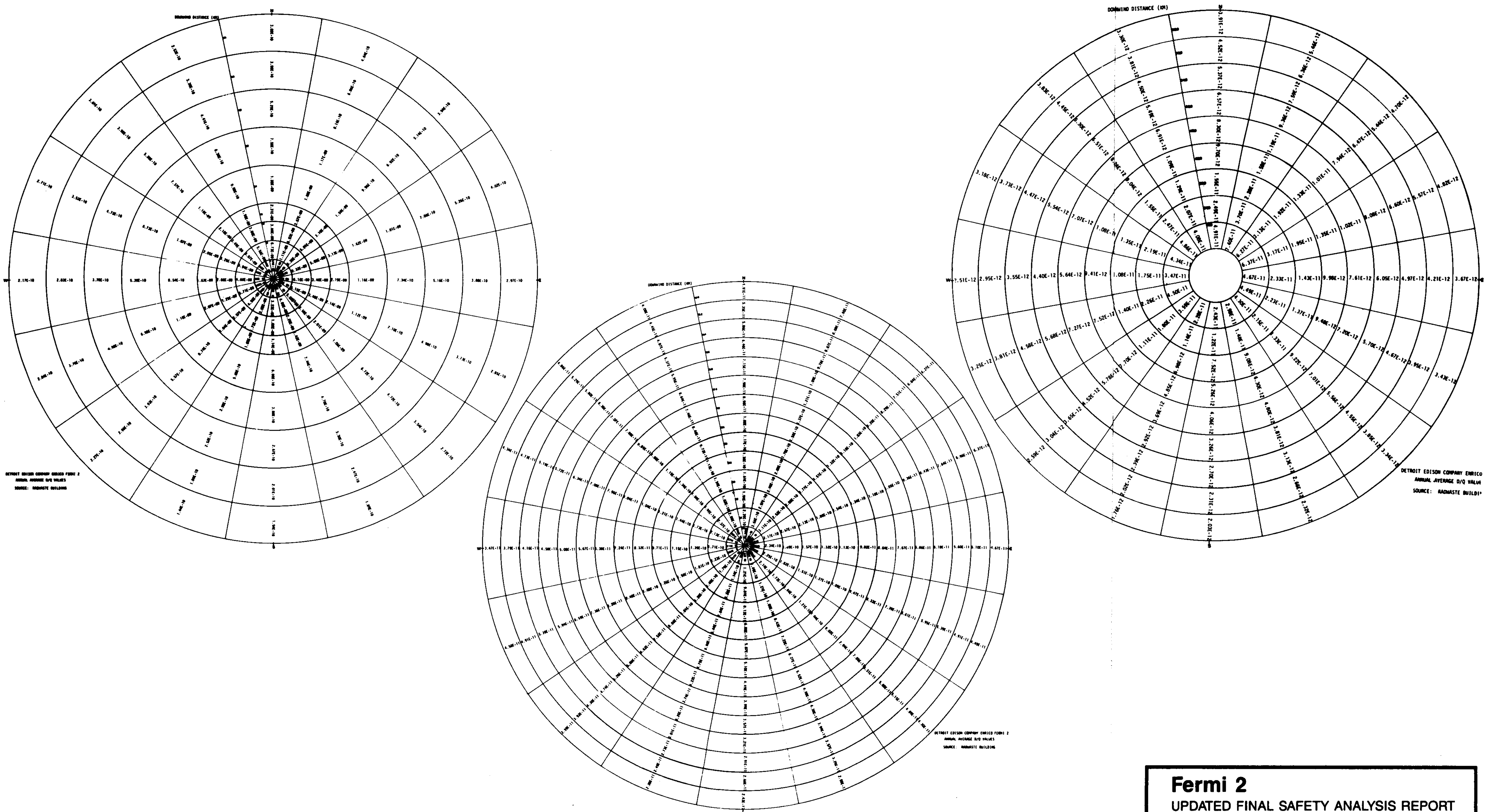

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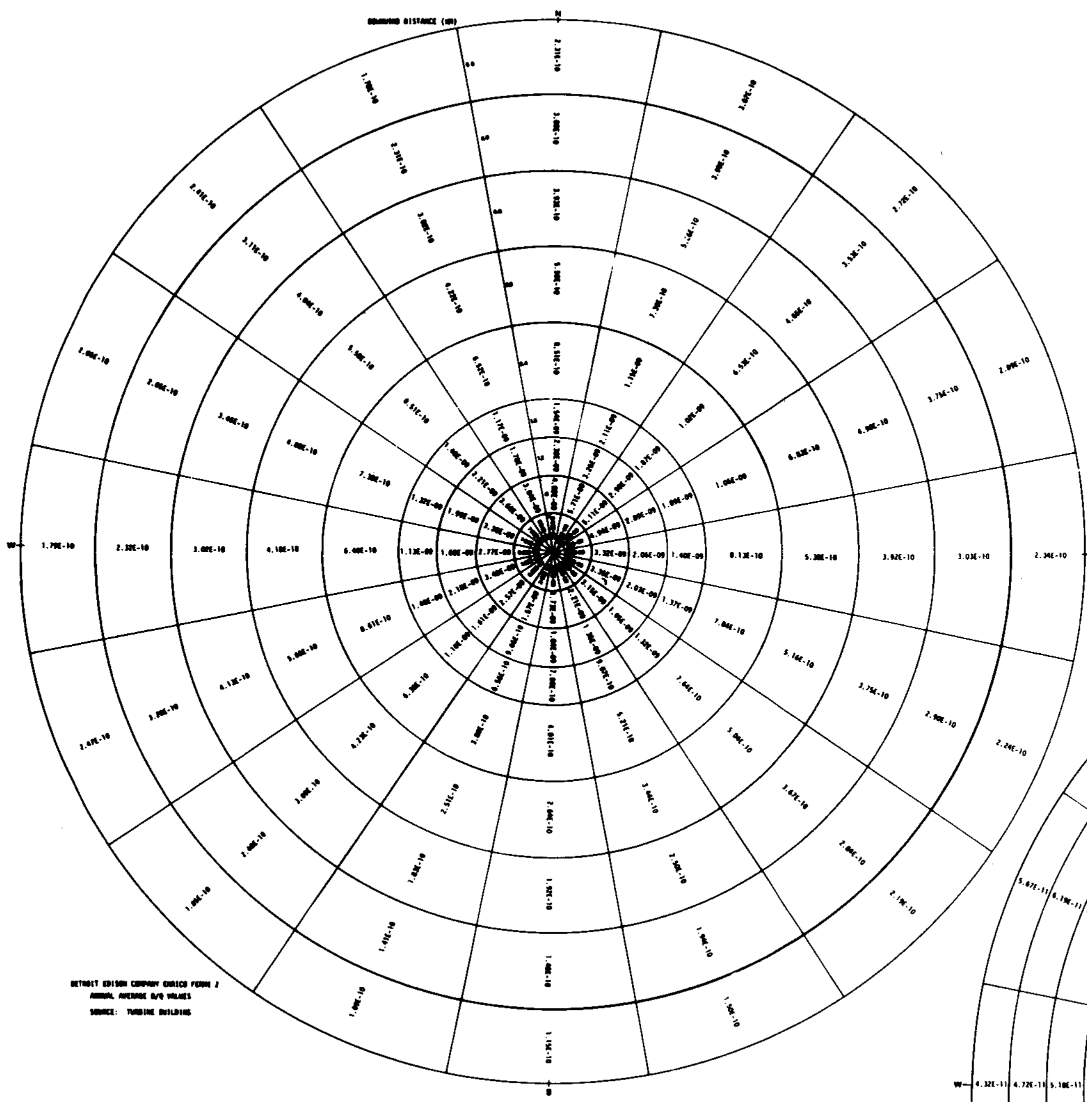
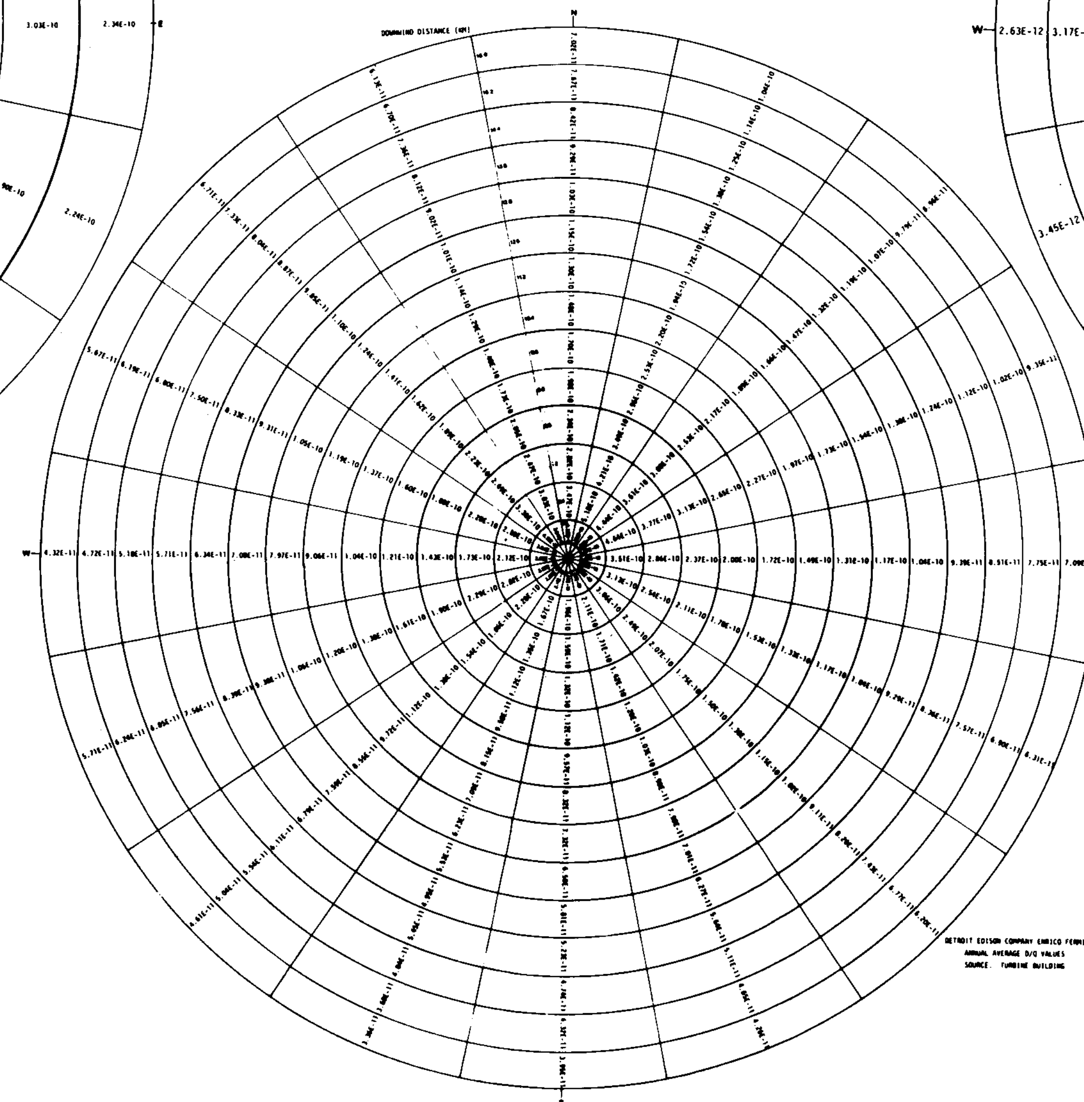
FIGURE 2.3-59

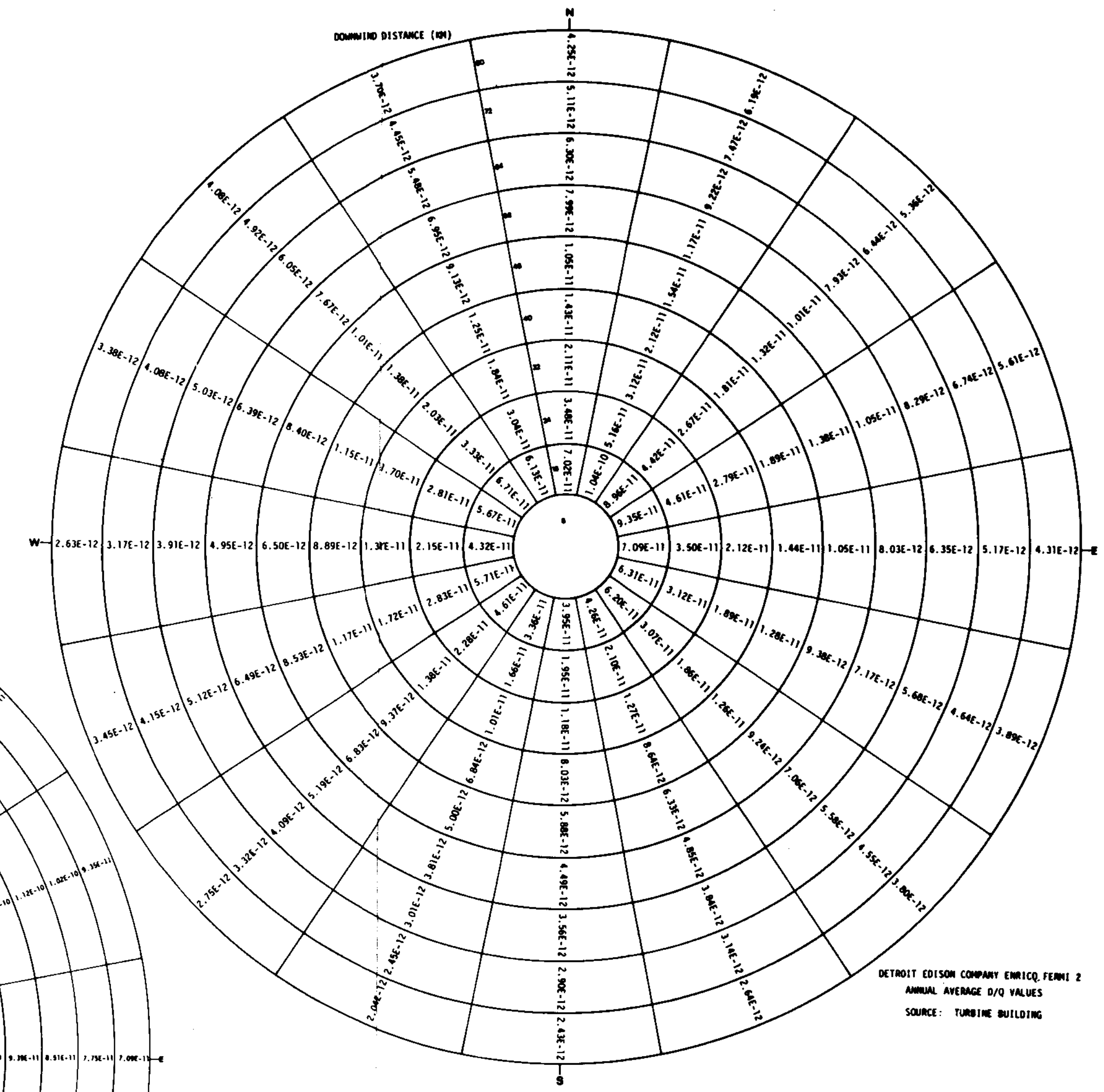
RELATIVE DEPOSITION D/Q VALUES
RADWASTE BUILDING SOURCE



DETROIT EDISON COMPANY ENRICO FERMI 2
ANNUAL AVERAGE D/Q VALUES
SOURCE: TURBINE BUILDING



DETROIT EDISON COMPANY ENRICO FERMI 2
ANNUAL AVERAGE D/Q VALUES
SOURCE: TURBINE BUILDING



DETROIT EDISON COMPANY ENRICO FERMI 2
ANNUAL AVERAGE D/Q VALUES
SOURCE: TURBINE BUILDING

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FIGURE 2.3-60

RELATIVE DEPOSITION D/Q VALUES
TURBINE BUILDING SOURCE

2.4. HYDROLOGIC ENGINEERING

2.4.1. Hydrologic Description

2.4.1.1. Site and Facilities

The Fermi site is located adjacent to the western shore of Lake Erie (Figure 2.4-1). Prior to construction of Fermi 2, the site area was a lagoon separated from Lake Erie by a barrier beach, known as Lagoona Beach, which formed the eastern site boundary. The Fermi 2 preconstruction topography is shown in Figure 2.4-2. The lagoon was connected to Lake Erie by Swan Creek, a perennial stream that discharges into Lake Erie about 1 mile north of the Fermi plant site. The site for Fermi 2 was prepared by excavating soft soils and rock, and constructing rock fill to a nominal plant grade elevation of 583 ft. All elevations refer to New York Mean Tide, 1935. The topography of the developed site as of December 10, 1972, is shown in Figure 2.4-3.

Category I structures housing safety-related equipment consist of the reactor/auxiliary building and the residual heat removal (RHR) complex. These structures are indicated in Figure 2.1-5. The plant site is not susceptible to flooding caused by surface runoff because of the shoreline location and the distance of the site from major streams. Plant grade is raised approximately 11 ft above the surrounding area to further minimize the possibility of flooding. Flooding of the site is conceivable only as the result of an extremely severe storm with a storm-generated rise in the level of Lake Erie. Protection of safety-related structures and equipment against this type of flooding is provided through the location, arrangement, and design of the structures with respect to the shoreline and possible storm-generated waves.

After the excavation of topsoil, peat, and soft clay, construction of the plant site to grade Elevation 583 ft (nominal) was accomplished using the following fill materials:

a. Crushed rock (1-1/2-in. maximum) within 10 ft from the building walls (water has been observed to run off rather than drain through this evenly graded crushed rock)

b. Crushed rock (6-in. maximum) inside the perimeter road (surrounding the plant main structures), except adjacent to buildings (this permits water to drain quite well)

c. Quarry run rock for most fill areas outside the perimeter road (surrounding the plant main structures) (providing good drainage for water under almost all circumstances)

d. Topsoil for grass was placed on a layer of 1-ft-deep crushed-rock fill, 1-1/2-in. maximum, to avoid being washed down.

Roof water that is collected through drainage systems from all structures and catch basins inside the perimeter road is collected and routed to the station storm-water drain system to prevent ponding of water adjacent to structures. Water in the plant storm-water drain system is then discharged into the overflow canal. In grassy areas outside the perimeter road, and in gravel areas, catch basins discharge water into the quarry run fill. In paved areas, the catch basins are usually tied to the storm-water drain system. The plant circulating water is treated within the closed loop circulating water system, which includes the 5.5-acre circulating water reservoir.

2.4.1.2. Hydrosphere

2.4.1.2.1. Regional Conditions

The region of the Fermi site is located within the western part of the Lake Erie drainage basin. The divide between the Lake Michigan and the Lake Erie watersheds lies about 50 miles west of the site. Perennial streams in the region generally flow in a southeasterly direction and discharge into Lake Erie. Tributaries of these streams are intermittent and form a dendritic drainage pattern.

The average precipitation in the region ranges from 30 in. to 36 in./yr (Subsection 2.3.1.2). Average annual runoff ranges from 10 to 16 in. Infiltration is highest in the western part of the region in areas where permeable soils occur in end moraines and beach lacustrine deposits. High runoff coefficients are characteristic of the relatively impermeable lacustrine soils in the eastern part of the region.

2.4.1.2.2. Swan Creek

The Fermi site is in the Swan Creek drainage basin. The watershed is an area of 109 square miles, elongated in shape from northwest to southeast (Figure 2.4-4). The basin is about 25 miles long with a maximum topographic relief of about 130 ft. The drainage area topography is flat to gently undulating and varies from about 700 ft elevation in the upper watershed to about 570 ft elevation at Lake Erie.

Land in the basin is mixed in use for residential, commercial, industrial, and agricultural purposes. The surface soils are primarily lacustrine clay with some lacustrine sand ridges at the head of the watershed. The infiltration capacity of the basin soils is low. Surface drainage is poor and drainage ditch improvements are common in the upper part of the basin. Stream channel flow is retarded by typical vegetative cover of deciduous trees and brush undergrowth. There are no flow-control structures on Swan Creek. Stream level near the site is controlled by the level of Lake Erie.

Gages were placed along Swan Creek in 1971 and the collected data indicate that runoff is greatest during the spring and early summer (Reference 1). Data on the adjacent River Raisin and Huron River also indicate that runoff is highest during spring and summer. However, Swan Creek stream flow is normally too low for water supply use.

2.4.1.2.3. Lake Erie

2.4.1.2.3.1. Lake Characteristics

Lake Erie is approximately 240 miles long and has a mean width of 40 miles. The lake is divided into three principal subbasins: (1) a small, shallow basin at the west end which borders the site and is partially restricted by a chain of barrier beaches and islands; (2) a flat, unrestricted, and rather shallow basin in the center; and (3) a small, relatively deep eastern basin. The average depth of the lake is 61 ft and the maximum depth is 210 ft. The longitudinal axis of the lake trends northeast-southwest, a direction coincident with strong and persistent winds that predominate under normal meteorological conditions. Wind stresses acting upon the lake surface over a sustained period can have a considerable effect on the level of the lake.

The most significant lake level variations are observed mainly at the western and eastern ends of the lake and are caused by transport of water as a result of sustained wind actions. Historical records show that in about 96 percent of all extreme cases, high water occurred at the eastern end of the lake and low water occurred at the western end. This is a result of the predominantly westerly winds causing the lake to set up at the eastern end.

The lake bottom in the vicinity of the site slopes very gently toward the east, reaching a depth of approximately 12 ft about 1/2 mile offshore. The soil deposits below the west end of the lake consist primarily of sand with intermittent layers of gravel and/or clay.

Two primary current patterns exist in the Lagoona Beach embayment. Winds moving from the northwest clockwise through northeast result in a general southwestward airflow over the entire embayment. This airflow creates the pattern of water movement shown in Figure 2.4-5. When the winds are from east-southeast clockwise through west, northward longshore currents are found to exist with a pronounced clockwise eddy formed south of the Point Mouillee marshes. This current pattern is shown in Figure 2.4-6.

When onshore winds from east clockwise through east-southeast and offshore winds from west-northwest clockwise through northwest occur, phase systems of current flow develop that produce variable patterns. The longshore currents shift from one primary current pattern to the other, reflecting changes in the local wind system. These phase changes are generally of short duration. Under ice cover, variations occur in the southward current flow and result in divergence of the currents immediately south of the existing plant intake and convergence north and east of Pointe Aux Peaux as shown in Figure 2.4-7.

2.4.1.2.3.2. Water Use

The use of potable and agricultural surface water within 10 miles of the plant site is presented in Subsection 2.1.4.2. Surface-water users withdrawing water from intakes in Lake Erie are the only surface-water users subject to the effects of accidental or normal releases of contaminants from the plant into the hydrosphere. The existing intakes along the western shore of Lake Erie have been examined to ensure that the dilution capacity of Lake Erie is sufficient to preclude adverse effects on users from releases of contaminants (Subsection 2.4.12). It is expected that future intakes will be located in the same approximate area and likewise will not be exposed to adverse effects of contaminants.

Municipalities with Lake Erie intakes, listed in Table 2.1-12, are located as shown in Figure 2.1-20. The municipal water intake nearest to the plant is the Monroe intake near Pointe Aux Peaux, approximately 2 miles southeast of the site, as shown in Figure 2.4-1. The Toledo intake is located about 18.6 miles due south of the plant site. The 1972 annual withdrawals at the Monroe and Toledo intakes were 2000 x 10^6 gal and 29,200 x 10^6 gal, respectively.

2.4.1.2.4. Ground Water

Regional ground water features are discussed in Subsection 2.4.13.1.1. Ground water in the site area occurs in a dolomite aquifer, underlying a mantle of relatively impermeable glacial deposits and recent sediments. This mantle ranges up to 40 ft in thickness. Water wells are of low yield and the water is highly mineralized. The aquifer characteristics and ground water uses are described in more detail in Subsection 2.4.13.2.

2.4.2. Floods

2.4.2.1. Flood History

2.4.2.1.1. Maximum Mean Monthly Lake Levels

Based upon data collected by the U.S. Lake Survey, Detroit, Michigan (Reference 2), the highest observed monthly mean water level during the period of record from 1860 to 1973 was +4.9 ft above Low Water Datum. This level occurred during June 1973, at Monroe, Michigan. During 1973, the monthly mean water level varied between +3.0 and +4.9 ft above Low Water Datum, a vertical variation of 1.9 ft (Figure 2.4-9). In 2019, it was identified that the maximum mean monthly lake level had exceeded +4.9 ft above the Low Water Datum. This condition persisted for several months in 2019 and recurred during 2020. To address the potential for maximum mean monthly lake levels to exceed the historical observations in Reference 2 and Figure 2.4-9, additional analyses were performed to consider the impact to the site from maximum mean monthly lake levels up to +6.4 ft above Low Water Datum. See Sections 2.4.2.1.6 and 2.4.2.2.6 for additional information.

2.4.2.1.2. Maximum Wind Tide

Lake gaging records at Monroe have been collected for the periods from 1932 to 1939 and from 1952 to the present. Data from gages at Gibraltar and Toledo have been in existence since 1897 and have been correlated with records from the Monroe gage. Based on this relationship, the calculated maximum wind tide at Monroe was +4.5 ft on January 30, 1939. In an earlier report covering the period 1886 to 1896, a maximum wind tide of +5.5 ft was reported at Monroe. The description of the easterly gales that produced this wind tide suggests that they were more intense than those reported during the past 77 years. Therefore, it is reasonable to accept +5.5 ft (Elevation 576.0 ft) as the maximum wind tide occurrence since 1886.

2.4.2.1.3. Seiche History

Seiche history is discussed in Subsection 2.4.5.2.

2.4.2.1.4. Swan Creek

Complete flood data are not available for Swan Creek as gages were not installed until 1971. Long-term information exists from gages on adjacent drainage basins. On the River Raisin near Monroe, the largest flood (record begins in 1938) occurred on March 29, 1950, and the second largest on April 6, 1947. On the Huron River at Ann Arbor, the largest flood (record begins in 1918) occurred on April 5, 1947. Maximum annual floods occur principally in April and May. Discharge frequencies at the mouth of Swan Creek, estimated using standard methods (References 3 and 4), are shown in Table 2.4-1.

The estimated 100-year frequency discharge of 9300 cfs on Swan Creek is significantly less than the probable maximum flood (PMF) flow of 89,000 cfs (Subsection 2.4.3.4). In

Subsection 2.4.3.5, it is demonstrated that the PMF flow on Swan Creek could not cause flooding at plant grade Elevation 583.0 ft. Therefore, water levels for the estimated discharges in Table 2.4-1 are not pertinent to site flood considerations.

2.4.2.1.5. Recent Storms

2.4.2.1.5.1. April 1966 Storm and Flood Analysis

On April 27, 1966, a persistent storm system moved into the Lake Erie drainage basin. During the month of the storm, the mean lake level at Toledo, Ohio, was 1.7 ft above the Low Water Datum of 570.5 ft. The maximum surge on Lake Erie occurred at Toledo while proportionately smaller surges were measured at distances from Toledo. The water level at Toledo reached 577.50 ft, which was 7.0 ft above the datum. The surge was driven by steady northeast winds with a directional duration of about 48 hr. At the time of peak surge, 1000 hr on the 27th, the maximum wind velocity measured at the Detroit River Light Station was 38 knots. However, a maximum wind velocity of 42 knots from the east-northeast was measured at 1300 hr, by which time the surge elevation had dropped to 575.93 ft.

Wave heights ranging from 6 to 7 ft were reported at the Toledo Harbor Light Station. To supplement the available wave data, a wave hindcast analysis was performed for the Fermi site. As discussed above, the times of peak surge and of peak wind velocity do not coincide, and this was considered in the hindcast analysis. The critical wind speed measured at the Detroit River Light Station was 38 knots from the northeast. This wind speed was increased by a factor of 1.30 to obtain a velocity representative of open-water conditions. The fetch aligned with the wind direction was 51,650 ft long and had associated with it a depth of approximately 13 ft at high water. A significant wave height and period of 3.8 ft and 3.2 sec, and a maximum wave height and period of 6.8 ft and 3.8 sec, would have been generated during this storm. Because the shoreline north of the Fermi site is oriented northeast, the waves that approached the site would have been attenuated by refraction and by the available depth of water over the sloping lake bottom. A conservative approximation of the lake bottom slope in this area is 1:100. Using this slope and the maximum wave period, the maximum supported wave height reaching the beach at the highest water level would have been about 1.3 ft. Waves larger than this would have broken too far seaward of the beach berm to have affected the site. The maximum runup elevation that would have been reached during this storm is 579.6 ft. This elevation is considerably less than the plant grade at the Fermi site of 583.0 ft and the probable maximum meteorological event (PMME) water level of 586.9 ft (Subsection 2.4.5).

2.4.2.1.5.2. November 1972 Storm and Flood Analysis

On November 13, 1972, a sudden storm moved into the Lake Erie drainage basin. The storm produced widespread flooding after the storm winds shifted from south to northeast, resulting in local evacuation within the low-lying areas along the western and southwestern shores. The total effect of the storm was that of a wind tide plus the abnormally high water level of Lake Erie, which existed at the time. In November, the mean lake level at Toledo was 3.6 ft above the Low Water Datum of 570.5 ft. The maximum surge on Lake Erie occurred at Toledo, while proportionately smaller surges were measured at distances from Toledo. The water level at Toledo reached 577.9 ft, which is 7.4 ft above the datum, while the maximum level at the Fermi site was 576.8 ft, which is 6.3 ft above the datum. Marblehead and Cleveland, Ohio, experienced maximum surges to Elevations 577.0 and 576.2 ft, respectively. The surge was driven by northeast winds with a directional duration of approximately 24 hr and a maximum velocity of about 40 knots over the central portion of the lake.

For most of November 12, 1972, winds were light and out of the southwest. Very late on the 12th and throughout the 13th, winds shifted gradually to northwest, then to northeast. By midday on November 13, the northeast winds were established and the velocity increased to 20 knots. The water level began rising at the Fermi site at 0800 hr on November 13. The maximum wind speed at Toledo was 25 knots and was reached early on November 14. By midday on the 14th, when the wind direction was changing to north, the water level at the Fermi site had reached its maximum elevation, 576.8 ft. The water level dropped rapidly, reaching a minimum level of elevation at 1800 hr on the 14th. Wind direction remained northerly throughout the 15th and velocity varied from 5 to 14 knots. Secondary and tertiary seiches were experienced on the 15th, but decayed rapidly from bottom friction. The troughs of these seiches resulted in lake elevations of 573.5 and 573.3 ft at the Fermi site. By November 16, the water level had stabilized at approximately Elevation 574.3 ft.

Waves during this storm were not measured at the site. Sufficient data describing the storm are available to hindcast the probable wave attack at the site. Waves were estimated at the Detroit River Light Station as ranging between 5 and 8 ft. Wind speed reached a maximum of 35 knots from the northeast at the Detroit River Light Station while Toledo Express Airport reported a maximum of 25 knots from direction N50°E. Applying a factor of 1.3 to the Detroit River Light Station yields an over-water wind velocity of 45.5 knots. The fetch aligned with the wind direction was approximately 51,000 ft long and had associated with it a depth of approximately 20 ft at high water. A significant wave height and period of 4.2 ft and 3.3 sec, and a maximum wave height and period of 7.6 ft and 4.0 sec, would have been generated during this storm.

The waves that approached the Fermi site would have been limited in height by the available depth of water over the gradually sloping lake bottom. Figure 2.4-10 shows the bathymetry offshore of the site.

A conservative approximation of the lake bottom slope in this area is 1:100. Using this slope and the maximum wave period, the maximum supported wave height reaching the beach at highest water level would have been 1.7 ft. Waves larger than this would have broken too far seaward of the beach berm to have affected the site.

The maximum runup elevation which would have been reached during this storm is 579.6 ft. This elevation is considerably less than the plant grade at the Fermi site of 583.0 ft and the PMME water level of 586.9 ft.

2.4.2.1.5.3. <u>April 1973 Storm and Flood Analysis</u>

Another storm moved into the Lake Erie Basin on April 9, 1973. Although this storm was less intense than the November 1972 storm, its total impact was nearly equal to the November storm because of the extremely high static lake level at the time.

In April 1973, the mean lake level at Toledo was measured by the U.S. Lake Survey as +4.76 ft above the Low Water Datum of 570.5 ft. The maximum surge associated with this spring storm was measured as +3.3 ft at Toledo, which brought the total stillwater level to 578.6 ft. This is 0.7 ft higher than the level reached by the November l972 storm.

On April 8, 1973, wind speeds ranged from 15 to 20 knots, blowing steadily from the northeast. On the morning of the 9th, the wind speed increased, reaching a maximum value of 35 knots and shifting gradually to the east-northeast by 1430 hr. The water level began rising at Toledo, Ohio, at 0100 hr on April 9 and reached maximum Elevation 578.57 ft at 1600 hr on the 9th. The water level dropped rapidly, reaching minimum level Elevation 573.2 ft at 0100 hr on the l0th.

Secondary and tertiary seiches were experienced on the 10th, but decayed rapidly from bottom friction. By April 11, the water level had stabilized at approximate Elevation 574.6 ft. At the height of the storm, an 8-ft wave height was reported at the Detroit River Light Station.

To supplement the available wave data, a wave hindcast analysis was performed for the Fermi site. The maximum wind speed measured at the Detroit River Light Station was 35 knots from direction N67.5°E. This wind speed was increased by a factor of 1.30 to obtain an over-water velocity. The fetch aligned with the wind direction was 66,900 ft long and had associated with it a depth of approximately 20 ft at high water. A significant wave height and period of 4.8 ft and 3.6 sec, and a maximum wave height and period of 8.6 ft and 4.3 sec, would have been generated during this storm.

The waves that approached the Fermi site would have been limited in height by the available depth of water over the gradually sloping lake bottom. A conservative approximation of the slope of the lake bottom is 1:100. Using this slope and the maximum wave period, the maximum supported wave height reaching the beach at highest water level would have been 2.0 ft. Waves larger than this would have broken too far seaward of the beach berm to have affected the site. The maximum runup elevation that would have been reached during this storm is 581.7 ft. This elevation is less than the plant grade at the Fermi site of 583.0 ft and the PMME water level of 586.9 ft.

2.4.2.1.5.4. June 1973 Storm and Flood Analysis

High static lake levels continued through 1973. During June the mean lake level measured at Toledo by the U.S. Lake Survey was approximately 4.9 ft above the Low Water Datum of 570.5 ft. The earlier April 1973 storm occurred at a time when the lake was approximately 4.8 ft above the Low Water Datum. The maximum instantaneous surge associated with this June storm was measured at +3.4 ft at Toledo, which brought the total stillwater level to 578.7 ft. This was 0.1 ft above the April 1973 storm and 0.8 ft higher than the November 1972 storm.

At the Fermi site, maximum stillwater levels recorded by the U.S. Lake Survey reached a peak hourly reading of 577.75 (Low Water Datum) at 0200 hr on June 17, 1973. The Fermi water-level recorder does not record instantaneous water levels; however, interpolation from stations at Toledo, Ohio, and Gibraltar, Michigan, yields an instantaneous high of approximately 578.6 ft. Detroit area newspapers reported a maximum flood stage of 578.4 ft.

Wind speeds with an easterly component at the west end of Lake Erie between June 17 and June 18 were generally light to moderate. The Toledo Express Airport recorded fastest 1-minute velocities of only 9.6 knots, while the Detroit River Light Station recorded velocities between 10 and 15 knots. In addition, the Canadian government reported easterly gusts to 34 knots with an average of 20.9 knots at their Southeast Shoal lighthouse near Pt. Pelee, Ontario. The duration of these easterly winds was about 25 hr with peak velocities reached in the first 6 hr.

Winds at the east end of the lake, at Buffalo, were only slightly higher but maintained an easterly component for approximately 34 hr. It was this long-duration, moderate-wind regime at the east end of Lake Erie that was primarily responsible for the flooding at the west end. Buffalo reported east winds 12 hr before Toledo. The east winds from Buffalo were met by westerly winds from Toledo, which resulted in a temporary water buildup (to Elevation 576.3 ft 4 in.) at Cleveland. When the Toledo winds finally switched from west to east, the light to moderate velocities were enough to push the surge into the western end of the lake.

Wave heights, which were estimated during the storm at the Detroit River Light Station, ranged from 2 to 5 ft. To supplement available data, a wave hindcast analysis was performed at the Fermi site. Assuming a maximum steady-state wind velocity of 21 knots blowing from the east (N90°E), and applying a factor of 1.3, an over-water wind velocity of 27.3 knots is obtained. The maximum fetch aligned with the wind direction was 199,500 ft and had associated with it a depth of approximately 25 ft at high water. A significant wave height and period of 3.9 ft and 3.2 sec, and maximum wave height and period of 7.0 ft and 3.8 sec, would have been generated during this storm.

The waves that approached the Fermi site would have been limited in height by the available depth of water over the gradually sloping lake bottom. A conservative approximation of the slope of the lake bottom is 1:100. Using this slope and the maximum wave period, the maximum supported wave height reaching the beach at highest water level would have been 1.3 ft. Waves higher than this would have broken too far seaward of the beach berm to have affected the site. The maximum runup elevation that would have been reached during this storm is 581.0 ft. This elevation is less than the plant grade at the Fermi site of 583.0 ft and the PMME water level of 586.9 ft.

2.4.2.1.5.5. <u>April 1974 Storm and Flood Analysis</u>

In 1974 the highest water level measured by the U.S. Lake Survey at Toledo occurred on April 8 at 12 noon. The maximum reading was the result of sustained high static lake levels and an early spring storm.

In March and April the mean lake level at Toledo was approximately 4.4 ft above the Low Water Datum of 570.5. The maximum surge associated with the storm that moved through the area on April 7 and 8 was measured at +3.6 ft, which brought the total stillwater level to 578.5 ft. This was 0.2 ft below the June 1973 storm and 0.1 ft below the spring storm of April 1973.

At the Fermi site, the maximum stillwater level recorded by the U.S. Lake Survey was at Elevation 577.6 ft, which occurred at 12 noon on April 8.

Fastest 1-minute wind speeds measured at the Toledo Express Airport had a northeasterly direction and obtained a maximum of 26 knots with an average of 16.3 knots. At the Detroit River Light Station, a maximum wind velocity of 28 knots from the northeast and an estimated wave height of 4 to 5 ft were recorded at l030 hr on April 8. At 1630 hr on April 8, the light station recorded an east-northeast wind at 25 knots and a wave height of 5 to 6 ft. At this time water levels were already dropping at both Toledo and the Fermi site.

To supplement the available wave data, a wave hindcast analysis was performed for the Fermi site. Assuming a maximum steady-state wind velocity of 28 knots from direction N67.5°E and applying a factor of 1.3, an over-water wind velocity of 36.4 knots is obtained. The maximum fetch aligned with the wind direction was 66,900 ft long and had associated with it a depth of approximately 20 ft at high water. A significant wave height and period of 3.8 ft and 3.2 sec, and a maximum wave height and period of 6.8 ft and 3.7 sec, would have been generated during this storm.

The waves that approached the Fermi site would have been limited in height by the available depth of water over the gradually sloping lake bottom. A conservative approximation of the slope of the lake bottom is 1:100. Using this slope and the maximum wave period, the maximum supported wave height would have been 1.6 ft. Waves larger than this would have broken too far seaward of the beach berm to have affected the site. The maximum runup elevation that would have been reached during this storm is 581.3 ft. This elevation is less than the plant grade at the Fermi site of 583.0 ft and the PMME water level of 586.9 ft.

2.4.2.1.6. 2019 and 2020 Lake Level Observations

In July 2019, it was identified that a Lake Erie water level reading in the main control room was above the design input water level assumed in the Fermi 2 design basis flood event. Although this reading was instantaneous and localized, subsequent investigation identified that the average monthly lake level had also exceeded the design input water level of +4.9 ft (corresponding to El. 575.3 ft NYMT-1935) assumed in the Fermi 2 design basis flood event. Using these higher lake levels and factoring in the wind-driven storm surge of 11.4 ft of wave runup height from Section 2.4.5.3, the resultant site stillwater elevation was greater than the existing design stillwater maximum of +16.4 ft (corresponding to El. 586.9 ft NYMT-1935) in Section 2.4.5.3 but lower than the flood design criteria of the Reactor/Auxiliary Building (El. 588.0 ft) and RHR Complex (El. 590.0 ft). This condition persisted for several months in 2019 and recurred in June 2020. To address these (and potential future) higher observed lake levels, a supplemental analysis of the site stillwater flood elevation was performed using the Bretschneider method (Reference 30) for determining storm surge. Using the Bretschneider method, a wind-driven storm surge of 10.1 ft was calculated. This supplemental analysis therefore establishes that the site stillwater elevation of +16.4 ft (corresponding to El. 586.9 ft NYMT-1935) remains the design basis flood event limit even assuming maximum monthly mean lake levels up to +6.4 ft (corresponding to El. 576.8 ft NYMT-1935).

2.4.2.2. Flood Design Consideration

2.4.2.2.1. Conditions Considered

The following basic types of hypothetical flooding conditions were considered in the design:

a. The PMF of 89,000 cfs on Swan Creek coincides with the mean monthly maximum water level of 575.3 ft in Lake Erie. In the discussion of backwater computations (Subsection 2.4.3.5), the resulting PMF flow elevation of 577.3 ft would provide a safety margin of 5.7 ft. Even by the use of a conservative slope/area computation (Subsection 2.4.3.5), the PMF elevation would be less than 582 ft, or 1 ft below plant grade at 583 ft and 1.5 ft below the elevation of plant door sills

b. Historically, the maximum probable wind tide of 11.6 ft coincides with a maximum monthly mean lake level of 575.3 ft. The resulting stillwater flood elevation at the plant site area in this case is 586.9 ft, or 3.90 ft above the plant grade elevation (Subsection 2.4.5.3). In those infrequent instances where the maximum monthly mean lake level exceeds historical averages in Reference 2 and Figure 2.4-9, a supplemental analysis described in Sections 2.4.2.1.6 and 2.4.2.2.6 has determined that the resulting stillwater flood elevation would not exceed +16.4 (corresponding to El. 586.9 ft NYMT-1935) as long as maximum monthly mean lake levels remain at or below +6.4 ft (corresponding to El. 576.8 ft NYMT-1935). This ensures that the storm surge continues to bound the high water level of a PMP and PMF event

c. Local probable maximum precipitation (PMP) runoff on the plant site coincident with runoff from the 2-square mile area above the plant site, assuming blockage of plant drainage, would result in no adverse effects on the safety-related (Category I) facilities. The estimated PMF of 25,300 cfs with a corresponding elevation of less than 582 ft, and the 15-minute PMP of 4.9 in. over the plant site with a grade elevation of 583 ft and door sills at 583.5 ft would not result in adverse plant site flooding, as further discussed in Subsection 2.4.2.3. The temporary local water buildup due to the failure of the plant drainage system will flow into the lower land and swamps at the northern end of the plant area and eventually discharge into Lake Erie through estuaries. The local temporary water buildup elevation will be substantially lower than the flood elevation due to the maximum wind tide, as described in item b. above

d. The potential dam failure effect is not applicable, as described in Subsection 2.4.4

e. The water level at the site is controlled by Lake Erie. The PMF flow from Swan Creek has no significant effect on the design water level at the site. The maximum lake stillwater level due to storm surge is Elevation 586.9 ft (Subsection 2.4.5.3). Plant grade is at Elevation 583.0 ft. At plant grade elevation, the lake water would extend approximately 2.5 miles inland from the plant site (Figure 2.4-11) and even further inland at maximum stillwater level.

The case (item b) above is clearly the most critical condition and is defined as the PMME.

2.4.2.2.2. Reactor/Auxiliary Building Flood Criteria

The Category I reactor/auxiliary building, which houses safety-related systems and components, is designed against flooding to Elevation 588.0 ft, or 1.1 ft above the PMME stillwater flood elevation of 586.9 ft. All doors and penetrations through the outside walls below the design flood elevation are of watertight design. All safety-related systems and equipment located inside this Category I structure are protected from the PMME flood. The reactor/auxiliary building is also designed to withstand wave action associated with this flooding. Maximum wave effects and forces are discussed in Subsection 2.4.5.4.

All interior floor drain systems inside the reactor/auxiliary building are not connected to the yard storm drainage system and, therefore, no potential water backflow into the structure is anticipated during the design flood condition. Shore protection is not required to preclude flooding of this structure.

The reactor/auxiliary building has only a few essential penetrations in the exterior walls. All of these penetrations below Elevation 588 ft are watertight.

The presence of the turbine building prevents waves and wave runup above the sill elevations on the east wall of the reactor/ auxiliary building, thereby preventing flooding of the buildings. The south wall of the reactor/auxiliary building has two large openings, two rail pockets with waterproofed seals and several waterproofed pipe-sleeved openings. These large openings are in an air-locked rail-car door and an air-locked personnel door. Both of these doors, however, will be air-locked and completely waterproofed to preclude wave runup flooding.

The reactor/auxiliary building roof is designed for a live load of 30 lb/ft^2. This load is equivalent to approximately 6 in. of water, or its equivalent in snow, or snow and ice load combined. Roof drains are designed for a rainfall of 4 in./hr. The reactor building roof water drains through openings in the parapet wall into scuppers and then down through conductors to the auxiliary building roof. Roof drains in the auxiliary building roof carry the runoff into the buried site drainage system by first passing through the turbine building roof drainage system.

2.4.2.2.3. Residual Heat Removal Complex Flood Criteria

The RHR complex is watertight to Elevation 590.0 ft. The north, south, and west walls have no openings. The east wall has approximately 30 waterproofed pipe-sleeved openings. The east wall also has four sets of double 3 ft by 7 ft doors for access to the building. These doors are normally closed and locked, and have their thresholds at Elevation 590.0 ft and extend to Elevation 597.0 ft. They are of steel construction and are shielded behind reinforced-concrete missile walls. The east wall also has eight 4” diameter openings with water tight seals located within each of the two RHR cable vaults at elevations above 590’-6”.

Waves reaching the east wall of the RHR complex across the flooded site would be diminished considerably by the stairs, the missile wall, and the landing at Elevation 590.0 ft in front of the doors. The insignificant amount of runup above the flooded elevation of 586.9

ft, or generated by the reduced waves, may find its way through the door threshold and door jambs, at Elevation 590.0 ft, and be diverted into the floor drain system in the building. The structure is also designed to withstand the wave action associated with this flooding. Shore protection is not required to preclude flooding of this structure.

The roofs of the RHR complex are provided with an adequate number of drainage pipes to pass runoff resulting from the PMP. The PMP was obtained from U.S. Weather Bureau (National Oceanic and Atmospheric Administration) information (Reference 5). Further, the storm-drainage provisions surrounding the RHR complex are designed to pass the discharge from the drain pipes as well as the runoff from surrounding areas. The plant area drainage system is designed so that there is no possibility of ponding near the RHR complex. The roofs of the RHR complex are designed for a postulated maximum ice and snow load of 70 lb/ft^2. This load is based on the simultaneous accumulation of the most severe postulated ice resulting from the mechanical draft cooling towers drift loss (21 lb/ft^2) plus the seasonal snowpack (30 lb/ ft^2), and on an additional ice load (19 lb/ft^2).

The mechanical draft cooling tower drift loss is based on an assumed drift loss of 0.015 percent, with the fans operating at full speed. For evaluating the ice loading on the RHR complex roof, a conservative value of 0.1 percent for drift loss was used at full speed. Under freezing conditions, the fans operate at half speed or are completely shut off. The total water loss under these conditions is less than 390 gal/hr. Based on the above, it is estimated that, with two towers operating for 30 days with no wind drift, and with the temperature below freezing, the maximum ice accumulation is less than 4-1/2 in. This amount of ice is equivalent to about 21 lb/ft^2 live load.

The seasonal snowpack load is based on results of reported research (Reference 6). According to this reference, the seasonal snowpack load is 30 lb/ft^2.

2.4.2.2.4. Category I Yard Structures Flood Design Criteria

The Category I piping and electrical ducts between the RHR complex and the reactor building are below the site flood elevation of 586.9 ft during the PMME. The RHR supply, RHR return, and emergency equipment service water pipelines to both divisions will continue to function during the flood.

There are two sets of Category I ductbanks between the RHR complex and the Reactor/Auxiliary building, with a Division I and Division II ductbank in each set. In each case, the buried cable ducts between the RHR complex and the Reactor/Auxiliary building provide adequate cable separation to maintain independence of redundant circuits.

The first set of ductbanks was installed during plant construction. The physical separation of the two redundant, below-grade circuits is 30 ft at the point the cable ducts leave the southeast corner of the reactor building. The ducts make a sweeping bend with a minimum separation of 20 ft between them. After the bend, the ducts parallel the reactor building in a westerly direction, with 24-ft separation. This separation is constant until the ducts pass under the rail-car air lock, where the separation widens until the ducts enter (still below grade) the RHR complex.

Each circuit is separately housed in a cast-in-place, rectangular reinforced-concrete duct. The duct is covered by successive layers of compacted rock fill placed up to the finished site grade of 583.0 ft. The duct runs vary in elevation from 573.0 ft minimum to 580.0 ft maximum. Since maximum ground water elevation is 576.0 ft, the cables are not specifically designed for continuous underwater service. For low voltage power, control and instrumentation cables, there is no long term mechanism for water related insulation degradation due to lack of voltage stressor or a credible common mode failure mechanism. Therefore, low voltage cables perform their design functions while their external surface remains continuously wetted due to surrounding water. 4160-V essential power circuits are not routed within these ductbanks.

The second set of ductbanks, associated manholes, and cable vaults is installed above the maximum ground water elevation of 576.0 ft with ducts sloped to the manholes, such that circuits contained are not subject to continuous wetting. These are also cast-in-place, rectangular reinforced concrete ductbanks, but are located with the ductbank top approximately six inches below the surface and manhole covers at grade level. The ductbanks rise above grade and enter above ground cable vaults at the RHR complex and also rise above grade at the entrance to the Reactor/Auxiliary building cable vaults. 4160-V essential power circuits are routed within these ductbanks.

The minimum elevation for cable termination in either the RHR complex or reactor building is 588.7 ft, which is above the site maximum probable stillwater elevation of 586.9 ft.

2.4.2.2.5. Site Drainage Flood Design Criteria

The storm drainage system is not used to protect Category I structures from local PMP flooding, as further discussed in Subsection 2.4.2.3. Inlet manholes in the immediate plant vicinity are located at the low points of relatively flat roadside and railroad track areas, and in local area depressions. The storm-drainage conduit discharges westward into the existing overflow canal for Fermi 1 and eventually into Lake Erie through estuaries. The storm-drainage system is designed as a gravity system with a minimum velocity of 3 fps flowing full for a rainfall intensity of 4 in./hr. Runoff coefficients used are 1.0 for roofs and paved areas and 0.5 for gravel and grassed areas. The closed storm-drainage system provides the normal means of drainage for the plant site and building roofs.

The sedimentation potential of the site drainage system for anticipated rainfall conditions is negligible since the site consists principally of firmly compacted crushed-rock fill and grassed areas, and the slopes of the ditches feeding the inlet of manholes are relatively flat. The resulting velocity of the drainage flow is nonscouring. Riprap or paving is provided for protection of outlet ends at all discharge points of the storm sewer system.

2.4.2.2.6. Bretschneider Methodology for Determination of Storm Surge

It has been observed that more recent maximum monthly mean lake levels may exceed historical data from Reference 2 and Figure 2.4-9. The site stillwater flood elevation in Section 2.4.5.3 of +16.4 ft (corresponding to El. 586.9 ft NYMT-1935) was originally established using the historical data from Reference 2 and Figure 2.4-9 for the initial lake level and combined with the Platzman method of determining wind tide/storm surge. To address the more recent lake levels which may exceed historical data, a new methodology was utilized. The Bretschneider method (Reference 30) of determining storm surge was identified as an NRC-approved methodology (Reference 31) for this application and shown to be acceptable for this analysis. Using the Bretschneider method and starting from higher lake levels, the overall amount of storm surge is calculated to be +10.1 ft. Therefore, with this methodology, the site stillwater elevation of +16.4 ft (corresponding to El. 586.9 ft NYMT-1935 in Section 2.4.5.3 remains the design basis flood event limit even assuming maximum monthly mean lake levels up to +6.4 ft (corresponding to El. 576.8 ft NYMT-1935).

In addition to establishing use of the Bretschneider method for determining storm surge, the effects of lake levels higher than the historical data from Reference 2 and Figure 2.4-9 was assessed in supplemental evaluations for various site flooding considerations. The supplemental evaluations were either found to be bounded by their existing analyses, given the resulting same stillwater flood level, or were determined to not result in site flood protection criteria being exceeded.

2.4.2.3. Effects of Local Intense Precipitation

Flooding due to a local PMP on the adjacent 2-square mile drainage area west of the plant site, as shown in Figure 2.4-4, was examined. The local PMP shown in Table 2.4-2 was determined by use of Reference 5. The hourly distribution of the maximum 6-hr rainfall was determined by procedures presented in Reference 7. The shorter 15-minute-duration PMP was extrapolated by use of similar procedures. Due to its small area, the rational formula with a runoff coefficient of 1.0 and concentration time of 15 minutes was applied to compute the peak discharge (Reference 8). The maximum PMP intensity of 15 minutes is assumed to be 4.9 in., as shown in Table 2.4-2. The calculated peak discharge due to the local PMP is 25,000 cfs, which is 10,000 cfs greater than indicated by the PMF peak envelope curve for the Great Lakes region. The Great Lakes PMF peak discharge envelope curve indicates a maximum flow of 15,000 cfs, which represents a more severe flood than would result from the relatively flat 2-square mile local area if determined by the unit hydrograph PMP calculation procedure.

The calculated peak discharge due to the local PMP is 25,000 cfs. Assuming, conservatively, that the peak discharge would pass the plant site only along the axis of the overflow canal (Figure 2.1-5), a hypothetical cross section approximately 1 mile in length and normal to the axis of the overflow canal was constructed to intersect the southernmost chimney on the plant site and the intersection of Langton and Leroux roads to the west of the site (Figure 2.4-3).

Using the slope/area method and conservative values of slope and roughness coefficient, 0.001 ft/ft and 0.07, respectively, a flow of 31,500 cfs was determined as passing through the cross section with a maximum water surface elevation of 582 ft (New York Mean Tide, 1935). The peak flow due to a local PMP, 25,000 cfs, would pass through the cross section at an even lower water surface elevation. In this analysis, channel or cross-section bottom was assumed to be at maximum monthly mean lake level. And, as stated earlier, all flow due to a local PMP was assumed to pass through the hypothetical cross section. Under actual conditions, a peak flow due to the local PMP would flow both south of the plant site and to Lake Erie, as well as through the hypothetical cross section. Water surface elevations due to a local PMP would therefore be lower in actuality than those determined in our analysis.

At a hypothetical water surface elevation of less than 582 ft (New York Mean Tide, 1935), as determined in the above analysis, the maximum water elevation at peak flow due to a local

PMP would be more than 1 ft below plant grade (583 ft, New York Mean Tide, 1935) and would not pose a threat to safety-related structures onsite.

With respect to that portion of a local PMP falling on the plant site itself, including roof structures, runoff overflowing the roof parapets and from the downspouts, assuming that the site drainage system was completely blocked, would flow overland under conditions of site gradient (Figure 2.1-5) to lower elevations surrounding the site and then to Lake Erie itself.

All door sills on safety-related structures are at least 6 in. above plant grade. Because there are no downspouts or scuppers located near doors on safety-related structures, ponded water under local PMP conditions, with the event of a blocked site drainage system, should drain overland, as described above, prior to reaching the base of door sills on safety-related structures.

The local PMP is shown in Table 2.4-2, and the description of the runoff model is given in Subsection 2.4.3.3.

The drainage system in the plant site area is designed with inlet manholes located at the low points of relatively flat roadside and railroad ditches and in local area depressions. The storm-drainage system is not used to protect Category I structures from local PMP flooding, as described in Subsection 2.4.2.2.

2.4.3. Probable Maximum Flood on Swan Creek

The PMF is an estimated flood that may be expected from the most severe combination of critical meteorologic and hydrologic conditions that are reasonably possible in the region (References 5 and 7). The PMF on Swan Creek was estimated as the maximum flood runoff resulting from a PMP occurring on the entire drainage basin of 109 square miles, as shown in Figure 2.4-4.

2.4.3.1. Probable Maximum Precipitation

The estimation of a PMP includes both time and areal distributions. Due to its small drainage area (109 square miles), the PMP is assumed uniformly distributed throughout the entire Swan Creek watershed. The time distribution of a PMP is obtained as follows. The PMP for various durations shown in Table 2.4-3 was obtained from the all-season PMP (Reference 5). Its 2-hr time distribution for the maximum 6-hr rainfall and time sequence were based on procedures presented in Reference 7. Table 2.4-3 shows the synthesized PMP for the Swan Creek watershed.

2.4.3.2. Precipitation Losses

An estimate of precipitation losses was obtained using data from References 9 and 10 and studies of other similar areas. Surface soils in the Swan Creek drainage area are largely comprised of lacustrine clays, which have low infiltration capacity (Reference 11). The land use is estimated as follows: 30 percent small grain, 30 percent forage and pasture, 25 percent row crops, and 15 percent wooded land and buildings. Considering the Swan Creek type ground cover and soil surface as compared to similar type areas in other locations where studies have been made, minimum loss rates are higher in the summer months than in the winter months. These minimum losses can be characterized as follows.

a. Winter initial losses vary from 0.0 to 0.2 in., and winter infiltration losses vary from 0.01 to 0.02 in./ hr

b. Summer initial losses vary from 0.5 to 1.2 in., and minimum summer infiltration rates are approximately 0.05 in./hr.

The Swan Creek losses adopted are initial losses of 0.5 in. and an infiltration rate of 0.02 in./hr during the probable maximum storm. This is assumed as occurring during a wet period with the most favorable antecedent conditions when the moisture capacity of the topsoil would be essentially satisfied. The adopted minimum losses for the Swan Creek area assuming the most favorable (to high runoff) antecedent (ground and rainfall) conditions are based on a conservative estimate for these conditions. The Swan Creek rainfall-excess relationships were determined by use of the minimum conservative losses during the PMP storm as shown in Table 2.4-4. The estimated precipitation losses and runoff are shown in Table 2.4-4.

2.4.3.3. Runoff Model

Because Swan Creek was ungaged prior to 1971, a synthetic unit hydrograph was developed for the 109-square mile basin, as shown in Figure 2.4-4, by using Snyder's method (Reference 12). The runoff was determined at the mouth of Swan Creek north of the site.

Figure 2.4-12 shows the synthetically derived unit hydrograph of 2-hr duration for the Swan Creek watershed. The hydrograph ordinates are shown in Table 2.4-4. Coefficients used in the derivation of the synthetic unit hydrograph are as follows: L = 25.4 miles, L_{ca} = 16.7 miles, C_t = 2.0, W_{50} = 16 hr, and W_{75} = 9 hr. The terms L and L_{ca} are distances measured on the U.S. Geological Survey (USGS) 7.5-minute topographical map for the site area. Time in hours, from start of rise to peak rate, or t_p, was determined using the formula

$$t_p = c_t(L * L_{ca})^{0.3}$$

The value of t_p was determined to be 12.3 hr using a basin parameter C_t of 2.0. Comparison of synthetic unit hydrograph values for Swan Creek with values for nearby stations with similar runoff characteristics as obtained from U.S. Army Corps of Engineers unpublished unit hydrographs is given in Table 2.4-5.

Table 2.4-5 illustrates the conservatism of the coefficients selected for the Swan Creek watershed. For example, a curve enveloping the q_p values would yield a unit hydrograph peak of about 3100 cfs for the 109 square miles as compared to the 4000 cfs peak adopted. The utilization of the extreme coefficient value was intended to include the possible nonlinear runoff response of Swan Creek due to high rainfall intensities.

2.4.3.4. Probable Maximum Flood Flow

The PMF for the 109-square mile watershed of Swan Creek was determined by appropriate application of the preceding analysis described in Subsections 2.4.3.1, 2.4.3.2, and 2.4.3.3. Base flow was assumed to be 100 cfs. The computed PMF hydrograph components are shown in Table 2.4-4.

The calculated basin-wide peak flow in Swan Creek due to the synthesized PMP is 89,000 cfs at the mouth of Swan Creek, as shown in Figure 2.4-13.

There are no dams or other regulating hydraulic structures on Swan Creek that could affect the hydrograph. The exact PMF stream course response cannot be assessed since Swan Creek has not been gaged for a sufficient period of time.

2.4.3.5. Water-Level Determinations

The water level at the site is controlled by Lake Erie. The PMF flow from Swan Creek has no significant effect on the design water level at the site. The maximum lake stillwater level due to storm surge is Elevation 586.9 ft (Subsection 2.4.2.2.1). Plant grade is at Elevation 583.0 ft. At plant grade elevation, the lake water would extend approximately 2.5 miles inland from the plant site (Figure 2.4-11) and even further inland at maximum stillwater level.

To estimate the maximum floodwater level, a section through the east end of the plant site and normal to Swan Creek was selected to compute backwater effects due to the PMF flow on Swan Creek. This section is 3.5 miles wide and is bounded by Port Sunlight Road to the north and Pointe Aux Peaux Road to the south (Figure 2.4-1). Neither of the roads was constructed as a flood-protection levee. In the vicinity of the control section, the land is flat, approximately at Elevation 572.5 ft (Figure 2.4-11).

The backwater calculations were done with the assumptions that the selected section has a water level at Elevation 575.3 ft, mean monthly maximum lake level, and the main plant structures are located 1500 ft west of this section. By applying the Manning formula (Reference 13) on a rectangular channel with a width of 3.5 miles and a bottom elevation of 572.5 ft, with a Manning's roughness coefficient of 0.07, the estimated rise of water level during a peak flood flow of 89,000 cfs is less than 2.0 ft. Therefore, the maximum flood level at the plant site due to the PMF flow from Swan Creek at the mean monthly maximum lake level is at approximately Elevation 577.3 ft, which provides a safety margin of more than 5.7 ft below the established plant grade of Elevation 583.0 ft.

The same procedures were applied using a higher peak flood flow of 115,000 cfs, resulting in an estimated maximum flood level at the plant site at Elevation 579.1 ft, which is 3.9 ft below the plant grade. Therefore, the PMF flow from Swan Creek has no flooding potential with respect to the plant site.

Additional computations, utilizing the slope/area method at a hypothetical cross section through Swan Creek above the plant site (Figure 2.4-4) determined that a flow of 106,000 cfs in Swan Creek would represent a maximum water surface elevation at the cross section of 582 ft (New York Mean Tide, 1935). The PMF of 89,000 cfs on Swan Creek (Subsection 2.4.3.4) should not cause flooding affecting safety-related structures at plant grade Elevation 583 ft (New York Mean Tide, 1935).

In the above computations by the slope/area method, a hypothetical cross section normal to Swan Creek and approximately 1.8 miles in length was chosen. Channel base or the bottom of the cross section was assumed to be at the elevation of the maximum monthly mean lake level. A slope of 0.001 ft/ft and a roughness coefficient of 0.07 were used in the computations.

2.4.3.6. Coincident Wind Wave Activity

A flood on Swan Creek would result in a landward extension of the lake. Therefore, wind activity determined for the lake would apply to the stream flood condition. Wave activity in Lake Erie is described in Subsection 2.4.5.4.

2.4.4. Potential Dam Failures (Seismically Induced)

There are no regulatory structures on Swan Creek. Nor are there dams on other streams or rivers in southeastern Michigan that should failure result because of seismic or other disturbances would affect water levels in Lake Erie along the plant shoreline.

2.4.5. Probable Maximum Surge and Seiche Flooding

2.4.5.1. Probable Maximum Winds and Associated Meteorological Parameters

Extensive studies have been made regarding the effects of wind setup on Lake Erie. Data developed by Platzman (Reference 14), which relate lake levels at Toledo and Buffalo to various wind conditions, were used to establish the wind setup for the site.

The Platzman one-dimensional wind setup model has been verified using four storms producing peak setup at Toledo (Reference 15). The model, valid for setup along the longitudinal axis of Lake Erie, has been shown to consistently calculate peak longitudinal setup greater than the measured peak longitudinal setup at Toledo when using the wind stress and bottom friction coefficients proposed by Platzman. Verification of this model is valid for input winds measured at the Ashtabula Coast Guard Station. The verification for one storm, and possibly a second, indicates that cross-lake wind setup can, at times, be significant and should be considered.

The conservatism of the model in predicting the longitudinal setup increases with increasing wind speed. For a maximum 3-hr average wind speed of 74 knots, the model is estimated to compute a longitudinal wind setup at Toledo 2 ft above the value which would be measured. Whereas an allowance should be made for the possibility of cross-lake setup occurring simultaneously with longitudinal setup at Toledo, an allowance is not required at the Fermi site near Monroe since Monroe is in the vicinity of the nodal point for cross-lake setup. The nodal point is the location where the change in stillwater level due to cross-lake setup is zero.

To establish meteorological conditions appropriate for calculation of the maximum probable wind setup for the site, winds with an easterly or northeasterly component that would be sustained for 6 to 9 hr were examined. The National Weather Records Center in Asheville, North Carolina, was commissioned to examine 25 years of wind records for eight stations in the vicinity of Lake Erie. The eight stations were Toledo, Windsor (Ontario), Sandusky, Cleveland, London (Ontario), Youngstown, Erie, and Buffalo. The National Weather Records Center tabulated (Reference 16) the speed, direction, and date of the fastest 1-minute wind having an easterly component.

The maximum, easterly 1-minute wind speeds observed for the 25-year period at the eastern four stations (London, Youngstown, Erie, and Buffalo) were 65, 37, 60, and 44 mph, respectively. The companion maximum, easterly 1-minute wind speeds observed at the western four stations (Toledo, Windsor, Sandusky, and Cleveland) were 40, 45, 35, and 35 mph respectively. Comprehensive analysis of these and other data (Reference 17) led to the conclusions that:

a. Maximum easterly wind speeds are substantially less than maximum westerly wind speeds

b. Maximum easterly wind speeds over the western portion of Lake Erie are somewhat less than maximum easterly wind speeds over the eastern portion of Lake Erie.

On this basis, a maximum, 1-minute easterly wind speed of 45 mph was selected as representative for the 25-year period of record for the site. This 1-minute value was converted to the probable maximum easterly wind as follows:

a. Overland wind speed was converted to over-water wind speed by multiplying the land value by 1.33. The maximum easterly wind speed over water is thus calculated as 60 mph. This wind speed is assumed to have a probability of once in 25 years

b. The maximum 1-minute easterly wind speed with a probability of once in 1000 years was calculated, using the method of Thom (Reference 18), to be 86 mph

c. A maximum 10-minute wind speed of 74 mph was calculated (Reference 19) by multiplying the maximum 1-minute easterly wind speed by 0.86

d. The 1000-year maximum easterly wind was taken as the maximum 10-minute wind speed of 74 mph.

The PMME data used to calculate the probable maximum wind tide at the Fermi site were obtained from the table of probable maximum wind estimates (over-water wind speeds) supplied by the AEC. The PMME wind speeds over the lake varied with time and distance along the lake axis. The peak 10-minute wind speed was 100 mph. Since the model used to calculate the probable maximum wind tide (Reference 14) is one dimensional, the PMME winds were directed along the axis of Lake Erie (N67.5°E). The PMME had a translational velocity of 20 mph moving from east to west, and duration of 60 hr.

2.4.5.2. Surge and Seiche History

2.4.5.2.1. Maximum Monthly Mean Lake Level

Historical maximum monthly mean water levels are discussed in Subsection 2.4.2.1.1.

2.4.5.2.2. Maximum Wind Tide

Historical maximum wind tides are discussed in Subsection 2.4.2.1.2.

2.4.5.2.3. Seiches

Seiches are periodic oscillations of the lake water level that are caused by changes in wind stress or barometric pressure acting upon the water surface. As the wind stress diminishes, the adverse gradient of the surface water cannot be maintained and an inertial surge of water occurs. Seiches also may result from very rapid changes in barometric pressure, usually associated with squall lines. However, sudden barometric disturbances are very infrequent on Lake Erie.

Analysis of gage records of Lake Erie indicates that the average period of oscillation for a seiche traveling between Toledo, Ohio, and Buffalo, New York, is approximately 14 to 15 hr. As a result of the greater depth of water at the east end of the lake and the generally higher wind speeds associated with the prevailing westerly winds, the maximum amplitudes of a seiche on Lake Erie occur at Buffalo.

Gages at Buffalo and Toledo indicate that the amplitude of the oscillations of a seiche decays rapidly with each subsequent oscillation. The rise in water level induced by the initial wind setup is greater than any subsequent rise associated with the seiche.

In addition to the general seiche that occurs over the entire lake surface, a local seiche may occur between the west end of Lake Erie and Point Pelee. Local seiches with amplitudes of up to 0.8 ft have been detected from gage records at Toledo and Monroe (Reference 20). These seiches can occur when the water body is in a state of equilibrium or constant stillwater level.

The stillwater level of Lake Erie near the Fermi site constantly changes in elevation, with respect to the rest of the lake during the PMME. This difference in water levels effectively damps out any seiche activity near the site. It is unlikely, therefore, that any seiche will occur simultaneously with the PMME. Consequently, for design purposes, no rise in water elevation from a seiche is considered.

2.4.5.3. Surge and Seiche Sources

The maximum PMME wind tide of 11.4 ft was calculated for the Fermi site with the PMME wind speeds as input to the verified Platzman one-dimensional wind setup model of Lake Erie (Reference 15). As an additional conservatism, the previously accepted wind tide of 11.6 ft was used for design purposes. This value does not include an allowance for cross-lake setup as none is required. Monroe is in the vicinity of the nodal point for cross-lake setup, where the change in stillwater level due to cross-lake setup is zero.

A total stillwater elevation of +16.4 ft (586.9 ft) was selected as the design maximum. This was based on the PMME defined by the AEC with a storm path along the axis of Lake Erie (N67.5°E). Elevation +16.4 ft results from a calculated wind tide of +11.6 ft superimposed on a maximum monthly mean lake level of +4.8 ft. This storm surge would occur at the Fermi site approximately 9 hr after the maximum wind reaches the shore. The storm surge hydrograph resulting from the PMME is shown in Figure 2.4-14.

No rise in water elevation resulting from a seiche was used in the design (Subsection 2.4.5.2.3).

2.4.5.4. Wave Action

2.4.5.4.1. Wind-Generated Waves

Wave characteristics are dependent upon wind speed, wind duration, water depth, and fetch length. Generated waves were calculated coincidental with the maximum storm surge hydrograph to determine the maximum flood elevations at the site. Fetch lengths were measured to the site from the axis of the lake (N67.5°E), from N78.75°E, and from due east (Figure 2.4-15). These fetches, hereafter referred to as degrees clockwise from north, have fetch lengths ranging from 11 to 33 nautical miles. Average lake depths range from 32 to 42 ft during probable maximum stillwater levels.

Using the AEC definition of probable maximum winds, component wind velocity profiles were plotted for fetch directions 67.5°, 78.75°, and 90.0° (Figure 2.4-16). Component wind velocities for fetch directions 78.75° and 90.0° were based on the wind velocity profile from 67.5°, the path of the storm.

The shallow water depths over the fetch approaching the Fermi site preclude deep-water wave activity; only shallow-water waves are generated during the PMME. The shallow-water wave generation curves of Bretschneider (Reference 21) were used to calculate significant wave heights and periods (Figure 2.4-14). The generated wave height and period profiles have a phase shift in time of +1.5 hr over the wind profiles to allow for the generation and travel of waves to the site.

The significant wave height is the normal available parameter from statistical analysis of synoptic weather charts. Approximate relations of the significant wave heights to other parameters of the normal wave spectra in nature have been defined. Assuming that the most probable maximum wave height, H_m, is given by the deep water simplified theoretical solution of Equation 2.4-1, then the ratio of H_m to H_s is 1.8 to 1.

$$H_m = 0.707 H_s \sqrt{\log_e N} \qquad (2.4\text{-}1)$$

where

N = number of waves during a period of steady-state conditions

H_s = significant wave height

This value is conservative, as the wave spectrum curve is flatter for shallow-water conditions near the Fermi site than for deep-water conditions applicable to the solution. Curves of H_m are presented in Figure 2.4-16.

2.4.5.4.2. Design Waves

2.4.5.4.2.1. Selection Bases

Selection of design waves depends on the wave climate at the site, the structures being considered, and the available water depths fronting the structures. Generated wave conditions during the PMME occurrence, offshore of the site location (Figure 2.4-16), are propagated shoreward to the various plant structures. In selecting design waves for various structures, the possible range of wave periods, heights, and approach directions during various times of the storm are considered to occur at critical conditions.

2.4.5.4.2.2. Incident Wave at Shoreline

The maximum stillwater level and the maximum offshore generated wave height do not occur simultaneously. Therefore, various stillwater levels are considered in selecting the critical wave conditions. The maximum generated wave height, significant wave height, and wave period (offshore of the plant site) are 21.9 ft, 12.2 ft, and 9.0 sec, respectively. These occur during the stillwater level of 582.8 ft, 1.50 hr after the maximum winds have crossed the shoreline (Figure 2.4-14). During the maximum stillwater level of 586.9 ft and 9 hr after the maximum winds have crossed the shoreline, the maximum wave height, significant wave height, and wave period are 14.0 ft, 7.8 ft, and 7.7 sec, respectively.

Design waves were generated offshore of the site location from approach directions 67.5° (path of PMME), 78.75°, and 90.0°. There should be no significant wave action south of 110° (i.e., normal to the shoreline) during the occurrence of the PMME, as this direction is a 42.5° departure from the wind direction. Waves north of 67.5° also are insignificant because of diminishing fetch length, shallow water depths, and change of direction through wave refraction. An 8-sec wave period generated from 67.5° would approach the plant site shoreline from due east because of refraction effects (Figure 2.4-10). A shorter wave period would not be affected by refraction as much as the 8-sec wave period.

As waves approach the shoreline, they start breaking in water depths approximately equal to their wave heights. Figure 2.4-14 shows breaking wave heights for shoreline toe elevations of 569 ft, 572 ft, and 575 ft. The upper breaking wave height limit considers the effects of wave setup. With continuous heavy wave action breaking against the shoreline, it is possible that the return flow of water lakeward will be slower, thus causing a pileup of water (wave setup) along the shoreline. The possibility of this wave setup was assumed to raise the stillwater level by an amount equal to one-tenth the breaking wave height. With this increase in stillwater level, a slightly higher wave could be supported before breaking.

In selecting the proper design wave that can attack the shoreline, Figure 2.4-14 is used. Design H_s and H_m curves were plotted from the maximum values of Figure 2.4-16. For a particular shoreline or shore barrier toe elevation, the breaking wave height is the controlling factor if it is less than the unbroken wave height during a given stillwater level. In Figure 2.4-14, which includes the storm surge hydrograph, the stillwater level is read off the right-hand ordinate while the wave parameters, H_m, H_s, and H_b, are read off the left-hand ordinate. In using either the significant wave height curve (H_s) or the maximum wave height curve (H_m), the breaking wave height curve (H_b) controls until it intersects (progressing positively from left to right along the TIME axis) the H_m or H_s curve. Thereafter, the unbroken wave height controls.

When using significant wave conditions and a toe elevation of 575.0 ft, the following applies:

a. For a time of +3 hr after the maximum winds reach shore, the design wave is a breaking wave of 7.9 ft to 8.6 ft, with a period of 8.8 sec, during a stillwater elevation of 584.0 ft

b. For a time of +9 hr, the design wave is a significant wave of 7.8 ft

c. The maximum design wave is a wave of 10.2 ft with a period of 8.4 sec and occurs during a stillwater elevation of 585.6 ft at a time of +5.1 hr.

2.4.5.4.2.3. Transmitted Wave

During the occurrence of the PMME, plant grade Elevation 583.0 ft is flooded for approximately 17 hr. Therefore, incident waves attacking the shoreline can be transmitted inland across the flooded plant grade. These transmitted wave heights depend on the available water depth above plant grade, the incident wave characteristics attacking the shoreline, the configuration of the shore barrier, and the location and configuration of other obstacles.

A rock shore barrier has been constructed in front of Fermi 2 along the shore between Plant Coordinate System Grid N6800 and N7800. The rock shore barrier crest elevation is 583 ft nominal; the toe elevation will be 572 ft nominal. For design wave considerations, a design toe elevation of 569.0 ft was used to allow for 3 ft of scour at the toe.

Transmitted wave heights (Reference 20) over the shore barrier are shown in Figure 2.4-17 for maximum and significant incident wave heights at the shore barrier. The incident water depth at the shore barrier toe and the inland depth of water above a plant grade elevation of 583.0 ft are also indicated in Figure 2.4-17.

Using this inland depth of water caused by flooding of plant grade, a curve indicating the maximum wave height that can be supported over the flooded plant grade, without breaking, is presented in Figure 2.4-17. During the maximum flooding of plant grade, the maximum supported wave height is less than the transmitted wave heights. Therefore, the maximum supported wave height is the controlling factor for plant structures located more than a few hundred feet inland from the shoreline. The maximum inland supported wave heights for plant grade Elevation 583.0 and 580.0 ft are 3.0 and 5.4 ft, respectively. The actual site grade at a given location may vary from the reference elevation of 583.0 ft. However, the resultant difference in the hydrostatic pressure due to the difference of supported wave heights would be insignificant.

Waves that are transmitted over the shore barrier will attack the office service and radwaste buildings of Fermi 2. These buildings are not Category I structures and, therefore, could be damaged during the storm without causing a safety concern to the public.

Small waves can reach the Category I structures by traveling around the northerly and southerly ends of the shore barrier. Waves traveling around the ends of the shore barrier undergo several effects, including the following:

a. Breaking caused by the shallow depths of the flooded plant grade

b. Diffraction around the ends of the other plant structures

c. Reflection off plant structures before reaching the Category I structures

d. Reduction caused by plant grade bottom friction and side friction of obstructing structures.

The significant wave period of 7.7 sec will approach the plant sites from due east, while lower period waves can approach the northerly end of the shore barrier from 65° (N65°E), and possibly approach the southerly end from 110° (E20°S). Waves approaching the north end of the shore barrier will be reduced to the maximum inland support wave heights of 3.0 and 5.4 ft for plant grade Elevations 583.0 and 580.0 ft, respectively, in approaching

Category I structures. Waves approaching the southerly end of the shore barrier will be reduced in height approaching Category I structures as a result of the maximum inland supported wave height and the protection provided by the office service and turbine buildings. Neglecting any reduction effects from protection provided by the office service and turbine buildings, waves approaching Category I structures from the south will be reduced to the maximum inland supported wave height of 3.0 ft for the plant grade elevation of 583.0 ft.

2.4.5.4.2.4. Wave Stability

In selecting the proper design wave for wave runup and wave forces against Category I structures, the wave period spectra must be considered since the significant wave period might not control. In calculating minimum wave periods, Equation 2.4-2 was used to determine the limiting wave steepness in shallow water (Reference 22).

$$H/L = 1/7 \tanh\left[\frac{2\pi d}{L}\right] \qquad (2.4\text{-}2)$$

As mentioned in Subsection 2.4.5.4.2.3, waves attacking Category I structures are controlled by the available water depth over the flooded plant grade elevations. For plant grades with very flat slopes, the maximum supported wave height is approximately 0.78 times the water depth. The plant grade of Fermi 2 is Elevation 583 ft 0 in., and therefore a maximum wave height of 3.0 ft can be supported. Where the plant grade elevation is 580 ft 0 in., a maximum wave height of 5.4 ft can be supported. With the plant grade elevation changing from 580.0 ft to 583.0 ft in the vicinity of Grid N8000, it would be possible for either the 3.0-ft or the 5.4-ft wave to strike the north or east sides of Category I structures. Minimum wave periods calculated for wave heights of 3.0 ft and 5.4 ft are 3.4 sec and 4.5 sec, respectively. The maximum wave period of about 9 sec (Reference 22) is for a significant wave height of 7.8 ft and a significant wave period of 7.7 sec.

2.4.5.5. Resonance

Resonance generated by waves can be a problem in enclosed bays or harbors when the natural period of oscillation of the bay is equal to the period of the incident waves. However, the Fermi site is not located in an enclosed embayment. The full exposure of the site to Lake Erie during PMME conditions, plus the flat slopes surrounding the site area, result in a natural period of oscillation of the flooded area that is much greater than that of the incident shallow-water storm waves. Consequently, resonance is not a problem at the site during the PMME occurrence.

2.4.5.6. Runup

2.4.5.6.1. Flood Levels

Refer to Subsection 2.4.2.2 for a discussion of flood levels.

2.4.5.6.2. Maximum Runup Elevations

Maximum runup elevations on the exposed north faces of the reactor/auxiliary building and the RHR complex are 593.0 and 598.0 ft for the 3.0-ft and 5.4-ft waves, respectively. The maximum runup elevation on the exposed south faces of the reactor/ auxiliary building and the RHR complex, the exposed east face of the RHR complex, and the west face of the reactor/auxiliary building is 593.0 ft for the 3.0-ft wave. This wave could possibly reach the west face of the reactor/auxiliary building by reflection from the east face of the RHR complex. The east face of the reactor/auxiliary building is not exposed to waves and wave runup. The west face of the RHR complex is landward of the storm direction and not subject to waves and wave runup. As previously stated, no shore protection is required to preclude flooding of these structures.

2.4.5.6.3. Wave Forces

Maximum wave pressures and forces against Fermi 2 Category I structures can result from a 3.0-ft or possibly a 5.4-ft wave striking the north or east faces of Category I structures. These wave heights are the maximum supported wave heights for plant grade Elevations 583.0 and 580.0 ft. Wave pressures and thrusts against smooth vertical walls have been calculated from nonbreaking, broken, and breaking wave conditions. The wave periods have been varied from the minimum wave period to the maximum wave period. The instantaneous impact forces produced by waves breaking against a structure result in intense shock pressure with a duration in the range of 1/100 to 1/1000 sec. The intense pressures occur when a thin cushion is entrapped by waves breaking on a structure.

The breaking wave conditions are calculated from Minikin's formula. In adapting Minikin's formula, unrealistic results are predicted for very flat slopes (slopes fronting a vertical wall). Therefore, when the actual slope is flatter than 20:1 or even 10:1 (horizontal to vertical), pressures derived from a 20:1 or 10:1 slope should be used. Pressures and thrusts from breaking wave conditions were calculated for both slope conditions. Porous fill material, which can become completely saturated during flooded conditions, is placed from the top of slab elevation of the Category I structure to the plant grade elevation. Therefore, hydrostatic pressures against Category I structures are considered to the depth of the upper surface of the slab of both buildings.

Wave pressure and thrust results for the reactor/auxiliary building and the RHR complex are presented in Figures 2.4-18 and 2.4-19. Wave pressure distribution diagrams are presented in Figures 2.4-20 and 2.4-21. The critical static pressure and thrust occur under the broken wave conditions, whereas the critical dynamic pressure and thrust occur under the breaking wave conditions for an assumed slope of 20:1 and the minimum wave periods of 3.4 to 4.5 sec. All Fermi 2 Category I structures are designed to withstand these forces.

2.4.5.7. Protective Structures

The importance of the shore barrier in providing protection for Category I structures during the PMME has been greatly reduced from the originally approved concept for the following reasons:

a. Category I structures are not susceptible to flooding from storm surge and wave runup

b. Category I structures are largely protected by other plant facilities

c. Category I structures are not subject to damage from transmitted waves behind the barrier

d. Category I structures are not endangered by wave forces from 3.0-ft to 5.4-ft waves

e. Damage to the shore barrier will not enable waves larger than 5.4 ft to break against Category I structures since these structures are located a minimum distance of 800 ft inland from the shoreline. Safety-related structures that are located this distance away would remain safe during the extreme high stillwater levels of the PMME.

The shore barrier design and location are shown in Figure 2.4-22. The parameters used in the shore barrier design are discussed in detail in this section. The shore barrier ends are to be constructed on a side slope of 3:1 (horizontal to vertical) as compared to the design slope of 2:1 used for the shore barrier. The ends of the shore barrier rubble-mound structures are of the same design as determined for the 2:1 slope. Criteria for construction of the multilayered barrier are shown in Figure
2.4-22. The ends have been flattened to a 3:1 slope to ensure that they can withstand conditions more severe than the design conditions.

A shore-barrier-slope-stability analysis was performed to deter-mine the factor of safety against sliding of the shore barrier, and it was concluded that the shore barrier has a sufficient factor of safety with regard to a sliding failure occurring at any soil layer. A report of this analysis was submitted to the NRC in July 1981.

The shore barrier, which allows for the possibility of 6 to 8 percent stone displacement during the PMME, extends from Grid N6800 to N7800 and preserves the integrity of the plant site fill placed to Elevation 583.0 ft.

The shore barrier, including the ends, consists of a rubble-mound structure using an armor cover of stone. A toe elevation of 572.0 ft, a crest elevation of 583.0 ft, and a lakeward-side slope of 2:1 (horizontal to vertical) were considered in its design. The design wave was based on the probable maximum storm event and a design shore barrier toe elevation of 569 ft, allowing for 3 ft of scour. Hudson's stability equation was used for determining the weights of armor units (Reference 21). Stability coefficients (K_D) listed in Reference 21 were used for significant wave conditions and are conservative values based on zero damage criteria for model studies. By allowing for some shore barrier damage (displacement of armor stones), a higher stability coefficient was used.

An armor cover was calculated using rough angular stone (density 165 lb/ft^3) placed on a 2:1 slope. Using a design toe elevation of 569.0 ft, the maximum significant breaking wave height (Figure 2.4-14) is found to be 12.2 ft during the probable maximum storm event. The possibility of some stone displacement (6 percent to 8 percent) was allowed for, with any displaced stones being replaced after the storm passed. A stability coefficient of 5.0 was used for two layers of stone placed randomly. This results in an armor layer 7.5 ft thick using 3.3-ton to 5-ton stone, as shown in Figure 2.4-22. The secondary layer is 3.5 ft thick with 600-lb to 1000-lb stone, while the filter layer is 1.5 ft thick, consisting of 30-lb to 50-lb stone. Below the filter layer is 1 ft of crushed rock (20 lb and under).

Where the plant grade elevation slopes from 580.0 to 583.0 ft, to the north of the Fermi 2 location, the slope is protected against the possibility of breaking 5.4-ft waves during the maximum stillwater level. Protection of the slope is achieved by lining it with suitable rock.

The NRC evaluated the as-built condition of the shore barrier and concluded that it met the requirements of General Design Criterion (GDC) 2 and was, therefore, acceptable on the basis that the inspection and maintenance program required by the Technical Requirements Manual provided reasonable assurance that the shore barrier would not be allowed to deteriorate significantly from its as-built configuration. The Technical Specifications require that the shore barrier be inspected on an annual basis and after major storms and seismic events exceeding operating-basis earthquake (OBE) intensity and be promptly restored to its prior condition in the event of any significant damage.

2.4.6. Probable Maximum Tsunami Flooding

The Fermi site is located in an area of the United States designated as having potentially minor seismic activity. Any tsunami activity in Lake Erie could only be generated by local seismic disturbances. Based on the history of the area, local seismic disturbances would result only in minor excitations in the lake. No tsunami has been recorded in Lake Erie; the only remotely similar phenomena observed have been low-amplitude seiches resulting from sudden barometric pressure differences. The low-amplitude seiches that could occur would be of negligible concern to the site.

2.4.7. Ice Flooding

Ice flooding is not a design basis at the Fermi site. The grade elevation of the plant site is at least 10 ft above the normal winter level of Lake Erie, and the emergency supply of water for cooling is not dependent upon natural bodies of water or the operation of intakes located where ice flooding could occur.

2.4.8. Cooling Water Canals and Reservoirs

2.4.8.1. Canals

A discharge canal is provided between the natural draft cooling towers and the circulating water reservoir. The canal is not part of a Category I system and is not safety related or necessary for the safe shutdown of the reactor.

2.4.8.2. Reservoirs

An open pond reservoir is provided as a collection basin from the natural draft cooling tower discharge to the circulating water pump house. The reservoir is not part of a Category I system and is not safety related or necessary for the safe shutdown of the reactor.

In addition, a reservoir is provided in the RHR complex. This is a Category I reservoir that is part of a closed cycle system that is not dependent upon natural bodies of water for makeup. The design basis for this complex in relation to water levels is described in Section 3.4.

2.4.9. Channel Diversions

The plant does not use water from channels; therefore, this subsection is not applicable.

2.4.10. Flooding Protection Requirements

All safety-related plant features are designed to withstand combinations of flood conditions and wave runup as discussed in Subsections 2.4.2.2 and 2.4.5.4. Protection of safety-related structures and components, including the effects of floods and waves, is discussed in Section 3.4 and Subsection 2.4.5.7.

2.4.11. Low Water Consideration

2.4.11.1. Low Flow in Rivers and Streams

Plant water sources are not related to the flow of rivers and streams in the area, except to the minor extent that these flows affect the general water level of Lake Erie.

2.4.11.2. Low Water Resulting From Surges, Seiches, or Tsunamis

2.4.11.2.1. Minimum Monthly Mean Lake Level

A summary of the historical minimum monthly mean lake levels was recorded by the U.S. Lake Survey during the period 1860 to 1973 and is presented in Figure 2.4-9. The minimum historic monthly mean lake level was reduced by approximately 40 percent of the recorded range of low water conditions (0.9) to give a minimum monthly mean design lake level of -1.5 ft below Low Water Datum.

2.4.11.2.2. Wind Setdown

Using the computer model prepared by Platzman (Reference 14 and Subsection 2.4.5.1), values were obtained for winds of varying speed from a westerly direction. Calculations based upon U.S. Weather Bureau data at Asheville, North Carolina, indicate that westerly winds of 70 mph sustained over a period of 6 hr would have a recurrence interval of one in 250 years. Using these values, the decrease in water level resulting from wind setdown at the site would be -9.2 ft (Elevation 561.3 ft).

Based upon probable maximum estimates of westerly winds furnished by the AEC, maximum wind setdown of the lake water level was calculated by Platzman's method (Reference 14) as -11.2 ft. The selected design wind setdown is -11.6 ft (Elevation 558.9 ft). This is identical to the calculated design PMME storm surge except with a minus instead of a plus sign.

2.4.11.2.3. Local Seiches and Tsunamis

For the same reasons as given in Subsections 2.4.5.2.3 and 2.4.6, no decrease in water level is assumed to occur from seiche and tsunami activity.

2.4.11.2.4. Design Level

Assuming that the effect of wind setdown occurs simultaneously with extreme minimum monthly lake levels, the resulting design stillwater level is Elevation -13.1 ft (Low Water Datum), or Elevation 557.4 ft.

The cooling water supply for safety-related systems is provided by the RHR complex, which contains its own water reservoir and is independent of ground water or lake-water level conditions. See Subsection 9.2.5 for a discussion of the RHR service water system.

2.4.11.3. Historical Low Water

The lowest observed monthly mean lake level during the period of record (1860 to 1973) was during February 1936, when Elevation -1.2 ft (Low Water Datum) was recorded. Low lake levels are generally recorded during the month of February. The most extreme setdown on record (1897 to present) was -7.1 ft on March 22, 1955. This level was calculated from gage records obtained at Gibraltar and Toledo.

If coincident occurrence of the minimum historical lake level and setdown is assumed (-8.3 ft), a minimum probable low water elevation of 562.2 ft is obtained. The conservatism of the design values is realized by comparing these figures with the respective -1.5-ft and -11.6-ft values that were combined for the design level elevation of -13.1 ft.

2.4.11.4. Future Control

There is no future control anticipated for Lake Erie (Reference 23). Drainage improvements on Swan Creek have been made, but no additional controls are planned (Reference 24).

2.4.11.5. Plant Requirements

As described in Subsection 9.2.5, the cooling water supply for safety-related systems is provided by the RHR service water system, which contains its own water reservoir and is independent of ground- or lake-water supplies.

The main plant cooling water supply is provided by the circulating water pond (Subsection 10.4.5) and requires only makeup water from Lake Erie.

2.4.11.6. Heat Sink Dependability Requirements

The RHR complex contains the ultimate heat sink for Fermi 2, which is the RHR service water system. The RHR complex includes a man-made structure with a self-contained reservoir and is discussed in Subsection 9.2.5. This service water complex is independent of local water-level conditions.

2.4.12. Environmental Acceptance of Effluents

Discharge of liquid radwaste effluents is through a decant line into Lake Erie. The release point is indicated in Figure 2.1-5. Liquid effluent accidentally released at the surface from the plant eventually flows either eastward into Lake Erie or into the north lagoon after percolation downward through the crushed-rock fill. The configuration of the surface-area drainage pattern does not permit flow westward toward inland areas. Since the lagoon drains into the lake via Swan Creek, liquid surficial discharges would ultimately reach and be diluted by waters of Lake Erie. Any percolation into ground water ultimately reaches Lake Erie (Subsection 2.4.13). The locations and users of surface and ground water pertinent to effluent releases from the plant are provided in Subsections 2.4.1.2 and 2.4.13. The effects of plant effluent releases to Lake Erie were examined by calculating dilution factors at the Monroe intake and the Toledo intake.

Studies of the currents and dilution capacity of Lake Erie were made by Ayers (Reference 25) who found that except under ice-cover conditions there are two primary current patterns, northward and southward, with a velocity range from 0.1 to 0.3 mph. During ice-cover periods, the current is predominantly southerly with a velocity of less than 0.1 mph. The probable percentages of occurrence of the current patterns are 30 percent, southerly; 50 percent, northerly; and 20 percent, phase system. The duration of ice-cover ranges from 1 to 4 months.

Based on Ayers' measurements, dilution factors for the Monroe intake and the Toledo intake were estimated and are summarized in Table 2.4-6. The dilution factors were determined using the plant blowdown discharge line into Lake Erie as the effluent release point.

The annual average dilution factor was calculated on the basis of 40 percent (southerly) and 60 percent (northerly) current directions, with an ice-cover duration of 2 months occurring during southerly current conditions. Current velocities used in the calculations are 0.394 fps under ice-free conditions and 0.117 fps under ice-cover conditions. The worst condition for dilution factors is based on a southerly current under ice-cover conditions with a current velocity of 0.04 fps.

The subsurface diffusion of accidental releases of liquid radioactive effluents is considered in Subsection 2.4.13.

2.4.13. Ground Water

2.4.13.1. Description and Onsite Use

Ground water is not used as a source of water supply for the plant. Ground water features are subsequently described.

2.4.13.1.1. Regional Ground Water Features

The project area is located in the eastern lake section of the central lowlands physiographic province (Figure 2.5-1). Bedrock formations dip northwest into the Michigan Basin. They are generally covered by glacial drift deposits that vary considerably in thickness and composition. The bedrock topography at the base of the drift is irregular as a result of erosion and differential scouring by Pleistocene glaciation.

The drift deposits range from nearly impervious till to coarse channel deposits of gravel and boulders. To the northwest of the site, drift deposits occur that are sufficiently thick and permeable enough to allow development of ground water. To the south, soluble limestone and dolomite formations compose the principal aquifers. The distribution of these regional aquifers, as described by the USGS (Reference 26), is shown in Figure 2.4-23. Regional aquifers capable of furnishing public ground water supplies do not exist near the site because the bedrock formations are not highly pervious and contain poor quality water. The drift is thin and consists of nearly impervious till. Ground water conditions in Monroe County are described by Sherzer (Reference 27) and by Mozola (Reference 11).

Bordering Lake Erie and surrounding the site area are soils associated with former higher stages of Lake Erie. The soils are thin, generally organic, and do not serve as aquifers. The soil units are described in Subsection 2.5.1.1.2. Geologic units in the site region, principally the bedrock formations, are described in detail in Subsection 2.5.1.1.

2.4.13.1.2. Local Ground Water Features

In the site area, geologic units consist of bedrock formations that are overlain by thin and nearly impervious till and lacustrine deposits (Subsection 2.5.1.2). At the site, the lacustrine and till units have been partially excavated and replaced with crushed-rock fill (Subsection 2.4.1.1).

The till and lacustrine deposits are too thin and impervious to serve as aquifers. They are about 14 ft thick at the site. Descriptions of these deposits are given in Subsection 2.5.1.2.7.

The test borings explored the bedrock formations beneath the site to depths of 324.7 ft, penetrating the Bass Islands Group and part of the Salina Group. The formations dip slightly to the northwest (Subsection 2.5.1.2.3.2). The uppermost bedrock formation at the site is the Bass Islands Group; the upper surface of the Bass Islands is erosional and somewhat irregular. It is covered with till and lacustrine deposits less than 20 ft thick. At the site, the upper surface of the Bass Islands is about 550 ft elevation (Subsection 2.5.1.2.2) and exists to a depth of about l00 ft (Figure 2.5-15). It is directly below glacial drift in a 7-mile-wide band bordering Lake Erie (Figure 2.5-5). The Bass Islands Group consists of thin-bedded, fractured, locally vuggy, gray-brown dolomite, with carbonaceous shale partings. The formation is described in greater detail in Subsection 2.5.1.2.2. The Bass Islands Group comprises a confined aquifer at the site. During the exploration borings program, there was artesian flow from a number of borings penetrating the Bass Islands Group (Figures 2.5-24 through 2.5-56). Ground water in the Bass Islands Group is confined by the overlying till and lacustrine deposits. During construction dewatering, the ground water is drawn down below the confining layer.

Below the Bass Islands Group are fractured limestone and dolomite formations of the Salina Group. The Salina Group formations appear to comprise aquifers even in the argillaceous beds because test borings at the plant site encountered artesian flows from them.

Water quality was sampled at various zones. The water is highly mineralized. Sulfate content was similar in all formations. Results of the chemical analyses of the zones tested are shown in Table 2.5-16 and discussed in Subsection 2.5.1.2.4.

The aquifers receive recharge by infiltration of precipitation on higher ground areas west of the site as indicated by a mapping of the regional ground water level, shown in Figure 2.4-24. Because the ground water surface approximates the shape of the land surface, water apparently can percolate through the till. The map was prepared from water levels measured in wells completed within the Bass Islands dolomite. These well locations are shown in

Figure 2.4-25. Water-level measurement data for the wells are presented in Table 2.4-7. The slope of the water level toward Lake Erie indicates that the lake comprises the ultimate sink for ground water flow.

The permeability data developed from pressure tests of borings at the Fermi site are described in Subsection 2.5.4.6. Of 29 tests in four borings, permeability varied from 210 to 2220 ft/yr. The average was 763 ft/yr. Because permeability is developed in rock joints and fractures, it can vary considerably from place to place.

Ground water is not a water supply source for the plant or any of its supporting facilities.

2.4.13.2. Sources

All municipal supplies within 25 miles of the site are from streams or lakes (Reference 28). In areas not served by municipal water systems, water supplies for domestic use are generally obtained from private wells. There are no industrial or municipal water wells in the site area (Reference 7). The network of private wells presently in use forms the source of water for domestic and livestock purposes in farms and homes west and north of the site, and for residences in the Stony Point area to the south, where the largest concentration of wells in the area occurs. The distribution of private water wells surrounding the site area is shown in Figure 2.4-26. This figure shows that there are about 4000 wells within 10 miles of the site. A survey of available drillers' records on approximately 400 wells in the site vicinity, filed at the Michigan Department of Natural Resources, shows that well depths generally do not exceed 70 ft. The wells are 4 to 6 in. in diameter, drilled into dolomite bedrock, and cased only through overburden soils into bedrock. Casings are uncemented, and the remainder of the hole below the casings is left open. Pumps are submersible or centrifugal (suction) type, having a capacity of about 10 gpm or less. The pumpage of water per well is probably on the order of 200 to 400 gal per day, typical of residential use. A certain amount of seasonal variation in water use can be expected because in summer months lawns and gardens are irrigated.

There has been virtually no long-term ground water level decline in the site area. The largest concentration of wells is in Stony Point. Pumping there may have lowered the water levels by 5 to 10 ft, on the basis of water levels reported on numerous drillers' logs since the 1940s. The radius of influence of pumping from these wells cannot be detected more than 1 mile away from Stony Point, on the basis of water-level data. Pumping from an onsite rock quarry operation in 1969-1972 caused a temporary lowering of water level. Pumping was terminated in June 1972 and the abandoned quarry was allowed to fill with ground water. The piezometric surface in the vicinity of the quarry returned to its normal level by the summer of 1973. The ground water level was monitored during the quarry dewatering and the data are shown in Table 2.4-7. Water level in the quarry is now approximately at land surface.

At the site, the confining layers have been stripped to permit the excavation for subgrade structures constructed in the aquifer. Backfill around the completed structures will not permit percolation into the aquifer at the site (Subsection 2.4.1.1).

The water use trend in the area is from ground water to surface water. The low transmissibility of the formation will not permit large-yielding water wells. Undesirable water quality is typical. As described in Subsection 2.5.1.2.9 and noted on boring logs, the ground water is high in sulfate content and hydrogen sulfide. Many neighboring communities, for example Woodland Beach and Berlin Township, have recently abandoned individual water wells in favor of a surface-water treatment-distribution system. Because surface water is available from nearby municipal systems for the communities in the area, the trend of increasing surface-water use and decreasing ground water use can be expected to continue in dense population areas. Isolated homesites, as on farms, will probably continue to use ground water.

Because of the trend toward decreasing use of ground water, it is improbable that any significant change in ground water gradient will occur from well pumping. The gradient is radially out from the deep foundations of Fermi 2. There are no domestic wells downgradient from the site. If, for any reason, a reversal of ground water gradient from the site to the water wells were to occur, it would have to be for some reason other than pumping from the wells. This is true because, in order to create a gradient from the site to the water wells, the water level at the wells would have to be drawn down below their depth. It is therefore considered highly improbable that there will be any ground water condition in the future resulting in gradient reversal from the site toward the water wells.

The regional lakeward gradient is shown on the contour map of Figure 2.4-25. Water-level data used to prepare the map are shown in Table 2.4-7. Water levels at the site were depressed as a result of dewatering for Fermi 2 quarry operation. Prior to construction of Fermi 2, water flowed naturally from many of the borings in the area, as indicated on the boring logs in Figures 2.5-24 through 2.5-56. On the basis of the above-grade static level implied by these flows and water levels in wells in peripheral areas, it is suggested that ground water level at the site is normally above 575 ft.

Water levels in wells fluctuate seasonally, generally highest in spring and lowest in fall. Seasonal fluctuations are not related to Lake Erie fluctuations, although seasonal peaks are somewhat coincidental. The Lake Erie fluctuations are of lower magnitude (Subsection 2.4.2) than ground water fluctuations. It is suggested that the fluctuations coincide because both water bodies respond to the same influences of recharge and evapotranspiration. Water-level fluctuations in the site vicinity since 1970 are provided by the data in Table 2.4-7.

The nearest government agency observation well is approximately 20 miles to the west, in the Dundee area. It is monitored by the USGS. Because the well is completed in glacial drift, water-level fluctuations in the well cannot be considered representative of water-level fluctuations that would occur in the bedrock formation wells in the site area.

Flow rates within the aquifer are highly variable, owing to the fractured and jointed nature of the bedrock. The width, density, and directional pattern of openings can vary from place to place, as indicated by exposures of rock in excavations of the Fermi 2 site and in the onsite rock quarry to the south. An average velocity of flow in the bedrock aquifer is derived on the following basis:

Porosity, n = 0.01, conservatively assumed (Reference 29)

Permeability, k = 2 ft/day, from tests in borings

Hydraulic gradient, $I = \frac{3 \text{ ft}}{2{,}500 \text{ ft}} = 0.0012,$ determined between wells 17M2 and 17Q1 (12/31/1973)

Velocity, V = kI/n = 0.24 ft/day

It is noted that the natural water-level gradient at the site is not available owing to construction dewatering at Fermi 2.

2.4.13.3. Accident Effects

Ground water conditions of the site (Subsection 2.4.13.1) consist of a bedrock aquifer confined under artesian pressure beneath a cap of relatively impervious glacial deposits. Under natural conditions, the ground water gradient is radially out from the deep foundations of Fermi 2.

In the unlikely event of an earthquake, minor cracking in the walls of at least the subgrade portion of the radwaste building structure could occur. The radwaste liquid storage tanks could also undergo stress cracking and leaking to allow fluid flow between the interior of the structure and the surrounding earth. Initially, liquid would be retained within the structure and diluted by inflowing ground water from the dolomite aquifer in contact with the structure. There would be a slow inflow of ground water and the water level inside the structure would rise until it attained the elevation of the piezometric level of the aquifer, approximately Elevation 575.0 ft. At this time, the radioactive material will have been diluted 10:1 or greater.

The time required to fill the structure would be on the order of 3 to 4 weeks. This length of time is determined on the basis of the following information:

a. During construction dewatering of the reactor building basement, pumping was stopped overnight and on weekends. The excavation became flooded up to 3 ft as a result of inflowing ground water. On one such occasion, the water-level rise in the excavation was measured. The rate of rise was 0.0281 ft/hr

b. It is assumed that this same rate of rise could occur in the radwaste building excavation, but adjusted to account for the space occupied by masonry and equipment, which is approximately one-third of the total floor area. The adjusted rate of rise is somewhat higher, almost 0.042 ft/hr

c. The rate of rise decreases continuously as the water level in the structure approaches ground water level. The assumption of a steady rate of water level rise of 0.042 ft/hr is therefore conservative.

During the 3- to 4-week period during which water is rising in the structure, equipment can be mobilized for pumping, storage, processing, and disposal of radioactive material.

If the structure is allowed to fill completely, diluted material would move into and through the aquifer at the same rate of flow and direction of movement as the existing ground water in the aquifer. The direction of movement to the perimeter of the owner controlled area would be east at a rate of 0.24 ft/day (Subsection 2.4.13.2) and would eventually discharge into Lake Erie.

The length of time required to travel the 460-ft distance from the structure to the Lake Erie shoreline is 1920 days. By this time, the specific activity of the radioactive material will have been below the limits set forth in 10 CFR 20. (For details of this accident analysis, see Subsection 15.7.3.)

For a discussion of flood protection of the onsite storage building, see Subsection 11.7.2.2.5.

2.4.13.4. Monitoring and Safeguard Requirements

It was demonstrated in Subsection 2.4.13.2 that no water wells are located downgradient from the site. As part of the operational radiological environmental monitoring program, Edison will measure the water level monthly in existing observation wells. The comparison of the data will show flow reversal if it occurs. Should a reversal in flow occur, grab samples would be taken and analyzed for gross beta and gamma isotopes if a path is available from the plant to the ground water. Results would be reported in accordance with the requirements of the Technical Specifications 5.6.2 and 5.6.3.

Under accident conditions, postulated in Subsection 2.4.13.3, monitoring wells will be drilled between the affected structures and the Lake Erie shoreline to monitor subsurface travel and dispersion of radioactive material. Exploratory drilling experience at the Fermi site indicates that truck-mounted drilling rigs are available from Detroit and Toledo and that an observation well could be drilled within several days.

2.4.13.5. Design Bases for Subsurface Hydrostatic Loadings

As described in Subsection 2.4.13.2, the natural ground water level at the site is on the order of 575 ft. As a conservative value for computing normal subsurface hydrostatic loadings, the ground water level is assumed to be 576.0 ft.

Because of the ground-level conditions, construction dewatering is necessary during all major building excavations. In the Fermi 2 construction, dewatering was done by sump pumps placed in the excavations. At the reactor building, grout curtains were installed to minimize ground water inflow and to prevent seepage that would cause falling rock from the walls of the excavations. The Fermi 2 reactor building excavation is 204 by 154 ft, with floor elevations of 540.0 and 551.0 ft.

Bedrock beneath the structure is dolomite, and was pressure grouted for added strength. The dewatering does not affect the structural integrity of the rock. All major safety-related structures have their foundations on bedrock and not within the overburden soils or drift (Subsection 2.5.4.11).

Water supply wells will not be used at the facility.

2.4.14. Technical Specifications and Emergency Operation Requirements

Fermi 2, together with its associated safety-related facilities, is designed to function in a safe manner despite the occurrence of any of the adverse hydrologic events previously discussed. These events have been postulated to occur in appropriate combinations, and such provisions for the safe operation of the plant have been incorporated into the design.

2.4.14.1. Flooding

The probable maximum water levels in Swan Creek resulting from precipitation or flood are discussed in Subsection 2.4.3. These levels are less than those anticipated from the probable maximum surge on Lake Erie.

2.4.14.2. Dam Failures

Potential dam failures are discussed in Subsection 2.4.4. It has been found that there are no regulatory structures on Swan Creek. In addition, there are no dams on other streams and rivers in southeastern Michigan, the failure of which would affect water levels in Lake Erie along the plant shoreline.

2.4.14.3. Surge and Seiche Flooding

The PMME is caused by storm surge. This event, discussed in Subsection 2.4.5, causes a stillwater level at the site of 586.9 ft, or 3.9 ft above plant grade elevation. As described, the Category I structures are designed for the PMME flood level plus runup from small waves generated on the flooded site. The openings in the structures are watertight and designed for the high-water levels.

The water levels associated with the seiche, discussed in Subsection 2.4.5, have been found to be less than the storm surge.

2.4.14.4. Tsunami

Tsunami is discussed in Subsection 2.4.6. Water levels associated with this event have been found to be less than for the storm surge.

2.4.14.5. Ice Flooding

Ice flooding is discussed in Subsection 2.4.7.

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TABLE 2.4-1 ESTIMATED DISCHARGE FREQUENCY - SWAN CREEK

Recurrence Interval (years)	Maximum Discharge (ft^3/sec)
2	2250
5	3500
10	4500
20	5800
50	7700
100	9300

TABLE 2.4-2 SYNTHESIZED LOCAL MAXIMUM PRECIPITATION[a]

Time (hr)	Cumulative Rainfall (in.)	Incremental Rainfall (in.)
1/4	4.9	4.9
1/2	7.0	2.1
3/4	8.8	1.8
1	10.2	1.4
2	14.3	4.1
3	18.0	3.7
4	21.3	3.3
5	24.2	2.9
6	26.9	2.7
12	29.2	2.3
18	31.0	1.8
24	32.4	1.4
30	33.2	0.8
36	33.8	0.6
42	34.3	0.5
48	34.7	0.4

[a] Data from Reference 5.

TABLE 2.4-3 SYNTHESIZED PROBABLE MAXIMUM PRECIPITATION FOR THE SWAN CREEK WATERSHED[a,b]

	Maxima for Durations Indicated		
Time (hr)	Cumulative Rainfall (in.)	Incremental Rainfall (in.)	Increments of Storm Sequence (2-hr periods)
2	10.7	10.7	0.2
4	16.0	5.3	0.2
6	20.2	4.2	0.2
8	21.4	1.2	0.2
10	22.0	0.6	0.2
12	22.5	0.5	0.2
14	23.0	0.5	0.2
16	23.4	0.4	0.2
18	23.8	0.4	0.2
20	24.2	0.4	0.2
22	24.5	0.3	0.3
24	24.8	0.3	0.3
26	25.1	0.3	0.3
28	25.4	0.3	0.3
30	25.6	0.2	0.4
32	25.8	0.2	0.5
34	26.0	0.2	0.6
36	26.2	0.2	1.2
38	26.4	0.2	5.3
40	26.6	0.2	10.7
42	26.8	0.2	4.2
44	27.0	0.2	0.5
46	27.2	0.2	0.4
48	27.4	0.2	0.4

[a] Drainage area 109 square miles.
[b] Data from Reference 5.

TABLE 2.4-4 ESTIMATED PRECIPITATION LOSSES AND RUNOFF, PROBABLE MAXIMUM FLOOD, SWAN CREEK[a]

Time (hr)	Unit Hydrograph (ft^3 /sec)	PMP	Loss	Runoff	Surface Runoff From Rainfall Excess (ft^3 /sec)	Base Flow (ft^3 /sec)	Total Discharge (ft^3 /sec)
0		0	0	0	0	100	100
2	410	0.2	0.2	0	0	100	100
4	1070	0.2	0.2	0	0	100	100
6	1860	0.2	0.2	0	0	100	100
8	2640	0.2	0.04	0.16	66	100	166
10	3420	0.2	0.04	0.16	236	100	336
12	4000	0.2	0.04	0.16	534	100	634
14	3820	0.2	0.04	0.16	957	100	1,057
16	3440	0.2	0.04	0.16	1,504	100	1,604
18	3010	0.2	0.04	0.16	2,144	100	2,244
20	2520	0.2	0.04	0.16	2,755	100	2,855
22	2060	0.3	0.04	0.26	3,347	100	3,447
24	1710	0.3	0.04	0.26	3,935	100	4,035
26	1410	0.3	0.04	0.26	4,524	100	4,624
28	1160	0.3	0.04	0.26	5,188	100	5,218
30	900	0.4	0.04	0.36	5,775	100	5,875
32	700	0.5	0.04	0.46	6,548	100	6,648
34	510	0.6	0.04	0.56	7,450	100	7,550
36	350	1.2	0.04	1.16	8,741	100	8,841
38	160	5.3	0.04	5.26	12,269	100	12,369
40	22	10.7	0.04	10.66	21,325	100	21,425
42	0	4.2	0.04	4.16	35,034	100	35,134
44		0.4	0.04	0.46	50,805	100	50,905
46		0.4	0.04	0.36	66,564	100	66,664
48		0.4	0.04	0.36	80,588	100	80,688
50					88,432	100	88,532

[a] Drainage area 109 square miles.

TABLE 2.4-5 U.S. ARMY CORPS OF ENGINEERS UNIT HYDROGRAPHS

Basin	Station	Drainage Area (mi^2)	q_p	t_p	C_p 640	C_t	$(LL_{ca})^{0.3}$	L	L_{ca}	t_r (hr)
Swan Creek[a]	Mouth, Michigan	109	36.7	12.3	451	2	6.14	25.4	16.67	2
Cedar River	East Lansing, Michigan	355	7.6	36.5	279	5.1	7.1	37	18	6
Sandusky River	Bucyrus, Ohio	89.8	27.1	21.0	569	3.39	6.2	27.5	16.3	6
Sebewaing River	Sebewaing, Michigan	105	28.46	11.0	313	2.50	4.44	16	9	6
Juscarawas River	Massillon, Ohio	507	8.06	44.4	358	6.34	7.0	41.0	16.0	6
Clinton River	Mt. Clemens, Michigan	733	17.5	22.2	441	3.81	6.62	32	17	6
Grand River	Lansing, Michigan	1230	6.8	38.5	260	3.4	11.2	75	42	6

[a] Synthetic unit hydrograph.

TABLE 2.4-6 DILUTION FACTOR ESTIMATES - LAKE ERIE INTAKES

Location	Normal Conditions				Annual Average	Worst Condition
	South Current		North Current			
	Ice-Free	Ice-Cover	Ice-Free	Ice-Cover		
Monroe intake	320	290	1.6×10^{11}	1.0×10^{10}	770	26
Toledo intake	1.6×10^{16}	9.0×10^{12}	3.1×10^{25}	1.1×10^{22}	5.4×10^{13}	4.3×10^{5}

TABLE 2.4-7 WATER WELL DATA[a]

Map Reference Number	Well Number	Depth (ft)	Elevation of Water Level (ft)	Date
R1	5S/8E-36R1[b]	77	594.0	9/9/64
			597.6	4/28/72
D1	5S/9E-2D1[b]	33	590.0	5/20/65
			588.11	4/28/72
J1	6S/9E-11J1[b]	--	581.22	2/3/72
K1	6S/9E-13K1	--	577.02	12/29/70
			577.25	12/30/70
			576.68	10/22/71
C1	6S/9E-23C1	35	580.74	2/3/72
			583.0	11/13/54
K1	6S/9E-23K1	95	572.0	11/24/69
			570.64	9/8/70
Q1[c]	6S/9E-23Q1	76	572.0	11/6/69
			575.4	9/8/70
			574.65	10/27/70
			576.39	12/29/70
			575.8	2/26/71
			577.0	3/26/71
			576.25	4/30/71
			576.3	5/28/71
			574.8	7/2/71
			573.0	7/30/71
			572.8	8/24/71
			573.52	10/22/71
			572.3	10/30/71
			579.13	4/28/72
C1	6S/9E-24C1	--	576.87	12/29/70
Q1[c]	6S/9E-24Q1	50	575.0	9/19/69
			574.76	9/8/70
			573.84	10/27/70
			575.97	12/29/70
			573.4	11/5/71

TABLE 2.4-7 WATER WELL DATA[a]

Map Reference Number	Well Number	Depth (ft)	Elevation of Water Level (ft)	Date
			573.4	12/3/71
			574.4	1/7/72
			575.4	2/4/72
			576.1	3/3/72
			579.8	4/7/72
			580.5	4/21/72
			580.73	4/29/72
			582.15	5/26/72
			578.57	6/23/72
			578.23	7/7/72
			577.73	8/23/72
			578.57	10/6/72
			581.90	11/24/72
			582.07	12/29/72
Q2	6S/9E-24Q2	70	571.0	11/6/53
Q3	6S/9E-24Q3	65	577.0	6/13/53
R1	6S/9E-24R1	127.5	577.0	3/27/51
L1	6S/9E-25L1	32	568.0	8/2/56
L2	6S/9E-25L2	45	572.0	7/9/52
L3	6S/9E-25L3	41.5	570.0	4/28/50
L4	6S/9E-25L4	50.5	565.0	7/3/50
L5	6S/9E-25L5	28.5	572.0	6/17/53
			575.04	2/3/72
M1	6S/9E-25M1	49.5	574.0	4/17/53
M1A	6S/9E-25M1A	37	570.0	10/18/55
M2	6S/9E-25M2	39	575.0	4/12/48
	6S/9E-35H1	34.5	569.0	1/20/49
J1	6S/10E-6J1[b]	52	575.0	8/31/63
Q1	6S/10E-6Q1[b]	55	570.0	10/17/53
Q2	6S/10E-6Q2[b]	56.5	575.0	7/3/47
A1	6S/10E-7A1[b]	55	576.0	9/18/53
A2	6S/10E-7A2[b]	116	570.0	12/12/69

TABLE 2.4-7 WATER WELL DATA[a]

Map Reference Number	Well Number	Depth (ft)	Elevation of Water Level (ft)	Date
			570.7	2/3/72
H1	6S/10E-7H1[b]	52	567.0	6/12/56
K1	6S/10E-7K1[b]	67	576.0	6/6/68
L1	6S/10E-7L1[b]	35	572.0	7/1/50
J1	6S/10E-8J1[b]	49	575.0	12/21/55
K1	6S/10E-8K1[b]	36	571.0	11/26/57
R1	6S/10E-8R1[b]	51	571.0	1/30/66
			570.63	9/8/70
			570.03	2/3/72
B1	6S/10E-16B1[b]	52	572.0	
C1	6S/10E-16C1	49	570.0	6/25/54
F1	6S/10E-17F1	59	562.0	2/17/64
			568.91	9/8/70
M2	6S/10E-17M2	--	567.59	10/27/70
			571.75	2/3/72
P1[c]	6S/10E-18P1	60	572.1	9/8/70
			571.84	12/30/70
			576.3	2/26/71
			576.6	1/26/71
			573.2	5/28/71
18P1[c]	6S/10E-19P1	--	574.0	7/2/71
			575.0	7/29/71
			573.25	8/27/71
			573.30	9/24/71
			573.30	10/30/71
			571.2	12/3/71
			573.5	1/7/72
			573.6	2/4/72
			574.0	3/3/72
			577.3	4/7/72
			578.3	4/21/72
			576.67	4/29/72

TABLE 2.4-7 WATER WELL DATA[a]

Map Reference Number	Well Number	Depth (ft)	Elevation of Water Level (ft)	Date
			579.00	5/26/72
			576.92	6/23/72
			576.17	7/7/72
			573.50	8/25/72
			576.58	10/6/72
			581.17	11/24/72
			581.50	12/29/72
R1	6S/10E-18R1	80	573.49	9/8/70
			569.24	10/27/70
			569.56	12/29/70
B1	6S/10E-19B1	65	577.0	12/22/64
B2	6S/10E-19B2	65	583.0	2/17/69
			576.86	9/8/70
			571.86	10/27/70
			568.94	12/29/70
			583.0	2/17/69
			576.42	9/8/70
			571.42	10/27/70
			568.3	12/29/70
			571.33	8/6/71
			570.26	8/27/71
			570.21	9/24/71
			570.14	10/30/71
			570.94	12/10/71
			570.94	1/7/72
			571.84	2/4/72
			572.34	3/3/72
			575.02	4/7/72
			578.19	4/21/72
			576.69	4/29/72
			576.76	5/26/72
			574.69	6/23/72

TABLE 2.4-7 WATER WELL DATA[a]

Map Reference Number	Well Number	Depth (ft)	Elevation of Water Level (ft)	Date
			573.69	7/7/72
			573.94	10/6/72
			579.11	11/24/72
B3	6S/10E-19B3	45	581.0	10/30/53
G1	6S/10E-19G1	--	591.0	3/2/56
H1[c]	6S/10E-19H1	--	570.7	5/12/71
			570.4	6/1/71
			570.75	7/2/71
			570.32	8/2/71
			570.21	8/27/71
			570.57	10/1/71
			569.8	11/5/71
			569.5	12/3/71
			570.25	12/23/71
			572.0	1/31/72
			571.3	2/25/72
			573.0	3/14/72
			574.4	4/7/72
			578.0	4/21/72
			576.67	4/29/72
			575.58	5/26/72
			573.25	6/23/72
			572.50	7/7/72
			570.67	8/25/72
			572.67	10/6/72
			578.17	11/24/72
			578.92	12/29/72
M1	6S/10E-19M1	56	580.0	5/17/68
			570.03	9/8/70
			572.36	2/3/72
M2	6S/10E-19M2	40.5	580.0	12/8/45
M3	6S/10E-19M3	31	582.0	4/12/49

TABLE 2.4-7 WATER WELL DATA[a]

Map Reference Number	Well Number	Depth (ft)	Elevation of Water Level (ft)	Date
P1	6S/10E-19P1	58	569.0	10/6/64
R1	6S/10E-19R1	45	566.72	9/8/70
			573.94	4/28/72
P1[c]	6S/10E-20P1	84	568.0	3/18/70
			568.0	4/1/70
			567.3	5/6/70
			559.8	8/10/70
			562.2	8/19/70
			563.58	3/1/71
			565.38	4/1/71
			562.58	5/3/71
			554.48	6/1/71
			548.38	7/1/71
			544.78	7/23/71
			Destroyed	--
P2[c]	6S/10E-20P2	--	568.0	3/18/70
			567.2	5/6/70
			564.3	6/25/70
			563.9	7/30/70
			563.8	8/18/70
			566.92	3/1/71
			567.62	4/1/71
			565.92	5/3/71
			564.52	6/1/71
			559.12	7/1/71
			556.77	8/2/71
			552.02	8/27/71
			551.81	10/1/71
			550.94	11/5/71
			549.61	12/3/71
			549.14	12/23/71
E1	6S/10E-20E1	62	583.0	10/27/70

TABLE 2.4-7 WATER WELL DATA[a]

Map Reference Number	Well Number	Depth (ft)	Elevation of Water Level (ft)	Date
			585.18	4/28/72
E2	6S/10E-20E2	--	580.51	12/29/70
N1	6S/10E-20N1	53.5	565.0	5/26/50
C1	6S/10E-28C1	58	569.0	12/12/50
D1	6S/10E-28D1	39	568.19	10/22/71
D2	6S/10E-28D2	51.5	571.0	3/12/51
E1[c]	6S/10E-28E1	--	567.97	9/8/70
			567.88	10/27/70
			569.84	12/29/70
			571.5	2/26/71
			572.1	3/26/71
			571.75	4/30/71
			570.4	5/28/71
			568.5	7/2/71
			566.0	7/30/71
			566.17	8/27/71
			565.82	9/24/71
			565.9	10/30/71
			566.17	12/3/71
			567.5	1/7/72
			569.3	2/4/72
			570.84	3/3/72
			572.1	4/7/72
			572.8	4/21/72
			572.42	4/29/72
			571.50	5/26/72
			570.00	6/23/72
			569.58	7/7/72
			569.17	8/25/72
			570.92	10/6/72
			573.00	11/24/72
			573.42	12/29/72

TABLE 2.4-7 WATER WELL DATA[a]

Map Reference Number	Well Number	Depth (ft)	Elevation of Water Level (ft)	Date
E2	6S/10E-28E2	74.5	574.5	6/30/51
E3	6S/10E-28E3	43	577.0	5/1/56
E4	6S/10E-28E4	56.5	575.0	4/19/52
E5	6S/10E-28E5	51	572.0	7/28/65
E6	6S/10E-28E6	--	568.8	10/22/71
E7	6S/10E-28E7	--	569.4	10/22/71
			576.4	5/1/72
F1	6S/10E-28F1	68	573.0	11/20/67
			571.81	10/22/71
M1	6S/10E-28M1	68	572.0	5/17/49
A1	6S/10E-29A1	--	566.52	10/22/71
			570.65	4/28/72
B1[c]	6S/10E-29B1	--	567.45	7/1/70
			567.42	8/3/70
			566.22	9/1/70
			566.37	10/1/70
			566.87	11/2/70
			567.07	12/2/70
			567.17	1/4/71
			566.6	2/1/71
			568.57	3/1/71
			569.57	4/1/71
			568.43	5/3/71
			567.87	6/1/71
			565.97	7/1/71
			564.82	8/2/71
			564.15	8/27/71
			564.15	10/1/71
			563.57	11/5/71
			563.57	12/3/71
			563.77	12/23/71
			564.57	1/31/72

TABLE 2.4-7 WATER WELL DATA[a]

Map Reference Number	Well Number	Depth (ft)	Elevation of Water Level (ft)	Date
			563.87	2/25/72
			564.37	3/14/72
			565.27	4/7/72
			566.24	4/21/72
			566.40	4/29/72
			567.07	5/26/72
			564.99	6/23/72
			564.90	7/7/72
			566.24	8/25/72
			567.07	10/6/72
			569.74	11/24/72
			570.07	12/29/72
D1	6S/10E-29D1	28.5	570.0	10/2/54
			563.25	10/22/71
			567.45	4/28/72
E1	6S/10E-29E1	38.5	572.0	7/16/53
E2	6S/10E-29E2	31	567.0	8/31/55
E3	6S/10E-29E3	60.5	572.0	7/13/62
E4	6S/10E-29E4	40	572.2	1970
			562.4	10/22/71
H1	6S/10E-29H1	39	571.0	
H2	6S/10E-29H2	38.5	569.0	10/15/47
J1	6S/10E-29J1	37	570.0	5/27/60
J2	6S/10E-29J2	35	567.0	6/4/56
			570.55	2/3/72
J3	6S/10E-29J3	35	572.0	1/8/53
J4	6S/10E-29J4	74	566.0	11/18/52
J5	6S/10E-29J5	46	568.0	7/25/64
J6	6S/10E-29J6	40	572.0	6/2/52
J7	6S/10E-29J7	45	571.0	6/13/53
J8	6S/10E-29J8	28	572.0	4/12/49
J9	6S/10E-29J9	38	570.0	5/13/50

TABLE 2.4-7 WATER WELL DATA[a]

Map Reference Number	Well Number	Depth (ft)	Elevation of Water Level (ft)	Date
J10	6S/10E-29J10	31	570.0	7/29/53
J11	6S/10E-29J11	36	572.0	6/14/57
K1	6S/10E-29K1	30	575.0	3/19/52
K2	6S/10E-29K2	47	573.0	6/7/63
Q1	6S/10E-29Q1	40	566.0	
R1	6S/10E-29R1	30	573.0	4/18/57
R2	6S/10E-29R2	50	564.0	11/16/54
B1	6S/10E-30B1	60	569.0	10/7/68
C1	6S/10E-30C1	40	569.0	11/26/63
			568.93	2/3/72
E1	6S/10E-30E1	29	571.0	8/8/45
H1	6S/10E-30H1	42.5	570.0	9/18/65
H2	6S/10E-30H2	49	572.0	10/28/57
A1	6S/10E-32A1	49	570.0	6/7/56
A2	6S/10E-32A2	41.5	575.0	6/11/51
P2[c]	6S/10E-20P2		546.94	1/31/72
			547.14	2/25/72
			540.34	3/14/72
			537.99	4/7/72
			540.77	4/21/72
			541.86	4/29/72
			542.94	5/26/72
			539.11	6/23/72
			540.44	7/7/72
			552.86	8/25/72
			557.19	10/6/72
			561.52	11/24/72
			564.69	12/29/72
P3	6S/10E-20P3	62	576.0	12/15/65
			551.55	7/25/72
E1[c]	6S/10E-21E1	42	557.91	7/1/70
			559.59	8/3/70

TABLE 2.4-7 WATER WELL DATA[a]

Map Reference Number	Well Number	Depth (ft)	Elevation of Water Level (ft)	Date
			555.02	9/1/70
			555.74	10/1/70
			556.74	11/2/70
			556.60	12/2/70
			556.94	1/4/71
			556.1	2/1/71
			557.14	3/1/71
			556.94	4/1/71
			555.49	5/3/71
			556.54	6/1/71
			555.94	7/1/71
			555.99	8/2/71
			556.53	8/28/71
			557.12	10/1/71
			556.24	11/5/71
			556.24	12/3/71
			556.64	12/23/71
			558.14	1/31/72
			559.44	2/25/72
			559.64	3/14/72
			562.16	4/7/72
			562.99	4/21/72
			561.91	4/29/72
			561.99	5/26/72
			564.16	6/23/72
			563.99	7/7/72
			560.32	8/25/72
			560.37	10/6/72
			560.91	11/24/72
			563.74	12/29/72

TABLE 2.4-7 WATER WELL DATA[a]

Map Reference Number	Well Number	Depth (ft)	Elevation of Water Level (ft)	Date

[a] Shown in Figure 2.4-25.

[b] Not shown in Figure 2.4-25.

[c] Monitor wells are underlined.

Explanation of well numbering system:

The well locations are identifiable by the well number. The well numbering system, which is commonly used by water resource agencies, including the U.S. Geological Survey, designates the location of the well within a 40-acre parcel of land. The standard one-square-mile section is subdivided into 40-acre parcels as follows:

D	C	B	A
E	F	G	H
M	L	K	J
N	P	Q	R

As an example, suppose a given well is located as follows:

a. Township 7 South

b. Range 10 East

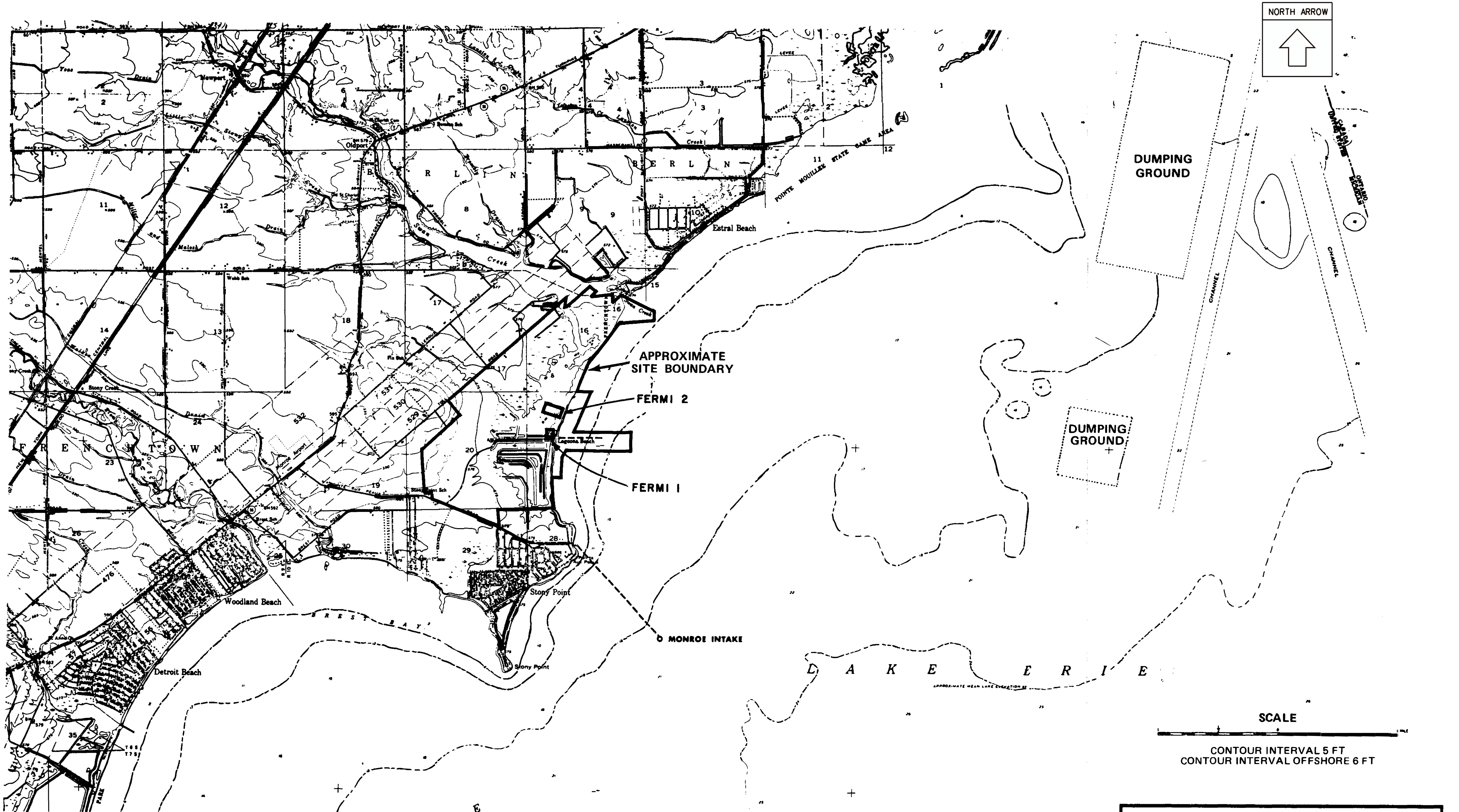
c. Section 32

d. northeast corner.

That well would be given the number, 7S/10E-32A1.

The number 1 following the letter A indicates that this is the first well inventoried in the 40-acre parcel lettered A.

All the wells within the immediate vicinity of the site are shown in Figure 2.4-25. These wells are identified and located by the last two digits of the previously described well numbering system and listed under the heading, "MAP Reference Number."



REFERENCE:
THIS MAP WAS PREPARED FROM PORTIONS OF THE FOLLOWING U.S.G.S. QUADRANGLES: ESTRAL BEACH, MICH., 1942, STONY POINT, MICH., 1952, ROCKWOOD, MICH., 1952, AND FLAT ROCK, MICH., 1952.

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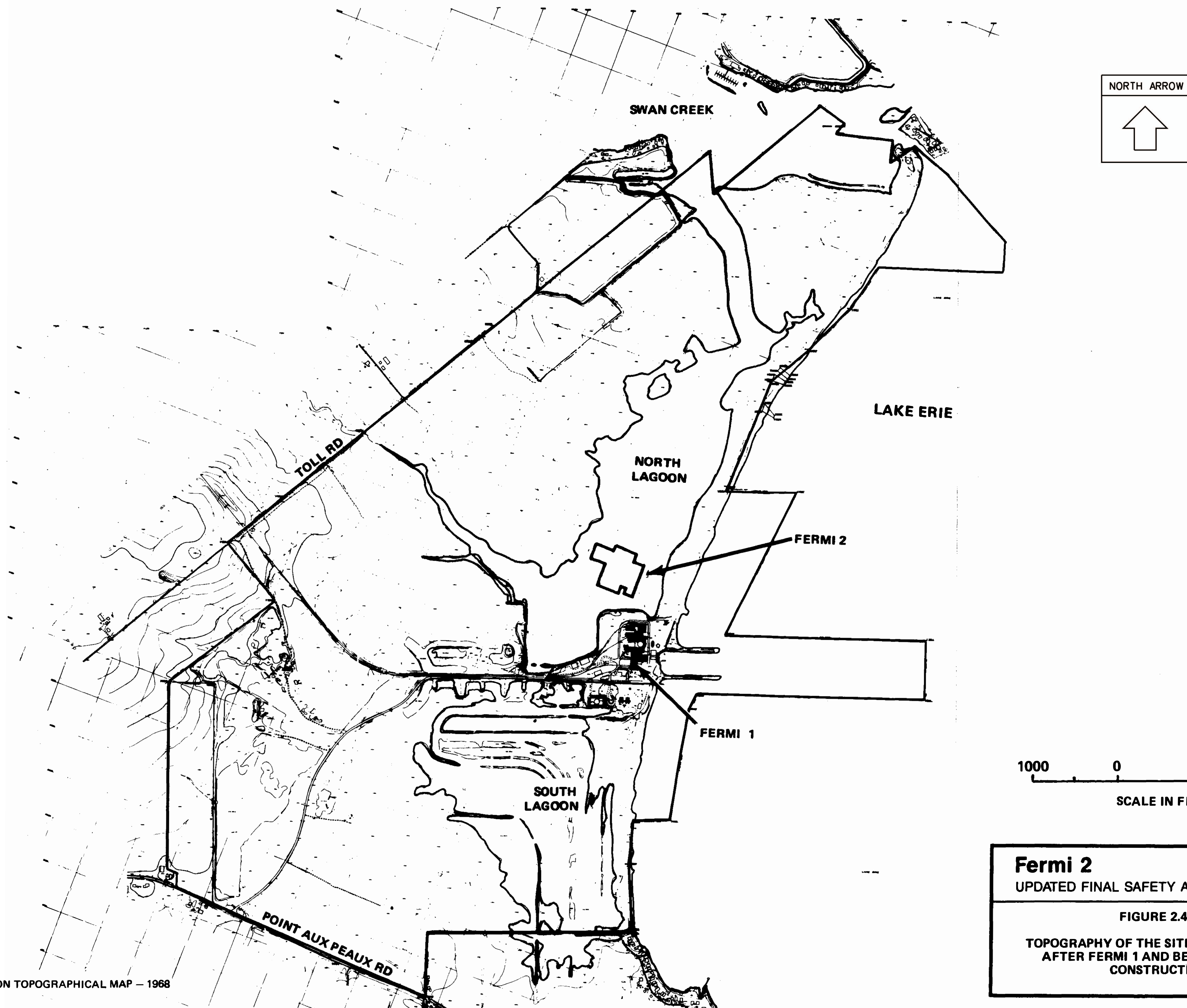
FIGURE 2.4-1

SITE VICINITY MAP



REFERENCE:
PORTION OF THE DETROIT EDISON TOPOGRAPHICAL MAP – 1968

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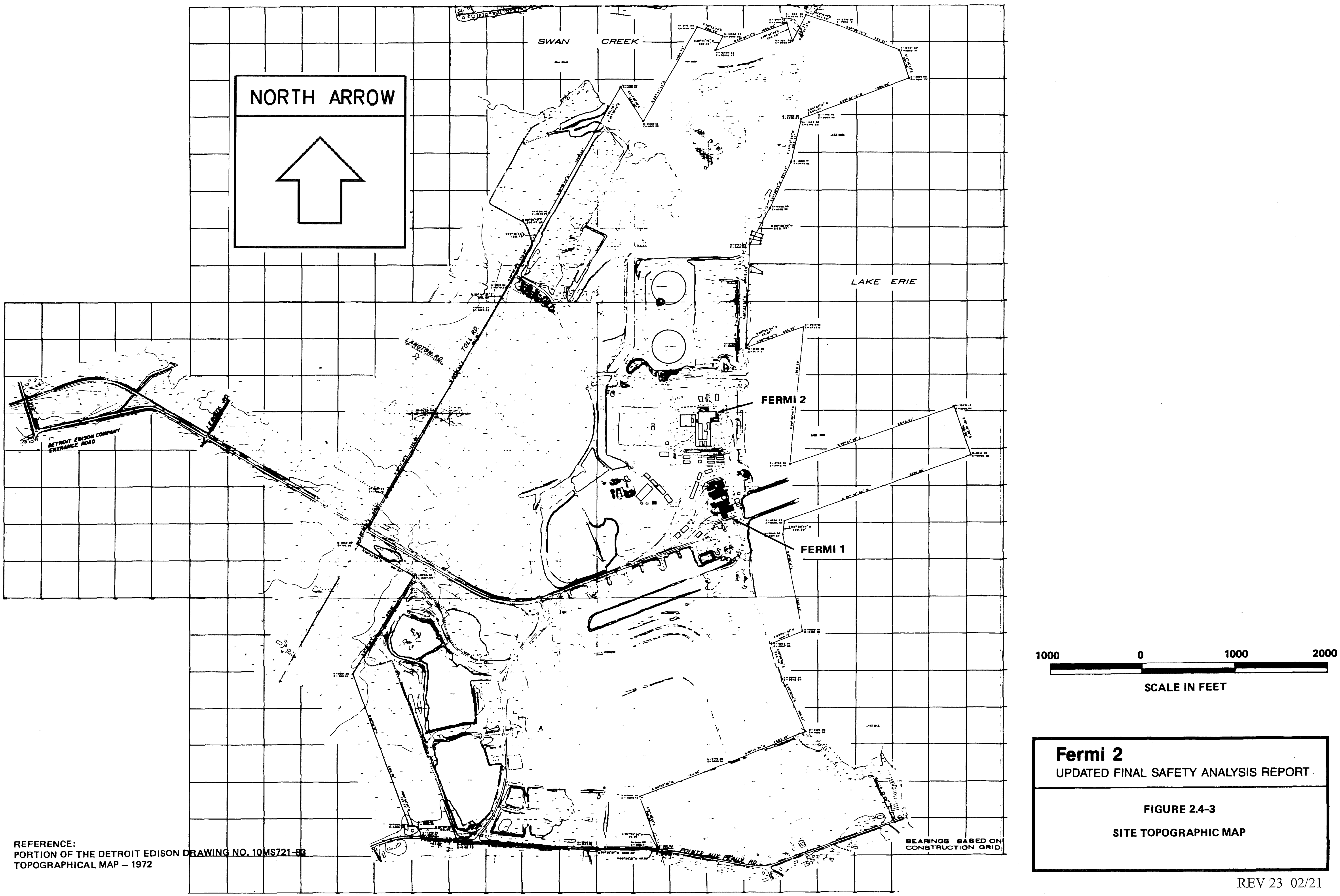
FIGURE 2.4-2

TOPOGRAPHY OF THE SITE AND ENVIRONS AFTER FERMI 1 AND BEFORE FERMI 2 CONSTRUCTION



REFERENCE:
PORTION OF THE DETROIT EDISON DRAWING NO. 10MS721-83
TOPOGRAPHICAL MAP – 1972

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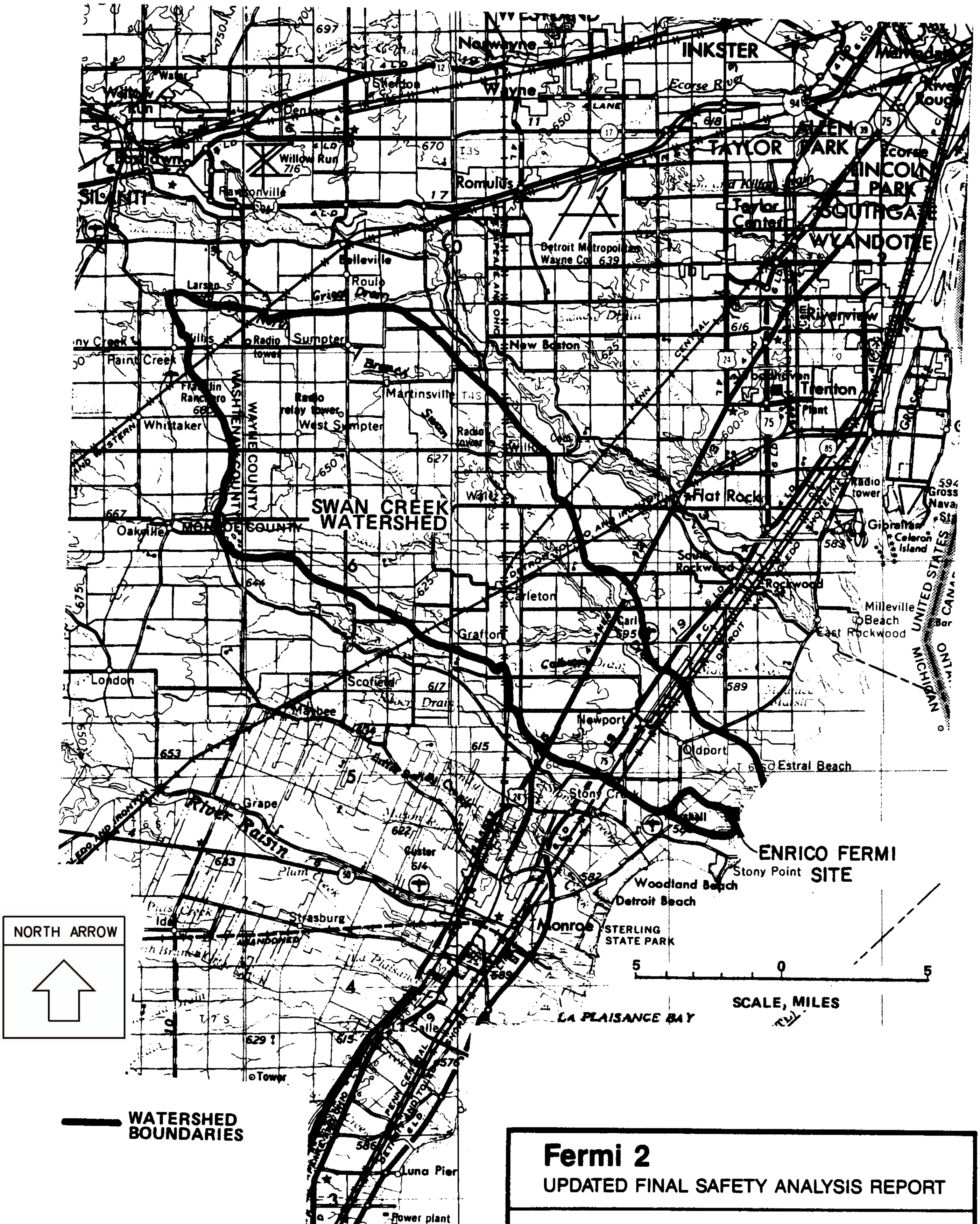
FIGURE 2.4-3
SITE TOPOGRAPHIC MAP



REFERENCE:
PORTIONS OF DETROIT AND TOLEDO
U.S.G.S. TOPOGRAPHIC MAPS.

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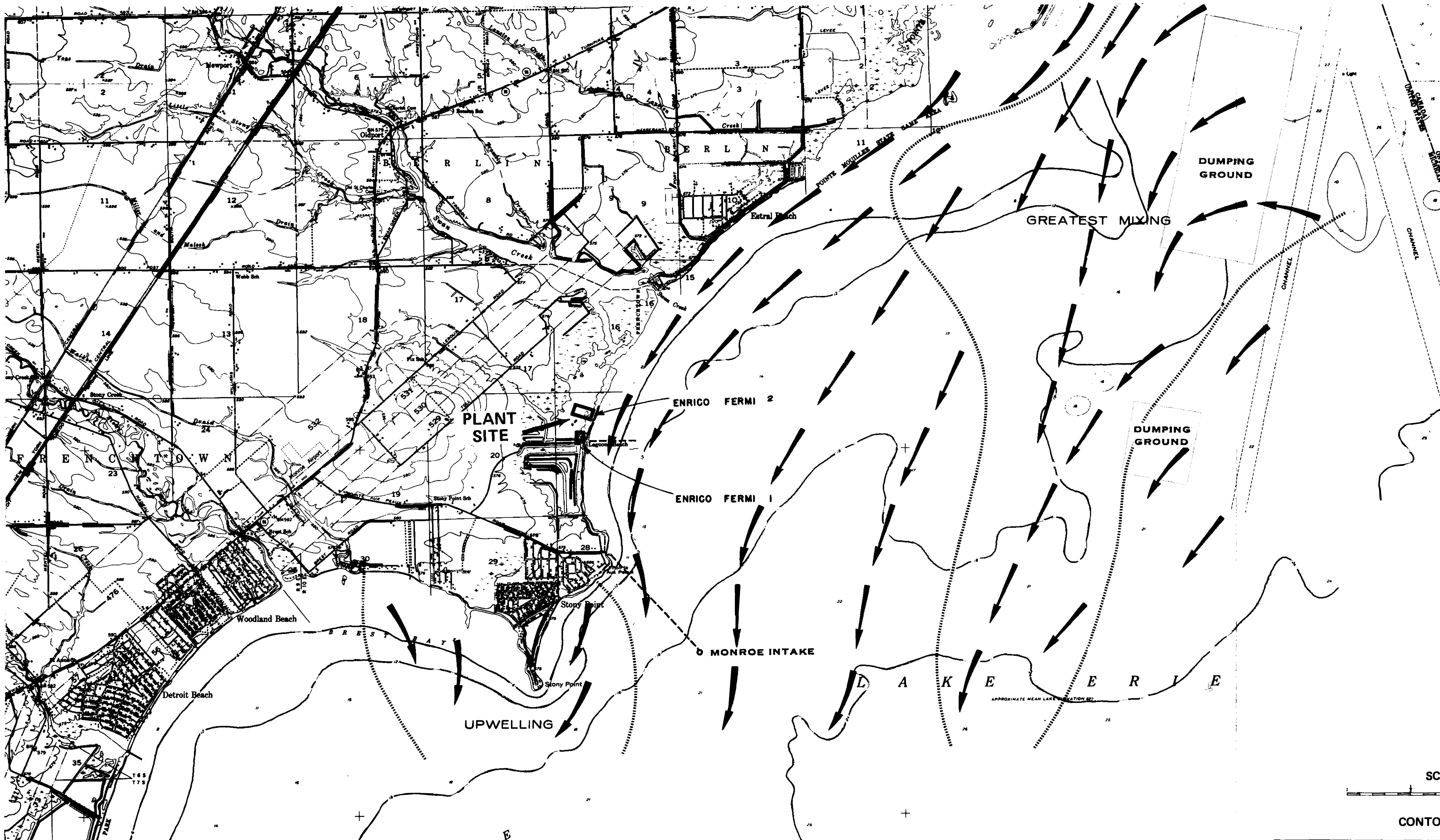
FIGURE 2.4-4

SWAN CREEK WATERSHED



REFERENCE:
THIS MAP WAS PREPARED FROM PORTIONS OF THE FOLLOWING U.S.G.S. TOPOGRAPHIC QUADRANGLES: ESTRAL BEACH, MICHIGAN, 1942, STONY POINT, MICHIGAN, 1952, ROCKWOOD, MICHIGAN, 1952, AND FLAT ROCK, MICHIGAN, 1952.

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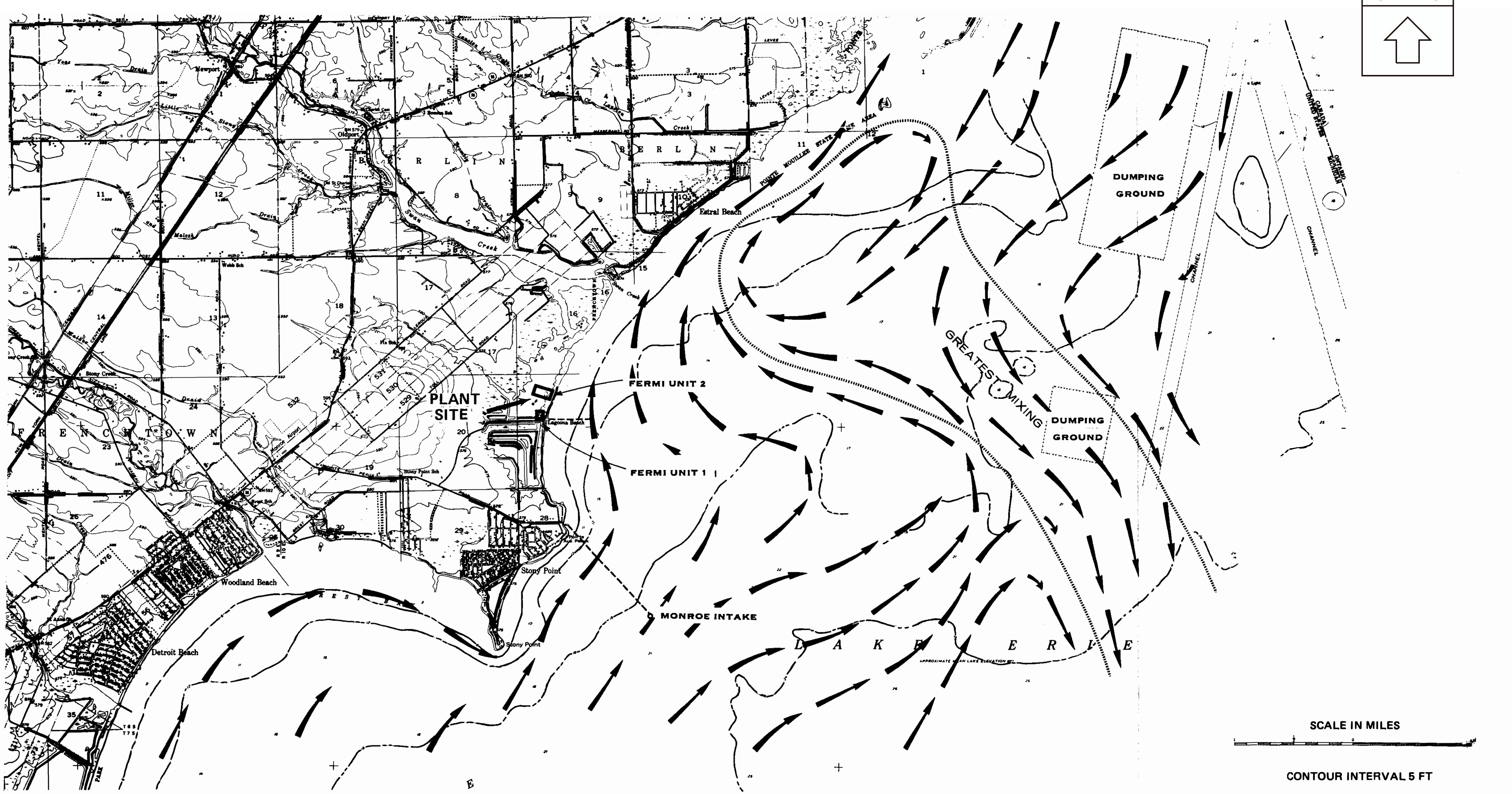
FIGURE 2.4-5

WATER CURRENT PATTERNS WITH WINDS FROM NORTHWEST THROUGH NORTHEAST



REFERENCE:
THIS MAP WAS PREPARED FROM PORTIONS OF THE FOLLOWING U.S.G.S. TOPOGRAPHIC QUADRANGLES: ESTRAL BEACH, MICHIGAN, 1942, STONY POINT, MICHIGAN, 1952, ROCKWOOD, MICHIGAN, 1952, AND FLAT ROCK, MICHIGAN, 1952.

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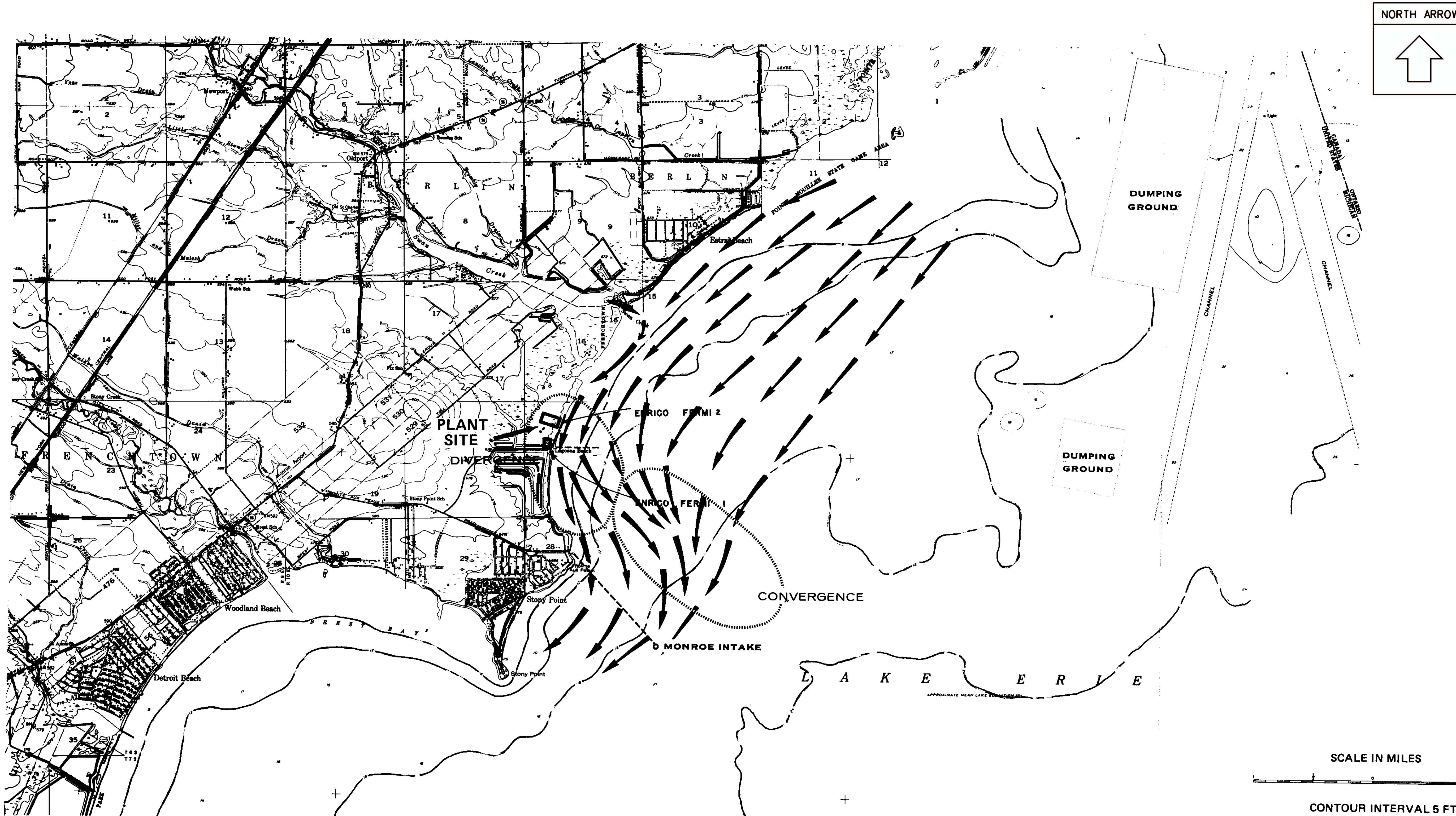
FIGURE 2.4-6

WATER CURRENT PATTERNS WITH WINDS FROM EAST-SOUTHEAST THROUGH WEST



REFERENCE:
THIS MAP WAS PREPARED FROM PORTIONS OF THE FOLLOWING U.S.G.S. TOPOGRAPHIC QUADRANGLES: ESTRAL BEACH, MICHIGAN, 1942, STONY POINT, MICHIGAN, 1952, ROCKWOOD, MICHIGAN, 1952, AND FLAT ROCK, MICHIGAN, 1952.

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FIGURE 2.4-7

WATER CURRENT PATTERNS UNDER ICE CONDITIONS

FIGURE 2.4-8 HAS BEEN DELETED

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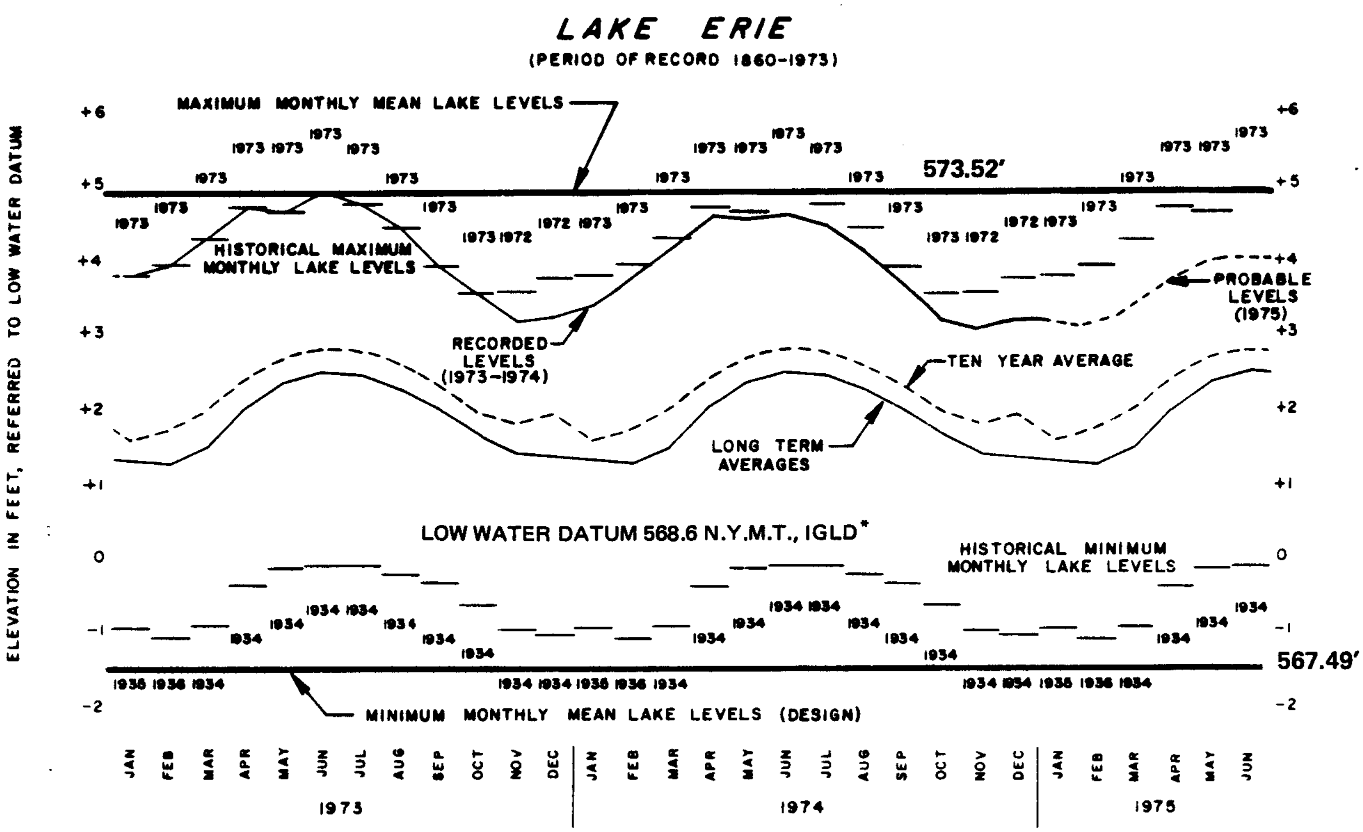

*ADD 1.94' TO CONVERT TO N.Y.M.T., 1935

REFERENCE:
U.S. DEPARTMENT OF COMMERCE, MONTHLY BULLETIN OF LAKE LEVELS FOR JANUARY 1974, NATIONAL OCEAN SURVEY, LAKE SURVEY CENTER.

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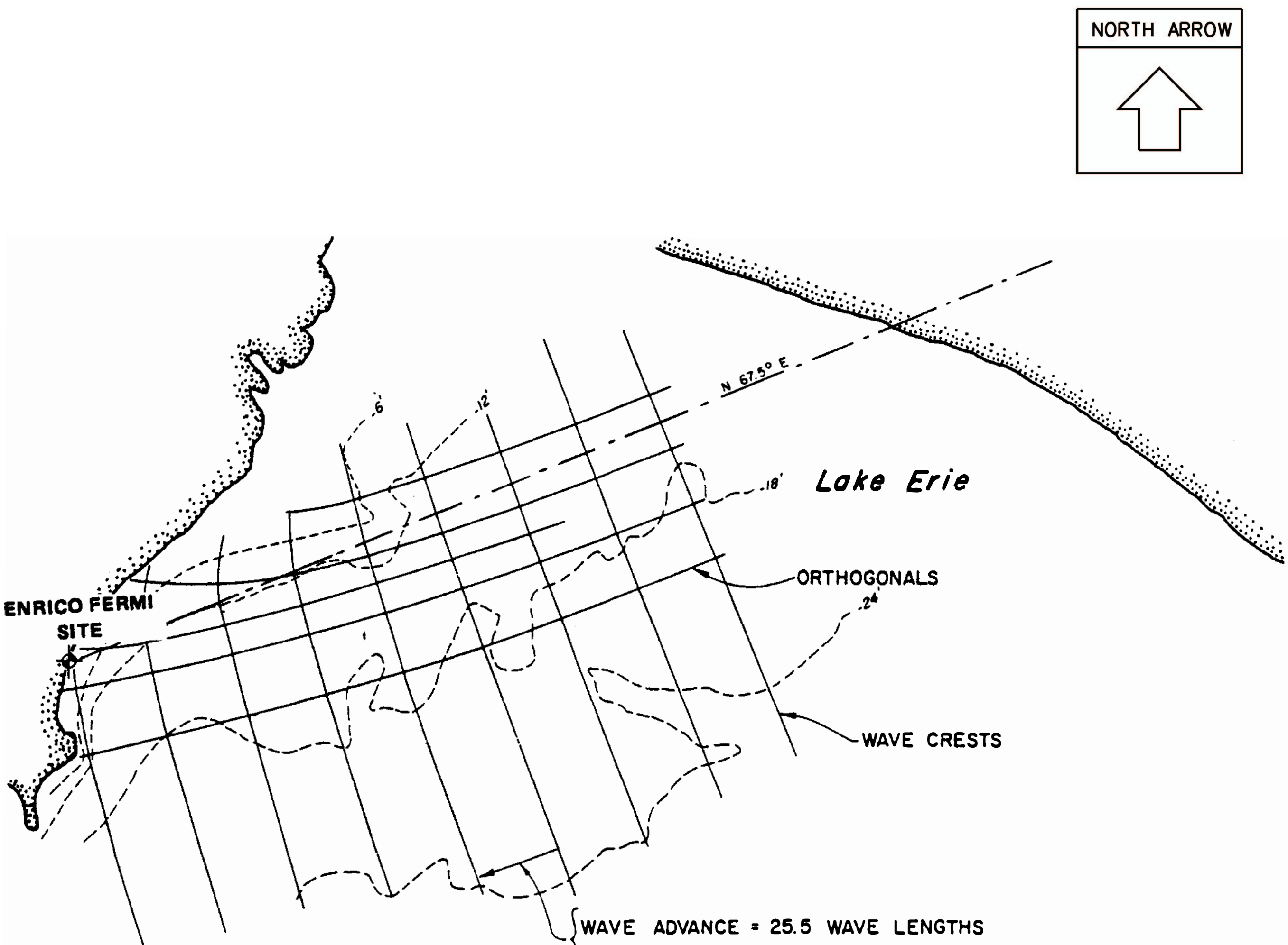
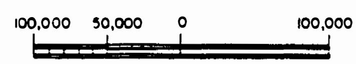
FIGURE 2.4-9

MAXIMUM AND MINIMUM MONTHLY MEAN LAKE LEVELS



LEGEND:
- - - - LAKE BOTTOM CONTOURS
SOUNDING DATUM: NYMT 1935
WAVES REFRACTED DURING TIDE = +16.4 FEET NYMT 1935
WAVE PERIOD = 8.0 SECONDS
WAVE DIRECTION FROM N67.5°E



SCALE IN FEET

REFERENCE:
U.S. LAKE SURVEY, CHART NO. 39, 1968

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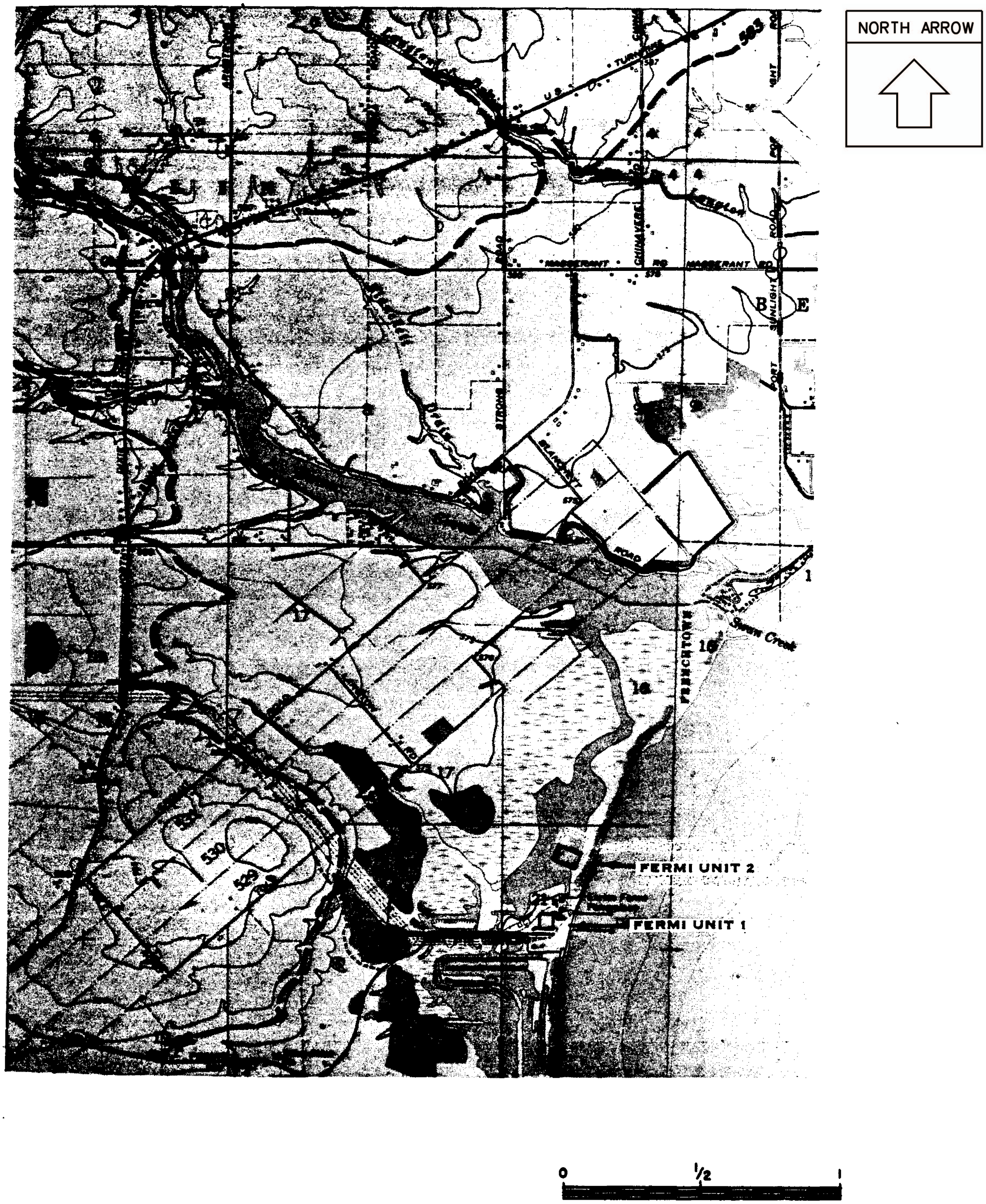
FIGURE 2.4-10

WAVE REFRACTION



REFERENCE:
U.S.G.S. TOPOGRAPHIC QUADRANGLE
STONY POINT, MICHIGAN – 1967.

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FIGURE 2.4-11

SITE AREA TOPOGRAPHY SHOWING 583-FT CONTOUR

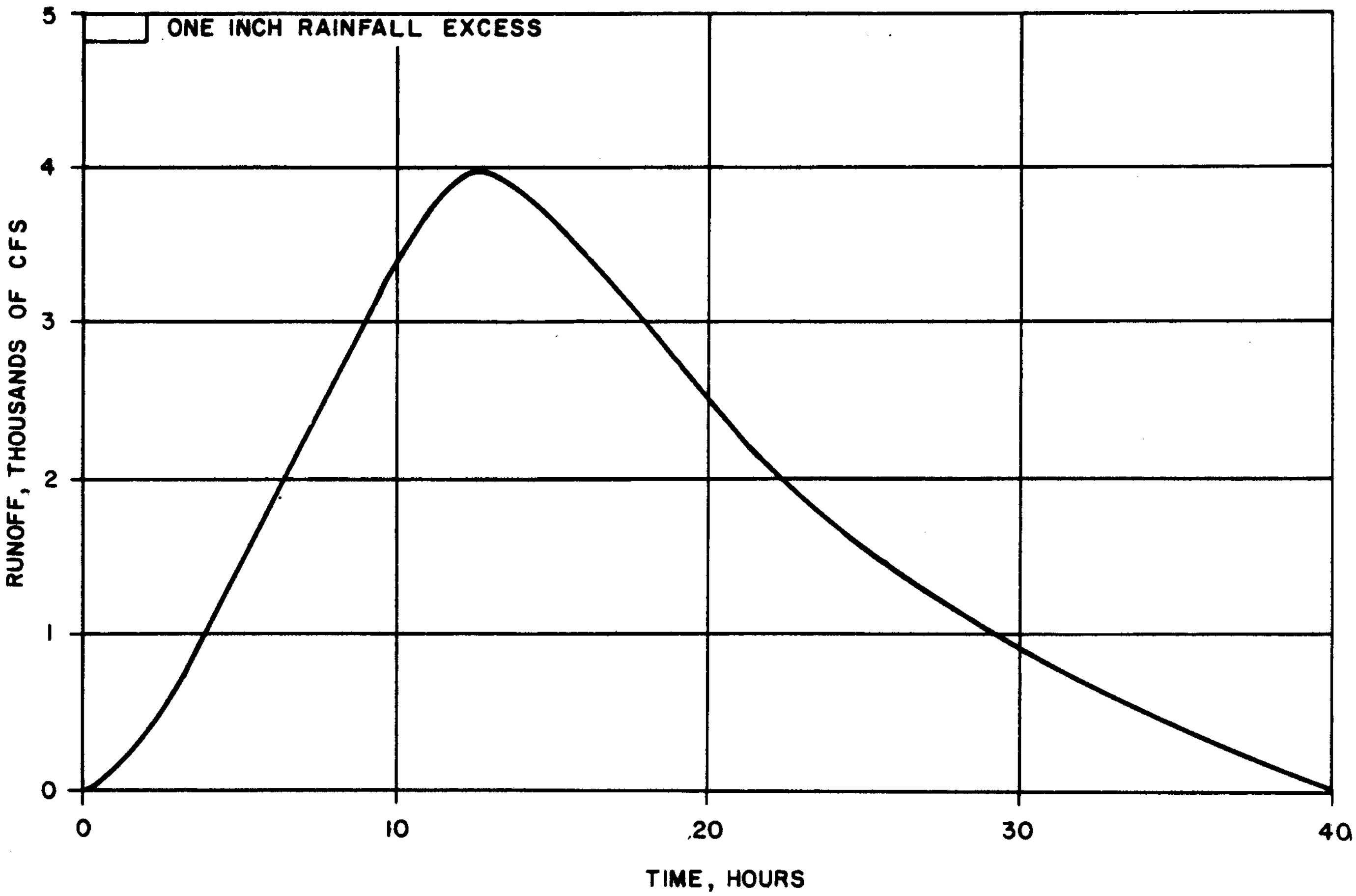

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FIGURE 2.4-12

UNIT HYDROGRAPH – SWAN CREEK AT MOUTH

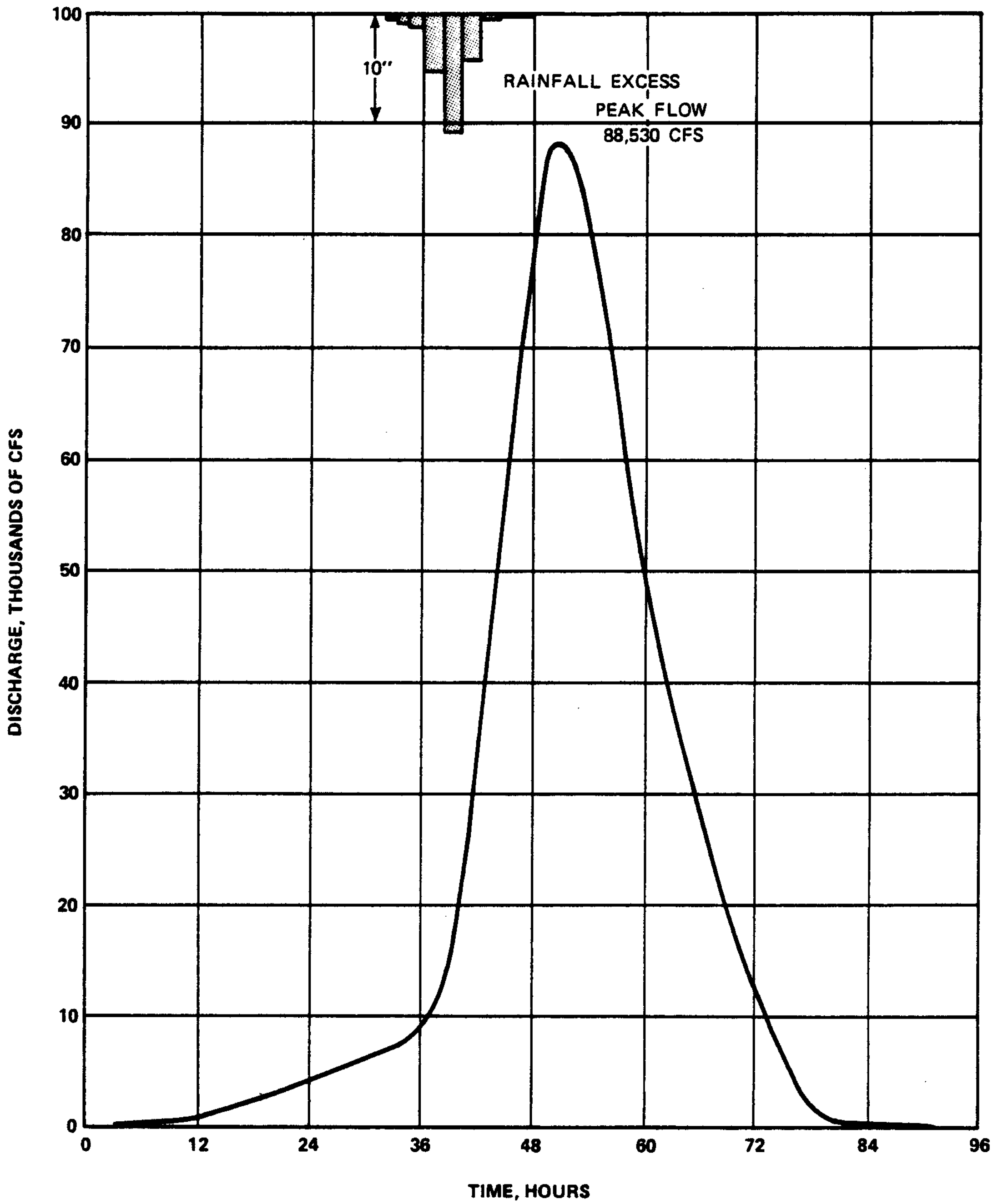

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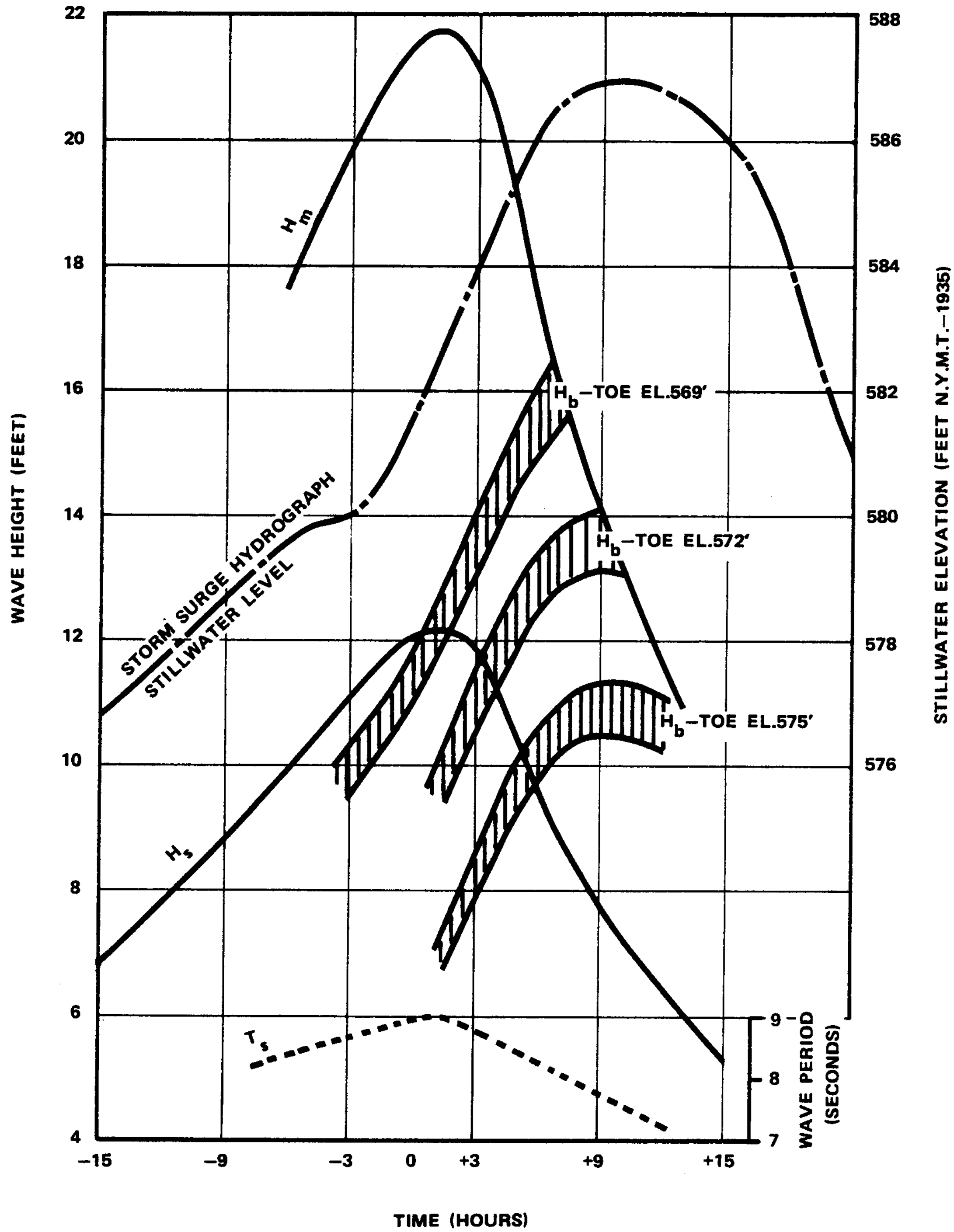
FIGURE 2.4-13

PMF HYDROGRAPH – SWAN CREEK AT MOUTH



LEGEND:

H_m = MAXIMUM HEIGHT

H_s = SIGNIFICANT WAVE HEIGHT

H_b = BREAKING WAVE HEIGHT FOR SHORE BARRIER TOR ELEVATION (UPPER LIMIT CONSIDERS WAVE SETUP)

T_s = SIGNIFICANT WAVE PERIOD

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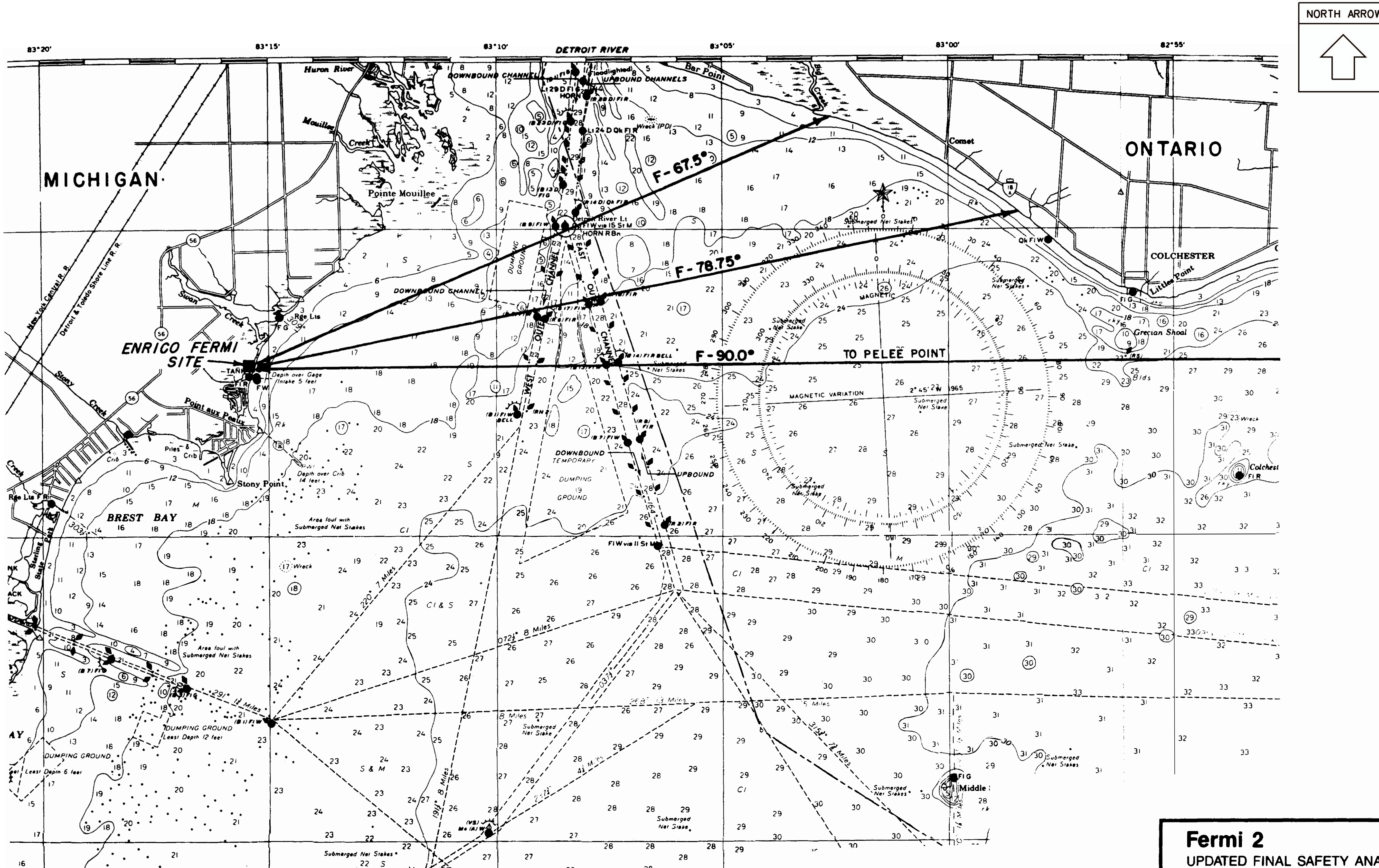
FIGURE 2.4-14

STORM SURGE HYDROGRAPH FOR PMME



REFERENCE:
U.S. LAKE SURVEY, CHART NO. 39, 1968

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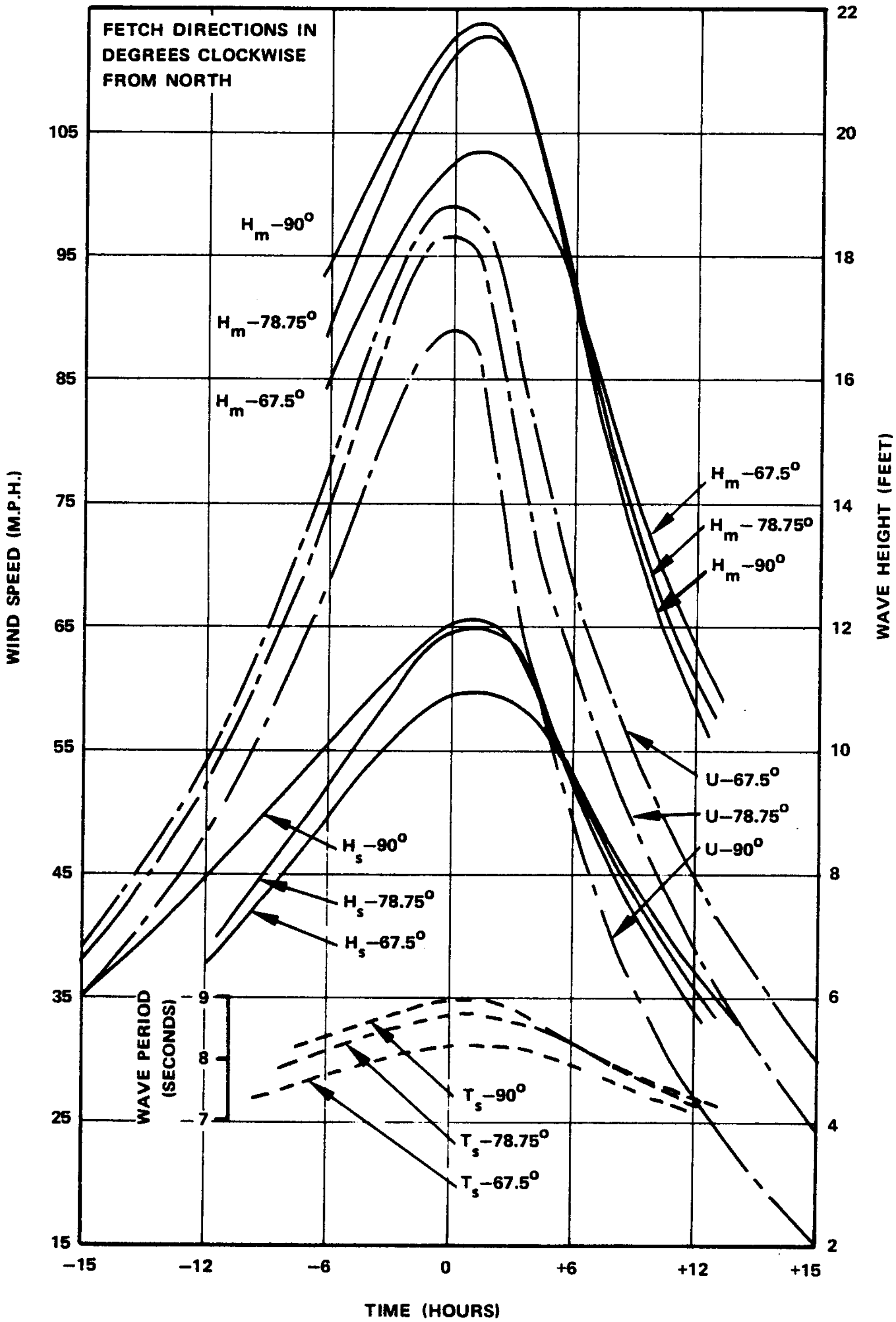
FIGURE 2.4-15

FETCH DIRECTIONS



LEGEND:

H_m = MAXIMUM HEIGHT

H_s = SIGNIFICANT WAVE HEIGHT

T_s = SIGNIFICANT WAVE PERIOD

U = COMPONENT WIND VELOCITY

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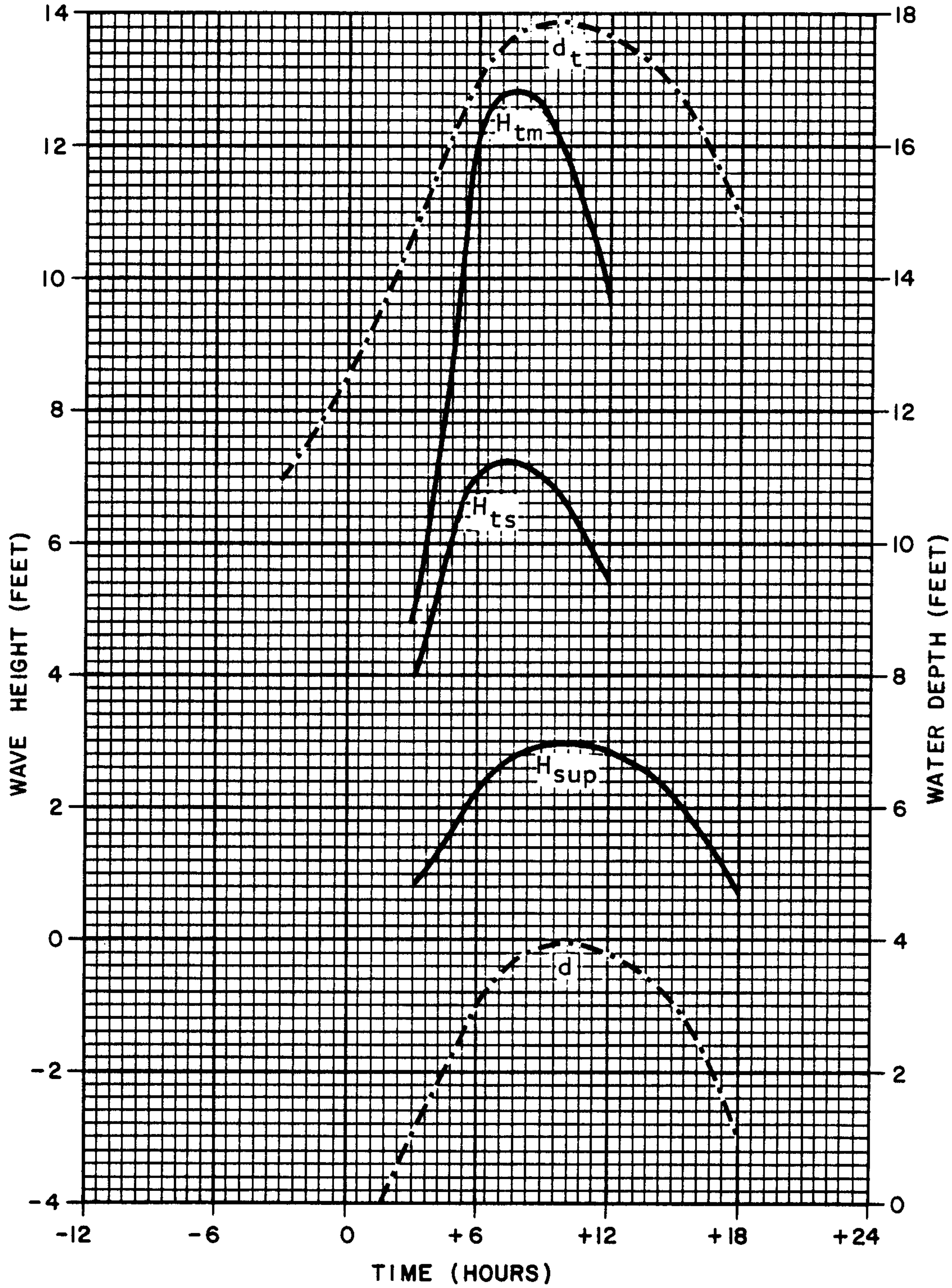
FIGURE 2.4-16

WIND AND WAVE CHARACTERISTICS VERSUS TIME



LEGEND:
ALL ELEVATIONS REFER TO NYMT, 1935.

FOR A SHORE BARRIER TOE ELEVATION OF 569.0 FT AND CREST ELEVATION OF 583.0 FT:

H_{tm} = WAVE HEIGHT TRANSMITTED OVER SHORE BARRIER FOR INCIDENT MAXIMUM WAVE HEIGHTS

H_{ts} = WAVE HEIGHT TRANSMITTED OVER SHORE BARRIER FOR INCIDENT SIGNIFICANT WAVE HEIGHTS

H_{sup} = MAXIMUM WAVE HEIGHT SUPPORTED OVER INLAND FLOODED PLANT GRADE (ELEVATION 583.0 FT) WITHOUT BREAKING

d_t = DEPTH OF WATER AT SHORE BARRIER WITH A TOE ELEVATION OF 569.0 FT

d = INLAND DEPTH OF WATER ABOVE PLANT GRADE ELEVATION OF 583.0 FT.

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FIGURE 2.4-17

TRANSMITTED AND SUPPORTED WAVE HEIGHTS VERSUS TIME

STATIC FORCES		BREAKING WAVE (MINIKIN METHOD)			NON-BREAKING WAVE (1) (SAINFLOU METHOD)			BROKEN WAVE
PRESSURE (PSF)		2,960			2,925			3,060
THRUST (LBS./FT. OF WALL)		70,100			68,700			75,000
DYNAMIC FORCES	WAVE PERIOD (SECONDS)	3.4	7.7	9.0	3.4	7.7	9.0	FORCES ARE INDEPENDENT OF WAVE PERIOD
PRESSURE (PSF)	10% SLOPE	2,460	660	520	150	180	182	122
	5% SLOPE	3,000	900	700				
THRUST (LBS./FT. OF WALL)	10% SLOPE	2,460	660	520	1,125	1,235	1,245	256
	5% SLOPE	3,000	900	700				

CASE I

D = 46.9' (DEPTH FROM STILLWATER LEVEL TO TOP OF REACTOR SLAB)
d = 3.9' (DEPTH FROM STILLWATER LEVEL TO TOP OF PLANT GRADE)
H = 3.0' (WAVE HEIGHT)

STATIC FORCES		BREAKING WAVE (MINIKIN METHOD)			NON-BREAKING WAVE (1) SAINFLOU METHOD)			BROKEN WAVE
PRESSURE (PSF)		3,100			2,925			3,160
THRUST (LBS./FT. OF WALL)		77,000			68,700			80,100
DYNAMIC FORCES	WAVE PERIOD (SECONDS)	4.5	7.7	9.0	4.5	7.7	9.0	FORCES ARE INDEPENDENT OF WAVE PERIOD
PRESSURE (PSF)	10% SLOPE	4,480	1,870	1,460	268	312	319	215
	5% SLOPE	5,500	2,460	1,950				
THRUST (LBS./FT. OF WALL)	10% SLOPE	8,060	3,360	2,640	3,664	3,900	3,950	814
	5% SLOPE	9,900	4,430	3,520				

(1) DYNAMIC FORCES OF NON-BREAKING WAVES RESULT FROM CLAPOTIS AFFECT.

CASE 2

D = 46.9' (DEPTH FROM STILLWATER LEVEL TO TOP OF REACTOR SLAB)
d = 6.9' (DEPTH FROM STILLWATER LEVEL TO TOP OF PLANT GRADE)
H = 5.4' (WAVE HEIGHT)

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FIGURE 2.4-18

WAVE PRESSURE AND FORCES AGAINST REACTOR BUILDING

STATIC FORCES		BREAKING WAVE (MINIKIN METHOD)			NON-BREAKING WAVE (1) (SAINFLOU METHOD)			BROKEN WAVE
PRESSURE (PSF)		2,334			2,240			2,371
THRUST (LBS./FT. OF WALL)		43,641			40,208			45,049
DYNAMIC FORCES	WAVE PERIOD (SECONDS)	3.4	7.7	9.0	3.4	7.7	9.0	FORCES ARE INDEPENDENT OF WAVE PERIOD
PRESSURE (PSF)	10% SLOPE	2,460	660	520	150	180	182	122
	5% SLOPE	3,000	900	700				
THRUST (LBS./FT. OF WALL)	10% SLOPE	2,460	660	520	1,125	1,235	1,245	256
	5% SLOPE	3,000	900	700				

CASE I

D = 36.9' (DEPTH FROM STILLWATER LEVEL TO TOP OF RHR SLAB)
d = 3.9' (DEPTH FROM STILLWATER LEVEL TO TOP OF PLANT GRADE)
H = 3.0' (WAVE HEIGHT)

STATIC FORCES		BREAKING WAVE (MINIKIN MMETHOD)			NON-BREAKING WAVE (1) (SAINFLOU METHOD)			BROKEN WAVE
PRESSURE (PSF)		2,409			2,240			2,477
THRUST (LBS./FT. OF WALL)		46,487			40,208			49,174
DYNAMIC FORCES	WAVE PERIOD (SECONDS)	4.5	7.7	9.0	4.5	7.7	9.0	FORCES ARE INDEPENDENT OF WAVE PERIOD
PRESSURE (PSF)	10% SLOPE	4,480	1,870	1,460	268	312	319	215
	5% SLOPE	5,500	2,460	1,950				
THRUST (LBS./FT. OF WALL)	10% SLOPE	8,060	3,360	2,640	3,664	3,900	3,950	814
	5% SLOPE	9,900	4,430	3,520				

(1) DYNAMIC FORCES OF NON-BREAKING WAVES RESULT FROM CLAPOTIS AFFECT.

CASE 2

D = 36.9' (DEPTH FROM STILLWATER LEVEL TO TOP OF RHR SLAB)
d = 6.9' (DEPTH FROM STILLWATER LEVEL TO TOP OF PLANT GRADE)
H = 5.4' (WAVE HEIGHT)

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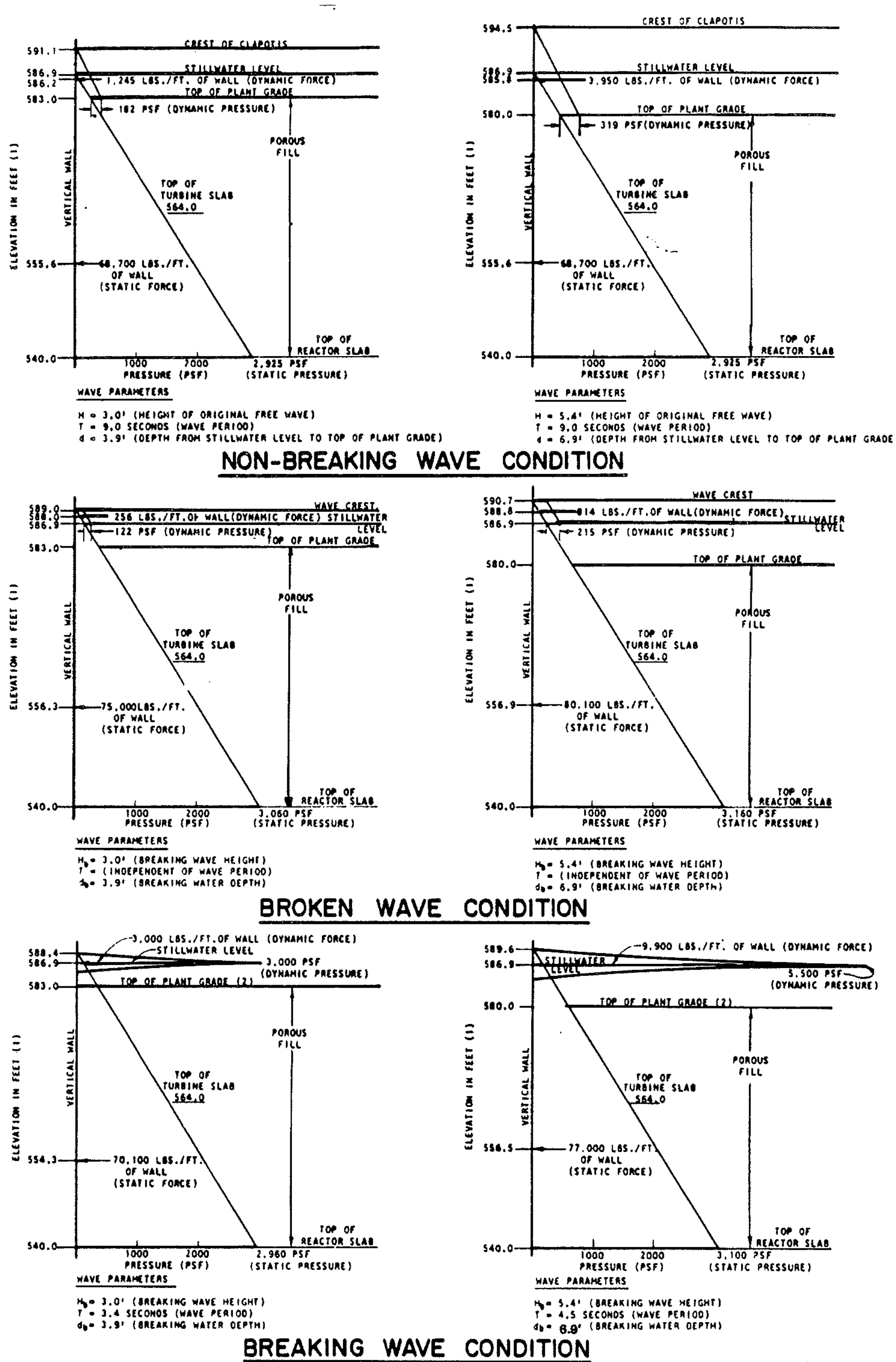
FIGURE 2.4-19

WAVE PRESSURE AND FORCES AGAINST RESIDUAL HEAT REMOVAL COMPLEX



NOTES:

1. ALL ELEVATIONS REFER TO NYMT, 1935 DATUM
2. 5 PERCENT SLOPE ASSUMED

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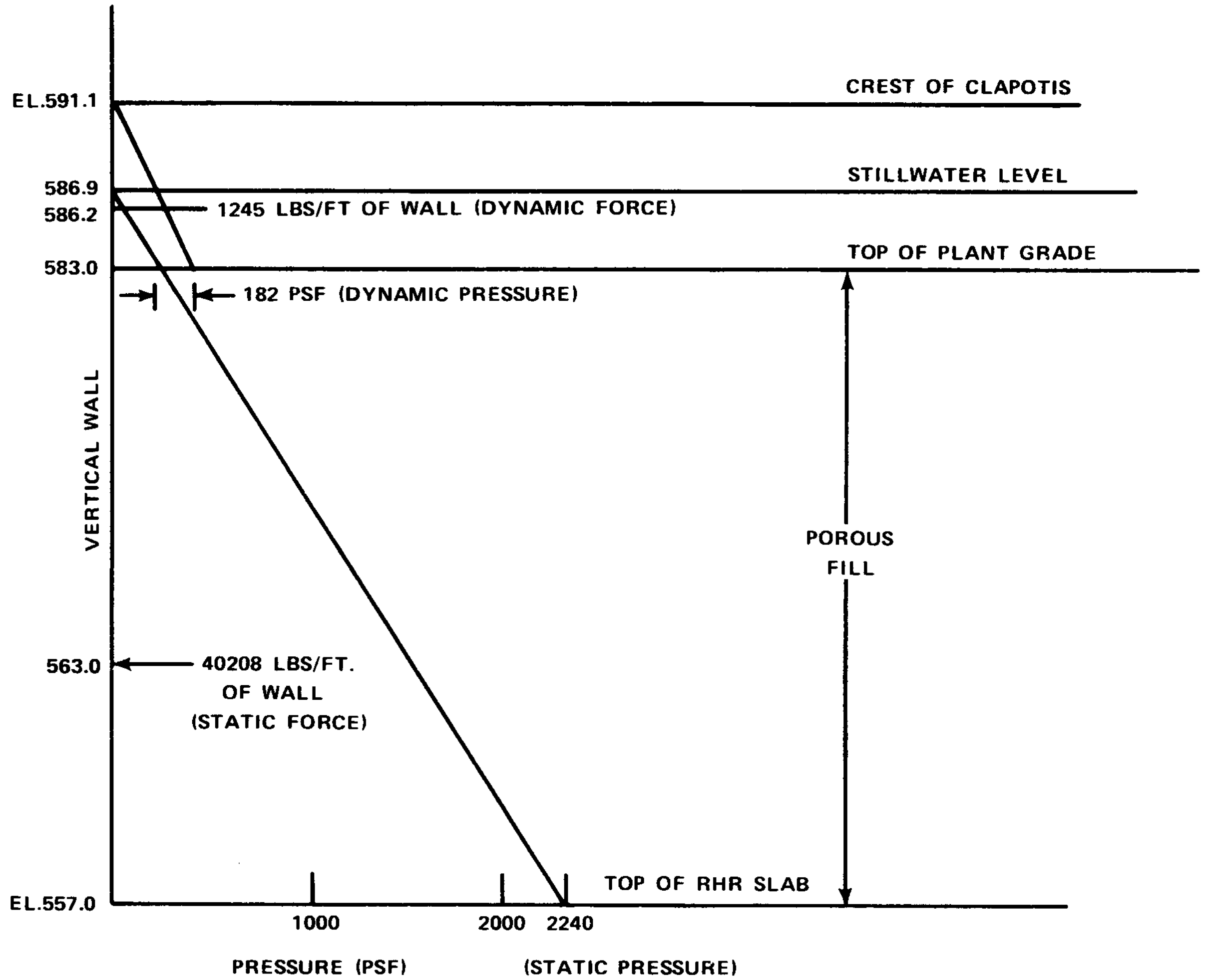
FIGURE 2.4-20

WAVE PRESSURE DISTRIBUTIONS AGAINST REACTOR/AUXILIARY BUILDING

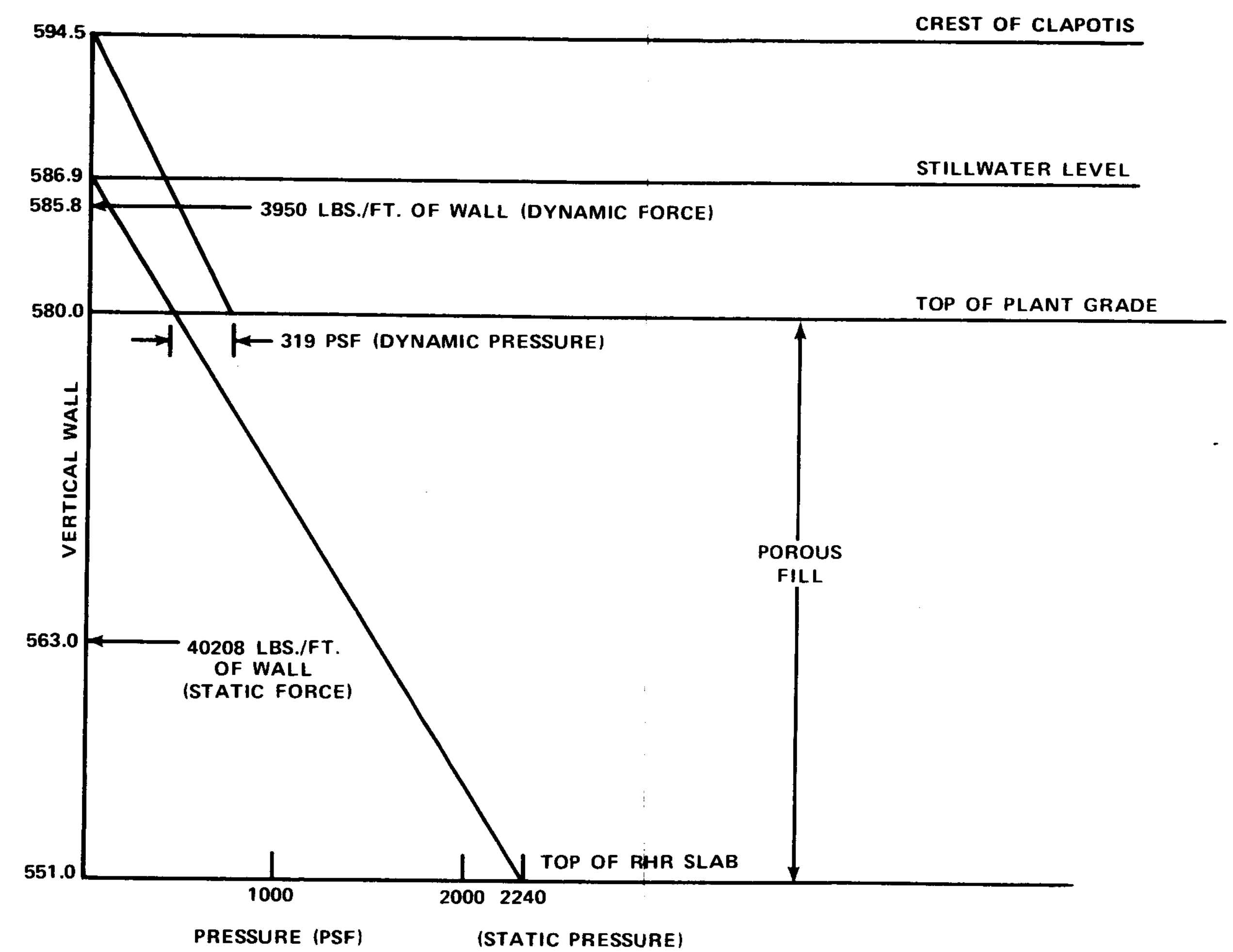


WAVE PARAMETERS

H = 3.0′ (HEIGHT OF ORIGINAL FREE WAVE)

T = 9.0 (SECONDS (WAVE PERIOD)

d = 3.9′ (DEPTH FROM STILLWATER LEVEL TO TOP OF PLANT GRADE)



WAVE PARAMETERS

H = 5.4′ (HEIGHT OF ORIGINAL FREE WAVE)

T = 9.0 SECONDS (WAVE PERIOD)

d = 6.9′ (DEPTH FROM STILLWATER LEVEL TO TOP OF PLANT GRADE)

NON–BREAKING WAVE CONDITION

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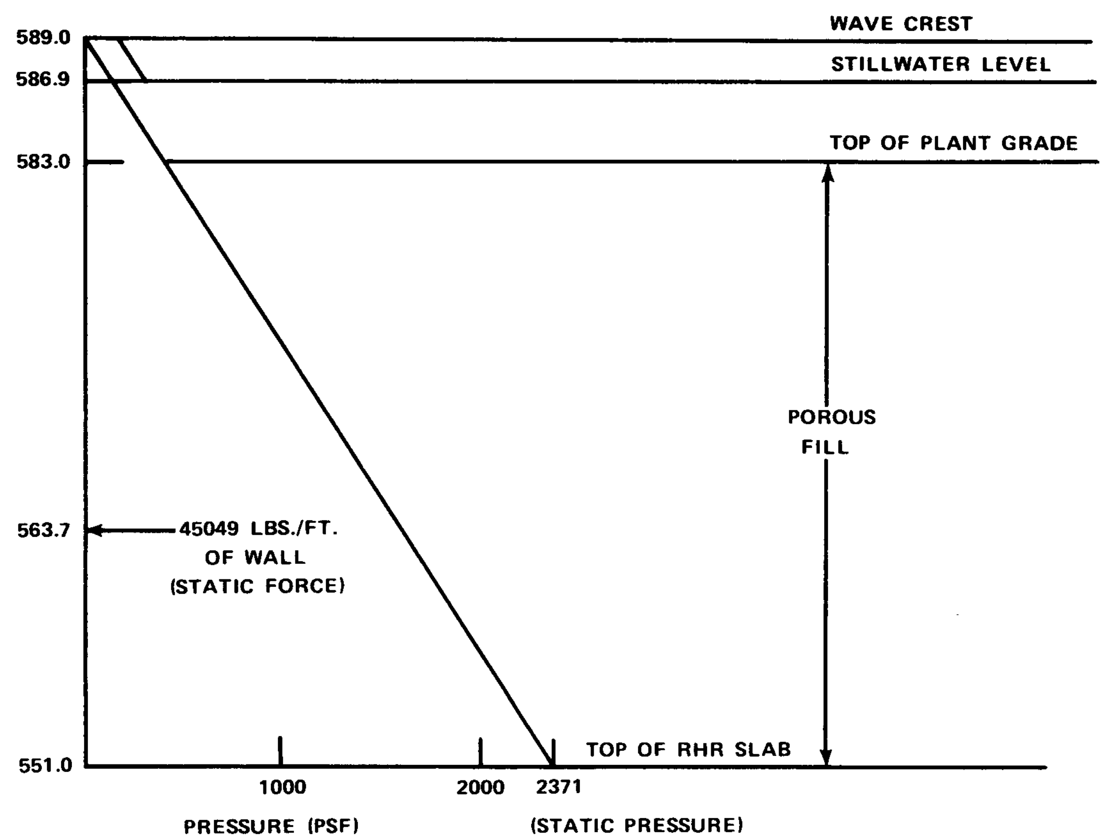
FIGURE 2.4-21, SHEET 1

WAVE PRESSURE DISTRIBUTION AGAINST RESIDUAL HEAT REMOVAL COMPLEX

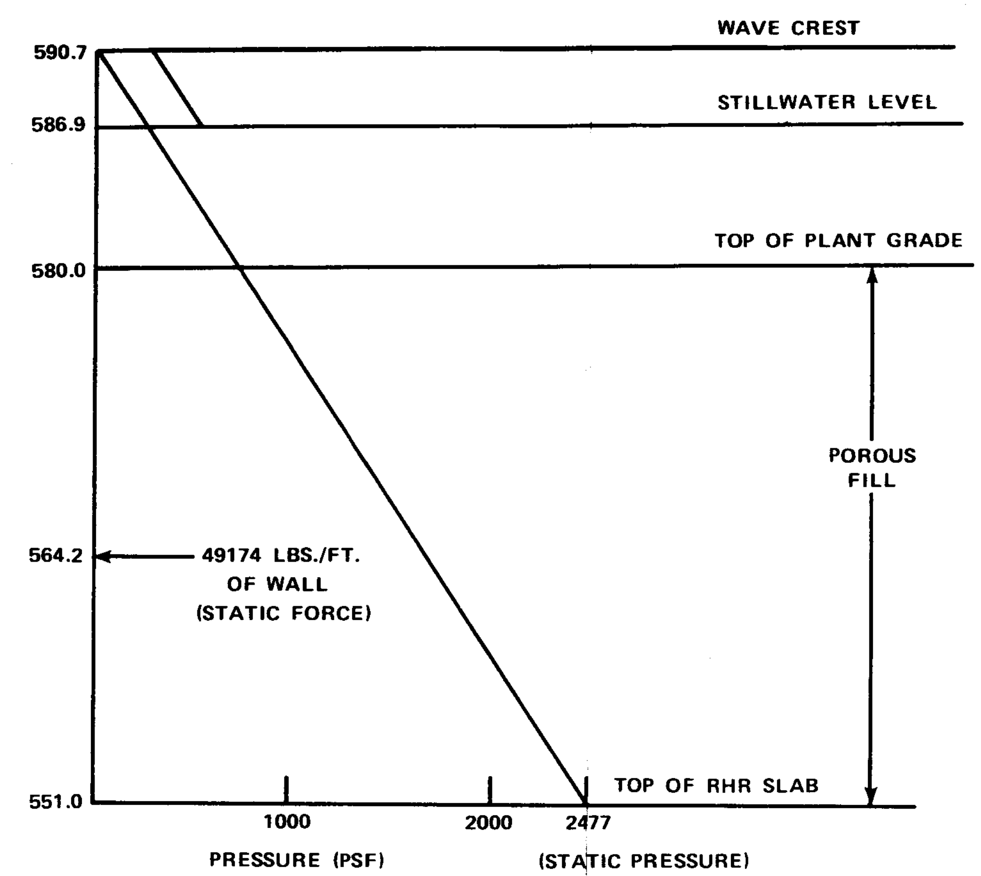


WAVE PARAMETERS

H_b = 3.0' (BREAKING WAVE HEIGHT)

T = (INDEPENDENT OF WAVE PERIOD)

d_b = 3.9' (BREAKING WATER DEPTH)



WAVE PARAMETERS

H_b = 5.4 (BREAKING WAVE HEIGHT)

T = (INDEPENDENT OF WAVE PERIOD)

d_b = 6.9' (BREAKING WATER DEPTH)

BROKEN WAVE CONDITION

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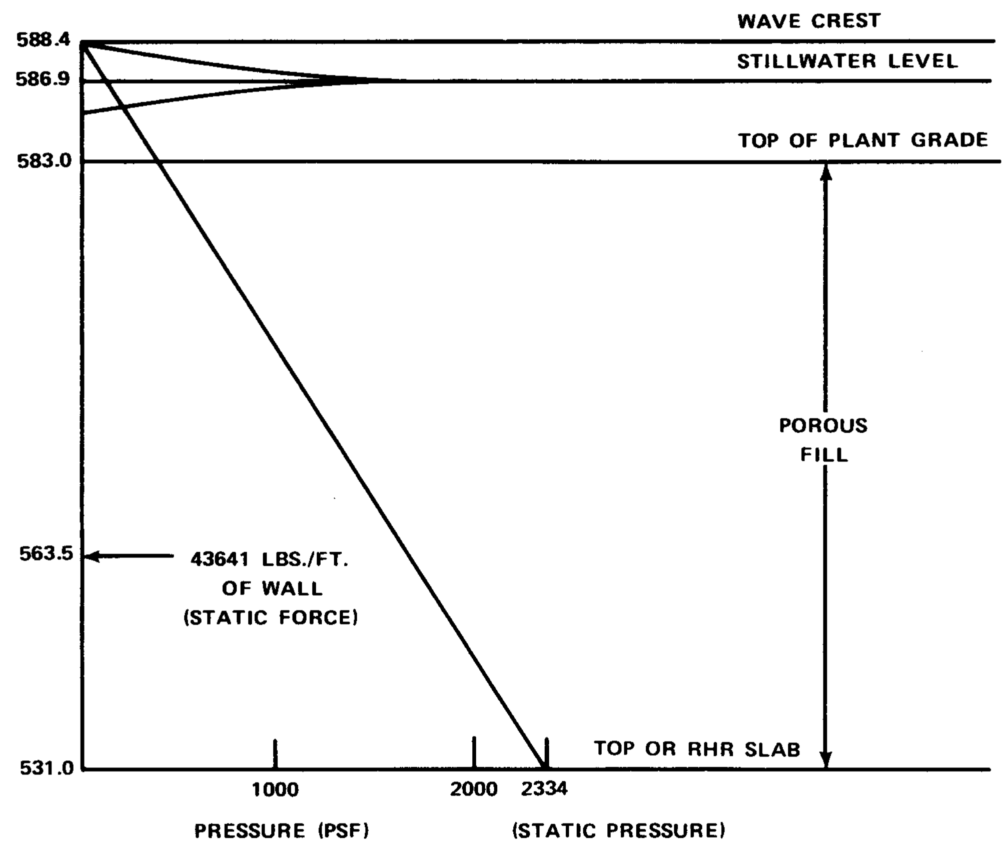
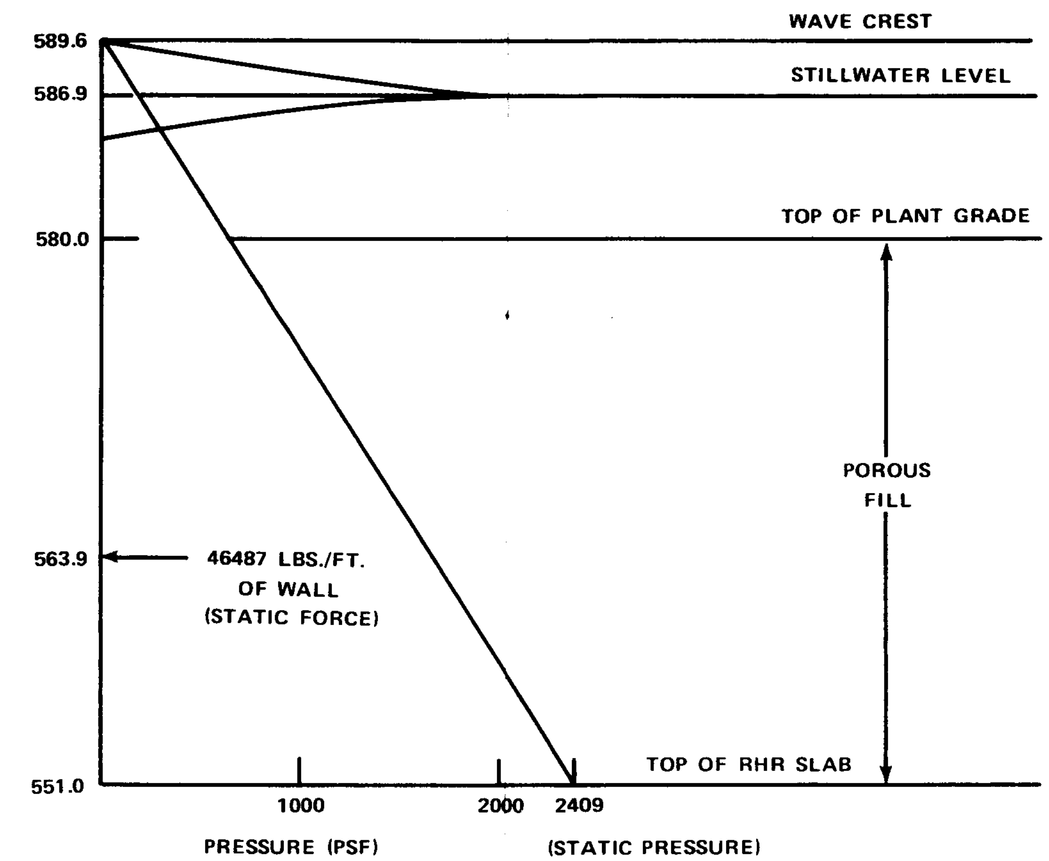
FIGURE 2.4-21, SHEET 2

WAVE PRESSURE DISTRIBUTION AGAINST RESIDUAL HEAT REMOVAL COMPLEX



WAVE PARAMETERS

H_b = 3.0' (BREAKING WAVE HEIGHT)
T = 3.4 SECONDS (WAVE PERIOD)
d_b = 3.9' (BREAKING WATER DEPTH)



WAVE PARAMETERS

H_b = 5.4' (BREAKING WAVE HEIGHT)
T = 4.5 SECONDS (WAVE PERIOD)
d_b = 6.9 (BREAKING WATER DEPTH)

BREAKING WAVE CONDITION

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FIGURE 2.4-21, SHEET 3

WAVE PRESSURE DISTRIBUTION AGAINST RESIDUAL HEAT REMOVAL COMPLEX

Figure Intentionally Removed
Refer to Plant Drawing C-0040

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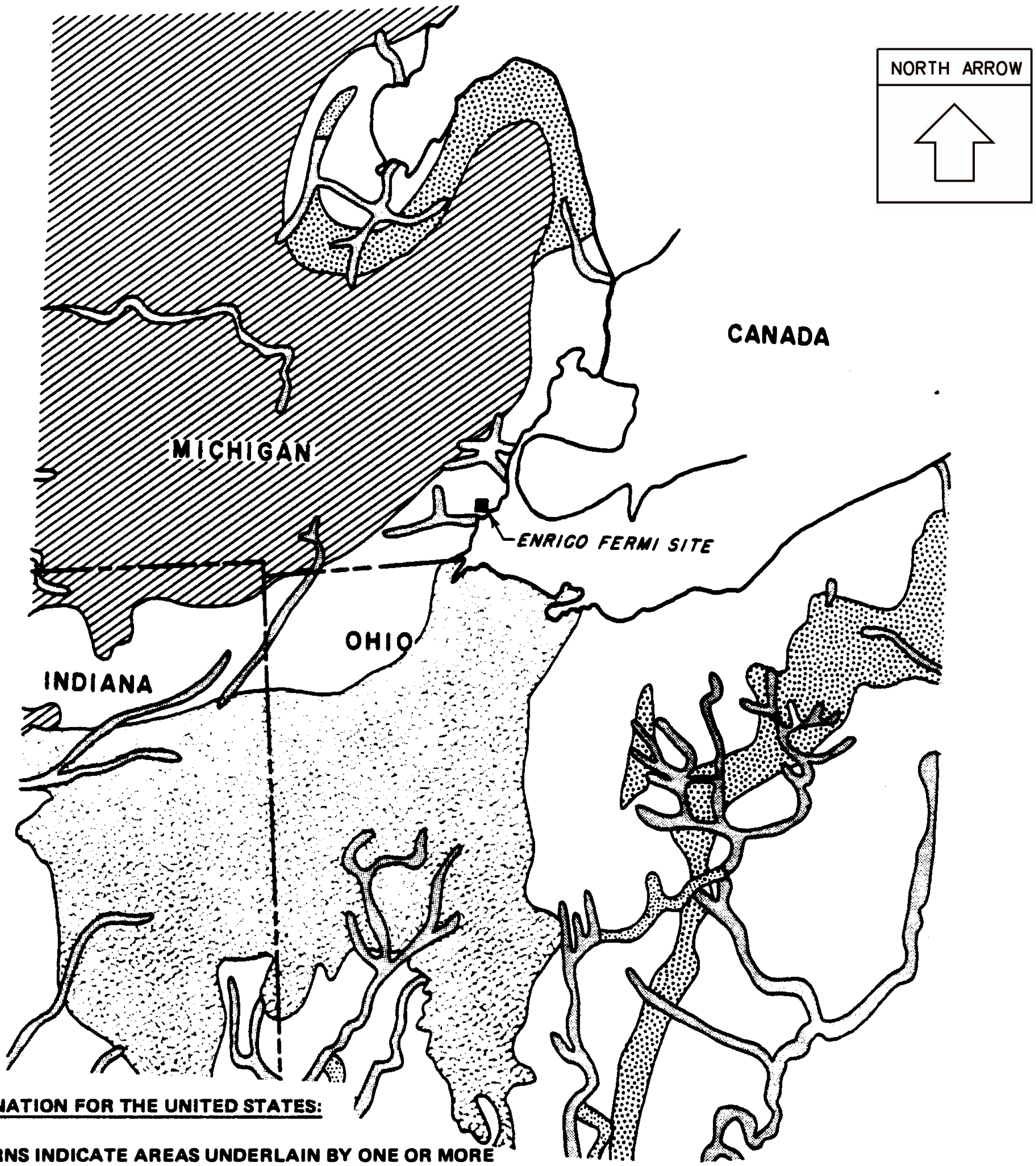
FIGURE 2.4-22

SHORE BARRIER DESIGN



EXPLANATION FOR THE UNITED STATES:

PATTERNS INDICATE AREAS UNDERLAIN BY ONE OR MORE AQUIFERS GENERALLY CAPABLE OF YEILDING TO A WELL AT LEAST 50 gpm OF WATER CONTAINING NOT MOR THAN 2000 ppm OF DISSOLVED SOLIDS (INCLUDING AREAS WHERE MORE HIGHLY MINERALIZED WATER IS ACTUALLY USED).

LEGEND:

UNCONSOLIDATED AND SEMICONSOLIDATED AQUIFERS

- ALLUVIAL SAND AND GRAVEL
- WATERCOURSE – ALLUVIAL VALLEY TRAVERSED BY PERENNIAL STREAM FROM WHICH RECHARGE CAN BE INDUCED
- SURFICIAL ALLUVIAL VALLEY NO LONGER TRAVERSED BY PERENNIAL STREAM (ABANDONED WATERCOURSE), OR BURIED ALLUVIAL VALLEY

CONSOLIDATED – ROCK AQUIFERS

- SANDSTONE (INCLUDES SOME SAND)
- CARBONATE ROCKS (LIMESTONE AND DOLOMITE; LOCALLY INCLUDE GYPSUM)

50 0 50

SCALE, MILES

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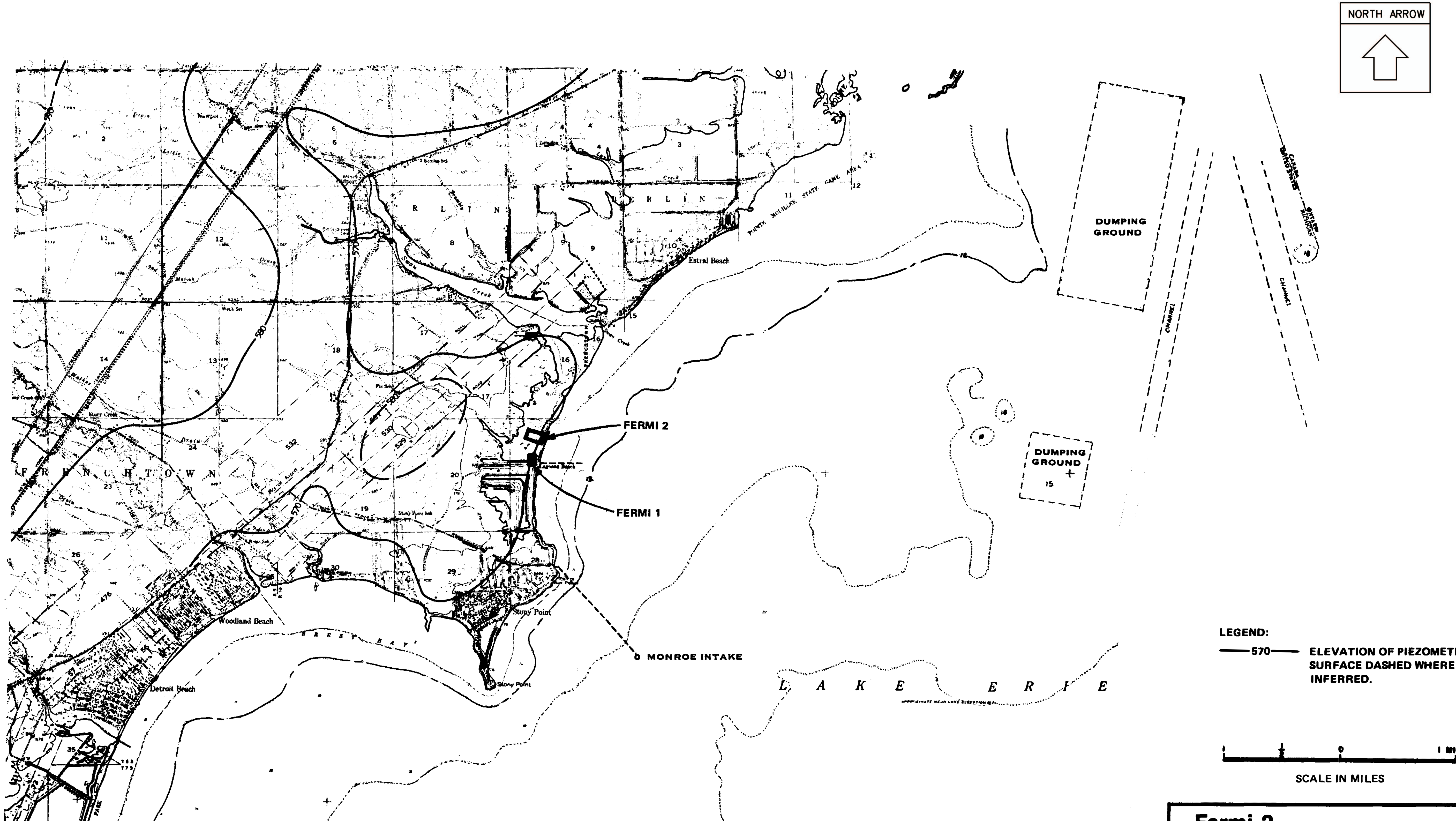
FIGURE 2.4-23

REGIONAL AQUIFER DISTRIBUTION

REFERENCE:
U.S. DEPARTMENT OF THE INTERIOR GEOLOGICAL SURVEY WATER SUPPLY PAPER NO. 1800, 1963.



REFERENCE:
THIS MAP WAS PREPARED FROM PORTIONS OF THE FOLLOWING U.S.G.S. TOPOGRAPHIC QUADRANGLES: ESTRAL BEACH, MICHIGAN, 1942, STONY POINT, MICHIGAN, 1952, ROCKWOOD, MICHIGAN, 1952, AND FLAT ROCK, MICHIGAN, 1952.

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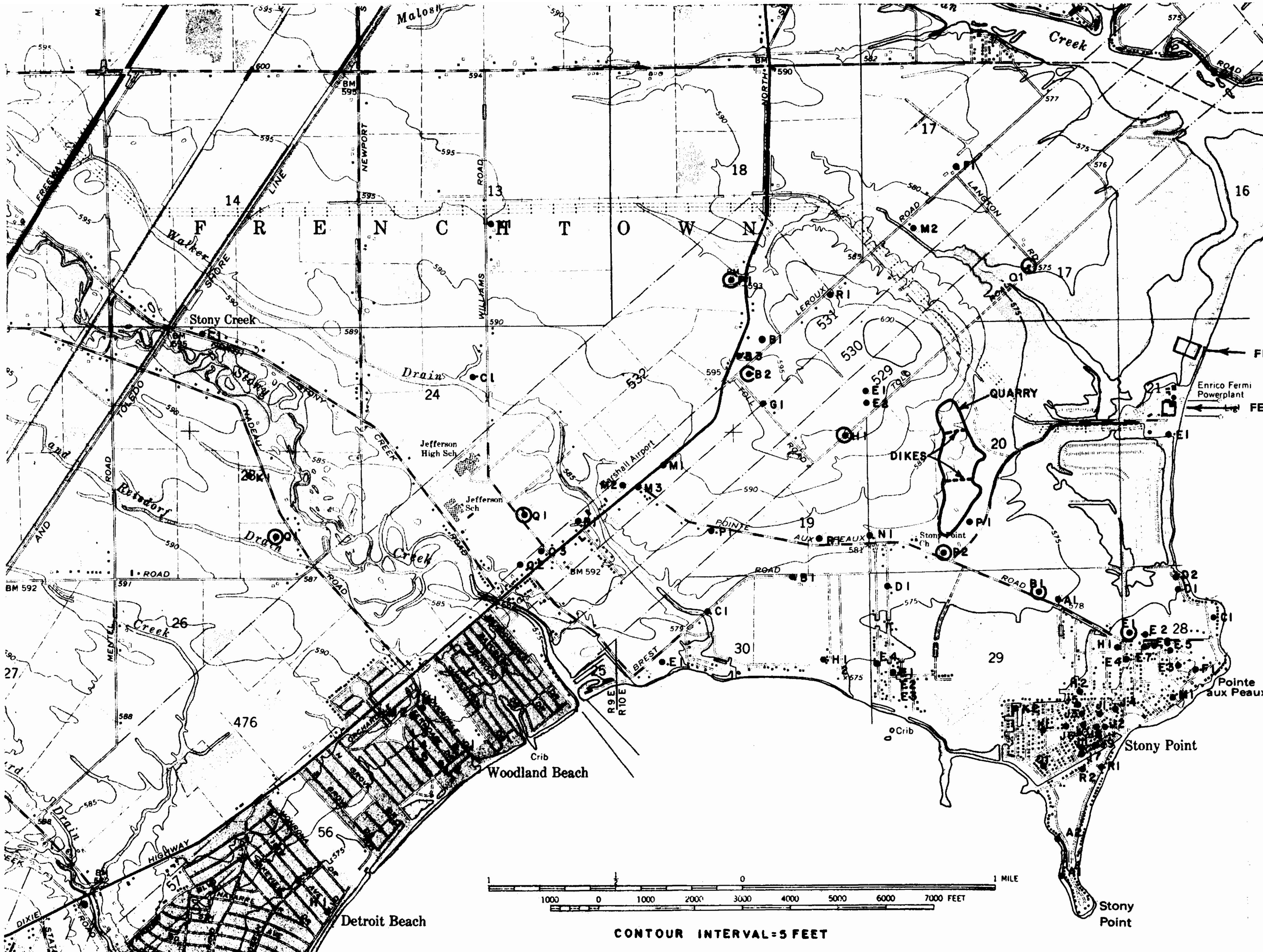
FIGURE 2.4-24

PIEZOMETRIC SURFACE 1961-1966



LEGEND:
- WELL LOCATION (SEE TABLE 2.4-7 FOR EXPLANATION OF WELL NUMBERING SYSTEM.)
- WELL WITH HYDROGRAPH PLOT.

REFERENCE:
U.S.G.S. TOPOGRAPHIC QUADRANGLE
STONY POINT, MICHIGAN – 1967.

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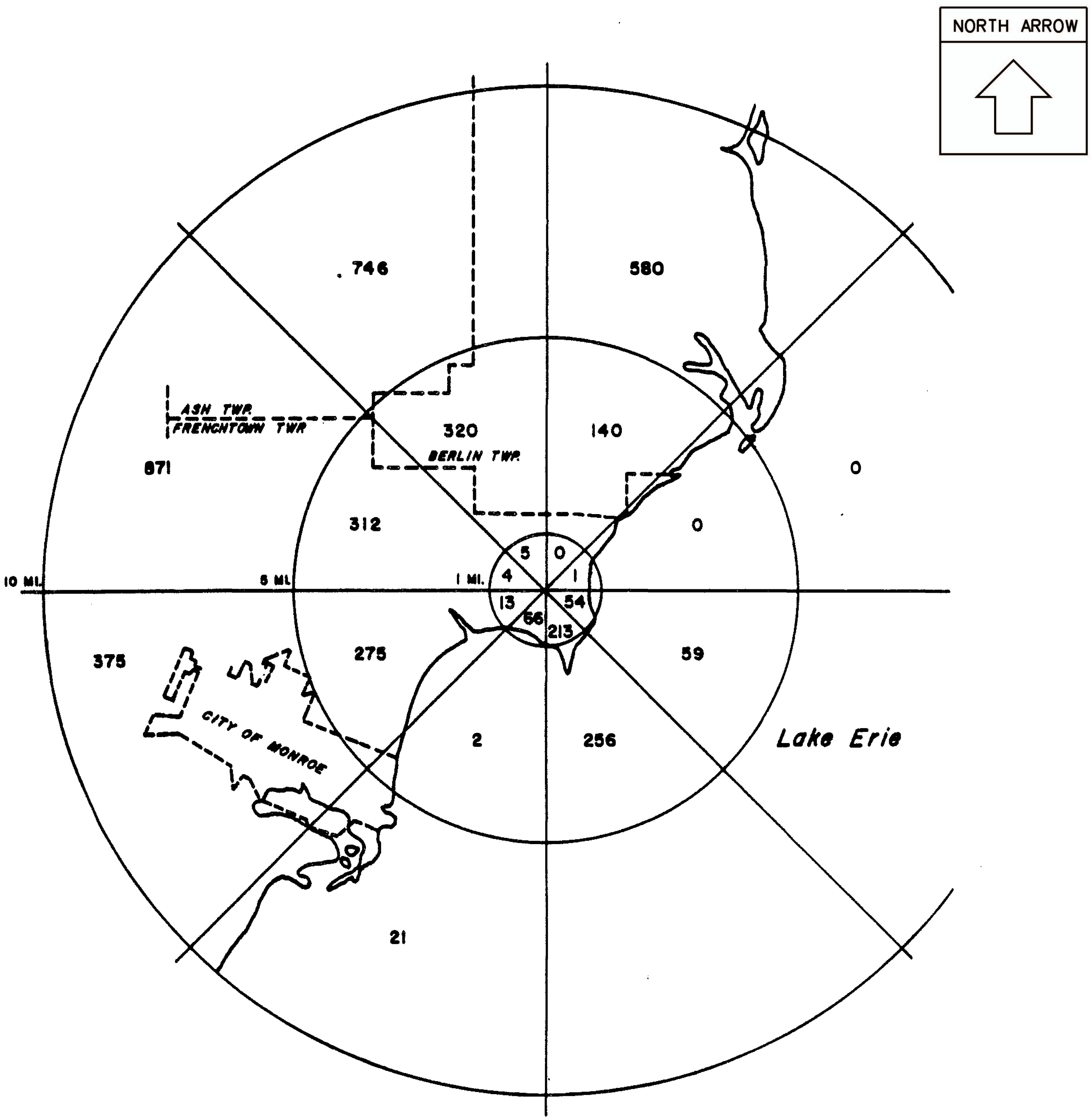
FIGURE 2.4-25

WELL LOCATIONS



LEGEND:
NUMBERS REFER TO NUMBER OF
GROUNDWATER WELLS IN EACH SECTOR.

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FIGURE 2.4-26

WATER WELL DISTRIBUTION

2.5. GEOLOGY AND SEISMOLOGY

The Fermi site is located on the shore of the western end of Lake Erie at Lagoona Beach, Frenchtown Township, Monroe County, Michigan. Geologic and seismic studies of the Fermi site were conducted for Fermi 2 in 1968 and 1969. Detailed foundation studies were performed for the Fermi 2 reactor/auxiliary building in 1969, and rock foundation grouting for these structures was performed in 1970. Detailed foundation studies were performed in 1972 for the Fermi 2 residual heat removal (RHR) complex. Foundation grouting for the RHR complex has been completed. The geologic, seismic, and foundation studies for Fermi 2 were conducted by Dames & Moore (D&M) with the results of a few of the studies presented in the Fermi 2 PSAR. The location of Fermi 2 is shown in Figure 2.4-1. The topography of the site with the location of the principal plant facilities is shown in Figure 2.4-3.

The site is located within the Central Stable Region tectonic province of the North American continent. Some regional faulting and seismic activity is known, but the region is characteristically one of relative stability. There are no known faults within 25 miles of the site and there are no capable faults within 200 miles of the site.

Approximately 3100 ft of Paleozoic sedimentary rocks overlie the Precambrian basement in the area. Overlying the Paleozoic sedimentary rock strata are Pleistocene soils of glacial origin that are less than 20 ft thick at the site. The site is located on the southeast side of the Michigan Basin. The sedimentary rock strata generally dip to the northwest toward the center of the Michigan Basin. The bedrock immediately underlying the site consists of dolomites of the Bass Islands Group of the Silurian System. The Bass Islands Group is competent dolomite with thin shale beds and is variably fractured and contains some vuggy zones. No geologic conditions are known that could have an adverse effect on the safety of plant facilities.

All major Fermi 2 Category I structures are supported in the Bass Islands dolomite. Foundation pressure grouting of the bedrock was performed to improve subsurface conditions. A test blasting program was conducted, and blast monitoring was provided during construction. Criteria for foundation treatment and design were formulated, based on foundation studies performed at the locations of Category I and other major structures.

All Category I structures are designed to respond to peak horizontal ground accelerations of the rock surface at foundation levels of 8 and 15 percent of gravity for the operating-basis earthquake (OBE) and safe-shutdown earthquake (SSE), respectively. Site-related response spectra were used to analyze the response of structures to earthquake ground motion.

The results of the geologic and seismic studies for Fermi 2 are summarized in Subsections 2.5.1 through 2.5.3. The stability of subsurface materials at the locations of Fermi 2 Category I and major structures is summarized in Subsection 2.5.4.

2.5.1. Basic Geologic and Seismic Information

Basic geologic and seismic data were obtained by D&M for the Fermi site from 1968 through 1972 in three major programs:

a. Geologic and seismic studies in 1968 for the Fermi 2 site

b. Foundation studies in 1969 for the reactor/auxiliary building

c. Foundation studies in 1972 for the RHR complex.

The general scope of these studies is outlined in the following paragraphs.

The geologic and seismic program of investigation conducted in 1968 at the Fermi site for Fermi 2 (Reference 1) included the following:

a. A thorough review of pertinent geologic literature (published and unpublished) and interviews with university and state geologists

b. A geologic reconnaissance of the site and surrounding area, and a review of maps and aerial photographs

c. Field explorations that were performed to evaluate the geologic and seismologic characteristics of the site, consisting of the following:

    1. Geologic test boring program
    2. Geologic inspection of the site and surrounding area
    3. Geophysical refraction survey
    4. Blast monitoring observations
    5. Micromotion measurements
    6. Borehole geophysical measurements
    7. Ground water observations

d. A laboratory soil- and rock-testing program for Fermi 2 was conducted.

In 1969, a comprehensive foundation investigation was performed at the Fermi 2 reactor/auxiliary building and adjacent structures (Reference 2). The field explorations consisted of the following:

a. Test boring program

b. Water pressure testing in selected borings

c. Ground water observations

d. Ground water sampling.

Laboratory testing during this investigation consisted of density and unconfined compression tests on selected rock cores and chemical analyses of ground water.

In 1972, a comprehensive foundation investigation was performed at the location of the Fermi 2 RHR complex (Reference 3). The field exploration program consisted of the following:

a. Test boring program

b. Water pressure testing

c. Piezometer installation

d. Geologic reconnaissance.

Laboratory testing for this investigation consisted of pulsating load triaxial tests, unconfined compression tests, consolidation tests, moisture-density tests on soil samples, and unconfined compression tests on rock cores.

Supplementary seismic evaluations were completed for the Fermi 2 site in October 1982 by Weston Geophysical Corporation. These evaluations led to the establishment of facility site specific response spectra that were subsequently used to validate the satisfactory nature of the original facility design-basis earthquake provisions. The site-specific earthquake was characterized in terms of Richter magnitude (from 4.9 to 5.9) and epicentral distance (25 km). Site-specific response spectra were developed from real-time histories for the appropriate magnitude and distance, and foundation conditions similar to the Fermi site. (Weston Geophysical Corporation, Draft Site Specific Response Spectra for Enrico Fermi 2; October 1982.)

2.5.1.1. Regional Geology

2.5.1.1.1. Physiography

The Fermi site is located in the northern portion of the midwestern United States in the Central Lowlands Physiographic Province. This physiographic province has been subdivided into eight physiographic sections. Michigan is located in the Eastern Lake Section (Figure 2.5-1).

The Eastern Lake Section is characterized by glacial landforms (including end moraines, ground moraines, outwash plains, kames, eskers, and drumlins) and by beach and lacustrine deposits formed during the fluctuations of the Great Lakes. The glacial deposits overlie maturely dissected bedrock cuestas and broad areas of relatively flat-lying bedrock. The bedrock is exposed locally. The bedrock surface was dissected prior to being covered with glacial drift. The rock surface tends to be gently rolling with well-developed valley systems.

The Fermi site is located on a lake plain formed during the high-water stages of Lake Erie. There is little topographic relief on the lake plain, which results in poor surface drainage. It has been dissected by eastward-flowing creeks and rivers. The relief on the lake plain within the vicinity of the project area is approximately 25 ft.

2.5.1.1.2. Stratigraphy

2.5.1.1.2.1. Soil Units

The soil units in the region include Pleistocene-aged deposits consisting of alluvium, lacustrine materials, peats, tills, outwash, glaciofluvial materials, glaciolacustrine materials, and residual soil. Figure 2.5-2 shows the distribution of surface Pleistocene glacial deposits of the southern peninsula of Michigan and portions of surrounding states. The site area is located in a glaciolacustrine section on the western edge of Lake Erie. The distribution of surface soil units within eastern Monroe County is shown in Figure 2.5-3. The soil deposits in Monroe County range in thickness from 0 to over 150 ft (Reference 4).

2.5.1.1.2.2. Rock Units

The distribution of the rock units that form the bedrock surface within the region is shown in Figure 2.5-4 and the stratigraphic sequence of the various-aged rock units is shown in the legend. The rock units in the Michigan Basin consist of sedimentary strata of Jurassic, Pennsylvanian, Mississippian, Devonian, Silurian, Ordovician, and Cambrian ages, as well as an igneous and/or metamorphic complex of Precambrian-aged rocks.

The sedimentary sequence in the Monroe County area includes Devonian- through Cambrian-aged strata. The local distribution of these strata is shown in Figure 2.5-5. These strata consist of 2500 to 3500 ft of limestones, dolomites, sandstones, and shales. The Precambrian basement in southeastern Michigan consists of crystalline rocks of igneous and metamorphic origin (Reference 4) and occurs at a depth of about 3100 ft.

2.5.1.1.3. Structural Geology

The Fermi site is located within the Central Stable Region tectonic province of the North American continent. This tectonic province is characterized by a thick sequence of sedimentary strata overlying the Precambrian basement. The Precambrian basement is exposed in Wisconsin, Minnesota, and the upper peninsula of Michigan. During Paleozoic and early Mesozoic time, the area was subjected to a series of vertical crustal movements that formed broad basins and arches. The arches and basins have been modified by local folding and faulting. Major geologic structures are shown in Figures 2.5-6 and 2.5-7. The relation between structures and gravimetric and magnetic anomalies is discussed in Subsection 2.5.1.1.5.2.

2.5.1.1.3.1. Folding

The distribution of major folds in the region is shown in Figure 2.5-6 and the characteristics of these folds are presented in Table 2.5-1. The Fermi site is located on the southeast side of the Michigan Basin, which corresponds to the northwest flank of the northeast-trending Findlay Arch. Ells (Reference 5) has proposed the name "Washtenaw Anticlinorium" to describe a broad northwesterly plunging structure in southeast Michigan that is composed of several smaller folds. This broad structural feature covers about 4500 square miles within Michigan and continues into Ohio, Ontario, and Lake Erie. Local structures within this broad structurally high region include the Howell Anticline, the Freedom Anticline, and the Lucas Monocline. The northwest-trending Howell Anticline is located north and northwest of the project area. The northwest-trending Freedom Anticline is located west of the project area, and the north-to-northwest-trending Lucas Monocline lies southeast of the project area and along the projected trend of the Bowling Green Fault.

The direction and amount of regional dip of the strata in south-eastern Michigan are variable. In the vicinity of the site, the strata dip northwest toward the Michigan Basin at 0.5° or less (Reference 4).

The Howell Anticline approaches to within about 25 miles north of the site and extends approximately 80 miles to the northwest. The northwest-southeast-trending fold is located on the southeast flank of the Michigan Basin and has a maximum structural relief, in the early Paleozoic rocks, of about 1000 ft (Reference 22 in Reference 5). The relief is less pronounced in the younger strata. It has been suggested that faulting is associated with the Howell Anticline (References 5, 6, and 7) as discussed in Subsection 2.5.1.1.3.2.

The Lucas Monocline is a north-to-northwest-trending series of folds in southeastern Michigan located approximately 30 miles southwest of the site. It has been inferred by Ells (Reference 5) that the Lucas Monocline may connect with or be associated with the Bowling Green Fault, which is mapped in northwest Ohio (References 6 and 8). Other researchers (Reference 9) have inferred that the Lucas Monocline is actually a fault structure. The folds bend northwestward in southern Michigan where they join the Freedom Anticline. The early Paleozoic rocks in this folded area have a maximum structural relief on the order of 500 ft.

The Chatham Sag (References 5 and 10) is a broad, gentle northwest-trending syncline that has been mapped as far south as the north shore of Lake Erie. The axis of the syncline lies about 50 miles northeast of the site. The Chatham Sag crosses the Findlay-Algonquin Arch System and is virtually unrecognizable in the early Paleozoic strata. A system of small faults, the most prominent of which is the Electric Fault, is associated with this structure.

Several small earthquakes have occurred near the juncture of the Findlay, Cincinnati, and Kankakee Arches. These earthquakes cannot be associated with any known structures, but are believed to have occurred along a zone of structural weakness that separates the three arches.

A portion of the U.S. Geological Survey (USGS) tectonic map of the United States is shown in Figure 2.5-8. This map shows the detail of some of the structural features in the Michigan Basin area.

2.5.1.1.3.2. Faulting

The distribution of major faults in the region is shown in Figure 2.5-7, and their characteristics are presented in Table 2.5-2. The Bowling Green, Electric, Tekonsha Trend, and Albion-Scipio Trend faults are the four major faults within 100 miles of the project area.

The Bowling Green Fault is located approximately 35 miles southwest of the site. It has been inferred by some workers (Reference 9) that faulting extends northward into southeast Michigan. Some (Reference 5) have inferred that major faulting is not present in this area in Michigan and have interpreted the structure to be a result of folding. Others (Reference 11) believe no major faulting to be affiliated with the structure at all, and interpret it as being a monocline.

Since the very existence of the fault is in question, no clear-cut evidence is available that would either indicate age of last movement or definition of the fault. For purposes of conservatism, the Bowling Green structure is assumed to be a fault. The fault is not believed to extend into Michigan (Reference 12). The evidence available for faulting is described as follows (Reference 7):

> A drop by faulting of more than 200 feet in the top of the Trenton Limestone is indicated between well locations in the vicinity of Findlay, Cygnet, and Bowling Green, Ohio. The fault which is down-thrown on the west extends northward and connects with the Lucas County (Ohio) - Monroe County (Michigan) monocline.

Thus, the only evidence of the age of last faulting is Middle Ordovician (based upon evidence in the Trenton Limestone).

Evidence of faulting along the west flank of the Howell Anticline has been presented (References 7 and 13) and it has been suggested that total vertical displacement may be as much as 1000 ft (Reference 13). The type of faulting, amount of displacement, and orientation have not been absolutely determined. More recent work (Reference 5) has revealed that faults of major displacement are not believed to exist in connection with the immediate west flank of the Howell Anticline and it is shown that, although minor faulting may have occurred along the west flank or across the structure, it is not of the magnitude generally described by earlier investigators. Developments of the Howell Anticline associated with major faulting may have begun as early as Late Ordovician and continued throughout most of the Paleozoic. If the presence of Jurassic-aged rock in the Michigan Basin is considered, developments may have taken place as late as Cretaceous time. The age of last faulting within the State of Michigan, however, appears to be Paleozoic (Reference 14).

A system of faults located 45 miles northeast of the site is associated with the Chatham Sag. The Electric Fault in this fault system has a reported maximum vertical displacement of 300 ft (Reference l5). Maximum displacements of less than 100 ft have been reported for other faults in this system (Reference 15).

Faulting has been postulated along the Tekonsha oil field structure, and several small seismic events have been tentatively correlated to these. The structure trends northwest-southeast for an inferred length of 60 miles. Only limited, minor structural indications of this fault have been recorded.

The age of the faulting in the southeastern portion of the Michigan Basin is assumed to be Ordovician, although some evidence exists of minor movement in post-Ordovician time (Ells, personal communication).

The Keweenawan-Lake Owen Fault System lies northwest of the Michigan Basin, approximately 430 miles northwest of the site. It has a northeast trend on the Keweenawan Peninsula in Lake Superior. Vertical displacements on this fault system of a few thousand feet to more than 9000 ft are known (Reference l6). This fault system is not associated with the Michigan Basin.

The Rough Creek-Kentucky River Fault System in southern Illinois and central Kentucky is approximately 350 miles south of the site.

2.5.1.1.3.3. Pop-up and Affiliated Structural Features

Pop-up features in bedrock have been identified in various parts of western New York State, and in Canada. The existence of several of these features has been documented (Reference 17) in various parts of the North American continent and their existence has been attributed to the release of postglacial horizontal compressive stresses. In addition to occurring in regions where activities of Man have been limited, these and affiliated phenomena have been seen in man-made structures such as excavations into bedrock.

Actual pop-ups have not been noted in southeastern Michigan or adjacent portions of Ohio, Indiana, or Canada, but surficial folding of Devonian shales has been observed in northwestern Ohio.

Although pop-ups have not been specifically documented in the site region, pop-ups or "heave" are fairly common occurrences in quarries in a wide range of localities due to a reduction of lithostatic load.

The small mound-like features noted during the mapping of excavation at the site are believed to be of organic origin. During the excavation process, no rockbursts, pop-ups, or heaves were seen. This can be attributed to a lack of compressive stresses as described in Reference 17 and insufficient depth of excavation to reduce lithostatic loading sufficiently to cause such features to occur.

2.5.1.1.4. Ground Water

In the region surrounding the site, ground water aquifers are present in two types of material: glacial outwash deposits and Paleozoic bedrock. An expanded discussion of regional ground water conditions is found in Subsection 2.4.13.

2.5.1.1.5. Geologic History

2.5.1.1.5.1. General

The study of geologic history provides an insight as to the tectonic stability of a region and a better understanding of stratigraphic relationships between various soil and rock units. It also furnishes correlative data that assist in the interpretation of events in adjacent regions.

An accurate interpretation of geologic history is the result of years of cumulative effort. It is based on numerous examinations of soil and rock units in exposures, and from borings with regard to lithology and fossil content.

The generalized stratigraphic succession and the distribution of the bedrock units in Michigan are presented in Figure 2.5-4. They are composite in nature. The entire series of stratigraphic units is not likely to be encountered at any given locality; however, it is a graphic illustration of the changing geologic history. Individual time units are discussed in the following paragraphs, and the tectonic and structural features mentioned are shown in Figures 2.5-6 and 2.5-7.

2.5.1.1.5.2. Precambrian

The basement rocks of Michigan are Precambrian in age. They include granite, felsic and mafic gneiss, volcanics, metavolcanics, metasediments, mafic volcanics, and mafic intrusives (Reference 18). Radiometric dates range from approximately 600 to 3500 million years (Reference 19). These rocks represent a complex series of geologic events that include sedimentation, uplift and erosion, subsidence and deposition, mountain building, volcanism, and igneous intrusions followed by erosion, which have produced an irregular surface upon which the overlying Paleozoic sediments have been unconformably deposited.

The regional Bouguer gravity map (Figure 2.5-9) and the regional magnetic map (Figure 2.5-10) of the Southern Peninsula of Michigan substantiate the conclusion that the basement rocks are both structurally and lithologically complex. The Mid-Michigan Anomaly, the dominant feature of the gravity map and to a lesser degree of the magnetic map, has been interpreted by Hinze (Reference 20) as originating from the mafic rocks of Keweenawan age similar to those that outcrop in the Lake Superior region. This feature consists of a positive gravity anomaly and a correlative magnetic high. Pirtle (Reference 21) states, "...it is believed that the principal folds now existing in the later sediments are controlled by trends of folding or lines of structural weakness which existed in the basement rocks." This opinion is still the prevalent one shared by most workers (Reference 20). The most obvious example of this correlation is the alignment of the Washtenaw Anticlinorium with the Mid-Michigan Anomaly in Washtenaw and Livingston Counties.

2.5.1.1.5.3. Cambrian

At the beginning of the Cambrian Period, a mountainous belt extended across most of the Upper Peninsula of Michigan. Erosion of topographic highs dominated while clastic sediments accumulated in the surrounding lowlands.

Paleozoic deposition in southern Michigan began when Late Cambrian seas spread across the interior of the continent, depositing clean sandstones, dolomites, and limestones characteristic of shallow, clear seas with bordering land masses of low relief.

The accumulation of sediments in the Michigan Basin originated with Late Cambrian subsidence. During this period of geologic history, the Michigan and Illinois Basins were not separated. This early, undifferentiated basin is known as the Eastern Interior Basin.

2.5.1.1.5.4. Ordovician

The Ordovician was the period during which Paleozoic seas became fully established in Michigan.

The variable nature of the rocks in southern Michigan, as revealed by deep-boring data, suggests fluctuating marine conditions. Deposition of Lower Ordovician dolomite and sandstone indicates that seas were present in the Lower Peninsula while absent in the Upper Peninsula. Two regressions of the sea during the Ordovician are indicated by unconformities within the sedimentary sequence of southern Michigan, one at the top of the Prairie du Chien Group during the Early Ordovician and the other at the top of the Eden Group during the Late Ordovician.

2.5.1.1.5.5. Silurian

Seas persisted in Michigan from Ordovician into Silurian time. Apparently, the entire state was occupied by offshore waters so that the Silurian marine deposits in Michigan are mainly chemical precipitates formed in clear seas. Locally, shallow banks supported reefs. It is believed that coral reef formations along the margins of the Michigan Basin effectively isolated the basin area from the main marine body and formed an evaporation basin. Great accumulations of Silurian salt, anhydrite, and gypsum were formed.

The Silurian was a time of accelerated downwarping of the Michigan Basin. Slight expressions of the Findlay and Kankakee Arches are seen in the Upper Silurian sediments in the southeast and southwest corners of Michigan, respectively.

Near the close of the Silurian Period, the seas withdrew from the Michigan Basin.

2.5.1.1.5.6. Devonian

During Early Devonian time, the southeastern portion of the Michigan Basin was subjected to erosion and/or nondeposition. To the north and northwest, however, marine sedimentation continued.

By Middle Devonian time, the Michigan Basin was fully occupied by the sea, which deposited limestones and, finally, shales in a relatively shallow-water environment.

2.5.1.1.5.7. Mississippian

Marine waters that existed since Middle Devonian time continued into Early Mississippian time. Alternating shales, siltstones, and sandstones are representative of sediments of Mississippian age.

Tilting of the Michigan Basin area is believed to have occurred in Early Mississippian time, resulting in a marked expression of the Findlay Arch and possibly the northeast-southwest trending folds in the central portion of the Michigan Basin. Toward the close of Early Mississippian time, a major regression of the sea maintained much of southern Michigan as a near-shore and beach environment.

Middle Mississippian rocks are absent, which indicates that either there was no deposition due to a complete withdrawal of the sea from Michigan, or there was deposition and subsequent erosion.

Upper Mississippian deposits indicate a transgression of the sea. Some evaporite deposits similar to those found in Silurian sediments are present. Near the close of the period, the seas freshened and limestone was deposited.

In latest Mississippian time, the Michigan Basin was subjected to uplifting and folding that involved the Precambrian basement features. This activity produced many of the structures in Paleozoic rocks of the Michigan Basin in which gas and oil later accumulated (References 19 and 22).

2.5.1.1.5.8. Pennsylvanian

The pattern of alternating sedimentation established during the Mississippian Period continued into Pennsylvanian time and reached its peak with a characteristic cyclical sedimentation of alternating marine, brackish-water, and terrestrial deposits. Organic accumulation in the brackish-water swamps formed widespread coal beds.

From Pennsylvanian time to the Pleistocene Epoch, the area remained above sea level.

Erosion prevailed in post-Pennsylvanian time with the exception of some terrestrial sandstone and shale deposition during the Jurassic Period. The entire Mesozoic Era was relatively inactive, although broad uplift and some erosion did occur. Minor fault activity is believed to have taken place along the Keweenawan Fault System into Cretaceous time.

Geologic evidence suggests that southern Michigan existed as a low stable land mass for over 200,000,000 years, while the Appalachian Mountains, Rocky Mountains, and other structural features in North America were being formed or were undergoing additional movements.

2.5.1.1.5.9. Jurassic

The geologic record is almost completely missing from the end of Pennsylvanian time until the Pleistocene. The only rocks representing this long span of time are some sedimentary strata that for many years were referred to simply as "red beds." Their age was long uncertain but was thought to be Pennsylvanian. Early maps showed them as such. In recent years, fossilized microscopic plant spores have been found in well samples from the red beds. They have been identified as being Late Jurassic in age (Reference 19). Surface exposures of the rocks have not been found, and their presence beneath the glacial drift has been demonstrated only by well samples. The Jurassic red beds are normally about 100 ft thick, but in places attain thicknesses of 300 to 400 ft (References 19 and 22). The rock consists mainly of sandstone, shale, and clay, with minor beds of limestone and gypsum.

2.5.1.1.5.10. Pleistocene

Glaciation began during Pleistocene time some 1,000,000 years ago. In general, four distinct glacial advances are recognized throughout North America during this division of geologic history. From oldest to youngest, these are known as the Nebraskan, Kansan, Illinoian, and Wisconsinan glacial stages. There is positive evidence in Michigan for only the Wisconsinan glacial advance. However, Illinoian and Kansan glacial deposits are found to the south of Michigan in Ohio and Indiana. Therefore, it is reasonable to assume that Michigan was overridden by at least these two earlier advances as well (Reference 19).

The Wisconsinan glacial deposits blanket large portions of Michigan (Figure 2.5-2). These deposits represent a complex series of ice lobes that advanced and retreated a number of times. The ice sheets modified the Great Lakes basin and are responsible for almost all of the present-day surface topography.

2.5.1.2. Site Geology

2.5.1.2.1. Physiography

The site area (Figure 2.4-3) is located on a featureless lacustrine plain (Figure 2.4-1) along the western shore of Lake Erie. The plain was formed during the high-water stages of Lake Erie. It is essentially flat lying and generally poorly drained, but it has been slightly dissected along Swan Creek, which flows into Lake Erie at the northern edge of the Fermi site. The plain slopes gently to the east. The average elevation of the lacustrine plain is about 660 ft above mean sea level, or approximately 90 ft above mean lake level. The relief within the site boundaries is approximately 9 ft.

2.5.1.2.2. Stratigraphy

2.5.1.2.2.1. Soil Units

Local sand deposits are encountered in an old channel of Swan Creek at the north end of the site, and in the barrier beach, which forms the shoreline of Lake Erie at the site. Other sand deposits are encountered offshore. The maximum thickness of sand encountered in the lake is 25 ft. More recent surficial deposits of silt, peat, and clay are encountered in the lower, swampy areas at the site. A compact, relatively impermeable till mantles the rock throughout the site area. Occasional boulders, up to 3 ft in diameter, are encountered near the bedrock surface. The till is approximately l4 ft thick and is overlain by about 7 ft of impermeable stratified lacustrine clay.

Approximately 5 ft of lacustrine peaty silts and clay had been removed from the site area at the time of the Fermi 2 foundation investigation. The surface of glacial till was exposed at an average elevation of 566 ft, which is approximately 6 ft below the water surface of adjacent Lake Erie. The till consists of nearly impermeable silty to sandy clays with varying amounts of gravel and cobbles.

The thickness of the till deposit on top of bedrock within the immediate Fermi 2 plant area, as determined from the borings, ranges from a minimum of 8 ft to a maximum of 15.5 ft, and has an average thickness of approximately 14 ft. Wider variations may be present since both the upper and lower surfaces of the till are erosional surfaces.

2.5.1.2.2.2. Rock Units

The bedrock strata in the site area range in age from Silurian to Precambrian as shown in Figure 2.5-11. The bedrock surface is shown in Figure 2.5-12. A total of 40 test borings were drilled at the site for Fermi 2 detailed foundation studies. The locations of these borings are shown in Figures 2.5-13 and 2.5-14. The deepest boring at the site extended 109 ft into the Unit C bed of the Salina Group. Relationships between the units encountered during the drilling program are shown in the subsurface sections, Figures 2.5-15 through 2.5-20.

The description of the stratigraphic units below Unit C of the Salina Group is based on published reports. The estimated thicknesses of these deeper units are based on logs of boreholes drilled in the general area and on interpretation of structural geologic maps of the general area.

Bass Islands Group - Dolomite of the Bass Islands Group forms the uppermost bedrock stratum at the site and overlies the Salina Group. In the borings at Fermi 2, the Bass Islands dolomite is a gray-brown, thinly bedded rock of dense, finely crystalline character. Black shale partings about 1/8 in. in thickness are interspersed throughout the dolomite at spacings of about 4 in. Both the dolomite bedding and the shale partings are essentially horizontal. Occasional soft gray clay seams between 1/4 in. and 8 in. in thickness occur at random in the dolomite and are usually associated with fractured zones and vugs. Two marker beds in the Bass Islands Group were penetrated by the borings and have been correlated throughout the site. The upper marker bed is an oolitic dolomite ranging from 1.8 to 3.5 ft in thickness. The lower marker bed is a soft black shale. Recovered thickness of the shale among the several borings ranges from 0.2 to 1.2 ft; however, its in-place thickness is greater than the amounts recovered.

Fractures are present to a variable degree in the Bass Islands Group; joints are relatively tight and discontinuous, and usually display only very minor solution activity. The dominant trends of joints are N45°-60°W and N40°-50°E and are nearly vertical in dip (Reference 23). Where the rock is densely fractured, intervals have closely spaced joints that form fragmented zones. Fractures are oriented from 0° (horizontal) to 90° (vertical), and the thickness and depths of these zones are variable throughout the site. The fragmented zones range in thickness from a few inches to as much as 4.5 ft, and average about 1 ft.

Small vugs are present throughout the Bass Islands Group. They range from barely visible to 2 in. in maximum dimension. The amount of open space created by vugs ranges from about 0 to 30 percent of the total rock mass, with an average of 5 percent to 10 percent. Numerous vugs are also present which are lined with crystals of the mineral celestite. Fractures connect some of the vuggy zones, which increases the permeability to the rock mass.

The thickness of the Bass Islands Group, where fully penetrated by the borings, increases from 13.5 ft at boring 20 where part has been removed by erosion, to 101 ft at boring 201 (Figures 2.5-13 and 2.5-14).

Salina Group - The Salina Group at the site is subdivided into five beds referred to as:

a. Unit G, shales and argillaceous dolomite

b. Unit E, argillaceous dolomite

c. Unit C, dolomite

d. Unit A-2, dolomite

e. Unit A-1, dolomite.

Borings at the site encountered only the lower portion of the Bass Islands Group and extended as deep as Unit C of the Salina. Beds of the Salina Group in the site area consist of alternating layers of dark gray dolomite and shale. The maximum thickness of Salina Group strata penetrated during drilling was 224 ft in boring 79. None of the borings passed through the Salina Group into lower strata. Some brecciation was noted at the Bass Islands-Salina contact.

No salt beds were encountered in the vicinity of the site. Figure 2.5-21 is an isopach map of the Salina salt beds in southeastern Michigan. Salt present in Wayne County thins to the south and is absent in Monroe County. The only salt underlying the site is an insignificant quantity in the form of very small salt crystals (1/16-in. in diameter) disseminated through several feet of a dense dolomite in the Unit G, E, and C formations.

The shale intervals of the Salina Group, as observed in recovered core, range from soft to hard and from 0.01 ft to 2.2 ft in thickness. Gray clay seams in the sequence are soft and occur predominantly in fractured and vuggy zones, and are responsible for the lower percentages of core recovery. The vugs are sedimentary features caused by decay of fossil matter or other depositional and consolidation features and do not indicate karst conditions at the site. Little of this material was recovered during drilling, but the maximum clay thicknesses are believed not to exceed 1 ft.

Unit G - Unit G directly overlies Unit E and consists of gray, hard and soft shales, dolomitic shales, and argillaceous dolomites with occasional traces of anhydrite. Unit G was observed to be about 60 ft thick at the site.

Unit E - Unit E, which directly overlies Unit C, consists of gray to brownish-gray, vuggy, shaly dolomite, dolomitic limestone, and limestone breccias. All vugs encountered in the borings were less than 2 in. in diameter. Due to the vugged zones, the unit is highly permeable and shows minor artesian ground water flow. Unit E is uniformly about 60 ft thick in the vicinity of the site.

Unit C - Unit C directly overlies the A-2 dolomite unit and consists of a buff to gray, hard, thin- to medium-bedded dolomite with thin seams of shaly dolomite and anhydrite. Generally, anhydrite layers were less than 6 in. in thickness and the thickest layer encountered was a 6-ft layer in boring 209 at approximate Elevation 295 ft. The base of Unit C was not penetrated in the borings drilled for this study. Unit C is estimated to be about 140 ft thick at the site.

Units A-2 and A-1 - The A-2 and A-1 units are buff-white to brownish-gray, very finely to finely crystalline dolomite. Stylolites, argillaceous thin layers, and partings are present. Although the test borings at the site did not go as deep as the A units, the units are considered to be present below the site.

Niagaran Group - The Niagaran Group consists of buff, gray, and light brown, fossiliferous, finely to coarsely crystalline dolomite. This group is stratigraphically equivalent to the Clinton and Guelph-Lockport Groups of southeastern Ontario, and has an estimated thickness of 425 ft near the site (Reference 24).

Cataract Group - This group is a buff to gray, fossiliferous dolomite with thin layers and partings of green to gray shale. Traces of pyrite and glauconite are present. Estimated thickness near the site, based on Michigan well logs, is 100 ft.

Richmond Group - The Richmond Group contains approximately 625 ft of shale and dolomite, based on Monroe County well logs. The shale is gray to green with some brick-red units throughout the section. Dolomite occurs as stringers within the shale and as gray to buff, fossiliferous beds containing red and gray shale seams.

Trenton-Black River Group - The Trenton Group is generally undivided in subsurface from the underlying Black River Group. These rocks consist of gray-brown to buff, fossiliferous dolomite and dolomitic limestone with noticeable oil stains and gas shows. Estimated thickness near the site is 825 to 850 ft. Several thin layers of metabentonitic clay occur within a 1-ft zone at the bottom of the Trenton Group. These layers have been noticed in drillers' logs of Monroe County and are discussed by Hussey (Reference 25). The Trenton-Black River Group unconformably overlies the St. Croixan Series at the site due to the local absence of Lower Ordovician deposits (Reference 16).

St. Croixan Series - The St. Croixan Series comprises dolomite, sandstone, and minor amounts of shale in approximately 475 ft of section. The dolomite is buff, white to gray, slightly glauconitic, finely crystalline, and occasionally shaly. The dolomite occurs in the upper section of the series and is underlain by buff, white to gray, fine- to coarse-grained sandstone. Gray shale layers occur throughout the sandstone as partings or more uncommonly as beds several feet in thickness.

Precambrian - The Precambrian basement is a metamorphic-igneous complex composed of granite and granitic gneiss (Reference l8). Estimated depth near the site to the Precambrian rock is about 3100 ft.

2.5.1.2.3. Structural Geology

The borings have not disclosed faulting at the site. Differential elevations in the bedrock strata were investigated and are interpreted as a shallow synclinal fold. The axis of the fold trends approximately N60°W and passes through the Fermi 2 area, as shown in Figures 2.5-22 and 2.5-23. The strata dip toward the axis of the fold at about 4° and 1.5° to the north and south sides, respectively. The axis of the synclinal fold plunges to the northwest at about 1.5°.

Several marker beds were used to trace the folding and to determine the configuration and continuity of the rock structures. The primary marker bed used was the lower oolitic horizon in the Bass Islands dolomite. Other marker beds were a thin continuous shale seam within the Bass Islands Group, and the contact between the Bass Islands Group and the Salina Group.

Small local folds of the shale, encountered at the site area, are quite common in southeastern Michigan and are not necessarily related to regional tectonic trends. Many have been detected through oil and gas exploration in Monroe and Wayne Counties.

2.5.1.2.3.1. Jointing

The Bass Islands dolomite is highly jointed. The vertical joints range from open to closed. Some are filled with gypsum, anhydrite, or selenite. The nature of this jointing has been observed in excavations for Fermi 2 and in a quarry located less than 1 mile west of Fermi 2. This quarry has been allowed to fill with water, and excavations for Fermi 2 have been filled so that observation of these joints has been obliterated. Nevertheless, mapping of the joints has been accomplished in the excavation for the reactor/auxiliary buildings (Reference 24) and more recently in the excavation for the RHR complex. Mapping of the excavation for the reactor/auxiliary building indicated trends of N45°-60°W and N60°-50°E. The RHR complex excavation exhibits joint trends of N21°-35°W and N54°-72°E. Quantity and degree of openness of jointing tends to decrease with depth in all excavations encountered at the site.

2.5.1.2.3.2. Folding

The regional structure at the site indicates a northwest dip of less than 0.5°. Local warpings superimposed on the regional dip are known to be present. Contour maps drawn using the base of an oolitic horizon marker bed within the Bass Islands Group indicate a shallow synclinal fold (Figures 2.5-22 and 2.5-23). The axis of the fold trends approximately N60°W and passes through the Fermi 2 area, as shown in Figures 2.5-22 and 2.5-23. The fold is asymmetrical and the strata on the northeast side dip southwest at about 4°. The strata on the southwest side dip northeast at about 1.5°. The axis of the syncline plunges northwest at about 1.5°. A small anticlinal feature superimposed on this shallow synclinal fold is indicated on Figure 2.5-23 on the basis of boring data. During the course of mapping of the excavation, this feature was also observed. It was noted that, in general, foundation surface bedding planes are higher in the east-central region of the excavation and gently dip to the south, west, and north, implying a slight doming of the bedding planes in this region of the excavation.

2.5.1.2.3.3. Faulting

There are no reported faults within 25 miles of the site. All reported regional faults are tabulated in Table 2.5-2 and are shown in Figure 2.5-7.

2.5.1.2.4. Ground Water

The surficial deposits at the site consist of low-permeability glacial till, lacustrine clay, and peat. Some fine sand is present along the shoreline of Lake Erie. The surficial deposits locally act as a confining layer above the Paleozoic bedrock aquifer, and a slight artesian pressure exists at the site. More detailed information on ground water conditions at the site is found in Subsections 2.4.13 and 2.5.4.6.

The rate of flow of artesian ground water was noted at varying depths during the 1968 and 1969 boring operations for Fermi 2 Category I structures and is shown in Table 2.5-3. Similarly, any noticeable odor of hydrogen sulfide gas was noted. These observations are presented on the boring logs. Chemical analyses of ground water were made and the results are given in Subsection 2.5.4.6.

2.5.1.2.5. Geologic History

The geologic history of the region is discussed in Subsection 2.5.1 and includes the history as represented by the geologic units from the Precambrian to the Pleistocene. At the site, the borings penetrated only the Middle and Early Silurian rocks (Niagaran and Cayugan Series) indicated on the site stratigraphic column, Figure 2.5-11. The presence of Precambrian, Cambrian, and Ordovician rocks underlying the Silurian sequence shown on the legend of the regional geologic map, Figure 2.5-4, has been proven by borings in areas adjacent to the site, and these rocks are probably present at the site. Those portions of the regional geologic history that are applicable to the site are the Precambrian, Cambrian, Ordovician, Silurian, and Pleistocene.

2.5.1.2.6. Hydrocarbon Production and Subsurface Gas Storage Potential

Neither hydrocarbon production nor subsurface gas storage is believed to have great potential within the site vicinity.

2.5.1.2.6.1. Hydrocarbon Production Potential

As mentioned in Subsection 2.5.1.2.2.2, oil stains and gas shows have been noted in the Trenton-Black River Group of Middle Ordovician age.

The Trenton-Black River Group does hold distinct possibilities for future hydrocarbon production. Virtually all Ordovician hydrocarbons have come from the eight-county area which includes Monroe and surrounding counties. Of this production, the AlbionScipio Trend, which crosses Calhoun, Hillsdale, and Jackson Counties, accounts for nearly 74 percent of the productive drilled acreage and most of the cumulative Ordovician hydrocarbons (Reference 26).

The eight-county area has been analyzed for hydrocarbon yield per square mile and has been thought to have been adequately drilled to assess its future potential.

Ells (Reference 26) says:

> For the purpose of estimating the amount of undiscovered hydrocarbons in the Middle Ordovician Trenton-Black River rocks, it is assumed that the eight-county area has been completely explored, that no additional fields will be found and that the total production from this area amounted to 92,694,457 bbl.

From this standpoint, although the majority of Ordovician oil is presently obtained from this eight-county area and primarily from the Albion-Scipio Trend, significant future hydrocarbon development is unlikely and the remainder of the Michigan Basin holds more promise for increased future development.

2.5.1.2.6.2. Subsurface Gas Storage Potential

Subsurface storage of gas has been successfully carried out in the State of Michigan and has been largely restricted to converted gas fields.

The nearest such field that has been used for subsurface storage of gas is the Northville Field in Wayne County. Other fields affiliated with subsurface gas storage are found in St. Clair and Macomb Counties at some distance from the site.

Monroe, Lenawee, and Washtenaw Counties and most of Wayne County are not considered prime candidates for gas storage. Increased gas storage is far more likely in regions of converted gas fields (Reference 27). This would preclude any great potential for subsurface storage of gas in isolated anticlinal structures as may occur in the site region.

2.5.1.2.7. Engineering Geology

Geologic conditions at the site are considered satisfactory for the support of the foundations of the Fermi 2 facilities. The foundations for all Category I structures are established into the Bass Islands dolomite beneath the glacial till and lacustrine deposits.

Fracturing is present to a variable degree in the Bass Islands Group. It ranges from sparse to dense. In the former case, the fractures occur as singular, isolated structures of different lengths and orientations. Other intervals are characterized by closely spaced fractures that form fragmented zones. The fragmented zones range in thickness from a few inches to as much as 4.5 ft. They average about 1 ft in thickness. The thicknesses and depths of these zones are variable. Occasionally they occur at similar elevations, but the extent of lateral continuity is difficult to ascertain.

Vuggy zones are present throughout the Bass Islands Group and range from barely visible size to 2 in. in maximum dimension. The amount of open space created by vugs ranges as high as 30 percent of the total rock mass with an average of 5 percent to 10 percent. Fractures connect some of the vuggy zones, the connections thereby increasing the permeability of the rock mass. Comprehensive subsurface explorations, careful inspection of all excavations, and monitoring of foundation grouting (Subsection 2.5.4) ensure that no cavities of detrimental size underlie the plant structures. Several sinkholes are known in Whiteford, Bedford, and Ida Townships of Monroe County (about 15 to 20 miles from the site), but none are reported or have been encountered in the site area (Reference 4). Nearly all occur in rocks of the Detroit River Group, which lie stratigraphically above the Bass Islands Group and are not present at the site.

A study of older published reports of drillers' logs and of four modern reports, including detailed study of well logs and cuttings conducted by Eschman, indicates that no salt deposits underlie the Fermi site (Reference l).

Figure 2.5-21 indicates the thickness of salt deposits in the Salina Group in southeastern Michigan. The contours shown represent points of equal thickness. The 0 isopach line or contour, therefore, represents the outer margin of the salt beds. The Fermi site is outside the salt area. The nearest occurrence of salt is shown to be about 10 to 15 miles north of the site.

There is no solution mining within 17 miles of the site and the local geology indicates that there is no likelihood of future solution-mining activity in the site area, because minable salt does not occur within 15 miles.

The closest reported salt-mining operation was in Wayne County about 17 miles north-northeast of the Fermi site (Reference 28). This is the same general area of current active mining operations that was studied in detail in the D&M report of the River Rouge Generating Plant site (Reference 29).

Accidental gas blowouts, associated with oil and gas exploration activity, have occurred to the north in the region (Reference 30). In blowouts, gas has been known to travel several miles along permeable horizons from the source well and cause damage in the outcrop area of the permeable stratum. However, there is no anticipated danger of gas blowouts at the site since the highest relatively permeable stratum in the area is the Salina E formation, which outcrops beyond the shoreline in Lake Erie.

The results of ground water chemical analyses show that ground water at the site contains concentrations of sulfates that are potentially deleterious to portland cement, concrete, or grout. The potential for sulfates affecting cement, concrete, or grout stems from their chemical composition.

When certain alumina-bearing compounds are present in the cement of a hardened concrete, its exposure to water containing sulfate ions results in the formation of ettringite, accompanied by a volumetric expansion within the fabric of the hardened paste, which can result in disruption of the gel structure. Hence, for concretes that will be exposed to sulfate containing soils or waters, low tricalcium aluminate ($3\ CaO \bullet A1_2O_3$) cements are often specified (Reference 31). For this reason, Type V, modified Type II, and Canadian Standards Association (CSA) A5-1971 cement was used for grouting and for all subsurface concrete construction that would come into contact with the ground water. Since there is no known tricalcium aluminate present within the Category I crushed-rock backfill and it is not bonded like a concrete or cement grout, there would be no similar deleterious effect upon the crushed-rock backfill. Consolidation characteristics are described in Subsection 2.5.4.

2.5.1.2.8. Test Borings

Geologic borings were drilled at the Fermi 2 site in 1968, 1969, and 1972 to determine the details of the lithology, structure, and physical properties of the subsurface strata. Borings were drilled in l970 to determine static and dynamic soil and rock properties. The borings range in depth from 12.1 to 324.7 ft below the ground surface and were drilled at the locations indicated in Figures 2.5-13 and 2.5-14.

Detailed descriptions of the soil and rock encountered in the borings are presented in Figures 2.5-24 to 2.5-56. The soils were classified. The Unified Soil Classification System is described in Figure 2.5-57.

Rock was cored utilizing NX and BX coring equipment and samples of the overburden soils were obtained. The field exploration program was conducted under the technical direction and supervision of D&M. Rock core from other borings drilled under the supervision of Soil and Foundations Associates was carefully examined by D&M.

Five of the borings were utilized for pressure tests to obtain water leakage data as an aid in establishing criteria for dewatering and foundation grouting. The results of pressure testing are shown to the right of boring logs 201, 203, 209, 210, and RHR-3 in Figures 2.5-33, 2.5-35, 2.5-42, 2.5-43, and 2.5-50.

2.5.1.2.9. Geophysical Explorations

Geophysical investigations performed at the site in 1968 consisted of a seismic refraction survey and a borehole geophysical survey. The velocity of compressional wave propagation and other dynamic properties of the natural subsurface materials were determined by these studies, and were used in evaluating the response of the materials to earthquake loading. The results of the field geophysical studies are presented in Figures 2.5-58 through 2.5-61. Micromotions were measured to indicate the pattern of vibration at the site based on ambient background vibration analyses. These measurements, given in Table 2.5-4, are of assistance in estimating any predominant natural period of vibration at the site.

Poisson's ratio and other dynamic moduli for the various materials (crushed-rock fill, glacial till, Bass Islands Group) in the stratigraphic section at the site were estimated based on computed and/or empirical data for similar materials. Shear wave velocities for the upper bedrock at the site were computed using the measured compressional wave velocities from the refraction survey and estimated Poisson's ratio. The computed shear wave velocities were then confirmed by the data developed in the borehole geophysical survey. In general, relatively good agreement was obtained from these two methods of evaluating shear wave velocity.

Compressional wave velocities for the deeper rock strata have been measured in the region. These data were used to compute shear wave velocities for the deeper rock strata, based on estimates of Poisson's ratio measured in similar materials.

Measured and computed geophysical data for the stratigraphic section at the site are presented in Figure 2.5-58.

2.5.1.2.9.1. Geophysical Borehole Logging

Borehole geophysical measurements were made in three deep borings by the Birdwell Division of Seismograph Service Corporation. Four types of logs were run, providing the following categories of reduced data:

a. Compressional wave velocity (in situ) (Figure 2.5-58) at each 1-ft interval

b. Shear wave velocity (in situ) (Figure 2.5-58) at each 1-ft interval. (In these three borings the shear velocity was not measured directly, but was calculated from an empirical relationship between compressional velocity and bulk density)

c. Poisson's ratio (Figure 2.5-58) computed from compressional wave velocity and shear wave velocity

d. Bulk density, derived from density log (Figure 2.5-58).

Representative logs are shown graphically in Figures 2.5-59 and 2.5-60.

2.5.1.2.9.2. Seismic Refraction Survey

Two seismic refraction surveys, shown in Figure 2.5-61, were conducted to evaluate the bedrock characteristics at the site during the 1968 Fermi 2 investigation. The seismic lines were located along the barrier beach at the east edge of the site, as shown in Figure 2.5-22. One line was 250 ft long and the other was 500 ft long with some overlap in coverage. The results of the seismic refraction surveys were used to obtain dynamic properties of the foundation materials. Permanent records of the compressional waves generated from this survey were obtained using an Electro- Technical Labs ER75012 Seismic Timer, a 12-trace refraction seismograph. Geophone spacing was 25 and 50 ft, respectively, for the two lines. The compressional velocities measured during these studies are presented in Figures 2.5-58 and 2.5-61. Access to additional geophysical refraction work in southeastern Michigan was provided by others. The compressional wave velocities measured in other regional surveys were slightly higher than the results obtained during this study. The other profiles were in slightly different material, higher in the geologic column.

During the refraction surveys, the vibration levels within the existing Fermi 1 plant, and wave data generated in the foundation materials by the explosive charges, were monitored by a blast monitoring program.

2.5.1.2.9.3. Ambient Vibration Measurements

Ambient vibration measurements were made at two locations during the 1968 Fermi 2 investigation using D&M Micromotion Equipment (Hosaka Recording System). This equipment, which measures ambient ground displacements, has a magnification of up to 150,000. The equipment is capable of recording ground displacements ranging in frequency from 1 cycle per second to 30 cycles per second. The ambient vibration records can be used to indicate predominant periods of ground motion at the site, under the test strain levels.

Ambient station measurement No. 1 was obtained on 2 ft of soil covering a rock outcrop in an old quarry located in the northwest portion of the site. The second measurement was on approximately 20 ft of soil overlying rock. At the first location, the intensity of ground motion was very low with only a slight suggestion of predominant periods, indicative of hard rock. At the second observation point, the intensity of ground motion was so low that it was obscured by machinery noise. The depth of bedrock at each location and the predominant ground periods observed are indicated in Table 2.5-4.

2.5.1.2.10. Laboratory Tests

During the 1968 investigations of Fermi 2, representative rock cores that were extracted from certain borings were subjected to a laboratory testing program to evaluate the physical properties of the rock encountered at the site (References 1 and 2). The depths of the rock cores that were tested and tabulated in Table 2.5-5 and in Appendix 2D represent depths from the original ground surface. In some cases the rock samples tested were from above the foundation level. Testing of rock samples from this zone was carried out in order to arrive at conservative foundation design parameters since the rock above foundation level is more weathered and less competent than the rock below. Laboratory tests included the following:

a. Density tests

b. Unconfined compression tests

c. Shockscope tests

d. Resonant column tests.

The density and unconfined compression tests were performed in accordance with ASTM standards. The shockscope and resonant column tests were performed according to generally accepted methods. There are no ASTM standards for these tests.

Chemical analyses of ground water samples were performed during the 1969 investigation.

Additional laboratory testing was performed in 1972 on soil samples and rock core obtained from borings at the Fermi 2 RHR complex (Reference 3).

2.5.1.2.10.1. Static Tests

Density Tests - Density tests were performed on representative rock cores that were selected from 1968 and 1969 borings made during the investigation of Fermi 2. The results of these tests are given in Table 2.5-5.

Unconfined Compression Tests - During the 1968 and 1969 Fermi 2 boring program, several representative unconfined compression tests were performed on selected rock samples to evaluate the strength and elasticity characteristics of the bedrock. The tests on the rock cores were performed by the Robert W. Hunt Company in accordance with ASTM standards. The results of the rock compression tests and associated density determinations are presented in Table 2.5-5.

Later, during the 1972 foundation investigation for the RHR complex, additional unconfined compression tests were performed by the Robert W. Hunt Company. The results of these tests are given in Table 2.5-6.

2.5.1.2.10.2. Dynamic Tests

Shockscope Tests - Several samples of the rock materials underlying the site were tested in the shockscope during the 1968 and 1969 studies. The shockscope is an instrument developed by D&M to measure the velocity of propagation of compressional waves in the material tested. The velocity of compressional wave propagation observed in the laboratory is used for correlation purposes with the field velocity measurements obtained in the geophysical refraction and borehole surveys.

In the shockscope test, samples are subjected to a physical shock under a range of confining pressures, and the time necessary for the shock wave to travel the length of the samples is measured using an oscilloscope. The velocity of compressional wave propagation is then computed. Since this velocity is proportional to the dynamic modulus of elasticity of the sample, the data also are used in evaluating dynamic elastic properties. The results of the tests are presented in Table 2.5-7.

Resonant Column Tests - Resonant column tests were performed on two representative samples of rock from the 1968 boring program to determine the shear modulus of rigidity of these materials. The samples are subjected to steady-state, sinusoidal, torsional forces applied to the top of the sample. The frequency of the force application is varied until the resonant frequency (the frequency associated with the maximum steady-state amplitude) is attained. The shear modulus is computed from the resonant frequency of the sample. The results of the resonant column tests are presented in Table 2.5-8.

2.5.1.2.11. Static and Dynamic Properties of Foundation Materials

Static and dynamic soil and rock properties of foundation materials for Fermi 2 were determined for the reactor/auxiliary building and adjacent turbine and office service buildings and are presented in Table 2.5-9 (Reference 32). The properties were modified for the Fermi 2 RHR complex in order to be representative of the local soil and rock conditions. The properties used for design criteria for the RHR complex are presented in Table 2.5-10 (Reference 3).

2.5.2. Vibratory Ground Motion

Basic Fermi 2 site vibratory ground-motion evaluations were conducted by D&M in 1968. A reaffirmation of the acceptability of this early work was provided by Weston Geophysical in 1982. The following paragraphs of this section present the data summarized from the original D&M investigation. However, any recent data of significance are identified and appropriately noted.

2.5.2.1. Geologic Conditions of the Site

A complete discussion of the regional stratigraphy, structure, and geologic history is found in Subsection 2.5.1. This site is located within the Central Stable Region of North America, an area in which the geologic structure is relatively simple. The region is characterized by a system of broad, circular to oblong sedimentary basins that include the Michigan, Appalachian, and Illinois Basins. Stable regions, including the Cincinnati Arch Complex (including the Findlay, Algonquin, and Kankakee Arches), separate the basins. Numerous secondary features are superimposed on these broad structures. The site lies along the southeast edge of the Michigan Basin and northwest of the axis of the Findlay Arch.

Precambrian crystalline basement rock lies about 3100 ft below the ground surface in the vicinity of the site. The crystalline basement complex is mantled by sedimentary rocks of Paleozoic age (Subsection 2.5.1.1.2.2). The bedrock surface at the site ranges in depth from approximately 15 to 30 ft below the existing ground surface. The overburden materials consist of sands, silts, and clays of Pleistocene age.

The uppermost bedrock unit at the site consists of the Bass Islands dolomite of Late Silurian age. Prior to glaciation, the Bass Islands Group was covered by deeply weathered and jointed rocks that experienced solution activity. Glacial advance and retreat scoured the younger rocks, and exposed the hard and relatively unweathered Bass Islands Group. The Bass Islands dolomite is on the order of 80 ft thick in the site area. The Salina Group underlies the Bass Islands and is about 525 ft thick near the site. This material consists of interbedded shales, limestones, and dolomites and is underlain by the Niagaran dolomite.

Faults have not been identified within the basement rocks or overlying sedimentary strata at the site. The closest fault, the Bowling Green Fault, is postulated approximately 35 miles southwest of the site. The vertical displacement of this fault is thought to be several hundred feet. Other known faults in the area are more distant from the site. Most faults in the region are believed to have been dormant since late Paleozoic time, at least 200 million years ago (Subsection 2.5.1). Folding is known throughout southeastern Michigan. The most prominent secondary feature is the Howell Anticline, located in the southeastern portion of the Michigan Basin. Since the area has undergone multiple Pleistocene glaciation, it may be inferred that this region has been subjected to repeated slight bending in the last few hundred thousand years (Subsection 2.5.1).

2.5.2.2. Underlying Tectonic Structures

A discussion of tectonic structures in the region surrounding the site is found in Subsection 2.5.1. The most significant structural features are listed below:

a. The Bowling Green Fault trends north-south in north-western Ohio. An inferred extension of this fault lies approximately 35 miles southwest of the site (Subsection 2.5.1.1.3.2)

b. The Howell Anticline, the most prominent fold in the region, approaches to within about 25 miles north of the site and extends approximately 80 miles to the northwest (Subsection 2.5.1.1.3.1)

c. The Chatham Sag is a broad, gentle, northwest-trending syncline that has been mapped as far south as the north shore of Lake Erie. The axis of the syncline lies about 50 miles northeast of the site. A system of faults, including the Electric Fault, is associated with this structure (Subsection 2.5.1.1.3.1)

d. The Keweenawan Fault System, which is characterized by vertical displacements from a few thousand feet to more than 9000 ft, lies northwest of the Michigan Basin approximately 430 miles northwest of the site. It has a northeast trend on the Keweenawan Peninsula in Lake Superior (Subsection 2.5.1.1.3.2)

e. The Rough Creek-Kentucky River fault complex in southern Illinois and central Kentucky approaches to within about 350 miles south of the site (Subsection 2.5.1.1.3.2).

2.5.2.3. Behavior During Prior Earthquakes

Although a few distant earthquakes have been felt at the site, detailed onsite studies suggest that their intensities have not been sufficient to affect local surface or subsurface materials. There is no physical evidence at the site to indicate that the area has experienced seismic activity at any time.

2.5.2.4. Engineering Properties of Materials Underlying the Site

The engineering properties of unconsolidated surficial deposits and bedrock are presented in Subsections 2.5.1 and 2.5.4. Seismic wave velocities are presented in Subsections 2.5.1.2.9, 2.5.1.2.9.2, and 2.5.4.2; density values are presented in Subsections 2.5.1.2.9.1, 2.5.1.2.10, and 2.5.4.2; water contents are indicated by wet and dry density values given in Subsection 2.5.1.2.10; rock quality designation is presented below and in Subsection 2.5.4.2; and strength characteristics are given in Subsections 2.5.1.2.9.1 and 2.5.4.2.

2.5.2.5. Earthquake History

2.5.2.5.1. 1968 Evaluation

The site is located in one of the most seismically stable regions in the United States. No earthquake epicenter has been located closer than about 25 miles and only seven earthquakes have been reported within 50 miles of the site since the beginning of the 19th century. None of these shocks were greater than Intensity V on the Modified Mercalli Scale.* Eleven earthquake epicenters of Intensity V to VIII have been reported within 50 to 100 miles of the site and another 24 of Intensity V to VII are located at distances between 100 and 200 miles. The closest Intensity VII shock was located at 90 miles and the closest Intensity VIII shock was located at 100 miles from the site.

A list of larger earthquakes located 200 or more miles from the site is presented in Table 2.5-12.

A list of earthquakes with epicenters located within a distance of about 200 miles from the site is presented in Table 2.5-13. This list presents all reported earthquakes within 50 miles of the site and significant shock (Intensity V and greater) within 200 miles of the site. The epicenters of these shocks are shown in Figure 2.5-62.

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* All intensity values in this subsection refer to the Modified Mercalli Scale. The intensity scale, which is described in Table 2.5-11, is a means of indicating the relative size of an earthquake in terms of its perceptible effect.

Although at least six shocks have been felt at the site within the past two centuries, the maximum intensity at the site has not exceeded Intensity IV. None of the recorded earthquakes caused any damage at or near the site.

Since the beginning of the 19th century, twelve earthquakes of Intensity V or greater have been reported within 100 miles of the site, and only 37 earthquakes of Intensity V or greater have been reported within about 200 miles of the site. The 1776 and 1925 events have not been located precisely enough to plot on the figure. Few were of high enough intensity to cause structural damage to reasonably well-built structures. None of these shocks were greater than Intensity VIII and only six can be considered more than minor disturbances. These earthquakes occurred in 1875 (Intensity VII), 1930 (Intensity VI and VII), 1931 (Intensity VII), and two in 1937 (Intensity VII and VIII). The epicenter of the closest of these shocks was about 100 miles from the site. These six earthquakes, along with a number of smaller shocks, are concentrated in a 40-mile-long northeast-southwest-trending zone extending south of Lima, Ohio. This zone of earthquake activity is located near the juncture of the Findlay, Cincinnati, and Kankakee Arches.

The earthquakes closest to the site were four Intensity III and IV shocks near Toledo, Ohio (about 30 miles distance), an 1877 Intensity V shock west of Detroit, Michigan (about 30 miles from the site), and a 1961 Intensity V shock in northern Ohio (about 55 miles south of the site). The several Intensity III and IV shocks were reported in the Toledo newspapers. These shocks were not felt at the site. The 1961 earthquake occurred near the Bowling Green Fault and/or the confluence of the Bowling Green Fault with the axis of the Findlay Arch. The 1877 Detroit shock has not been related to any specific geologic structure. Although one or more of these small shocks may have been felt in the vicinity of the site, there were no reports of disturbance near the site, and no damaging effects were experienced. It is estimated that intensities at the site due to these shocks were on the order of III or less. The other five earthquakes within 50 miles of the site were Intensity V or smaller and probably were not felt at the site.

For purposes of this study, it is considered that the most significant earthquakes in the region were the 1937 Intensity VII to VIII earthquakes south of Lima, Ohio; the 1947 Intensity VI earthquake in south-central Michigan; the 1943 Intensity V earthquake in Lake Erie, about 100 miles east of the site; and the 1961 Intensity V earthquake in northern Ohio. This evaluation has been made considering such factors as epicentral intensity (with regard to both damage to structures and perceptible area), distance from the site, and geologic structure (with regard to the possible relationship of geologic structure near the earthquake epicenter to structure near the site). A discussion of each of these significant earthquakes follows.

The earthquake of March 8, 1937, was the single most significant shock recorded within 200 miles of the site during the period of record. The shock occurred in an area that has experienced the most concentrated earthquake activity within the region.

The area is located at the south end of the Findlay Arch near the confluence of the Cincinnati and Kankakee Arches. Residual stress fields from late Mississippian time may still be slightly active in this area and this locality is probably weaker than the surrounding region due to the confluence of structural features. Earthquakes in the region were generally located at the transition between major tectonic features, rather than within a structural block. The earthquake was felt in an area of about 150,000 square miles. The shock was reported in the

Detroit newspapers and was felt near the site with about Intensity IV. The effect in Michigan was not great and no damage resulted.

The earthquake of August 9, 1947, occurred at approximately 8:47 p.m. northeast of Kalamazoo, Michigan. The effects near the epicenter were minor, consisting primarily of damage to a few brick chimneys. There also were reports of loose plaster shaken from ceilings and loose bricks shaken from a few buildings. Based on the damage reports, the epicentral intensity of this earthquake was Intensity VI. The earthquake was felt within an area almost 200 miles in radius. The shock was felt in the vicinity of the site with Intensity III or less. This shock may be related to the Tekonsha oil field structure (see Subsection 2.5.1.1.3.2).

The earthquake of March 8, 1943, occurred at about 11:26 p.m. The maximum intensity of this shock was probably Intensity V and the duration of shaking was only several seconds. It was felt in a relatively large and irregular area extending from Toronto, Ontario, as far south as Zanesville, Ohio. The total perceptible area of this shock was on the order of 40,000 square miles. Its location in the middle of Lake Erie reduced the area likely to sustain damage. The damage from this earthquake was trivial, with the highest intensity (VI) reported in Cleveland, Ohio. In Detroit, houses shook and windows rattled, but there were no reports of damage or of tall-building disturbance which is usual for more distant larger shocks. The shock was felt in the vicinity of the site and was reported to be about Intensity III. This shock may be related to an extension of the Chatham Sag into the northern part of Lake Erie.

The Intensity V earthquake of February 22, 1961, was the largest and most recent shock within 55 miles of the site. The epicenter of this shock has been located near the southern end of the Bowling Green Fault. Since only one seismograph recorded this shock, its specific location is somewhat tenuous. The shock was felt only in the local area and no damage resulted. The shock was not felt in the vicinity of the site. The limited perceptibility of this recent earthquake, indicating a rather low energy release, minimizes its significance in this study.

2.5.2.5.2. 1986 Reaffirmation

Earthquake reassessment activities, in which new site-specific earthquakes were defined and which provided documentation of the satisfactory conclusions reached from evaluation of the preceding earthquake history, were completed in 1982.

Additional seismic activity has occurred since 1968 and is summarized through July of 1986 in the following paragraphs.

Six more earthquakes have occurred within 200 miles of the site. Two of these were minor disturbances located near Colechester, Ontario, with epicentral intensities of III and IV. One occurred in 1968 near Attica, Michigan, with an epicentral intensity of V. The three others were located in Ohio near Celina, Perry, and St. Mary's and had intensities of VI, VI, and V respectively.

Six other earthquakes can be added to the list of earthquakes located 200 or more miles from the site. A 1975 earthquake was located near Wellston, Ohio (Intensity V), about 215 miles from the site. A major earthquake shook Sharpsburg, Kentucky (Intensity VII) in July 1980, about 300 miles from the site. A 1984 earthquake was located near Sudbury, Ontario (Intensity V), about 350 miles from the site. Two other 1984 earthquakes of Intensity V were located about 285 miles from the site near Clay City, Indiana. Finally, one 1985 earthquake near Edgebrook, Illinois, which is located about 250 miles from the site also had an intensity of V.

Documentation for all these earthquakes has been provided in Tables 2.5-12 and 2.5-13 and their epicenters are shown in Figure 2.5-62.

The most significant earthquakes since 1968 are the 1977 Ohio earthquake, the 1980 Kentucky earthquake, and the 1986 Perry earthquake.

The June 1977 earthquake was located near Celina, Ohio, and had a Richter magnitude of 3.2. The earthquake was felt over about 550 sq km^2 of western Ohio from Celina, south to Chickasaw, west to Fort Recovery, and north to Rockford. Several instances of slight damage were reported in the area. The maximum intensity reported was a VI near Celina, Coldwater, Fort Recovery, and Rockford, Ohio.

Damage ranged from sidewalk cracks to plaster cracks and hairline cracks in exterior walls. The estimated intensity at the site is a II.

The shock of July 27, 1980, is the strongest earthquake to be centered in Kentucky and the strongest earthquake to be felt in this region since the southern Illinois earthquake of 1968. It was felt over an area of approximately 600,000 km^2 of the central United States and Canada. The epicenter was located near Sharpsburg, Kentucky, and the epicentral magnitude and intensity were 5.1 and VII respectively. The worst damage was at Maysville, Kentucky, approximately 50 km north of the epicenter, where 37 business structures and 269 residences suffered damage of some degree. Most of the significant damage to structures occurred in the older downtown section of the city. The damage was mostly to older brick structures probably built during the middle 1800s.

Ground cracks were reported to have occurred about 12 km from the epicenter at Owingsville and Little Rock, Kentucky. Reports of the duration of ground vibration were about 15 sec of strong motions and up to several minutes for sensible vibrations.

The intensity in Michigan varied from II to IV and was reported to be at II in Monroe, Michigan.

The earthquake of January 1986, was located about 11 miles south of the Perry Nuclear Power Plant site and had a Richter magnitude of 4.96.

The earthquake was rated as a Modified Mercalli Intensity of VI. Seventeen people were treated for minor injuries. Structural damage was confined to slightly damaged chimneys, cracks in concrete and under blockwalls, some cracked and fallen plaster, a few broken windows, and some well-water silting.

The January 31, 1986, Ohio earthquake was felt at the Fermi site as a Mercalli Intensity IV event. No unusual conditions were observed. The earthquake was not strong enough to be designated an event at Fermi. However, detailed earthquake instrumentation evaluations were completed and evaluation procedures and instrumentation interpretation techniques were verified.

2.5.2.6. Correlation of Epicenters With Geologic Structures

The majority of the significant earthquakes in the region can be associated with well-defined geologic structural zones (Figure 2.5-62). The major geologic structures are described in Subsection 2.5.1.1.3 and are shown in Figures 2.5-6 and 2.5-7. As indicated by Tables 2.5-1 and 2.5-2, the folding and faulting in the central stable region are principally Paleozoic. Recent investigations (References 33 and 34) have indicated that the present seismic activity is not related to surface faulting. Seismic activity occurs in regions bounded by structures of Paleozoic age. The random nature of epicentral locations is the result of stress release in randomly distributed Precambrian crustal blocks (Subsection 2.5.1.1.5.2 contains a more complete discussion). Any present seismic activity occurring near a fault or fold of Paleozoic age does not indicate that the structure is active.

To the north and west of the site, earthquakes are rare and appear to occur near anticlinal structures in northern Michigan. To the west of the site, earthquake activity has consisted of infrequent minor shocks that occur in the random epicentral region of southern Wisconsin and northern and central Illinois. To the south, at Anna, Ohio, recent investigations (Reference 35) conducted in the area indicate that earthquake activity is associated with complex Precambrian basement structures. Geologic conditions in this area are unique and the seismic events that occurred here cannot be considered random. However, as described in Subsection 2.5.2.9, in defining the maximum earthquake, an event similar to the Anna event was considered to be able to occur along the axis of the Findlay Arch at its closest approach to the site. These recent studies only indicate that the acceleration values used in design are more conservative than had previously been assumed.

The zone of major earthquake activity closest to the site is in the vicinity of New Madrid, Missouri, more than 500 miles to the southwest. Earthquakes near New Madrid in 1811 and 1812 are considered among the largest ever to have occurred in the United States. It is reported that these shocks (possible Intensity XI) were felt in an area of 2 million square miles and changed the surficial topography in an area of about 30,000 to 50,000 square miles. The structural damage resulting from these earthquakes was small due to the lack of construction and habitation in the region.

It is estimated that intensities felt in the vicinity of the Fermi site due to these shocks were probably on the order of III to IV. Their influence would be predominant only at low frequencies and is enveloped by existing design criteria. These earthquakes occurred within the extensively faulted New Madrid (Reel Foot) seismographic region (Reference 36). The geologic structure in southern Illinois and western Kentucky is not related to the geologic structure in the vicinity of the site. The Rough Creek fault complex crosses major regional structures and probably forms a boundary separating the stable continental interior to the north from the seismogenic upper Mississippi Embayment. There is no geologic evidence to relate this fault system with structure or faulting within the continental interior. Thus, the seismically active region at the boundary and to the south should be considered dissimilar and distinct from the seismically quiet region to the north.

Another area of concentrated earthquake activity is in the vicinity of Cleveland, Ohio. Since the turn of the century, five Intensity V shocks have been reported in this area. No shock larger than Intensity V has been reported and none of these earthquakes were large enough to have been felt in Michigan. These shocks have not been related to a known tectonic feature. Several small shocks in southern Michigan, northern Indiana, and in Lake Erie, similarly, cannot be positively related to known faults. The 1947 southern Michigan shock apparently is coincident with the alignment of the Tekonsha oil field and may be associated with oil field structures. Structure and faulting is inferred for the oil field. The validity of an Intensity VI shock in 1883 in southern Michigan has been questioned. Although the magnitude of this earthquake is dubious, its location may indicate a relation to oil field structures.

The 1947 Intensity VI south-central Michigan shock and the 1943 Intensity V Lake Erie shock are the largest earthquakes in the region that cannot be positively related to specific tectonic features. Since the geologic structures in the region are believed to have been dormant since Paleozoic time, earthquake activity in the area may represent final crustal readjustment to Pleistocene glacial advance and retreat. Glacial rebound in the site area is nonexistent as far as is known.

2.5.2.7. Identification of Capable Faults

No known capable faults occur within 200 miles of the site. Significant tectonic structures that occur within 200 miles of the site, however, are described in Subsection 2.5.2.2 and their locations are shown in Figure 2.5-7. A description of these structures is included in Subsection 2.5.1.1.3 and a summary of the major faults is given in Table 2.5-2. Information on the activity of the structures is included in Subsections 2.5.2.5 and 2.5.2.6.

2.5.2.8. Description of Capable Faults

No known capable faults occur within 200 miles of the site. For a description of regional faulting, see Subsection 2.5.3.

2.5.2.9. Maximum Earthquake

The effect at the site of a possible future earthquake similar to a large historical shock has been investigated. For this evaluation, the first shock considered was the March 8, 1937, Intensity VIII earthquake near Lima, Ohio. Should a shock similar to this earthquake occur in the vicinity of the confluence of the Findlay, Cincinnati, and Kankakee Arches, the attenuated ground acceleration at the site would be less than 5 percent of gravity.

A review of the regional seismic history indicates that the shocks occurring near Lima, Ohio, have been localized within a very small area. The epicentral areas generally trend north-south and are quite limited in extent. An additional shock (1961) was located near the confluence of the Bowling Green Fault and the axis of the Findlay Arch. Even if a shock as large as the 1937 Lima shock were to occur at this location, or at the closest approach of the Bowling Green Fault, or the axis of the Findlay Arch to the site, the maximum expected ground acceleration would be less than 10 percent of gravity.

The 1811-1812 Intensity XII New Madrid, Missouri, series of earthquakes was also studied. Should a shock as large occur as close to the site as the closest approach of the Rough Creek-Kentucky River fault complex (about 350 miles), the attenuated ground acceleration at the site would be less than 5 percent of gravity.

It is also concluded that either of these occurrences would result in ground motion at the site significantly less than that selected for the safe-shutdown earthquake (SSE).

Small earthquakes similar to the 1947 and 1943 shocks (Subsection 2.5.2.6) could occur in the vicinity of the site. On this basis, the effect of a shock similar to the 1947 south-central Michigan or the 1943 Lake Erie earthquake with an epicenter near the site has been considered. A conservative estimate of the maximum horizontal ground acceleration at the rock surface, due to such a shock, is less than 10 percent of gravity.

Confirmatory site-specific earthquake evaluations were completed in 1982 to reaffirm the acceptability of the established Fermi 2 facility seismic design bases. This site-specific evaluation was completed assuming a Richter magnitude 4.9 to 5.9 quake with an epicenter less than 25 km from the site. This assumption is consistent with a quake at the Fermi 2 site similar to that which occurred in Anna, Ohio, in March 1937, and which would also account for a quake at the site such as the July 27, 1980, Kentucky experience in the Central Stable Region as well as the recent January 31, 1986, Perry, Ohio, event.

Site-specific spectra were derived directly from representative real-time histories for the appropriate magnitude and distance, and foundation conditions similar to the Fermi site. The 84 percentile of such spectra represented the comparative evaluation level for which the facility seismic design capability was reaffirmed.

2.5.2.10. Safe-Shutdown Earthquake

Category I structures at the plant are founded on rock and are designed so that they can be safely shut down in the event ground accelerations at the site exceed those that are operationally tolerable. Consequently, an evaluation has been made of the degree of ground motion that is remotely possible, considering both seismic history and geologic structure. In developing the SSE evaluation, consideration was given to the fact that there is a history of minor to moderate earthquake activity in the region that cannot be related directly to known tectonic features. Category I structures, systems, and components are designed for a safe shutdown due to horizontal zero period ground accelerations at the rock surface at foundation level, of 15 percent of gravity (0.15g).

2.5.2.11. Site-Specific Earthquake

In response to a request from the Geosciences Branch, a site- specific earthquake ground response spectrum (essentially per Regulatory Guide 1.60 pegged at 0.15g horizontal) was developed, exhibiting a significantly higher ground response than the SSE ground response. Reevaluation of structures, systems, and components required for cold shutdown was presented to the NRC in the Supplementary Seismic Evaluation Report, Detroit Edison Report No. EF2-53332, Revision 1, dated July 15, 1981. Also see Subsection 3.7.1.2.1.

2.5.2.12. Operating-Basis Earthquake

On the basis of the seismic history of the area, it does not appear likely that the site will be subjected to significant earthquake ground motion during the life of the plant. However, Category I structures are conservatively designed to respond, within elastic limits, and with no loss of function, to a horizontal ground acceleration on the rock surface at foundation level of 8 percent of gravity (0.08g). Subsequent review by Weston Geophysical demonstrated that the operating-basis earthquake (OBE) peak horizontal ground acceleration of 0.08g has a return period, as a minimum, of the order of 100 to 300 years.

2.5.3. Surface Faulting

No faults are known within 25 miles of the site. Detailed information concerning faulting on a regional and site basis is included in Subsections 2.5.1.1.3 and 2.5.2.7.

2.5.3.1. Geologic Conditions of the Site

Details of the stratigraphy, structure, and geologic history of the site are found in Subsection 2.5.1.2.

2.5.3.2. Evidence of Fault Offset

No faults are known within 25 miles of the site (Subsection 2.5.1.1.3).

2.5.3.3. Identification of Capable Faults

No faults are known within 25 miles of the site (Subsection 2.5.1.1.3).

2.5.3.4. Earthquakes Associated With Capable Faults

No faults are known within 25 miles of the site, and no earthquakes have been reported closer than 25 miles from the site (Subsections 2.5.1.1.3 and 2.5.2.5).

2.5.3.5. Correlation of Epicenters With Capable Faults

No faults or earthquake epicenters have been reported within 25 miles of the site (Subsections 2.5.1.1.3 and 2.5.2.5).

2.5.3.6. Description of Capable Faults

No faults are known within 25 miles of the site (Subsection 2.5.1.1.3).

2.5.3.7. Zone Requiring Detailed Faulting Investigation

There is no known geologic basis for the possible existence of faulting in the site area. Therefore a detailed faulting investigation is not warranted.

2.5.3.8. Results of Faulting Investigation

A review of all available literature, conferences with geological organizations, and onsite investigations revealed that no surface or subsurface faults exist within 25 miles of the site (Subsection 2.5.1.1.3.2).

2.5.3.9. Design Basis for Surface Faulting

Surface faulting at the site is not considered for design.

2.5.4. Stability of Subsurface Materials

2.5.4.1. Geologic Features

Pertinent geologic features of the site are discussed in detail in Subsection 2.5.1.2. Competent bedrock strata underlie the site and there are no major solution cavities or zones of solution weathering in the site area. However, due to the presence of zones of extensively fractured or highly vugged rock, pressure grouting was used to provide assurance that zones of this type are not horizontally continuous across the site. The foundation rock will satisfactorily support all static and dynamic loads imposed by all Category I and other heavy settlement sensitive structures.

2.5.4.2. Properties of Underlying Materials

A description of the site geology is given in Subsection 2.5.1.2. Test boring data are presented in Subsection 2.5.1.2.8. Grain- size classification is presented in Subsection 2.5.1.2.8; consolidation characteristics are given in Subsection 2.5.4.5.2; water content is indicated by wet and dry densities given in Subsection 2.5.1.2.10; unit weight values are given in Subsection 2.5.1.2.9; shear moduli are presented below; damping is considered below; and Poisson's ratio values are given below and in Subsection 2.5.1.2.9. Seismic wave velocities are given below and in Subsection 2.5.1.2.8. Density values are given below. Rock quality designations are considered below and in Subsection 2.5.2.4. Strength characteristics are given below.

Based on an analysis of the results of laboratory testing together with a review of published data and a comparative evaluation of the soil and rock materials at the residual heat removal (RHR) complex (Reference 3) with those determined for the reactor site (Reference 2), design parameters were developed and are presented in Tables 2.5-9 and 2.5-10.

The parameters presented in Tables 2.5-9 and 2.5-10 are discussed below. A brief description of the method of determining the values is given, and the range of variation is discussed.

2.5.4.2.1. Density

The densities given for the rock fill material were determined from large-scale density tests performed in a compacted test fill (Reference 2). In determining the submerged density, the rock fill material was assumed to have a specific gravity equivalent to that of dolomite. The range of variation given is considered appropriate for a controlled compacted fill of 1.5 in. and smaller crusher-run rock. The densities for the in situ glacial till and their range of variation were assessed from the moisture- density tests performed on relatively undisturbed samples. An appropriate specific gravity was used in calculating the submerged density.

Bedrock density and its range of variation were determined from the results of measured densities of representative rock cores.

2.5.4.2.2. Wave Velocities

The compression and shear wave velocities presented in Table 2.5-9 for the crushed-rock fill, glacial till, and in situ rock are measured values (References 1, 2, and 3). The range of variation of wave velocities has been estimated with consideration for the inherent uncertainties in methods of measurement and variations in grain size, density, and strength of the various materials.

2.5.4.2.3. Poisson's Ratio

The tabulated values of Poisson's ratio for the compacted rock fill and glacial till were computed from the shear and compression wave velocities. Where possible, the load-settlement data from plate load tests were compared to provide a further check on the values computed from the wave velocities. Values for in situ rock were estimated from the seismic investigation (Reference 1).

The range of variation for Poisson's ratio was estimated with consideration for probable differences in wave velocities, grain size, density, and strength of the materials being considered.

2.5.4.2.4. Static Modulus of Elasticity

The tabulated static moduli of elasticity for the rock fill and glacial till were computed from the results of load-settlement behavior recorded during plate load testing and, for the glacial till, from unconfined compression tests performed on relatively undisturbed samples (References 1, 2, and 3).

Laboratory values for static modulus of elasticity were derived from unconfined compression tests. Based on certain empirical formulae (Reference 37) and literature research (References 38 and 39), combined with experience, knowledge, or rock characteristics such as Rock Quality Designation (RQD), vugs, discontinuities, and clay seams and tempered with conservatism, a factor of 0.25 was applied to the average laboratory values. This figure was then taken to be the in situ static modulus of elasticity. A range of ±50 percent was utilized in presenting this value to account for the expected variability of characteristics within the Bass Islands Group.

2.5.4.2.5. Dynamic Modulus of Elasticity

The dynamic moduli for the glacial till were determined from elastic analysis of the data provided by the Pulsating Load Triaxial Tests. The dynamic moduli of the compacted rock fill and the bedrock were determined by elastic analysis of the results of the field seismic studies (References 2 and 3).

The range of values presented reflects the accuracy of field measurement and analysis together with the anticipated variations in grain size, density, and/or strength of the various materials.

2.5.4.2.6. Shear Moduli

The shear moduli of the till maerials were computed from the results of Pulsating Load Triaxial Tests. For the compacted rock fill and the bedrock, the shear moduli were computed using the elastic relationship between the shear modulus, modulus of elasticity, and Poisson's ratio. The range of values reflects inherent uncertainties in methods of analysis and anticipated variations in grain size, density, and/or strength of the various materials.

2.5.4.2.7. Damping Values

The tabulated values of damping are based largely on a review of available published data. The values of damping presented for the glacial till were computed from the results of Pulsating Load Triaxial testing. The damping capacity of the bedrock was developed from various dynamic tests (Reference 1). All of the tabulated damping values are expressed as a percentage of critical damping.

2.5.4.2.8. Rock Quality

The quality of the rock as observed in recovered drill core was evaluated by measuring:

a. Rock quality designation

b. Fragmented zones

c. Fracture density.

The data are included on the core boring logs (Figures 2.5-33 through 2.5-55).

The average RQD in the upper 15 to 20 ft of bedrock in all borings at the RHR complex was 47 percent, or the "poor" quality classification. The average core recovery throughout this depth interval was 92.4 percent, sufficiently high to yield reliable RQD values.

Fragmented zones are present. They range in thickness from 6 in. to 3 ft and occur at different elevations in each boring. The lack of depth and thickness correlation between borings suggests that the fragmented zones are not continuous laterally across the site.

Fracture density ranged typically from very close (less than 2 in.) to close (2 to 6 in.) in the upper 15 to 20 ft of bedrock at both the RHR complex and the reactor site. The fracture density is directly influenced by the spacing of shale partings along with the core separates during drilling operations and subsequent handling.

2.5.4.2.9. Rock Strength

Corrected values for ultimate compressive strength and modulus of elasticity of bedrock, as determined by laboratory unconfined compression tests, are presented in Table 2.5-5. Elastic moduli values were computed from plots of unit axial stress versus unit axial strain derived from laboratory test results. Records of these laboratory test results are contained in Appendix 2D. Results of unconfined compression tests on rock from borings taken from the reactor site and from the RHR complex are presented in Tables 2.5-5 and 2.5-6.

2.5.4.3. Plot Plan

A topographic map of the site showing the location of Fermi 2 facilities is given in Figure 2.4-3. The plant facilities are shown in relation to bedrock topography in Figure 2.5-12. The boring plan in relation to plant facility locations is given in Figures 2.5-13 and 2.5-14. Subsurface sections in relation to plant facilities are presented in Figures 2.5-15 through 2.5-20.

Structural geology in relation to facility location is shown in Figures 2.5-22 and 2.5-23.

2.5.4.4. Soil and Rock Characteristics

A table and profiles of a compressional and shear wave velocity survey are presented in Subsection 2.5.1 and in Figures 2.5-58 through 2.5-61. Graphic core boring logs are presented in Subsection 2.5.1 and in Figures 2.5-24 through 2.5-56. Compressional and shear wave velocities are presented in Subsections 2.5.1.2.9, 2.5.1.2.10, and 2.5.4.2.

2.5.4.5. Excavations and Backfill

2.5.4.5.1. Rock Excavation

Early in the reactor building excavation, a test blasting program was conducted to control the excavation blasting at Fermi 2 relative to Fermi 1 (References 13, 40, 41, and 42). Ground motions were measured at varying distances from test blasts for a selected range of blast loads, and attenuation data were developed as shown in Figure 2.5-63. The blasting criteria for limiting onsite seismic disturbances were (a) particle velocity limited to 1 in./sec, and (b) particle acceleration limited to 5 percent of gravity. The blasting program was carefully supervised by qualified engineering personnel and was monitored with instruments.

Subsequent to blasting operations, the exposed foundation bedrock was sluiced with high-pressure water jets and carefully examined by a qualified geologist to ensure that no excessive natural fracturing or blasting back-break existed that might be unsuitable for foundation support. All heavily fractured rock, clay seams, weathered shale, and other unsuitable materials exposed at final foundation grade were removed.

Based on the limiting criteria, the production shot loads for the reactor/auxiliary building foundation excavation were as follows.

Pounds per Delay	Minimum Distance From Fermi 1 (ft)
25	400
40	500
50	600
65	700
80	800
100	900
150	1000
175	1100
200	1200

The charge limitation for the initial blasting to excavate for the RHR complex foundation was based on the distance to Fermi 2 facilities, as follows:

Pounds per Delay	Distance to the Nearest 144-in.-Diameter Circulating Water Pipe (ft)
0.30	60
0.60	75
1.40	100
3.50	150
6.25	200

On the basis of blast-induced ground or structure motions measured during initial blasts (Reference 43), the charge limitation was increased as follows:

Pounds per Delay	Distance to the Circulating Water Pipe (ft)
1.0	60
1.0	75
1.4	100
3.5	150
6.25	200

2.5.4.5.2. Earthwork

Fill materials required to raise the site to required final grade were obtained from an onsite rock quarry and supplemented by offsite quarry-supplied rock. Fill placed at the site and properly compacted was used for the support of minor structures. All Category I and other major structures are supported on competent bedrock; the walls were framed and placed on the structural base slab. Crushed rock was then compacted in layers between the walls and the blast-excavated rock face.

A test section of compacted stone fill material was constructed to permit onsite plate load testing and seismic studies of the fill material (Reference 3). Plate load tests were performed on both the compacted crushed-rock fill and the in situ glacial till. The locations of the plate load tests are indicated in Figure 2.5-14. The results of the plate load tests are given in Table 2.5-14. A seismic investigation of the compacted crushed- rock test area was also performed. The results of the compression wave velocity measurements are shown in Figure 2.5-64.

Information on compaction criteria, gradation criteria, methods of placing and compacting, and thickness of lifts of the crushed- rock structural backfill is found in Detroit Edison specification 3071-37, Fill Materials, Placement and Compaction (Appendix 2C), and in Building Work specification for RHR Complex 3071-142.

Because of the difficulty of preparing representative samples for laboratory testing, there were no laboratory static or dynamic tests performed on samples of the crushed-stone compacted fill material. Crushed-stone compacted fill material obtained a high degree of density when placed in accordance with specifications 3071-37 and 3071-142. This dense compacted-rock fill with its select gradation was further reinforced by the interlocking mechanism of the angular, well-graded particle sizes of the rock fragments and afforded resistance to penetration by conventional sampling methods. Field plate load and seismic tests were used as the basis for deriving the values presented in Table 2.5-9.

The replacement of the underground service water piping has been analyzed in accordance with the UFSAR to allow the use of controlled Low Strength Material (CLSM) and 21AA backfill material in the installation of the buried pipe. This results in partial CLSM and 21AA backfill material against the RHR complex walls.

Consolidation tests were done on relatively undisturbed samples of glacial till (Reference 3). The results of the tests are shown in Figure 2.5-65.

There are no Category I buildings placed directly on crushed-rock fill. Additional testing on the in-place structural backfill after its placement in accordance with the specification for such placement was not performed. The onsite quality control program required constant inspection to ensure that the work was being performed in accordance with the referenced specification. Since the test results taken from the large compacted test fill area formed the basis for developing the specification, assurance that specification objectives throughout the site were being met was obtained by using trained personnel in a continuously monitored quality control (QC) program.

Fill that did not meet the specification requirements was rejected. Construction supervision and constant QC inspection were utilized to ensure that all work was continuously performed in accordance with the specifications.

During the course of safety evaluation review, the NRC requested additional information regarding backfill (drawings) for structures and components. This information was provided to the NRC with Reference 32 in June 1981, wherein it was mentioned that the following representative drawings show the backfill at the site: 6C721-2106, 6C721-2324, 6M721-2680, and 6M721-4232.

2.5.4.6. Ground Water Conditions

A summary of ground water conditions appears in Subsection 2.4.13. The history of ground water conditions at the site is summarized below.

The natural surficial deposits at the site consist of low- permeability glacial till, lacustrine clay, and peat. The surficial deposits locally act as a confining layer above the Paleozoic bedrock aquifer, and a slight artesian pressure exists at the site.

Various parameters were investigated and their relationships to local ground water features have been noted.

Pressure tests were conducted in borings 201, 203, 209, and 210 in 1969 during the comprehensive foundation investigation for the reactor/auxiliary building. Test data are shown in Table 2.5-15. The results of these tests are presented to the right of the boring logs as shown on Figures 2.5-33, 2.5-35, 2.5-42, and 2.5-43. Pressure testing was accomplished by means of inflatable packers set in the area to be tested. Water under pressure was forced into this area and the rate of take of the water at various pressures was recorded in gallons per minute. From these data, permeability of the rock was calculated by use of the following formula:

$$K = C_p \frac{Q}{H} \qquad (2.5\text{-}1)$$

where

K = permeability in feet per year

Q = flow in gallons per minute

H = head of water in feet of water acting on the test section

C_p = a constant of 4900 for nx-sized hole and a 10-ft test section (Reference 44)

Ground water observations were made by observing the rate of artesian flow at varying depths. These observations were made by drilling to a certain depth and collecting water as it flowed from the top of the boring and timing the rate of filling of a container of known volume in gallons. It was then possible to determine rate of artesian flow in gallons per minute at various levels in the boring.

Further ground water observations were made after completion of the borings by inserting standpipes in the borings, allowing the water to rise to its static level, and measuring the elevation of the top of the water. Other observations were made at this time in regard to water quality. These observations ranged from simply noting the odor of H_2S gas (shown on the boring logs) to collecting ground water samples for chemical analyses of the ground water.

In 1972, foundation investigations for the RHR complex included the installation of six piezometers in borings RHR 1, 2, 5, 6, 7, and 8. The installation of these piezometers and data gathered from them refute the 1969 water-level data in that water levels are generally much lower and artesian flow is not noted. This is due exclusively to construction dewatering. The overall result has been to reverse the ground water gradient at the plant site from toward the lake to away from the lake.

During quarry operations between 1969 and 1972, a decline in ground water level occurred. Also, during this period a decline occurred because of a regional drought condition. After the spring of 1971, the quarry operation was restricted to the southern end. The northern part was diked and functioned as a ground water recharge pit, with the water level maintained full at about Elevation 570 ft. Quarry operations ceased on June 30, 1972. Water-level observations were made during and after the quarry operations in several observation wells, as shown in Figure 2.4-25. Water-level data are given in Table 2.4-7.

As mentioned above, dewatering was carried out specifically for rock excavation. Conventional dewatering by pumping from sumps was employed. A grout curtain was constructed around the reactor/auxiliary building rock excavation to decrease the extent of dewatering required and to minimize the extent of depression of the surrounding ground water level.

The curtain wall grout plan for the excavation of the Fermi 2 reactor/auxiliary building (References 45 and 46) delineated 96 grout holes spaced at 12-ft centers and located as shown in Figure 2.5-66. A grout curtain was not used for the RHR complex excavation.

Grouting of the rock mass under the plant facilities will force that moving ground water which would have flowed through the grouted rock to be diverted around it. This diversion will increase slightly the ground water flow rate in the rock immediately outside and below the grout curtain and might increase slightly the solutioning of the carbonate rocks in that zone. In view of the low flow rate of the ground water in the bedrock aquifer (see Subsection 2.4.13.2), the minor expected increase in flow rate through diversion of ground water around the grout curtain is not expected to significantly accelerate solutioning at the site.

Water samples for laboratory analyses were obtained from stratigraphic horizons within the site area during the 1969 boring program. The elevations at which water samples were obtained are noted in the boring logs. Some water samples were obtained from artesian flows at various depths during the borings, usually after the boring had flowed for several hours. After completion of the boring, the remaining samples were obtained from borings 210 and 209 at 10-ft intervals between double-inflatable packers from artesian flow through a 3/4-in. discharge pipe. At each sample interval, the water flowed a minimum of 20 minutes before a sample was taken.

Selected ground water samples were tested to determine pH, sulfate content, and chloride content. These tests were performed by Mr. Bernard Erlin, Materials and Concrete Consultant. The results of chemical analyses of ground water samples are shown in Table 2.5-16. All of the ground water tested had a relatively high sulfate content, in the range of 1168 to 1865 ppm. The depth at which ground water samples were obtained varied from the rock surface to more than 200 ft below the rock surface. No marked variation of sulfate content with depth was observed.

The chloride content of the ground water, as sampled, ranged from 21 to 1164 ppm. The random and occasional high chloride contents measured were affected by boring operations where salt was used as an additive to the boring fluid. Salt was used with the boring fluid in borings 209 and 210 and in zones of close fractures; this would have affected the chloride content of ground water sampled from adjacent borings. Based on the results of measured chloride content of samples that should not have been affected by salt in the boring fluid, the natural ground water at the site appears to have a chloride content of less than 100 ppm.

The hydrogen ion concentration (pH) of the ground water ranged from 7.3 to 8.1; thus, the ground water is not acidic.

Although the ground water was not tested for the presence of free carbon dioxide, it can reasonably be assumed that the water has been saturated with calcium carbonate by its passage through limestone and dolomitic bedrock.

2.5.4.7. Response of Soil and Rock To Dynamic Loading

Response spectra for the SSE and the OBE are presented in Figures 2.5-67 and 2.5-68 respectively.

The SSE (originally designated design-basis earthquake or DBE on the project) was anchored at the zero period acceleration level previously described and configured to match the shape of existing spectra for similar site conditions. At the time the facility design bases were established, spectra from El Centro 1940, Olympia 1949, El Centro 1934, Helena 1935, and Taft 1952 were used in developing envelope spectra for design bases purposes.

The OBE was similarly shaped but anchored at a zero period acceleration approximately half the SSE. In the decade since the Fermi design bases were established, more conservative assumptions have been made regarding the shape of facility site response spectra in intermediate frequency ranges. For this reason, the Fermi project developed a site-specific earthquake response spectrum, incorporating all potential conservatisms, and reevaluated those items in the facility necessary for shutdown with a loss of offsite power, to ensure the acceptability of the plant with respect to site-specific earthquake excitation. These activities reaffirmed the Fermi 2 seismic design adequacy.

Soil structure interaction phenomena were evaluated at the Fermi site, and found to be negligible. Category I structures at Fermi 2 are founded in bedrock. A study completed for the Fermi 2 structures founded on rock showed that it can be safely assumed in accordance with existing studies and the unique finite element analysis undertaken for Fermi, that the Fermi 2 foundation behaves as a rigid medium, and that soil structure interaction effects are negligible. Therefore, the site earthquake response spectra developed for the bedrock represent the base excitation to be experienced by facility Category I structures.

Category I buried piping and electrical ducting runs between Category I structures at the Fermi site. These buried pipes and ducts have been subjected to a rigorous dynamic analysis including the effects of interaction with the supporting foundation material. Flexibility has been provided at all building and manhole intersection points to minimize potential concrete strains. The design integrity of these buried components is proven by evaluation of anticipated earthquake wave propagation phenomena.

The response spectra indicate the estimated response of a structure subjected to earthquake ground motion. The spectra are presented over a range of frequencies corresponding to the natural frequencies of the various structural elements. The spectra represent the maximum amplitude of motion in the various elements of the structure for typical degrees of damping. Response spectra are also discussed in Section 3.7.

2.5.4.8. Liquefaction Potential

All Category I structures are supported within the Bass Islands dolomite, which is not susceptible to liquefaction.

2.5.4.9. Earthquake Design Basis

The earthquake design basis is presented in Subsection 2.5.2.

2.5.4.10. Static Analyses

The strength of the foundation rock was evaluated in the laboratory by means of unconfined compression tests (Subsection 2.5.1.2.10). Considering these values to be appropriate for rock with an RQD of 100, a reduction factor was selected based on an assessment of the measured RQD values, information on vug volume and size, fracture orientation and spacing, and presence of clay and shale seams (Subsection 2.5.1.2.2.2). On this basis, the ultimate bearing capacity of the rock mass in the plant and RHR complex is considered to be on the order of 300,000 lb/ft^2. Using a factor of safety of 12, the recommended design bearing capacity is 25,000 lb/ft^2. However, no credit was taken for a possible increase in the recommended bearing capacity by rock grouting.

Settlement was computed using the elastic moduli information with modifications based on experience, RQD, vugs, discontinuities, and clay seams to produce conservative deformation moduli appropriate for the in situ rock. The total settlement of the RHR complex is estimated to be on the order of 0.25 in. for an assumed applied pressure of 3000 lb/ft^2. The total settlement of the reactor /auxiliary building is conservatively estimated to be on the order of 0.3 to 0.5 in. for an assumed applied pressure of 25,000 lb/ft^2.

Computed lateral pressures are presented in Table 2.5-17. In computing lateral pressures appropriate for the compacted rock fill, it was necessary to estimate the probable angle of internal friction of this material. Based on observation of the material placed in the field and on research of available published data, the angle of internal friction was assumed to be 40°.

All static lateral pressure data presented in Table 2.5-17 are expressed as equivalent fluid pressures. For rigid walls, the tabulated values of lateral pressures are derived for the case of earth pressure "at rest." For cantilever walls, the tabulated values are derived for the case of "active" earth pressure.

Dynamic lateral pressure increments due to rock fill were determined using methods described in Reference 47. The dynamic increments of lateral pressure on the walls of the substructures due to ground water were obtained using Westergard's Theory (Reference 48), modified by Matuo and Ohara (Reference 49). These lateral pressure increments for the RHR complex and reactor/auxiliary building are provided in Figures 3.8-48 and 3.8-49, respectively.

Static pressures imposed by rock on rigid or cantilever walls above the ground water level will be negligible. The lateral pressure in rock cuts below the water table will be limited to hydrostatic water pressure.

2.5.4.11. Criteria and Design Methods

2.5.4.11.1. Foundations

The criteria for foundation support are based on the properties of the underlying materials (Subsection 2.5.4.2) and soil and rock characteristics (Subsection 2.5.4.4).

The ultimate bearing capacity of the rock mass in the plant area is estimated to be on the order of 300,000 lb/ft^2 (Subsection 2.5.4.10). Assuming a combined static and dynamic maximum loading as high as 25,000 lb/ft^2, the factor of safety against further foundation failure could exceed 12. Considering the rock to be strengthened by the grouting operations, the factor of safety is considerably in excess of 12. The average foundation load data for Category I and other structures are given in Table 2.5-18. The average foundation loads are considerably less than the assumed 25,000 lb/ft^2; therefore, the factor of safety will be larger than 12.

The criteria for seismic design are presented in Subsections 2.5.2.10 and 2.5.2.11. Seismic design methods are presented in Section 3.7.

2.5.4.11.2. Cement

In consideration of the high sulfate content of the natural ground water, sulfate-resistant cement was used for all cement grout and subsurface concrete that will be in contact with the ground water. Type V portland cement conforming to the requirements of ASTM Designation C150-68 was used. In concrete work above Elevation 573.0 ft, Type II portland cement conforming to the requirements of ASTM Designation C150-68 was used. As stated in Subsection 2.5.1.2.7, CSA A5-1971 cement was also used.

The use of calcium chloride or other chlorides as admixtures incorporated into concrete or grout mixtures was prohibited as such admixtures reduce the resistance of the concrete or grout to sulfate attack.

2.5.4.12. Techniques To Improve Subsurface Conditions

2.5.4.12.1. Grouting - Reactor/Auxiliary Building

Rock strata below the foundation levels of the Category I structures were pressure grouted. It ensured that no continuous open zones existed across the excavation in the bedrock. The complete grouting program for the reactor/auxiliary building was successfully carried out (References 50, 51, and 52).

The sequence of grouting operations for the reactor/auxiliary building consisted of drilling, washing, pressure testing, and grouting each grout hole. The elevations of the bases of grout holes were selected for the reactor/auxiliary building at elevations of 483 and 499 ft, respectively. These elevations were chosen on careful study of RQD, core recovery, and fracture data, modified after visual inspection of the rock core itself. Since the in situ rock was judged to be sufficiently sound to support the vertical loads and grouting was performed only to provide a more homogeneous rock mass beneath the structures, it was judged that grouting into the underlying Salina Group would have no effect on foundation stability. Grouting was performed in two stages, herein referred to as first and second zones, extending to depths of 6 and 50 ft below the rock surface, respectively. Initial or primary holes within each zone were spaced 30 ft on centers, and final closure was achieved by subsequently grouting all intermediate holes (secondary, tertiary, and quaternary holes). The locations of all holes are presented in Figures 2.5-69 and 2.5-70.

During grouting operations, two additional grout holes were drilled (Nos. 75A and 76A). Hole 75A was drilled to replace hole 75, which was abandoned when a drill bit was lodged in the hole. Hole 76A was drilled because of the low grout take (1.5 ft^3) in hole 77. The relatively low grout take in hole 76A indicated that intermediate holes were probably not necessary when low grout takes are recorded.

All grout holes were drilled with percussion drilling equipment, and any anomalies in the general rate of penetration of drilling were noted. On some holes, detailed logs of rate of penetration were recorded. These records assisted in delineating the extent of rock fracturing and thus assisted the planning of grout mixes. In general, the rate of penetration of rock varied between 20 and 50 sec/ft. Very few voids were encountered; the largest was a 20-in. void observed in hole 67. All grout holes penetrated to an elevation of 515 ft, with the exception of holes 51 and 27, which extended to 518 and 526 ft, respectively. These two holes were terminated short because of drilling difficulties.

Subsequent to drilling operations, holes were washed and pressure tested. On many holes, the drilling operations combined with a relatively large flow of ground water provided clean holes. Consequently, no additional washing was required. Each hole was pressure tested at a selected pressure and the steady water take was recorded. The results of pressure testing were used in determining the initial grout mixes for each particular hole.

Grout mixes injected into the grout holes all contained a 2:1 ratio of cement to flyash. The ratio of water to cement plus flyash varied from 3:1 to slightly less than 1:1. For holes with high grout takes, final grout mixes included sand, which was added to give a sand-to-cement ratio of 1:1 or 1.5:1. All holes were pressure grouted in one stage. The grouting of each hole was started with a water-to-cement plus flyash ratio of 3:1 or 2:1. If the pressure did not increase after approximately 10 ft^3 of grout had been pumped, then the mix was thickened initially by decreasing the water-to-cement ratio and then further, if necessary, by adding sand to the mix. All holes were grouted to refusal. Individual grout takes for various mixes are summarized in Table 2.5-19.

A total of 1644 ft^3 of pressure grout was injected into the grout holes. An additional 72.5 ft^3 of grout was used to backfill the upper portion of the holes above the packer. Table 2.5-20 summarizes the grout take for each zone. Detailed descriptions of the foundation rock encountered in five exploratory borings, drilled following completion of the grouting program, are presented in Figures 2.5-71 through 2.5-75. Grout encountered in rock cores is noted in the logs of borings. Only one void of 0.3 ft was encountered in the post-grout exploratory boring in boring 216. Since boring 216 was drilled within 5 ft of a secondary grout hole and the void contained no grout, it was not an interconnected void, but an isolated feature. Upon completion, all five of the exploratory borings were tremie grouted.

Subsequent to grouting operations, a complete rock subgrade inspection of the reactor/auxiliary building was carried out; the results of this inspection are summarized in Figure 2.5-76.

2.5.4.12.2. Grouting - Residual Heat Removal Complex

The sequence of grouting operations (References 53 and 54) for the RHR complex consisted of drilling, washing, and grouting each grout hole. The elevation of the bases of the holes was selected at 530 ft. Grouting was performed in two zones extending to depths of 6 and 20 ft below a concrete leveling mat placed over the original rock surface at Elevation 550 ft. Initial or primary holes within each zone were spaced 30 ft on centers and final closure was achieved by subsequently grouting all intermediate holes (secondary, tertiary, and a few quaternary holes). Figures 2.5-77 through 2.5-81 show locations of all holes, as well as amounts of grout taken.

Prior to drilling and grouting operations, eight exploratory holes were core drilled to depths of 20 ft, and then washed and pressure tested. The logs of these borings are shown in Figures 2.5-82 through 2.5-85. Each interval was tested at a selected pressure and the steady water take was recorded.

All grout holes were drilled with percussion drilling equipment and then washed prior to grouting. Grout mixes injected into the grout holes contained a 1:1 to 1.5:1 ratio of cement to flyash. The ratio of water to cement plus flyash varied from 3:1 to approximately 1:1. The grouting of each hole was generally started with a water-to-cement plus flyash ratio of 3:1 and if the pressure did not increase after approximately 10 minutes, the mix was thickened by decreasing the water-to-cement ratio. All holes were grouted to refusal.

Table B1, Appendix 2B, summarizes the grout take for each zone. Detailed descriptions of the foundation rock encountered in eight exploratory borings drilled following completion of the grouting program are presented in Figures 2.5-86 through 2.5-89, and water-pressure test results are shown in Table B2, Appendix 2B.

Subsequent to cleaning the exposed rock surface, and prior to placement of the concrete mat, a complete rock subgrade inspection was carried out. A map summarizing the results of this inspection is shown in Figure 2.5-90. In addition, photographs were taken completely covering the side walls of the excavation and are available for inspection.

A detailed report on the results of the foundation treatment is found in Appendix 2B.

2.5.4.12.3. Effectiveness of Grouting Program

The grouting program was intended to seal cracks in the foundation bedrock that may have been horizontally continuous. As part of the preliminary explorations and later the grouting program, observations were made during drilling with respect to water losses and dropping of drill rods. It was observed that water losses were generally not great and that there were no instances of drill rod drop. Based on these observations, no areas of major or continuous solution activity were detected. However, the core recovered did show vugs, indicating that minor solution activity was present. To ensure that no continuous horizontal zones could be present below Category I structures, pressure grouting was undertaken. The grouting program has the further benefit of enhancing the bearing capacity of the rock.

The grouting program consisted of drilling primary, secondary, and, where necessary, tertiary grout holes until the requirements for discontinuing grouting were achieved. Subsequent to grouting, a number of holes were drilled to ascertain the effectiveness of the grouting program. The borings drilled after grouting generally produced the same results as the exploratory holes prior to grouting. That is, the core recovery and RQD showed no appreciable difference. Furthermore, the postgrouting borings showed very little evidence of grout in the core or drill water.

The lack of grout in postgrouting borings is attributed to the nonexistence of open or continuous solutioning in the bedrock. The low grout takes during consolidation grouting and the lack of grout in postgrouting borings provide evidence of the noncontinuity of any open features. In addition, the lack of both drill rod drops and water losses in postgrouting borings further indicates that no open channels exist in the bedrock foundation.

2.5.4.12.4. Base Slab Construction

The reactor/auxiliary building base slab is a 4-ft-thick reinforced-concrete slab consisting of 4000 psi concrete at 28 days with ASTM A-615 grade 60 reinforcing steel. The slab is supported by a leveling slab also constructed of 4000 psi concrete that is in turn supported by pressure-grouted competent bedrock. Shortly after placement of the base slab, radial superficial cracks appeared. A report covering the investigation and treatment of these cracks is documented in Reference 55.

All possibilities that may have caused the cracking of the slab were considered. However, after a review of all of the postulated potential causes for the surface hairline cracks, and a detailed observation and mapping of the location, arrangement, depth, and thickness of the cracks themselves, it is concluded that the cracks were most probably caused by the restraint of the slab at its perimeter during temperature fluctuations and by shrinkage strains that developed during the curing of the thick and heavily reinforced concrete slab. The cracks were very thin, and most of them did not penetrate the full depth of the slab. The lack of differential vertical displacement on both sides of a crack indicated that vertical shear planes resulting from upheaval or settlement of the underlying concrete level slab or grouted bedrock had not occurred. The radial symmetry of the cracks further supported the belief that vertical displacement, local, random, or general in orientation, did not occur. As stated on page A7 of the D&M report "Results of Rock Foundation Treatment," dated January 12, 1975 (Reference 23), "No zones of excessive fracturing or highly vugged material exist in horizontal layers across the site; localized openings in the foundation rock have been adequately treated; and the near surface fractures have been filled." Part B of the same referenced report outlines the careful attention placed on preparing the rock surface to receive the 2- to 4-ft-thick level mat and then the 4-ft-thick structural slab that later developed thin radial superficial cracks.

After reviewing these data, reviewing the conclusions presented by consultants, and observing and investigating the extent and orientation of the cracking, it is concluded that the source of the cracking is not the solutioning or jointing in the bedrock. The placement of crushed-rock fill outside the subbasement walls and at an elevation higher than the slab was not related to the cracking. The schedule for fill placement was done one section at a time and generally followed the initial observation of radial cracking.

2.5.5. Slope Stability

During the excavation for the reactor/auxiliary building and RHR complex, which included blasting, there were no instances of instability of the excavation slopes and therefore no need for stabilization measures.

There are no excavation or natural slopes whose failure could adversely affect the safe operation of the plant. However, a shore barrier was erected at the east end of the plant bordering on Lake Erie. For a discussion of the shore barrier, see Subsections 2.4.5 and 3.4.4.5.

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TABLE 2.5-1 SUMMARY OF MAJOR FOLDS IN REGION OF FERMI 2

Name	Identification[a]	Major Movement
Kankakee Arch	S, B, G	Ordovician or Devonian to Late Mississippian
Michigan Basin	S, B, G	Early to Late Paleozoic
Appalachian Basin	S, B, G	Early to Late Paleozoic
Valley & Ridge	S, B, G	Late Paleozoic
Cincinnati Arch	B	Ordovician to Post - Pennsylvanian
Findlay Arch	B	Cambrian to Devonian
Algonquin Arch	B	Cambrian to Devonian
Waverly Arch	B	Early Ordovician
Howell Anticline	B, G	Ordovician through Mississippian
Lucas Monocline	B, G	Ordovician through Mississippian
Freedom Anticline	B, G	Ordovician through Mississippian
Chatham Sag	B	Late Silurian and Post-Silurian
Washtenaw Anticlinorium	B	Middle Ordovician through Late Mississippian
Logansport Sag	B	Ordovician or Devonian to Late Mississippian
Francisville Arch	B	Mississippian

[a] S = Surface.
B = Borehole.
G = Geophysical.

TABLE 2.5-2 SUMMARY OF MAJOR FAULTS

Fault Name	Identification[a]	Displacement	Last Movement
Bowling Green Fault	S, B, G	West side down	Post-Middle Ordovician to Pre-Devonian
Electric Fault	B	South side down	Post-Silurian
Tekonsha Trend	B, G	(Fracture zone)	Post-Ordovician
Rough Creek-Kentucky River Fault System	G S, B, G	North side down (Except Kentucky River Fault, south side down)	Cretaceous (Rough Creek) Post-Ordovician to Pre-Mississippian (Kentucky River)
Keweenawan-Lake Owen Fault System	S, B, G	South side down	Keweenawan and Post - Keweenawan
Albion-Scipio Trend	B, G	(Fracture zone)	Post-Middle Ordovician to Pre-Pennsylvanian
Royal Center Fault	B	Southeast side down	Post-Devonian
Fortville Fault	B	Southeast side down	Post-Devonian

[a] S = Surface.
B = Borehole.
G = Geophysical.

TABLE 2.5-3 OBSERVED WATER FLOW AND WATER LEVEL DATA

Boring Number	Surface Elevation	Boring Bottom Elevation	Artesian Flow From Elevation 550-510 (gpm)	Artesian Flow From Bottom of Boring (gpm)	Piezometric Surface 12-19-69 (lake level at Fermi 1, 573.0)	Piezometric Surface 12-19-69 (lake level at Fermi 1, 572.8)
201	565.0	451.4	5	20	569.5	570.0
202	564.3	438.0	5	36	568.4	569.9
203	565.4	448.9	3	22	569.8	569.8
204	564.9	452.4	3	10	568.9	569.7
205	565.8	448.6	3	50	570.0	569.9
206	567.2	455.9	0	3	570.1	569.7
207	566.8	454.8	5	17	569.9	569.6
208	566.9	454.2	0.5	0.5	569.9	569.9
209	567.0	253.1	2	60	571.9	571.1
210	566.6	451.6	0.5	20	569.9	569.8
211	567.4	452.4	0	10	570.2	569.8
212	567.2	410.4	4	43	569.4	569.7
213	568.0	452.5	0	0	570.0	569.8
214	565.6	453.2	5	5	569.0	569.6

TABLE 2.5-4 AMBIENT VIBRATION MEASUREMENTS

Ambient Station Number	Depth of Bedrock (ft)	Predominant Period of Ground Motion (sec)
1	2	0.7 to 1.1
2	20	0.10

TABLE 2.5-5 ROCK COMPRESSION TEST RESULTS FERMI 2 REACTOR/AUXILIARY BUILDING SITE

Boring Number	Depth Below Original Surface (ft)	Elevation (ft)	Formation[a]	Density (lb/ft^3)	Ultimate Compressive Strength (lb/ft^2)	Modulus of Elasticity (lb/ft^2)
20	27.0	546.7	BI	154	2.26×10^6	9.0×10^8
32A	52.0	527.6	BI	145	1.39×10^6	6.28×10^8
28	106.0	466.5	S	162	1.30×10^6	3.75×10^8
4	58.0	514.5	BI	138	1.12×10^6	6.51×10^8
201	50.7	514.3	BI	151	1.29×10^6	5.75×10^8
201	73.2	491.8	BI	169	1.62×10^6	5.04×10^8
202	49.2	515.1	BI	146	1.41×10^6	3.89×10^8
203	58.2	507.2	BI	154	1.31×10^6	3.17×10^8
208	16.2	550.7	BI	145	0.62×10^6	3.29×10^8
210	20.6	546.0	BI	153	0.99×10^6	2.2×10^8
211	18.4	549.0	BI	170	2.70×10^6	1.8×10^8
211	35.1	532.3	BI	146	0.85×10^6	2.5×10^8
213	24.6	543.4	BI	149	0.82×10^6	7.2×10^8

[a] BI = Bass Islands Group.
S = Salina Group.

TABLE 2.5-6 ROCK COMPRESSION TEST RESULTS - FERMI 2 RHR COMPLEX

Boring Number	Depth (ft)	Formation[a]	Ultimate Compressive Strength (lb/ft^2)
RHR-2	39.1	BI	1.31×10^6
RHR-3	29.2	BI	1.18×10^6
RHR-4	31.0	BI	1.46×10^6
RHR-5	40.5	BI	1.20×10^6
RHR-6	29.2	BI	1.49×10^6
RHR-7	33.9	BI	1.06×10^6
RHR-8	36.3	BI	1.09×10^6

[a] BI = Bass Islands Group.

TABLE 2.5-7 SHOCKSCOPE TEST RESULTS

Boring Number	Depth (ft)	Formation[a]	Velocity of Compressional Wave Propagation (ft/sec)
4	28.5	BI	12,500
4	36	BI	10,500
4	42	BI	10,000
4	58.5	BI	11,000
18	29	BI	14,000
18	40	BI	14,500
79	30	BI	11,500
79	97	BI	12,500
79	240	S	14,500

[a] BI = Bass Islands Group.
S = Salina Group.

TABLE 2.5-8 RESONANT COLUMN TEST RESULTS

Boring Number	Depth (ft)	Formation[a]	Rock Type	Shear Modulus (lb/ft^2)
32A	25	BI	Dolomite	150×10^6
25	96	S	Calcareous Shale	30×10^6

[a] BI = Bass Islands Group.
S = Salina Group.

TABLE 2.5-9 STATIC AND DYNAMIC SOIL AND ROCK PROPERTIES - REACTOR/AUXILIARY BUILDING

Property	Crushed-Rock Fill	In Situ Glacial Till	Bass Islands Bedrock
Density (lb/ft^3):			
Dry density	139 ± 4%	125 ± 4%	150 ± 10%
Wet density	144 ± 5%	140 ± 5%	--
Submerged density	90 ± 3%	80 ± 3%	110 ± 10%
Wave velocities (ft/sec):			
Compression wave	2,500 ± 15%	7,700 ± 7%	13,000 ± 10%
Shear wave	900 ± 25%	2,200 ± 15%	7,600 ± 15%
Poisson's Ratio:			
Static or dynamic	0.4 ± 10%	0.45 ± 10%	0.24 ± 10%
Modulus of elasticity (lb/ft^2):			
Static	$1.2 \times 10^6 \pm 25\%$	$0.5 \times 10^6 \pm 20\%$	$120 \times 10^6 \pm 50\%$
Dynamic	$4.0 \times 10^6 \pm 30\%$	$1.2 \times 10^6 \pm 30\%$	$180 \times 10^6 \pm 50\%$
Increase per foot of depth	$0.48 \times 10^6 \pm 25\%$	$0.48 \times 10^6 \pm 20\%$	0
Shear modulus (lb/ft^2):			
Dynamic	$1.4 \times 10^6 \pm 30\%$	$0.4 \times 10^6 \pm 30\%$	$72 \times 10^6 \pm 50\%$
Increase per foot of depth	$0.17 \times 10^6 \pm 25\%$	$0.17 \times 10^6 \pm 20\%$	0
Damping values (percent of critical):			
Within earthquake levels	7% to 10%	5% to 8%	1%

TABLE 2.5-10 STATIC AND DYNAMIC SOIL AND ROCK PROPERTIES - RHR COMPLEX

	Crushed-Rock Fill	Glacial Till[a]	Bass Islands Bedrock
Density (lb/ft^3)			
Dry density	139 ± 4%	124 ± 2%	150 ± 10%
Wet density	144 ± 5%	139 ± 2%	
Submerged density	90 ± 3%	77 ± 2%	110 ± 10%
Wave velocities (ft/sec)			
Compression wave	2500 ± 15%	7700 ± 7%	13000 ± 10%
Shear wave	900 ± 25%	2200 ± 15%	7600 ± 15%
Poisson's Ratio			
Static or dynamic	0.4 ± 10%	0.45 ± 10%	0.24 ± 10%
Static modulus of elasticity (lb/ft^2)	1.2×10^6 ± 25%	4.0×10^5 ± 30%	120×10^6 ± 50%
Dynamic modulus of elasticity (lb/ft^2)			
Single 1.0%		1.2×10^5 ± 50%	
Amplitude shear 0.1%	4.0×10^6 ± 30%	4×10^5 ± 50%	180×10^6 ± 50%
Strain 0.01%		13×10^5 ± 50%	
Static modulus of rigidity (lb/ft^2)	4.0×10^5 ± 30%	1.4×10^5 ± 30%	48×10^6 ± 50%
Dynamic modulus of rigidity (lb/ft^2)			
Single 1.0%		0.7×10^5 ± 50%	
Amplitude shear 0.1%	1.4×10^6 ± 30%	2.5×10^5 ± 50%	72×10^6 ± 50%
Strain 0.01%		7.5×10^5 ± 50%	
Damping values (percent of critical damping)			
Single 1.0%		19.0%	
Amplitude shear 0.1%	7% to 10%	17.0%	1%
Strain 0.01%		9.0%	
Modulus of subgrade reaction (lb/ft^3)	1.0×10^6 ± 25%		6.5×10^5 ± 50%

[a] Values reported were determined specifically for in situ conditions. However, the glacial till, compacted to at least 95 percent of maximum dry density, is expected to exhibit static and dynamic properties that fall within the ranges of variation reported in this table.

TABLE 2.5-11 MODIFIED MERCALLI INTENSITY (DAMAGE) SCALE OF 1931 (Abridged)

I. Not felt except by a very few under especially favorable circumstances (I, Rossi-Forel Scale)

II. Felt only by a few persons at rest, especially on upper floors of buildings. Delicately suspended objects may swing (I to II, Rossi-Forel Scale)

III. Felt quite noticeably indoors, especially on upper floors of buildings, but many people do not recognize it as an earthquake. Standing motorcars may rock slightly. Vibration like passing of truck. Duration estimated (III, Rossi-Forel Scale)

IV. During the day felt indoors by many, outdoors by few. At night some awakened. Dishes, windows, doors disturbed; walls make creaking sound. Sensation like heavy truck striking building. Standing motorcars rocked noticeably (IV to V, Rossi-Forel Scale)

V. Felt by nearly everyone, many awakened. Some dishes, windows, etc., broken; a few instances of cracked plaster; unstable objects overturned. Disturbances of trees, poles, and other tall objects sometimes noticed. Pendulum clocks may stop (V to VI, Rossi-Forel Scale)

VI. Felt by all, many frightened and run outdoors. Some heavy furniture moved; a few instances of fallen plaster or damaged chimneys. Damage slight (VI to VII, Rossi-Forel Scale)

VII. Everybody runs outdoors. Damage negligible in buildings of good design and construction; slight to moderate in well-built ordinary structures; considerable in poorly built or badly designed structures; some chimneys broken. Noticed by persons driving motorcars (VII, Rossi-Forel Scale)

VIII. Damage slight in specially designed structures; considerable in ordinary substantial buildings, with partial collapse; great in poorly built structures. Panel walls thrown out of frame structures. Fall of chimneys, factory stacks, columns, monuments, walls. Heavy furniture overturned. Sand and mud ejected in small amounts. Changes in well water. Persons driving motorcars disturbed (VII+ to IX-, Rossi-Forel Scale)

IX. Damage considerable in specially designed structures; well-designed frame structures thrown out of plumb; great in substantial buildings, with partial collapse. Buildings shifted off foundations. Ground cracked conspicuously. Underground pipes broken (IX+, Rossi-Forel Scale)

X. Some well-built wooden structures destroyed; most masonry and frame structures destroyed with foundations; ground badly cracked. Rails bent. Landslides considerable from river banks and steep slopes. Shifted sand and mud. Water splashed (slopped) over banks (X, Rossi-Forel Scale)

XI. Few, if any (masonry) structures remain standing. Bridges destroyed. Broad fissures in ground. Underground pipelines completely out of service. Earth slumps and land slips in soft ground. Rails bent greatly

XII. Damage total. Waves seen on ground surface. Lines of sight and level distorted. Objects thrown upward into the air

TABLE 2.5-12 DISTANT EARTHQUAKE EPICENTERS (200 OR MORE MILES FROM THE SITE) (1800-1986)

Date	Time	Maximum Intensity	Location	North Latitude	West Longitude	Affected Area (square miles)	Approx. Distance From Site (miles)	Estimated Intensity at Site
1811 Dec 16	0200	XII	New Madrid, Missouri	36.6	89.6	2,000,000	530	III - IV
1812 Jan 23	-	XII	New Madrid, Missouri	36.6	89.6	2,000,000	530	III - IV
1812 Feb 7	-	XII	New Madrid, Missouri	36.6	89.6	2,000,000	530	III - IV
1870 Oct 20	1125	IX	Montreal-Quebec, Canada	47.4	70.5	1,000,000	730	IV
1886 Aug 31	2159	X	Charleston, South Carolina	32.9	80.0	2,000,000	650	IV
1895 Oct 31	0508	VIII	Charleston, Missouri	37.0	89.4	1,000,000	460	III
1905 Mar 13	1030	V	Menominee	45.0	87.7	Local	300	-
1909 Jan 22	2115	V	Houghton, Michigan	47.2	88.6	Local	435	0
1909 May 26	0842	VII	Beloit, Wisconsin	42.5	89.0	500,000	290	0
1909 Sep 27	0345	VII	Indiana	39.0	87.7	30,000	310	0
1925 Feb 28	0919	IX	St. Lawrence River	47.6	70.1	1,000,000	780	II
1926 Nov 5	0953	VII	Southeast Ohio	39.1	82.1	350	205	0
1929 Aug 12	0625	IX	Attica, New York	42.9	78.3	100,000	270	II
1935 Nov 1	0104	VI	Timiskaming, Ontario	46.8	79.1	1,000,000	340	III - IV
1944 Sep 5	0039	VIII	Cornwall-Massena	44.9	74.5	175,000	480	II
1963 Feb 27	0600	IV	Grimsby, Ontario	43.2	79.5	-	220	0
1968 Nov 9	1203	VIII	Southeast Illinois	38.5	88.0	1,000,000	350	II
1975 Feb 16	2321	V	Near Wellston, Ohio	39.0	82.4	Local	215	0
1980 Jul 27	1852	VII	Sharpsburg, Kentucky	37.8	83.7	260,000	300	II
1984 Jul 6	1724	V	Near Sudbury, Ontario	46.5	81.2	Local	350	0
1984 Jul 28	2339	V	Near Clay City, Indiana	39.2	87.1	Local	285	0
1984 Aug 29	0650	V	Near Clay City, Indiana	39.4	87.2	Local	285	0
1985 Sep 9	2206	V	Near Edgebrook, Illinois	41.9	88.0	Local	250	0

TABLE 2.5-13 EARTHQUAKE EPICENTERS WITHIN 200 MILES OF THE SITE[a] (1776-1986)

Date	Time	Maximum Intensity	Location	North Latitude	West Longitude	Affected Area (square miles)	Approx. Distance From Site (miles)	Estimated Intensity at Site
1776 Summer	0800	VI	Near Muskingum River	-	-	-	170	-
1833 Feb 4	-	VI	Near Kalamazoo, Michigan	42.3	85.6	-	125	-
1857 Mar 1	-	V	Near Eastlake, Ohio	41.7	81.2	-	110	-
1872 Feb 6	0800	V	Wenona, Michigan	43.5	83.5	Local	110	0
1875 Jun 18	0743	VII	Urbana and Sidney, Ohio	40.2	84.0	40,000	130	-
1877 Aug 17	1050	V	SE Michigan near Detroit	42.3	83.3	200	25	0
1882 Feb 9	1500	V	Swandors and Dodkins near Anna, Ohio	40.5	84.0	Local	110	0
1883 Feb 4	0500	VI	Indiana and Michigan, felt at Kalamazoo	42.3	85.6	8,000	125	-
1884 Sep 19	1414	VI	Near Lima, Ohio	40.7	84.1	125,000	95	IV
1900 Apr 9	1400	VI	Near Brunswick, Ohio	41.4	81.8	-	95	III
1901 May 17	0100	VI	Southeast Ohio	39.3	82.5	7,000	190	0
1902 Jun 14	0700	V	Near Dover, Ohio	40.3	81.4	-	150	0
1906 Apr 23	0712	V	Near Ada, Ohio	40.7	83.6	-	90	II
1906 Jun 27	1610	V	Fairport, Ohio	41.4	81.6	400	95	0
1925 Mar 27	2306	V	Southwestern Ohio	-	-	-	170	-
1926 Oct 28	0240	III	East Toledo, Ohio	41.6	83.6	Local	30	0
	0500	IV	Toledo, Ohio	41.6	83.6	Local	30	0
1927 Oct 29	-	V	Near Alliance, Ohio	40.9	81.2	-	125	-
1928 Sep 9	1500	V	Lorain and Cleveland, Ohio	41.5	82.0	1,500	70	0
1929 Mar 8	0406	V	Bellefontaine, Ohio	40.4	84.2	5,000	130	0
1930 Sep 20	1440	VI	Anna, Ohio	40.3	84.3	-	125	0
1930 Sep 30	1440	VII	Anna, Ohio	40.3	84.3	-	130	-
1930 Nov 20	-	III	Near Brighton, Michigan	42.6	83.4	-	45	II
1931 Jun 10	0330	V	Malinta, Ohio	41.6	84.0	-	55	-
1931 Sep 20	1805	VII	Anna, Sidney, Houston, Ohio	40.2	84.3	40,000	130	0
1932 Jan 22	-	V	Near Akron, Ohio	41.1	81.5	-	110	0
1937 Mar 2	0948	VII	Anna, Sidney, Ohio	40.7	84.0	90,000	110	III

TABLE 2.5-13 EARTHQUAKE EPICENTERS WITHIN 200 MILES OF THE SITE[a] (1776-1986)

Date	Time	Maximum Intensity	Location	North Latitude	West Longitude	Affected Area (square miles)	Approx. Distance From Site (miles)	Estimated Intensity at Site
1937 Mar 3	0450	V	Anna, Sidney, Ohio	40.5	84.0	Local	110	0
1937 Mar 9	2445	VIII	Anna, Sidney, Ohio	40.6	84.0	150,000	100	IV
1938 Mar 13	1040	II	Detroit River	42.3	83.1	Local	25	II
1943 Mar 9	2226	V	Lake Erie	42.2	80.9	40,000	120	IV
1947 Aug 9	2047	VI	South-Central Michigan	42.0	85.0	50,000	90	III
1948 Jan 18	Night	III	Toledo, Ohio	41.6	83.6	Local	30	-
1952 Jun 20	0438	VI	Zanesville, Ohio	39.8	82.2	10,000	170	0
1953 Jun 12	2345	IV	Toledo, Ohio	41.6	83.6	Local	30	0
1955 May 26	1309	V	Cleveland, Ohio	41.5	81.7	Local	85	0
1955 Jun 28	2016	V	Cleveland, Ohio	41.5	81.7	Local	85	0
1956 Jan 27	1103	V	West-Central Ohio	40.5	84.0	Local	110	0
1957 Jun 29	0525	V	Southeast of London, Ontario	42.9	81.2	Local	120	0
1958 May 1	1647	V	Cleveland, Ohio	41.3	81.4	Local	110	0
1961 Feb 22	0344	V	Findlay, Ohio	41.2	83.4	Local	55	0
1967 Apr 7	2340	V	Columbus, Ohio	39.6	82.5	3,000	165	0
1968 Oct 31		V	Attica, Michigan	43.0	83.0	Local	80	II
1976 Feb 2	2114	III	Colechester, Ontario	42.0	82.7	Local	25	II
1977 Jun 17	1539	VI	Near Celina, Ohio	40.7	84.6	200	110	II
1980 Aug 20	0934	IV	Near Colechester, Ontario	41.9	83.0	Local	15	III
1986 Jan 31	1646	VI	Near Perry, Ohio	41.7	81.2	-	110	IV
1986 Jul 12	0819	V	St. Mary's Ohio	40.6	84.4	Local	115	0

a. Earthquakes of Intensity V or greater only are tabulated beyond a distance of 50 miles from the site. All known shocks within 50 miles of the site are indicated.

TABLE 2.5-14 RESULTS OF PLATE LOAD TESTS ON FILL AND TILL

		Average Movement of Plate For a Contact Stress of 10,000 lb/ft	
Material	Plate Diameter (in.)	Initial Load Cycle (in.)	Average of Rebound Cycle (in.)
Fill	12	0.035	0.006
	24	0.091	0.027
	30	0.097	0.040
Till	12	0.050	0.040
	24	0.092	0.049
	30	0.101	0.052

TABLE 2.5-15 WATER PRESSURE TEST DATA

Boring Number	Test Section Depth (ft)	Water Pressure (psi)	Period of Steady Flow (minutes)	Water Intake (gpm)	Calculated Permeability (ft/yr)
201	23-1/2 - 33-1/2	25	20	2.5	211
	33 - 43	30	20	8.0	564
	43-1/2 - 53-1/2	45	10	7.0	327
	53 - 64	75	10	6.0	169
	63-1/2 - 73-1/2	70	10	8.0	240
203	15 - 25	13	20	8.5	1380
	21 - 31	17	20	12.4	1540
	30 - 40	30	20	9.0	635
	39 - 49	37	20	24.0	1370
	48 - 58	55	20	10.5	404
	57 - 67	55	20	6.5	250
	66 - 76	55	20	5.5	210
	75 - 85	55	20	23.0	884
	84 - 94	55	20	22.0	845
	93 - 103	55	20	22.0	845
	102 - 112	65	20	19.0	616
209	36 - 46	30	20	11.5	810
	43 - 53	30	20	19.0	1340
	52 - 62	40	5	6.0	316
	61 - 71	40	10	13.0	685
	70 - 80	40	10	13.0	685
	79 - 89	40	10	2.0	105
	88 - 98	40	10	10.0	526
	97 - 107	40	10	3.0	158
	106 - 116	40	20	17.6	930
	115 - 125	40	15	16.6	875

TABLE 2.5-15 WATER PRESSURE TEST DATA

Boring Number	Test Section Depth (ft)	Water Pressure (psi)	Period of Steady Flow (minutes)	Water Intake (gpm)	Calculated Permeability (ft/yr)
	124 - 134	40	15	16.0	845
	133 - 143	40	20	15.0	790
	142 - 152	40	20	9.5	500
210	14 - 24	15	15	15.8	2220
	23 - 33	30	20	15.5	1090
	45 - 55	50	20	11.5	486
	54 - 64	50	20	16.5	697
	63 - 73	50	15	21.0	888
	72 - 82	50	20	21.0	888
	81 - 91	50	20	20.0	845
	90 - 100	50	20	15.0	634

Note: Permeabilities were calculated using the method outlined in Reference 4; i.e., using the formula K = Cp (Q/H)

where K = permeability in feet per year

Cp = a constant dependent on hole size

Q = flow in gallons per minute

H = applied pressure in feet of water units

TABLE 2.5-16 CHEMICAL ANALYSES OF GROUND WATER

Boring Number	Depth (ft)	Formation[a]	pH	Chloride (C1-, ppm)	Sulfate (SO_4--, ppm)
201	30.0	BI	7.65	33	1685
201	85.0	BI	7.60	34	1747
204	18.0	BI	8.00	43	1661
205	17.4	BI	8.10	45	1865
205	27.4	BI	8.00	43	1733
205	117.0	S	7.30	424	1790
207	19.8	BI	7.40	356	1776
207	20.0	BI	7.70	51	1747
208	27.2	BI	7.90	1164	1168
208	110.0	S	8.10	183	1282
209	92.0-102.0	BI-S	8.10	102	1771
209	97.0-107.0	BI-S	8.05	156	1738
209	102.0-112.0	S	8.00	91	1738
209	132.0-142.0	S	7.80	116	1757
209	147.0-152.0	S	8.10	122	1800
209	151+	S	8.10	115	1757
209	210+	S	7.90	162	1771
210	20.4-30.5	BI	7.60	603	1738
210	30.4-40.5	BI	7.65	547	1728
210	40.4-50.5	BI	8.00	1145	1709
210	50.4-60.5	BI	8.00	362	1742
210	60.4-70.5	BI	8.10	198	1709
210	70.4-80.5	BI	7.70	65	1752
210	80.4-90.5	BI-S	8.00	156	1699
210	90.4-100.0	S	7.50	21	1718
210	67+	BI	7.70	48	1747

[a] BI = Bass Islands Group.
S = Salina Group.

TABLE 2.5-17 LATERAL PRESSURE VALUES[a]

Lateral Pressure ($lb/ft^2/ft$)	Crushed-Rock Fill	Bass Islands Bedrock
Static-rigid wall above water	96[b,c]	0
Static-rigid wall submerged	122[b,c]	63
Static-cantilever wall above water	32[c]	0
Static-cantilever wall submerged	80[c]	63
Dynamic-rigid wall above water	[d]	-
Dynamic-rigid wall below water	[d]	-

[a] During the course of safety evaluation review, the NRC requested additional information regarding the technique for the dynamic lateral pressure computation. This information was provided to the NRC as Reference 32.

[b] Alternate values calculated per Reference 56 were used in the re-analysis of some subsurface exterior walls.

[c] A factor of safety of 1.5 is applied to these values when the foundation walls are required to perform safety-related functions.

[d] See Figures 3.8-48 and 3.8-49.

TABLE 2.5-18 FOUNDATION DATA

	Approximate Plan Dimensions (ft x ft)	Foundation Elevations[a] (ft)	Approximate Uniform Applied Foundation Load (lb/ft^2)
Category I			
Reactor building	120 x 155	536	7500
Auxiliary building	80 x 155	536	4000 to 5000
RHR Complex	120 x 310	547	4000 to 5000
Other structures			
Turbine house	210 x 375	558	5000
Radwaste building	100 x 190	552	2500

[a] USGS datum.

TABLE 2.5-19 CURTAIN WALL GROUTING SUMMARY OF GROUT TAKES

Hole Number[a]	Grout Take in Cubic Feet[b] Mix A[c]	Mix B[d]	Mix C[e]	Total	Observed Horizontal Distance of Grout Travel (ft)
1	3		10	13	12
2	1.5	10.5		12	
3	6	3		9	12
4	3			3	
5	9			9	
6	6			6	
7		18		18	
8		6		6	
9	6			6	
10	6	9		15	
11	9			9	
12	4.5			4.5	
13	10.5			10.5	
14	1.5			1.5	
15	10.5	6		16.5	
16	3			3	
17	18	3		21	36
18	3			3	
19	6	4.5		10.5	24
20	3	3		6	
21	3	1.5		4.5	
22	12	18		30	12
23	6	10.5		16.5	24
24	10.5	6		16.5	12
25	9	12		21	12
26	9	3		12	
27	12	24		36	24
28	9	9		18	12
29	9	18	10	37	
30	6	15	7.5	28.5	24
31	9	27	10	46	12
32	12	3		15	12
33	9	12		21	12
34	6	12		18	12
35	10.5	21	5	36.5	12

TABLE 2.5-19 CURTAIN WALL GROUTING SUMMARY OF GROUT TAKES

Hole Number[a]	Grout Take in Cubic Feet[b] Mix A[c]	Mix B[d]	Mix C[e]	Total	Observed Horizontal Distance of Grout Travel (ft)
36	1.5			1.5	12
37		18	27	45	12
38		1.5		1.5	
39		21	44	65	24
40	9	24	26	59	24
41	12	18		30	12
42	12	21		33	12
43	7.5	3		10.5	
44	1.5			1.5	
45	12	9		21	
46	12	21		33	12
47	12	3		15	24
48	12	10.5		22.5	12
49	12	12		24	
50	12	18		30	
51	12	30	5	47	12
52	9	10.5		19.5	24
53	6	12		18	12
54	12	27		39	12
55	7.5	3		10.5	
56	1.5			1.5	
57	12	15		27	12
58	9	12		21	12
59	1.5			1.5	
60	10.5	18		28.5	12
61	7.5	18	5	30.5	
62	7.5	15		22.5	
63		9	18	27	24
64	9		21	30	24
65		21	46	67	24
66	15	30	15	60	36
67	24	6		30	12
68	15			15	
69	22.5	3		25.5	
70	19.5			19.5	

TABLE 2.5-19 CURTAIN WALL GROUTING SUMMARY OF GROUT TAKES

Hole Number[a]	Grout Take in Cubic Feet[b] Mix A[c]	Mix B[d]	Mix C[e]	Total	Observed Horizontal Distance of Grout Travel (ft)
71	1.5			1.5	12
72	15	12	10	37	12
73	18	7.5		25.5	24
74	15	9		24	12
75	Abandoned - Driller Lost Drill Bit in Hole				
75A	9	12		21	24
76		12		12	
76A		6		6	
77		1.5		1.5	
78		7.5		7.5	12
79		21		21	24
80		15		15	

[a] All grout holes were brought to refusal with a grout pressure ranging from 8 psi to 20 psi with the exception of holes 2, 3, and 68 in which there was a heavy grout return through the surface of the rock which was highly fractured above packer.

[b] An additional 72-1/2 ft^3 of grout was used for filling inside the casing subsequent to pressure grouting.

[c] Mix A – Water:cement + flyash ratio of 2:1 or greater.

[d] Mix B - Water:cement + flyash ratio of 1.5:1 or less

[e] Mix C - Water:cement + flyash ratio of 1:1 or less plus a water:sand ratio of 1:1.

TABLE 2.5-20 SUMMARY OF GROUTING FIRST ZONE GROUTING

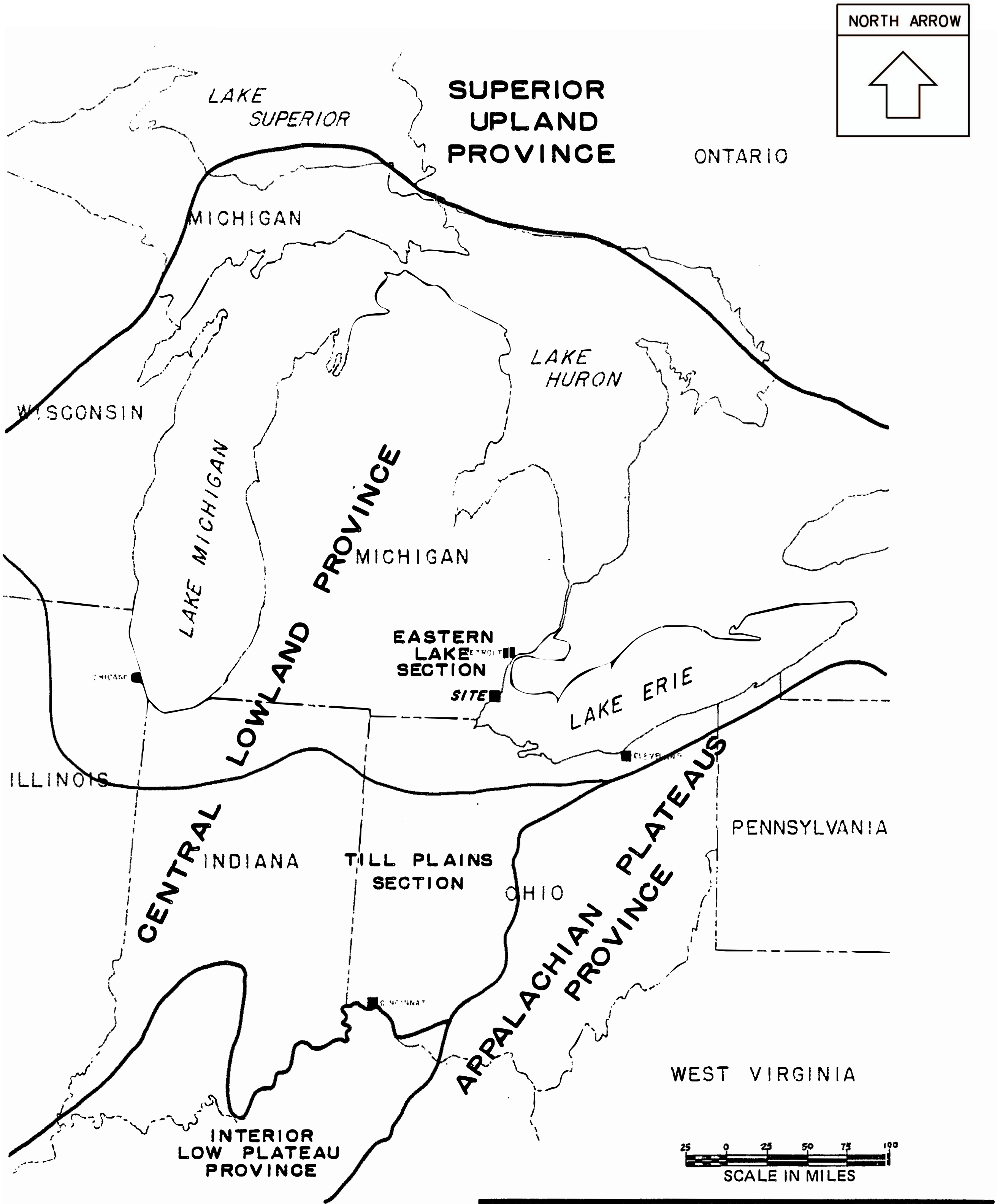
(holes drilled 10 ft into rock)

Holes Drilled	Holes With Take	Percent Holes With Take	Sacks Cement and Flyash	Unit Take (sacks per foot of hole)
Primary	75	87	1629.00	3.17
Secondary	65	75	1066.25	2.08
Tertiary	39	29	174.00	0.21
Quaternary	7	27	109.25	0.84
Total	186	--	2978.00	--
Average		52.75		1.58

SECOND ZONE GROUTING

(holes drilled approximately 50 ft into rock)

Holes Drilled	Holes With Take	Percent Holes With Take	Sacks Cement and Flyash	Unit Take (sacks per foot of hole)
Primary	91	99	1340.25	0.46
Secondary	89	100	652.50	0.31
Tertiary	47	98	357.75	0.18
Quaternary	9	100	106.50	0.27
Total	236	--	2457.00	--
Average		99.22		0.31



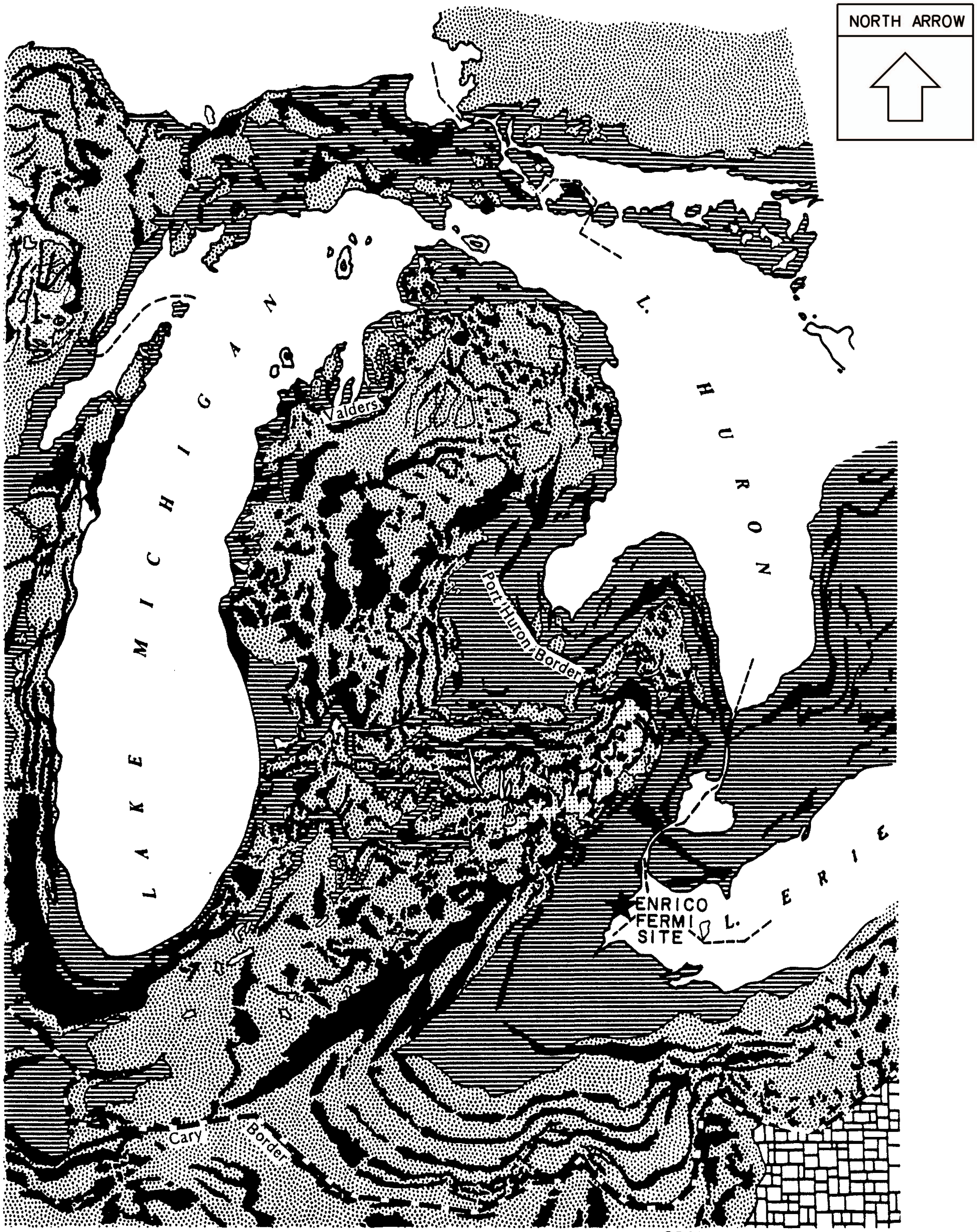
REFERENCE:
MODIFIED FROM FENNEMAN, N. 1946; PHYSICAL DIVISIONS OF THE UNITED STATES IN COOPERATION WITH THE PHYSIOGRAPHIC COMMITTEE OF THE U. S. GEOLOGICAL SURVEY.

MODIFIED FROM: BASEMENT ROCK MAP OF THE UNITED STATES, COMPILED BY RICHARD W. BAYLEY, UNITED STATES GEOLOGICAL SURVEY, AND WILLIAM MUEHLBERGER, UNIVERSITY OF TEXAS, 1968.

Fermi 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 2.5-1

CENTRAL LOWLAND PROVINCE REGIONAL PHYSIOGRAPHIC MAP



LEGEND:

- LAKE SEDIMENTS
- NO GLACIAL DEPOSITS
- ICE CONTACT STRATIFIED DRIFT
- WISCONSIN END MORAINES
- GROUND MORAINES AND OUTWASH PLAINS

SCALE IN MILES

50 0 50

REFERENCE:

GEOLOGICAL SOCIETY OF AMERICA 1959, GLACIAL MAP OF THE UNITED STATES EAST OF THE ROCKY MOUNTAINS.

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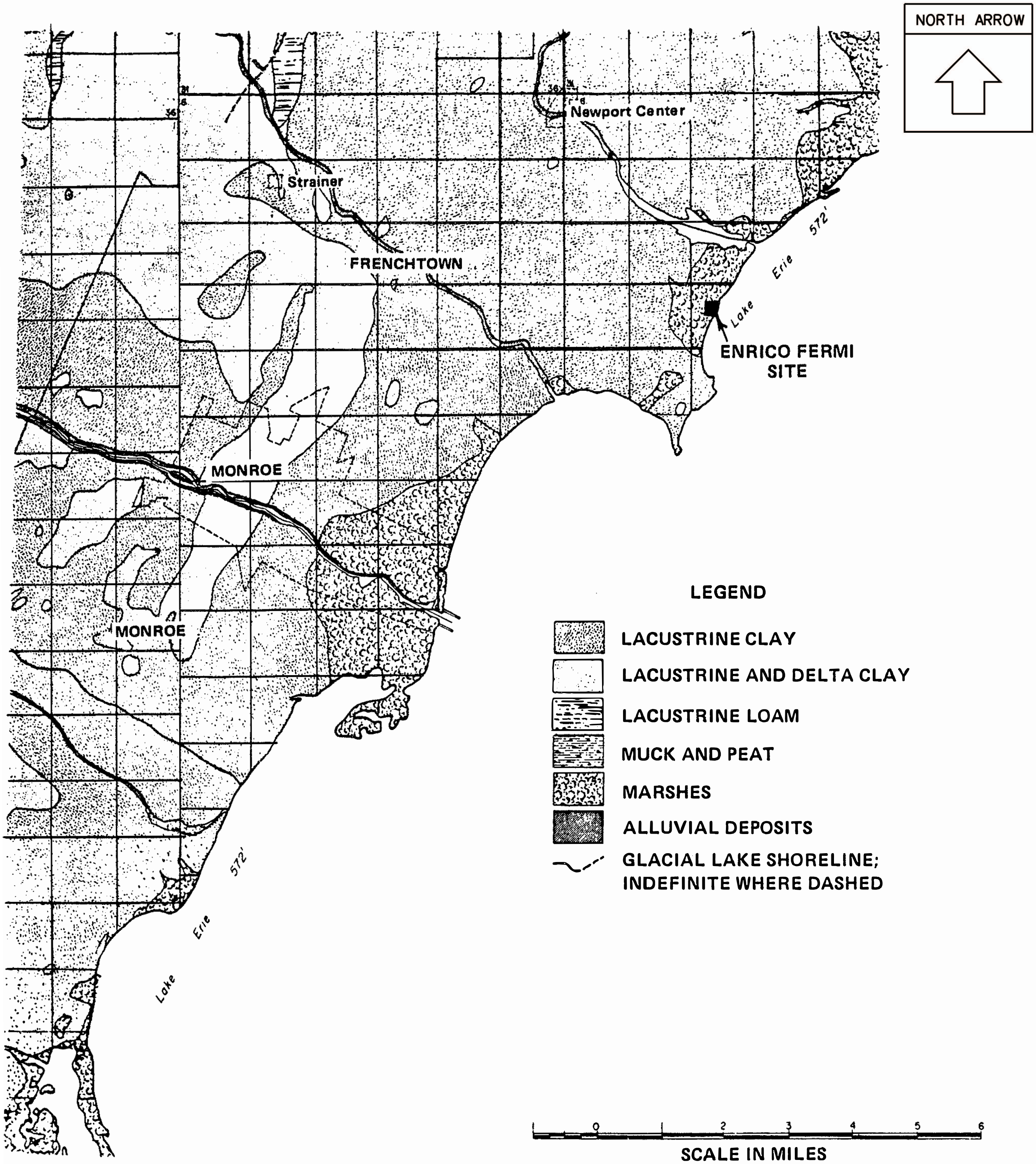
FIGURE 2.5-2

REGIONAL SURFACE GEOLOGICAL MAP



REFERENCE:
MAZOLA, A. J., 1969, GLACIAL DEPOSITS OF MONROE COUNTY, MICHIGAN; FROM REPORT OF INVESTIGATION 13, GEOLOGY FOR ENVIRONMENTAL PLANNING IN MONROE COUNTY, MICHIGAN; GEOLOGICAL SURVEY DIVISION, DEPARTMENT OF NATURAL RESOURCES.

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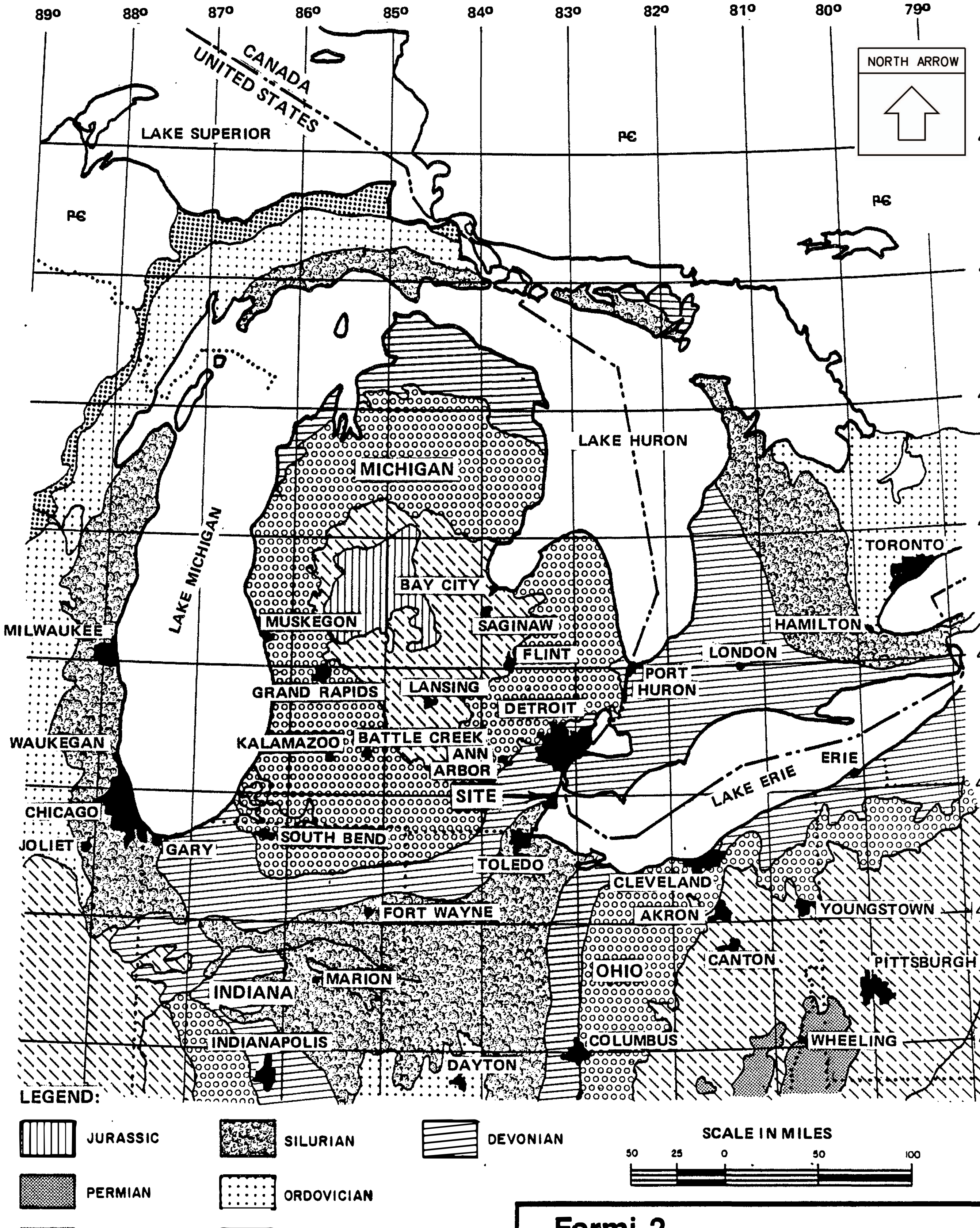
FIGURE 2.5-3

AREA SURFACE GEOLOGICAL MAP



REFERENCE:

THIS MAP WAS PREPARED FROM:
A) "GEOLOGIC MAP OF NORTH AMERICA" BY THE U.S.G.S., 1965
B) "BEDROCK OF MICHIGAN" BY THE MICHIGAN STATE GEOLOGICAL SURVEY, 1968

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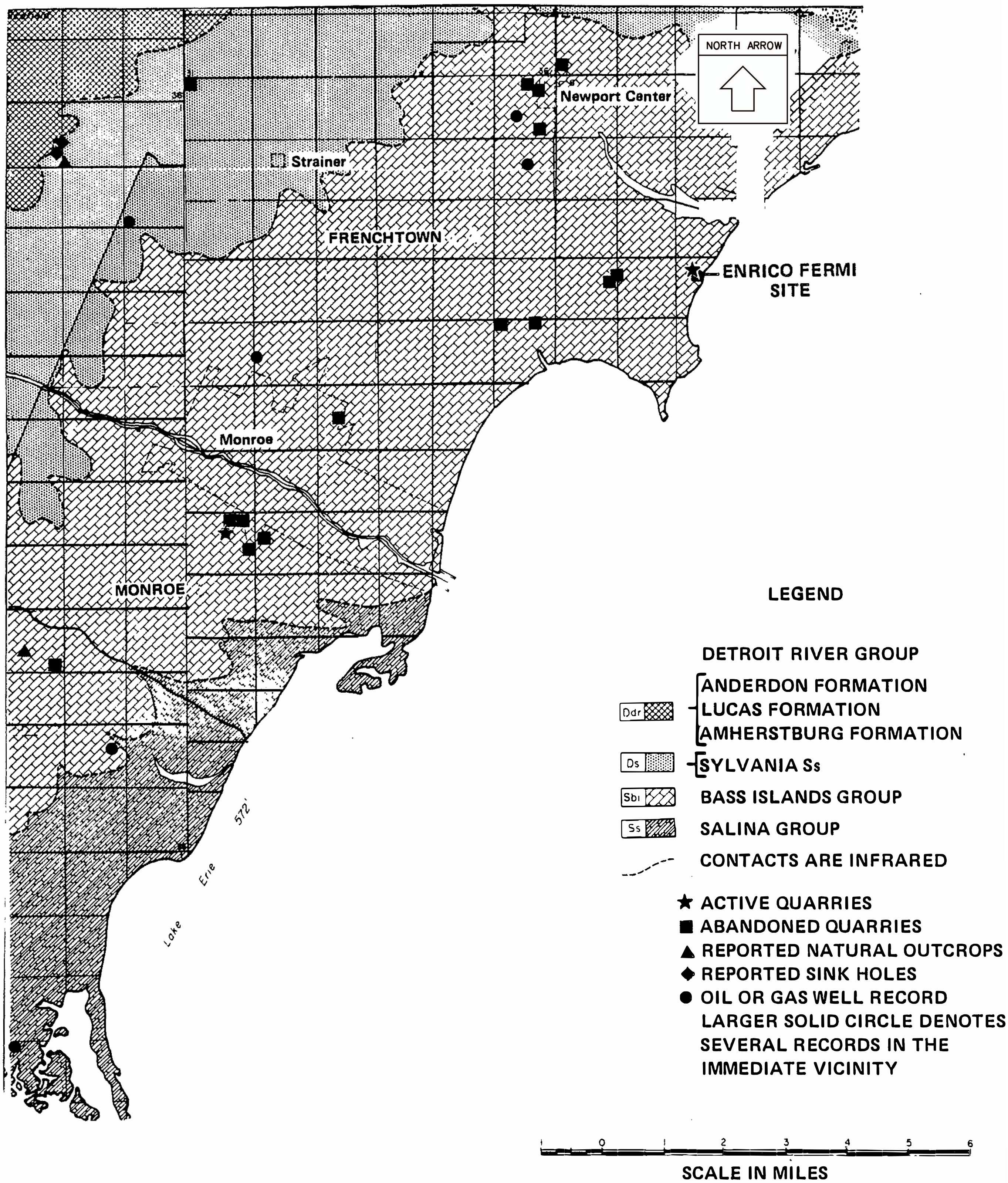
FIGURE 2.5-4

REGIONAL BEDROCK GEOLOGICAL MAP



REFERENCE:
MAZOLA, A. J., 1969, BEDROCK GEOLOGIC MAP OF MONROE COUNTY, MICHIGAN: FROM REPORT OF INVESTIGATION 13, GEOLOGY FOR ENVIRONMENTAL PLANNING IN MONROE COUNTY, MICHIGAN; GEOLOGICAL SURVEY DIVISION, DEPARTMENT OF NATURAL RESOURCES, 1970.

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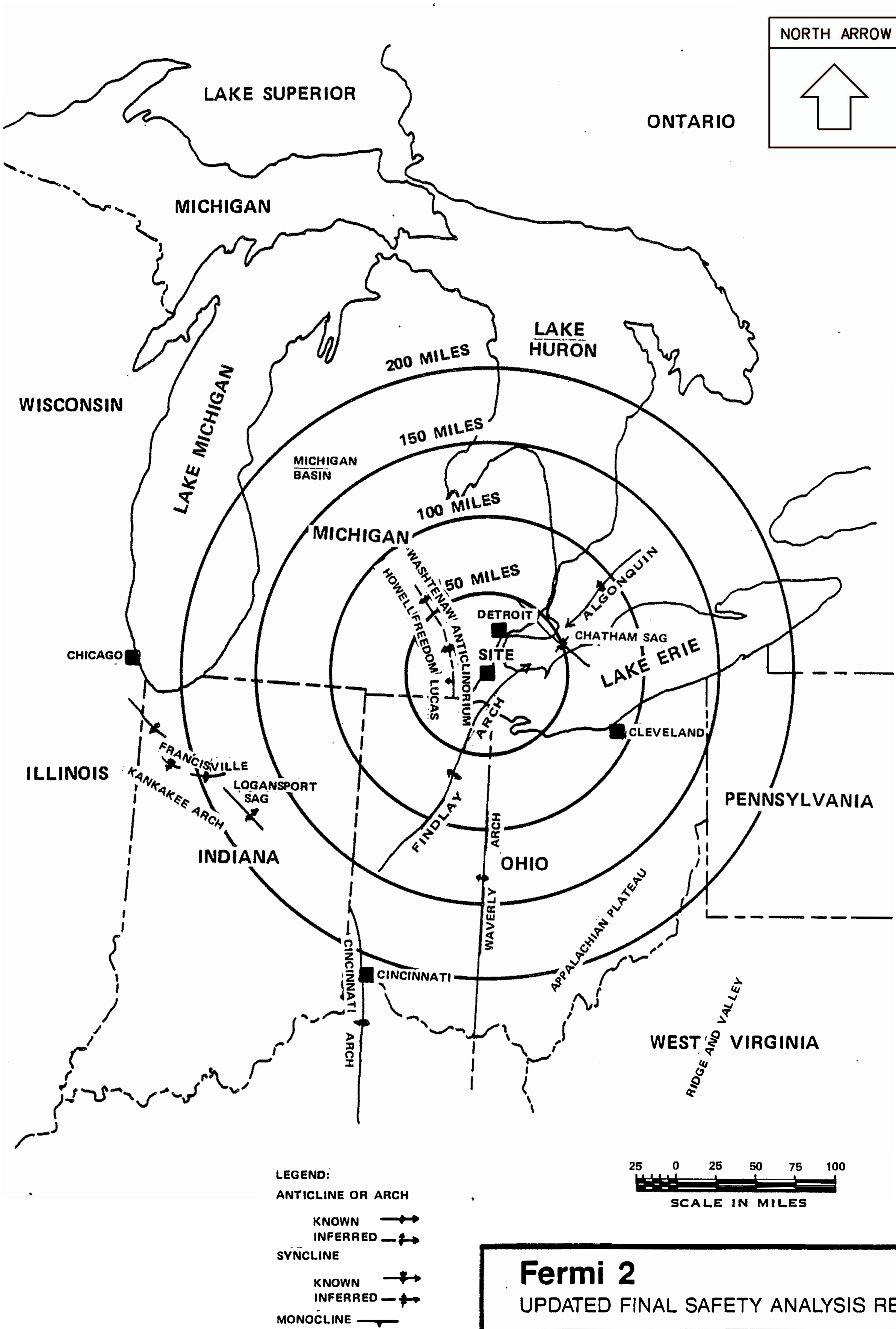
FIGURE 2.5-5

AREA BEDROCK GEOLOGICAL MAP



REFERENCE:
ELLS, G. D., 1969, ARCHITECTURE OF THE MICHIGAN BASIN IN STUDIES OF THE PRECAMBRIAN OF THE MICHIGAN BASIN: MICHIGAN BASIN GEOLOGICAL SOCIETY.

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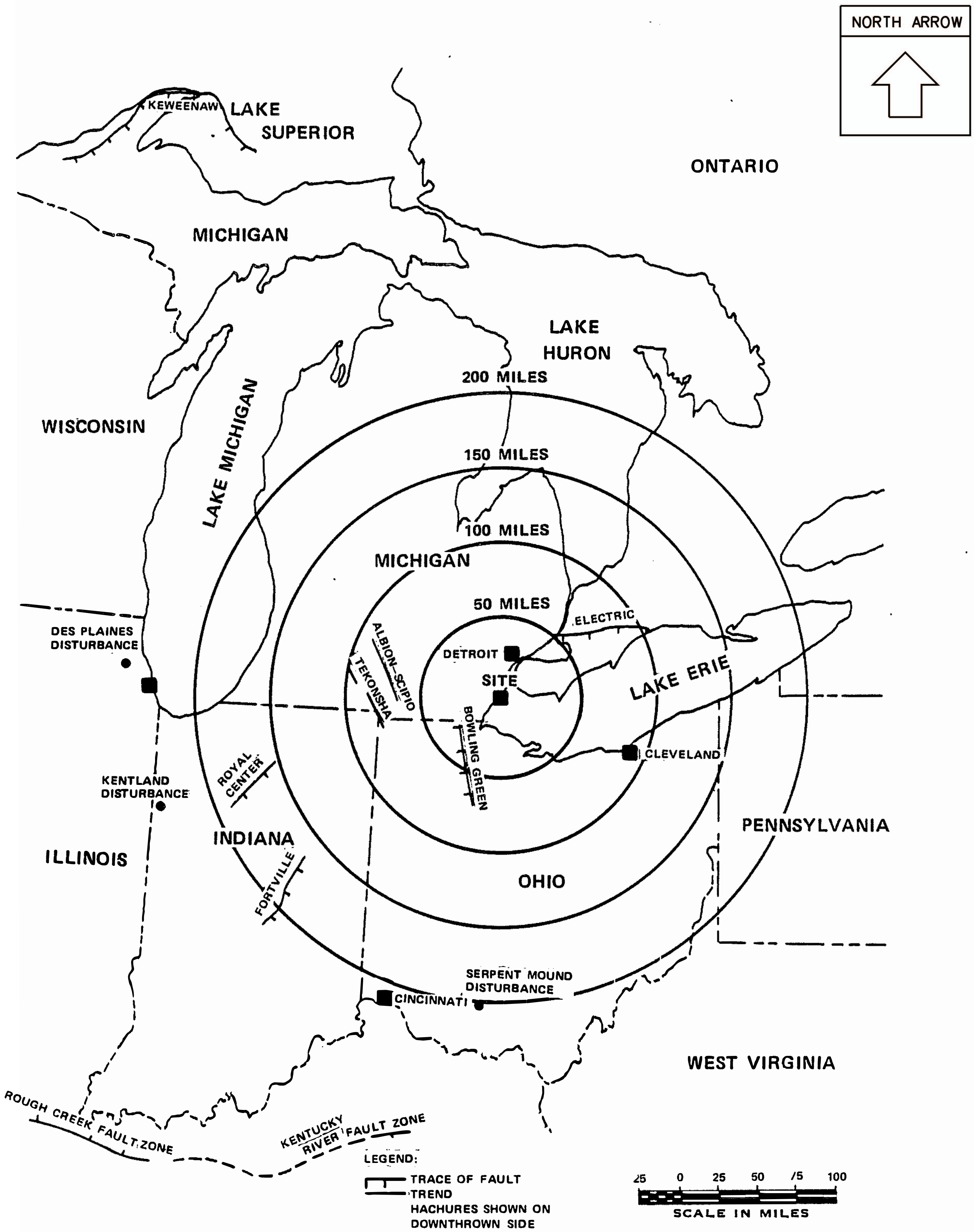
FIGURE 2.5-6

MAJOR FOLDS MAP



REFERENCE:
BRIGHAM, R. J., 1972, STRUCTURAL GEOLOGY OF SOUTHWESTERN ONTARIO AND SOUTHEASTERN MICHIGAN, ONTARIO MINES AND NORTHERN AFFAIRS AFFAIRS. PETROLEUM RESOURCES SECTION PAPER 71-2.
BRISTOL, H. M., AND T. C. BUSHBACH, 1971, STRUCTURAL FEATURES OF THE EASTERN INTERIOR REGION OF THE UNITED STATES IN ILLINOIS GEOLOGICAL SURVEY, ILLINOIS PETROLEUM PUB 96.

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FIGURE 2.5-7

MAJOR FAULTS MAP

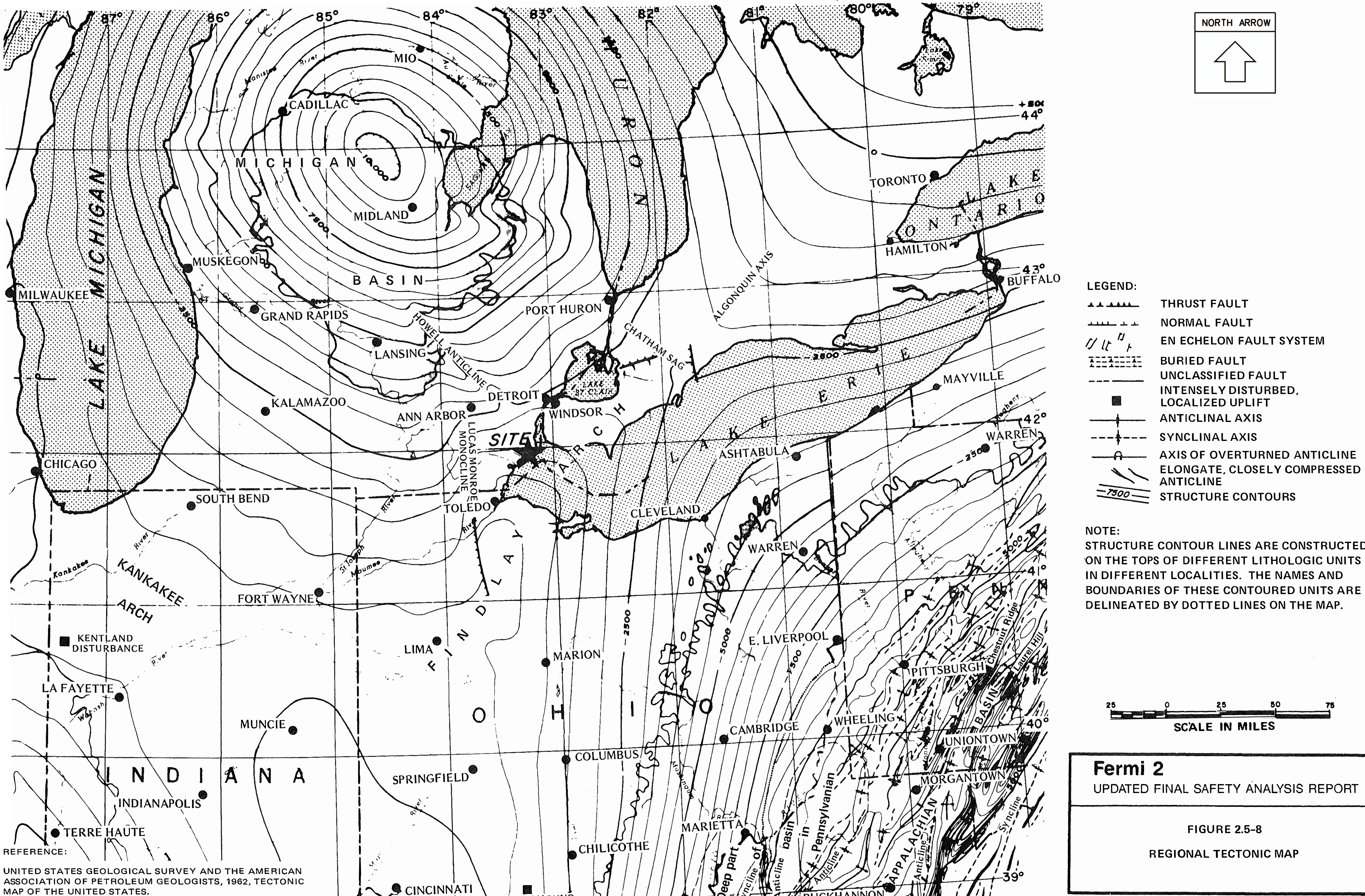

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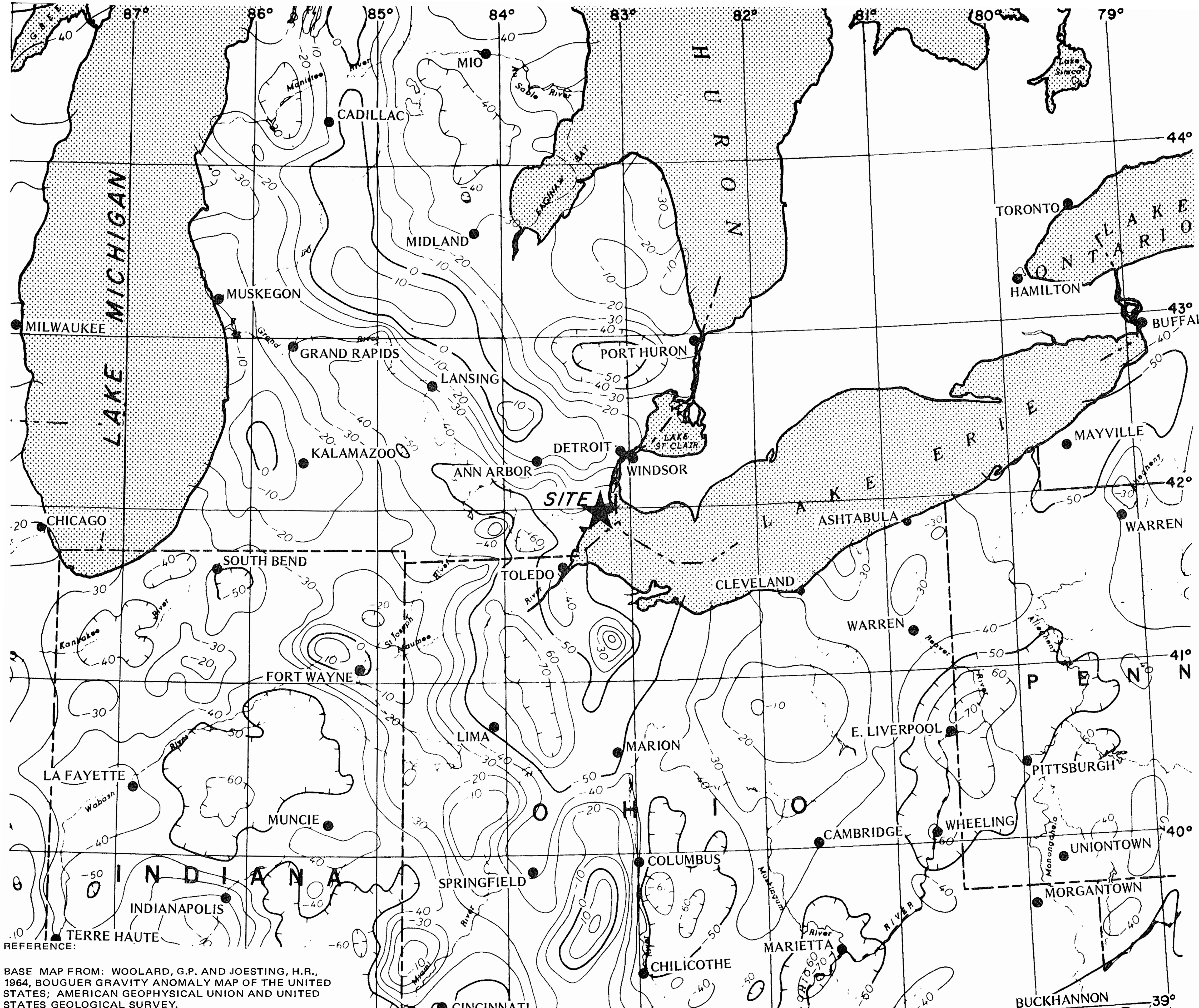
FIGURE 2.5-8

REGIONAL TECTONIC MAP



REFERENCE:

BASE MAP FROM: WOOLARD, G.P. AND JOESTING, H.R., 1964, BOUGUER GRAVITY ANOMALY MAP OF THE UNITED STATES; AMERICAN GEOPHYSICAL UNION AND UNITED STATES GEOLOGICAL SURVEY.

NORTH ARROW

LEGEND:

-60- BOUGUER GRAVITY CONTOUR (CONTOUR INTERVAL 10 MILLIGALS)

25 0 25 50 75

SCALE IN MILES

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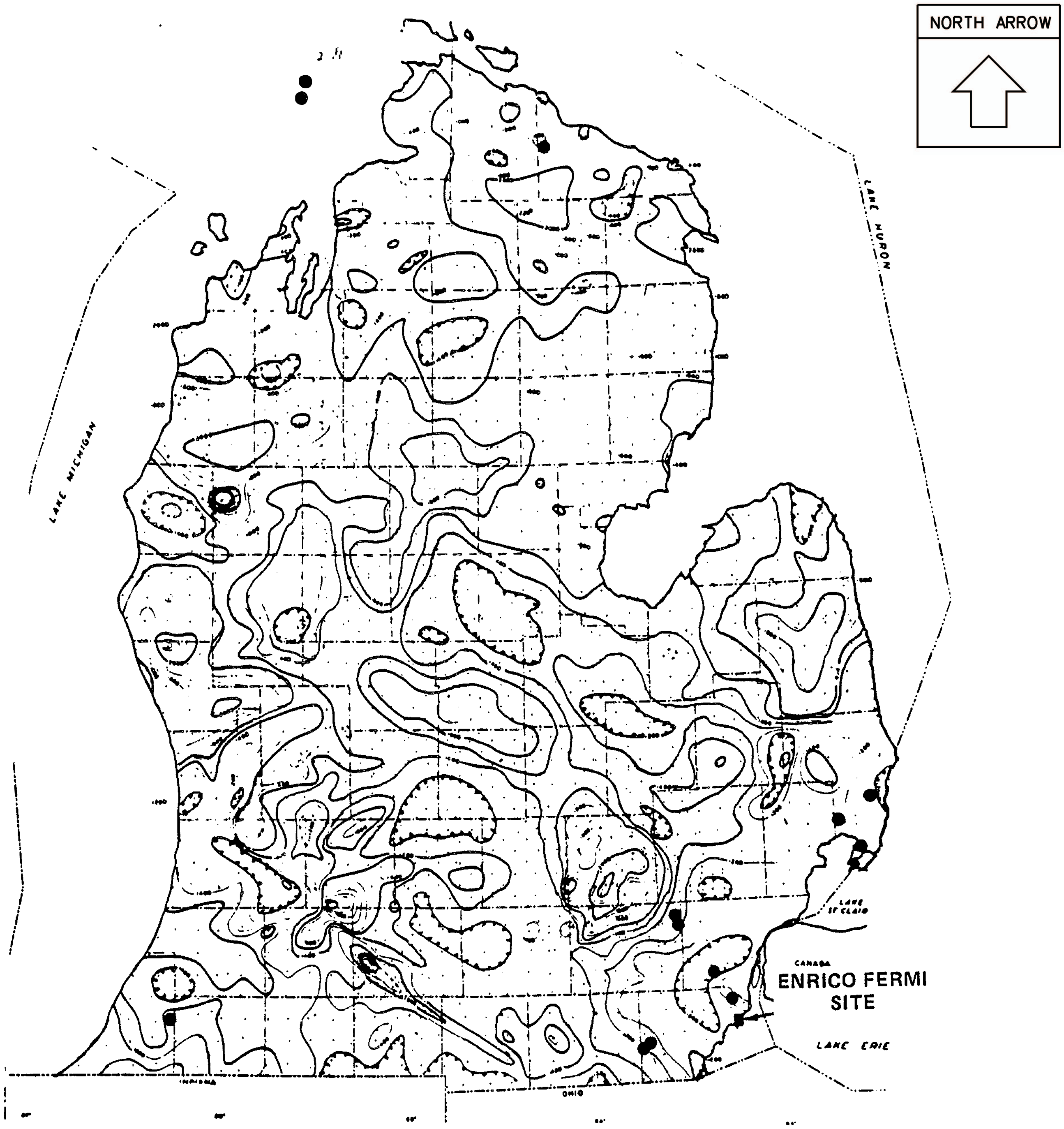
FIGURE 2.5-9

REGIONAL BOUGUER GRAVITY MAP



KEY:
● INDICATES PRECAMBRIAN SAMPLE
CONTOUR INTERVAL = 100 GAMMAS

SCALE IN MILES
30 10 0 20 40

REFERENCE:

MAGNETIC MAP –
A) HINZE, W.J., AND MERRITT, D.W., 1969, BASEMENT ROCKS OF THE SOUTHERN PENINSULA OF MICHIGAN IN STUDIES OF THE PRECAMBRIAN OF THE MICHIGAN BASIN: MICHIGAN BASIN GEOLOGICAL SOCIETY
B) THE PRECAMBRIAN WELL LOCATIONS ARE FROM THE MICHIGAN GEOLOGICAL SURVEY, 1968, MICHIGAN'S OIL AND GAS FIELDS, 1967: ANNUAL STATISTICAL SUMMARY NO. 8.

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FIGURE 2.5-10

REGIONAL MAGNETIC MAP

SYSTEM	STRATIGRAPHIC NOMENCLATURE	GRAPHIC LOG	AVERAGE THICKNESS (FEET)	BEDS	LITHOLOGY
QUAT.	Recent and Pleistocene		15–30		Lake Deposits and Glacial Till
SILURIAN	Bass Islands Group		80		Dolomite
SILURIAN	Salina Group		525	G	Shales and Shaly Dolomite
				E	Shaly Dolomite, Limestone and Limestone Breccias
				C	Dolomite and Shaly Dolomite
				A	Limestone and Dolomite
SILURIAN	Niagaran Group		425		Dolomite
SILURIAN	Cataract Group		100		Shale and Dolomite
ORDOVICIAN	Richmond Group		625		Shale and Dolomite
ORDOVICIAN	Trenton – Black River Group		825–850		Dolomites and Shales
CAMBRIAN	St. Croixian Series		475		Sandstones (with some Dolomites)
PRE-CAMBRIAN					Granitic Gneiss

NOTE:
THICKNESS OF THE BASS ISLANDS GROUP AND PART OF THE SALINA GROUP BASED ON SITE EXPLORATORY BORINGS. OTHER THICKNESSES BASED ON MICHIGAN WELL LOGS, BRIGHAM, (1972) FISHER, (1969) AND ELLS, (ORAL COMMUNICATION)

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FIGURE 2.5-11

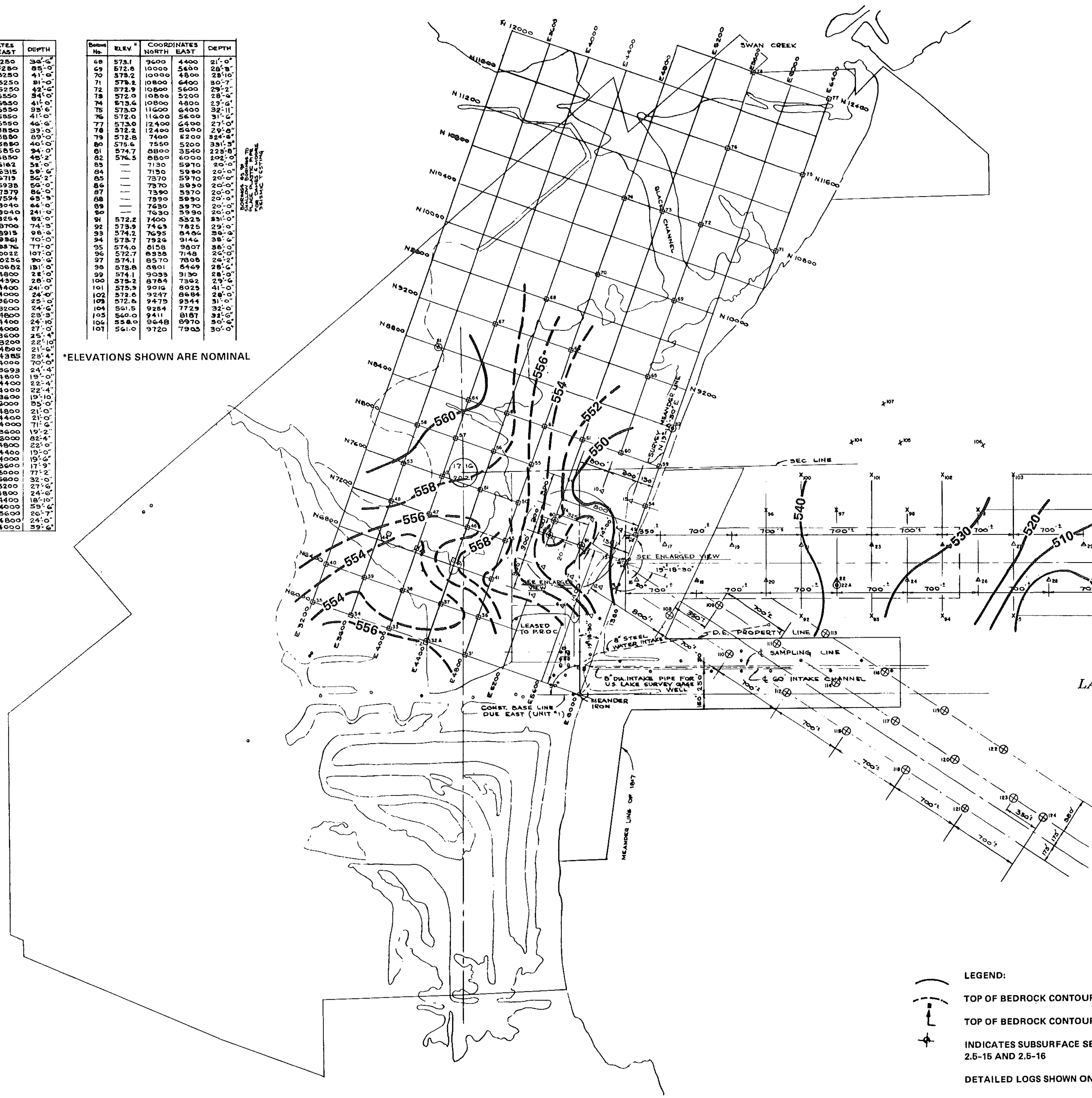
SITE STRATIGRAPHIC COLUMN

Boring No.	ELEV.*	COORDINATES NORTH	EAST	DEPTH
1	573.0	6780	5250	36'-6"
2	571.7	7080	5250	85'-0"
3	572.4	7380	5250	41'-0"
4	572.5	7680	5250	81'-0"
5	573.4	7980	5250	42'-6"
6	573.5	6780	5550	34'-0"
7	572.7	7080	5550	41'-0"
8	572.3	7380	5550	93'-6"
9	573.4	7680	5550	41'-0"
10	569.9	7980	5550	46'-6"
11	573.8	6780	5850	39'-0"
12	572.6	7080	5850	89'-0"
13	572.6	7380	5850	40'-0"
14	571.6	7680	5850	94'-0"
15	573.2	7980	5850	45'-2"
16	571.8	7251	6162	52'-0"
17	570.0	7676	6315	59'-6"
18	572.5	7446	6719	56'-2"
19	572.0	7892	6938	56'-0"
20	573.7	7678	7379	86'-0"
21	574.2	8124	7594	65'-9"
22	574.3	7909	8040	66'-0"
22A	577.3	7909	8040	241'-0"
23	574.3	8355	8254	82'-0"
24	573.5	8141	8700	74'-3"
25	573.8	8587	8915	98'-6"
26	572.8	8372	9361	70'-0"
27	571.8	8818	9576	77'-0"
28	573.0	8604	10022	107'-0"
29	572.7	9050	10236	90'-6"
30	573.1	8835	10682	131'-0"
31	572.7	6000	4800	22'-0"
32	579.7	5990	4390	28'-0"
32A	579.7	5990	4400	241'-0"
33	573.3	6000	4000	24'-0"
34	574.2	6000	3600	25'-0"
35	575.1	6000	3200	24'-6"
36	572.9	6400	4800	23'-3"
37	572.7	6400	4400	24'-10"
38	573.4	6400	4000	27'-0"
39	573.0	6400	3600	25'-4"
40	573.3	6400	3200	22'-10"
41	572.1	6800	4800	21'-6"
42	572.8	6855	4385	23'-4"
43	573.1	6850	4000	70'-0"
44	573.0	6892	3693	24'-4"
45	573.1	7200	4800	19'-0"
46	573.1	7200	4400	22'-4"
47	573.6	7200	4000	22'-4"
48	574.1	7200	3600	19'-10"
49	574.1	7680	6000	35'-0"
50	573.7	7600	4800	21'-0"
51	573.1	7600	4400	21'-0"
52	573.6	7600	4000	71'-6"
53	574.1	7600	3600	19'-2"
54	577.0	7980	6000	82'-4"
55	573.0	8000	4800	22'-0"
56	573.0	8000	4400	19'-0"
57	573.0	8000	4000	19'-6"
58	574.0	8000	3600	17'-9"
59	576.8	8400	6000	77'-2"
60	573.0	8400	5600	32'-0"
61	573.2	8400	5200	27'-6"
62	573.2	8400	4800	24'-6"
63	572.7	8400	4400	18'-10"
64	573.0	8400	4000	59'-6"
65	571.7	9200	5600	26'-7"
66	573.3	9200	4800	24'-0"
67	573.0	9200	4000	39'-6"

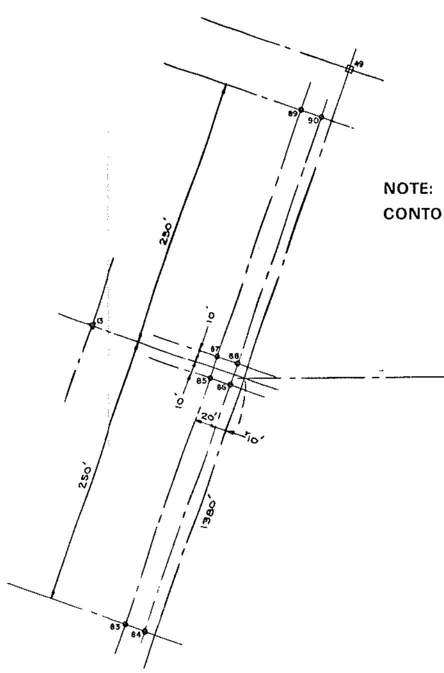
Boring No.	ELEV.*	COORDINATES NORTH	EAST	DEPTH
68	573.1	9600	4400	21'-0"
69	572.8	10000	5600	28'-8"
70	573.2	10000	4800	28'-10"
71	573.2	10800	6400	30'-7"
72	572.9	10800	5600	29'-2"
73	572.0	10800	5200	28'-6"
74	573.6	10800	4800	29'-6"
75	573.0	11600	6400	32'-11"
76	572.0	11600	5600	31'-6"
77	573.0	12400	6400	27'-0"
78	572.2	12400	5600	29'-8"
79	572.8	7400	5200	324'-8"
80	575.6	7550	5200	331'-3"
81	574.7	8800	3540	223'-8"
82	576.5	8800	6000	202'-0"
83	—	7130	5970	20'-0"
84	—	7130	5990	20'-0"
85	—	7370	5970	20'-0"
86	—	7370	5990	20'-0"
87	—	7390	5970	20'-0"
88	—	7390	5990	20'-0"
89	—	7630	5970	20'-0"
90	—	7630	5990	20'-0"
91	572.2	7400	5525	331'-0"
92	573.9	7463	7825	29'-0"
93	574.2	7695	8486	36'-6"
94	573.7	7926	9146	38'-6"
95	574.0	8158	9807	38'-0"
96	572.7	8338	7148	26'-0"
97	574.1	8570	7808	26'-2"
98	573.8	8801	8469	28'-6"
99	574.1	9033	9130	28'-0"
100	575.2	8784	7362	29'-6"
101	575.9	9016	8025	41'-0"
102	572.8	9247	8684	28'-0"
103	572.8	9479	9344	31'-0"
104	561.5	9254	7729	32'-0"
105	560.0	9411	8187	32'-6"
106	558.0	9648	8970	30'-6"
107	561.0	9720	7903	30'-0"

BORINGS 83 TO 90 SHALLOW BORINGS TO PLACE PLASTIC PIPE FOR DAMES & MOORE SEISMIC TESTING

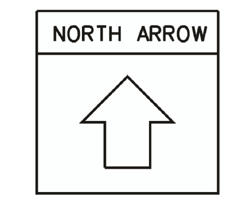
*ELEVATIONS SHOWN ARE NOMINAL



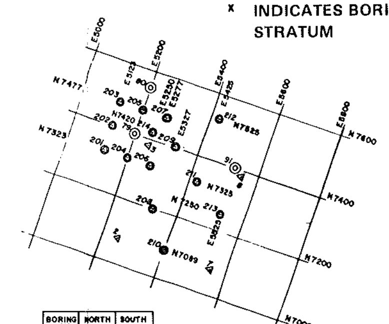
NOTE:
CONTOUR INTERVAL IS 2 FEET



ENLARGED VIEW OF SEISMIC STUDY BORINGS



- o INDICATES PROPOSED BORING LOCATIONS FOR UNIT NO. 2 (201-21)
- ⊕ INDICATES PROPOSED BORING LOCATIONS FOR UNIT NO. 2 (108-124)
- ∘ INDICATES BORING LOCATION TAKEN FOR UNIT NO. 1
- ▲ INDICATES PROPOSED BORING LOCATIONS FOR UNIT 2 (1-31)
- ◻ INDICATES PROPOSED INLAND BORING LOCATIONS FOR UNIT 2 (31-78
- ⊚ INDICATES DEEP BORING LOCATION
- • INDICATES BORING LOCATIONS FOR SEISMIC SOIL RESPONSE STUDY
- x INDICATES BORING LOCATIONS TO BOTTOM OF SAND STRATUM



BORING NO.	NORTH	SOUTH
201	7323	5123
202	7400	5123
203	7477	5123
204	7323	5200
205	7477	5200
206	7323	5277
207	7477	5277
208	7200	5327
209	7400	5327
210	7069	5400
211	7325	5425
212	7525	5425
213	7250	5525
214	7420	5280

ENLARGED VIEW FOR ADDITIONAL BORINGS IN REACTOR, AUX. BLDG., TURBINE AND RADWASTE BLDGS

LEGEND:

- TOP OF BEDROCK CONTOUR (10 FOOT CONTOUR INTERVAL)
- TOP OF BEDROCK CONTOUR (2 FOOT CONTOUR INTERVAL)
- INDICATES SUBSURFACE SECTION SHOWN ON FIGURES 2.5-15 AND 2.5-16

DETAILED LOGS SHOWN ON FIGURES 2.5-24 THRU 2.5-56.

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FIGURE 2.5-12

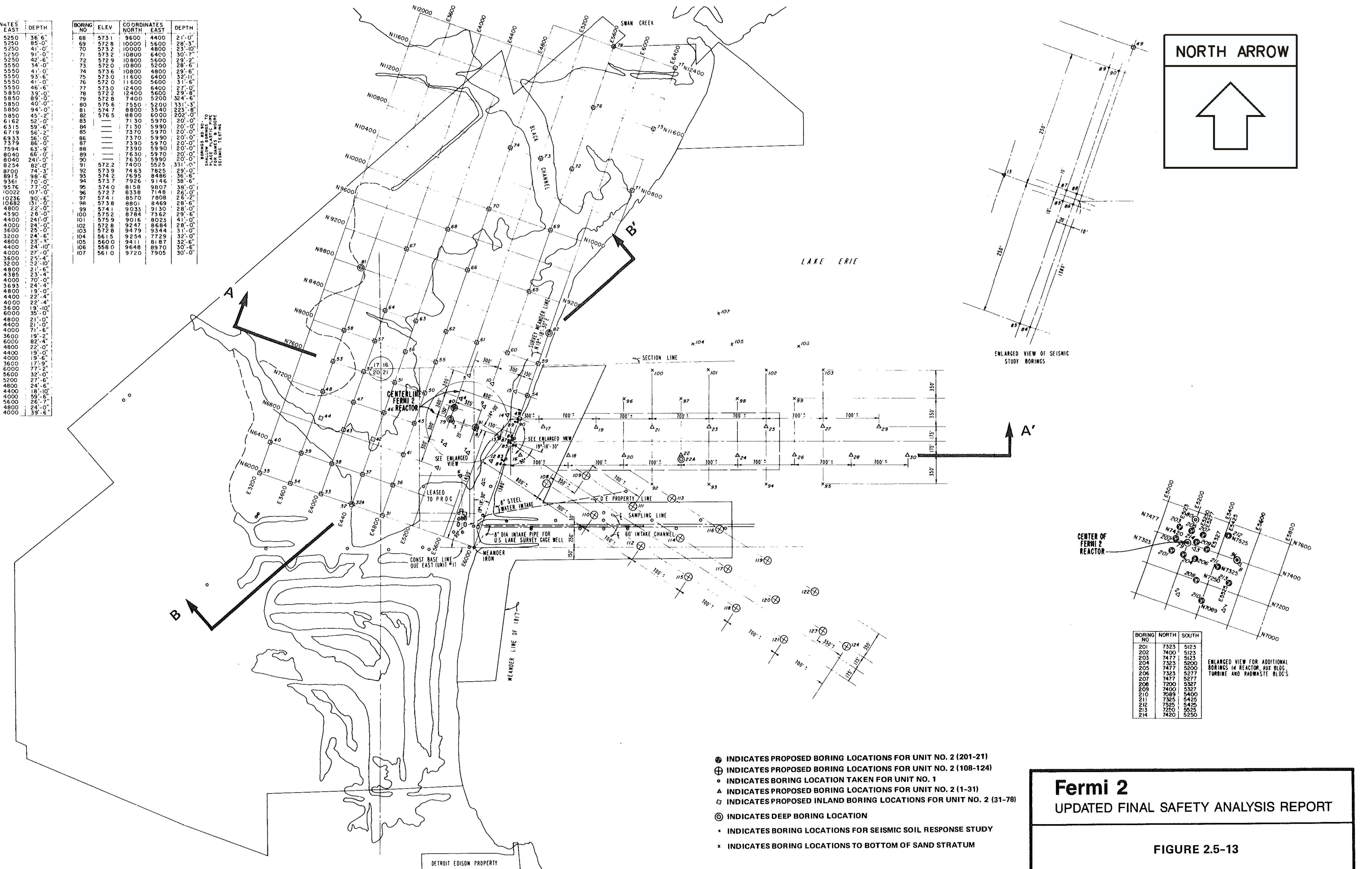
BEDROCK TOPOGRAPHIC MAP – SITE

DETROIT EDISON COMPANY DRAWING NO. 6MS721-40. REV. I

BORING NO	ELEV	COORDINATES NORTH	COORDINATES EAST	DEPTH
1	5730	6780	5250	36'6"
2	571.7	7080	5250	85'-0"
3	5724	7380	5250	41'-0"
4	5725	7680	5250	91'-0"
5	5734	7980	5250	42'-6"
6	5735	6780	5550	34'-0"
7	572.7	7080	5550	41'-0"
8	5723	7380	5550	93'-6"
9	5734	7680	5550	41'-0"
10	5699	7980	5550	46'-6"
11	573.8	6780	5850	39'-0"
12	5726	7080	5850	89'-0"
13	572.6	7380	5850	40'-0"
14	5716	7680	5850	94'-0"
15	5732	7980	5850	45'-2"
16	571.8	7251	6162	52'-0"
17	5700	7676	6315	59'-6"
18	5725	7446	6719	56'-2"
19	5720	7892	6933	56'-0"
20	5737	7678	7379	86'-0"
21	5742	8124	7594	63'-9"
22	5743	7909	8040	66'-0"
22A	5773	7909	8040	241'-0"
23	5743	8355	8254	82'-0"
24	5735	8141	8700	74'-3"
25	5738	8587	8915	98'-6"
26	5728	8372	9361	70'-0"
27	5718	8818	9576	77'-0"
28	5730	8604	10022	107'-0"
29	5727	9050	10236	90'-6"
30	5731	8835	10682	131'-0"
31	572.7	6000	4800	22'-0"
32	5797	5990	4390	28'-0"
32A	5797	5990	4400	241'-0"
33	5733	6000	4000	24'-0"
34	574.2	6000	3600	25'-0"
35	573.1	6000	3200	24'-6"
36	5729	6400	4800	23'-3"
37	572.7	6400	4400	24'-10"
38	5734	6400	4000	27'-0"
39	5730	6400	3600	25'-4"
40	5733	6400	3200	22'-10"
41	572.1	6800	4800	21'-6"
42	572.8	6855	4385	23'-4"
43	573.1	6850	4000	70'-0"
44	5730	6892	3693	24'-4"
45	5731	7200	4800	19'-0"
46	5731	7200	4400	22'-4"
47	5736	7200	4000	22'-4"
48	5741	7200	3600	19'-10"
49	574.1	7680	6000	35'-0"
50	5737	7600	4800	21'-0"
51	5731	7600	4400	21'-0"
52	5736	7600	4000	71'-6"
53	5741	7600	3600	19'-2"
54	5770	7980	6000	82'-4"
55	5730	8000	4800	22'-0"
56	5730	8000	4400	19'-0"
57	5730	8000	4000	19'-6"
58	5740	8000	3600	17'-9"
59	5768	8400	6000	77'-2"
60	5730	8400	5600	32'-0"
61	5732	8400	5200	27'-6"
62	5732	8400	4800	24'-6"
63	5727	8400	4400	18'-10"
64	5730	8400	4000	59'-6"
65	5717	9200	5600	26'-7"
66	5733	9200	4800	24'-0"
67	5730	9200	4000	39'-6"

BORING NO	ELEV	COORDINATES NORTH	COORDINATES EAST	DEPTH
68	5731	9600	4400	21'-0"
69	5728	10000	5600	28'-3"
70	5732	10000	4800	23'-10"
71	5732	10800	6400	30'-7"
72	5729	10800	5600	29'-2"
73	5720	10800	5200	28'-6"
74	573.6	10800	4800	29'-6"
75	573.0	11600	6400	32'-11"
76	5720	11600	5600	31'-6"
77	5730	12400	6400	27'-0"
78	5722	12400	5600	29'-8"
79	5728	7400	5200	324'-6"
80	575.6	7550	5200	331'-3"
81	5747	8800	3540	223'-8"
82	5765	8800	6000	202'-0"
83	—	7130	5970	20'-0"
84	—	7130	5990	20'-0"
85	—	7370	5970	20'-0"
86	—	7370	5990	20'-0"
87	—	7390	5970	20'-0"
88	—	7390	5990	20'-0"
89	—	7630	5970	20'-0"
90	—	7630	5990	20'-0"
91	572.2	7400	5525	331'-0"
92	5739	7463	7825	29'-0"
93	5742	7695	8486	36'-6"
94	573.7	7926	9146	38'-6"
95	5740	8158	9807	38'-0"
96	5727	8338	7148	26'-0"
97	5741	8570	7808	26'-2"
98	5738	8801	8469	28'-6"
99	574.1	9033	9130	28'-0"
100	5752	8784	7362	29'-6"
101	5759	9016	8023	41'-0"
102	5728	9247	8684	28'-0"
103	5728	9479	9344	31'-0"
104	561.5	9254	7729	32'-0"
105	5600	9411	8187	32'-6"
106	5580	9648	8970	30'-6"
107	5610	9720	7905	30'-0"

BORINGS 83-90 - SHALLOW BORINGS TO PLACE PLASTIC PIPE FOR DAMES & MOORE SEISMIC TESTING



BORING NO	NORTH	SOUTH
201	7323	5123
202	7400	5123
203	7477	5123
204	7323	5200
205	7477	5200
206	7323	5277
207	7477	5277
208	7200	5327
209	7400	5327
210	7089	5400
211	7325	5425
212	7525	5425
213	7250	5525
214	7420	5250

ENLARGED VIEW FOR ADDITIONAL BORINGS IN REACTOR, AUX BLDG, TURBINE AND RADWASTE BLDG'S

- INDICATES PROPOSED BORING LOCATIONS FOR UNIT NO. 2 (201-21)
- INDICATES PROPOSED BORING LOCATIONS FOR UNIT NO. 2 (108-124)
- INDICATES BORING LOCATION TAKEN FOR UNIT NO. 1
- INDICATES PROPOSED BORING LOCATIONS FOR UNIT NO. 2 (1-31)
- INDICATES PROPOSED INLAND BORING LOCATIONS FOR UNIT NO. 2 (31-78)
- INDICATES DEEP BORING LOCATION
- INDICATES BORING LOCATIONS FOR SEISMIC SOIL RESPONSE STUDY
- INDICATES BORING LOCATIONS TO BOTTOM OF SAND STRATUM

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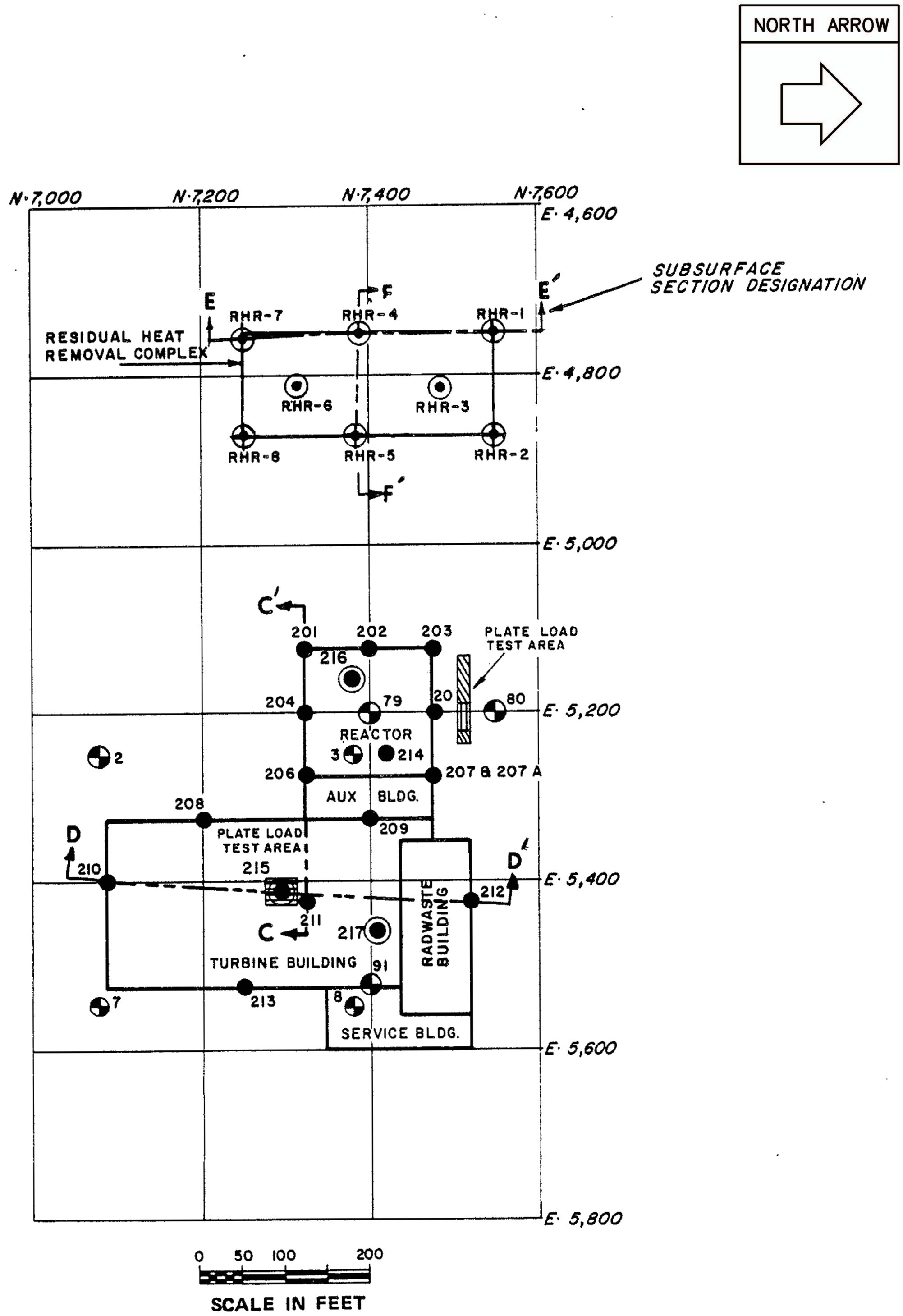
FIGURE 2.5-13

BORING PLAN – SITE VICINITY

DETROIT EDISON COMPANY DRAWING 6MS721-40



KEY:

- BORINGS DRILLED FOR P.S.A.R. (1968)
- BORINGS DRILLED FOR SUPPLEMENT TO P.S.A.R. (1969)
- BORINGS DRILLED FOR SOIL AND ROCK STUDIES (1970)
- BORINGS DRILLED FOR RHR COMPLEX FOUNDATION INVESTIGATION (1972)

SOURCE DRAWING REFERENCE:
REFERENCE 3, PLATE 2

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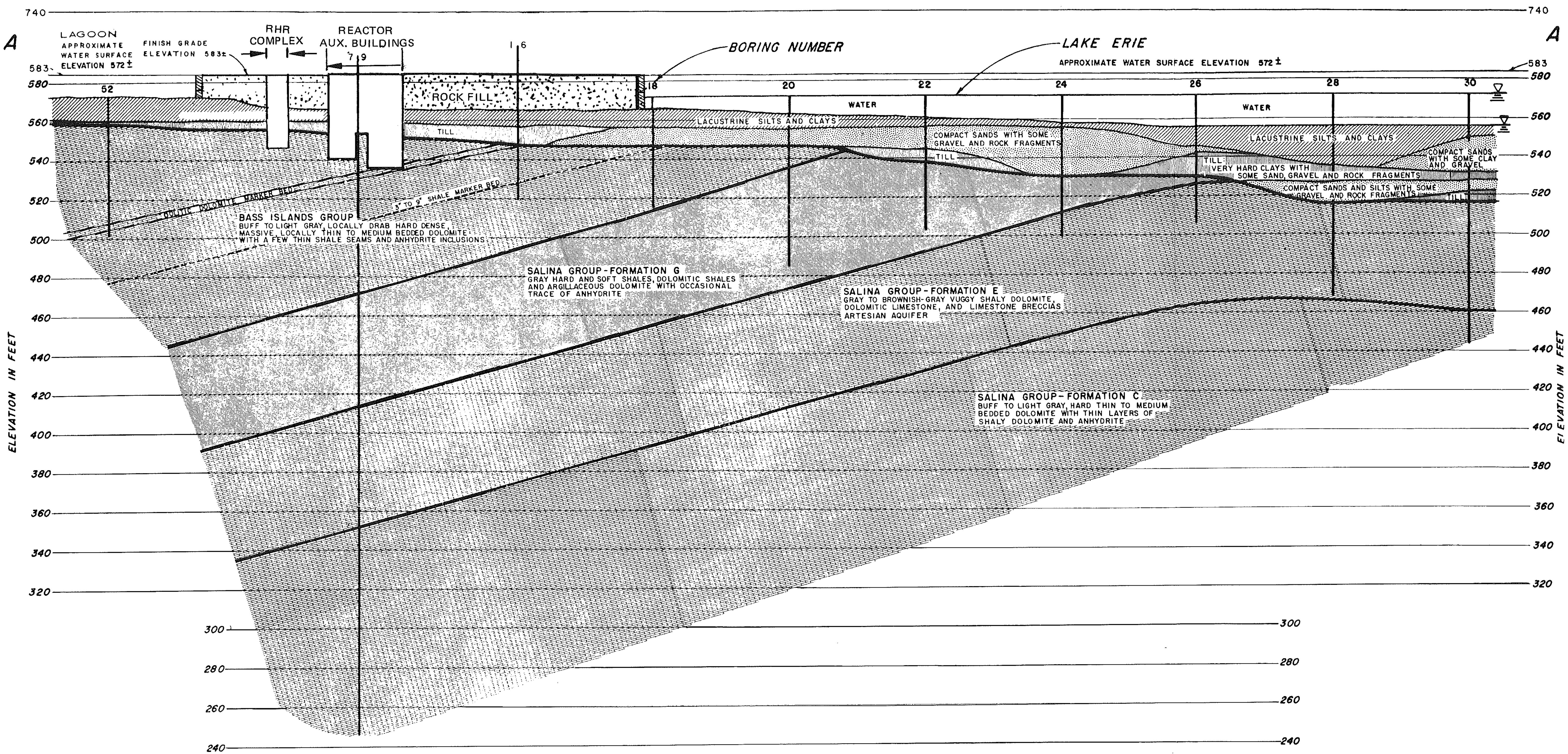
FIGURE 2.5-14

BORING PLAN – REACTOR/AUXILIARY BUILDING, RHR COMPLEX, TURBINE RADWASTE BUILDING, AND SERVICE BUILDING



SECTION A - A'

100 0 100 200 300 400 500

SCALE IN FEET

NOTES:

ELEVATIONS REFER TO GREAT LAKES SURVEY DATUM.

GROUND SURFACE ELEVATIONS ARE CORRECT ONLY AT TEST BORING LOCATIONS.

THE DEPTH AND THICKNESS OF THE SOIL STRATA AND THE DEPTH OF THE ROCK STRATA INDICATED ON THE SUBSURFACE SECTION WERE OBTAINED BY INTERPOLATING BETWEEN TEST BORINGS. INFORMATION ON ACTUAL SOIL AND ROCK CONDITIONS EXISTS ONLY AT THE TEST BORING LOCATIONS AND IT IS POSSIBLE THAT THE SOIL AND ROCK CONDITIONS BETWEEN THE TEST BORINGS MAY VARY FROM THOSE INDICATED.

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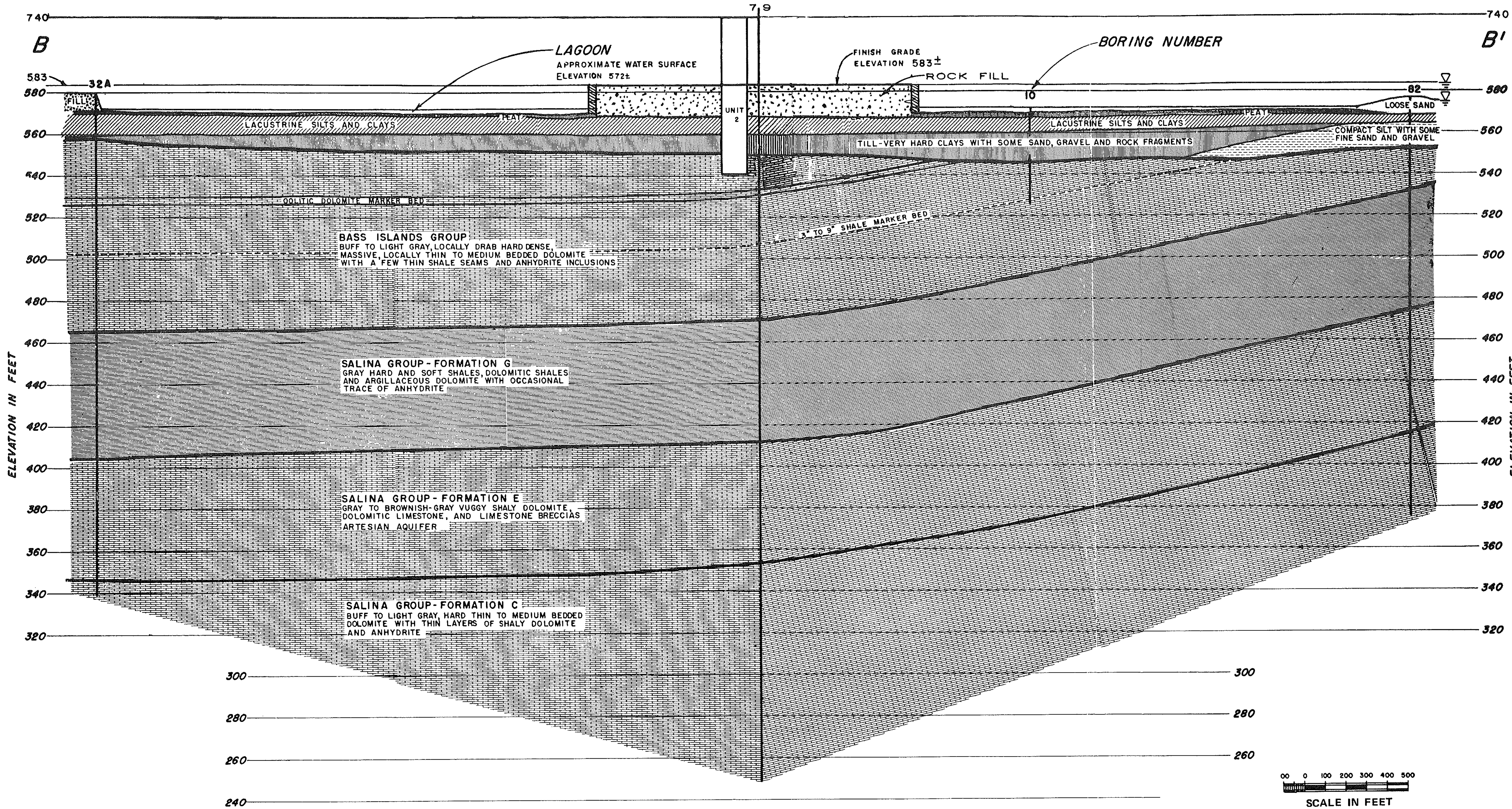
FIGURE 2.5-15

SUBSURFACE SECTION A-A' FROM FIGURE 2.5-13



SECTION B - B'

NOTES:

ELEVATIONS REFER TO GREAT LAKES SURVEY DATUM.

GROUND SURFACE ELEVATIONS ARE CORRECT ONLY AT TEST BORING LOCATIONS.

THE DEPTH AND THICKNESS OF THE SOIL STRATA AND THE DEPTH OF THE ROCK STRATA INDICATED ON THE SUBSURFACE SECTION WERE OBTAINED BY INTERPOLATING BETWEEN TEST BORINGS. INFORMATION ON ACTUAL SOIL AND ROCK CONDITIONS EXISTS ONLY AT THE TEST BORING LOCATIONS AND IT IS POSSIBLE THAT THE SOIL AND ROCK CONDITIONS BETWEEN THE TEST BORINGS MAY VARY FROM THOSE INDICATED.

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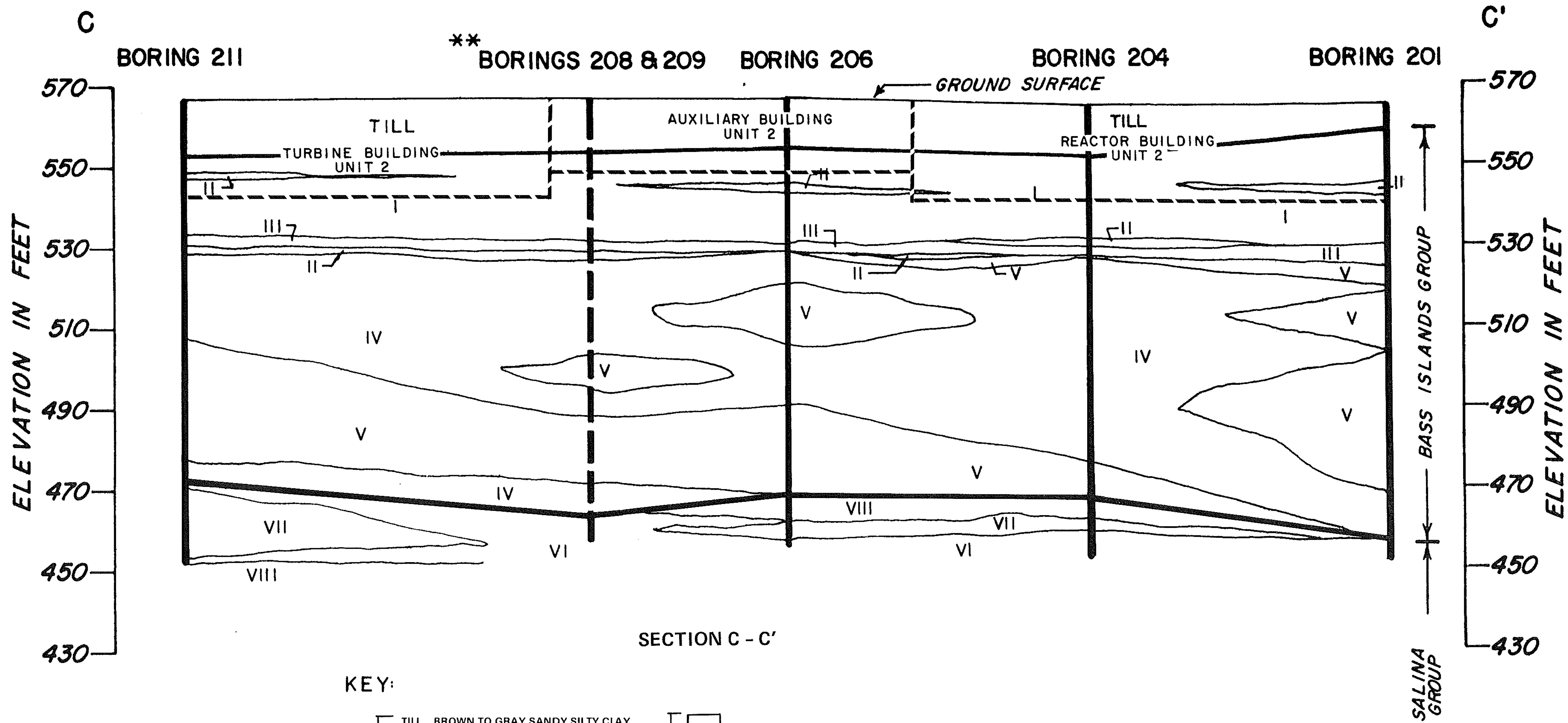
FIGURE 2.5-16

SUBSURFACE SECTION B-B' FROM FIGURE 2.5-13



KEY:

TILL	BROWN TO GRAY SANDY SILTY CLAY WITH SOME COBBLES AND BOULDERS (TILL).
I	GRAY TO BROWN MICROCRYSTALLINE ARGILLACEOUS DOLOMITE. FRACTURES VERY CLOSE TO MODERATELY CLOSE, 0°-90°. VUGS LESS THAN 10% WITH ZONES OF 20-40%, 1/16 TO 1/2 INCH.
II	GRAYISH BLUE TO GRAY WITH BLUE STREAKED MICROCRYSTALLINE DOLOMITE. FRACTURES VERY CLOSE TO CLOSE, NEAR HORIZONTAL WITH SOME 90°. VUGS 5-10% WITH SOME ZONES UP TO 40%, 1/32 TO 1/2 INCH.
III	LIGHT GRAY TO BROWN OOLITIC DOLOMITE. FRACTURES CLOSE TO MODERATELY CLOSE, 0°-45° AND 40° TO 90°. SOME FRAGMENTED ZONES. VUGS UP TO 10% WITH ZONES OF UP TO 40%, 1/32 TO 1/2 INCH.
IV	LIGHT GRAY TO TAN MICROCRYSTALLINE ARGILLACEOUS DOLOMITE. THINLY BEDDED WITH DARK GRAY SHALE PARTINGS AND LAMINAE. FRACTURES VARY FROM ZONES OF FRAGMENTED AND VERY CLOSE, 0°-90° TO ZONES OF MODERATELY CLOSE TO WIDE, 0° TO 20° AND 30°-70°. VUGS LESS THAN 10% WITH THIN ZONES OF 10 TO 20%, 1/32 TO 1/2 INCH.
V	LIGHT GRAY TO BROWN ARGILLACEOUS DOLOMITE. FRACTURES CLOSE TO VERY CLOSE, 0° TO 90°. VUGS LESS THAN 10%, 1/16 TO 1-1/2 INCHES.

BASS ISLANDS GROUP

VI	DARK GRAY DOLOMITIC SHALE. FRACTURES CLOSE TO VERY CLOSE, 0° TO 60° WITH OCCASIONAL FRAGMENTED ZONES. VUGS IN DOLOMITIC MATERIAL UP TO 10%, 1/32 TO 1/2 INCH.
VII	GRAY ARGILLACEOUS DOLOMITE. FRACTURES CLOSE TO VERY CLOSE WITH FRAGMENTED ZONES, 0° TO 90°. VUGS LESS THAN 10%, 1/16 TO 1/2 INCH.
VIII	GRAYISH-BLUE BRECCIATED DOLOMITE HEALED WITH BLUISH-GRAY CLAY MATRIX. FRACTURES VERY CLOSE TO FRAGMENTED, 0° TO 90°. VUGS IN DOLOMITE FRAGMENTS LESS THAN 10%, 1/8 TO 1/2 INCH.

SALINA GROUP

NOTES:

GROUND SURFACE ELEVATIONS ARE CORRECT ONLY AT TEST BORING LOCATIONS.

THE DEPTH AND THICKNESS OF THE SOIL AND ROCK STRATA INDICATED ON THE GENERALIZED SUBSURFACE SECTIONS WERE OBTAINED BY INTERPOLATING BETWEEN TEST BORINGS. INFORMATION ON ACTUAL SOIL AND ROCK CONDITIONS EXISTS ONLY AT THE TEST BORINGS AND IT IS POSSIBLE THAT THE SOIL AND ROCK CONDITIONS BETWEEN THE TEST BORINGS MAY VARY FROM THOSE INDICATED.

**EXTRAPOLATED TO CROSS-SECTION LINE FROM MORE THAN 80 FEET

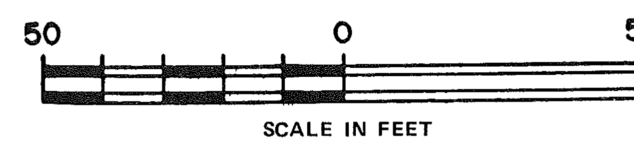


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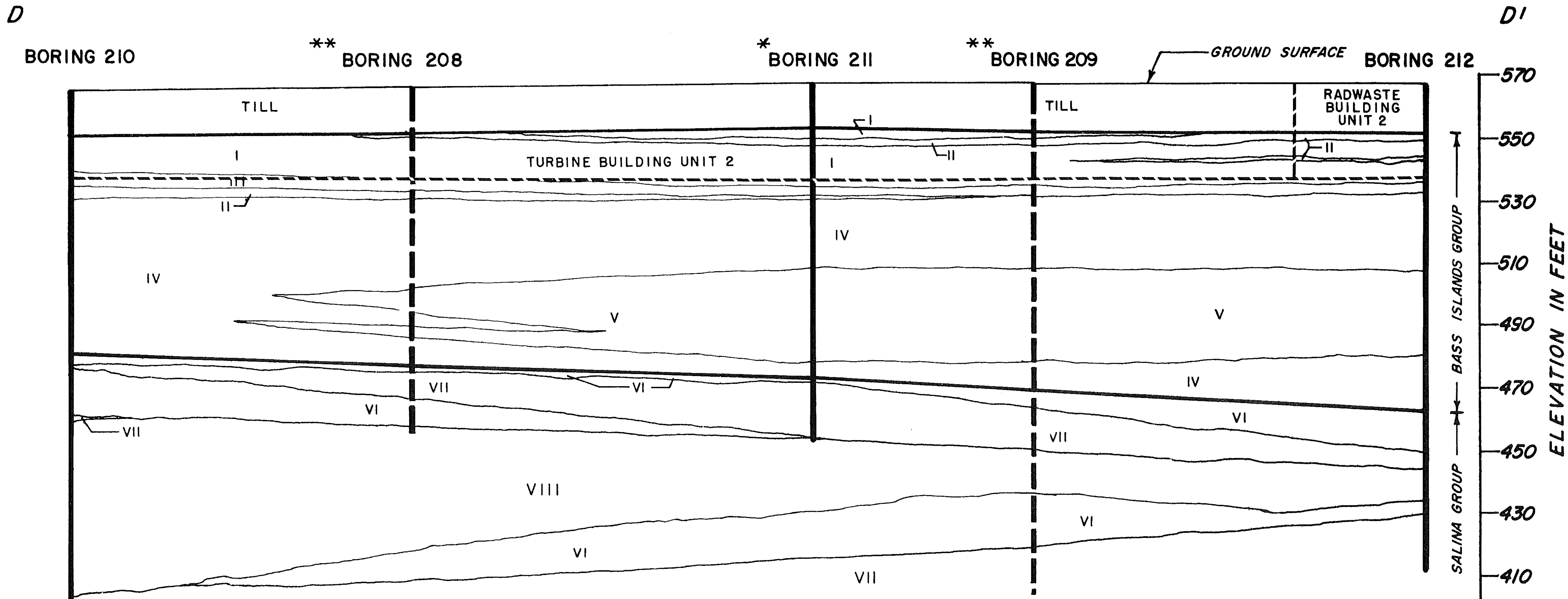
FIGURE 2.5-17

SUBSURFACE SECTION C-C' FROM FIGURE 2.5-14



SECTION D - D'

NOTES:

GROUND SURFACE ELEVATIONS ARE CORRECT ONLY AT TEST BORING LOCATIONS.

THE DEPTH AND THICKNESS OF THE SOIL AND ROCK STRATA INDICATED ON THE GENERALIZED SUBSURFACE SECTIONS WERE OBTAINED BY INTERPOLATING BETWEEN TEST BORINGS. INFORMATION ON ACTUAL SOIL AND ROCK CONDITIONS EXISTS ONLY AT THE TEST BORINGS AND IT IS POSSIBLE THAT THE SOIL AND ROCK CONDITIONS BETWEEN THE TEST BORINGS MAY VARY FROM THOSE INDICATED.

**EXTRAPOLATED TO CROSS SECTION LINE FROM MORE THAN 80 FEET
*EXTRAPOLATED TO CROSS SECTION LINE FROM LESS THAN 20 FEET

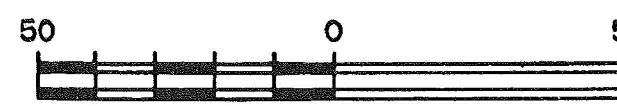
KEY

BASS ISLANDS GROUP

TILL	BROWN TO GRAY SANDY SILTY CLAY WITH SOME COBBLES AND BOULDERS (TILL).
I	GRAY TO BROWN MICROCRYSTALLINE ARGILLACEOUS DOLOMITE. FRACTURES VERY CLOSE TO MODERATELY CLOSE, 0°-90°. VUGS LESS THAN 10% WITH ZONES OF 20-40%, 1/16 TO 1/2 INCH.
II	GRAYISH BLUE TO GRAY WITH BLUE STREAKED MICROCRYSTALLINE DOLOMITE. FRACTURES VERY CLOSE TO CLOSE, NEAR HORIZONTAL WITH SOME 90°. VUGS 5-10% WITH SOME ZONES UP TO 40%, 1/32 TO 1/2 INCH.
III	LIGHT GRAY TO BROWN OOLITIC DOLOMITE. FRACTURES CLOSE TO MODERATELY CLOSE, 0°-45° AND 40° TO 90°. SOME FRAGMENTED ZONES. VUGS UP TO 10% WITH ZONES OF UP TO 40%, 1/32 TO 1/2 INCH.
IV	LIGHT GRAY TO TAN MICROCRYSTALLINE ARGILLACEOUS DOLOMITE. THINLY BEDDED WITH DARK GRAY SHALE PARTINGS AND LAMINAE. FRACTURES VARY FROM ZONES OF FRAGMENTED AND VERY CLOSE, 0°-90° TO ZONES OF MODERATELY CLOSE TO WIDE, 0° TO 20° AND 30°-70°. VUGS LESS THAN 10% WITH THIN ZONES OF 10 TO 20%, 1/32 TO 1/2 INCH.

SALINA GROUP

V	LIGHT GRAY TO BROWN ARGILLACEOUS DOLOMITE. FRACTURES CLOSE TO VERY CLOSE, 0° TO 90°. VUGS LESS THAN 10%, 1/16 TO 1-1/2 INCHES.
VI	DARK GRAY DOLOMITIC SHALE. FRACTURES CLOSE TO VERY CLOSE, 0° TO 60° WITH OCCASIONAL FRAGMENTED ZONES. VUGS IN DOLOMITIC MATERIAL UP TO 10%, 1/32 TO 1/2 INCH.
VII	GRAY ARGILLACEOUS DOLOMITE. FRACTURES CLOSE TO VERY CLOSE WITH FRAGMENTED ZONES, 0° TO 90°. VUGS LESS THAN 10%, 1/16 TO 1/2 INCH.
VIII	GRAYISH-BLUE BRECCIATED DOLOMITE HEALED WITH BLUISH-GRAY CLAY MATRIX. FRACTURES VERY CLOSE TO FRAGMENTED, 0° TO 90°. VUGS IN DOLOMITE FRAGMENTS LESS THAN 10%. 1/8 TO 1/2 INCH.



SCALE IN FEET

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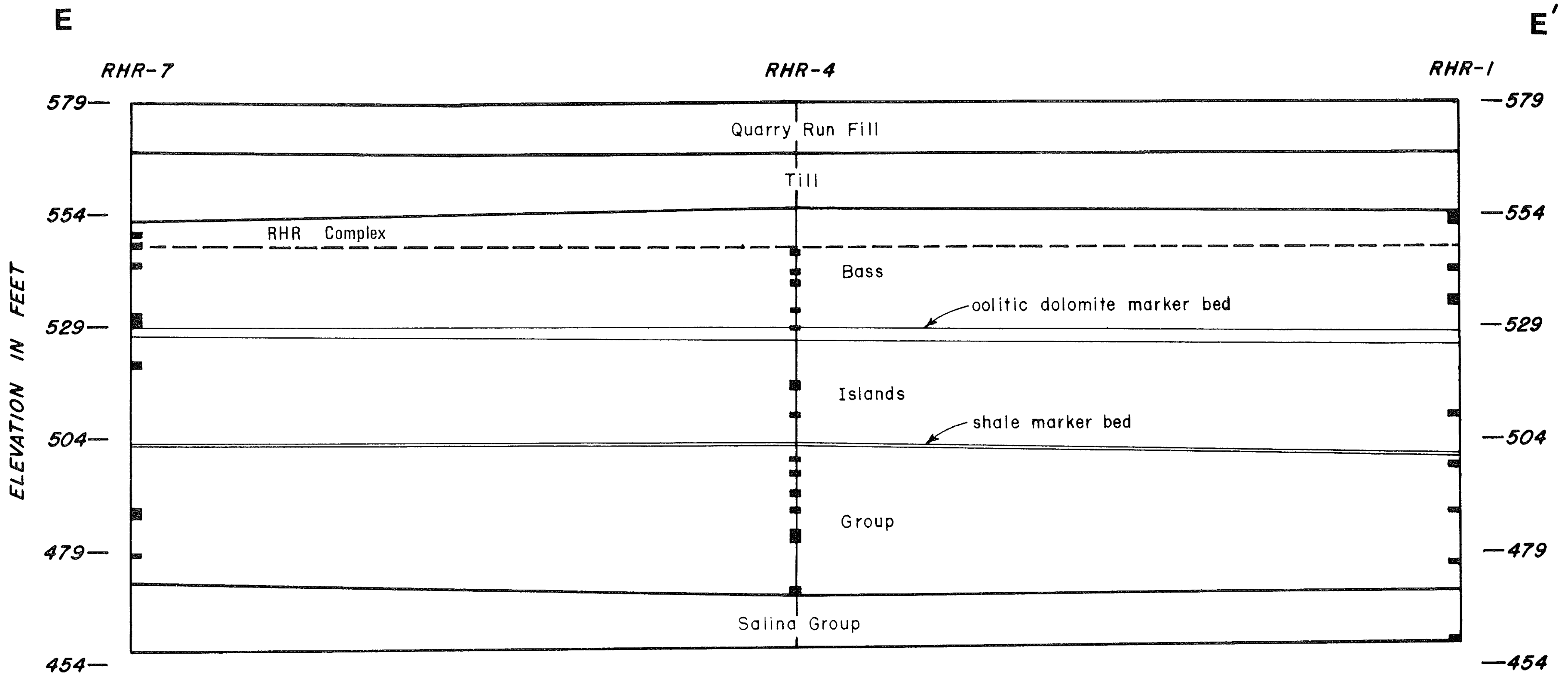
FIGURE 2.5-18

SUBSURFACE SECTION D-D' FROM FIGURE 2.5-14



SECTION E - E'

LEGEND:

FRAGMENTED ZONE

NOTES:

ELEVATIONS REFER TO N.Y.M.T., 1935.
SURFACE ELEVATIONS ARE CORRECT ONLY AT TEST BORING LOCATIONS.
THE DEPTH AND THICKNESS OF THE SOIL STRATA AND THE DEPTH OF THE ROCK STRATA INDICATED ON THE SUBSURFACE SECTION WERE OBTAINED BY INTERPOLATING BETWEEN TEST BORINGS. INFORMATION ON ACTUAL SOIL AND ROCK CONDITIONS EXISTS ONLY AT THE TEST BORING LOCATIONS AND IT IS POSSIBLE THAT THE SOIL AND ROCK CONDITIONS BETWEEN THE TEST BORINGS MAY VARY FROM THOSE INDICATED.

25 0 25

SCALE IN FEET

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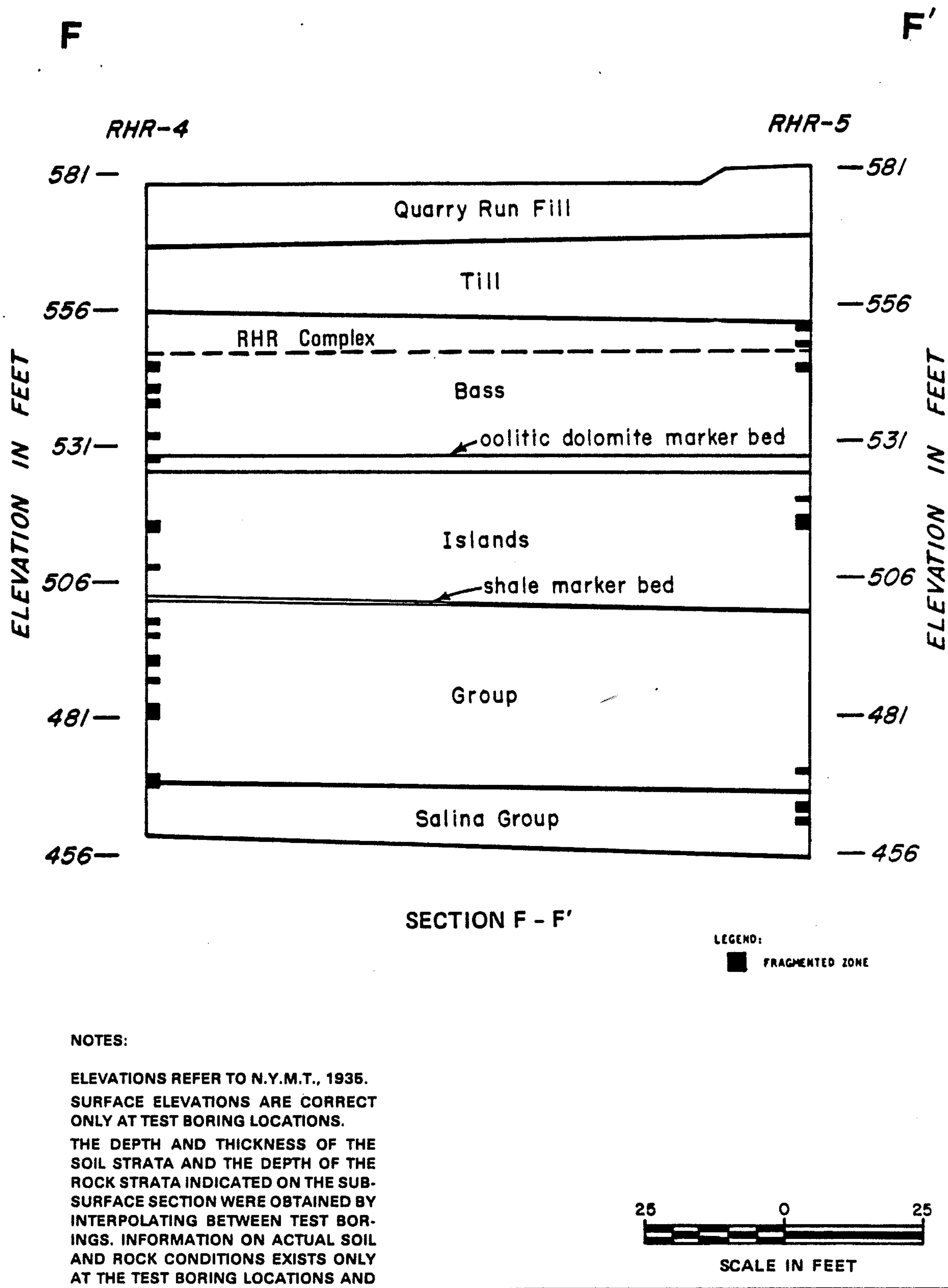
FIGURE 2.5-19

SUBSURFACE SECTION E-E' FROM FIGURE 2.5-14

REFERENCE PLATE 6A



NOTES:

ELEVATIONS REFER TO N.Y.M.T., 1935.

SURFACE ELEVATIONS ARE CORRECT ONLY AT TEST BORING LOCATIONS.

THE DEPTH AND THICKNESS OF THE SOIL STRATA AND THE DEPTH OF THE ROCK STRATA INDICATED ON THE SUBSURFACE SECTION WERE OBTAINED BY INTERPOLATING BETWEEN TEST BORINGS. INFORMATION ON ACTUAL SOIL AND ROCK CONDITIONS EXISTS ONLY AT THE TEST BORING LOCATIONS AND IT IS POSSIBLE THAT THE SOIL AND ROCK CONDITIONS BETWEEN THE TEST BORINGS MAY VARY FROM THOSE INDICATED.

REFERENCE 3
PLATE 6D

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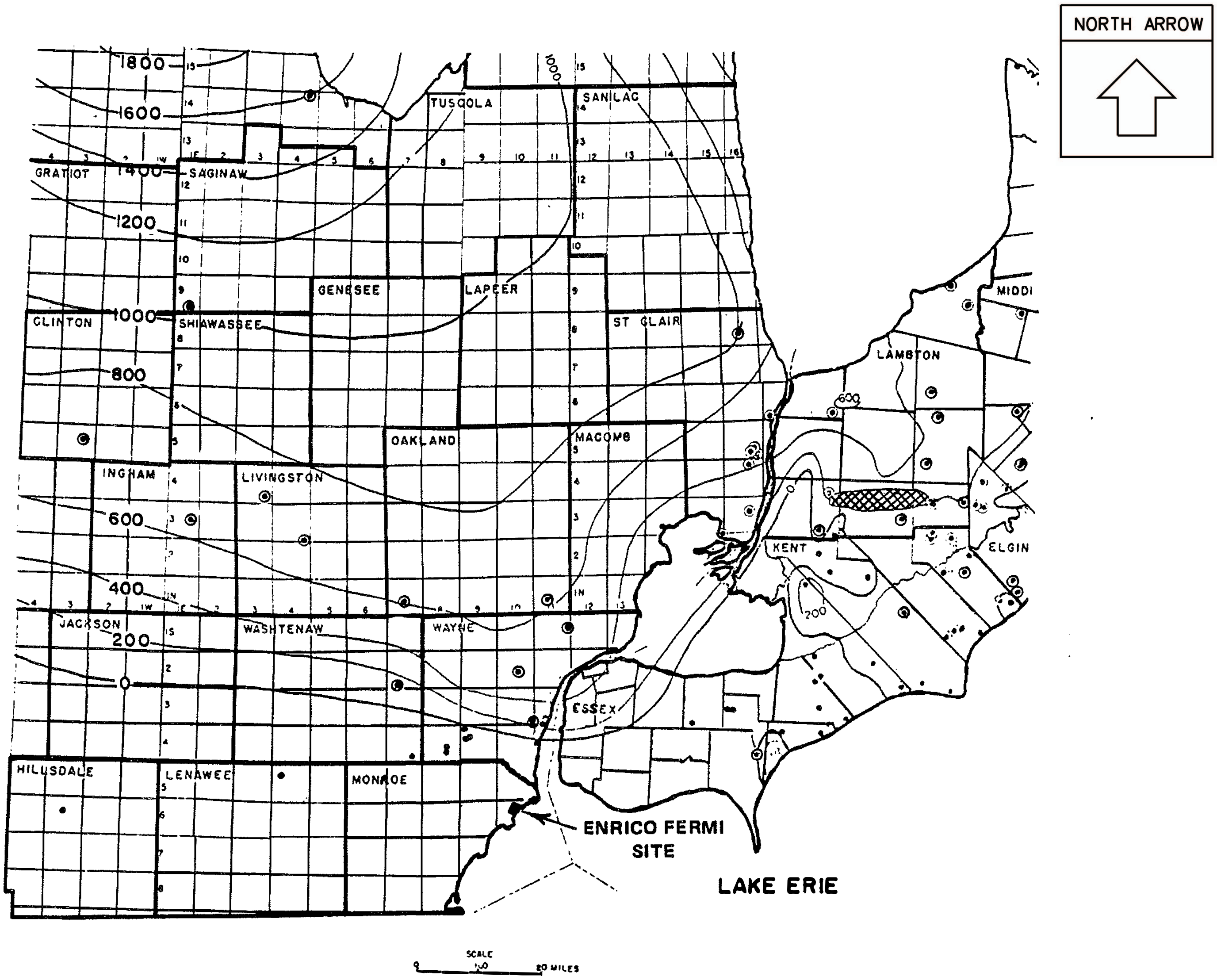
FIGURE 2.5-20

SUBSURFACE SECTION F-F' FROM FIGURE 2.5-14



LEGEND:
ISOPACH SHOWING TOTAL THICKNESS OF SALT. ISOPACH INTERVAL 200 FEET.

- ◉ WELL REPORTING SALT IN SALINA FORMATION
- • WELL WITH NO SALT IN SALINA FORMATION
- DAWN GAS FIELD, SALT 0 TO OVER 300 FEET THICK

0 10 20
SCALE IN MILES

REFERENCE:
LANDES, K. K., 1945, THE SALINA AND BASS ISLANDS ROCK IN THE MICHIGAN BASIN: USGS., PRELIMINARY DM-40, OIL AND GAS INV. SER.

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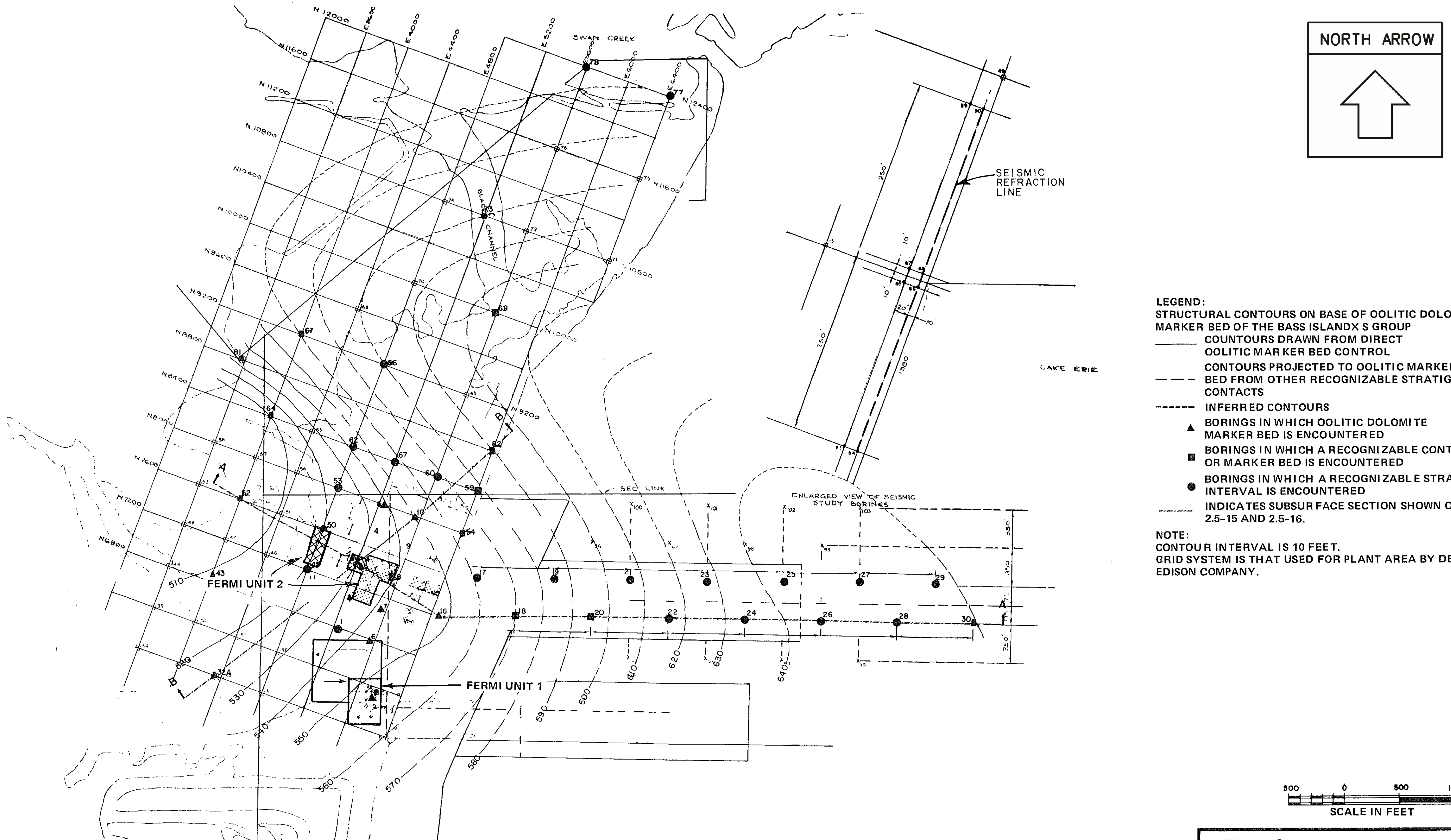
FIGURE 2.5-21

ISOPACH MAP – TOTAL THICKNESS OF SALT IN SALINA FORMATION IN SOUTHEASTERN MICHIGAN



LEGEND:
STRUCTURAL CONTOURS ON BASE OF OOLITIC DOLOMITE MARKER MARKER BED OF THE BASS ISLANDX S GROUP
COUNTOURS DRAWN FROM DIRECT OOLITIC MAR KER BED CONTROL
CONTOURS PROJECTED TO OOLITIC MARKER BED FROM OTHER RECOGNIZABLE STRATIGRAPHIC CONTACTS
INFERRED CONTOURS
BORINGS IN WHICH OOLITIC DOLOMITE MARKER BED IS ENCOUNTERED
BORINGS IN WHICH A RECOGNIZABLE CONTACT OR MARKER BED IS ENCOUNTERED
BORINGS IN WHICH A RECOGNIZABLE STRATIGRAPHIC INTERVAL IS ENCOUNTERED
INDICATES SUBSUR FACE SECTION SHOWN ON FIGURES 2.5-15 AND 2.5-16.

NOTE:
CONTOUR INTERVAL IS 10 FEET.
GRID SYSTEM IS THAT USED FOR PLANT AREA BY DETROIT EDISON COMPANY.

REFERENCE:
MAP PREPARED FROM DRAWING 6MS721-40 BY THE DETROIT EDISON COMPANY ENGINEERING DESIGN AND SERVICES DEPARTMENT.

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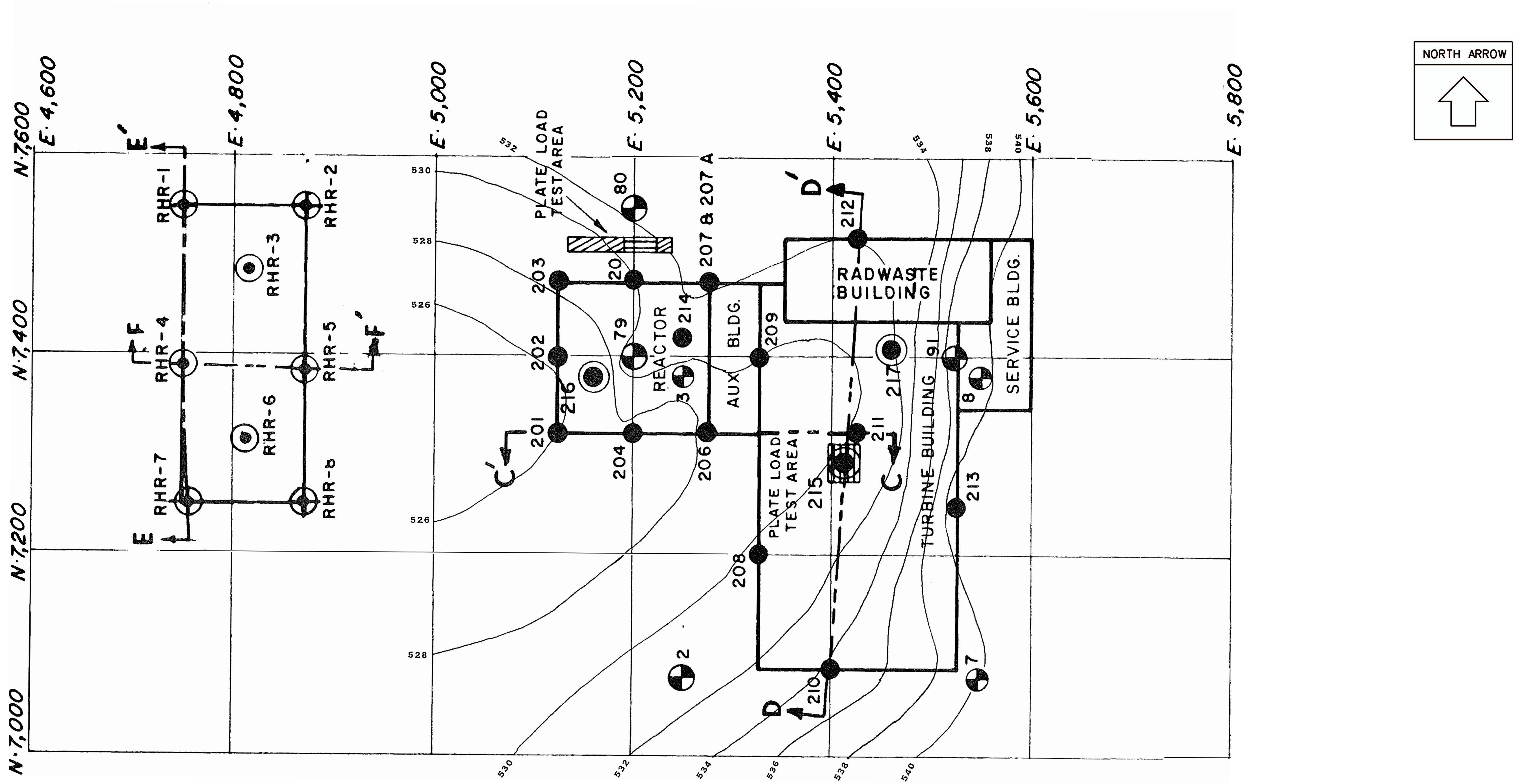
FIGURE 2.5-22

STRUCTURAL CONTOUR MAP OF SITE VICINITY



LEGEND:

540 STRUCTURAL CONTOURS ON THE BASE OF THE OOLITIC DOLOMITE MARKER BED OF THE BASS ISLANDS GROUP

BORINGS DRILLED IN 1968; OOLITIC MARKER BED ENCOUNTERED

BORINGS DRILLED IN 1969; OOLITIC MARKER BED ENCOUNTERED

INDICATES SUBSURFACE SECTION

BORINGS DRILLED IN 1968 (LOG NOT PRESENTED WITH REPORT)

0 50 100 200

SCALE IN FEET

NOTE:

CONTOUR INTERVAL IS TWO FEET
ELEVATIONS REFER TO U.S.G.S. DATUM

REFERENCE 45
PLATE 1

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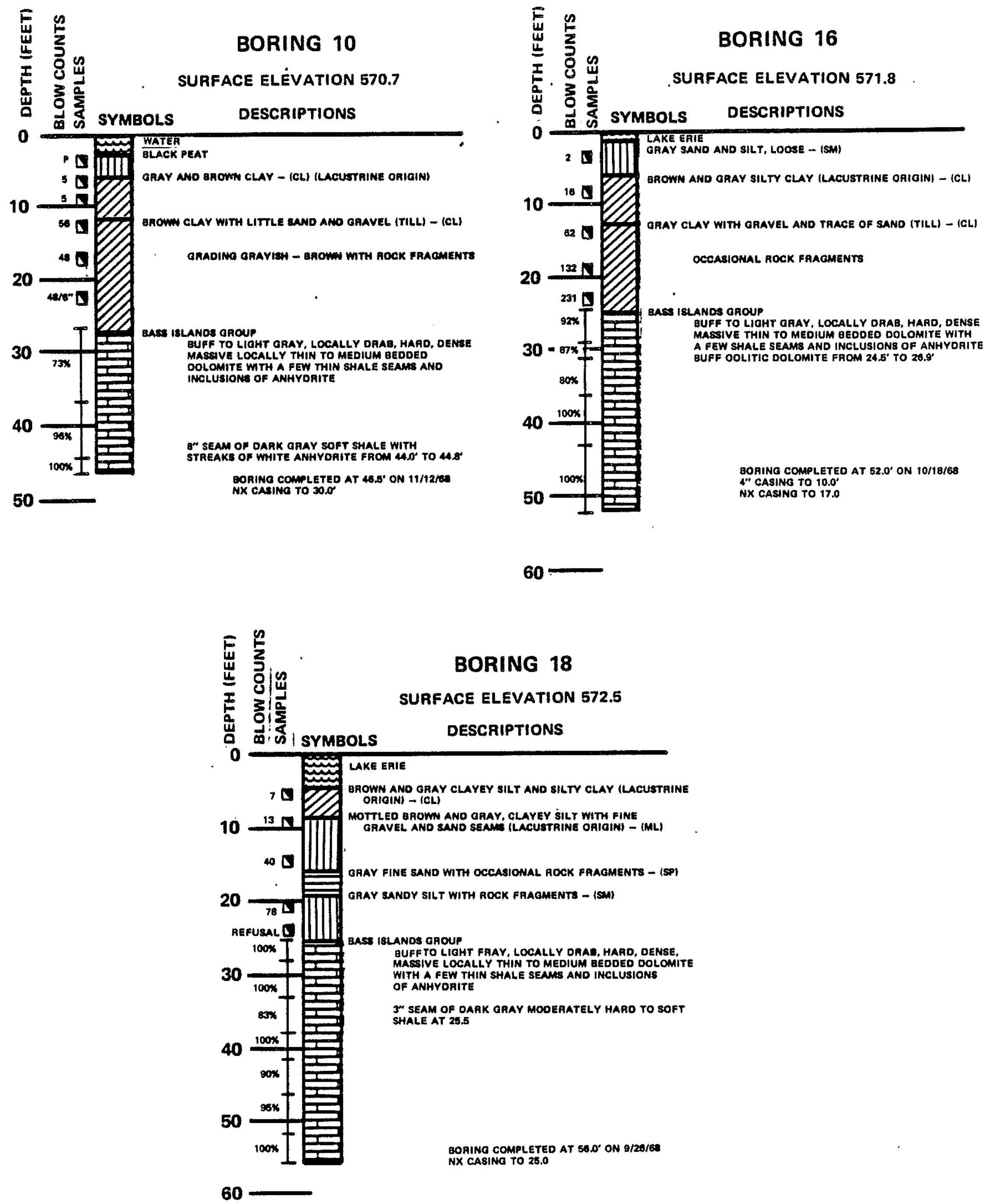
FIGURE 2.5-23

STRUCTURAL CONTOUR MAP OF SPECIFIC SITE AREA



NOTES:

ALL ELEVATIONS REFER TO NEW YORK MEAN TIDE, 1935

INDICATES STANDARD PENETRATION TEST. FIGURES UNDER THE BLOW COUNT COLUMN INDICATE THE NUMBER OF BLOWS REQUIRED TO DRIVE A SAMPLER, WITH AN OUTSIDE DIAMETER TO TWO INCHES, ONE FOOT WITH A 140 POUND WEIGHT FALLING 30 INCHES.

INDICATES A SAMPLING ATTEMPT WITH NO RECOVERY.

100% INDICATES DEPTH, LENGTH, AND PERCENT OF CORE RUN RECOVERED.

ALL CORE WAS NX SIZE EXCEPT WHERE NOTED.

REFERENCE:
FERMI 2 PSAR – FIGURE 2.5-4.1

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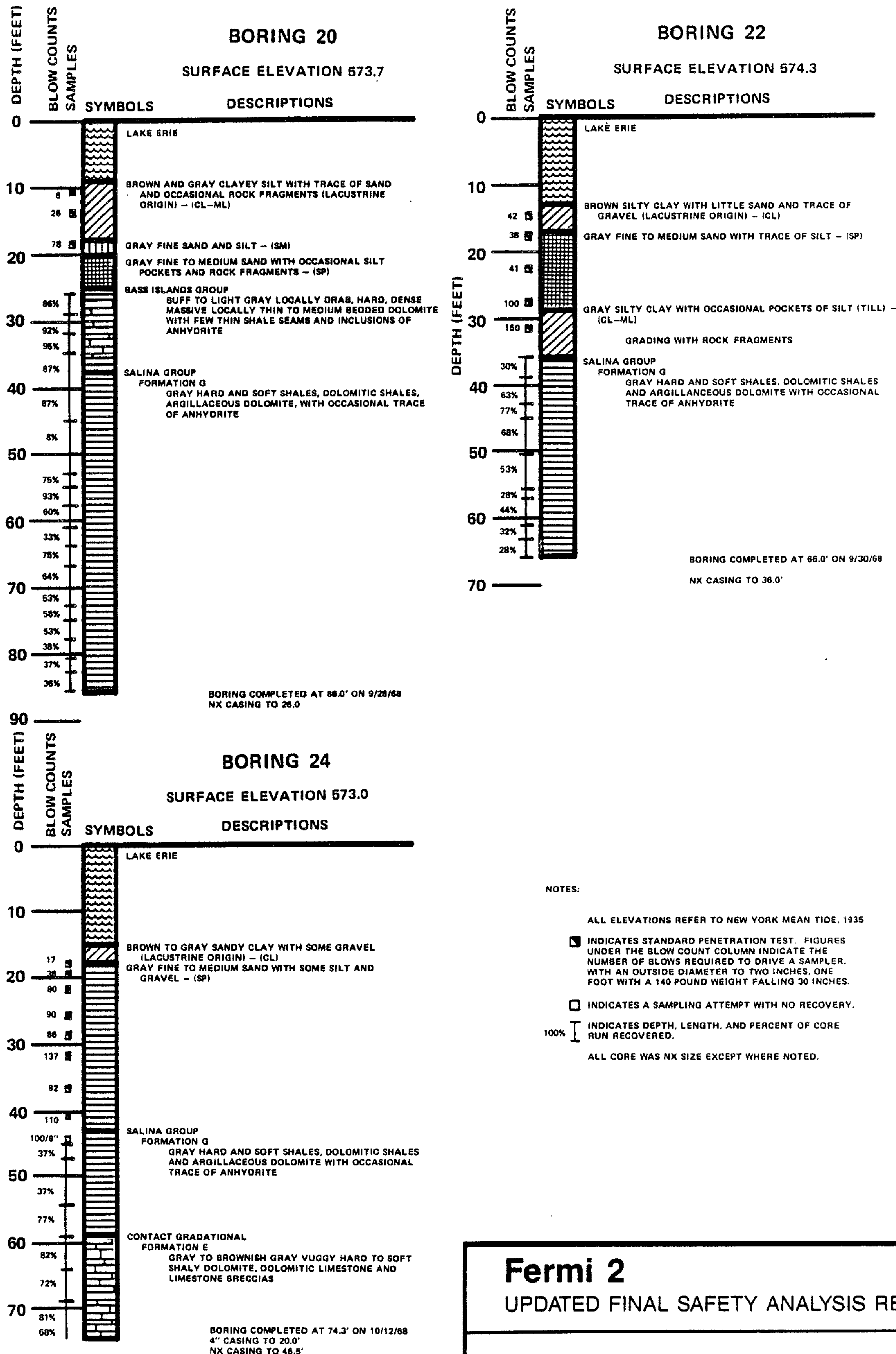
FIGURE 2.5-24

LOGS OF BORINGS 10, 16, AND 18



REFERENCE:
FERMI 2 PSAR – FIGURE 2.5-4.2

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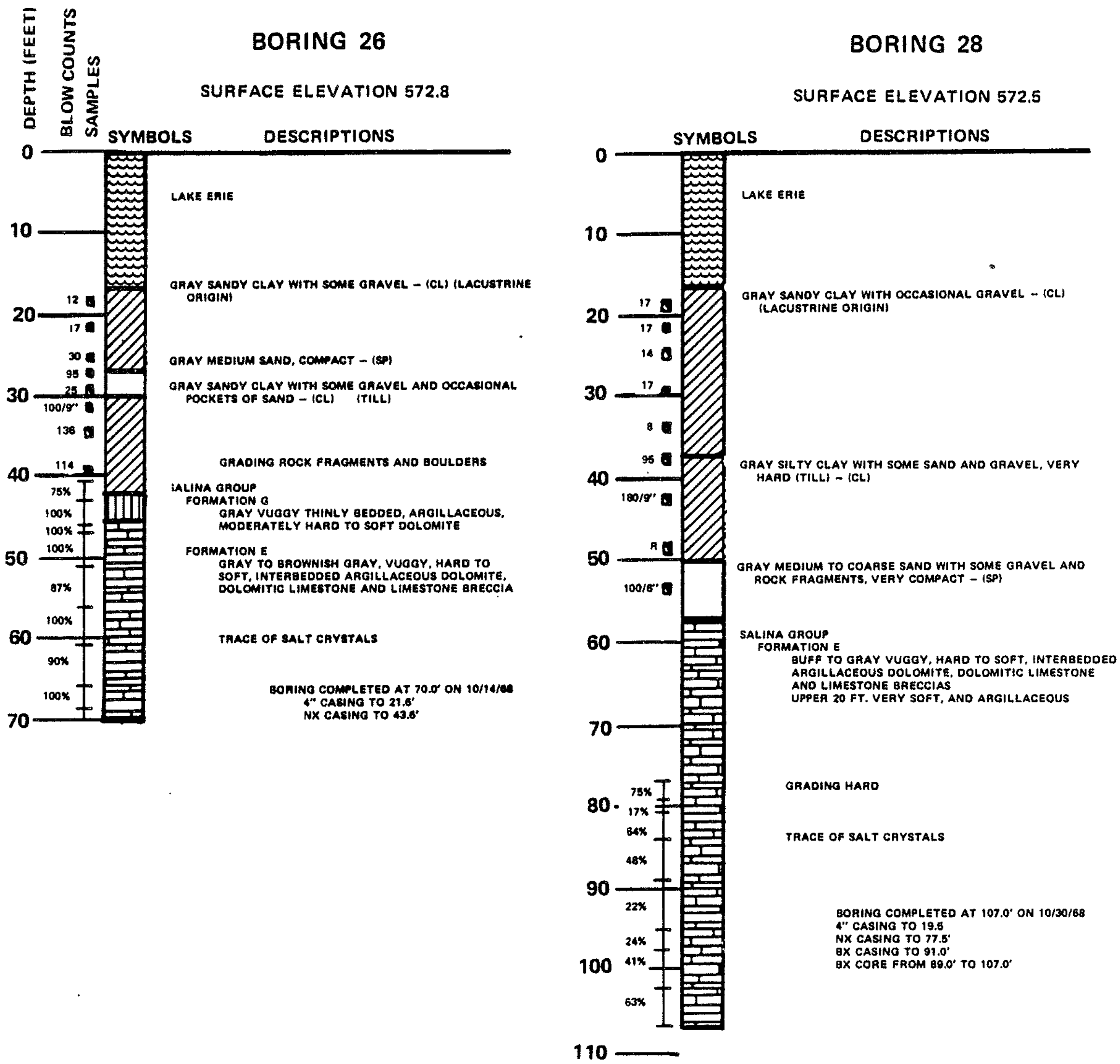
FIGURE 2.5-25

LOGS OF BORINGS 20, 22, AND 24



NOTES:

ALL ELEVATIONS REFER TO NEW YORK MEAN TIDE, 1935

INDICATES STANDARD PENETRATION TEST. FIGURES UNDER THE BLOW COUNT COLUMN INDICATE THE NUMBER OF BLOWS REQUIRED TO DRIVE A SAMPLER, WITH AN OUTSIDE DIAMETER OF TWO INCHES, ONE FOOT WITH A 140 POUND WEIGHT FALLING 30 INCHES.

INDICATES A SAMPLING ATTEMPT WITH NO RECOVERY.

100% INDICATES DEPTH, LENGTH, AND PERCENT OF CORE RUN RECOVERED.

ALL CORE WAS NX SIZE EXCEPT WHERE NOTED.

REFERENCE:
FERMI 2 PSAR – FIGURE 2.5-4.3

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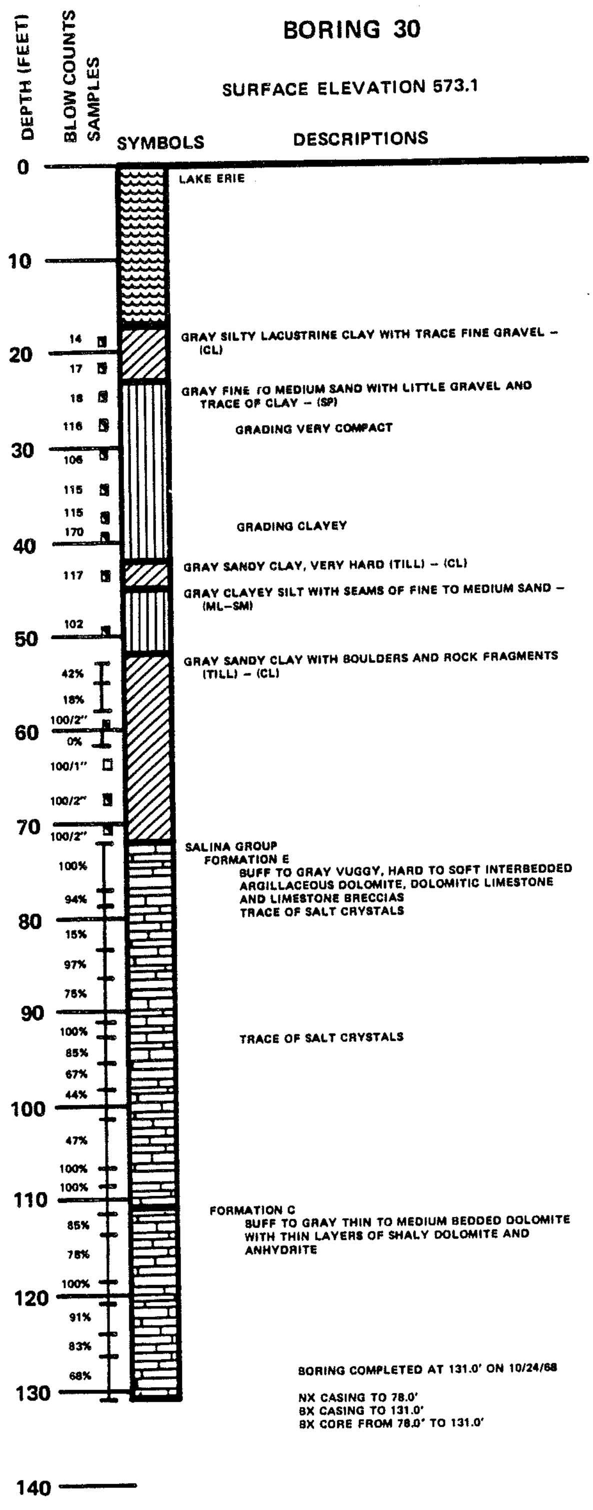
FIGURE 2.5-26

LOGS OF BORINGS 26 AND 28



NOTES:

ALL ELEVATIONS REFER TO NEW YORK MEAN TIDE, 1935

■ INDICATES STANDARD PENETRATION TEST. FIGURES UNDER THE BLOW COUNT COLUMN INDICATE THE NUMBER OF BLOWS REQUIRED TO DRIVE A SAMPLER, WITH AN OUTSIDE DIAMETER OF TWO INCHES, ONE FOOT WITH A 140 POUND WEIGHT FALLING 30 INCHES.

□ INDICATES A SAMPLING ATTEMPT WITH NO RECOVERY.

100% INDICATES DEPTH, LENGTH, AND PERCENT OF CORE RUN RECOVERED.

ALL CORE WAS NX SIZE EXCEPT WHERE NOTED.

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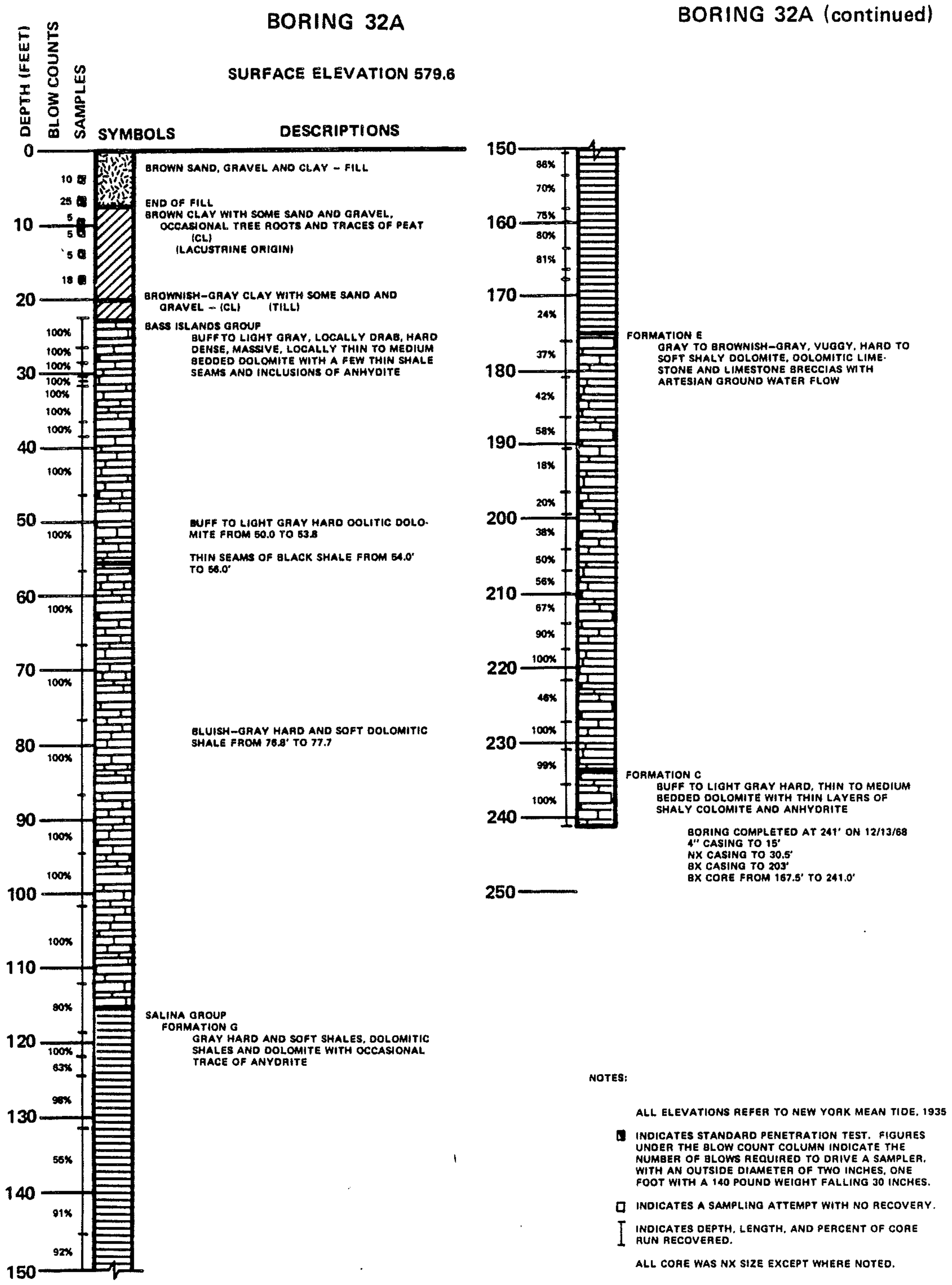
FIGURE 2.5-27

LOG OF BORING 30

REFERENCE:
FERMI 2 PSAR – FIGURE 2.5-4.4



REFERENCE:
FERMI 2 PSAR – FIGURE 2.5-4.5

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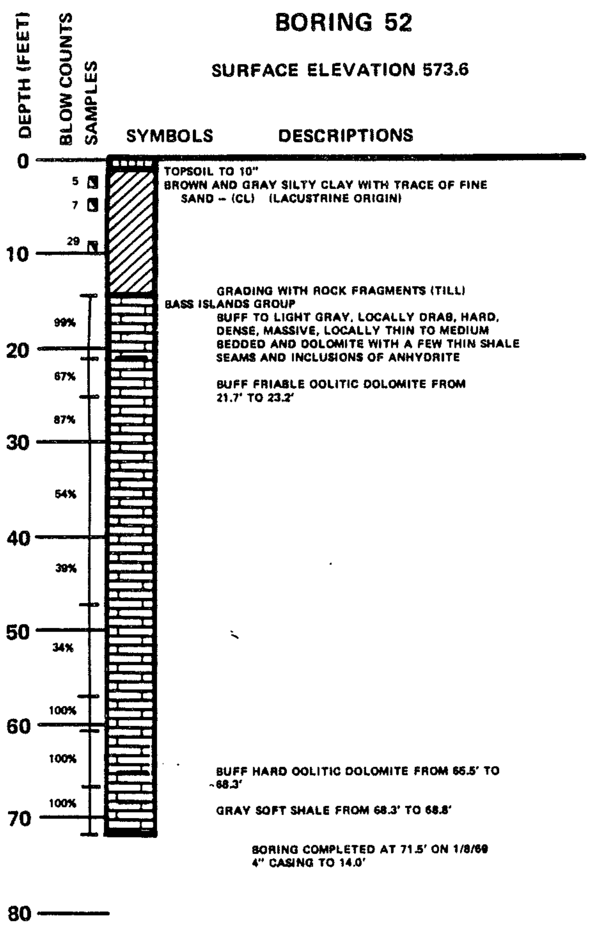
FIGURE 2.5-28

LOG OF BORING 32A



NOTES:

ALL ELEVATIONS REFER TO NEW YORK MEAN TIDE, 1935

INDICATES STANDARD PENETRATION TEST, FIGURES UNDER THE BLOW COUNT COLUMN INDICATE THE NUMBER OF BLOWS REQUIRED TO DRIVE A SAMPLER, WITH AN OUTSIDE DIAMETER OF TWO INCHES, ONE FOOT WITH A 140 POUND WEIGHT FALLING 30 INCHES.

INDICATES A SAMPLING ATTEMPT WITH NO RECOVERY.

100% INDICATES DEPTH, LENGTH, AND PERCENT OF CORE RUN RECOVERED.

ALL CORE WAS NX SIZE EXCEPT WHERE NOTED.

REFERENCE:
FERMI 2 PSAR – FIGURE 2.5-4.6

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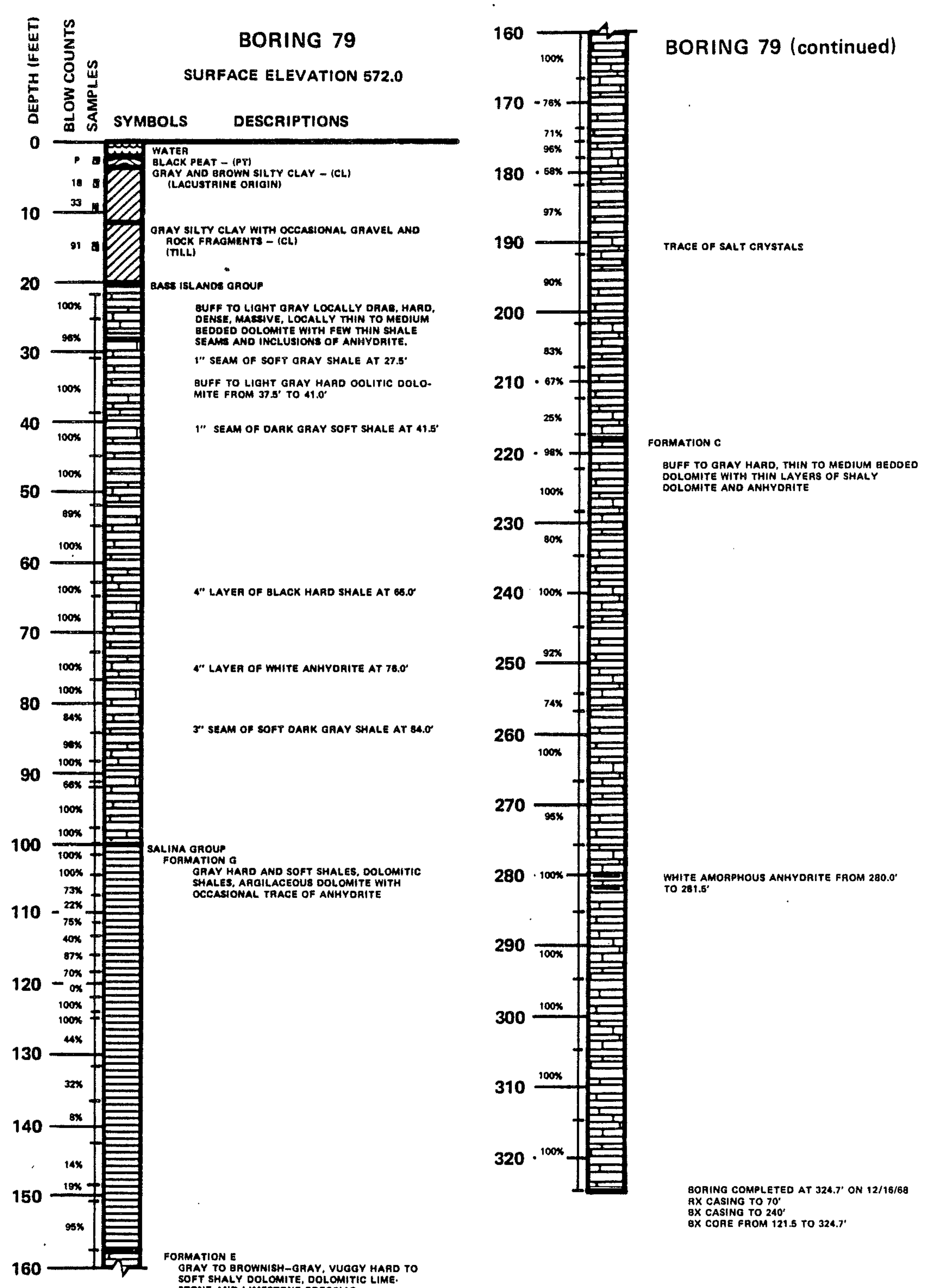
FIGURE 2.5-29

LOG OF BORING 52



NOTES:

ALL ELEVATIONS REFER TO NEW YORK MEAN TIDE, 1935

■ INDICATES STANDARD PENETRATION TEST. FIGURES UNDER THE BLOW COUNT COLUMN INDICATE THE NUMBER OF BLOWS REQUIRED TO DRIVE A SAMPLER, WITH AN OUTSIDE DIAMETER TO TWO INCHES, ONE FOOT WITH A 140 POUND WEIGHT FALLING 30 INCHES.

□ INDICATES A SAMPLING ATTEMPT WITH NO RECOVERY.

100% INDICATES DEPTH, LENGTH, AND PERCENT OF CORE RUN RECOVERED.

ALL CORE WAS NX SIZE EXCEPT WHERE NOTED.

REFERENCE:
FERMI 2 PSAR – FIGURE 2.5-4.7

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FIGURE 2.5-30

LOG OF BORING 79

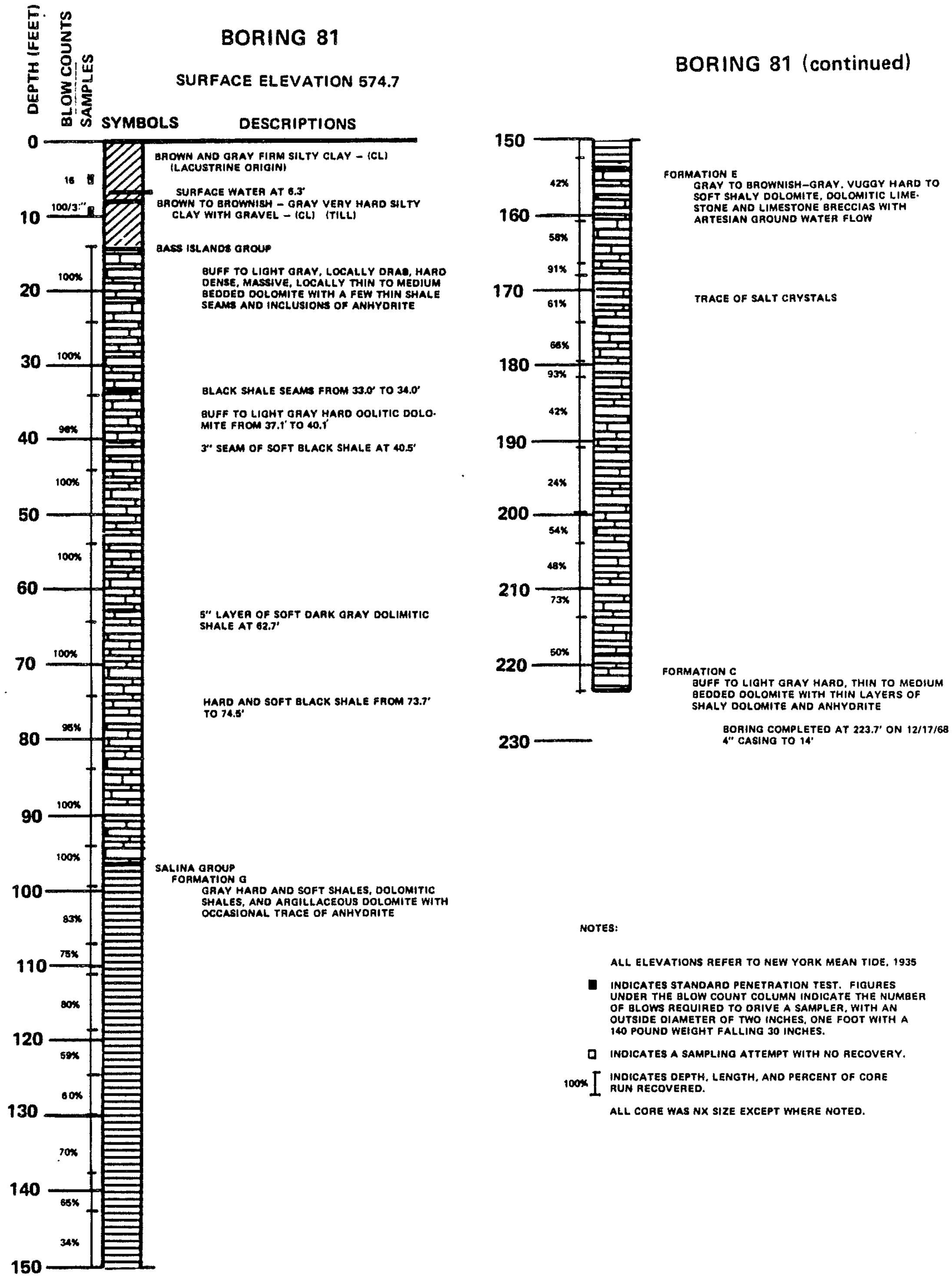

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FIGURE 2.5-31

LOG OF BORING 81

REFERENCE:
FERMI 2 PSAR – FIGURE 2.5-4.8

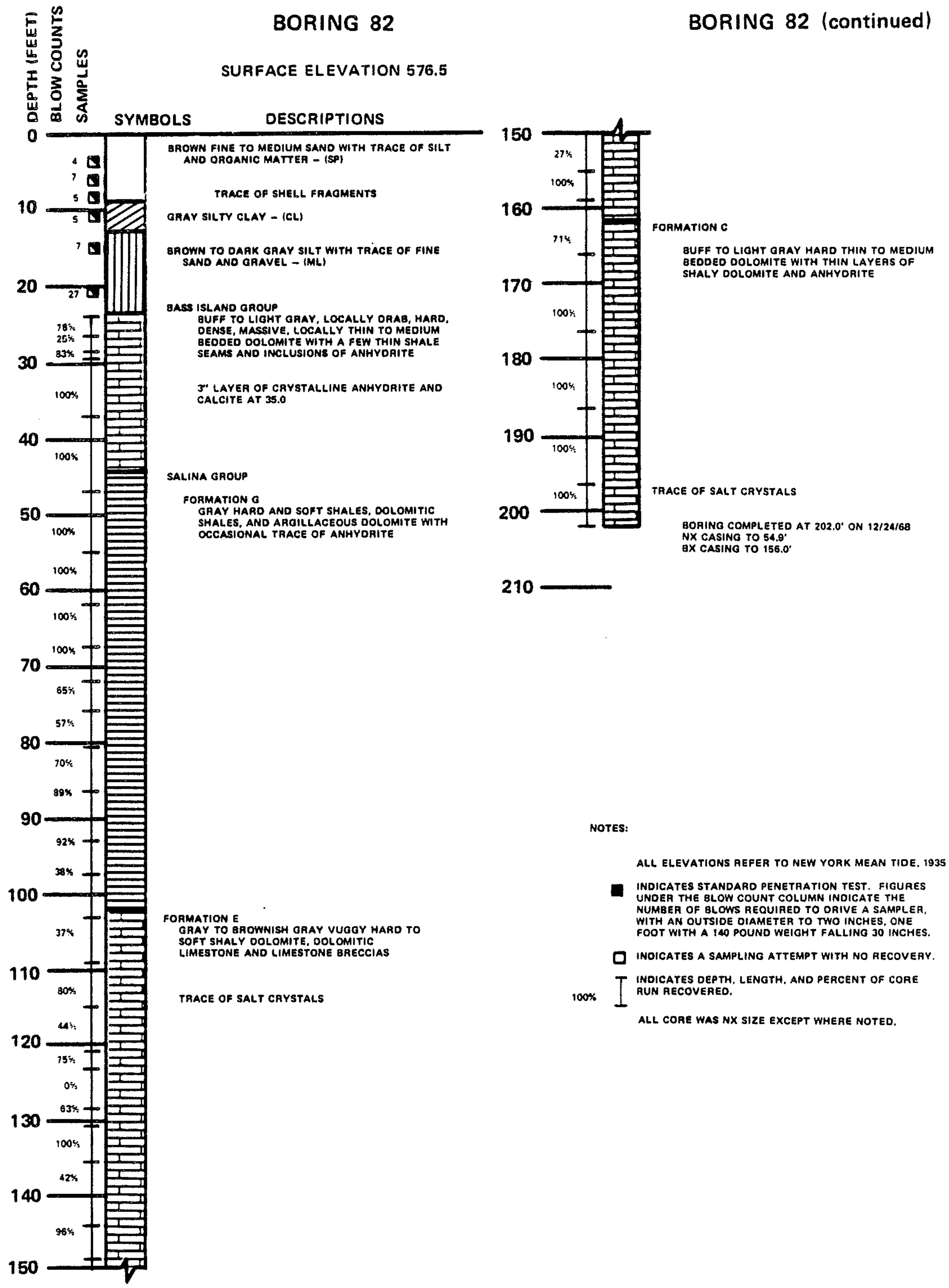

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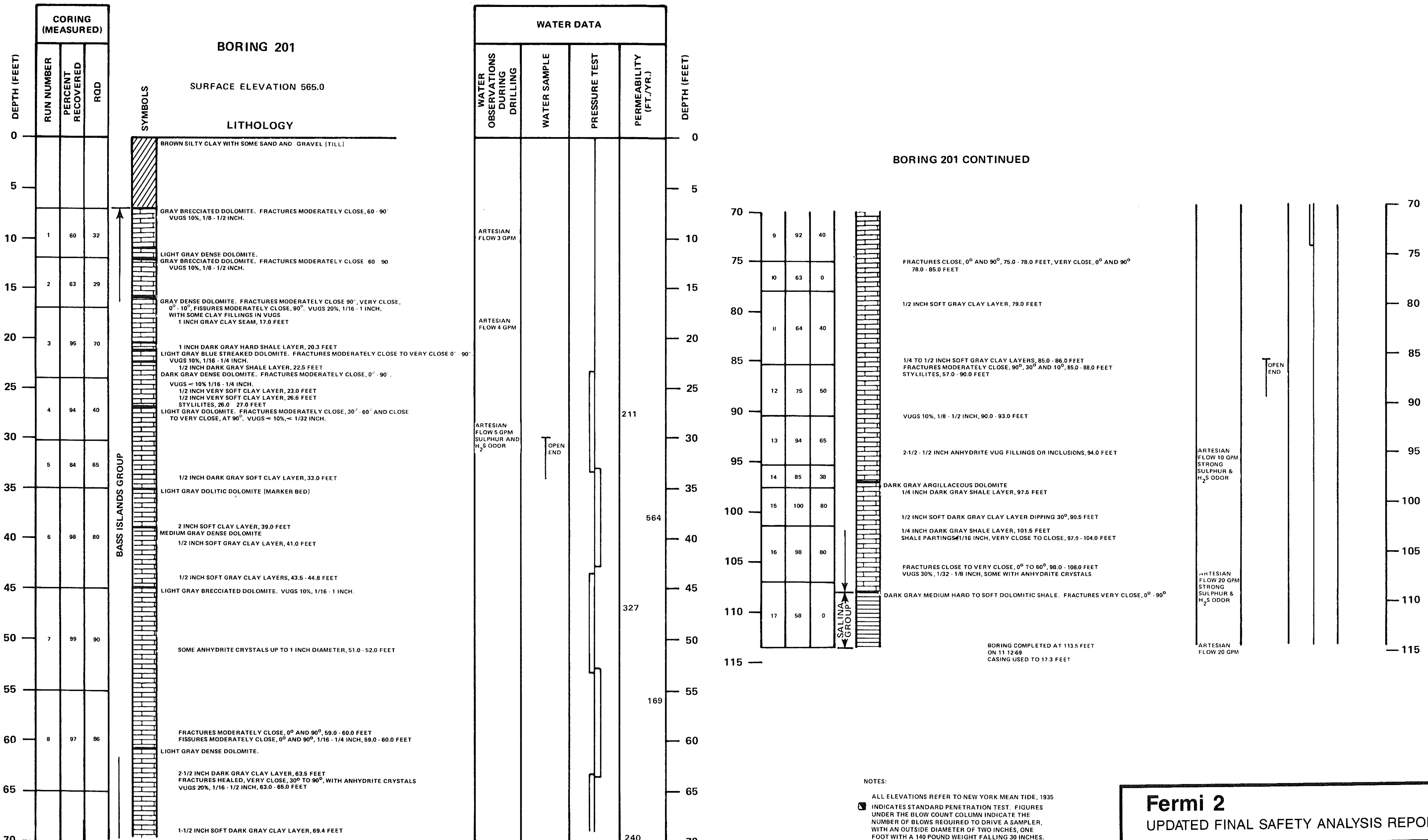
FIGURE 2.5-32

LOG OF BORING 82

REFERENCE:
FERMI 2 PSAR – FIGURE 2.5-4.9



NOTES:

ALL ELEVATIONS REFER TO NEW YORK MEAN TIDE, 1935

INDICATES STANDARD PENETRATION TEST. FIGURES UNDER THE BLOW COUNT COLUMN INDICATE THE NUMBER OF BLOWS REQUIRED TO DRIVE A SAMPLER, WITH AN OUTSIDE DIAMETER OF TWO INCHES, ONE FOOT WITH A 140 POUND WEIGHT FALLING 30 INCHES.

INDICATES A SAMPLING ATTEMPT WITH NO RECOVERY.

100% INDICATES DEPTH, LENGTH, AND PERCENT OF CORE RUN RECOVERED.

ALL CORE WAS MX SIZE EXCEPT WHERE NOTED.

REFERENCE:
DAMES & MOORE FIGURES 2.5-22.10 AND 2.5-22.11 REVISED

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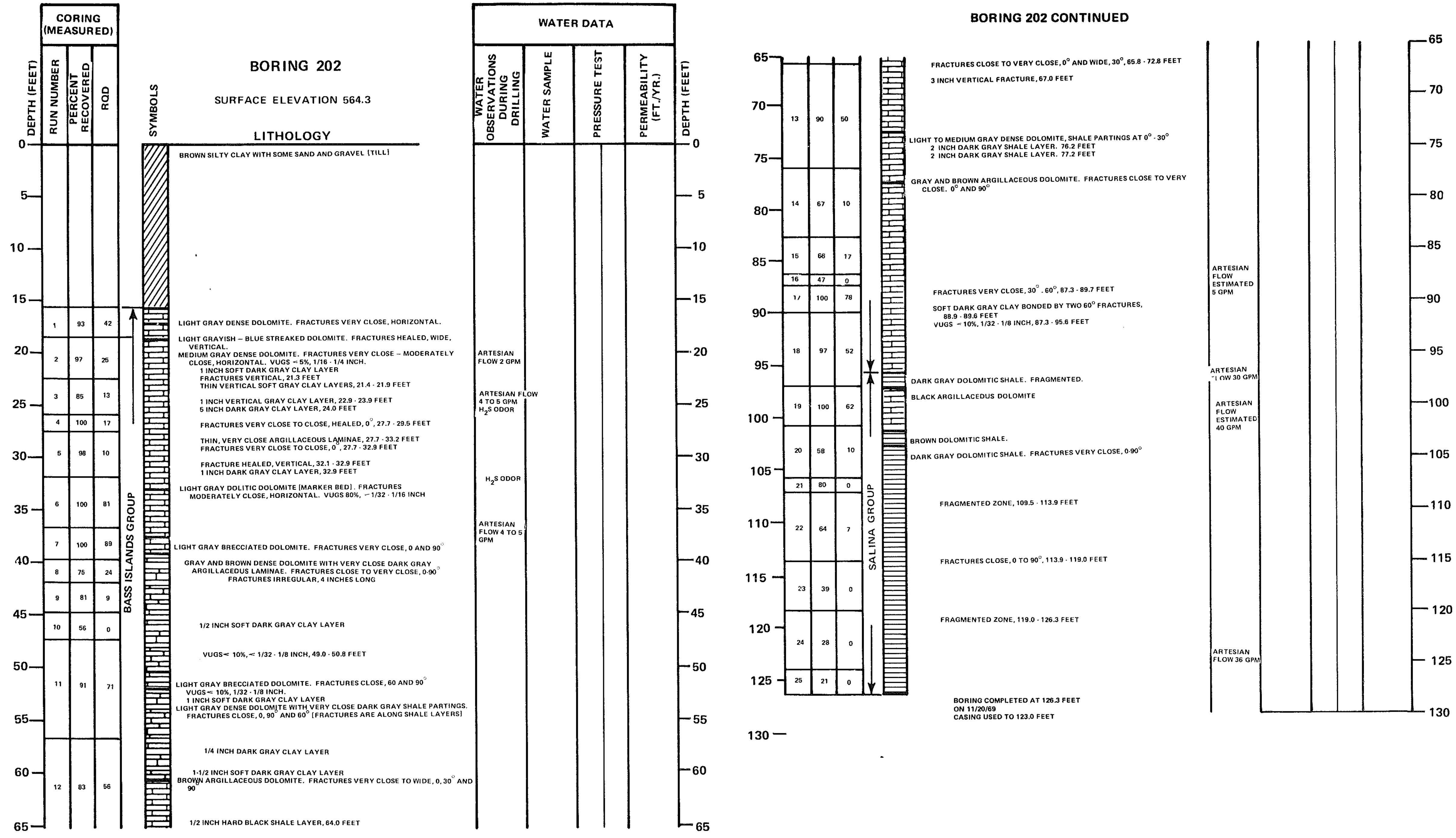
FIGURE 2.5-33

LOG OF BORING 201



NOTES:

ALL ELEVATIONS REFER TO NEW YORK MEAN TIDE, 1935

INDICATES STANDARD PENETRATION TEST. FIGURES UNDER THE BLOW COUNT COLUMN INDICATE THE NUMBER OF BLOWS REQUIRED TO DRIVE A SAMPLER, WITH AN OUTSIDE DIAMETER OF TWO INCHES, ONE FOOT WITH A 140 POUND WEIGHT FALLING 30 INCHES.

INDICATES A SAMPLING ATTEMPT WITH NO RECOVERY.

100% INDICATES DEPTH, LENGTH, AND PERCENT OF CORE RUN RECOVERED.

ALL CORE WAS MX SIZE EXCEPT WHERE NOTED.

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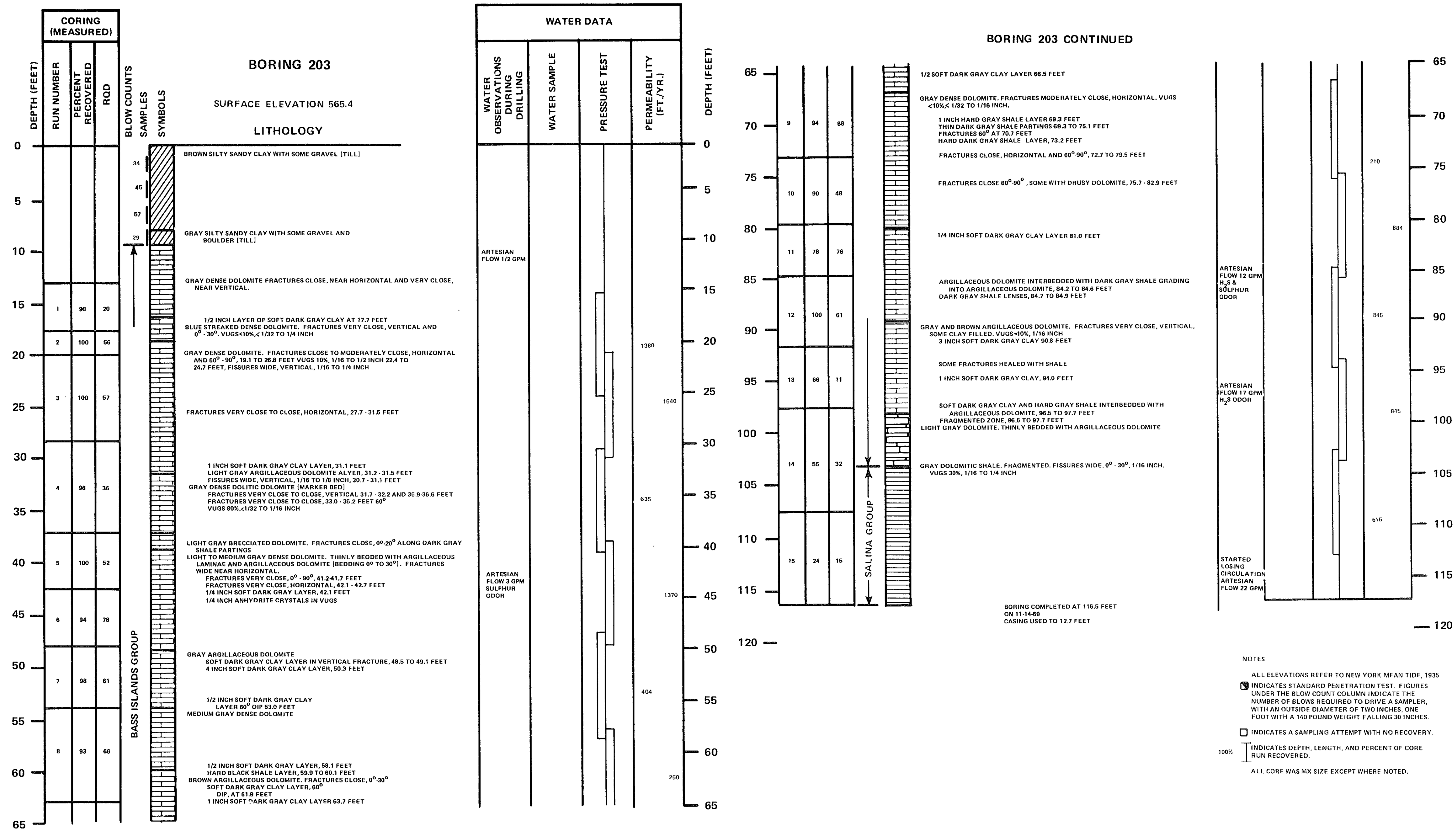
FIGURE 2.5-34

LOG OF BORING 202

REFERENCE:
DAMES & MOORE FIGURES 2.5-22.12 AND 2.5-22.13



REFERENCE:
DAMES & MOORE FIGURES 2.5-22.14 AND 2.5-22.15

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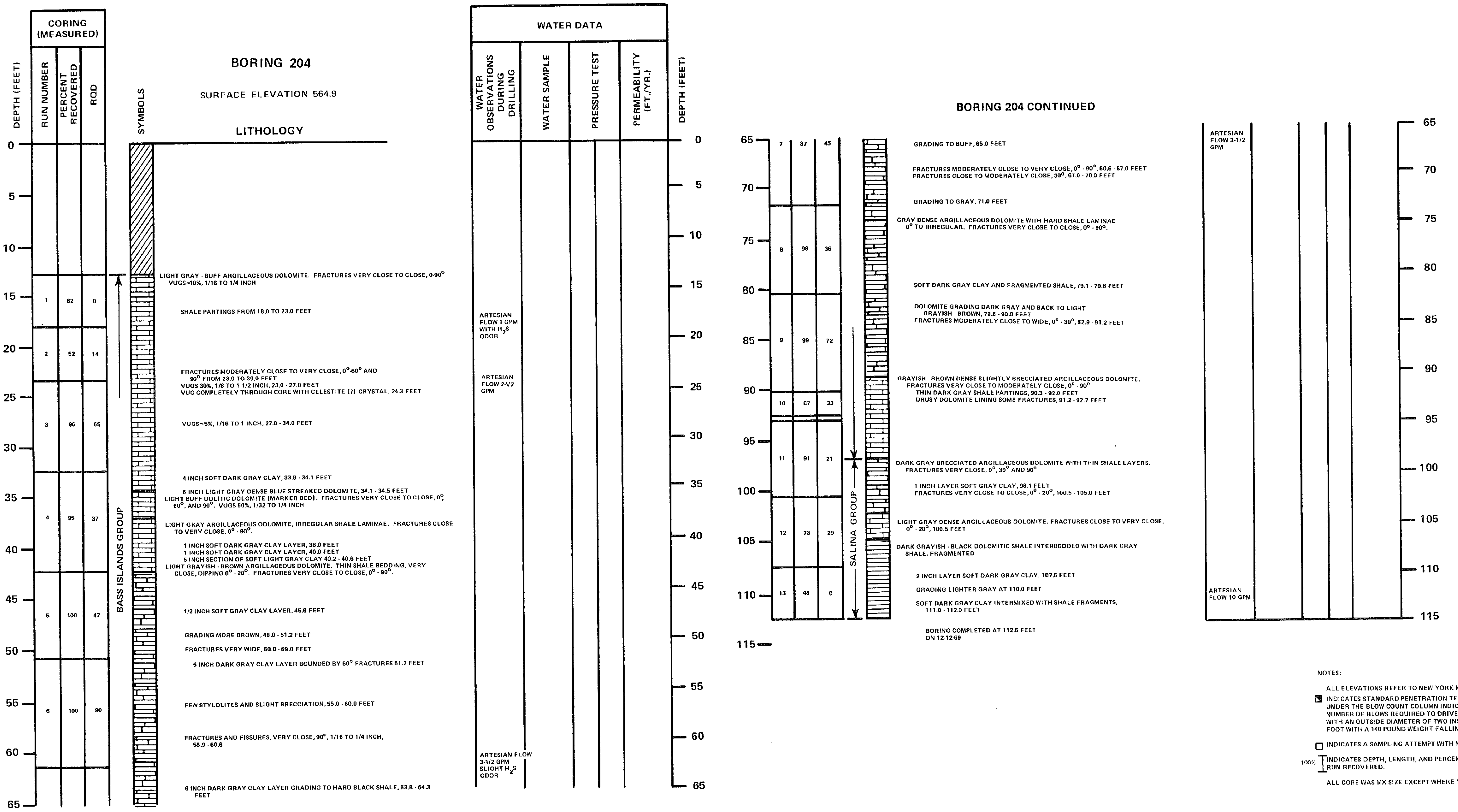
FIGURE 2.5-35

LOG OF BORING 203



NOTES:

ALL ELEVATIONS REFER TO NEW YORK MEAN TIDE, 1935

INDICATES STANDARD PENETRATION TEST. FIGURES UNDER THE BLOW COUNT COLUMN INDICATE THE NUMBER OF BLOWS REQUIRED TO DRIVE A SAMPLER, WITH AN OUTSIDE DIAMETER OF TWO INCHES, ONE FOOT WITH A 140 POUND WEIGHT FALLING 30 INCHES.

INDICATES A SAMPLING ATTEMPT WITH NO RECOVERY.

100% INDICATES DEPTH, LENGTH, AND PERCENT OF CORE RUN RECOVERED.

ALL CORE WAS MX SIZE EXCEPT WHERE NOTED.

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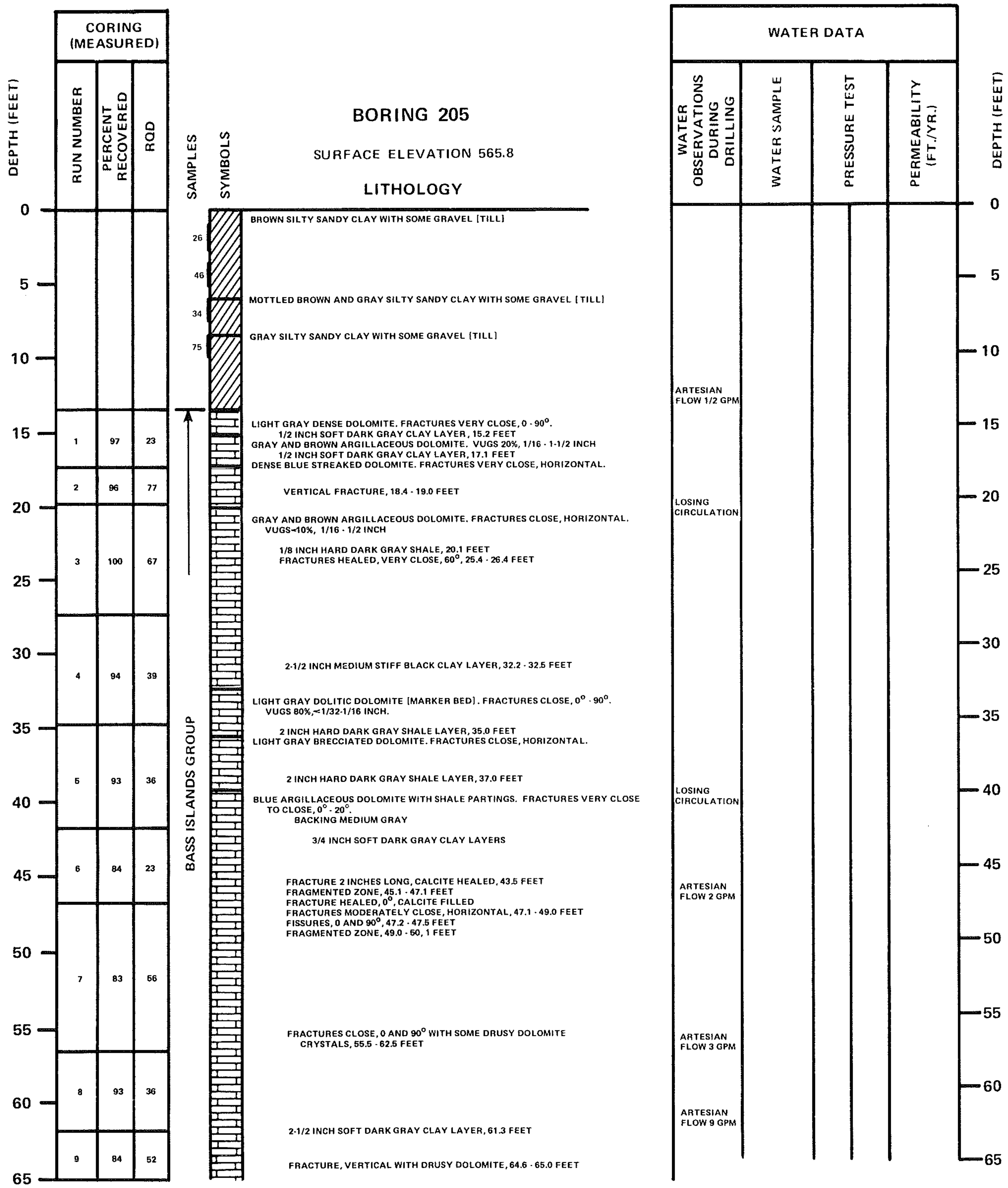
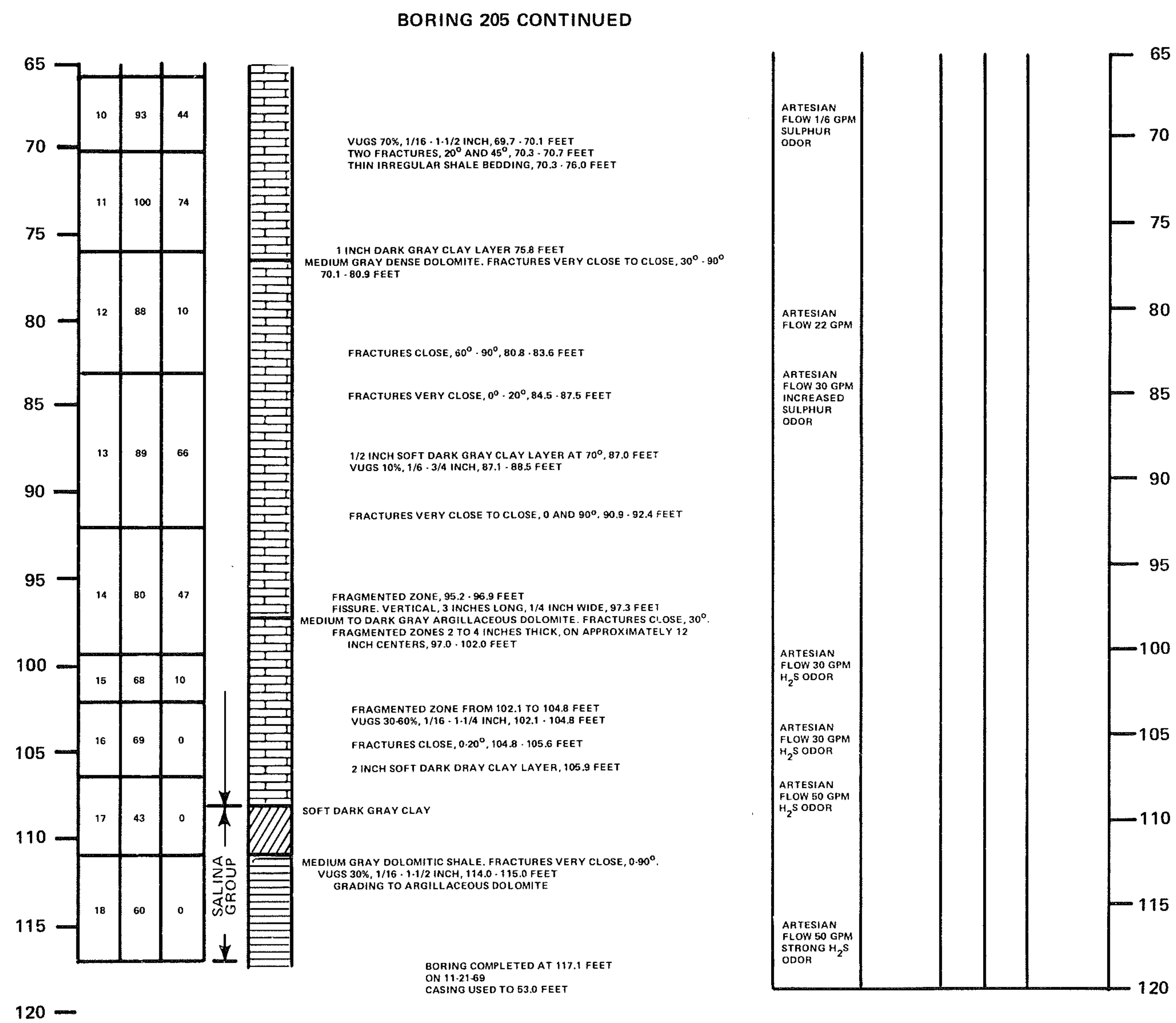
FIGURE 2.5-36

LOG OF BORING 204

REFERENCE:
DAMES & MOORE FIGURES 2.5-22.16 AND 2.5-22.17





NOTES:

ALL ELEVATIONS REFER TO NEW YORK MEAN TIDE, 1935

INDICATES STANDARD PENETRATION TEST. FIGURES UNDER THE BLOW COUNT COLUMN INDICATE THE NUMBER OF BLOWS REQUIRED TO DRIVE A SAMPLER, WITH AN OUTSIDE DIAMETER OF TWO INCHES, ONE FOOT WITH A 140 POUND WEIGHT FALLING 30 INCHES.

INDICATES A SAMPLING ATTEMPT WITH NO RECOVERY.

100% INDICATES DEPTH, LENGTH, AND PERCENT OF CORE RUN RECOVERED.

ALL CORE WAS MX SIZE EXCEPT WHERE NOTED.

REFERENCE:
DAMES & MOORE FIGURES 2.5-22.18 AND 2.5-22.19

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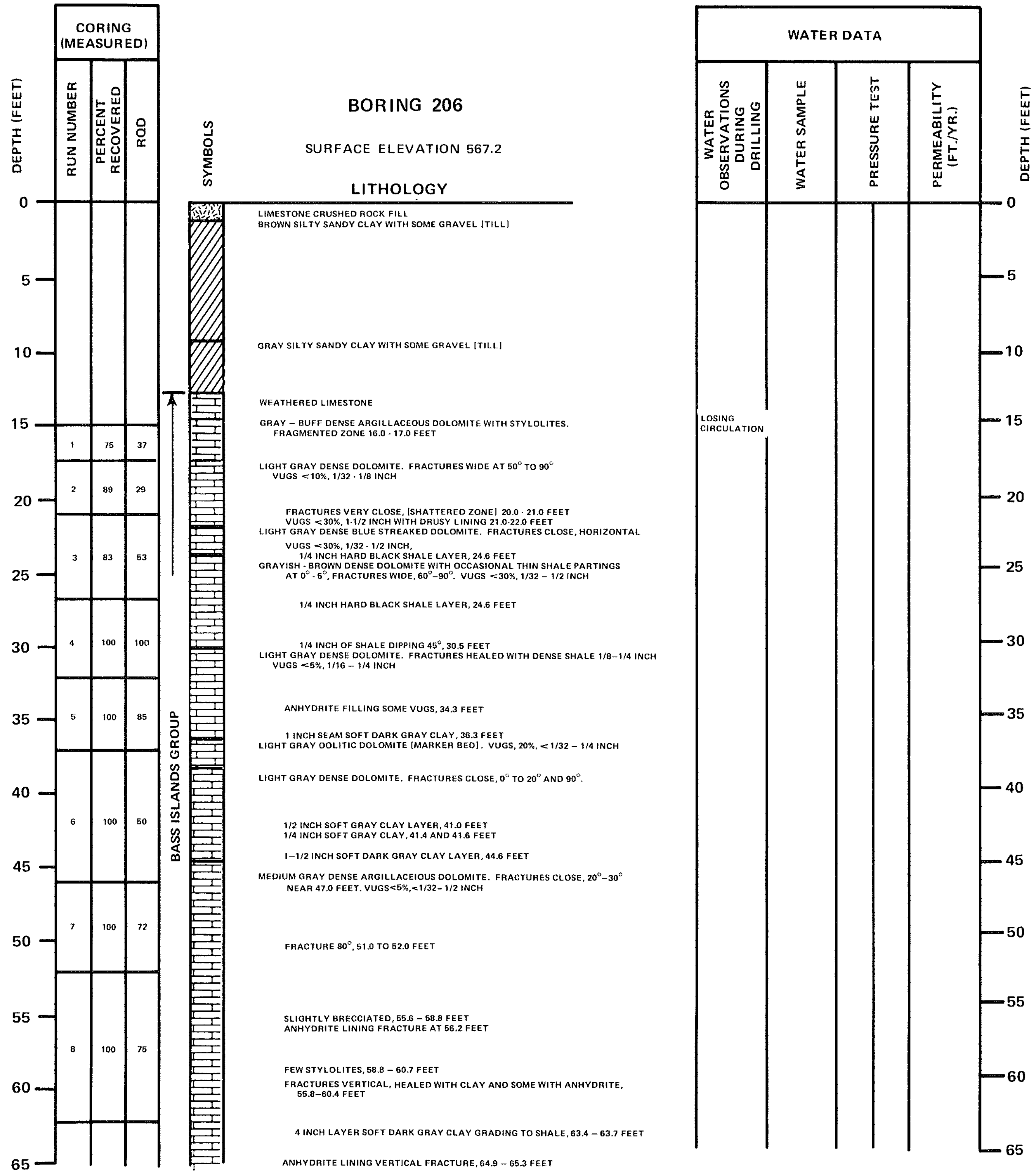
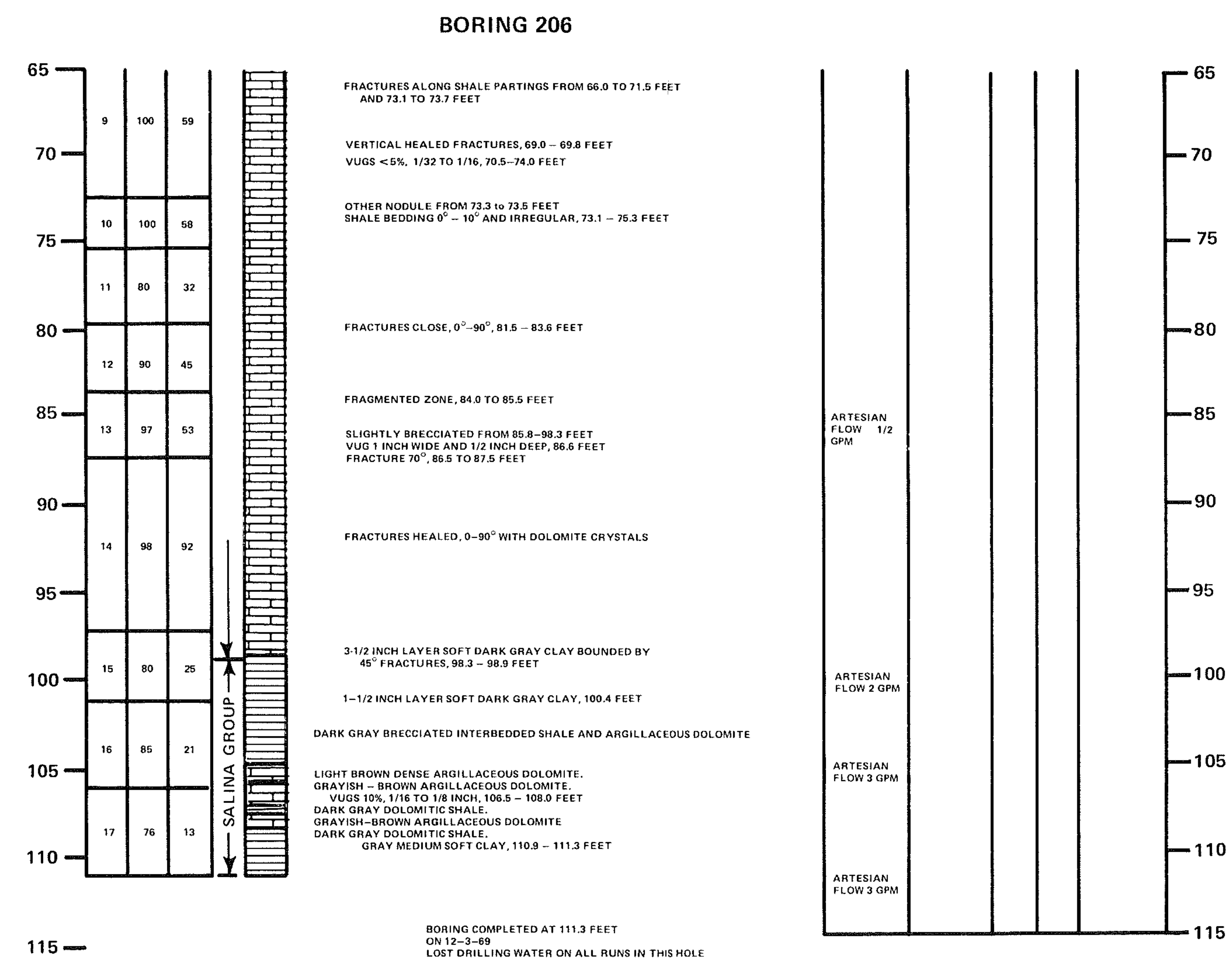
FIGURE 2.5-37

LOG OF BORING 205





NOTES:

ALL ELEVATIONS REFER TO NEW YORK MEAN TIDE, 1935

INDICATES STANDARD PENETRATION TEST. FIGURES UNDER THE BLOW COUNT COLUMN INDICATE THE NUMBER OF BLOWS REQUIRED TO DRIVE A SAMPLER, WITH AN OUTSIDE DIAMETER OF TWO INCHES, ONE FOOT WITH A 140 POUND WEIGHT FALLING 30 INCHES.

INDICATES A SAMPLING ATTEMPT WITH NO RECOVERY.

100% INDICATES DEPTH, LENGTH, AND PERCENT OF CORE RUN RECOVERED.

ALL CORE WAS MX SIZE EXCEPT WHERE NOTED.

REFERENCE:
DAMES & MOORE FIGURES 2.5-22.20 AND 2.5-22.21

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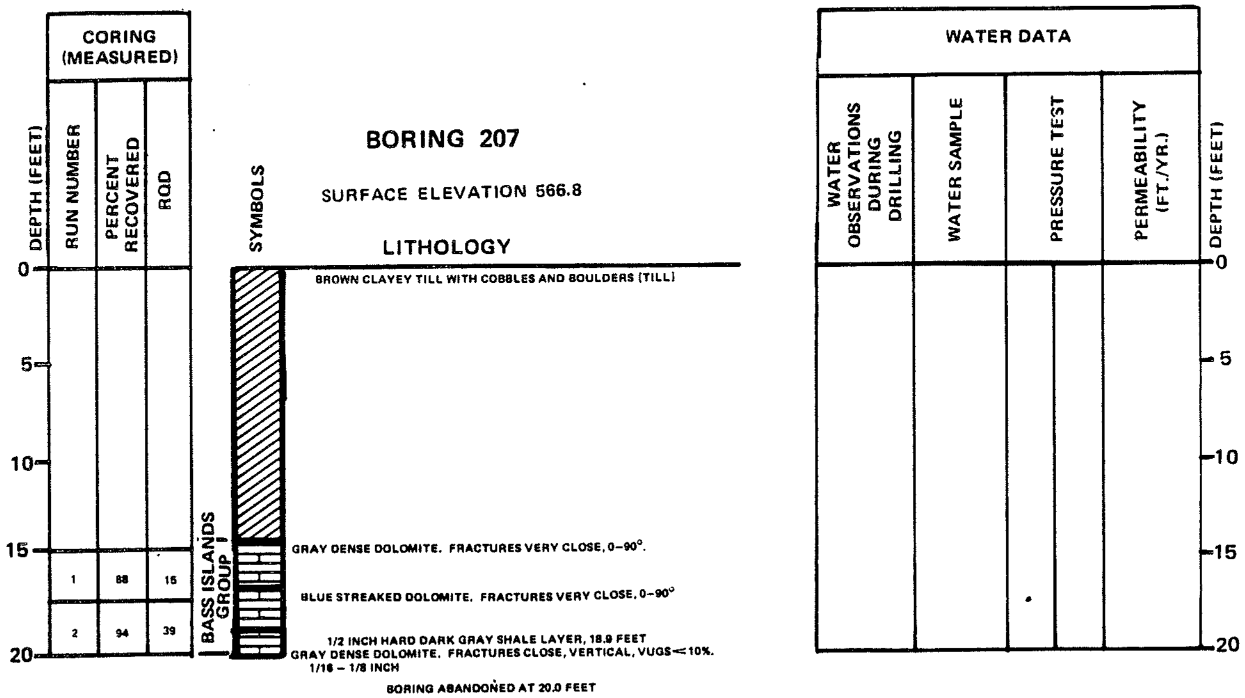
FIGURE 2.5-38

LOG OF BORING 206



NOTES:

ALL ELEVATIONS REFER TO NEW YORK MEAN TIDE, 1935

INDICATES STANDARD PENETRATION TEST. FIGURES UNDER THE BLOW COUNT COLUMN INDICATE THE NUMBER OF BLOWS REQUIRED TO DRIVE A SAMPLER WITH AN OUTSIDE DIAMETER OF TWO INCHES, ONE FOOT WITH A 140 POUND WEIGHT FALLING 30 INCHES

INDICATES A SAMPLING ATTEMPT WITH NO RECOVERY

100% INDICATES DEPTH, LENGTH, AND PERCENT OF CORE RUN RECOVERED.

ALL CORE WAS MX SIZE EXCEPT WHERE NOTED

REFERENCE:
DAMES & MOORE FIGURE 2.5-22.22

Fermi 2
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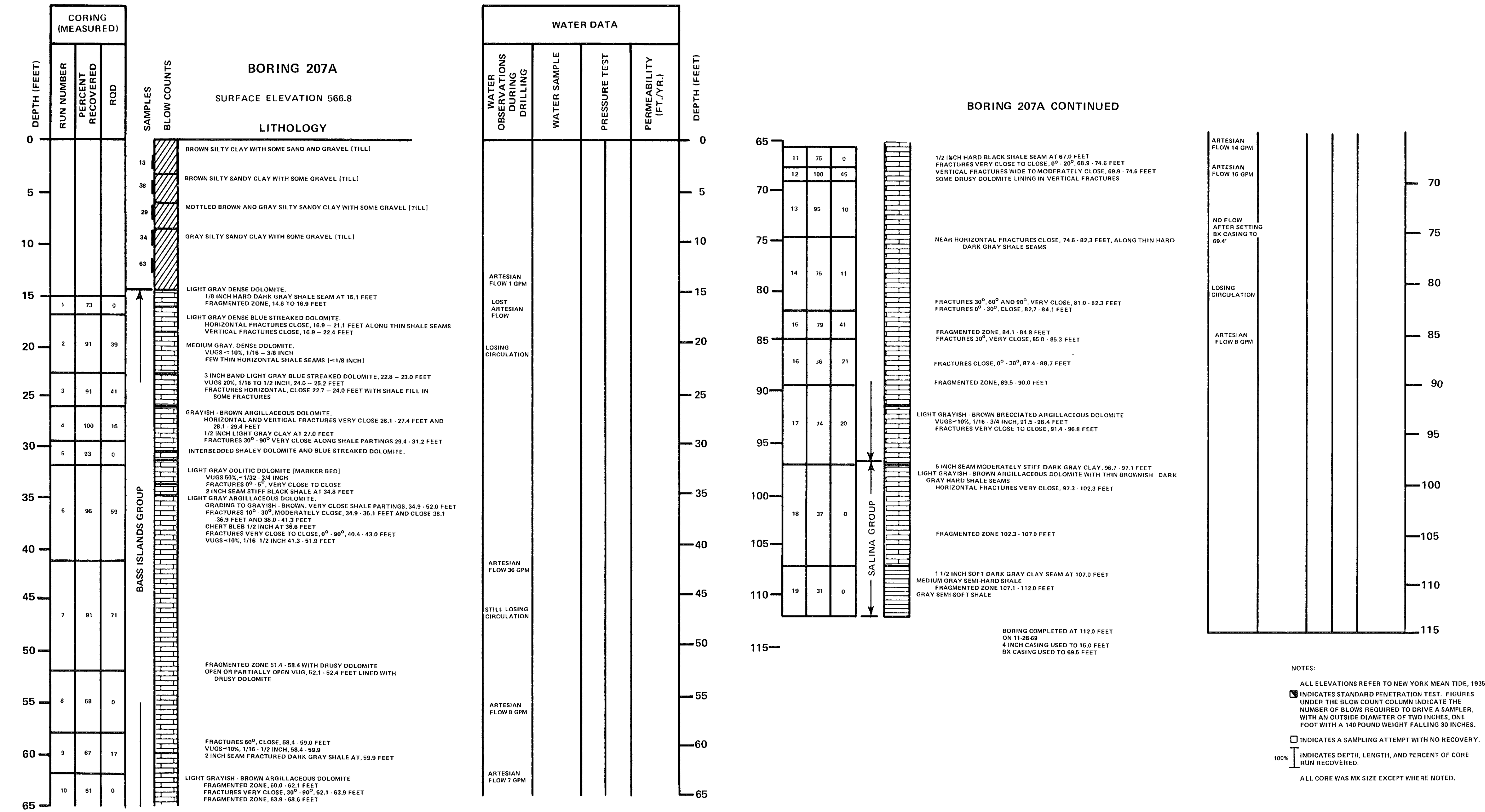
FIGURE 2.5-39

LOG OF BORING 207



REFERENCE:
DAMES & MOORE FIGURES 2.5-22.23 AND 2.5-22.24

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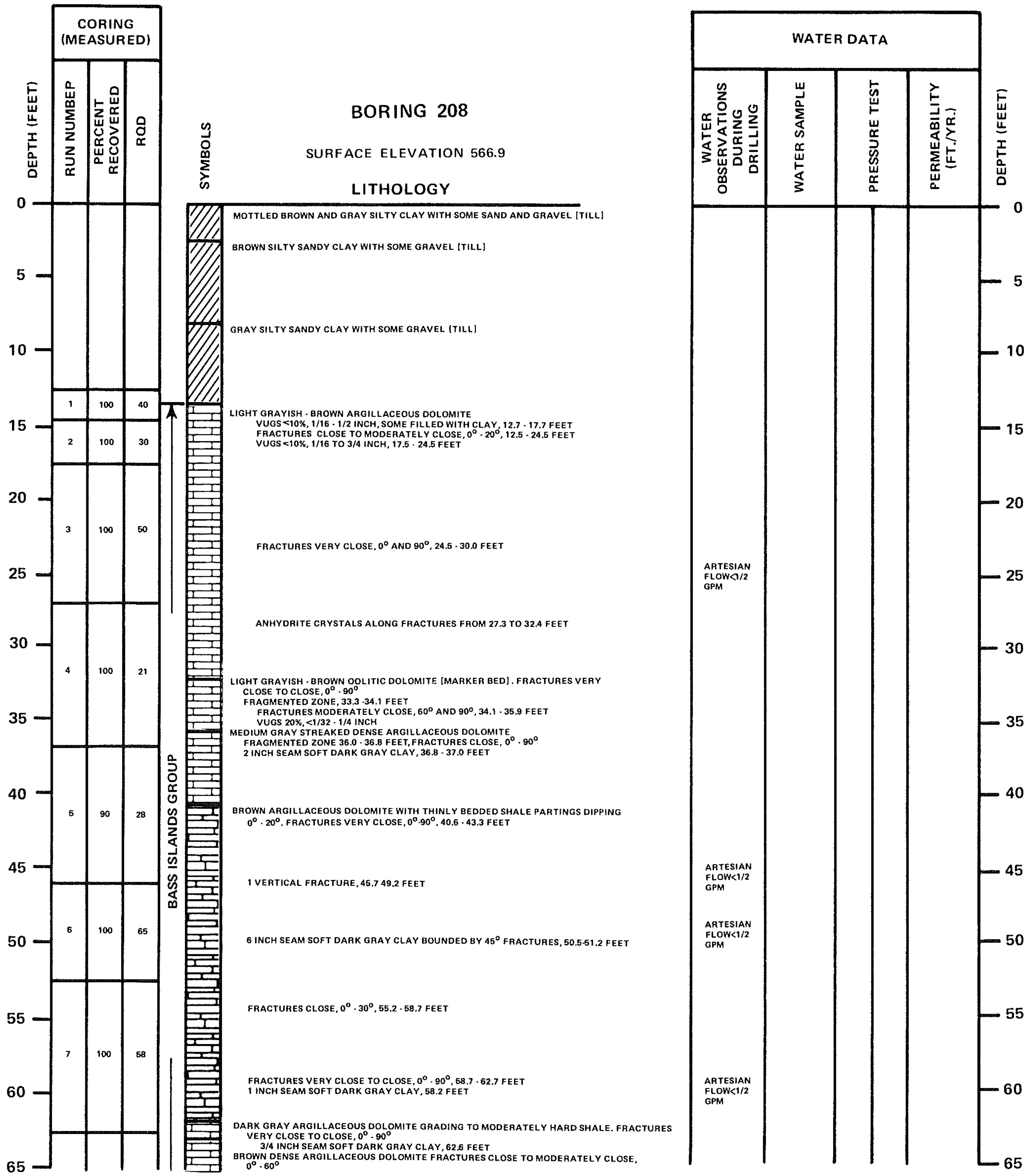
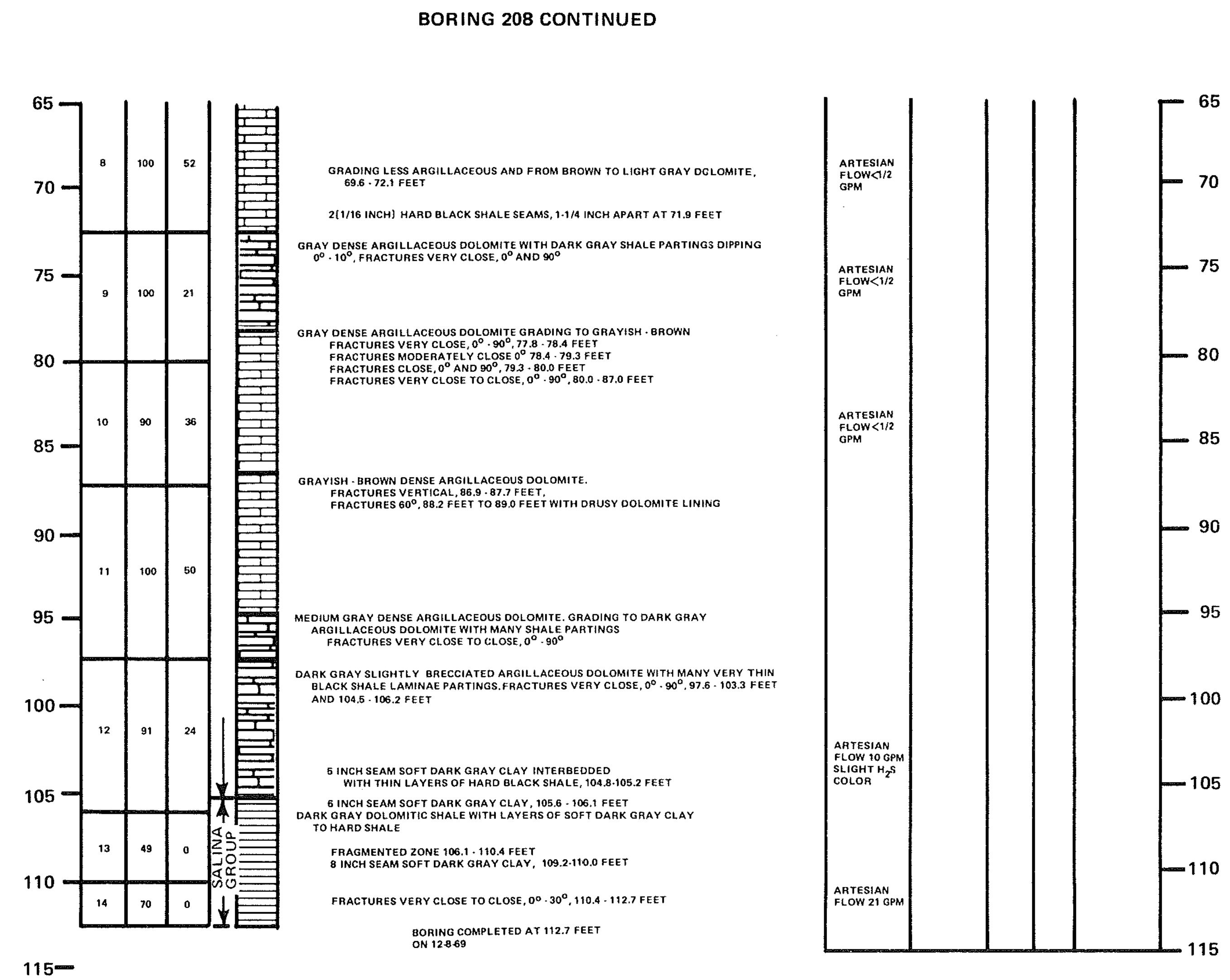
FIGURE 2.5-40

LOG OF BORING 207A





NOTES:

ALL ELEVATIONS REFER TO NEW YORK MEAN TIDE, 1935

INDICATES STANDARD PENETRATION TEST. FIGURES UNDER THE BLOW COUNT COLUMN INDICATE THE NUMBER OF BLOWS REQUIRED TO DRIVE A SAMPLER, WITH AN OUTSIDE DIAMETER OF TWO INCHES, ONE FOOT WITH A 140 POUND WEIGHT FALLING 30 INCHES.

INDICATES A SAMPLING ATTEMPT WITH NO RECOVERY.

100% INDICATES DEPTH, LENGTH, AND PERCENT OF CORE RUN RECOVERED.

ALL CORE WAS MX SIZE EXCEPT WHERE NOTED.

REFERENCE:
DAMES & MOORE FIGURES 2.5-22.25 AND 2.5-22.26

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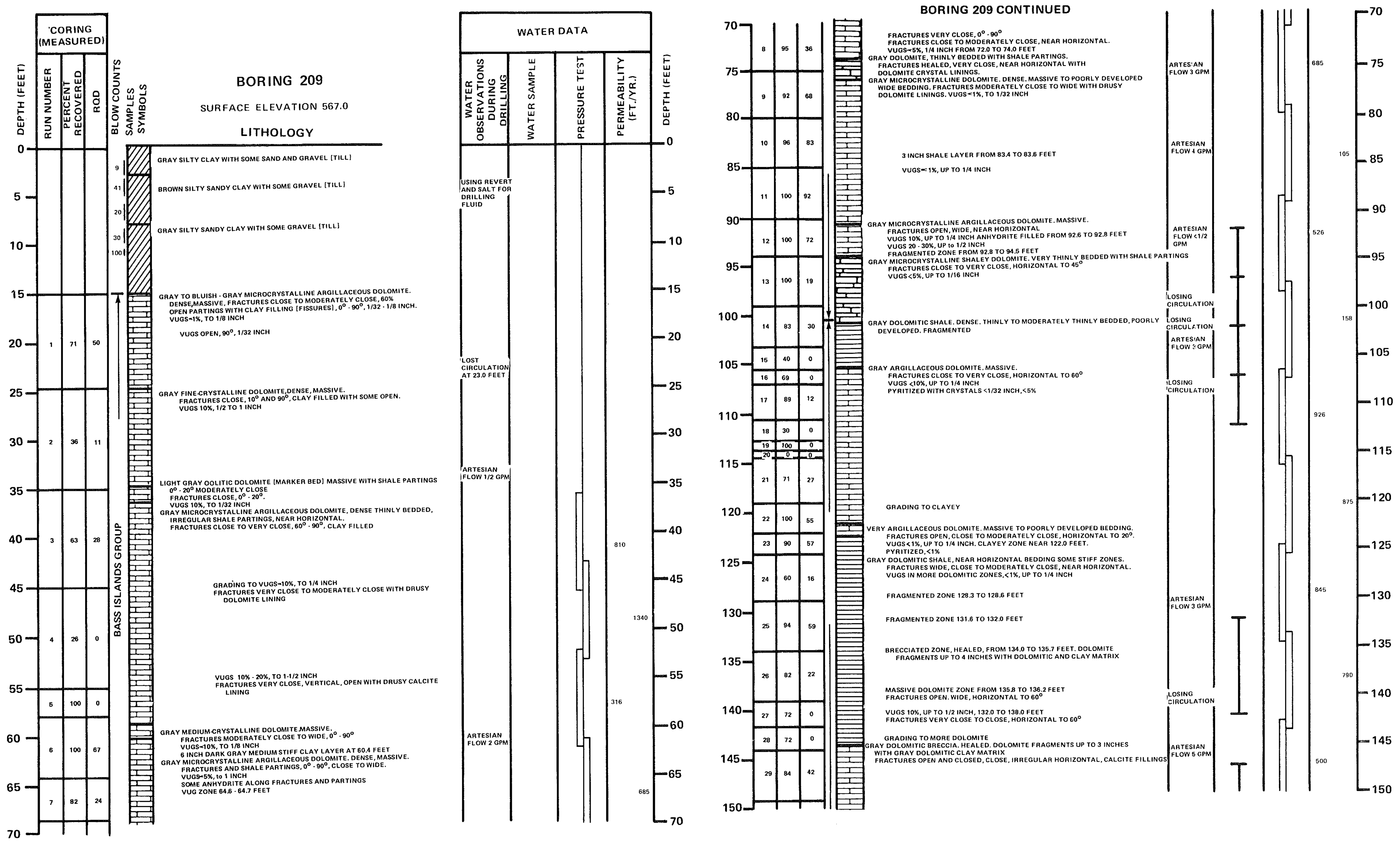
FIGURE 2.5-41

LOG OF BORING 208



NOTES:

ALL ELEVATIONS REFER TO NEW YORK MEAN TIDE, 1935

INDICATES STANDARD PENETRATION TEST. FIGURES UNDER THE BLOW COUNT COLUMN INDICATE THE NUMBER OF BLOWS REQUIRED TO DRIVE A SAMPLER, WITH AN OUTSIDE DIAMETER OF TWO INCHES, ONE FOOT WITH A 140 POUND WEIGHT FALLING 30 INCHES.

INDICATES A SAMPLING ATTEMPT WITH NO RECOVERY.

100% INDICATES DEPTH, LENGTH, AND PERCENT OF CORE RUN RECOVERED.

ALL CORE WAS MX SIZE EXCEPT WHERE NOTED.

REFERENCE:
DAMES & MOORE FIGURES 2.5-22.27 AND 2.5-22.28

Fermi 2

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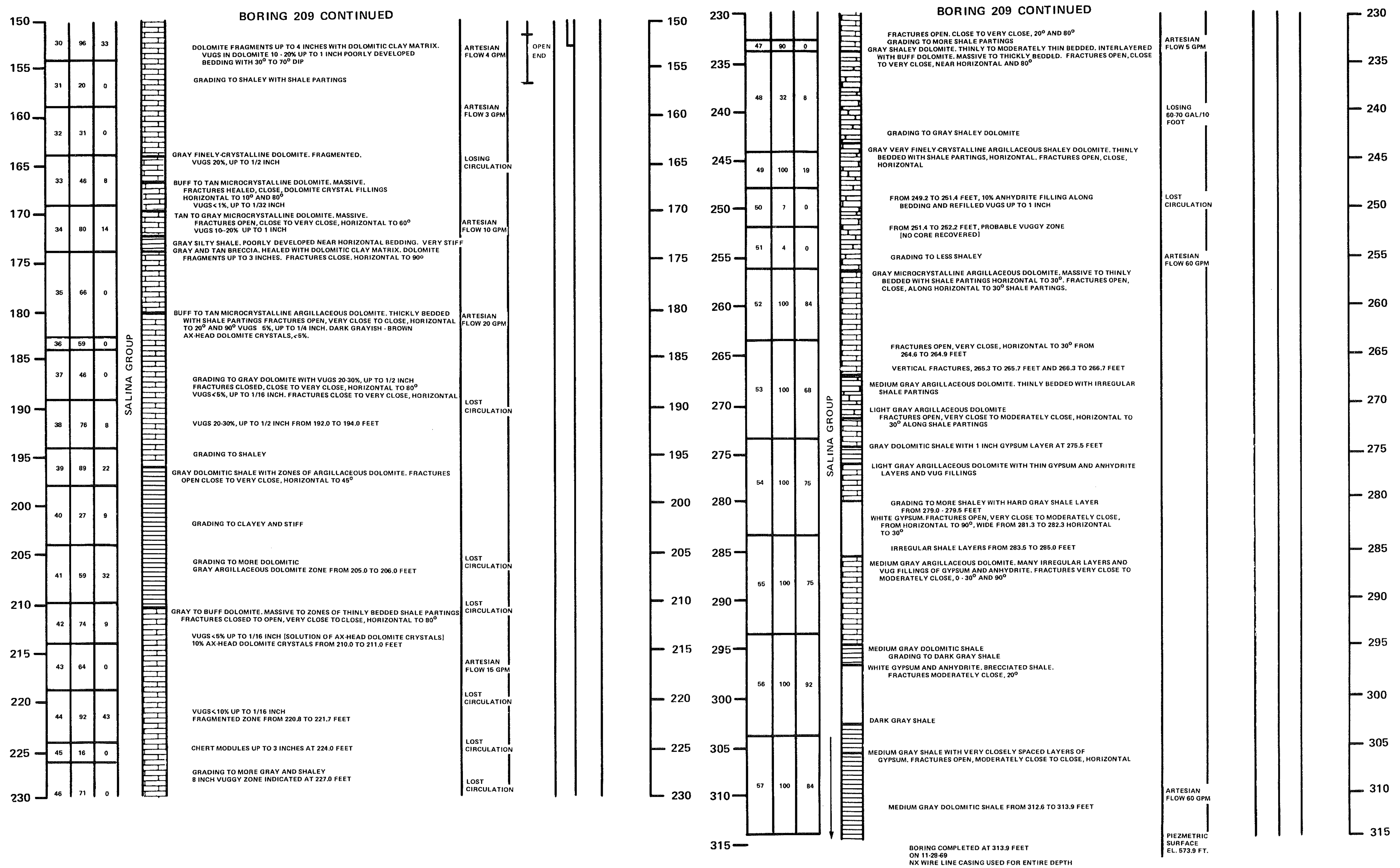
FIGURE 2.5-42, SHEET 1

LOG OF BORING 209



NOTES:

ALL ELEVATIONS REFER TO NEW YORK MEAN TIDE, 1935

INDICATES STANDARD PENETRATION TEST. FIGURES UNDER THE BLOW COUNT COLUMN INDICATE THE NUMBER OF BLOWS REQUIRED TO DRIVE A SAMPLER, WITH AN OUTSIDE DIAMETER OF TWO INCHES, ONE FOOT WITH A 140 POUND WEIGHT FALLING 30 INCHES.

INDICATES A SAMPLING ATTEMPT WITH NO RECOVERY.

100% INDICATES DEPTH, LENGTH, AND PERCENT OF CORE RUN RECOVERED.

ALL CORE WAS MX SIZE EXCEPT WHERE NOTED.

REFERENCE:
DAMES & MOORE FIGURES 2.5-22.29 AND 2.5-22.30

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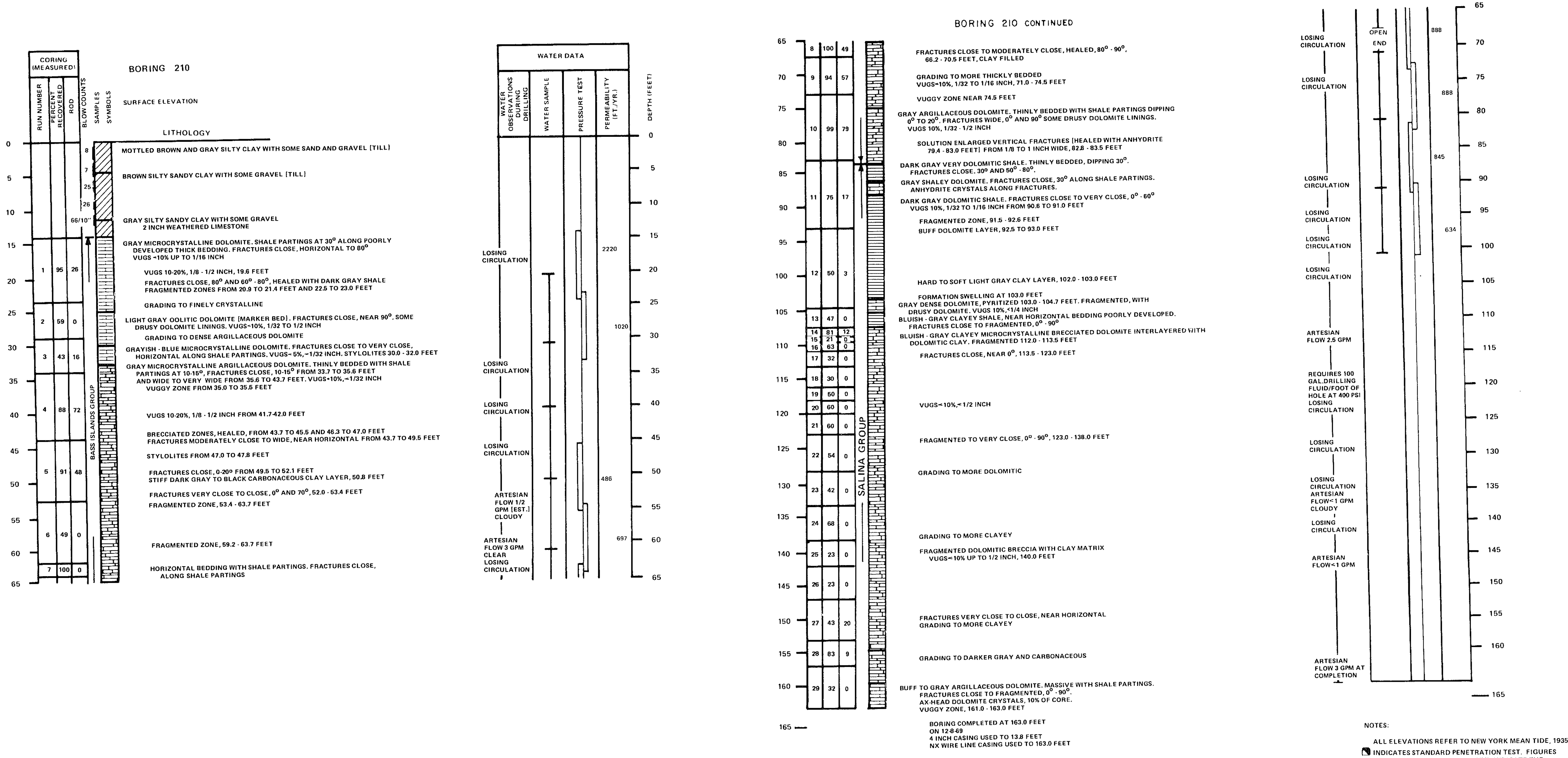
FIGURE 2.5-42, SHEET 2

LOG OF BORING 209



NOTES:

ALL ELEVATIONS REFER TO NEW YORK MEAN TIDE, 1935

INDICATES STANDARD PENETRATION TEST. FIGURES UNDER THE BLOW COUNT COLUMN INDICATE THE NUMBER OF BLOWS REQUIRED TO DRIVE A SAMPLER, WITH AN OUTSIDE DIAMETER OF TWO INCHES, ONE FOOT WITH A 140 POUND WEIGHT FALLING 30 INCHES.

INDICATES A SAMPLING ATTEMPT WITH NO RECOVERY.

100% INDICATES DEPTH, LENGTH, AND PERCENT OF CORE RUN RECOVERED.

ALL CORE WAS NX SIZE EXCEPT WHERE NOTED.

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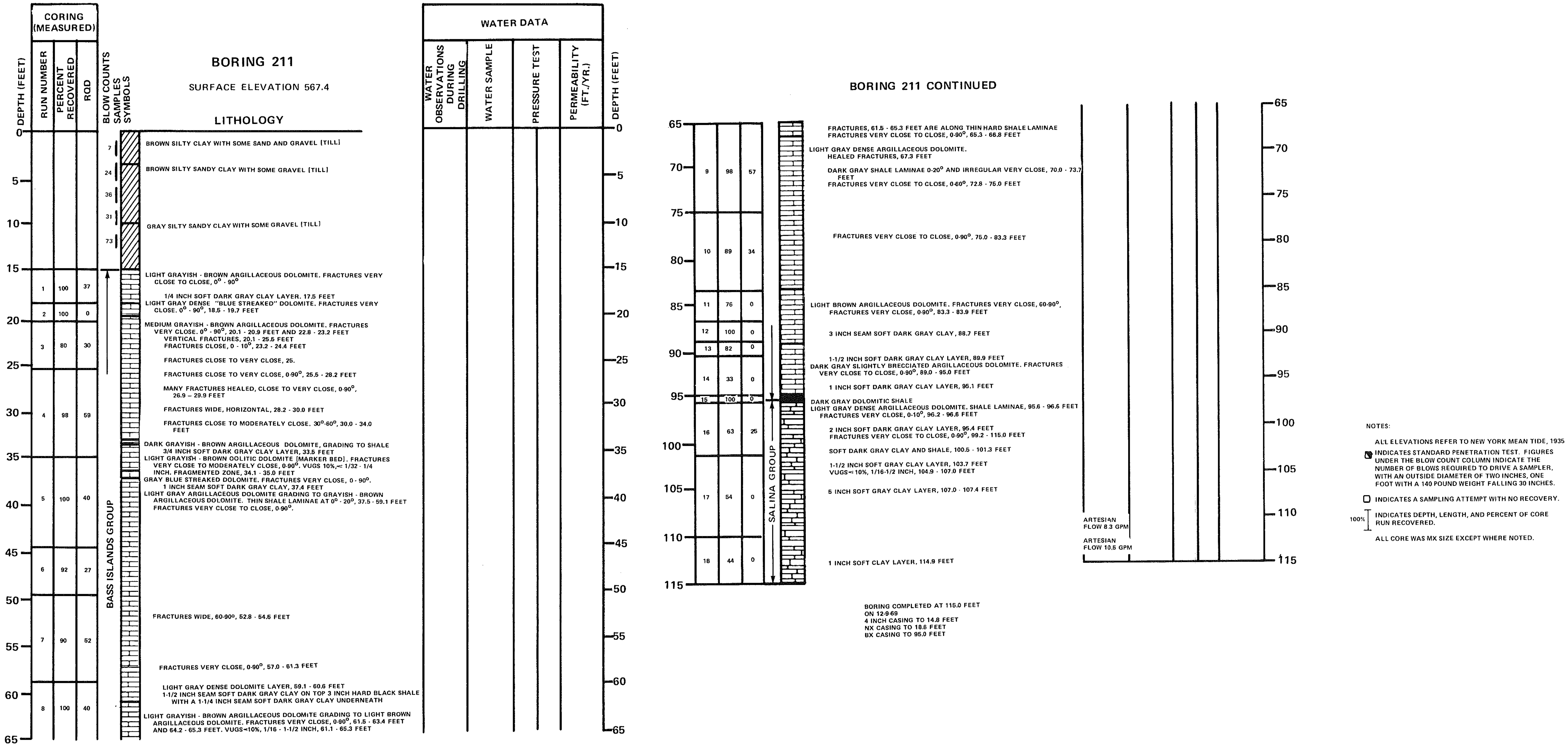
UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 2.5-43

LOG OF BORING 210

REFERENCE:
DAMES & MOORE FIGURES 2.5-22.31, 2.5-22.32 AND 2.5-22.33

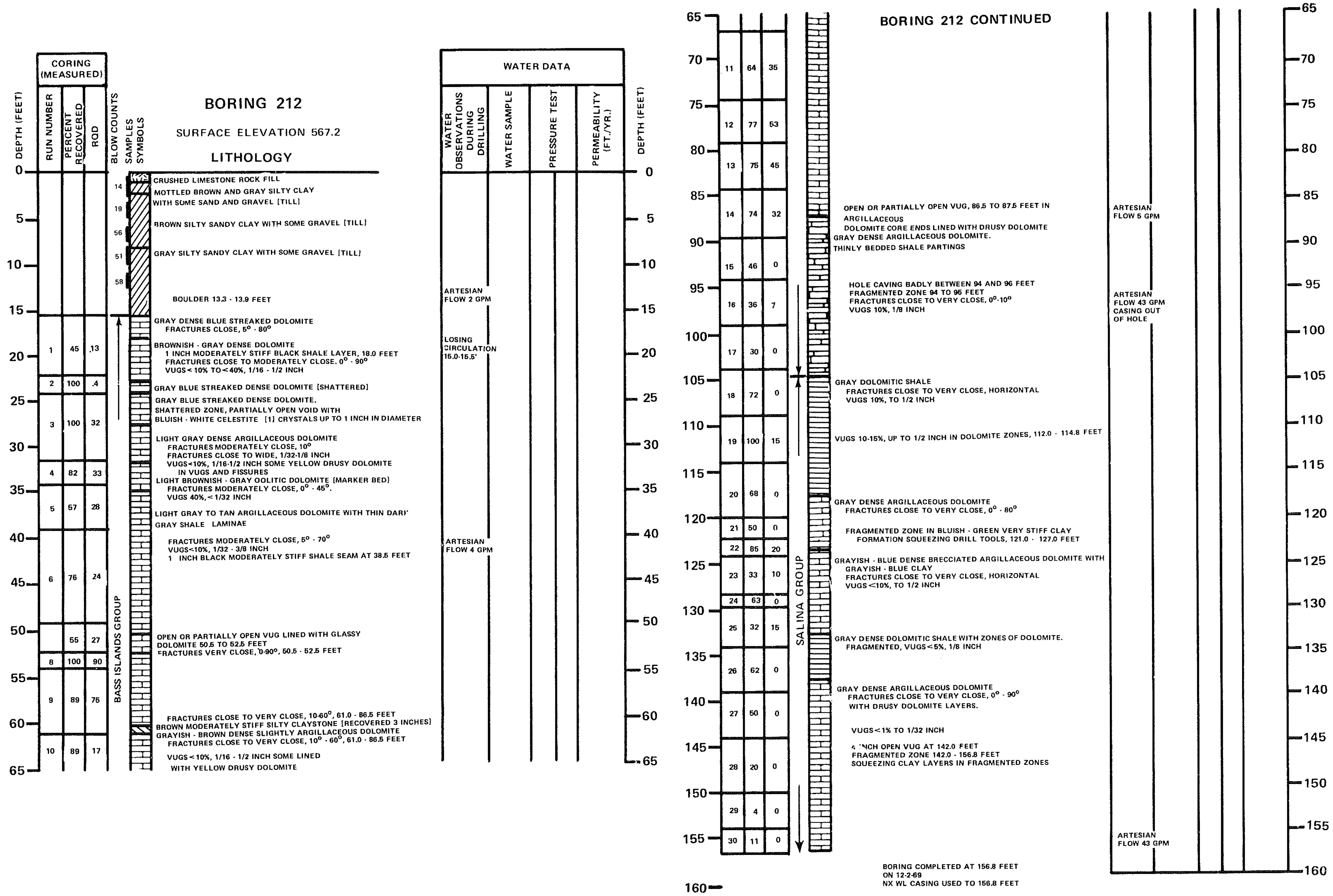


REFERENCE:
DAMES & MOORE FIGURES 2.5-22.34 AND 2.5-22.35

Fermi 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 2.5-44

LOG OF BORING 211



NOTES:

ALL ELEVATIONS REFER TO NEW YORK MEAN TIDE, 1935

INDICATES STANDARD PENETRATION TEST. FIGURES UNDER THE BLOW COUNT COLUMN INDICATE THE NUMBER OF BLOWS REQUIRED TO DRIVE A SAMPLER, WITH AN OUTSIDE DIAMETER OF TWO INCHES, ONE FOOT WITH A 140 POUND WEIGHT FALLING 30 INCHES.

INDICATES A SAMPLING ATTEMPT WITH NO RECOVERY.

100% INDICATES DEPTH, LENGTH, AND PERCENT OF CORE RUN RECOVERED.

ALL CORE WAS MX SIZE EXCEPT WHERE NOTED.

REFERENCE:
DAMES & MOORE FIGURES 2.5-22.36, 2.5-22.37 AND 2.5-22.38

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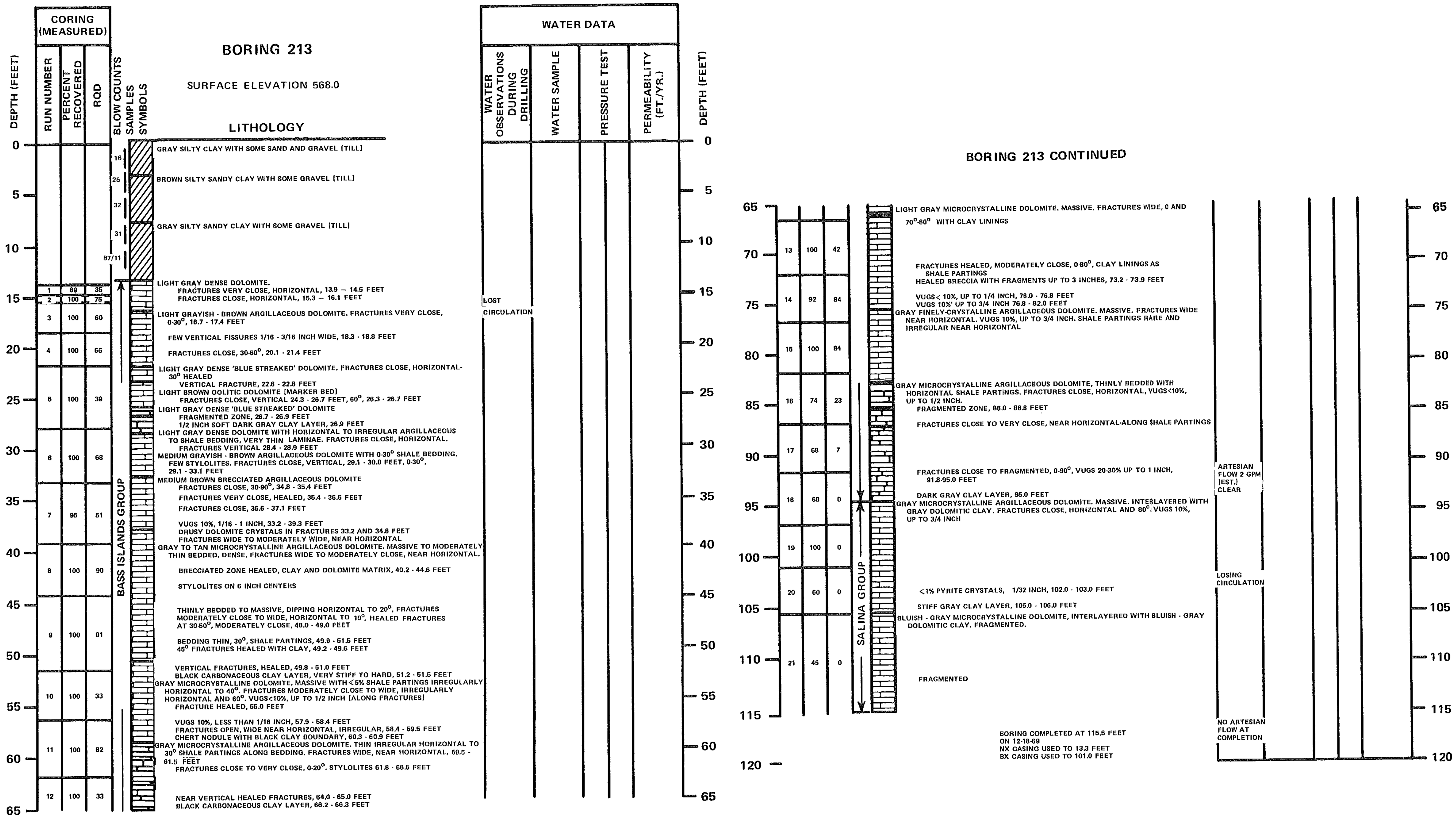
FIGURE 2.5-45

LOG OF BORING 212



NOTES:

ALL ELEVATIONS REFER TO NEW YORK MEAN TIDE, 1935

INDICATES STANDARD PENETRATION TEST. FIGURES UNDER THE BLOW COUNT COLUMN INDICATE THE NUMBER OF BLOWS REQUIRED TO DRIVE A SAMPLER, WITH AN OUTSIDE DIAMETER OF TWO INCHES, ONE FOOT WITH A 140 POUND WEIGHT FALLING 30 INCHES.

INDICATES A SAMPLING ATTEMPT WITH NO RECOVERY.

100% INDICATES DEPTH, LENGTH, AND PERCENT OF CORE RUN RECOVERED.

ALL CORE WAS MX SIZE EXCEPT WHERE NOTED.

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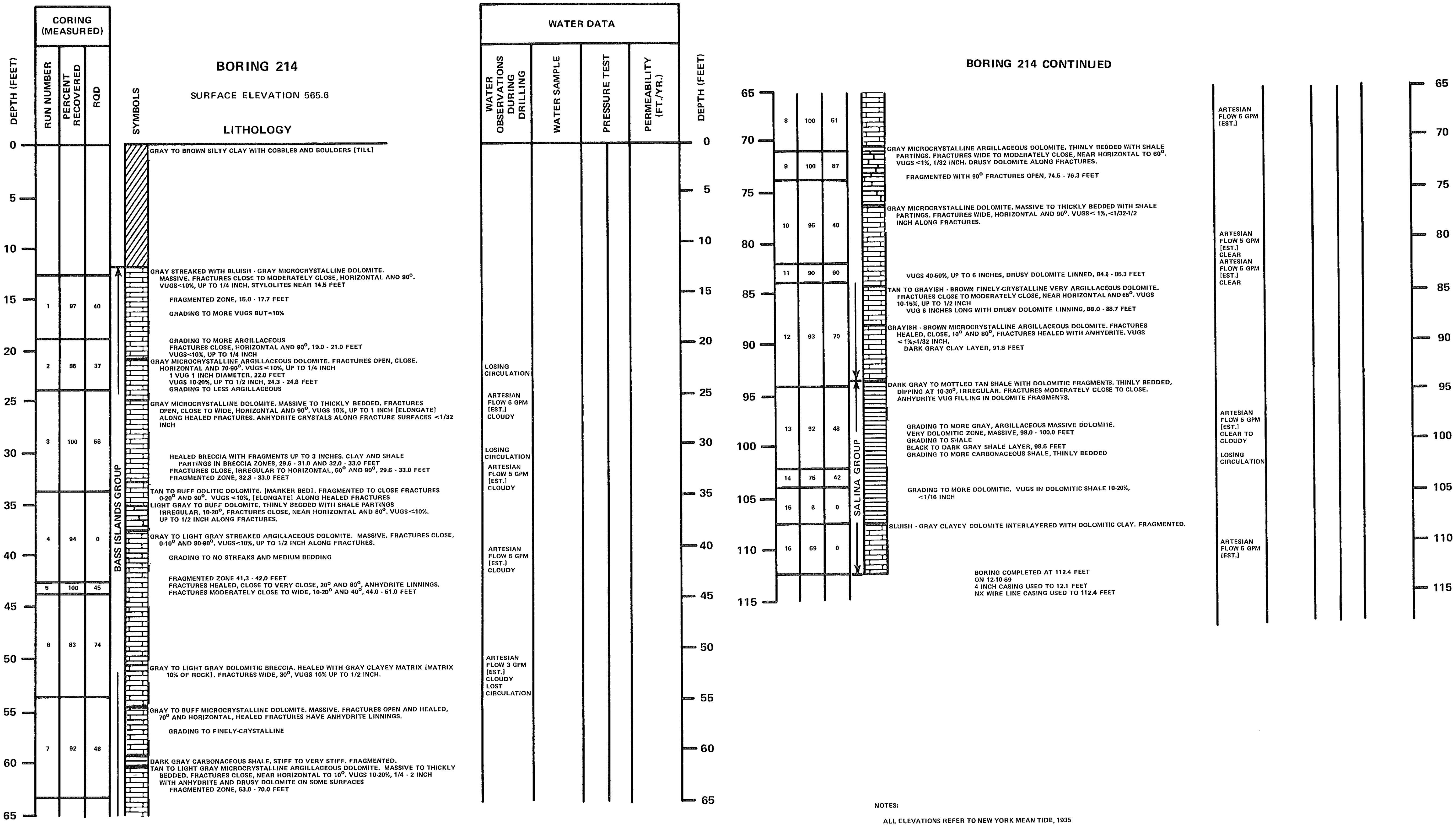
UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 2.5-46

LOG OF BORING 213

REFERENCE:
DAMES & MOORE FIGURES 2.5-22.39 AND 2.5-22.40



NOTES:

ALL ELEVATIONS REFER TO NEW YORK MEAN TIDE, 1935

INDICATES STANDARD PENETRATION TEST. FIGURES UNDER THE BLOW COUNT COLUMN INDICATE THE NUMBER OF BLOWS REQUIRED TO DRIVE A SAMPLER, WITH AN OUTSIDE DIAMETER OF TWO INCHES, ONE FOOT WITH A 140 POUND WEIGHT FALLING 30 INCHES.

INDICATES A SAMPLING ATTEMPT WITH NO RECOVERY.

100% INDICATES DEPTH, LENGTH, AND PERCENT OF CORE RUN RECOVERED.

ALL CORE WAS MX SIZE EXCEPT WHERE NOTED.

Fermi 2
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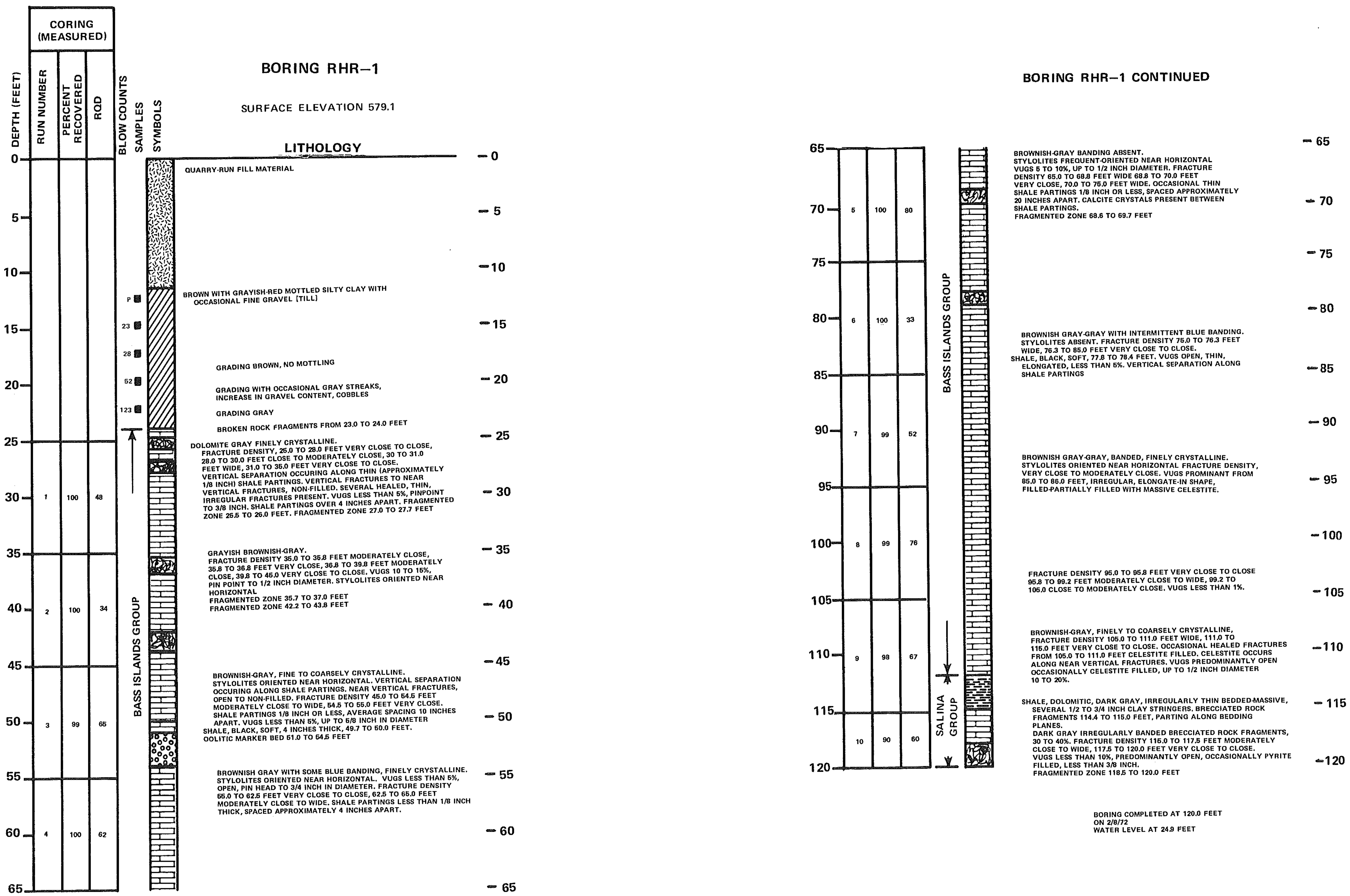
FIGURE 2.5-47

LOG OF BORING 214

REFERENCE:
DAMES & MOORE FIGURES 2.5-22.41 AND 2.5-22.42



NOTES:

ELEVATIONS REFER TO NEW YORK MEAN TIDE, 1935

52 ▩ INDICATES SOIL SAMPLE RECOVERED IN A DAMES & MOORE (3½ INCH O.D.) SAMPLER. FIGURES UNDER THE BLOW COUNT COLUMN INDICATE THE NUMBER OF BLOWS REQUIRED TO DRIVE THE SAMPLER 12 INCHES WITH A 455 POUND WEIGHT FALLING 30 INCHES.

RQD – ROCK QUALITY DESIGNATION

A MODIFIED CORE RECOVERY PERCENTAGE IN WHICH ALL THE PIECES OF SOUND CORE OVER 4-INCHES LONG ARE COUNTED AS RECOVERY. THE MODIFIED SUM OF CORE RECOVERED IS THEN EXPRESSED AS A PERCENTAGE OF THE TOTAL LENGTH OF THE CORE RUN.

5% – VUGS INDICATES THE ESTIMATED RATIO OF VUGGED CORE SURFACE AREA TO TOTAL CORE SURFACE AREA. BOTH OPEN AND FILLED VUGS ARE INCLUDED IN THE VUGGED CATEGORY.

FRACTURE DENSITY TERMINOLOGY:

VERY CLOSE – LESS THAN 2 INCHES APART
CLOSE – 2 TO 6 INCHES
MODERATELY CLOSE – 6 TO 12 INCHES
WIDE – GREATER THAN 12 INCHES

REFERENCE:
DAMES & MOORE PLATES A-1A AND A-1B

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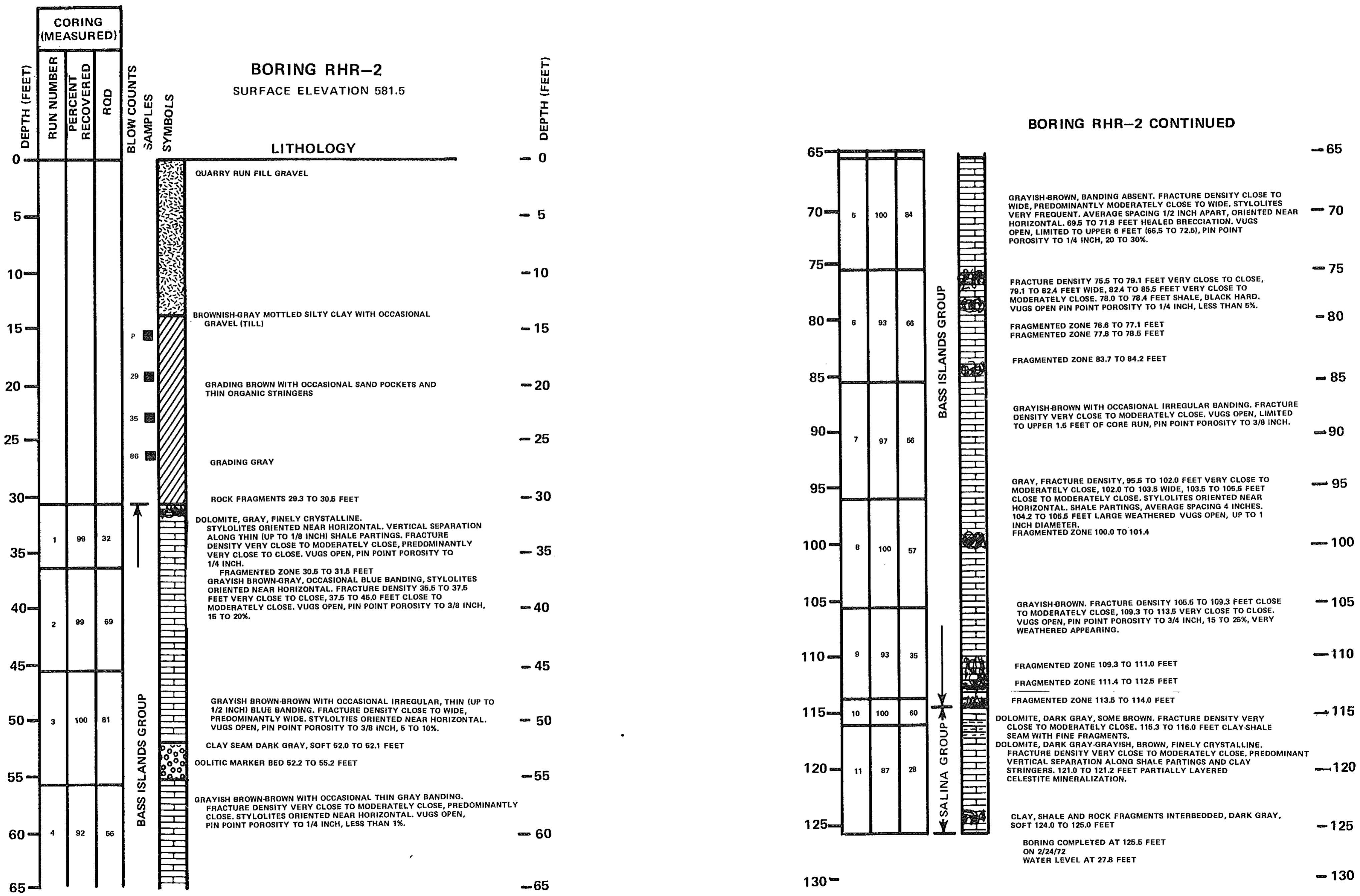
FIGURE 2.5-48

LOG OF BORING RHR-1



NOTES:

ELEVATIONS REFER TO NEW YORK MEAN TIDE, 1935

52 ■ INDICATES SOIL SAMPLE RECOVERED IN A DAMES & MOORE (3½ INCH O.D.) SAMPLER. FIGURES UNDER THE BLOW COUNT COLUMN INDICATE THE NUMBER OF BLOWS REQUIRED TO DRIVE THE SAMPLER 12 INCHES WITH A 455 POUND WEIGHT FALLING 30 INCHES.

RQD – ROCK QUALITY DESIGNATION

A MODIFIED CORE RECOVERY PERCENTAGE IN WHICH ALL THE PIECES OF SOUND CORE OVER 4-INCHES LONG ARE COUNTED AS RECOVERY. THE MODIFIED SUM OF CORE RECOVERED IS THEN EXPRESSED AS A PERCENTAGE OF THE TOTAL LENGTH OF THE CORE RUN.

5% – VUGS INDICATES THE ESTIMATED RATIO OF VUGGED CORE SURFACE AREA TO TOTAL CORE SURFACE AREA. BOTH OPEN AND FILLED VUGS ARE INCLUDED IN THE VUGGED CATEGORY.

FRACTURE DENSITY TERMINOLOGY:

VERY CLOSE – LESS THAN 2 INCHES APART
CLOSE – 2 TO 6 INCHES
MODERATELY CLOSE – 6 TO 12 INCHES
WIDE – GREATER THAN 12 INCHES

REFERENCE:
DAMES & MOORE PLATES A-1C AND A-1D

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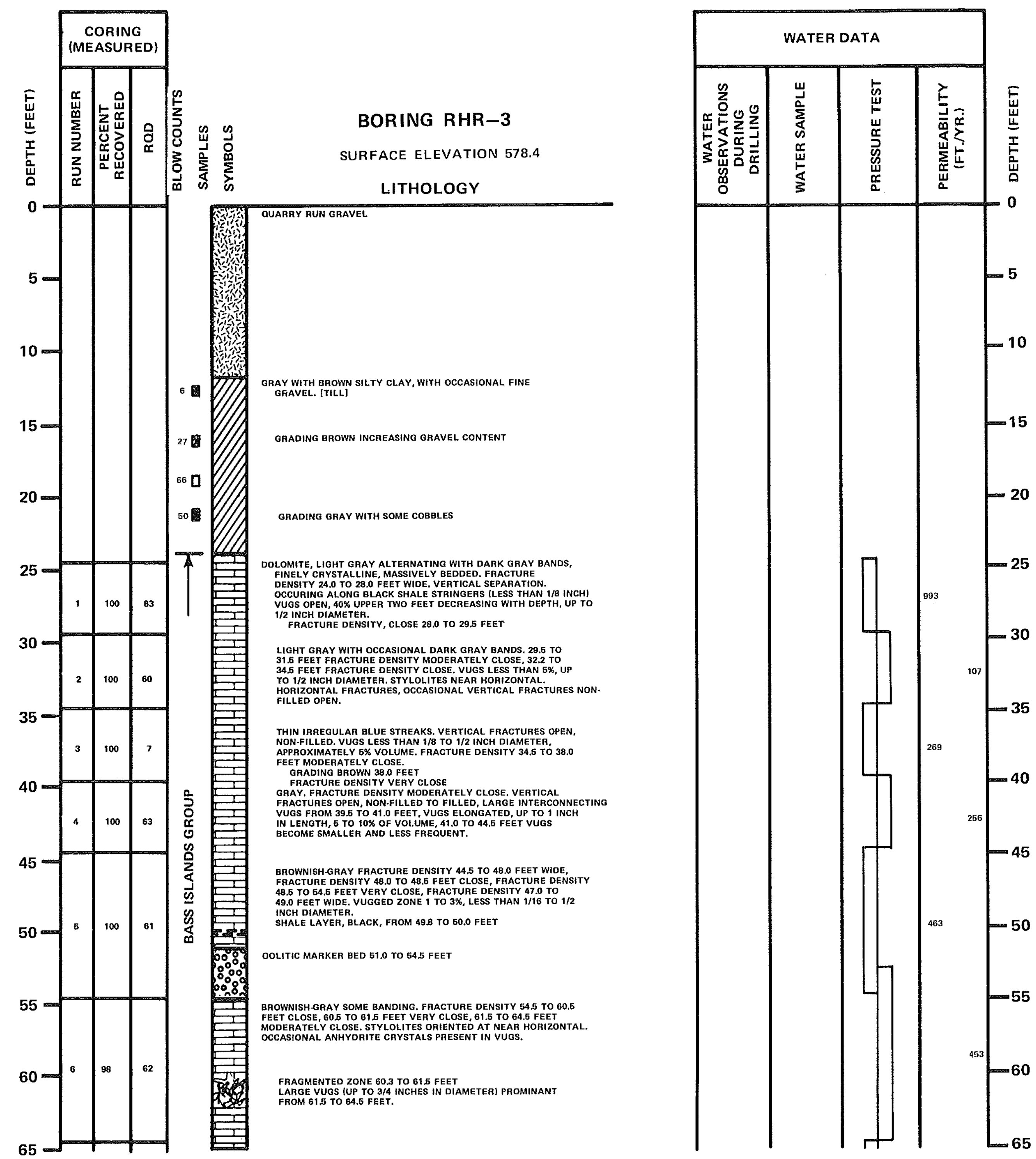
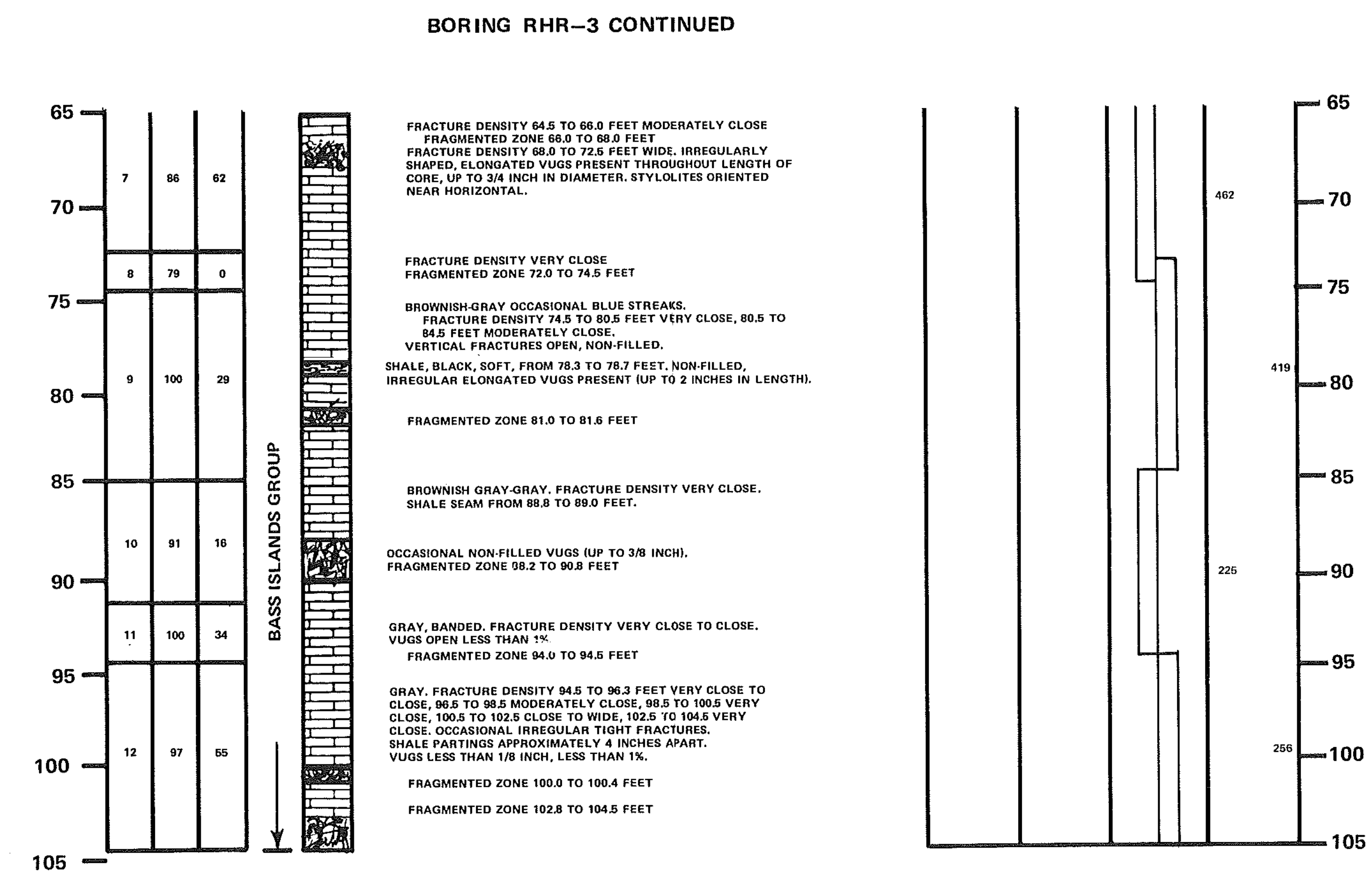
FIGURE 2.5-49

LOG OF BORING RHR-2





BORING COMPLETED AT 104.5 FEET ON 2/3/72

NOTES:

ELEVATIONS REFER TO NEW YORK MEAN TIDE, 1935

52 INDICATES SOIL SAMPLE RECOVERED IN A DAMES & MOORE (3½ INCH O.D.) SAMPLER. FIGURES UNDER THE BLOW COUNT COLUMN INDICATE THE NUMBER OF BLOWS REQUIRED TO DRIVE THE SAMPLER 12 INCHES WITH A 455 POUND WEIGHT FALLING 30 INCHES.

RQD – ROCK QUALITY DESIGNATION

A MODIFIED CORE RECOVERY PERCENTAGE IN WHICH ALL THE PIECES OF SOUND CORE OVER 4-INCHES LONG ARE COUNTED AS RECOVERY. THE MODIFIED SUM OF CORE RECOVERED IS THEN EXPRESSED AS A PERCENTAGE OF THE TOTAL LENGTH OF THE CORE RUN.

5% – VUGS INDICATES THE ESTIMATED RATIO OF VUGGED CORE SURFACE AREA TO TOTAL CORE SURFACE AREA. BOTH OPEN AND FILLED VUGS ARE INCLUDED IN THE VUGGED CATEGORY.

FRACTURE DENSITY TERMINOLOGY:

VERY CLOSE – LESS THAN 2 INCHES APART
CLOSE – 2 TO 6 INCHES
MODERATELY CLOSE – 6 TO 12 INCHES
WIDE – GREATER THAN 12 INCHES

REFERENCE:
DAMES & MOORE PLATES A-1E AND A-1F

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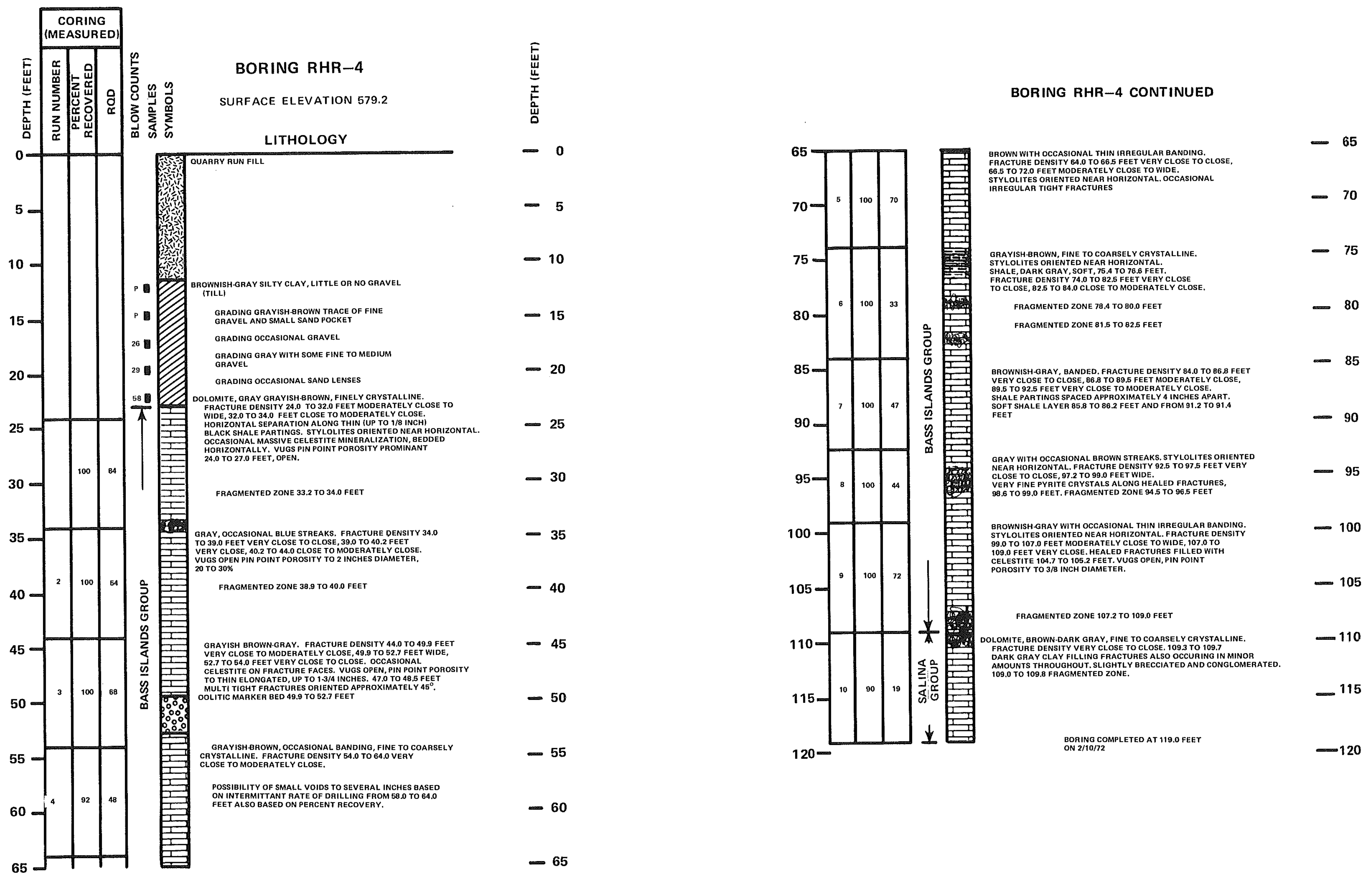
FIGURE 2.5-50

LOG OF BORING RHR-3



NOTES:

ELEVATIONS REFER TO NEW YORK MEAN TIDE, 1935

52 ▮ INDICATES SOIL SAMPLE RECOVERED IN A DAMES & MOORE (3½ INCH O.D.) SAMPLER. FIGURES UNDER THE BLOW COUNT COLUMN INDICATE THE NUMBER OF BLOWS REQUIRED TO DRIVE THE SAMPLER 12 INCHES WITH A 455 POUND WEIGHT FALLING 30 INCHES.

RQD – ROCK QUALITY DESIGNATION

A MODIFIED CORE RECOVERY PERCENTAGE IN WHICH ALL THE PIECES OF SOUND CORE OVER 4-INCHES LONG ARE COUNTED AS RECOVERY. THE MODIFIED SUM OF CORE RECOVERED IS THEN EXPRESSED AS A PERCENTAGE OF THE TOTAL LENGTH OF THE CORE RUN.

5% – VUGS INDICATES THE ESTIMATED RATIO OF VUGGED CORE SURFACE AREA TO TOTAL CORE SURFACE AREA. BOTH OPEN AND FILLED VUGS ARE INCLUDED IN THE VUGGED CATEGORY.

FRACTURE DENSITY TERMINOLOGY:

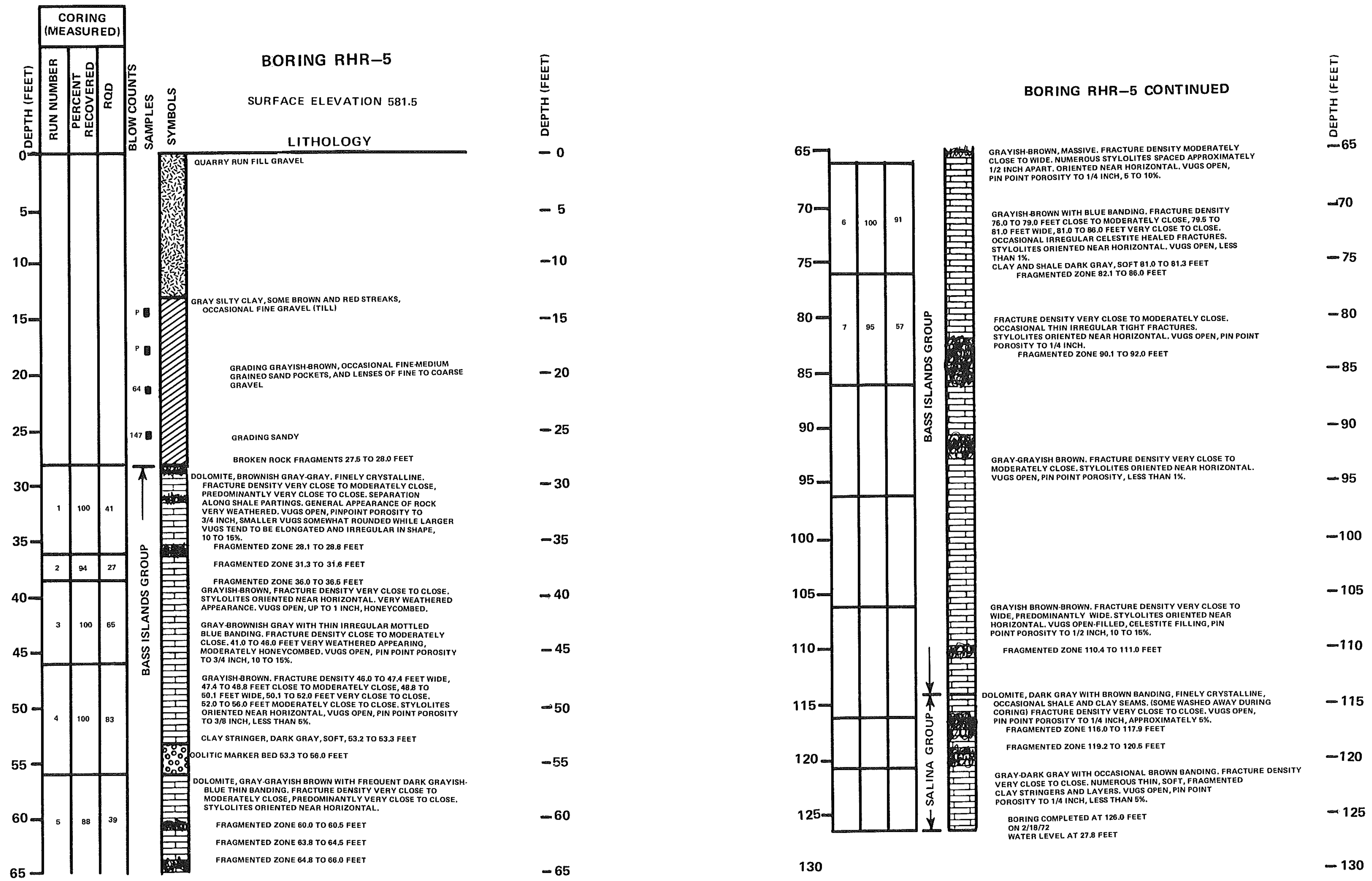
VERY CLOSE – LESS THAN 2 INCHES APART
CLOSE – 2 TO 6 INCHES
MODERATELY CLOSE – 6 TO 12 INCHES
WIDE – GREATER THAN 12 INCHES

REFERENCE:
DAMES & MOORE PLATES A-1G AND A-1H

Fermi 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 2.5-51

LOG OF BORING RHR-4



NOTES:

ELEVATIONS REFER TO NEW YORK MEAN TIDE, 1935

52 ▪ INDICATES SOIL SAMPLE RECOVERED IN A DAMES & MOORE (3½ INCH O.D.) SAMPLER. FIGURES UNDER THE BLOW COUNT COLUMN INDICATE THE NUMBER OF BLOWS REQUIRED TO DRIVE THE SAMPLER 12 INCHES WITH A 455 POUND WEIGHT FALLING 30 INCHES.

RQD – ROCK QUALITY DESIGNATION

A MODIFIED CORE RECOVERY PERCENTAGE IN WHICH ALL THE PIECES OF SOUND CORE OVER 4-INCHES LONG ARE COUNTED AS RECOVERY. THE MODIFIED SUM OF CORE RECOVERED IS THEN EXPRESSED AS A PERCENTAGE OF THE TOTAL LENGTH OF THE CORE RUN.

5% – VUGS INDICATES THE ESTIMATED RATIO OF VUGGED CORE SURFACE AREA TO TOTAL CORE SURFACE AREA. BOTH OPEN AND FILLED VUGS ARE INCLUDED IN THE VUGGED CATEGORY.

FRACTURE DENSITY TERMINOLOGY:

VERY CLOSE – LESS THAN 2 INCHES APART
CLOSE – 2 TO 6 INCHES
MODERATELY CLOSE – 6 TO 12 INCHES
WIDE – GREATER THAN 12 INCHES

REFERENCE:
DAMES & MOORE PLATES A-1I AND A-1J

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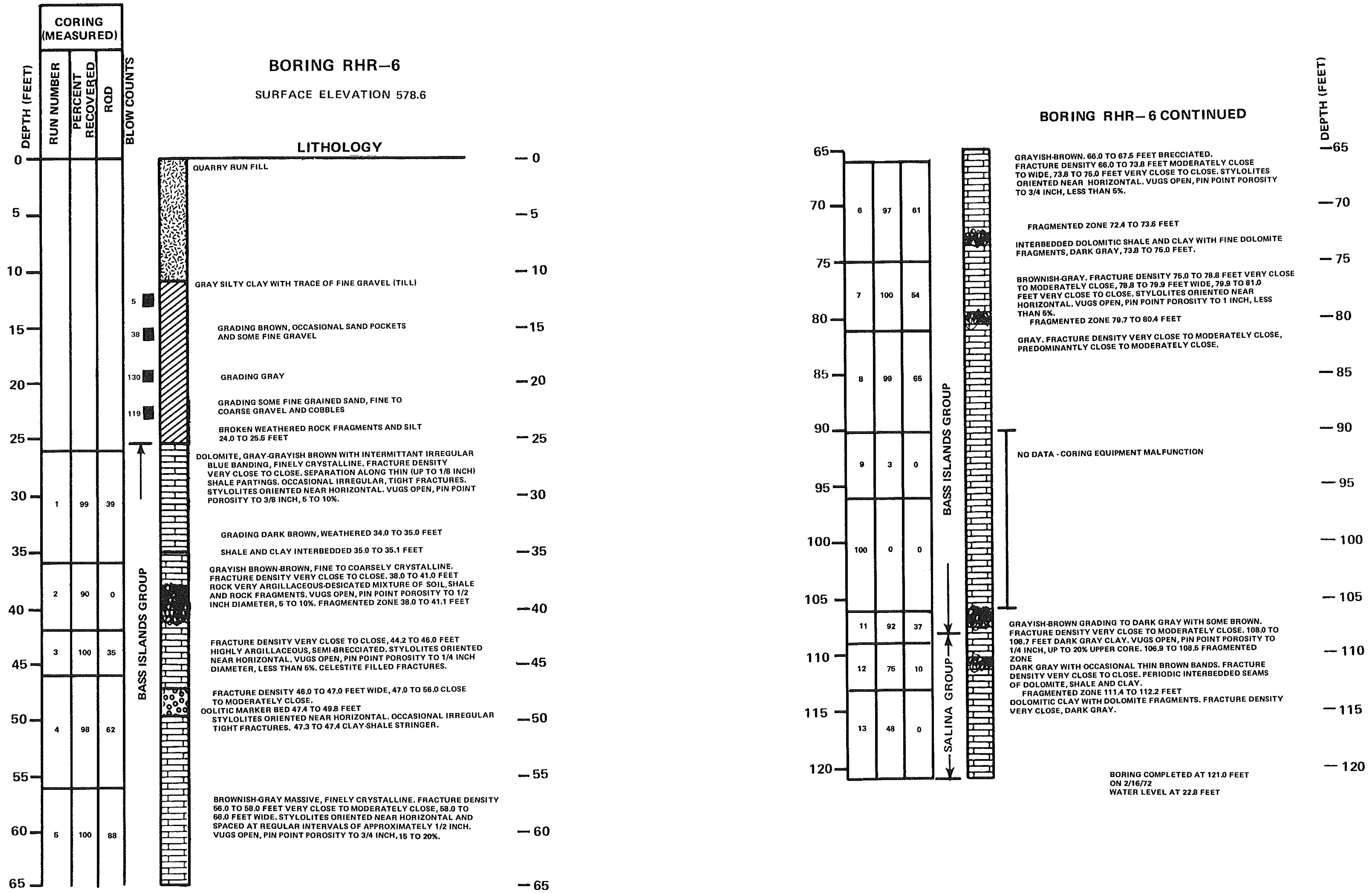
FIGURE 2.5-52

LOG OF BORING RHR-5



NOTES:

ELEVATIONS REFER TO NEW YORK MEAN TIDE, 1935

52 ■ INDICATES SOIL SAMPLE RECOVERED IN A DAMES & MOORE (3½ INCH O.D.) SAMPLER. FIGURES UNDER THE BLOW COUNT COLUMN INDICATE THE NUMBER OF BLOWS REQUIRED TO DRIVE THE SAMPLER 12 INCHES WITH A 455 POUND WEIGHT FALLING 30 INCHES.

RQD – ROCK QUALITY DESIGNATION

A MODIFIED CORE RECOVERY PERCENTAGE IN WHICH ALL THE PIECES OF SOUND CORE OVER 4-INCHES LONG ARE COUNTED AS RECOVERY. THE MODIFIED SUM OF CORE RECOVERED IS THEN EXPRESSED AS A PERCENTAGE OF THE TOTAL LENGTH OF THE CORE RUN.

5% – VUGS INDICATES THE ESTIMATED RATIO OF VUGGED CORE SURFACE AREA TO TOTAL CORE SURFACE AREA. BOTH OPEN AND FILLED VUGS ARE INCLUDED IN THE VUGGED CATEGORY.

FRACTURE DENSITY TERMINOLOGY:

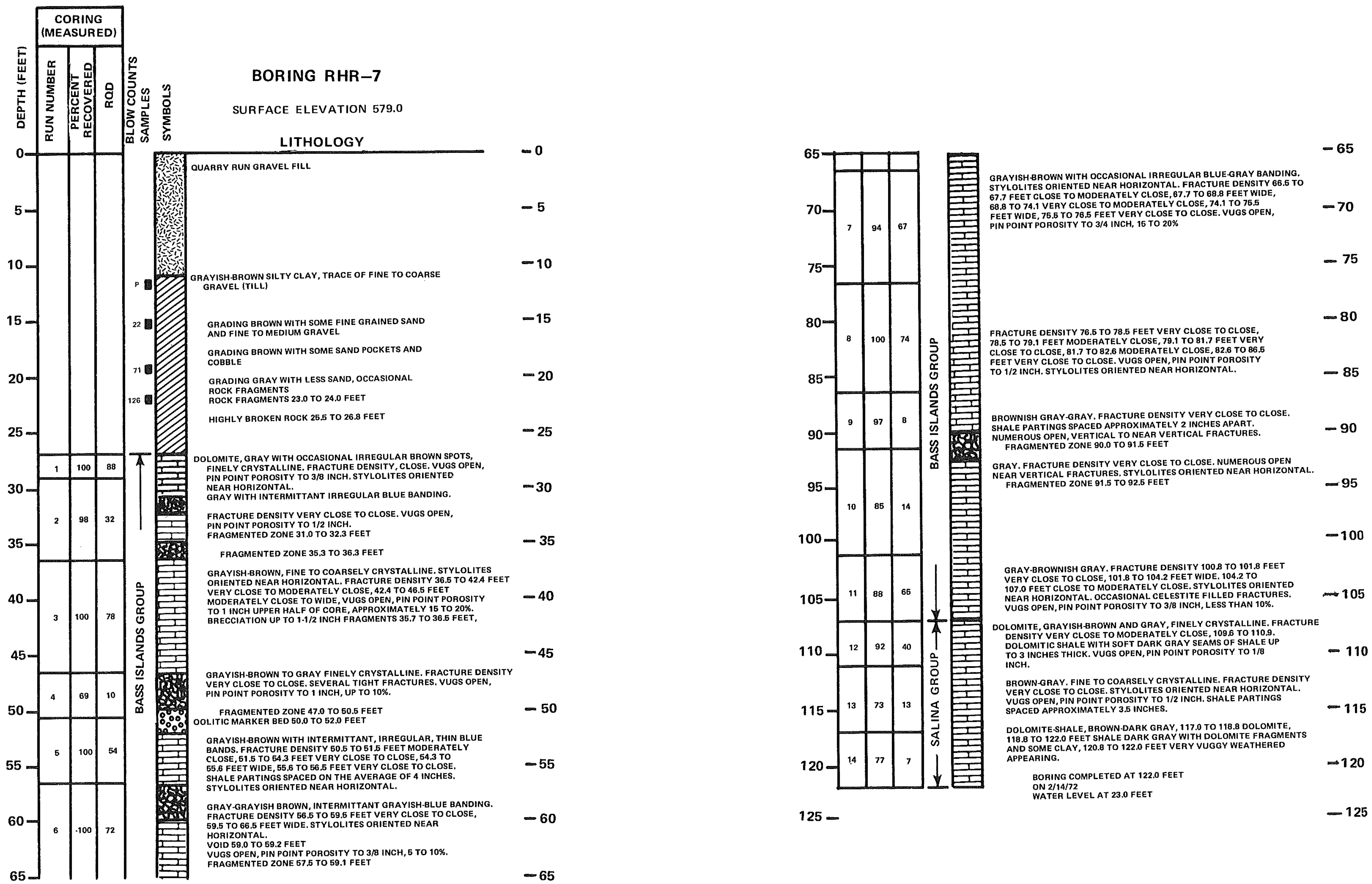
VERY CLOSE – LESS THAN 2 INCHES APART
CLOSE – 2 TO 6 INCHES
MODERATELY CLOSE – 6 TO 12 INCHES
WIDE – GREATER THAN 12 INCHES

REFERENCE:
DAMES & MOORE PLATES A-1K AND A-1L

Fermi 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 2.5-53

LOG OF BORING RHR-6



NOTES:

52 ■ ELEVATIONS REFER TO NEW YORK MEAN TIDE, 1935

INDICATES SOIL SAMPLE RECOVERED IN A DAMES & MOORE (3½ INCH O.D.) SAMPLER. FIGURES UNDER THE BLOW COUNT COLUMN INDICATE THE NUMBER OF BLOWS REQUIRED TO DRIVE THE SAMPLER 12 INCHES WITH A 455 POUND WEIGHT FALLING 30 INCHES.

RQD – ROCK QUALITY DESIGNATION

A MODIFIED CORE RECOVERY PERCENTAGE IN WHICH ALL THE PIECES OF SOUND CORE OVER 4-INCHES LONG ARE COUNTED AS RECOVERY. THE MODIFIED SUM OF CORE RECOVERED IS THEN EXPRESSED AS A PERCENTAGE OF THE TOTAL LENGTH OF THE CORE RUN.

5% – VUGS INDICATES THE ESTIMATED RATIO OF VUGGED CORE SURFACE AREA TO TOTAL CORE SURFACE AREA. BOTH OPEN AND FILLED VUGS ARE INCLUDED IN THE VUGGED CATEGORY.

FRACTURE DENSITY TERMINOLOGY:

VERY CLOSE – LESS THAN 2 INCHES APART
CLOSE – 2 TO 6 INCHES
MODERATELY CLOSE – 6 TO 12 INCHES
WIDE – GREATER THAN 12 INCHES

REFERENCE:
DAMES & MOORE PLATES A-1M AND A-1N

Fermi 2

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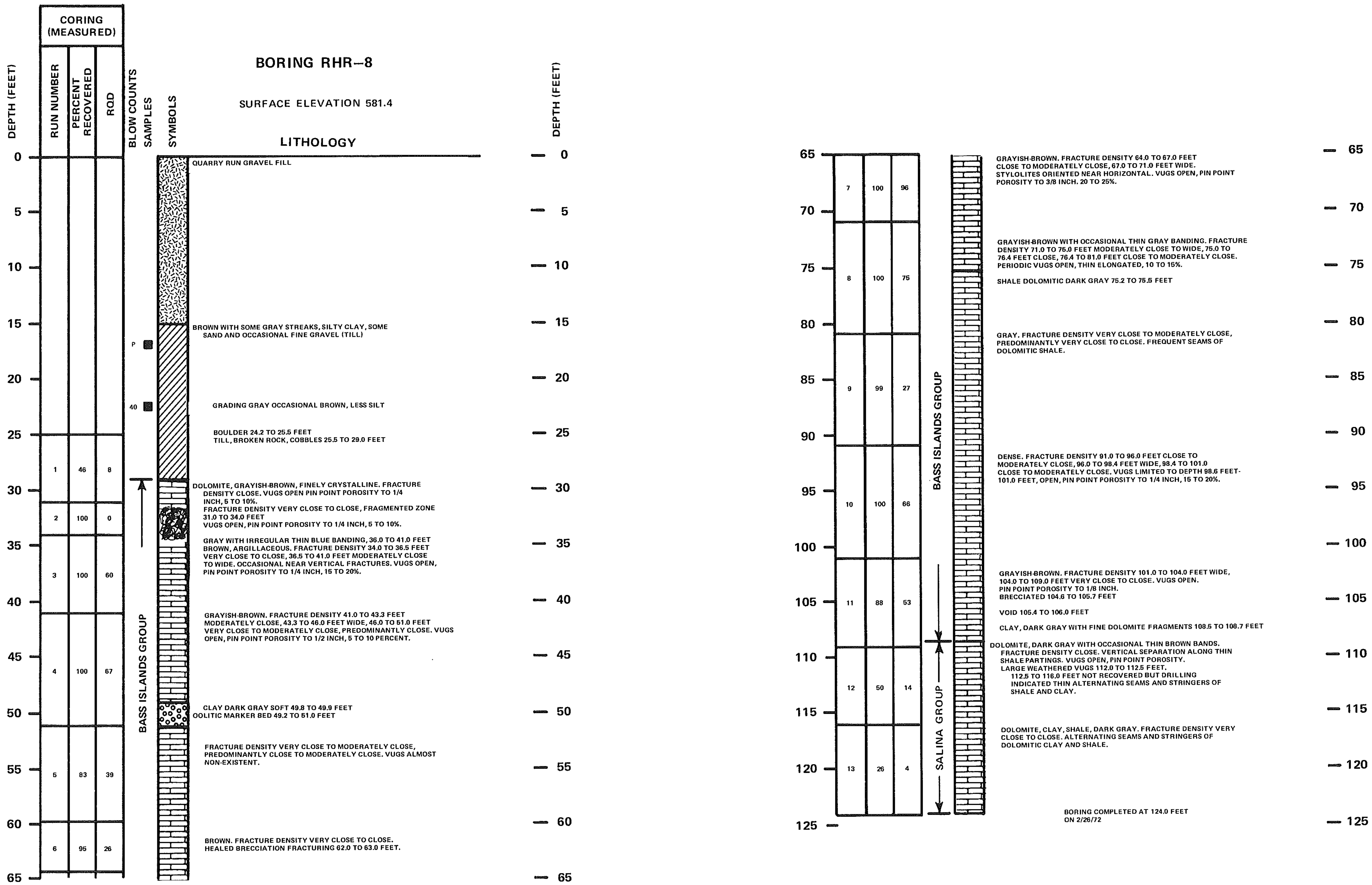
FIGURE 2.5-54

LOG OF BORING RHR-7



NOTES:

ELEVATIONS REFER TO NEW YORK MEAN TIDE, 1935

52 ■ INDICATES SOIL SAMPLE RECOVERED IN A DAMES & MOORE (3½ INCH O.D.) SAMPLER. FIGURES UNDER THE BLOW COUNT COLUMN INDICATE THE NUMBER OF BLOWS REQUIRED TO DRIVE THE SAMPLER 12 INCHES WITH A 455 POUND WEIGHT FALLING 30 INCHES.

RQD – ROCK QUALITY DESIGNATION

A MODIFIED CORE RECOVERY PERCENTAGE IN WHICH ALL THE PIECES OF SOUND CORE OVER 4-INCHES LONG ARE COUNTED AS RECOVERY. THE MODIFIED SUM OF CORE RECOVERED IS THEN EXPRESSED AS A PERCENTAGE OF THE TOTAL LENGTH OF THE CORE RUN.

5% – VUGS INDICATES THE ESTIMATED RATIO OF VUGGED CORE SURFACE AREA TO TOTAL CORE SURFACE AREA. BOTH OPEN AND FILLED VUGS ARE INCLUDED IN THE VUGGED CATEGORY.

FRACTURE DENSITY TERMINOLOGY:

VERY CLOSE – LESS THAN 2 INCHES APART
CLOSE – 2 TO 6 INCHES
MODERATELY CLOSE – 6 TO 12 INCHES
WIDE – GREATER THAN 12 INCHES

REFERENCE:
DAMES & MOORE PLATES A-1O AND A-1P

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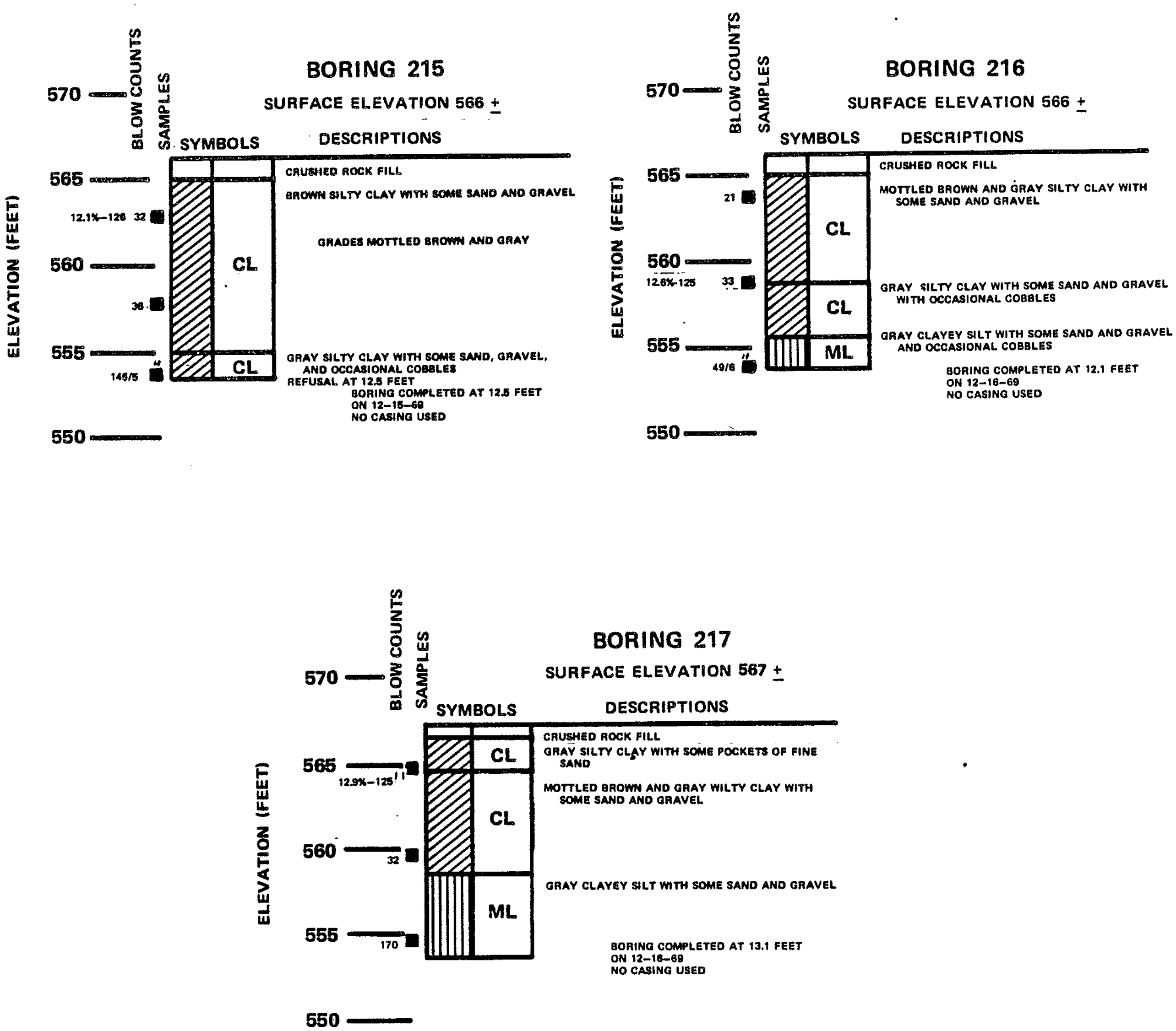
FIGURE 2.5-55

LOG OF BORING RHR-8



NOTES:

ELEVATIONS REFER TO N.Y.M.T., 1935

12.1% – 126 INDICATES FIELD MOISTURE CONTENT OF 12.1 PERCENT AND DRY DENSITY OF 126 POUNDS PER CUBIC FOOT.

32 ■ INDICATES SOIL SAMPLE RECOVERED IN A DAMES & MOORE (3¼ INCH O.D.) SAMPLER. FIGURES UNDER THE BLOW COUNT COLUMN INDICATE THE NUMBER OF BLOWS REQUIRED TO DRIVE THE SAMPLER 12 INCHES WITH A 350 POUND WEIGHT FALLING 30 INCHES

REFERENCE:
REFERENCE 32, PLATE A-1

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FIGURE 2.5-56

LOGS OF BORINGS 215, 216, AND 217

UNIFIED SOIL CLASSIFICATION SYSTEM

MAJOR DIVISIONS			GRAPH SYMBOL	LETTER SYMBOL	TYPICAL DESCRIPTIONS
COARSE GRAINED SOILS	GRAVEL AND GRAVELLY SOILS	CLEAN GRAVELS (LITTLE OR NO FINES)		GW	WELL-GRADED GRAVELS, GRAVEL SAND MIXTURES, LITTLE OR NO FINES
				GP	POORLY-GRADED GRAVELS, GRAVEL-SAND MIXTURES, LITTLE OR NO FINES
	MORE THAN 50 % OF COARSE FRACTION RETAINED ON NO 4 SIEVE	GRAVELS WITH FINES (APPRECIABLE AMOUNT OF FINES)		GM	SILTY GRAVELS, GRAVEL-SAND-SILT MIXTURES
				GC	CLAYEY GRAVELS, GRAVEL-SAND-CLAY MIXTURES
	SAND AND SANDY SOILS	CLEAN SAND (LITTLE OR NO FINES		SW	WELL-GRADED SANDS, GRAVELLY SANDS, LITTLE OR NO FINES
MORE THAN 50 % OF MATERIAL IS LARGER THAN NO 200 SIEVE SIZE				SP	POORLY-GRADED SANDS, GRAVELLY SANDS, LITTLE OR NO FINES
	MORE THAN 50% OF COARSE FRACTION PASSING NO 4 SIEVE	SANDS WITH FINES (APPRECIABLE AMOUNT OF FINES)		SM	SILTY SANDS, SAND-SILT MIXTURES
				SC	CLAYEY SANDS, SAND-CLAY MIXTURES
FINE GRAINED SOILS	SILTS AND CLAYS	LIQUID LIMIT LESS THAN 50		ML	INORGANIC SILTS AND VERY FINE SANDS, ROCK FLOUR, SILTY OR CLAYEY FINE SANDS OR CLAYEY SILTS WITH SLIGHT PLASTICITY
				CL	INORGANIC CLAYS OF LOW TO MEDIUM PLASTICITY, GRAVELLY CLAYS, SANDY CLAYS, SILTY CLAYS, LEAN CLAYS
				OL	ORGANIC SILTS AND ORGANIC SILTY CLAYS OF LOW PLASTICITY
	SILTS AND CLAYS	LIQUID LIMIT GREATER THAN 50		MH	INORGANIC SILTS, MICACEOUS OR DIATOMACEOUS FINE SAND OR SILTY SOILS
MORE THAN 50 % OF MATERIAL IS SMALLER THAN NO 200 SIEVE SIZE				CH	INORGANIC CLAYS OF HIGH PLASTICITY, FAT CLAYS
				OH	ORGANIC CLAYS OF MEDIUM TO HIGH PLASTICTY, ORGANIC SILTS
HIGHLY ORGANIC SOILS				PT	PEAT, HUMUS, SWAMP SOILS WITH HIGH ORGANIC CONTENTS

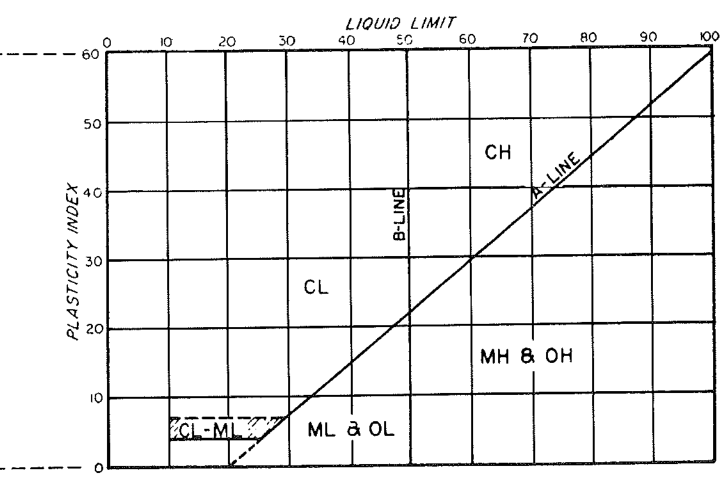
FOR LABORATORY CLASSIFICATION OF FINE-GRAINED SOILS

SOIL CLASSIFICATION CHART

MATERIAL SIZE	PARTICLE SIZE			
	LOWER LIMIT		UPPER LIMIT	
	MILLIMETERS	SIEVE SIZE	MILLIMETERS	SIEVE SIZE *
SAND				
FINE	.074	#200 *	0.42	#40 *
MEDIUM	0.42	#40 *	2.00	#10 *
COARSE	2.00	#10 *	4.76	#4 *
GRAVEL				
FINE	4.76	#4 *	19.1	3/4" •
COARSE	19.1	3/4" •	76.2	3" •
COBBLES	76.2	3" •	304.8	12" •
BOULDERS	304.8	12" •	914.4	36"

* U.S. STANDARD • CLEAR SQUARE OPENINGS

GRADATION CHART



PLASTICITY CHART

NOTES:
1. DUAL SYMBOLS ARE USED TO INDICATE BORDERLINE CLASSIFICATIONS.
2. WHEN SHOWN ON THE BORING LOGS, THE FOLLOWING TERMS ARE USED TO DESCRIBE THE CONSISTENCY OF COHESIVE SOILS AND THE RELATIVE COMPACTNESS OF COHESIONLESS SOILS.

COHESIVE SOILS

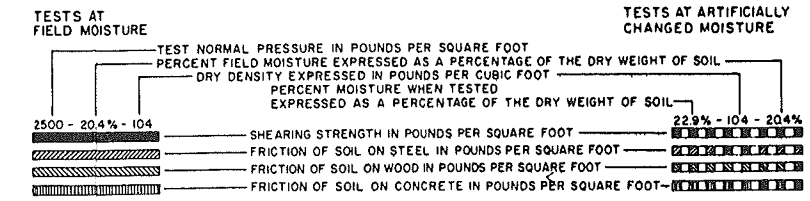
	(APPROXIMATE SHEARING STRENGTH IN KSF)
VERY SOFT	LESS THAN 25
SOFT	0.25 TO 0.5
MEDIUM STIFF	0.5 TO 1.0
STIFF	1.0 TO 2.0
VERY STIFF	2.0 TO 4.0
HARD	GREATER THAN 4.0

COHESIONLESS SOILS

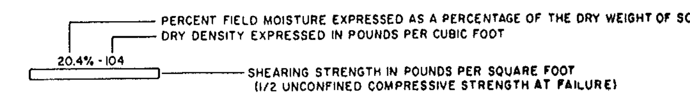
VERY LOOSE
LOOSE
MEDIUM DENSE
DENSE
VERY DENSE

THESE ARE USUALLY BASED ON AN EXAMINATION OF SOIL SAMPLES, PENETRATION RESISTANCE, AND SOIL DENSITY DATA.

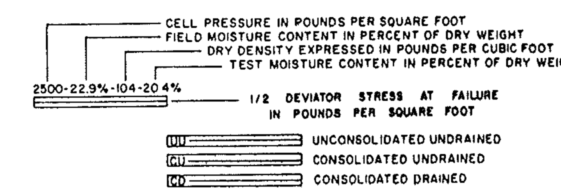
KEY TO TEST DATA



DIRECT SHEAR AND FRICTION TESTS



UNCONFINED COMPRESSION TESTS



TRIAXIAL COMPRESSION TESTS

YIELD, PEAK OR ULTIMATE STRENGTHS ARE IDENTIFIED ON SHEAR TEST DATA ON THE BORING LOGS AS FOLLOWS:

* YIELD STRENGTH
** PEAK STRENGTH
*** ULTIMATE STRENGTH

SHEAR TEST RESULTS

■ INDICATES UNDISTURBED SAMPLE
☒ INDICATES DISTURBED SAMPLE
□ INDICATES SAMPLING ATTEMPT WITH NO RECOVERY

I INDICATES LENGTH OF CORING RUN

NOTE:
DEFINITIONS OF ANY ADDITIONAL DATA REGARDING SAMPLES ARE ENTERED ON THE FIRST LOG ON WHICH THE DATA APPEAR.

SAMPLES

REFERENCE:
REFERENCE 32, PLATE A-2

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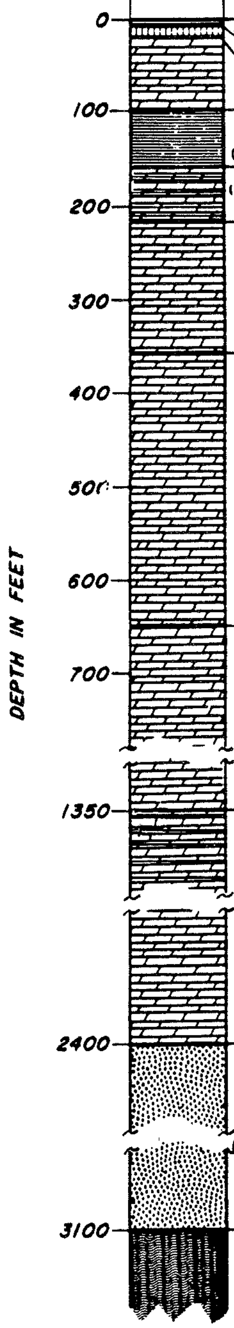
FIGURE 2.5-57

UNIFIED SOIL CLASSIFICATION SYSTEM



SYMBOL	DESCRIPTION	COMPRESSIONAL WAVE VELOCITY (FT./SEC.)	POISSON'S RATIO (ESTIMATED)	SHEAR WAVE VELOCITY (FT./SEC.) (COMPUTED)	TOTAL UNIT WEIGHT (LBS./CU. FT.)
	RECENT LAGOON DEPOSITS	1000	.45	300	95
	GLACIAL TILL	6500	.40	2650	130
	BASS ISLANDS DOLOMITE	13,000	.24	7600	158
	SALINA GROUP G FORMATION (SHALES AND SHALY DOLOMITE)	8000	.34	3900	138
	E FORMATION (SHALY DOLOMITE, LIMESTONE AND LIMESTONE BRECCIAS)	9000	.30	4800	142
	C FORMATION (DOLOMITE AND SHALY DOLOMITE)	14,000	.24	8200	160
	A FORMATION (LIMESTONE AND DOLOMITE)	15,600	.24	9100	168
	MIDDLE AND EARLY SILURIAN SEDIMENTS (PREDOMINANTLY DOLOMITES AND LIMESTONES)	15,600	.20	9500	168
	ORDOVICIAN SEDIMENTS (SHALE, SHALY DOLOMITES AND DENSE DOLOMITES)	15,600	.20	9500	168
	CAMBRIAN SEDIMENTS (PREDOMINANTLY SANDSTONES)	15,600	.20	9500	168
	PRECAMBRIAN (GRANITIC GNEISS)	19,200	.15	12,300	170

REFERENCE:
FERMI 2 PSAR – FIGURE 2.5-14

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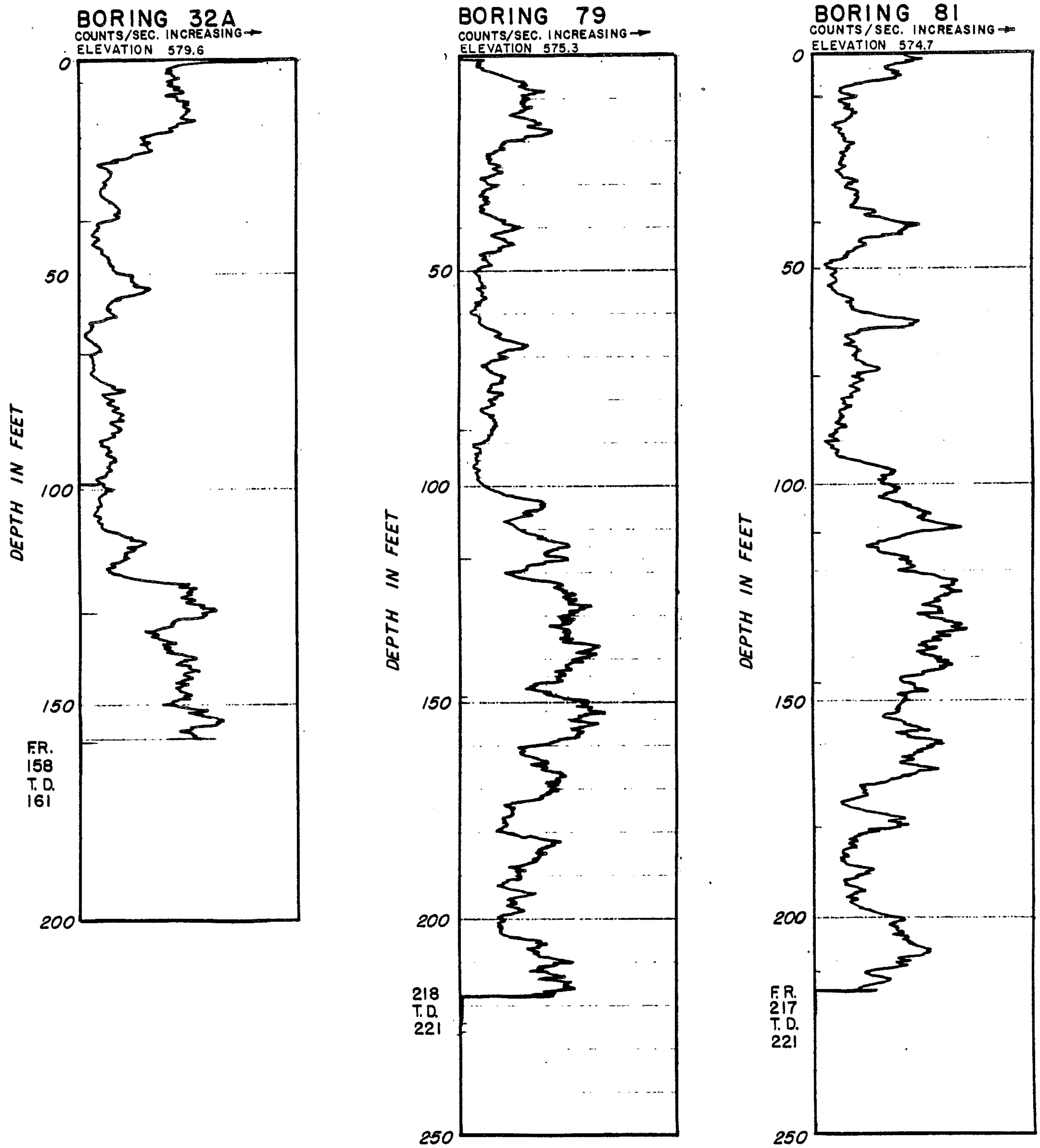
FIGURE 2.5-58

STRATIGRAPHIC COLUMN SHOWING GEOPHYSICAL DATA



NOTE:
GEOPHYSICAL LOGS BY THE BIRDWELL DIVISION
OF SEISMOGRAPHIC SERVICE CORPORATION

REFERENCE:
FERMI 2 PSAR – FIGURE 2.5-13.1

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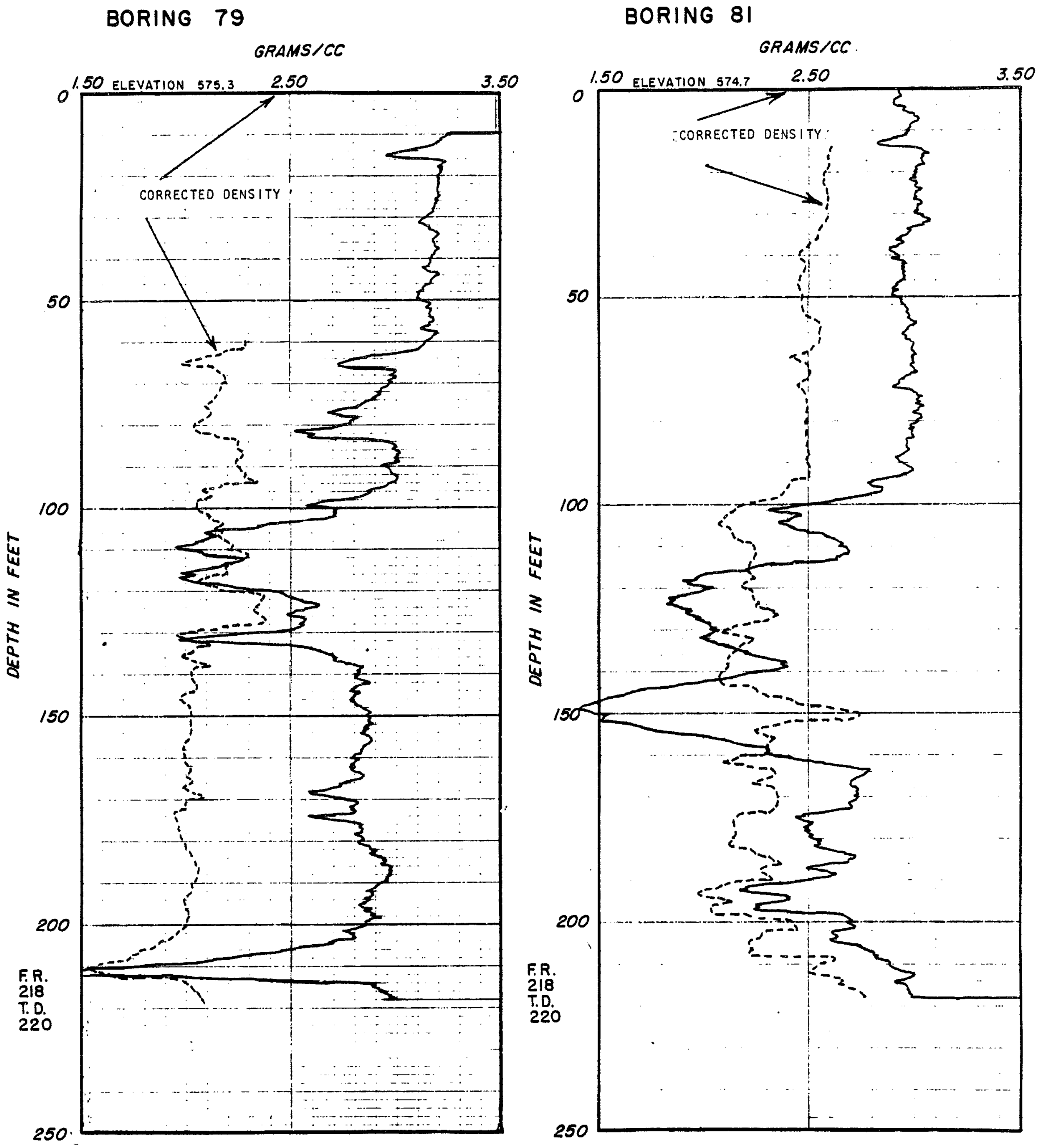
FIGURE 2.5-59

BOREHOLE GEOPHYSICAL MEASUREMENTS
GAMMA RAY LOGS – BORINGS 32A, 79, AND 81



NOTE:
GEOPHYSICAL LOGS BY THE BIRDWELL DIVISION
OF SEISMOGRAPHIC SERVICE CORPORATION

REFERENCE:
FERMI 2 PSAR – FIGURE 2.5-13.2

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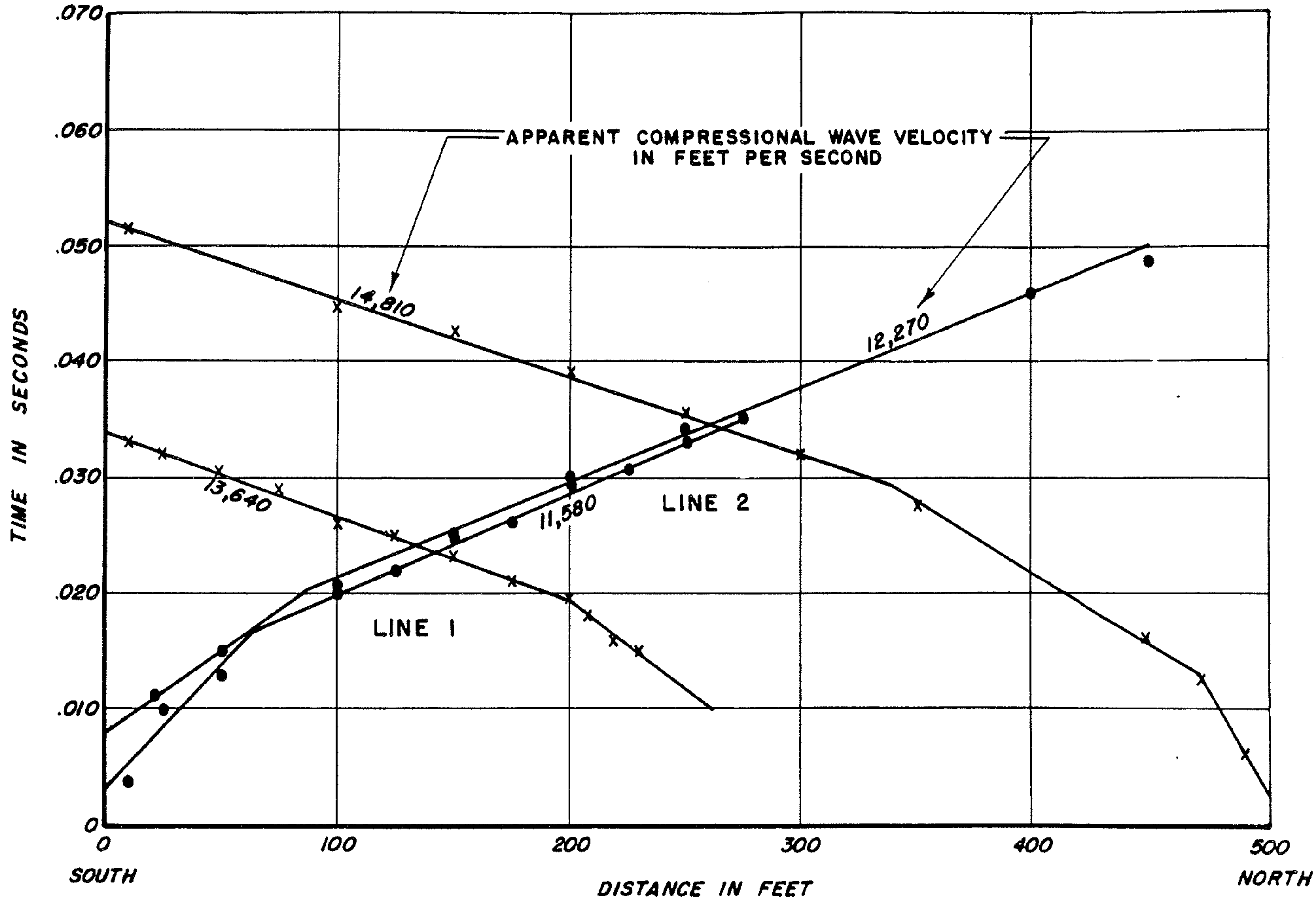
FIGURE 2.5-60

BOREHOLE GEOPHYSICAL MEASUREMENTS
DENSITY LOGS – BORINGS 79 AND 81



V_1 = 1000 FPS, 0-3FT
V_2 = 6500 ± 1000 FPS, 3-23 FT
V_3 = 13,000 ± 500 FPS, 20+ FT

REFERENCE:
FERMI 2 PSAR – FIGURE 2.5-5

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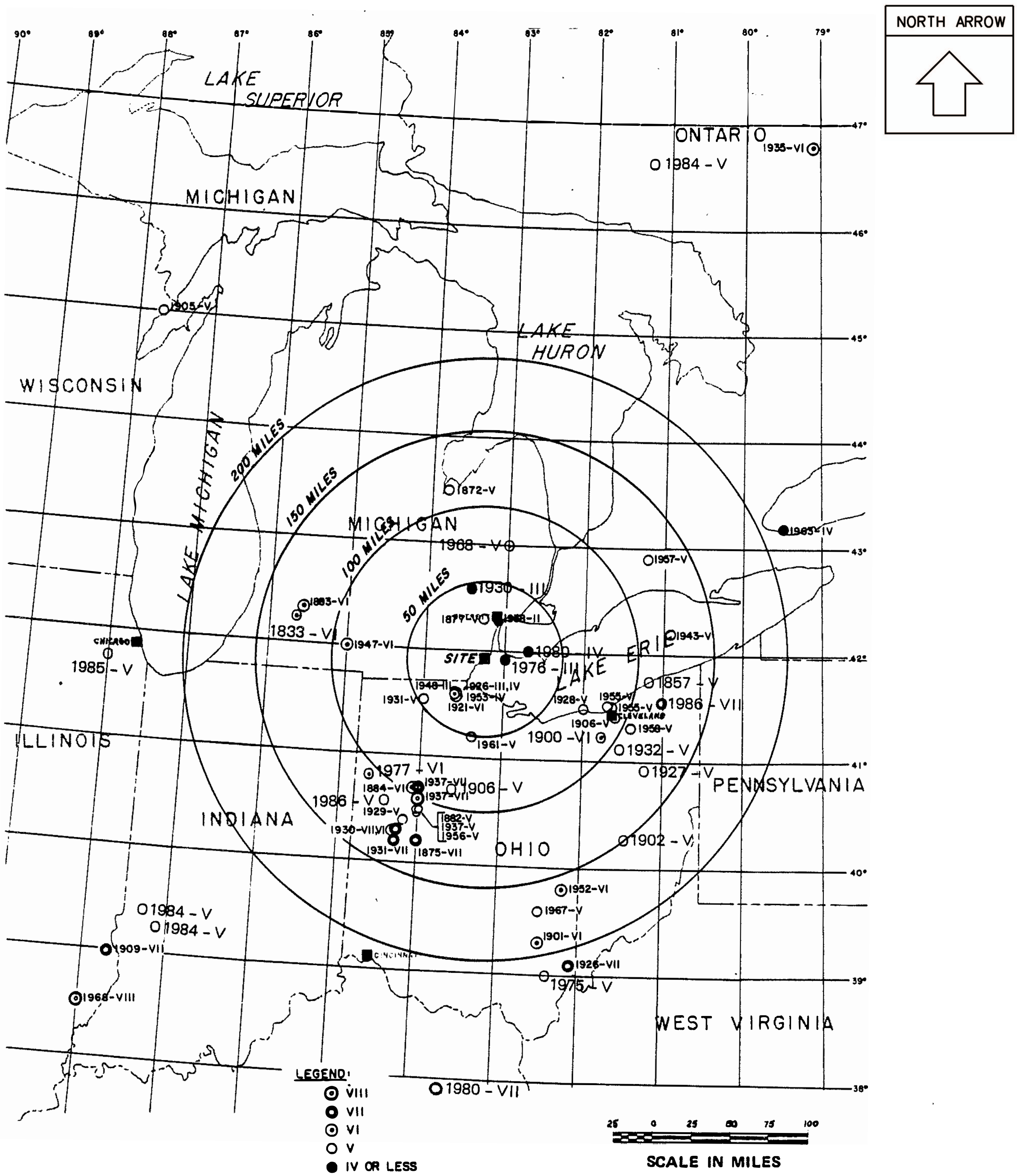
FIGURE 2.5-61

SEISMIC REFRACTION SURVEY



REFERENCE:
MODIFIED FROM: BASEMENT ROCK MAP OF THE UNITED STATES, COMPILED BY RICHARD W. BAYLEY, UNITED STATES GEOLOGICAL SURVEY, AND WILLIAM MUEHLBERGER, UNIVERSITY OF TEXAS, 1968.

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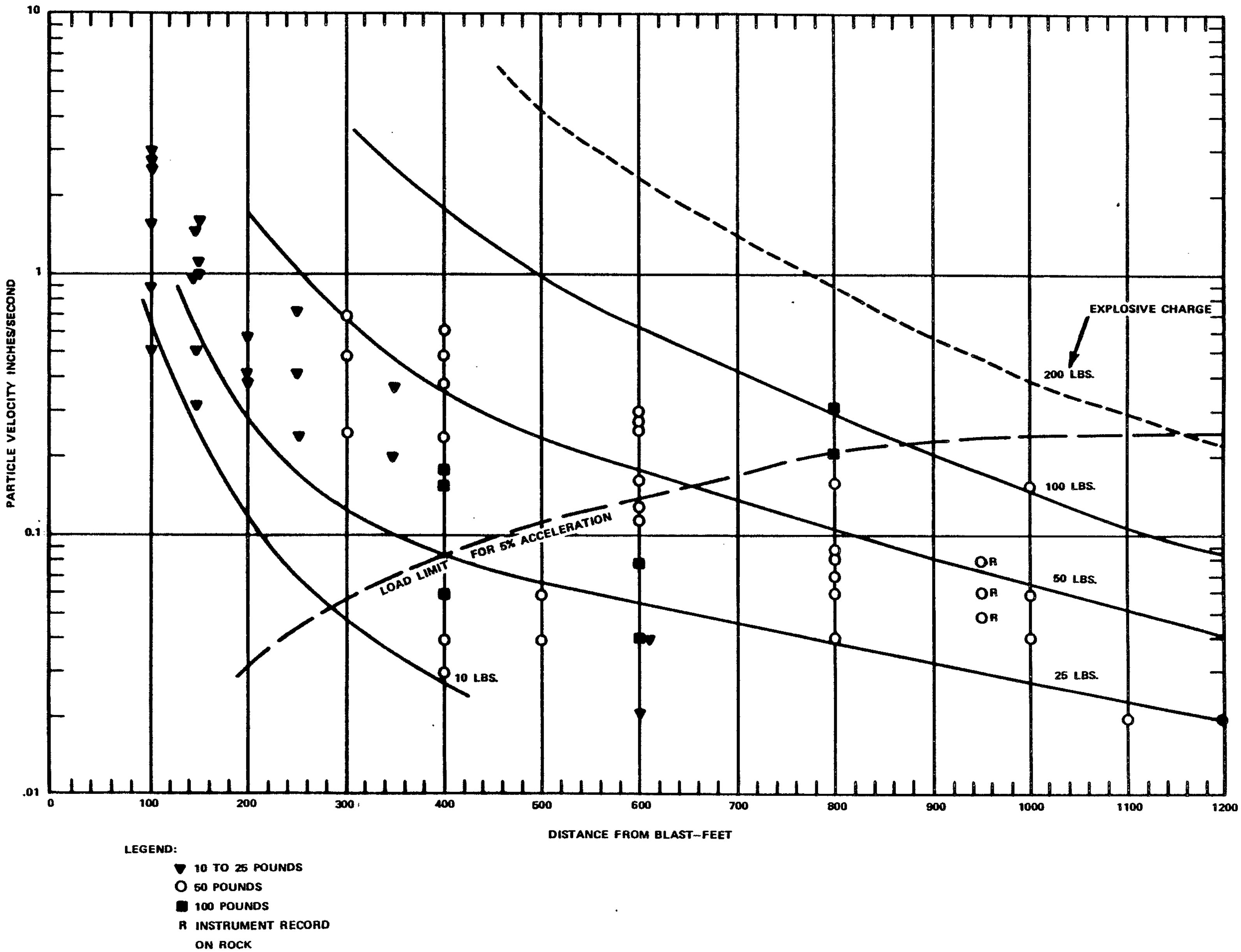
FIGURE 2.5-62

EPICENTER MAP



REFERENCE:
FERMI 2 PSAR – FIGURE 2.5-17
DAMES & MOORE FIGURE 2.5-22.8

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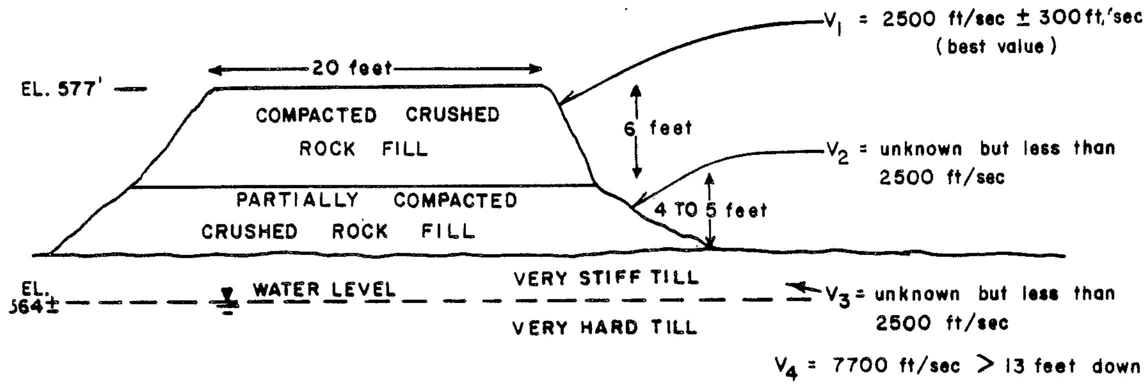
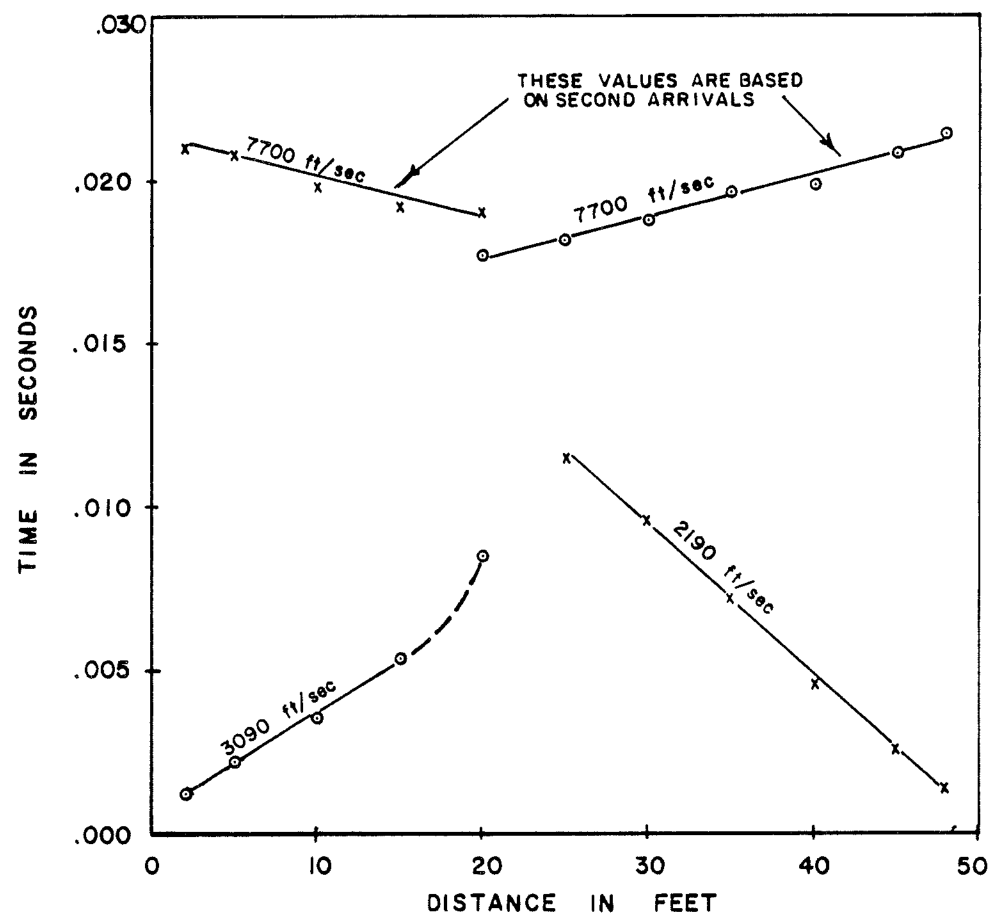
FIGURE 2.5-63
ATTENUATION CURVES



TYPICAL CROSS SECTION OF FILL



NOTE:
ALL ELEVATIONS REFER TO NEW YORK MEAN TIDE, 1935

REFERENCE:
REFERENCE 32, PLATE A-3

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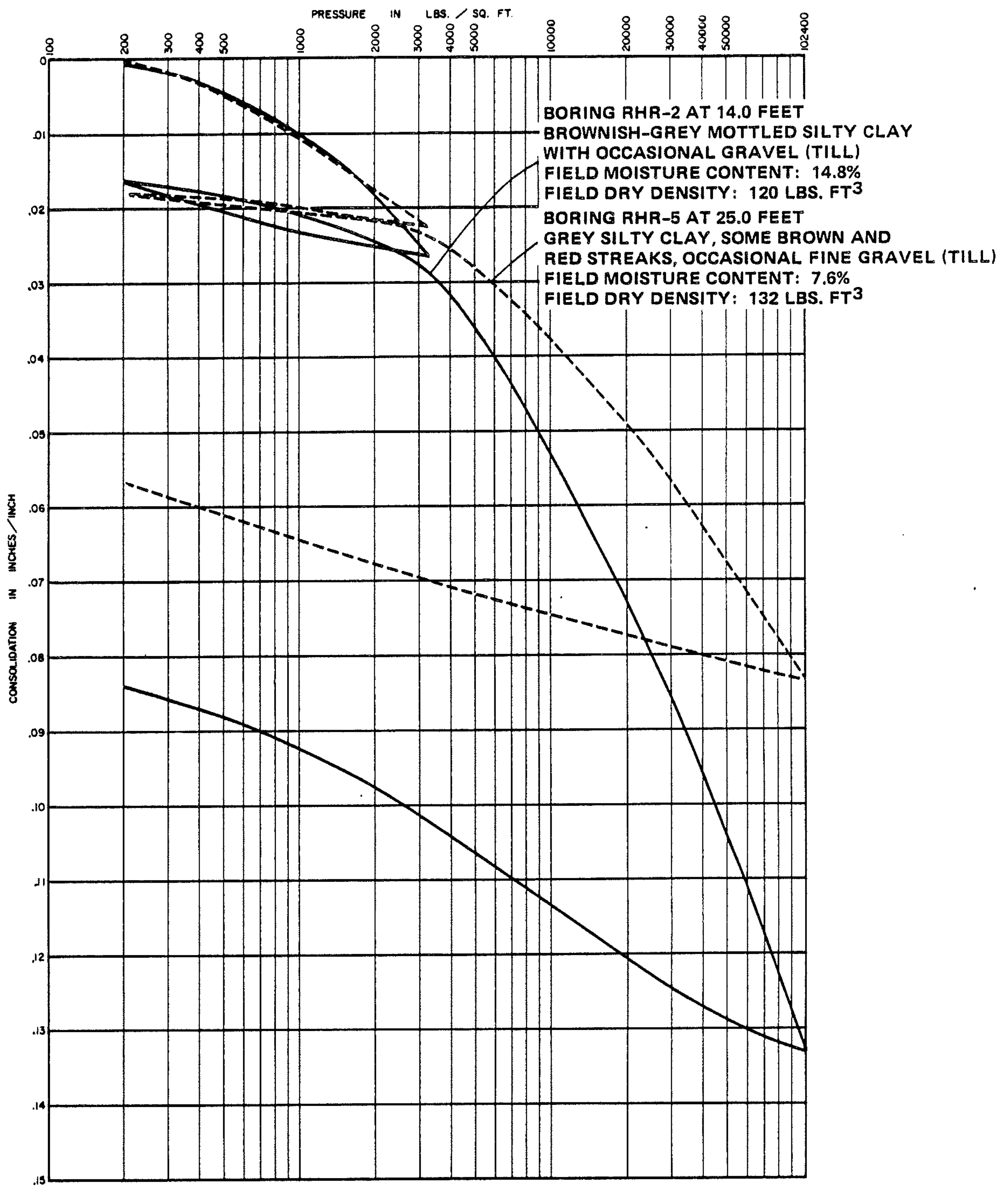
FIGURE 2.5-64

SEISMIC REFRACTION SURVEY OF FILL



REFERENCE:
REFERENCE 3, PLATE A-6

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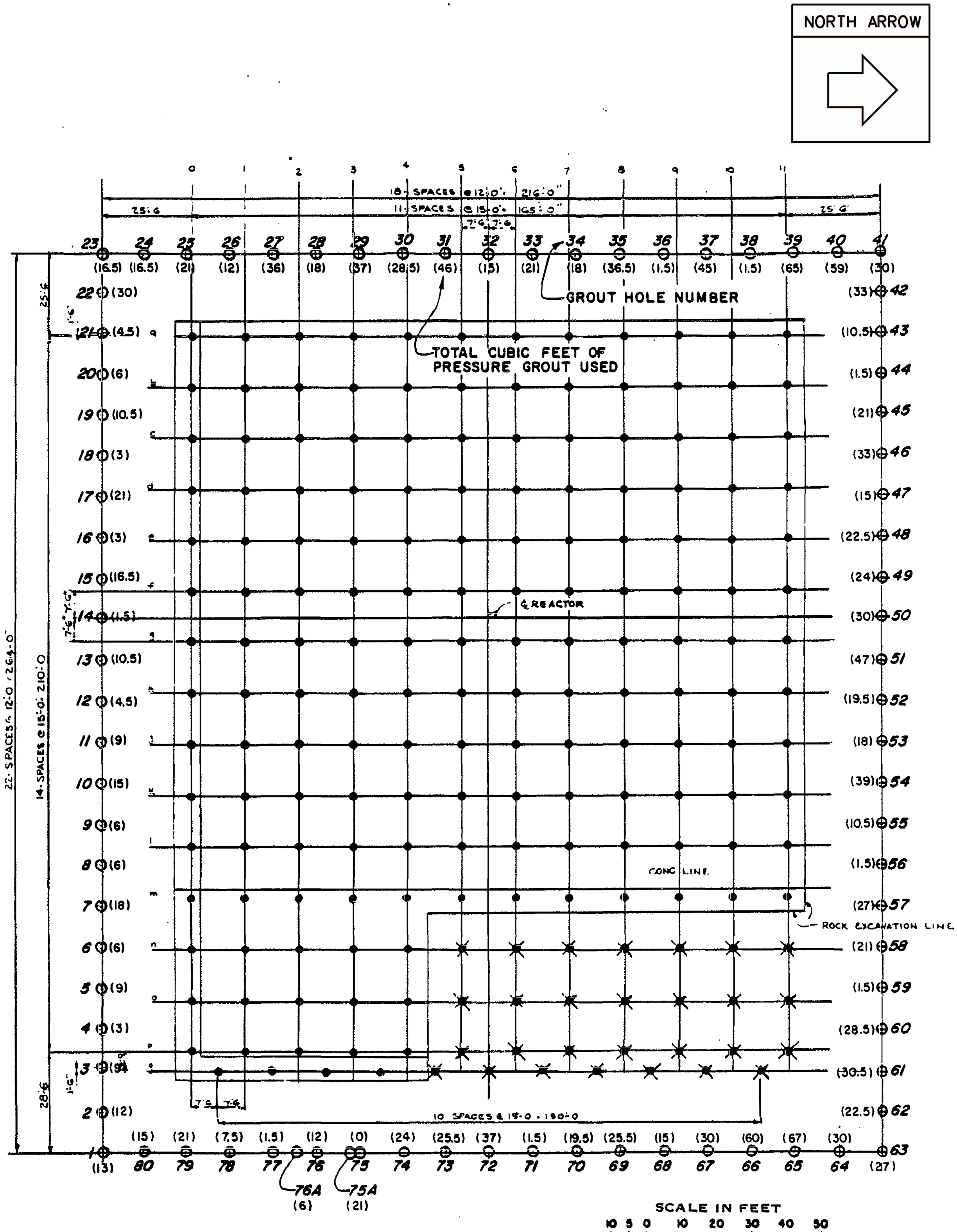
FIGURE 2.5-65

CONSOLIDATION TEST DATA



KEY TO GROUT HOLES:

- ○ CURTAIN WALL GROUT HOLES TO EL. 515± DRILLED FROM TOP OF GLACIAL TILL
- ● FOUNDATION GROUT HOLES TO EL. 483± DRILLED FROM ROCK SURFACE
- ✱ FOUNDATION GROUT HOLES TO EL. 499± DRILLED FROM ROCK SURFACE

REFERENCE:
REFERENCE 46, PLATE 1

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FIGURE 2.5-66

GROUT HOLE LOCATION PLAN
REACTOR/AUXILIARY BUILDING

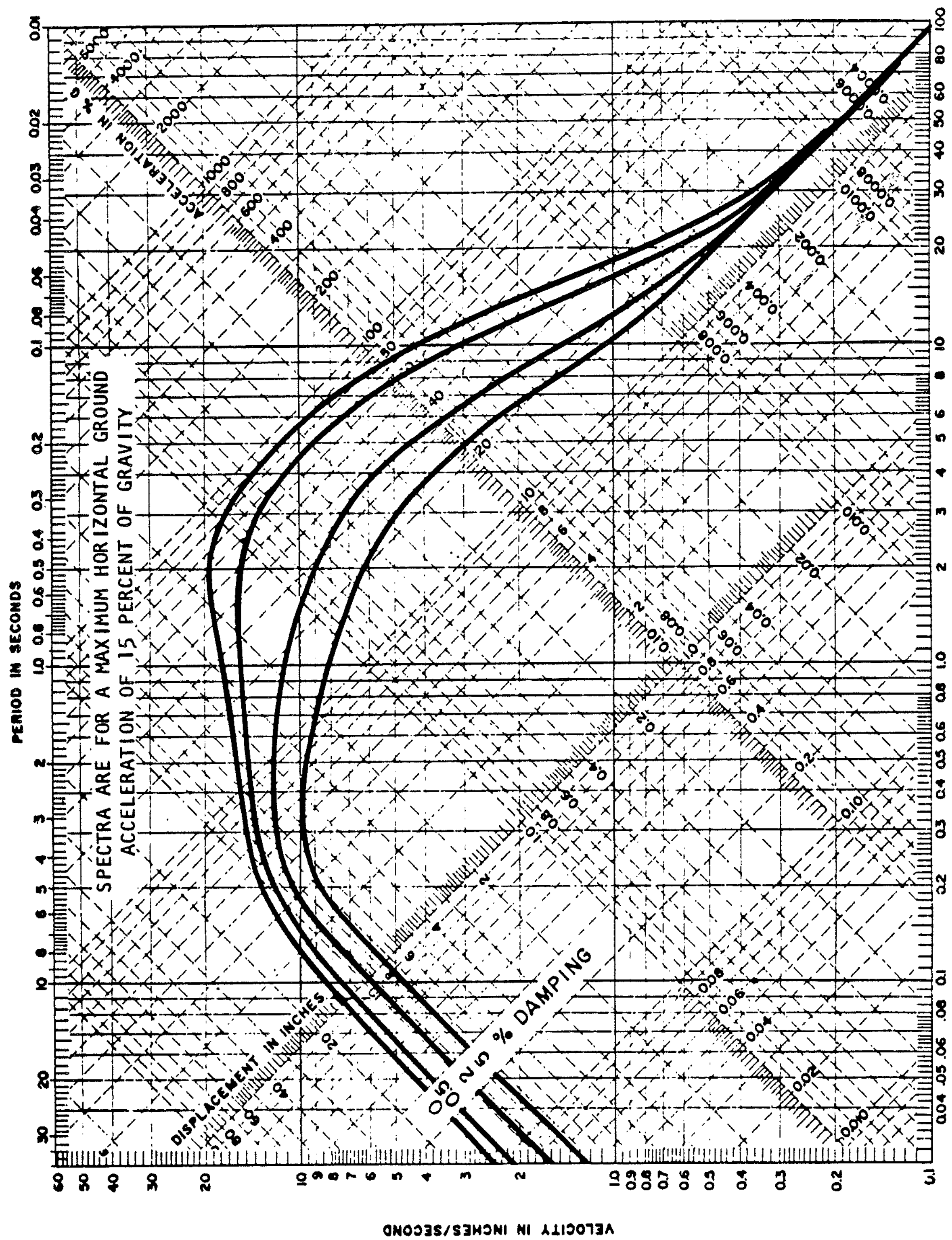

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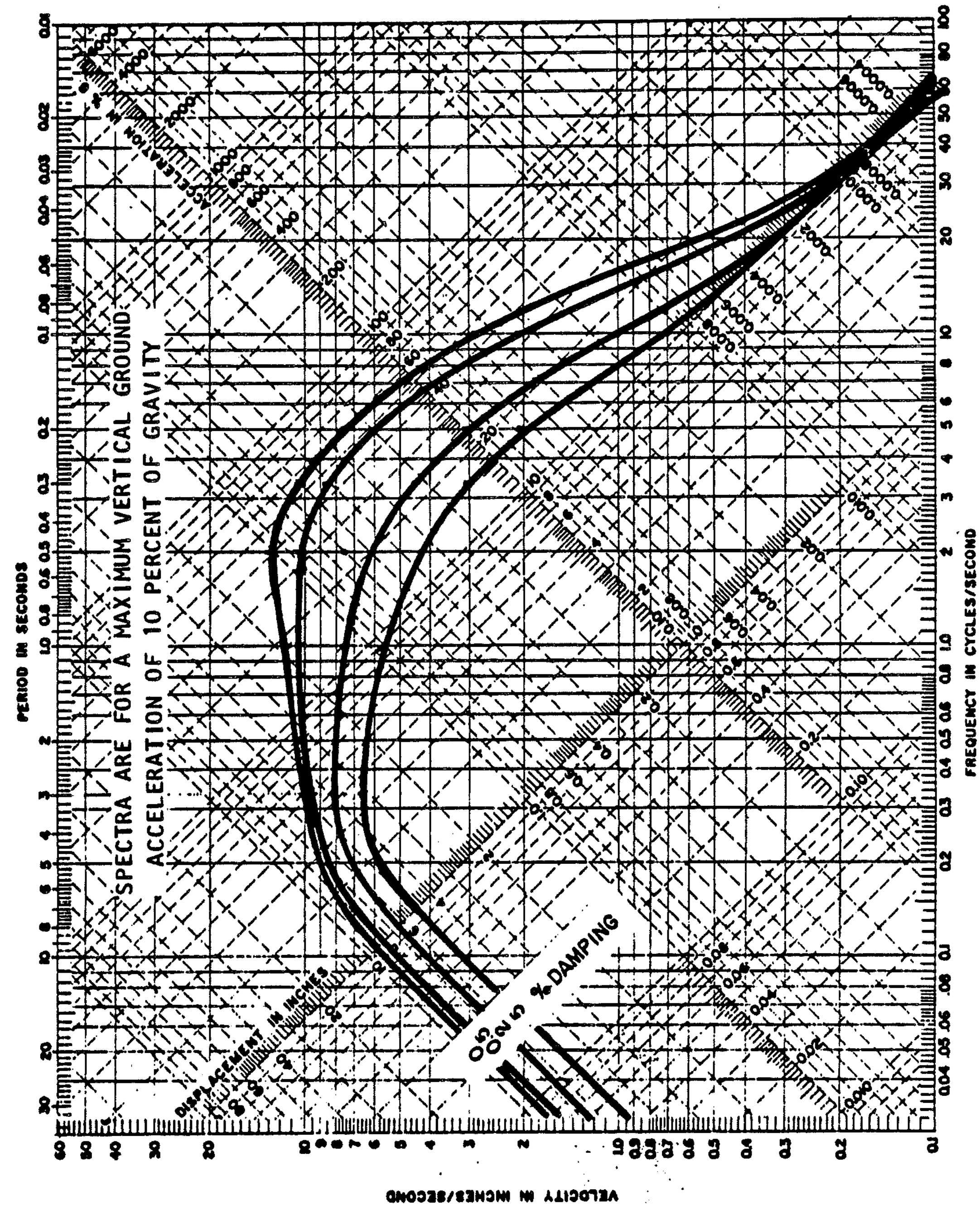
FIGURE 2.5-67, SHEET 1

RESPONSE SPECTRA FOR SAFE-SHUTDOWN EARTHQUAKE – ROCK FOUNDATION (HORIZONTAL)

REFERENCE:
DAMES & MOORE REPORT, REFERENCE 3



REFERENCE:
DAMES & MOORE REPORT, REFERENCE 3

Fermi 2

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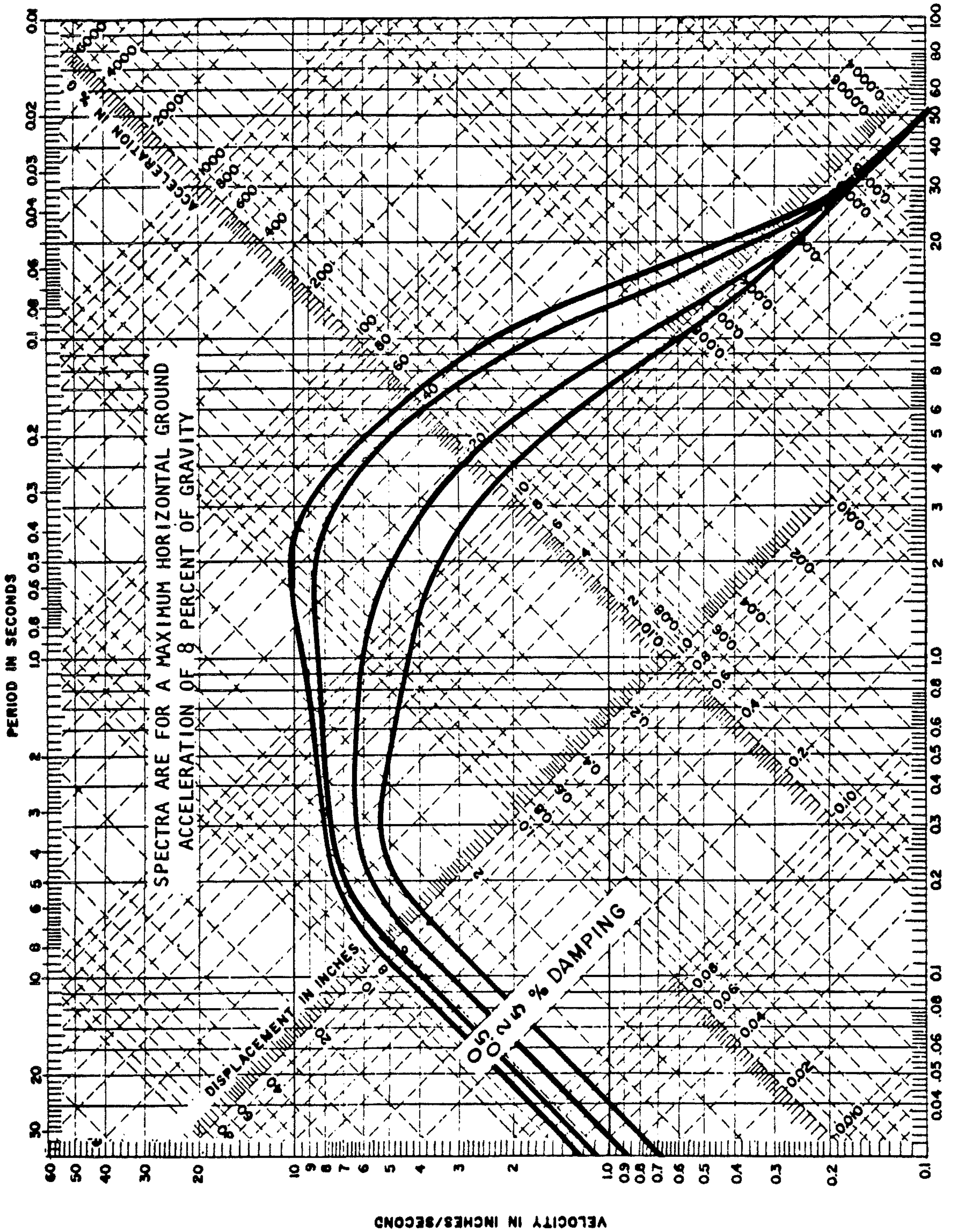
FIGURE 2.5-67, SHEET 2

RESPONSE SPECTRA FOR SAFE-SHUTDOWN EARTHQUAKE – ROCK FOUNDATION (VERTICAL)



REFERENCE:
DAMES & MOORE REPORT, REFERENCE 3

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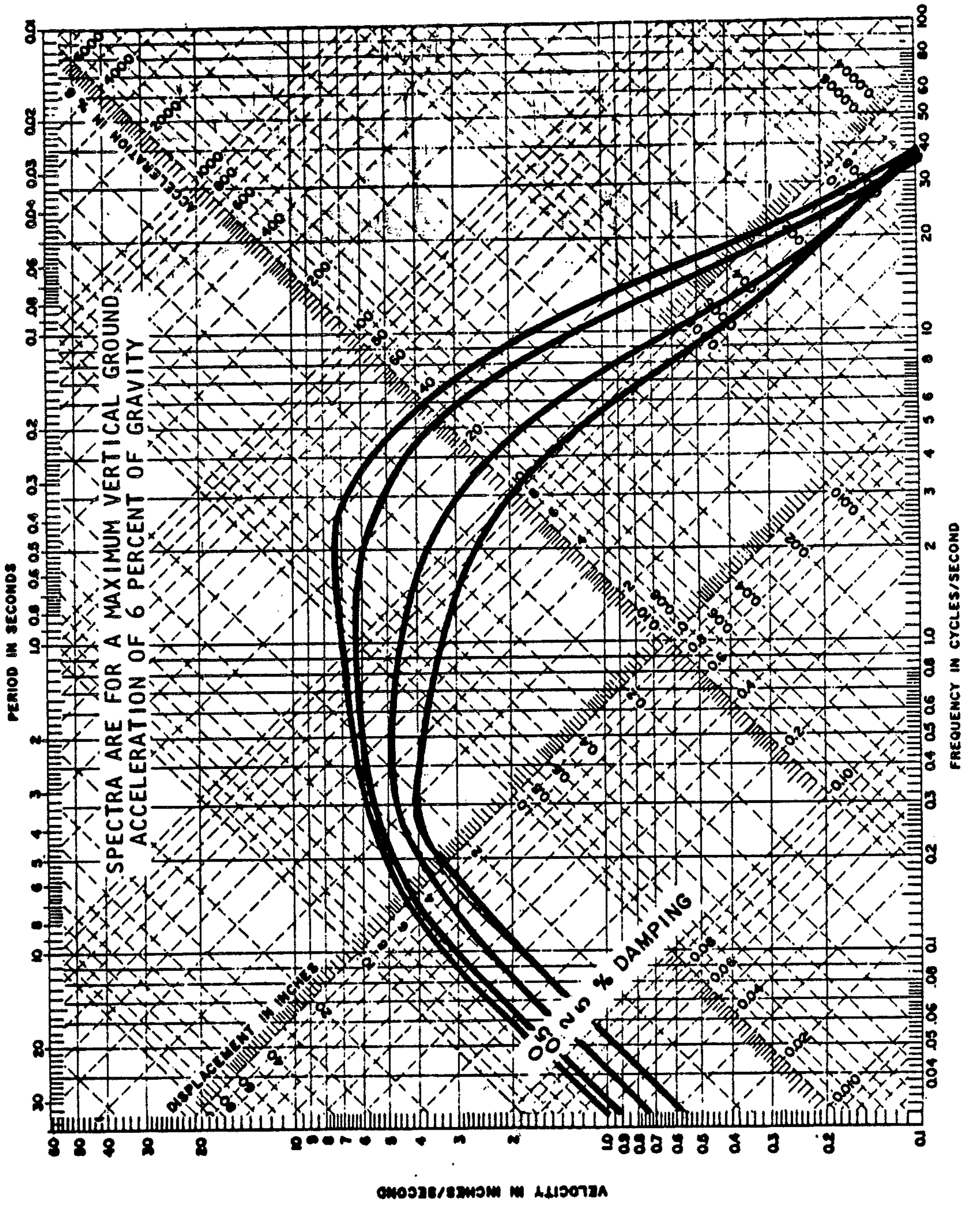
FIGURE 2.5-68, SHEET 1

RESPONSE SPECTRA FOR OPERATING BASIS EARTHQUAKE – ROCK FOUNDATION (HORIZONTAL)



REFERENCE:
DAMES & MOORE REPORT, REFERENCE 3

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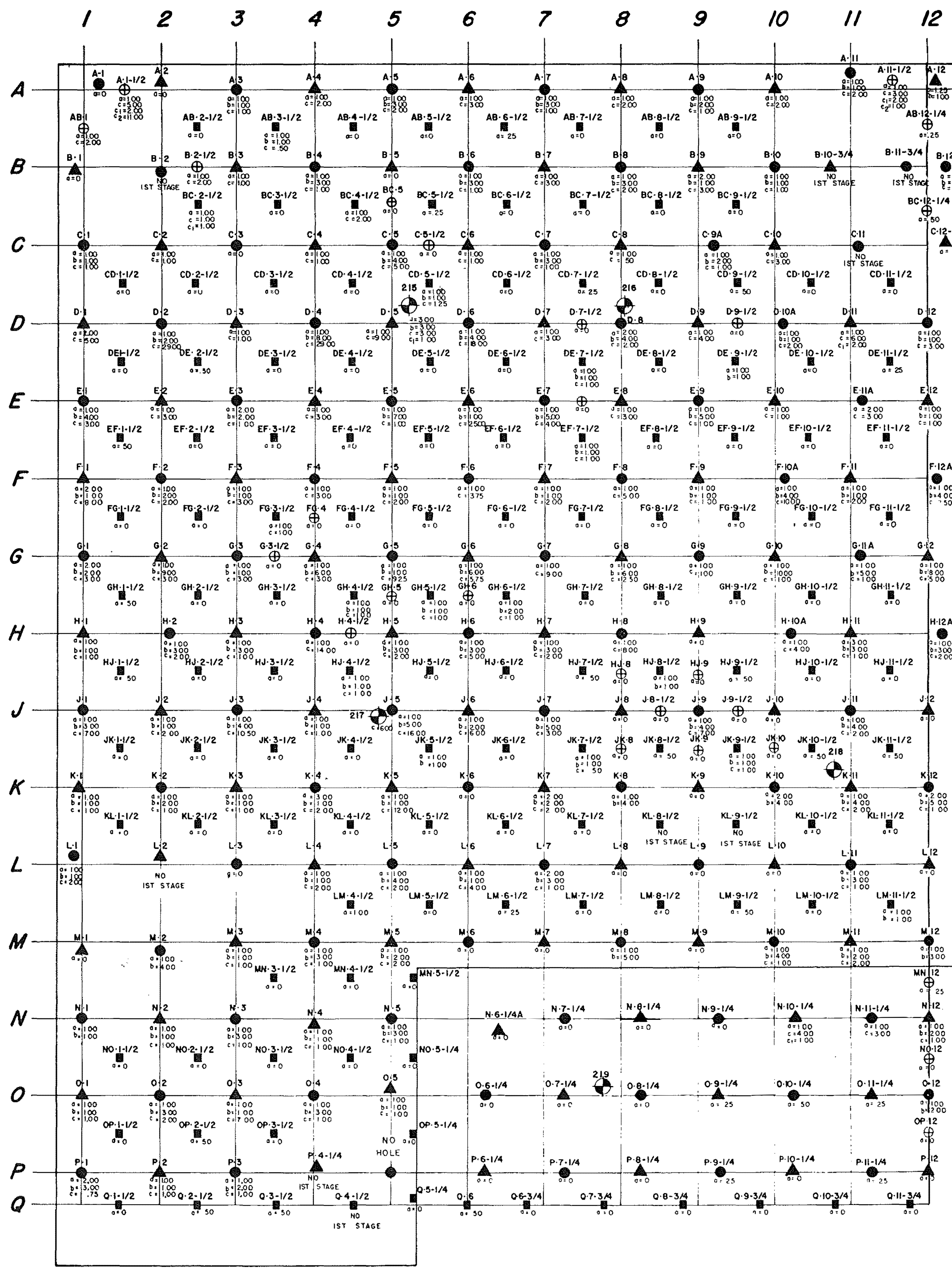
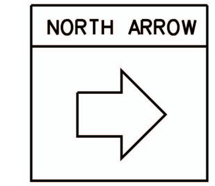
FIGURE 2.5-68, SHEET 2

RESPONSE SPECTRA FOR OPERATING-BASIS EARTHQUAKE – ROCK FOUNDATION (VERTICAL)





KEY:

- PRIMARY HOLE
- SECONDARY HOLE
- TERTIARY HOLE
- QUATERNARY HOLE
- CORE HOLE (SAME VALUES INDICATED 1ST AND 2ND STAGE)

BATCH LEGEND:

a = NUMBER OF BATCHES 3:1 MIX
b = NUMBER OF BATCHES 1.5:1 MIX
c = NUMBER OF BATCHES .67:1 MIX
c_1 = NUMBER OF BATCHES .67:1+ 1 C.F. SAND MIX
c_2 = NUMBER OF BATCHES .67:1+ 2 C.F. SAND MIX

NOTES:

1. ANY OF THE ABOVE SYMBOLS (a, b, c, c_1, c_2) FOLLOWED BY ZERO (0) INDICATES AN ATTEMPT TO GROUT WITH THE INDICATED MIX BUT RESULTED IN A "NO TAKE".
2. NO ATTEMPT AT GROUTING IS INDICATED BY "NO 1ST STAGE" IMMEDIATLY UNDER HOLE.

5 0 5 10 15 20 25
SCALE IN FEET

REFERENCE:
REFERENCE 23, PLATE A-1

Fermi 2

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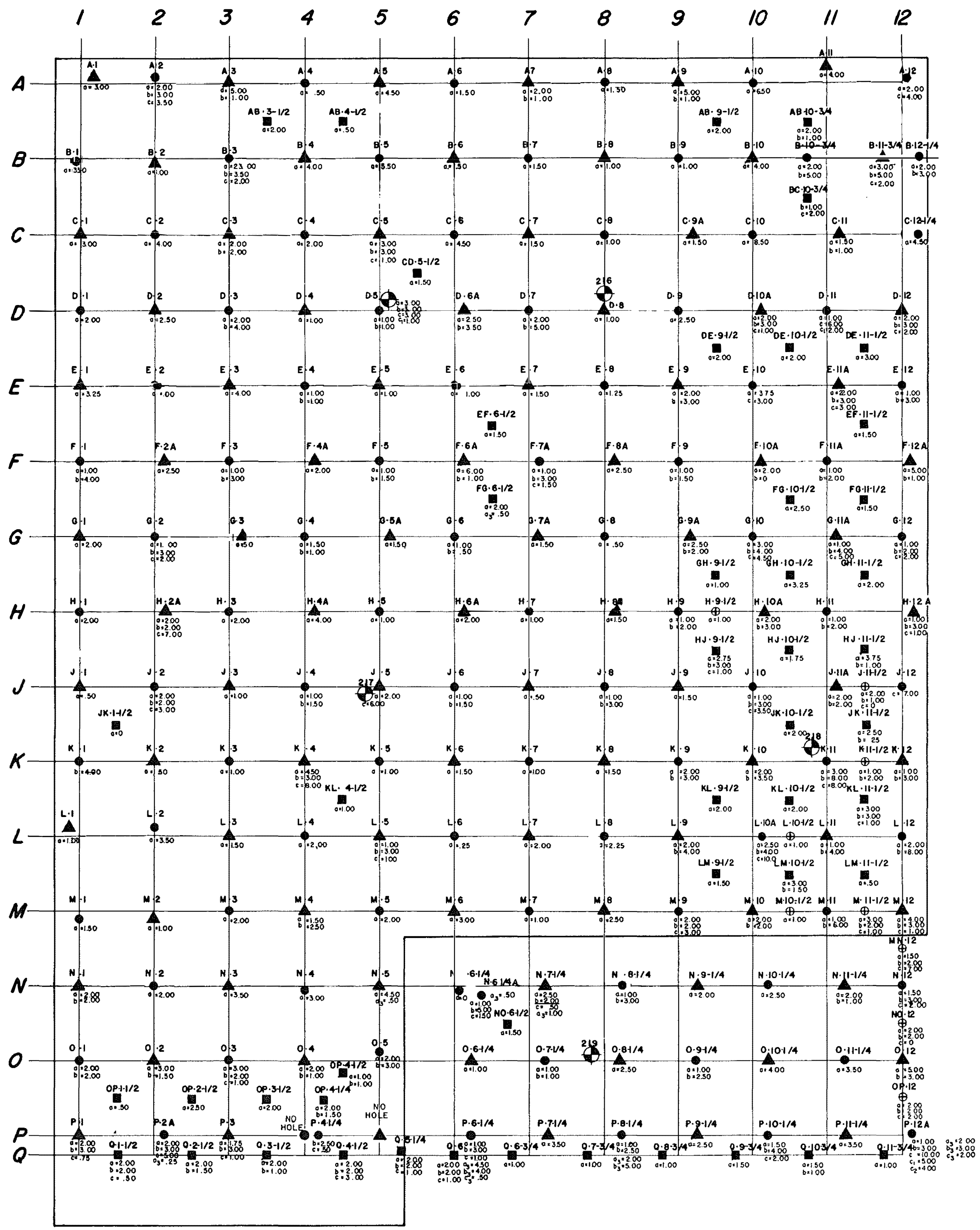
FIGURE 2.5-69

FOUNDATION TREATMENT
FIRST ZONE GROUTING
REACTOR/AUXILIARY BUILDING



NORTH ARROW

KEY:
- PRIMARY HOLE
- SECONDARY HOLE
- TERTIARY HOLE
- QUATERNARY HOLE
- CORE HOLE (SAME VALUES INDICATED 1ST AND 2ND STAGE)

BATCH LEGEND (2ND STAGE):

a = NUMBER OF BATCHES 3:1 MIX
b = NUMBER OF BATCHES 1.5:1 MIX
c = NUMBER OF BATCHES .67:1 MIX
c_1 = NUMBER OF BATCHES .67:1+ 1 C.F. SAND MIX
c_2 = NUMBER OF BATCHES .67:1+ 2 C.F. SAND MIX

BATCH LEGEND (3RD STAGE):

a_3 = NUMBER OF BATCHES 3:1 MIX
b_3 = NUMBER OF BATCHES 1.5:1 MIX
c_3 = NUMBER OF BATCHES .67:1 MIX

NOTES:

1. ANY OF THE ABOVE SYMBOLS (a, b, c, c_1, c_2) FOLLOWED BY ZERO (0) INDICATES AN ATTEMPT TO GROUT WITH THE INDICATED MIX BUT RESULTED IN A "NO TAKE".

5 0 5 10 15 20 25
SCALE IN FEET

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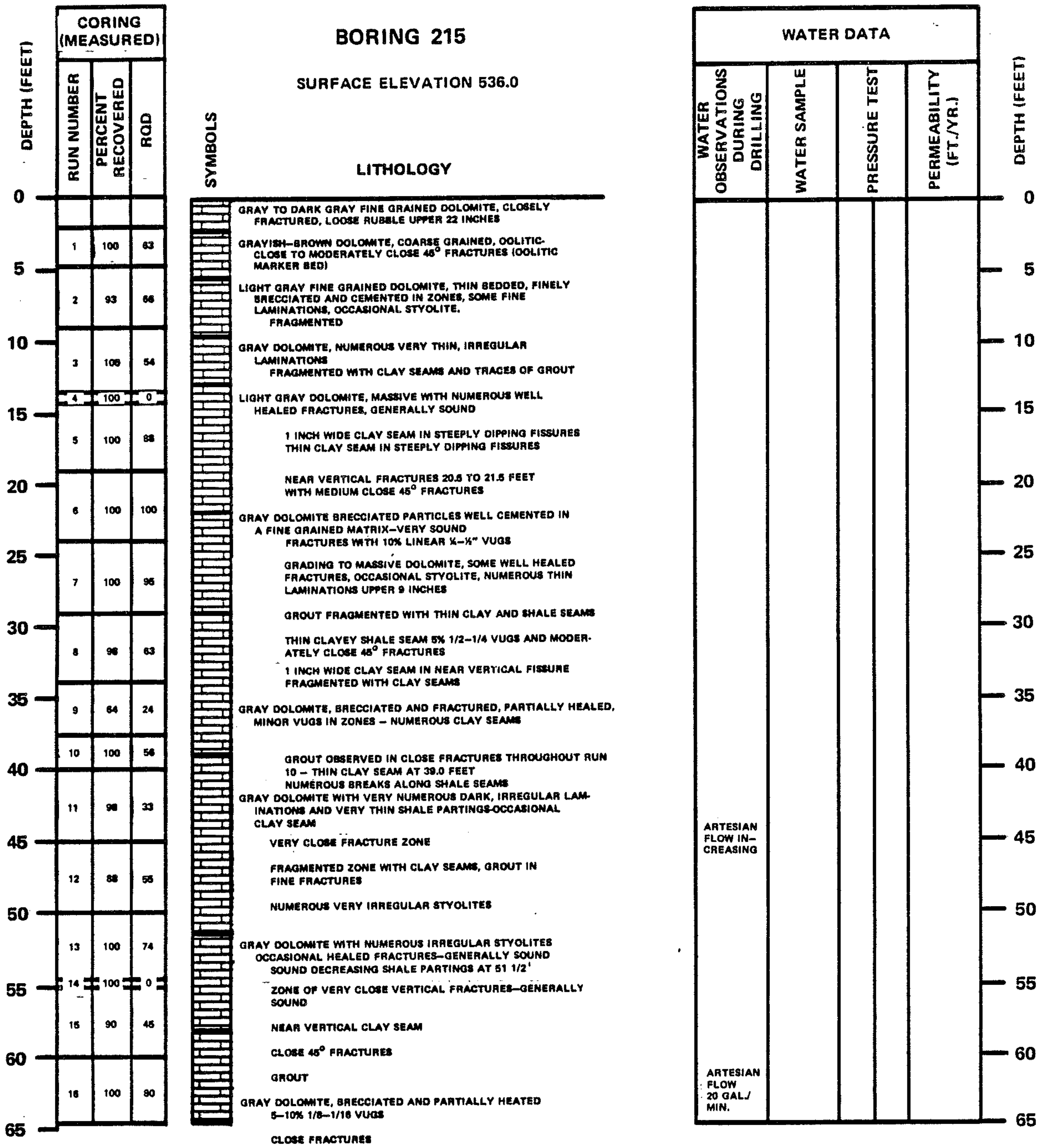
FIGURE 2.5-70

FOUNDATION ZONE TREATMENT
SECOND ZONE GROUTING
REACTOR/AUXILIARY BUILDING

REFERENCE:
REFERENCE 23, PLATE A-2



BORING COMPLETED AT 64.9 FEET ON 9–16–70
CASING USED TO A DEPTH OF 54.0 FEET.
NO DRILLING MUD USED
ARTESIAN WATER FROM 10.0 FEET

NOTES:

ELEVATIONS REFER TO N.Y.M.T., 1935

RQD – ROCK QUALITY DESIGNATION
A MODIFIED CORE RECOVERY PERCENTAGE IN WHICH ALL THE PIECES OF SOUND CORE OVER 4 INCHES LONG ARE COUNTED AS RECOVERY. THE MODIFIED SUM OF CORE RECOVERED IS THEN EXPRESSED AS A PERCENTAGE OF THE TOTAL LENGTH OF THE CORE RUN.

% – VUGS INDICATES THE ESTIMATED RATIO OF VUGGED CORE SURFACE AREA TO TOTAL CORE SURFACE AREA. BOTH OPEN AND FILLED VUGS ARE INCLUDED IN THE VUGGED CATEGORY.

FRACTURE DENSITY TERMINOLOGY
VERY CLOSE–LESS THAN 2 INCHES APART
CLOSE–2 TO 6 INCHES
MODERATELY CLOSE–6 TO 12 INCHES
WIDE –GREATER THAN 12 INCHES

REFERENCE:
REFERENCE 23, PLATE A-3A

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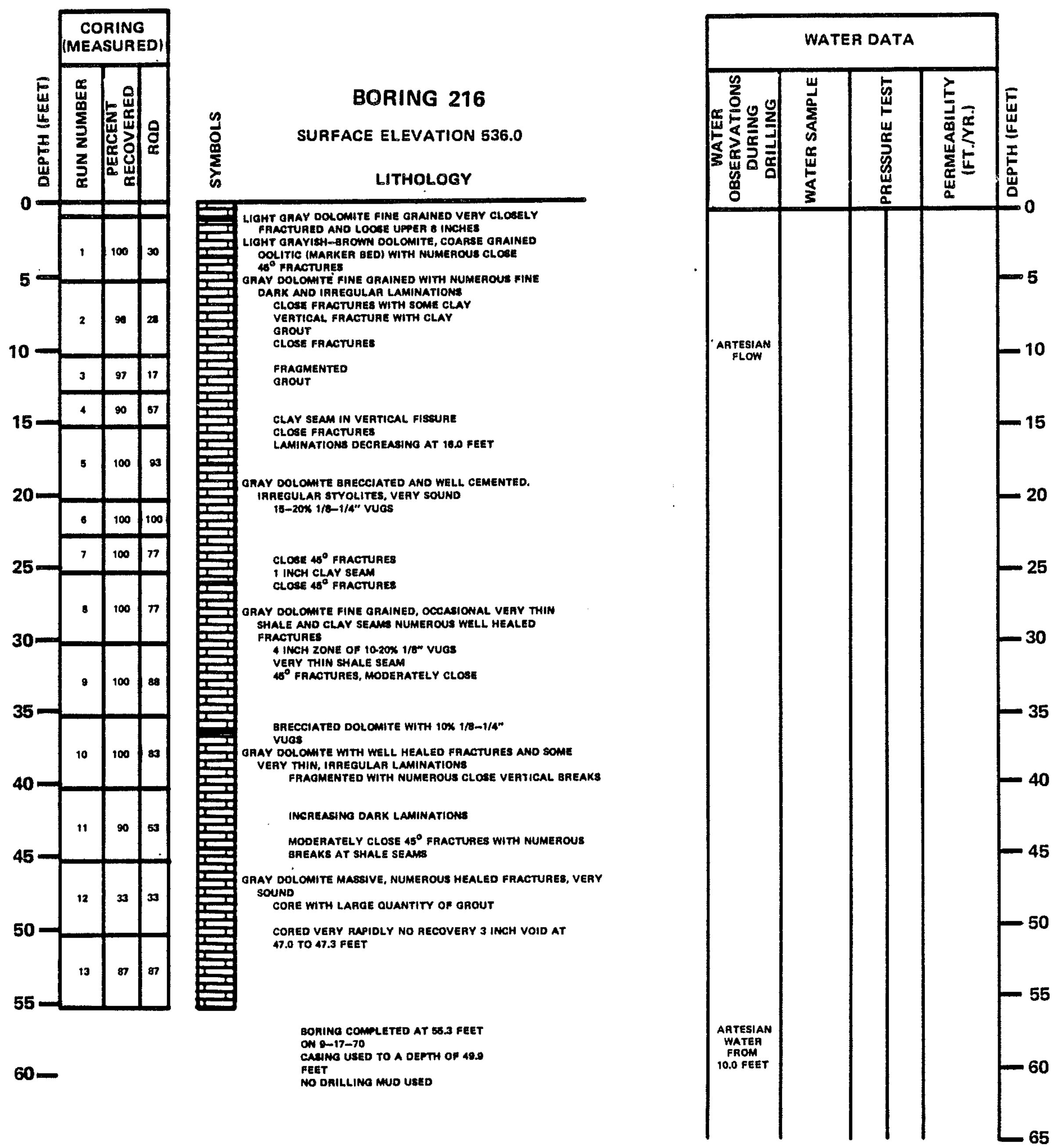
FIGURE 2.5-71

LOG OF BORING 215



NOTES:

ELEVATIONS REFER TO N.Y.M.T., 1935

RQD – ROCK QUALITY DESIGNATION
A MODIFIED CORE RECOVERY PERCENTAGE IN WHICH ALL THE PIECES OF SOUND CORE OVER 4 INCHES LONG ARE COUNTED AS RECOVERY. THE MODIFIED SUM OF CORE RECOVERED IS THEN EXPRESSED AS A PERCENTAGE OF THE TOTAL LENGTH OF THE CORE RUN.

% – VUGS INDICATES THE ESTIMATED RATIO OF VUGGED CORE SURFACE AREA TO TOTAL CORE SURFACE AREA. BOTH OPEN AND FILLED VUGS ARE INCLUDED IN THE VUGGED CATEGORY.

FRACTURE DENSITY TERMINOLOGY
VERY CLOSE–LESS THAN 2 INCHES APART
CLOSE–2 TO 6 INCHES
MODERATELY CLOSE–6 TO 12 INCHES
WIDE–GREATER THAN 12 INCHES

REFERENCE:
REFERENCE 23, PLATE A-3B

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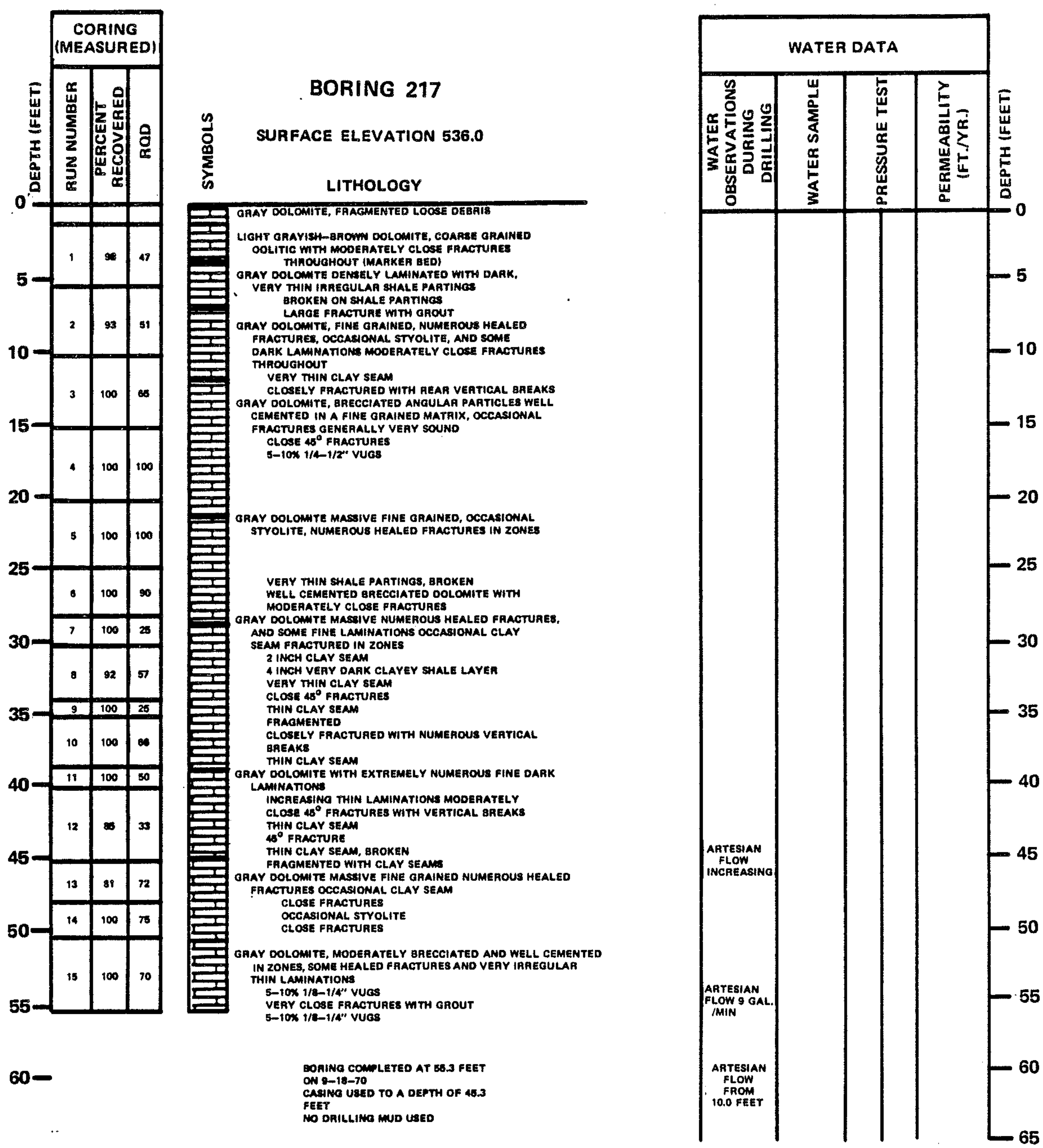
FIGURE 2.5-72

LOG OF BORING 216



NOTES:

ELEVATIONS REFER TO N.Y.M.T., 1935

RQD - ROCK QUALITY DESIGNATION
A MODIFIED CORE RECOVERY PERCENTAGE IN WHICH ALL THE PIECES OF SOUND CORE OVER 4 INCHES LONG ARE COUNTED AS RECOVERY. THE MODIFIED SUM OF CORE RECOVERED IS THEN EXPRESSED AS A PERCENTAGE OF THE TOTAL LENGTH OF THE CORE RUN.

% - VUGS INDICATES THE ESTIMATED RATIO OF VUGGED CORE SURFACE AREA TO TOTAL CORE SURFACE AREA. BOTH OPEN AND FILLED VUGS ARE INCLUDED IN THE VUGGED CATEGORY.

FRACTURE DENSITY TERMINOLOGY
VERY CLOSE-LESS THAN 2 INCHES APART
CLOSE-2 TO 6 INCHES
MODERATELY CLOSE-6 TO 12 INCHES
WIDE -GREATER THAN 12 INCHES

REFERENCE:
REFERENCE 23, PLATE A-3C

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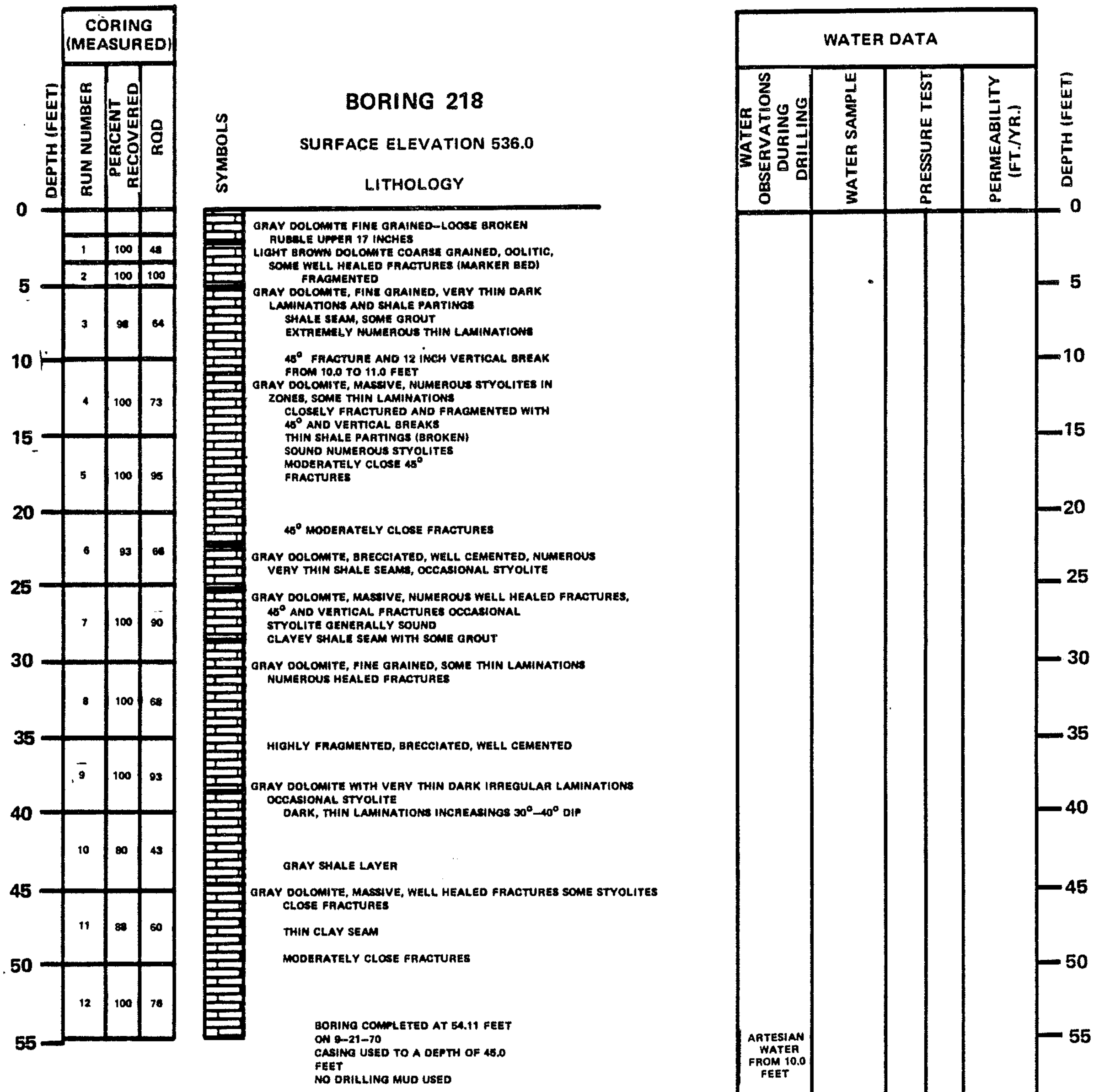
FIGURE 2.5-73

LOG OF BORING 217



NOTES:

ELEVATIONS REFER TO N.Y.M.T., 1935

RQD – ROCK QUALITY DESIGNATION
A MODIFIED CORE RECOVERY PERCENTAGE IN WHICH ALL THE PIECES OF SOUND CORE OVER 4 INCHES LONG ARE COUNTED AS RECOVERY. THE MODIFIED SUM OF CORE RECOVERED IS THEN EXPRESSED AS A PERCENTAGE OF THE TOTAL LENGTH OF THE CORE RUN.

% – VUGS INDICATES THE ESTIMATED RATIO OF VUGGED CORE SURFACE AREA TO TOTAL CORE SURFACE AREA. BOTH OPEN AND FILLED VUGS ARE INCLUDED IN THE VUGGED CATEGORY.

FRACTURE DENSITY TERMINOLOGY
VERY CLOSE–LESS THAN 2 INCHES APART
CLOSE–2 TO 6 INCHES
MODERATELY CLOSE–6 TO 12 INCHES
WIDE–GREATER THAN 12 INCHES

REFERENCE:
REFERENCE 23, PLATE A-3D

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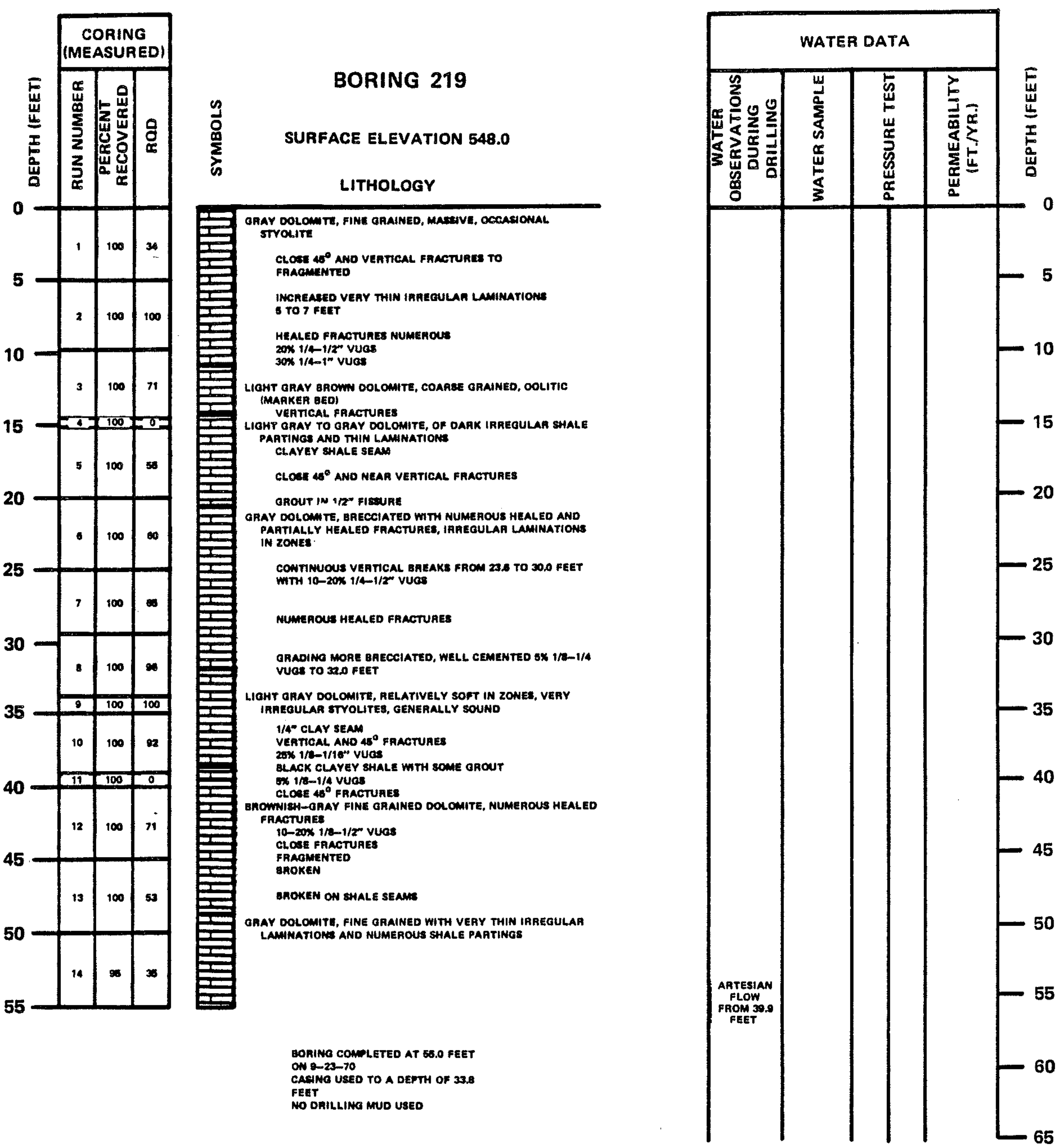
FIGURE 2.5-74

LOG OF BORING 218



NOTES:

ELEVATIONS REFER TO N.Y.M.T., 1935

RQD – ROCK QUALITY DESIGNATION
A MODIFIED CORE RECOVERY PERCENTAGE IN WHICH ALL THE PIECES OF SOUND CORE OVER 4 INCHES LONG ARE COUNTED AS RECOVERY. THE MODIFIED SUM OF CORE RECOVERED IS THEN EXPRESSED AS A PERCENTAGE OF THE TOTAL LENGTH OF THE CORE RUN.

% – VUGS INDICATES THE ESTIMATED RATIO OF VUGGED CORE SURFACE AREA TO TOTAL CORE SURFACE AREA. BOTH OPEN AND FILLED VUGS ARE INCLUDED IN THE VUGGED CATEGORY.

FRACTURE DENSITY TERMINOLOGY
VERY CLOSE–LESS THAN 2 INCHES APART
CLOSE–2 TO 6 INCHES
MODERATELY CLOSE–6 TO 12 INCHES
WIDE –GREATER THAN 12 INCHES

REFERENCE:
REFERENCE 23, PLATE A-3E

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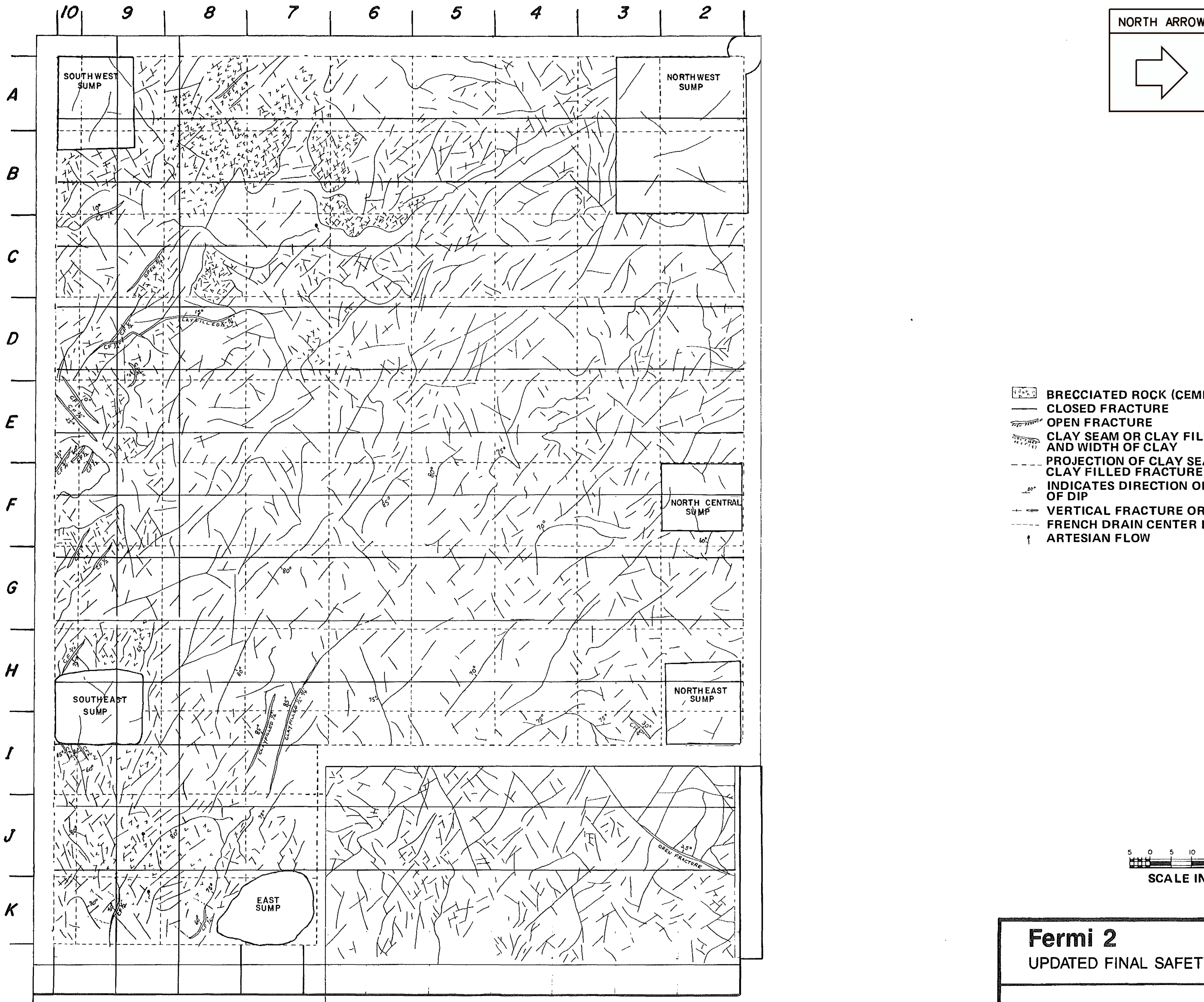
FIGURE 2.5-75

LOG OF BORING 219



BRECCIATED ROCK (CEMENTED)
CLOSED FRACTURE
OPEN FRACTURE
CLAY SEAM OR CLAY FILLED FRACTURE AND WIDTH OF CLAY
PROJECTION OF CLAY SEAM OR CLAY FILLED FRACTURE
INDICATES DIRECTION OF AND ANGLE OF DIP
VERTICAL FRACTURE OR CLAY SEAM
FRENCH DRAIN CENTER LINE
ARTESIAN FLOW

5 0 5 10 15 20 25
SCALE IN FEET

REFERENCE:
REFERENCE 23, PLATE B-1

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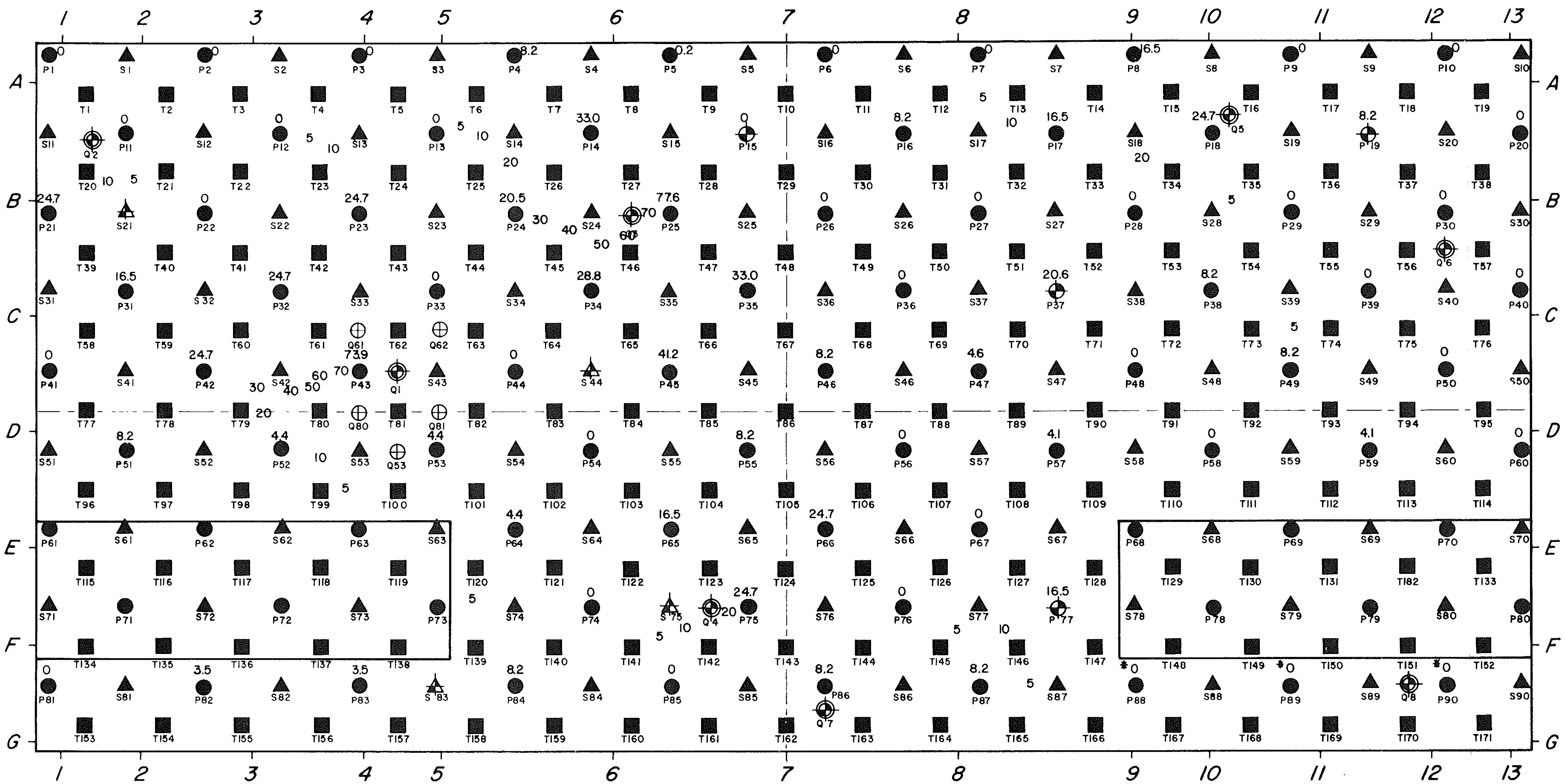
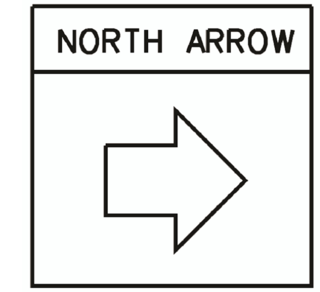
FIGURE 2.5-76

FOUNDATION RACK SURFACE FEATURES
REACTOR/AUXILIARY BUILDING





EXPLANATION

- PRIMARY GROUT HOLES
- SECONDARY GROUT HOLES
- TERTIARY GROUT HOLES
- QUATERNARY GROUT HOLES

8.2 GROUT VOLUME IN CUBIC FEET-MIX WITH 1:1 (CEMENT:FLY ASH) AND 1.6:1 (WATER: CEMENT PLUS FLY ASH)

*8.2 MIX WITH 1:1 (CEMENT:FLY ASH) AND 1.2:1 (WATER:CEMENT PLUS FLY ASH)

0 NO GROUT TAKEN BY ROCK

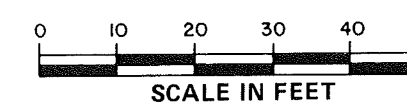
OR PRE-GROUTING EXPLORATORY HOLES (SYMBOLS CORRESPOND TO EITHER A PRIMARY OR SECONDARY GROUT HOLE POSITION)

POST-GROUTING EXPLORATORY HOLES

2 A BUILDING COLUMN LINES

APPROXIMATE BUILDING AND EXCAVATION LINES

BUILDING CENTER LINE



REFERENCE:
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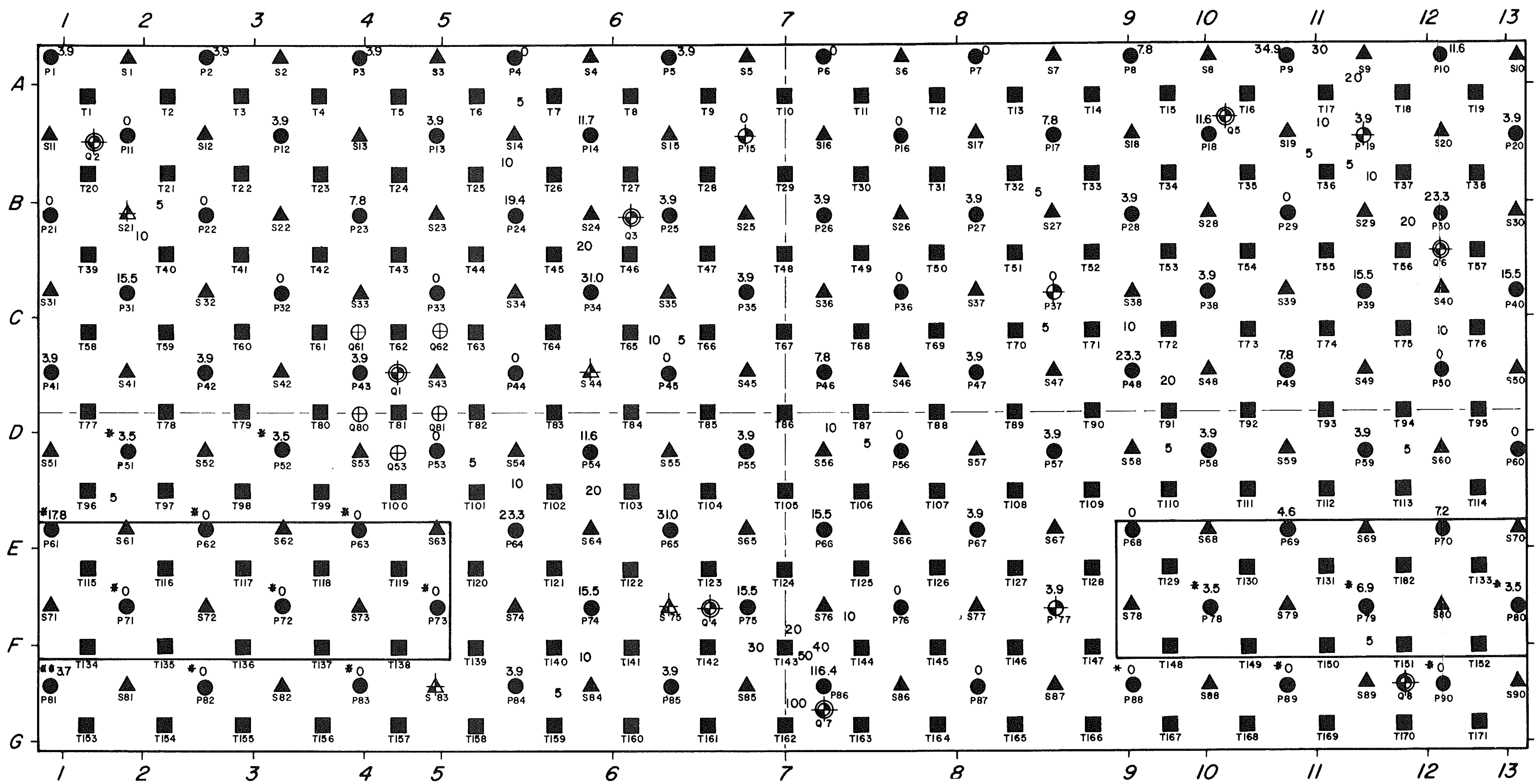
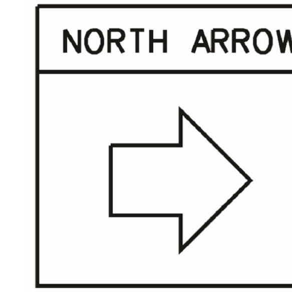
FIGURE 2.5-77

PRIMARY HOLES – FIRST ZONE GROUTING (0-6 FT) RESIDUAL HEAT REMOVAL COMPLEX





PRIMARY GROUT HOLES
SECONDARY GROUT HOLES
TERTIARY GROUT HOLES
QUATERNARY GROUT HOLES

3.9 GROUT VOLUME IN CUBIC FEET-MIX WITH 1.5:1 (CEMENT:FLY ASH) AND 2:1 (WATER: CEMENT PLUS FLY ASH)

*3.9 MIX WITH 1:1 (CEMENT:FLY ASH) AND 1.2:1 (WATER:CEMENT PLUS FLY ASH)

* * 3.9 MIX WITH 1:1 (CEMENT:FLY ASH) AND 1:1 (WATER:CEMENT PLUS FLY ASH)

0 NO GROUT TAKEN BY ROCK

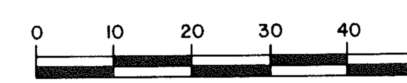
OR PRE-GROUTING EXPLORATORY HOLES (SYMBOLS CORRESPOND TO EITHER A PRIMARY OR SECONDARY GROUT HOLE POSITION)

POST-GROUTING EXPLORATORY HOLES

2 A BUILDING COLUMN LINES

APPROXIMATE BUILDING AND EXCAVATION LINES

BUILDING CENTER LINE



SCALE IN FEET

REFERENCE:
MODIFIED FROM LEE TURZILLO CONTRACTING COMPANY
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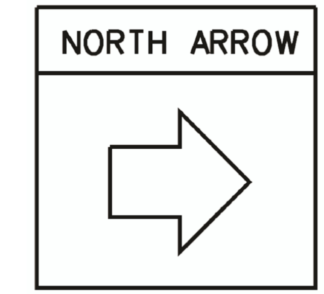
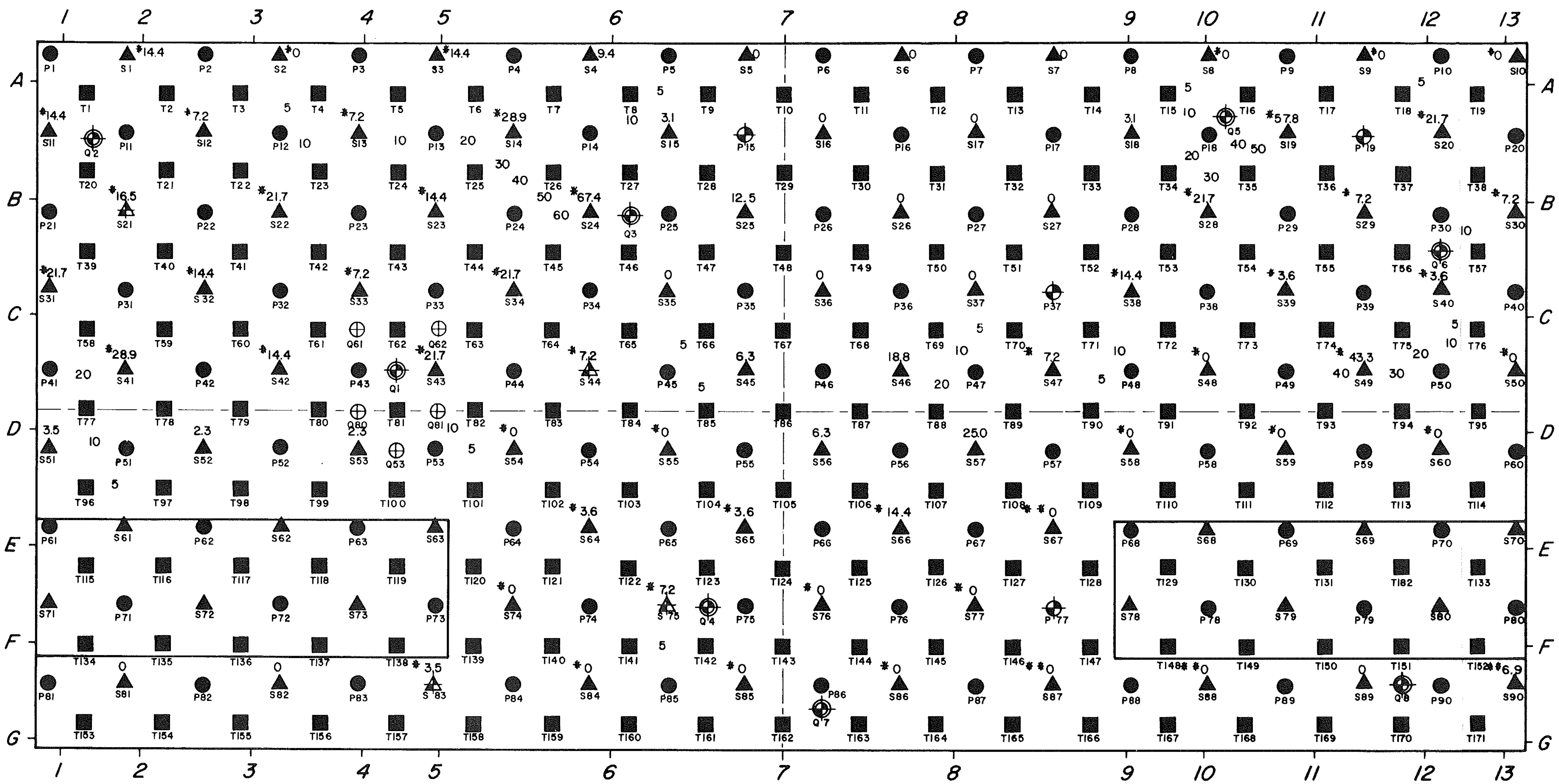
FIGURE 2.5-78

PRIMARY HOLES – SECOND ZONE GROUTING (6-20 FT) RESIDUAL HEAT REMOVAL COMPLEX





EXPLANATION

- PRIMARY GROUT HOLES
- SECONDARY GROUT HOLES
- TERTIARY GROUT HOLES
- QUATERNARY GROUT HOLES

7.2 GROUT VOLUME IN CUBIC FEET-MIX WITH 2:1 (CEMENT:FLY ASH) AND 3:1 (WATER: CEMENT PLUS FLY ASH)

*7.2 MIX WITH 1.5:1 (CEMENT:FLY ASH) AND 1.8:1 (WATER:CEMENT PLUS FLY ASH)

**7.2 MIX WITH 1:1 (CEMENT:FLY ASH) AND 1.2:1 (WATER:CEMENT PLUS FLY ASH)

0 NO GROUT TAKEN BY ROCK

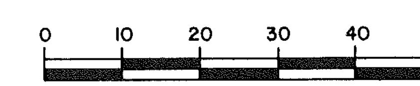
OR PRE-GROUTING EXPLORATORY HOLES (SYMBOLS CORRESPOND TO EITHER A PRIMARY OR SECONDARY GROUT HOLE POSITION)

POST-GROUTING EXPLORATORY HOLES

2 A BUILDING COLUMN LINES

APPROXIMATE BUILDING AND EXCAVATION LINES

BUILDING CENTER LINE



SCALE IN FEET

REFERENCE:
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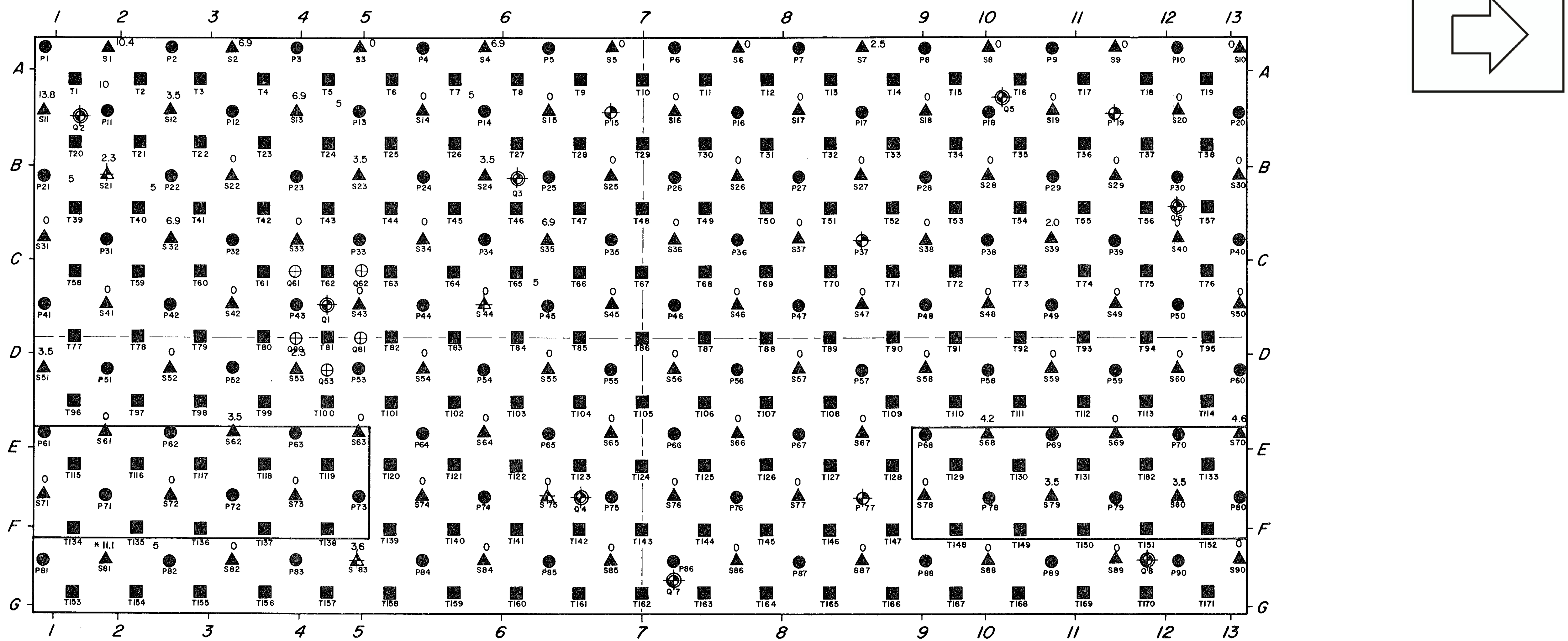
FIGURE 2.5-79

SECONDARY HOLES – FIRST ZONE GROUTING (0-6 FT) RESIDUAL HEAT REMOVAL COMPLEX



EXPLANATION

- PRIMARY GROUT HOLES
- SECONDARY GROUT HOLES
- TERTIARY GROUT HOLES
- QUATERNARY GROUT HOLES

3.5 GROUT VOLUME IN CUBIC FEET-MIX WITH 1:1 (CEMENT:FLY ASH) AND 1.2:1 (WATER: CEMENT PLUS FLY ASH)

* 3.5 MIX WITH 1:1 (CEMENT:FLY ASH) AND 1:1 (WATER:CEMENT PLUS FLY ASH)

0 NO GROUT TAKEN BY ROCK

PRE-GROUTING EXPLORATORY HOLES (SYMBOLS CORRESPOND TO EITHER A PRIMARY OR SECONDARY GROUT HOLE POSITION)

POST-GROUTING EXPLORATORY HOLES

2 A BUILDING COLUMN LINES

APPROXIMATE BUILDING AND EXCAVATION LINES

BUILDING CENTER LINE

0 10 20 30 40 50

SCALE IN FEET

REFERENCE:
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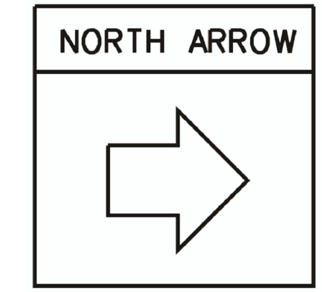
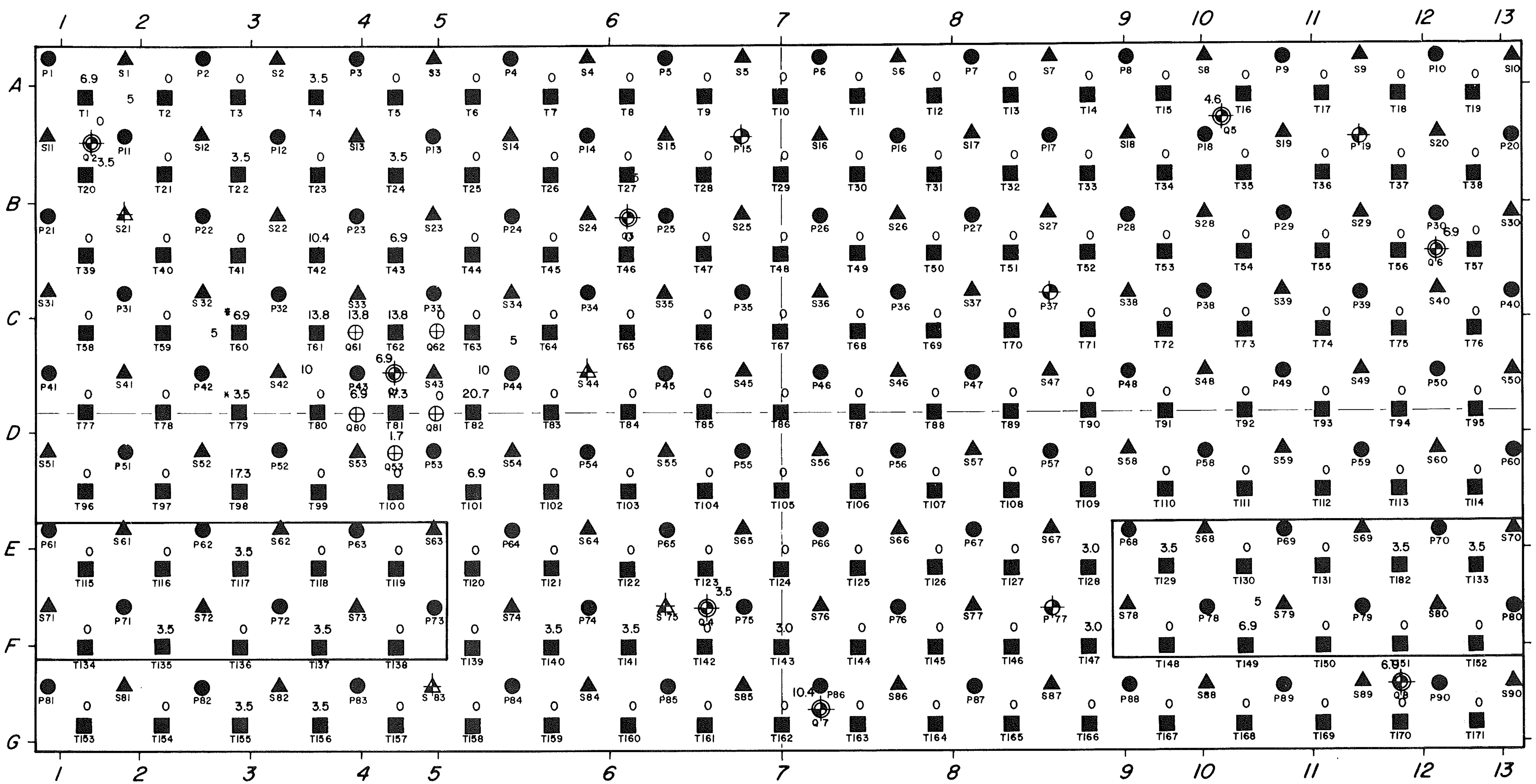
FIGURE 2.5-80

SECONDARY HOLES – SECOND ZONE GROUTING (6-20 FT) RESIDUAL HEAT REMOVAL COMPLEX



NORTH ARROW



EXPLANATION

PRIMARY GROUT HOLES

SECONDARY GROUT HOLES

TERTIARY GROUT HOLES

QUATERNARY GROUT HOLES

6.9 OR 6.9 OR 6.9 GROUT VOLUME IN CUBIC FEET-MIX WITH 1:1 (CEMENT:FLY ASH) AND 1.2:1 (WATER: CEMENT PLUS FLY ASH)

* 6.9 MIX WITH 1.5:1 (CEMENT:FLY ASH) AND 1.5:1 (WATER:CEMENT PLUS FLY ASH)

0 NO GROUT TAKEN BY ROCK

OR PRE-GROUTING EXPLORATORY HOLES (SYMBOLS CORRESPOND TO EITHER A PRIMARY OR SECONDARY GROUT HOLE POSITION)

POST-GROUTING EXPLORATORY HOLES

2 A BUILDING COLUMN LINES

APPROXIMATE BUILDING AND EXCAVATION LINES

BUILDING CENTER LINE

0 10 20 30 40 50

SCALE IN FEET

REFERENCE:
MODIFIED FROM LEE TURZILLO CONTRACTING COMPANY
DRAWING NO. 2410-1, FEBRUARY 19, 1974

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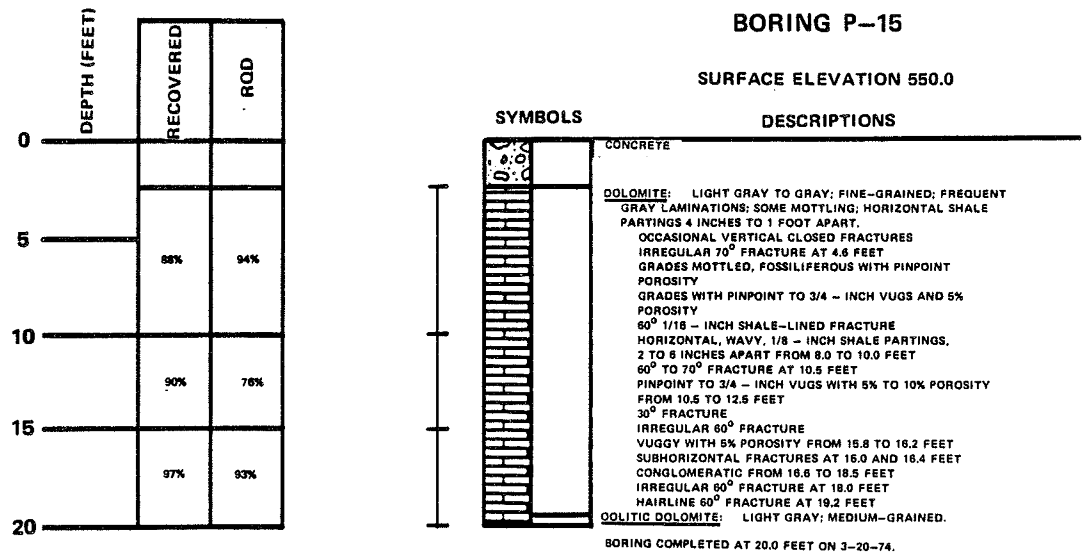
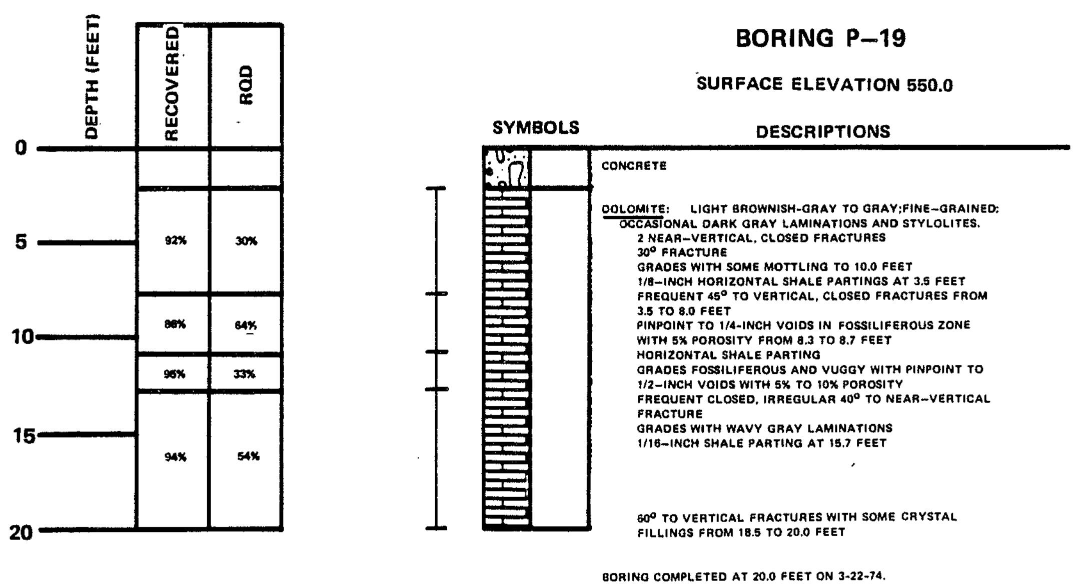
FIGURE 2.5-81

TERTIARY AND QUATERNARY HOLES
SINGLE ZONE GROUTING (0-20 FT)
(CONTOURS ON TERTIARY GROUTING ONLY)
RESIDUAL HEAT REMOVAL COMPLEX





REFERENCE:
DAMES & MOORE REPORT – RESULTS OF ROCK FOUNDATION TREATMENT, RESIDUAL HEAT REMOVAL COMPLEX, FERMI 2, JUNE 1974

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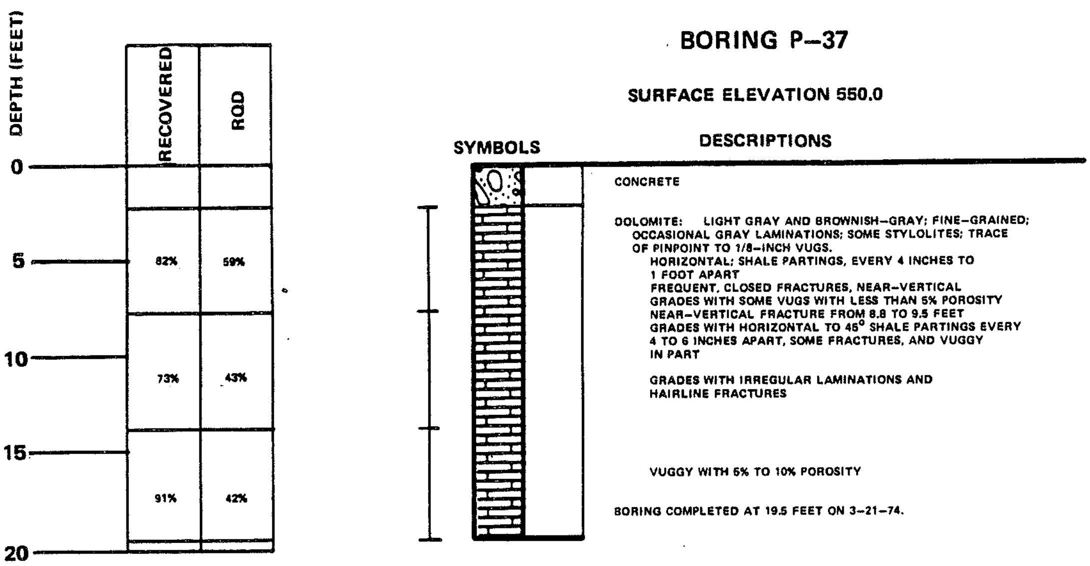
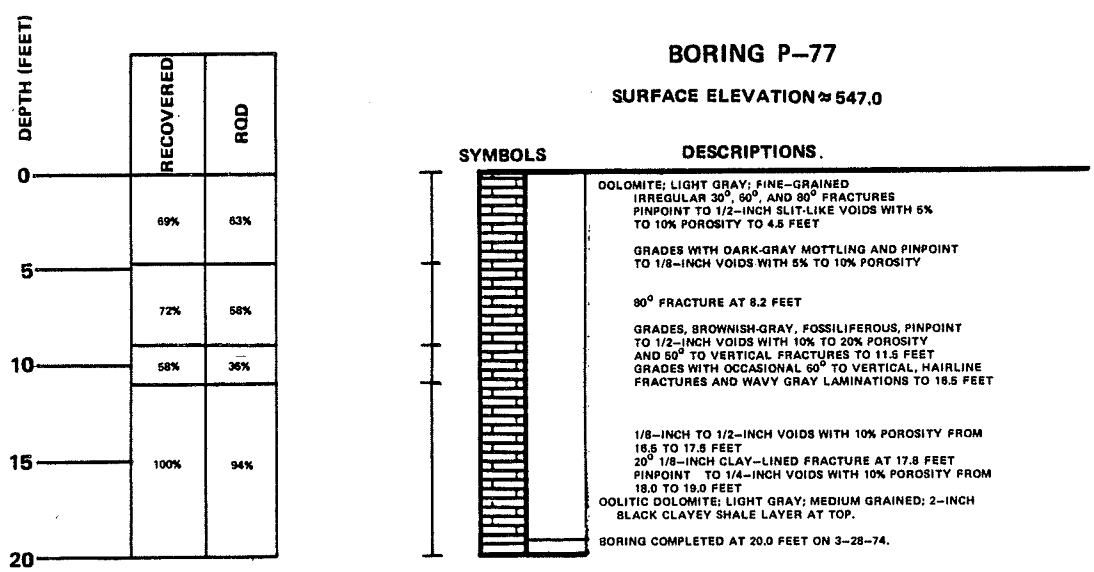
FIGURE 2.5-82

LOG OF BORINGS P-15 AND P-19





REFERENCE:
DAMES & MOORE REPORT – RESULTS OF ROCK FOUNDATION TREATMENT, RESIDUAL HEAT REMOVAL COMPLEX, FERMI 2, JUNE 1974

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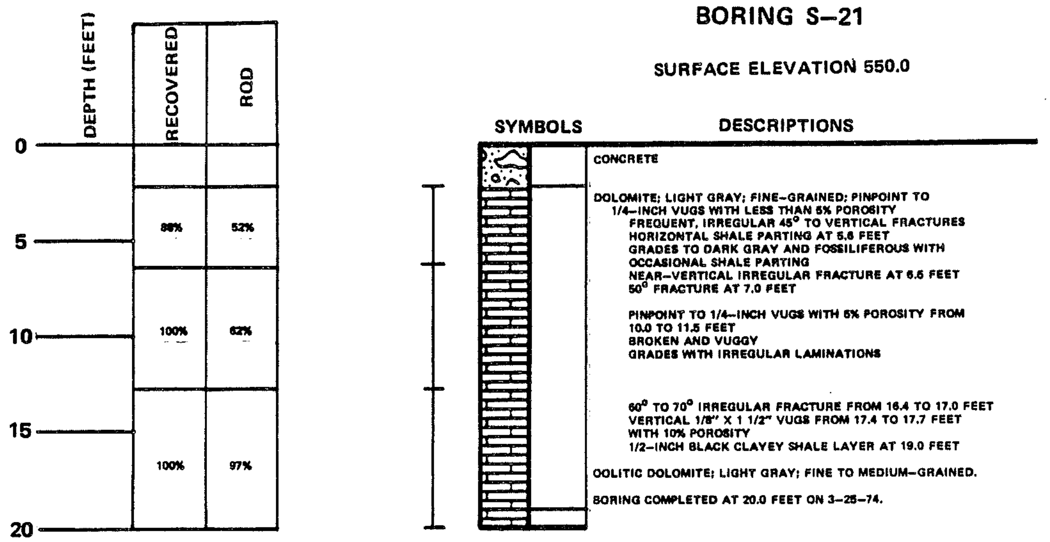
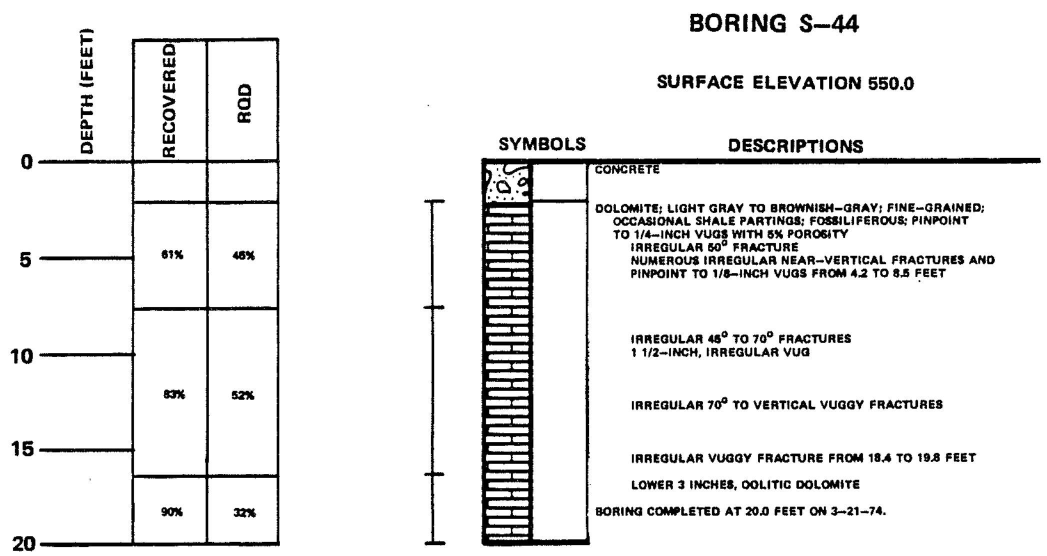
FIGURE 2.5-83

LOG OF BORINGS P-37 AND P-77





REFERENCE:
DAMES & MOORE REPORT – RESULTS OF ROCK FOUNDATION TREATMENT, RESIDUAL HEAT REMOVAL COMPLEX, FERMI 2, JUNE 1974

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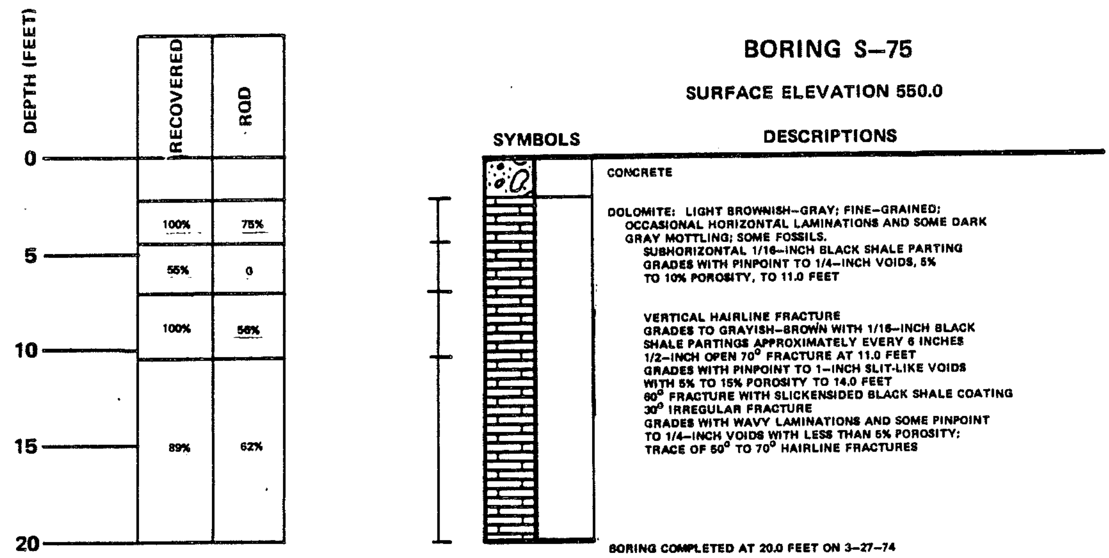
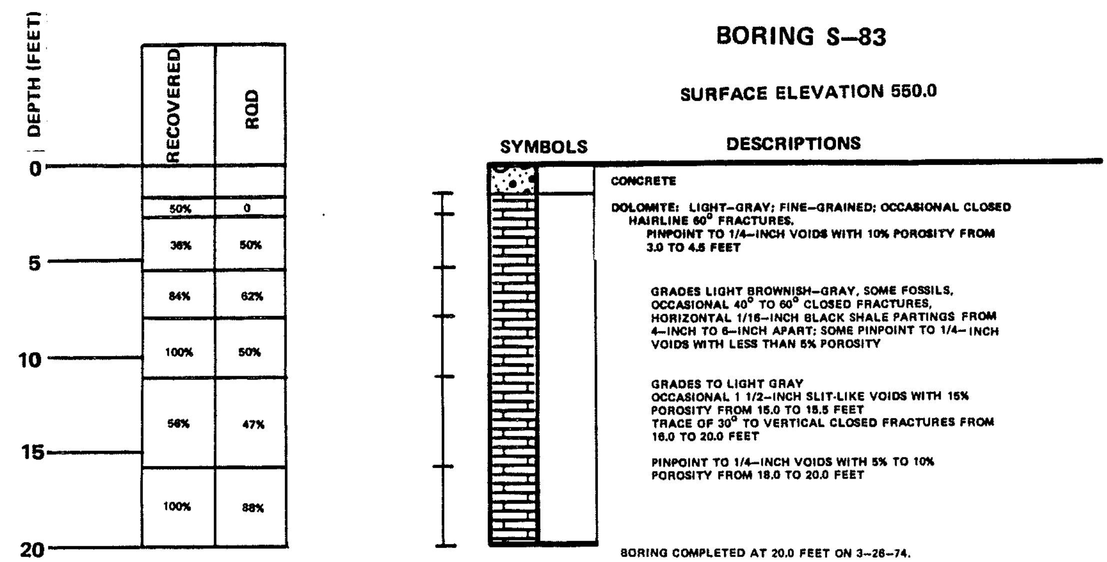
FIGURE 2.5-84

LOG OF BORINGS S-21 AND S-44





REFERENCE:
DAMES & MOORE REPORT – RESULTS OF ROCK FOUNDATION TREATMENT, RESIDUAL HEAT REMOVAL COMPLEX, FERMI 2, JUNE 1974

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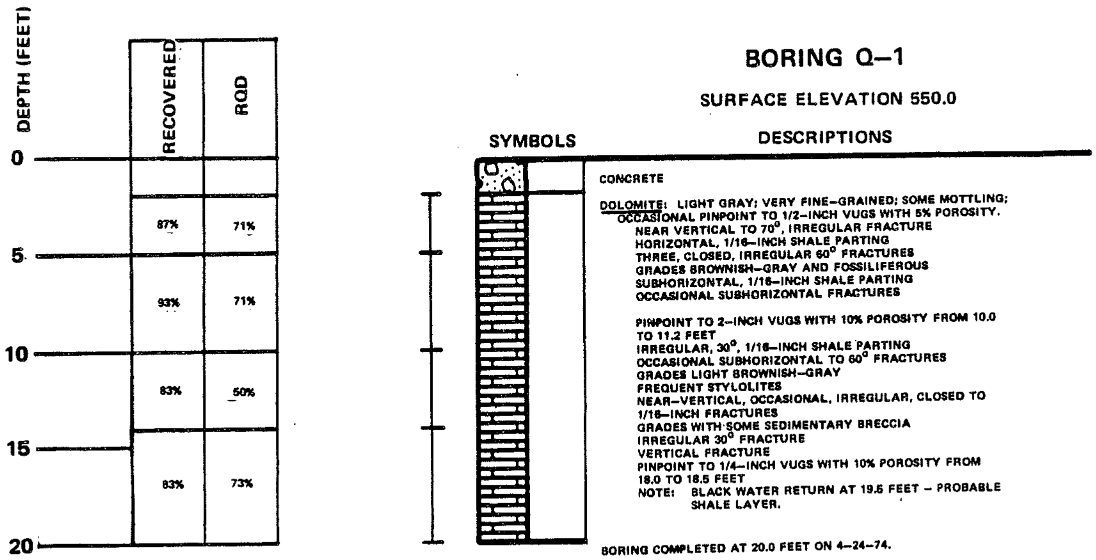
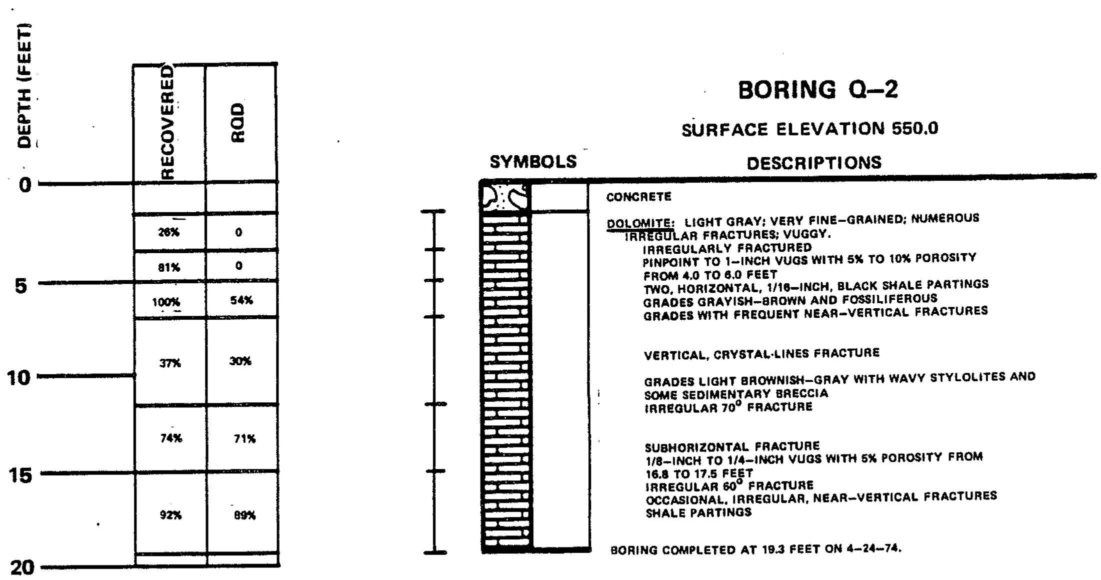
FIGURE 2.5-85

LOG OF BORINGS S-75 AND S-83





REFERENCE:
DAMES & MOORE REPORT – RESULTS OF ROCK FOUNDATION TREATMENT, RESIDUAL HEAT REMOVAL COMPLEX, FERMI 2, JUNE 1974

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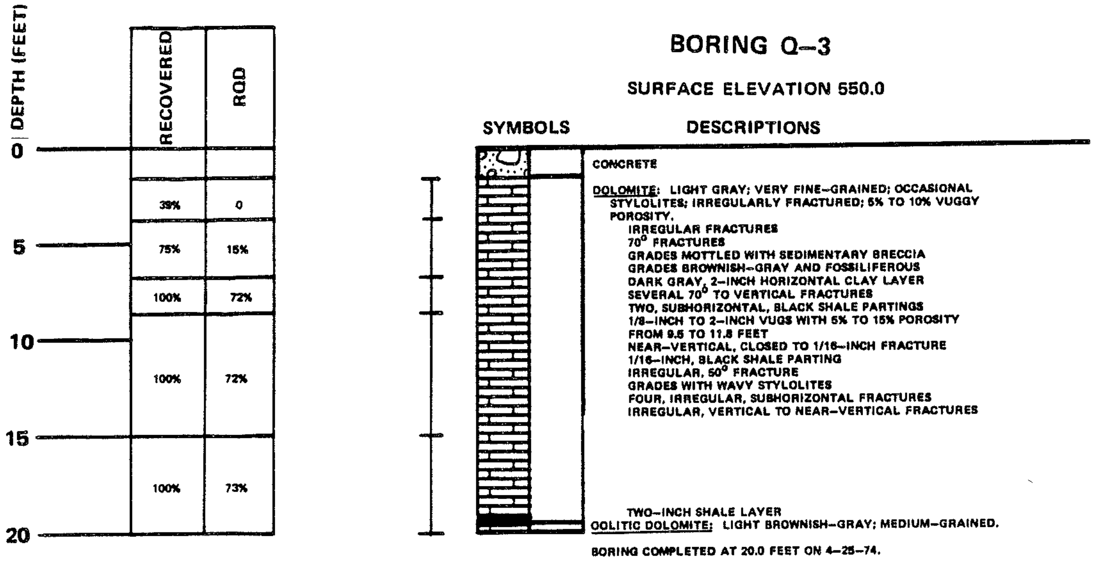
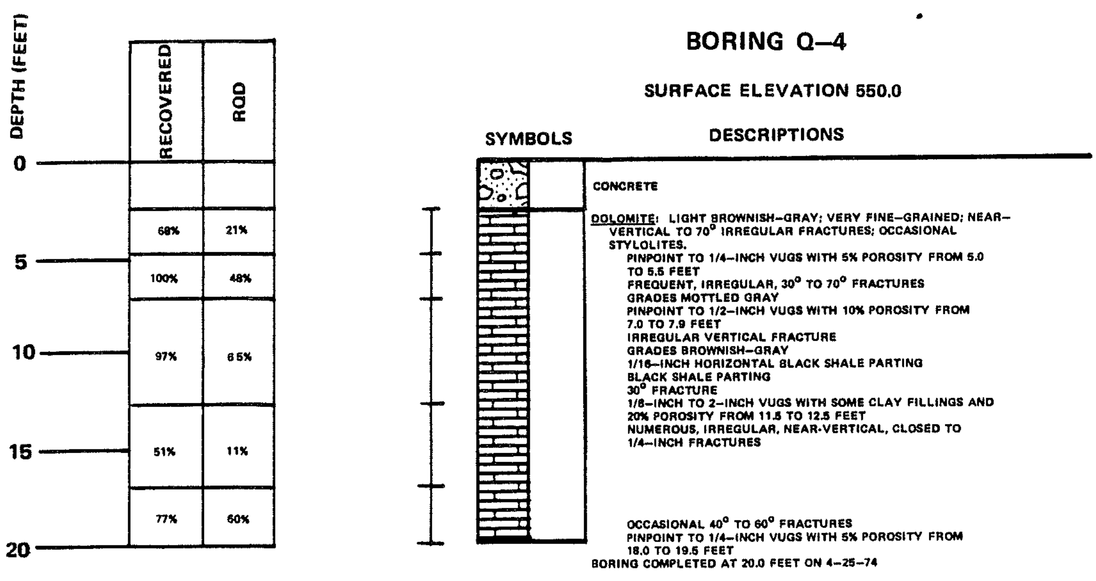
FIGURE 2.5-86

LOG OF BORINGS Q-1 AND Q-2





REFERENCE:
DAMES & MOORE REPORT – RESULTS OF ROCK FOUNDATION TREATMENT, RESIDUAL HEAT REMOVAL COMPLEX, FERMI 2, JUNE 1974

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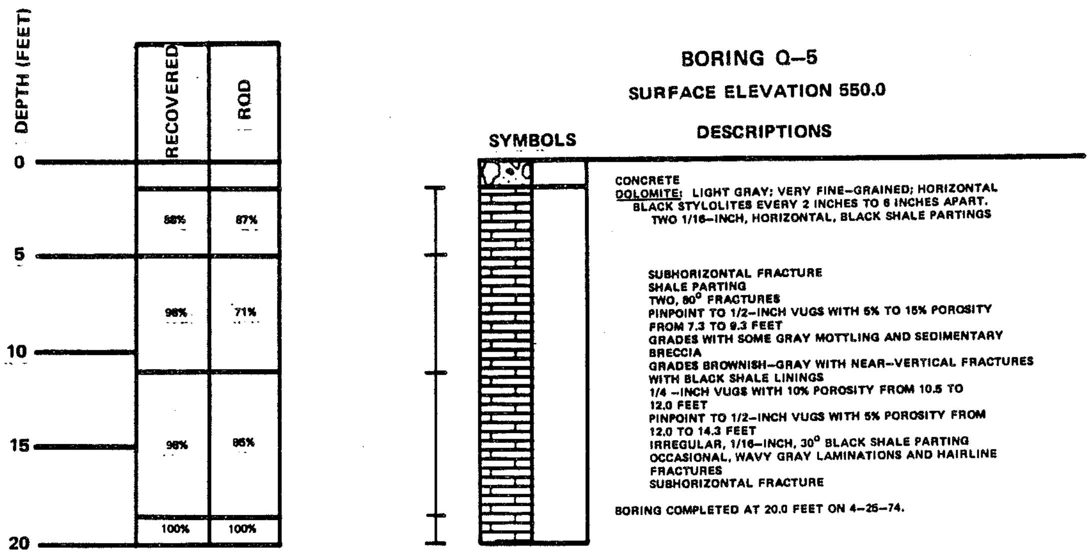
FIGURE 2.5-87

LOG OF BORINGS Q-3 AND Q-4



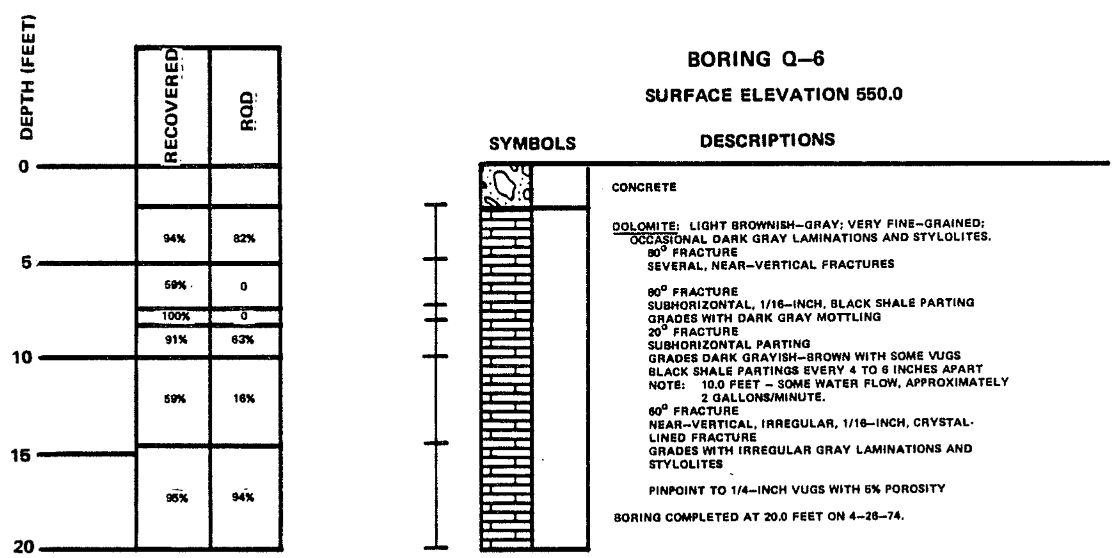


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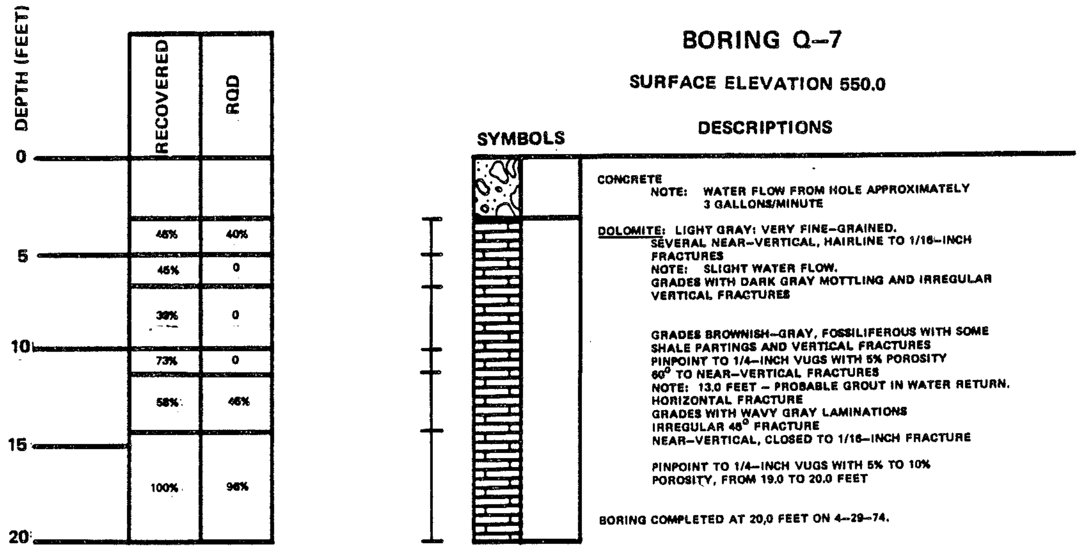
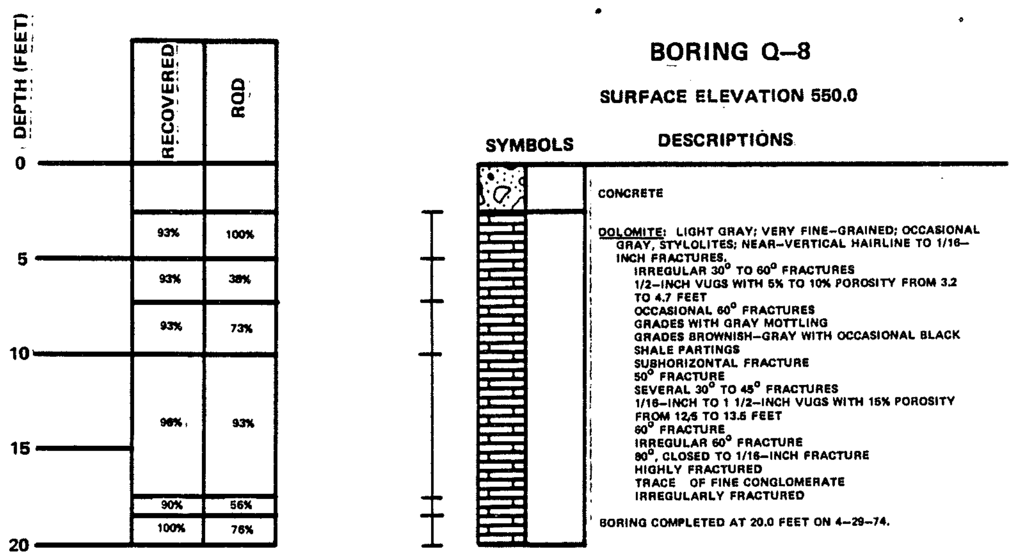
FIGURE 2.5-88

LOG OF BORINGS Q-5 AND Q-6

REFERENCE:
DAMES & MOORE REPORT – RESULTS OF ROCK FOUNDATION TREATMENT, RESIDUAL HEAT REMOVAL COMPLEX, FERMI 2, JUNE 1974





REFERENCE:
DAMES & MOORE REPORT – RESULTS OF ROCK FOUNDATION TREATMENT, RESIDUAL HEAT REMOVAL COMPLEX, FERMI 2, JUNE 1974

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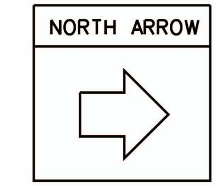
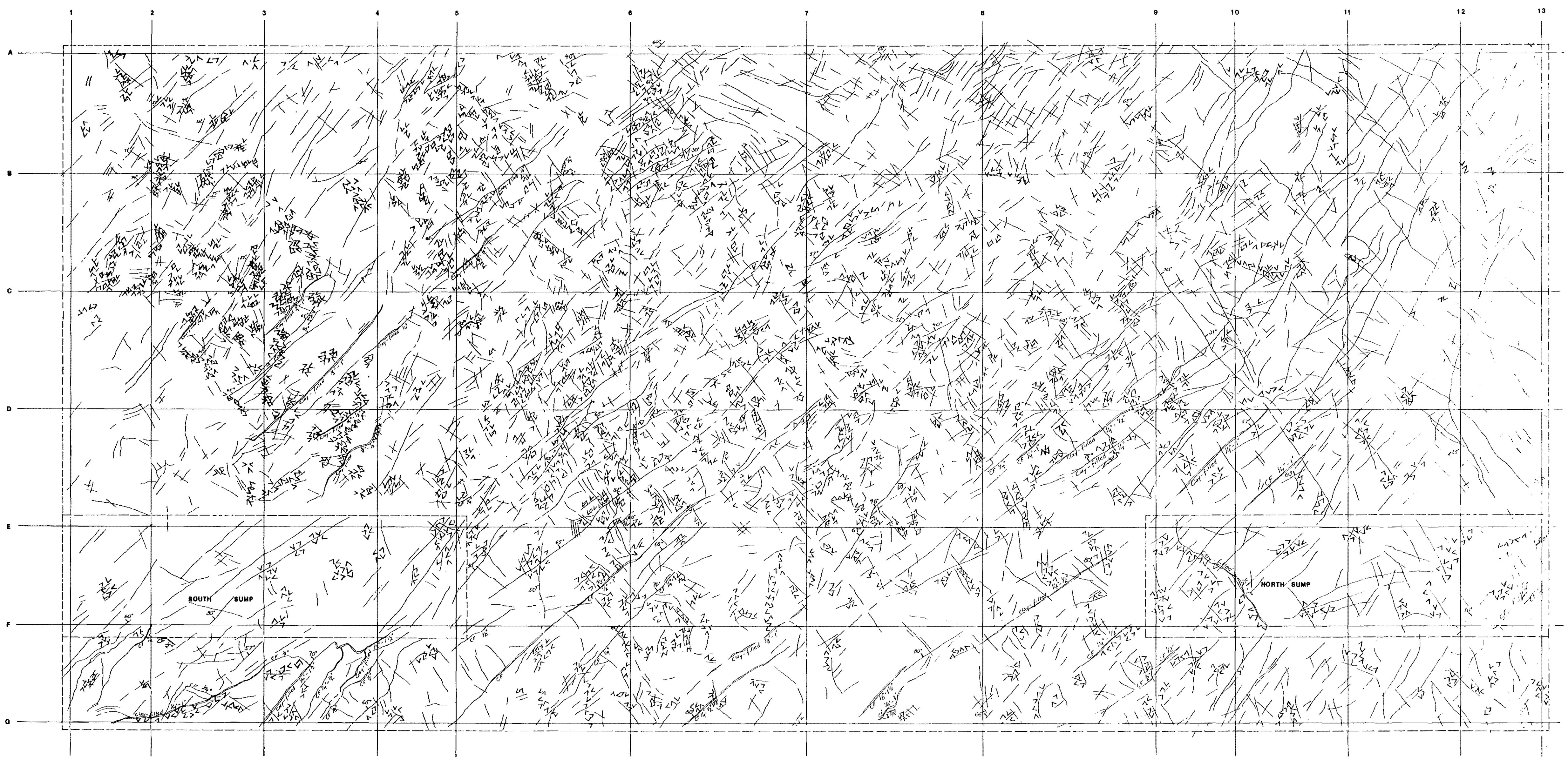
FIGURE 2.5-89

LOG OF BORINGS Q-7 AND Q-8





EXPLANATION:

CLOSED FRACTURE (INCLUDES SOME OPEN FRACTURES LESS THAN 1/2 INCH WIDE)

OPEN FRACTURE (GREATER THAN 1/2 INCH WIDE)

CLAY–FILLED FRACTURE OR CLAY SEAM AND WIDTH OF CLAY

DIRECTION AND ANGLE OF DIP

VERTICAL FRACTURE OR CLAY SEAM

COLUMN LINES

EXCAVATION NEAT LINE

CLOSELY FRACTURED ROCK (INCLUDES CEMENTED SEDIMENTARY BRECCIA)

10 0 10 20

SCALE IN FEET

Fermi 2

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FIGURE 2.5-90

FOUNDATION ROCK SURFACE FEATURES
RESIDUAL HEAT REMOVAL COMPLEX

APPENDIX 2A

ANNUAL AVERAGE X/Q VALUES

(UNDECAYED AND UNDEPLETED)

(DEPLETED AND DECAYED)

AND

RELATIVE DEPOSITION D/Q VALUES

FOR THE

CONTAINMENT BUILDING

RADWASTE BUILDING

TURBINE BUILDING

BY

DISTANCE AND SECTOR

TABLE 2A-1 ANNUAL AVERAGE X/Q VALUES FOR THE CONTAINMENT BUILDING (UNDECAYED AND UNDEPLETED)

	Downwind Distance (KM)				
Sector	0.4	0.8	1.2	1.6	2.4
NNE	1.31E-06	4.16E-07	2.68E-07	2.03E-07	1.37E-07
NE	1.06E-06	3.50E-07	2.28E-07	1.75E-07	1.21E-07
ENE	1.02E-06	3.49E-07	2.30E-07	1.78E-07	1.24E-07
E	7.40E-07	2.54E-07	1.77E-07	1.39E-07	9.88E-08
ESE	7.18E-07	2.45E-07	1.67E-07	1.30E-07	9.13E-08
SE	6.75E-07	2.28E-07	1.54E-07	1.19E-07	8.29E-08
SSE	5.11E-07	1.67E-07	1.14E-07	8.80E-08	6.19E-08
S	4.86E-07	1.52E-07	1.02E-07	7.88E-08	5.45E-08
SSW	3.76E-07	1.27E-07	8.70E-08	6.78E-08	4.78E-08
SW	3.96E-07	1.48E-07	1.05E-07	8.24E-08	5.78E-08
WSW	5.41E-07	1.98E-07	1.35E-07	1.05E-07	7.25E-08
W	4.76E-07	1.64E-07	1.08E-07	8.17E-08	5.49E-08
WNW	6.68E-07	2.15E-07	1.39E-07	1.04E-07	6.97E-08
NW	7.03E-07	2.25E-07	1.51E-07	1.17E-07	8.12E-08
NNW	7.47E-07	2.31E-07	1.52E-07	1.16E-07	8.00E-08
N	7.84E-07	2.52E-07	1.66E-07	1.28E-07	8.86E-06

Source: Containment Building

TABLE 2A-1 ANNUAL AVERAGE X/Q VALUES FOR THE CONTAINMENT BUILDING (UNDECAYED AND UNDEPLETED)

	Downwind Distance (KM)				
Sector	3.2	4.0	4.8	5.6	6.4
NNE	1.04E-07	8.27E-08	6.84E-08	5.80E-08	5.01E-08
NE	9.30E-08	7.51E-08	6.26E-08	5.34E-08	4.63E-03
ENE	9.53E-08	7.69E-08	6.41E-08	5.47E-08	4.75E-08
E	7.65E-08	6.20E-08	5.18E-08	4.43E-08	3.85E-08
ESE	7.08E-08	5.76E-08	4.84E-08	4.15E-08	3.63E-08
SE	6.38E-08	5.16E-08	4.32E-08	3.69E-08	3.22E-08
SSE	4.81E-08	3.92E-08	3.30E-08	2.84E-08	2.49E-08
S	4.20E-08	3.42E-08	2.87E-08	2.47E-08	2.16E-08
SSW	3.70E-08	3.01E-08	2.52E-08	2.16E-08	1.88E-08
SW	4.40E-08	3.50E-08	2.88E-08	2.43E-08	2.09E-08
WSW	5.47E-08	4.34E-08	3.56E-08	3.00E-08	2.57E-08
W	4.09E-08	3.23E-08	2.64E-08	2.22E-08	1.91E-08
WNW	5.20E-08	4.12E-08	3.38E-08	2.85E-08	2.45E-08
NW	6.20E-08	4.96E-08	4.10E-08	3.47E-08	2.99E-08
NNW	6.11E-08	4.92E-08	4.10E-08	3.49E-08	3.03E-08
N	6.78E-08	5.45E-08	4.53E-08	3.86E-08	3.34E-08

Source: Containment Building

TABLE 2A-1 ANNUAL AVERAGE X/Q VALUES FOR THE CONTAINMENT BUILDING (UNDECAYED AND UNDEPLETED)

	Downwind Distance (KM)				
Sector	7.2	8.0	8.8	9.6	10.4
NNE	4.39E-08	3.90E-08	3.49E-08	3.16E-08	2.88E-08
NE	4.08E-08	3.63E-08	3.27E-08	2.96E-08	2.70E-08
ENE	4.18E-08	3.72E-08	3.35E-08	3.04E-08	2.77E-08
E	3.40E-08	3.03E-08	2.73E-08	2.48E-08	2.26E-08
ESE	3.21E-08	2.87E-08	2.60E-08	2.37E-08	2.17E-08
SE	2.85E-08	2.55E-08	2.30E-08	2.09E-08	1.92E-08
SSE	2.21E-08	1.98E-08	1.80E-08	1.64E-08	1.51E-08
S	1.92E-08	1.72E-08	1.56E-08	1.42E-08	1.31E-08
SSW	1.66E-08	1.49E-08	1.34E-08	1.22E-08	1.12E-08
SW	1.82E-08	1.61E-08	1.43E-08	1.29E-08	1.17E-08
WSW	2.24E-08	1.97E-08	1.76E-08	1.58E-08	1.43E-08
W	1.66E-08	1.47E-08	1.31E-08	1.18E-08	1.07E-08
WNW	2.14E-08	1.90E-08	1.70E-08	1.53E-08	1.39E-08
NW	2.62E-08	2.32E-08	2.07E-08	1.87E-08	1.70E-08
NNW	2.66E-08	2.37E-08	2.13E-08	1.93E-08	1.77E-08
N	2.94E-08	2.61E-08	2.34E-08	2.12E-08	1.93E-08

Source: Containment Building

TABLE 2A-1 ANNUAL AVERAGE X/Q VALUES FOR THE CONTAINMENT BUILDING (UNDECAYED AND UNDEPLETED)

	Downwind Distance (KM)				
Sector	11.2	12.0	12.8	13.6	14.4
NNE	2.63E-08	2.43E-08	2.25E-08	2.09E-08	1.95E-08
NE	2.48E-08	2.29E-08	2.12E-08	1.97E-08	1.84E-08
ENE	2.54E-08	2.35E-08	2.18E-08	2.03E-08	1.90E-08
E	2.08E-08	1.92E-08	1.79E-08	1.66E-08	1.56E-08
ESE	2.00E-08	1.86E-08	1.73E-08	1.62E-08	1.52E-08
SE	1.77E-08	1.64E-08	1.52E-08	1.42E-08	1.34E-08
SSE	1.39E-08	1.29E-08	1.20E-08	1.13E-08	1.06E-08
S	1.21E-08	1.12E-08	1.05E-08	9.81E-09	9.23E-09
SSW	1.03E-08	9.52E-09	8.86E-09	8.27E-09	7.75E-09
SW	1.06E-08	9.77E-09	9.01E-09	8.34E-09	7.76E-09
WSW	1.30E-08	1.19E-08	1.10E-08	1.02E-08	9.44E-09
W	9.74E-09	8.94E-09	8.25E-09	7.65E-09	7.12E-09
WNW	1.27E-08	1.17E-08	1.08E-08	1.01E-08	9.37E-09
NW	1.55E-08	1.43E-08	1.32E-08	1.22E-08	1.14E-08
NNW	1.62E-08	1.50E-08	1.39E-08	1.29E-08	1.21E-08
N	1.77E-08	1.63E-08	1.51E-08	1.41E-08	1.31E-08

Source: Containment Building

TABLE 2A-1 ANNUAL AVERAGE X/Q VALUES FOR THE CONTAINMENT BUILDING (UNDECAYED AND UNDEPLETED)

	Downwind Distance (KM)				
Sector	15.2	16.0	24.0	32.0	40.0
NNE	1.82E-08	1.71E-08	1.03E-08	7.13E-09	5.33E-09
NE	1.73E-08	1.62E-08	9.85E-09	6.84E-09	5.13E-09
ENE	1.78E-08	1.67E-08	1.02E-08	7.14E-09	5.37E-09
E	1.46E-08	1.38E-08	8.46E-09	5.93E-09	4.48E-09
ESE	1.43E-08	1.35E-08	8.50E-09	6.09E-09	4.67E-09
SE	1.26E-08	1.19E-08	7.46E-09	5.32E-09	4.07E-09
SSE	1.00E-08	9.45E-09	6.03E-09	4.34E-09	3.35E-09
S	8.70E-09	8.23E-09	5.26E-09	3.79E-09	2.93E-09
SSW	7.28E-09	6.86E-09	4.27E-09	3.02E-09	2.30E-09
SW	7.24E-09	6.78E-09	4.00E-09	2.74E-09	2.03E-09
WSW	8.80E-09	8.23E-09	4.31E-09	3.25E-09	2.39E-09
W	6.65E-09	6.23E-09	3.69E-09	2.53E-09	1.88E-09
WNW	8.77E-09	8.23E-09	4.95E-09	3.43E-09	2.57E-09
NW	1.06E-08	9.98E-09	5.96E-09	4.10E-09	3.06E-09
NNW	1.13E-08	1.07E-08	6.53E-09	4.57E-09	3.44E-09
N	1.23E-08	1.15E-08	6.98E-09	4.84E-09	3.62E-09

Source: Containment Building

TABLE 2A-1 ANNUAL AVERAGE X/Q VALUES FOR THE CONTAINMENT BUILDING (UNDECAYED AND UNDEPLETED)

	Downwind Distance (KM)				
Sector	48.0	56.0	64.0	72.0	80.0
NNE	4.19E-09	3.42E-09	2.86E-09	2.44E-09	2.11E-09
NE	4.04E-09	3.30E-09	2.76E-09	2.36E-09	2.05E-09
ENE	4.24E-09	3.47E-09	2.91E-09	2.49E-09	2.16E-09
E	3.55E-09	2.91E-09	2.45E-09	2.10E-09	1.82E-09
ESE	3.75E-09	3.11E-09	2.64E-09	2.27E-09	1.99E-09
SE	3.26E-09	2.70E-09	2.28E-09	1.97E-09	1.72E-09
SSE	2.70E-09	2.24E-09	1.90E-09	1.65E-09	1.44E-09
S	2.36E-09	1.96E-09	1.66E-09	1.44E-09	1.26E-09
SSW	1.83E-09	1.51E-09	1.27E-09	1.09E-09	9.53E-10
SW	1.59E-09	1.29E-09	1.07E-09	9.13E-10	7.90E-10
WSW	1.86E-09	1.50E-09	1.24E-09	1.05E-09	9.06E-10
W	1.47E-09	1.19E-09	9.92E-10	8.44E-10	7.29E-10
WNW	2.02E-09	1.65E-09	1.38E-09	1.18E-09	1.03E-09
NW	2.40E-09	1.95E-09	1.63E-09	1.39E-09	1.20E-09
NNW	2.73E-09	2.23E-09	1.87E-09	1.60E-09	1.40E-09
N	2.85E-09	2.33E-09	1.95E-09	1.66E-09	1.44E-09

Source: Containment Building

TABLE 2A-2 ANNUAL AVERAGE X/Q VALUES FOR THE RADWASTE BUILDING (UNDECAYED AND UNDEPLETED)

	Downwind Distance (KM)				
Sector	0.4	0.8	1.2	1.6	2.4
NNE	3.04E-06	1.05E-06	6.17E-07	4.40E-07	2.73E-07
NE	2.45E-06	8.69E-07	5.21E-07	3.76E-07	2.38E-07
ENE	2.41E-06	8.70E-07	5.21E-07	3.76E-07	2.38E-07
E	1.70E-06	6.21E-07	3.94E-07	2.89E-07	1.36E-07
ESE	1.73E-06	6.12E-07	3.82E-07	2.79E-07	1.80E-07
SE	1.55E-06	5.45E-07	3.39E-07	2.47E-07	1.58E-07
SSE	1.22E-06	4.15E-07	2.61E-07	1.91E-07	1.24E-07
S	1.10E-06	3.71E-07	2.33E-07	1.69E-07	1.09E-07
SSW	8.68E-07	3.13E-07	1.94E-07	1.42E-07	9.10E-08
SW	8.93E-07	3.51E-07	2.20E-07	1.60E-07	1.01E-07
WSW	1.12E-06	4.24E-07	2.65E-07	1.92E-07	1.21E-07
W	1.06E-06	3.72E-07	2.25E-07	1.60E-07	9.87E-08
WNW	1.58E-06	5.26E-07	3.18E-07	2.26E-07	1.40E-07
NW	1.50E-06	5.19E-07	3.30E-07	2.39E-07	1.52E-07
NNW	1.68E-06	5.63E-07	3.49E-07	2.51E-07	1.59E-07
N	1.63E-06	5.73E-07	3.58E-07	2.60E-07	1.65E-07

Source: Radwaste Building

TABLE 2A-2 ANNUAL AVERAGE X/Q VALUES FOR THE RADWASTE BUILDING (UNDECAYED AND UNDEPLETED)

	Downwind Distance (KM)				
Sector	3.2	4.0	4.8	5.6	6.4
NNE	1.93E-07	1.47E-07	1.17E-07	9.62E-08	8.12E-08
NE	1.70E-07	1.31E-07	1.05E-07	8.68E-08	7.35E-08
ENE	1.70E-07	1.31E-07	1.05E-07	8.72E-08	7.41E-08
E	1.34E-07	1.04E-07	8.38E-08	6.97E-08	5.94E-08
ESE	1.30E-07	1.01E-07	8.21E-08	6.86E-08	5.87E-08
SE	1.14E-07	8.86E-08	7.18E-08	5.99E-08	5.12E-08
SSE	9.02E-08	7.02E-08	5.71E-08	4.79E-08	4.11E-08
S	7.93E-08	6.17E-08	5.02E-08	4.21E-08	3.61E-08
SSW	6.59E-08	5.11E-08	4.13E-08	3.45E-08	2.94E-08
SW	7.12E-08	5.41E-08	4.30E-08	3.53E-08	2.97E-08
WSW	8.55E-08	6.49E-08	5.16E-08	4.24E-08	3.56E-08
W	6.93E-08	5.25E-08	4.16E-08	3.42E-08	2.87E-08
WNW	9.90E-08	7.50E-08	5.96E-08	4.90E-08	4.13E-08
NW	1.08E-07	8.25E-08	6.58E-08	5.42E-08	4.57E-08
NNW	1.14E-07	8.78E-08	7.06E-08	5.85E-08	4.96E-08
N	1.18E-07	9.05E-08	7.26E-08	6.01E-08	5.09E-08

Source: Radwaste Building

TABLE 2A-2 ANNUAL AVERAGE X/Q VALUES FOR THE RADWASTE BUILDING (UNDECAYED AND UNDEPLETED)

	Downwind Distance (KM)				
Sector	7.2	8.0	8.8	9.6	10.4
NNE	6.99E-08	6.10E-08	5.39E-08	4.82E-08	4.34E-08
NE	6.35E-08	5.56E-08	4.93E-08	4.41E-08	3.98E-08
ENE	6.41E-08	5.62E-08	4.99E-08	4.47E-08	4.04E-08
E	5.15E-08	4.53E-08	4.03E-03	3.62E-08	3.27E-08
ESE	5.11E-08	4.51E-08	4.03E-08	3.63E-08	3.30E-08
SE	4.46E-08	3.93E-08	3.51E-08	3.16E-08	2.87E-08
SSE	3.58E-08	3.17E-08	2.84E-08	2.56E-08	2.33E-08
S	3.15E-08	2.79E-08	2.50E-08	2.26E-08	2.05E-08
SSW	2.56E-08	2.25E-08	2.01E-08	1.81E-08	1.64E-08
SW	2.55E-08	2.22E-08	1.96E-08	1.74E-08	1.57E-08
WSW	3.05E-08	2.66E-08	2.34E-08	2.08E-08	1.87E-08
W	2.46E-08	2.15E-08	1.89E-08	1.69E-08	1.52E-08
WNW	3.54E-08	3.09E-08	2.73E-08	2.43E-08	2.19E-08
NW	3.93E-08	3.43E-08	3.03E-08	2.70E-08	2.43E-08
NNW	4.29E-08	3.76E-08	3.34E-08	2.99E-08	2.70E-08
N	4.39E-08	3.85E-08	3.41E-08	3.05E-08	2.75E-08

Source: Radwaste Building

TABLE 2A-2 ANNUAL AVERAGE X/Q VALUES FOR THE RADWASTE BUILDING (UNDECAYED AND UNDEPLETED)

Sector	Downwind Distance (KM) 11.2	12.0	12.8	13.6	14.4
NNE	3.94E-08	3.59E-08	3.30E-08	3.05E-08	2.82E-08
NE	3.62E-08	3.31E-08	3.04E-08	2.81E-08	2.61E-08
ENE	3.68E-08	3.37E-08	3.11E-08	2.87E-08	2.67E-08
E	2.99E-08	2.74E-08	2.53E-08	2.34E-08	2.18E-08
ESE	3.02E-08	2.78E-08	2.57E-08	2.39E-08	2.23E-08
SE	2.63E-08	2.42E-08	2.24E-08	2.08E-08	1.94E-08
SSE	2.14E-08	1.97E-08	1.83E-08	1.70E-08	1.59E-08
S	1.88E-08	1.74E-08	1.61E-08	1.50E-08	1.40E-08
SSW	1.50E-08	1.38E-08	1.27E-08	1.18E-08	1.10E-08
SW	1.42E-08	1.29E-08	1.19E-08	1.09E-08	1.01E-08
WSW	1.69E-08	1.54E-08	1.41E-08	1.30E-08	1.20E-08
W	1.37E-08	1.25E-08	1.15E-08	1.06E-08	9.80E-09
WNW	1.98E-08	1.81E-08	1.66E-08	1.53E-08	1.42E-08
NW	2.21E-08	2.01E-08	1.85E-08	1.71E-08	1.58E-08
NNW	2.46E-08	2.25E-08	2.07E-08	1.92E-08	1.78E-08
N	2.50E-08	2.29E-08	2.11E-08	1.95E-08	1.81E-08

Source: Radwaste Building

TABLE 2A-2 ANNUAL AVERAGE X/Q VALUES FOR THE RADWASTE BUILDING (UNDECAYED AND UNDEPLETED)

	Downwind Distance (KM)				
Sector	15.2	16.0	24.0	32.0	40.0
NNE	2.63E-08	2.46E-08	1.42E-08	9.63E-09	7.09E-09
NE	2.43E-08	2.28E-08	1.33E-08	9.03E-09	6.67E-09
ENE	2.49E-08	2.33E-08	1.37E-08	9.38E-09	6.95E-09
E	2.03E-08	1.90E-08	1.13E-08	7.75E-09	5.76E-09
ESE	2.09E-08	1.96E-08	1.20E-08	8.35E-09	6.29E-09
SE	1.82E-08	1.71E-08	1.03E-08	7.20E-09	5.41E-09
SSE	1.49E-08	1.40E-08	8.59E-09	6.02E-09	4.55E-09
S	1.31E-08	1.23E-08	7.56E-09	5.30E-09	4.00E-09
SSW	1.03E-08	9.64E-09	5.79E-09	4.00E-09	2.99E-09
SW	9.42E-09	8.79E-09	5.06E-09	3.41E-09	2.50E-09
WSW	1.11E-08	1.04E-08	5.90E-09	3.94E-09	2.87E-09
W	9.11E-09	8.50E-09	4.88E-09	3.28E-09	2.40E-09
WNW	1.32E-08	1.24E-08	7.16E-09	4.84E-09	3.57E-09
NW	1.47E-08	1.37E-08	7.95E-09	5.37E-09	3.95E-09
NNW	1.66E-08	1.56E-08	9.15E-09	6.24E-09	4.63E-09
N	1.68E-08	1.57E-08	9.20E-09	6.25E-09	4.62E-09

Source: Radwaste Building

TABLE 2A-2 ANNUAL AVERAGE X/Q VALUES FOR THE RADWASTE BUILDING (UNDECAYED AND UNDEPLETED)

Sector	Downwind Distance (KM) 48.0	56.0	64.0	72.0	80.0
NNE	5.51E-09	4.45E-09	3.70E-09	3.14E-09	2.71E-09
NE	5.19E-09	4.20E-09	3.49E-09	2.97E-09	2.56E-09
ENE	5.43E-09	4.40E-09	3.66E-09	3.11E-09	2.69E-09
E	4.51E-09	3.66E-09	3.06E-09	2.60E-09	2.25E-09
ESE	4.97E-09	4.07E-09	3.42E-09	2.92E-09	2.54E-09
SE	4.27E-09	3.49E-09	2.92E-09	2.50E-09	2.17E-09
SSE	3.61E-09	2.96E-09	2.48E-09	2.13E-09	1.85E-09
S	3.17E-09	2.59E-09	2.18E-09	1.86E-09	1.62E-09
SSW	2.35E-09	1.92E-09	1.60E-09	1.37E-09	1.19E-09
SW	1.94E-09	1.57E-09	1.30E-09	1.10E-09	9.48E-10
WSW	2.21E-09	1.77E-09	1.46E-09	1.24E-09	1.06E-09
W	1.86E-09	1.50E-09	1.24E-09	1.05E-09	9.04E-10
WNW	2.77E-09	2.24E-09	1.86E-09	1.58E-09	1.36E-09
NW	3.07E-09	2.48E-09	2.05E-09	1.74E-09	1.50E-09
NNW	3.61E-09	2.93E-09	2.44E-09	2.07E-09	1.79E-09
N	3.60E-09	2.91E-09	2.42E-09	2.06E-09	1.78E-09

Source: Radwaste Building

TABLE 2A-3 ANNUAL AVERAGE X/Q VALUES FOR THE TURBINE BUILDING (UNDECAYED AND UNDEPLETED)

	Downwind Distance (KM)				
Sector	0.4	0.8	1.2	1.6	2.4
NNE	6.10E-06	2.05E-06	1.07E-06	7.30E-07	4.25E-07
NE	5.27E-06	1.80E-06	9.37E-07	6.39E-07	3.75E-07
ENE	5.75E-06	1.97E-06	1.02E-06	6.91E-07	4.05E-07
E	4.81E-06	1.61E-06	8.43E-07	5.73E-07	3.37E-07
ESE	4.36E-06	1.43E-06	7.56E-07	5.15E-07	3.07E-07
SE	4.32E-06	1.40E-06	7.39E-07	5.02E-07	2.96E-07
SSE	3.16E-06	1.01E-06	5.38E-07	3.67E-07	2.19E-07
S	3.33E-06	1.04E-06	5.63E-07	3.84E-07	2.29E-07
SSW	2.38E-06	7.81E-07	4.13E-07	2.82E-07	1.67E-07
SW	2.33E-06	8.12E-07	4.08E-07	2.74E-07	1.57E-07
WSW	2.88E-06	9.90E-07	4.98E-07	3.34E-07	1.92E-07
W	2.26E-06	7.42E-07	3.84E-07	2.59E-07	1.50E-07
WNW	3.27E-06	1.05E-06	5.51E-07	3.72E-07	2.17E-07
NW	3.94E-06	1.28E-06	6.62E-07	4.47E-07	2.60E-07
NNW	4.17E-06	1.35E-06	7.10E-07	4.81E-07	2.83E-07
N	3.97E-06	1.33E-06	6.92E-07	4.71E-07	2.75E-07

Source: Turbine Building

TABLE 2A-3 ANNUAL AVERAGE X/Q VALUES FOR THE TURBINE BUILDING (UNDECAYED AND UNDEPLETED)

	Downwind Distance (KM)				
Sector	3.2	4.0	4.8	5.6	6.4
NNE	2.89E-07	2.14E-07	1.67E-07	1.36E-07	1.13E-07
NE	2.57E-07	1.91E-07	1.50E-07	1.22E-07	1.02E-07
ENE	2.76E-07	2.05E-07	1.61E-07	1.31E-07	1.09E-07
E	2.31E-07	1.72E-07	1.35E-07	1.10E-07	9.18E-08
ESE	2.12E-07	1.59E-07	1.26E-07	1.03E-07	8.69E-08
SE	2.04E-07	1.52E-07	1.20E-07	9.82E-08	8.24E-08
SSE	1.52E-07	1.15E-07	9.07E-08	7.45E-08	6.28E-08
S	1.58E-07	1.18E-07	9.34E-08	7.64E-08	6.42E-08
SSW	1.15E-07	8.60E-08	6.77E-08	5.53E-08	4.64E-08
SW	1.05E-07	7.74E-08	6.01E-08	4.85E-08	4.03E-08
WSW	1.29E-07	9.49E-08	7.37E-08	5.95E-08	4.94E-08
W	1.02E-07	7.51E-08	5.86E-08	4.75E-08	3.95E-08
WNW	1.47E-07	1.09E-07	8.53E-08	6.91E-08	5.76E-08
NW	1.77E-07	1.31E-07	1.02E-07	8.29E-08	6.90E-08
NNW	1.93E-07	1.44E-07	1.13E-07	9.16E-08	7.65E-08
N	1.87E-07	1.39E-07	1.09E-07	8.82E-08	7.36E-08

Source: Turbine Building

TABLE 2A-3 ANNUAL AVERAGE X/Q VALUES FOR THE TURBINE BUILDING (UNDECAYED AND UNDEPLETED)

Sector	Downwind Distance (KM) 7.2	8.0	8.8	9.6	10.4
NNE	9.62E-08	8.32E-08	7.30E-08	6.48E-08	5.80E-08
NE	8.70E-08	7.54E-08	6.63E-08	5.90E-08	5.29E-08
ENE	9.33E-08	8.10E-08	7.12E-08	6.33E-08	5.68E-08
E	7.85E-08	6.81E-08	5.99E-08	5.33E-08	4.79E-08
ESE	7.46E-08	6.51E-08	5.75E-08	5.14E-08	4.63E-08
SE	7.06E-08	6.14E-08	5.42E-08	4.83E-08	4.35E-08
SSE	5.40E-08	4.72E-08	4.17E-08	3.73E-08	3.36E-08
S	5.50E-08	4.79E-08	4.23E-08	3.77E-08	3.39E-08
SSW	3.97E-08	3.46E-08	3.05E-08	2.71E-08	2.44E-08
SW	3.42E-08	2.95E-08	2.58E-08	2.29E-08	2.05E-08
WSW	4.19E-08	3.61E-08	3.16E-08	2.80E-08	2.50E-08
W	3.36E-08	2.91E-08	2.55E-08	2.26E-08	2.02E-08
WNW	4.90E-08	4.24E-08	3.72E-08	3.30E-08	2.95E-08
NW	5.87E-08	5.07E-08	4.45E-08	3.94E-08	3.53E-08
NNW	6.53E-08	5.66E-08	4.97E-08	4.42E-08	3.96E-08
N	6.27E-08	5.43E-08	4.77E-08	4.24E-08	3.80E-08

Source: Turbine Building

TABLE 2A-3 ANNUAL AVERAGE X/Q VALUES FOR THE TURBINE BUILDING (UNDECAYED AND UNDEPLETED)

Sector	Downwind Distance (KM) 11.2	12.0	12.8	13.6	14.4
NNE	5.24E-08	4.76E-08	4.35E-08	4.00E-08	3.70E-08
NE	4.78E-08	4.35E-08	3.99E-08	3.67E-08	3.39E-08
ENE	5.13E-08	4.68E-08	4.28E-08	3.94E-08	3.65E-08
E	4.33E-08	3.95E-08	3.62E-08	3.33E-08	3.08E-08
ESE	4.20E-08	3.84E-08	3.53E-08	3.26E-08	3.03E-08
SE	3.94E-08	3.60E-08	3.30E-08	3.05E-08	2.83E-08
SSE	3.06E-08	2.80E-08	2.57E-08	2.38E-08	2.21E-08
S	3.08E-08	2.81E-08	2.58E-08	2.38E-08	2.21E-08
SSW	2.21E-08	2.02E-08	1.85E-08	1.71E-08	1.58E-08
SW	1.84E-08	1.67E-08	1.53E-08	1.40E-08	1.30E-08
WSW	2.25E-08	2.04E-08	1.86E-08	1.71E-08	1.57E-08
W	1.82E-08	1.65E-08	1.51E-08	1.39E-08	1.28E-08
WNW	2.67E-08	2.42E-08	2.22E-08	2.04E-08	1.88E-08
NW	3.18E-08	2.89E-08	2.64E-08	2.43E-08	2.24E-08
NNW	3.58E-08	3.26E-08	2.98E-08	2.75E-08	2.54E-08
N	3.43E-08	3.12E-08	2.85E-08	2.63E-08	2.43E-08

Source: Turbine Building

TABLE 2A-3 ANNUAL AVERAGE X/Q VALUES FOR THE TURBINE BUILDING (UNDECAYED AND UNDEPLETED)

	Downwind Distance (KM)				
Sector	15.2	16.0	24.0	32.0	40.0
NNE	3.43E-08	3.19E-08	1.31E-08	1.21E-08	8.86E-09
NE	3.15E-08	2.94E-08	1.68E-08	1.13E-08	8.27E-09
ENE	3.39E-08	3.16E-08	1.81E-08	1.22E-08	8.94E-09
E	2.87E-08	2.67E-08	1.54E-08	1.04E-08	7.61E-09
ESE	2.82E-08	2.64E-08	1.55E-08	1.06E-08	7.90E-09
SE	2.63E-08	2.46E-08	1.43E-08	9.74E-09	7.21E-09
SSE	2.06E-08	1.93E-08	1.14E-08	7.81E-09	5.81E-09
S	2.06E-08	1.92E-08	1.12E-08	7.63E-09	5.65E-09
SSW	1.47E-08	1.37E-08	7.96E-09	5.39E-09	3.97E-09
SW	1.20E-08	1.12E-08	6.31E-09	4.21E-09	3.07E-09
WSW	1.46E-08	1.35E-08	7.58E-09	5.01E-09	3.63E-09
W	1.19E-08	1.11E-08	6.24E-09	4.15E-09	3.02E-09
WNW	1.75E-08	1.63E-08	9.23E-09	6.16E-09	4.50E-09
NW	2.08E-08	1.93E-08	1.09E-08	7.27E-09	5.30E-09
NNW	2.36E-08	2.20E-08	1.26E-08	8.42E-09	6.17E-09
N	2.25E-08	2.10E-08	1.20E-08	8.02E-09	5.87E-09

Source: Turbine Building

TABLE 2A-3 ANNUAL AVERAGE X/Q VALUES FOR THE TURBINE BUILDING (UNDECAYED AND UNDEPLETED)

Sector	Downwind Distance (KM) 48.0	56.0	64.0	72.0	80.0
NNE	6.85E-09	5.51E-09	4.56E-09	3.86E-09	3.32E-09
NE	6.40E-09	5.16E-09	4.28E-09	3.62E-09	3.12E-09
ENE	6.93E-09	5.59E-09	4.63E-09	3.93E-09	3.39E-09
E	5.91E-09	4.77E-09	3.96E-09	3.35E-09	2.89E-09
ESE	6.19E-09	5.03E-09	4.20E-09	3.58E-09	3.10E-09
SE	5.63E-09	4.56E-09	3.80E-09	3.23E-09	2.79E-09
SSE	4.56E-09	3.71E-09	3.10E-09	2.64E-09	2.29E-09
S	4.41E-09	3.58E-09	2.98E-09	2.53E-09	2.19E-09
SSW	3.09E-09	2.50E-09	2.08E-09	1.77E-09	1.53E-09
SW	2.37E-09	1.90E-09	1.57E-09	1.33E-09	1.14E-09
WSW	2.78E-09	2.23E-09	1.83E-09	1.54E-09	1.32E-09
W	2.33E-09	1.87E-09	1.54E-09	1.30E-09	1.12E-09
WNW	3.48E-09	2.80E-09	2.32E-09	1.96E-09	1.69E-09
NW	4.08E-09	3.28E-09	2.71E-09	2.29E-09	1.97E-09
NNW	4.78E-09	3.85E-09	3.19E-09	2.70E-09	2.33E-09
N	4.55E-09	3.66E-09	3.03E-09	2.57E-09	2.21E-09

Source: Turbine Building

TABLE 2A-4 ANNUAL AVERAGE X/Q VALUES FOR THE CONTAINMENT BUILDING (DECAYED AND DEPLETED)

	Downwind Distance (KM)				
Sector	0.4	0.8	1.2	1.6	2.4
NNE	1.23E-06	3.81E-07	2.45E-07	1.84E-07	1.24E-07
NE	9.96E-07	3.20E-07	2.08E-07	1.59E-07	1.10E-07
ENE	9.65E-07	3.20E-07	2.11E-07	1.63E-07	1.13E-07
E	6.98E-07	2.33E-07	1.63E-07	1.28E-07	9.06E-08
ESE	6.76E-07	2.25E-07	1.53E-07	1.19E-07	8.34E-08
SE	6.37E-07	2.10E-07	1.42E-07	1.09E-07	7.57E-08
SSE	4.81E-07	1.54E-07	1.05E-07	8.07E-08	5.64E-08
S	4.58E-07	1.39E-07	9.34E-08	7.15E-08	4.94E-08
SSW	3.55E-07	1.17E-07	8.01E-08	6.23E-08	4.37E-08
SW	3.75E-07	1.37E-07	9.74E-08	7.64E-08	5.33E-08
WSW	5.12E-07	1.83E-07	1.26E-07	9.70E-08	6.66E-08
W	4.50E-07	1.52E-07	9.99E-08	7.50E-08	4.99E-08
WNW	6.31E-07	1.98E-07	1.28E-07	9.51E-08	6.28E-08
NW	6.67E-07	2.08E-07	1.39E-07	1.07E-07	7.43E-08
NNW	7.06E-07	2.12E-07	1.39E-07	1.06E-07	7.26E-08
N	7.42E-07	2.32E-07	1.53E-07	1.17E-07	8.07E-08

Source: Containment Building

TABLE 2A-4 ANNUAL AVERAGE X/Q VALUES FOR THE CONTAINMENT BUILDING (DECAYED AND DEPLETED)

	Downwind Distance (KM)				
Sector	3.2	4.0	4.8	5.6	6.4
NNE	9.27E-08	7.36E-08	6.06E-08	5.13E-08	4.42E-08
NE	8.40E-08	6.76E-08	5.62E-08	4.79E-08	4.15E-08
ENE	8.65E-08	6.96E-08	5.79E-08	4.93E-08	4.27E-08
E	6.98E-08	5.64E-08	4.71E-08	4.02E-08	3.49E-08
ESE	6.44E-08	5.23E-08	4.38E-08	3.75E-08	3.27E-08
SE	5.79E-08	4.67E-08	3.89E-08	3.33E-08	2.89E-08
SSE	4.37E-08	3.55E-08	2.99E-08	2.57E-08	2.24E-08
S	3.79E-08	3.07E-08	2.58E-08	2.21E-08	1.93E-08
SSW	3.37E-08	2.73E-08	2.28E-08	1.95E-08	1.70E-08
SW	4.03E-08	3.20E-08	2.62E-08	2.20E-08	1.88E-08
WSW	4.99E-08	3.94E-08	3.22E-08	2.70E-08	2.30E-08
W	3.69E-08	2.89E-08	2.36E-08	1.97E-08	1.68E-08
WNW	4.64E-08	3.65E-08	2.99E-08	2.51E-08	2.15E-08
NW	5.63E-08	4.49E-08	3.70E-08	3.12E-08	2.68E-08
NNW	5.52E-08	4.42E-08	3.67E-08	3.12E-08	2.70E-08
N	6.14E-08	4.92E-08	4.08E-08	3.46E-08	2.99E-08

Source: Containment Building

TABLE 2A-4 ANNUAL AVERAGE X/Q VALUES FOR THE CONTAINMENT BUILDING (DECAYED AND DEPLETED)

	Downwind Distance (KM)				
Sector	7.2	8.0	8.8	9.6	10.4
NNE	3.87E-08	3.42E-08	3.06E-08	2.76E-08	2.51E-08
NE	3.65E-08	3.25E-08	2.91E-08	2.64E-08	2.40E-08
ENE	3.75E-08	3.34E-08	3.00E-08	2.72E-08	2.48E-08
E	3.07E-08	2.73E-08	2.46E-08	2.23E-08	2.03E-08
ESE	2.89E-08	2.59E-08	2.34E-08	2.13E-08	1.95E-08
SE	2.55E-08	2.28E-08	2.06E-08	1.87E-08	1.71E-08
SSE	1.99E-08	1.78E-08	1.61E-08	1.47E-08	1.35E-08
S	1.71E-08	1.53E-08	1.39E-08	1.26E-08	1.16E-08
SSW	1.50E-08	1.34E-08	1.21E-08	1.10E-08	1.00E-08
SW	1.64E-08	1.44E-08	1.28E-08	1.15E-08	1.04E-08
WSW	2.00E-08	1.76E-08	1.56E-08	1.40E-08	1.26E-08
W	1.46E-08	1.29E-08	1.14E-08	1.03E-08	9.28E-09
WNW	1.87E-08	1.65E-08	1.47E-08	1.32E-08	1.20E-08
NW	2.33E-08	2.06E-08	1.83E-08	1.65E-08	1.49E-08
NNW	2.37E-08	2.11E-08	1.89E-08	1.71E-08	1.56E-08
N	2.62E-08	2.33E-08	2.08E-08	1.88E-08	1.71E-08

Source: Containment Building

TABLE 2A-4 ANNUAL AVERAGE X/Q VALUES FOR THE CONTAINMENT BUILDING (DECAYED AND DEPLETED)

Sector	Downwind Distance (KM) 11.2	12.0	12.8	13.6	14.4
NNE	2.29E-08	2.11E-08	1.95E-08	1.81E-08	1.68E-08
NE	2.20E-08	2.03E-08	1.87E-08	1.74E-08	1.62E-08
ENE	2.27E-08	2.09E-08	1.94E-08	1.80E-08	1.68E-08
E	1.87E-08	1.72E-08	1.60E-08	1.49E-08	1.39E-08
ESE	1.79E-08	1.66E-08	1.54E-08	1.44E-08	1.35E-08
SE	1.57E-08	1.46E-08	1.35E-08	1.26E-08	1.18E-08
SSE	1.24E-08	1.15E-08	1.08E-08	1.01E-08	9.44E-09
S	1.07E-08	9.94E-09	9.26E-09	8.67E-09	8.14E-09
SSW	9.20E-09	8.50E-09	7.89E-09	7.36E-09	6.88E-09
SW	9.45E-09	8.64E-09	7.95E-09	7.34E-09	6.81E-09
WSW	1.15E-08	1.05E-08	9.61E-09	8.87E-09	8.22E-09
W	8.44E-09	7.72E-09	7.10E-09	6.56E-09	6.09E-09
WNW	1.09E-08	1.00E-08	9.24E-09	8.55E-09	7.95E-09
NW	1.36E-08	1.25E-08	1.15E-08	1.06E-08	9.87E-09
NNW	1.43E-08	1.32E-08	1.22E-08	1.13E-08	1.06E-08
N	1.57E-08	1.44E-08	1.33E-08	1.24E-08	1.15E-08

Source: Containment Building

TABLE 2A-4 ANNUAL AVERAGE X/Q VALUES FOR THE CONTAINMENT BUILDING (DECAYED AND DEPLETED)

	Downwind Distance (KM)				
Sector	15.2	16.0	24.0	32.0	40.0
NNE	1.57E-08	1.47E-08	8.73E-09	5.96E-09	4.41E-09
NE	1.52E-08	1.43E-08	8.55E-09	5.88E-09	4.37E-09
ENE	1.58E-08	1.48E-08	8.95E-09	6.19E-09	4.63E-09
E	1.30E-08	1.22E-08	7.44E-09	5.17E-09	3.88E-09
ESE	1.27E-08	1.20E-08	7.50E-09	5.33E-09	4.07E-09
SE	1.11E-08	1.05E-08	6.53E-09	4.62E-09	3.52E-09
SSE	8.89E-09	8.40E-09	5.32E-09	3.81E-09	2.93E-09
S	7.67E-09	7.25E-09	4.60E-09	3.30E-09	2.53E-09
SSW	6.46E-09	6.09E-09	3.75E-09	2.63E-09	1.99E-09
SW	6.34E-09	5.92E-09	3.43E-09	2.31E-09	1.70E-09
WSW	7.64E-09	7.13E-09	4.08E-09	2.72E-09	1.97E-09
W	5.67E-09	5.30E-09	3.08E-09	2.07E-09	1.52E-09
WNW	7.42E-09	6.95E-09	4.10E-09	2.80E-09	2.07E-09
NW	9.21E-09	8.61E-09	5.04E-09	3.42E-09	2.52E-09
NNW	9.89E-09	9.29E-09	5.61E-09	3.88E-09	2.90E-09
N	1.08E-08	1.01E-08	6.01E-09	4.12E-09	3.06E-09

Source: Containment Building

TABLE 2A-4 ANNUAL AVERAGE X/Q VALUES FOR THE CONTAINMENT BUILDING (DECAYED AND DEPLETED)

Sector	Downwind Distance (KM) 48.0	56.0	64.0	72.0	80.0
NNE	3.44E-09	2.77E-09	2.29E-09	1.93E-09	1.66E-09
NE	3.42E-09	2.76E-09	2.29E-09	1.93E-09	1.66E-09
ENE	3.63E-09	2.94E-09	2.44E-09	2.07E-09	1.79E-09
E	3.06E-09	2.48E-09	2.07E-09	1.76E-09	1.52E-09
ESE	3.26E-09	2.68E-09	2.25E-09	1.93E-09	1.67E-09
SE	2.81E-09	2.30E-09	1.93E-09	1.65E-09	1.43E-09
SSE	2.35E-09	1.93E-09	1.63E-09	1.40E-09	1.22E-09
S	2.03E-09	1.67E-09	1.41E-09	1.21E-09	1.05E-09
SSW	1.57E-09	1.28E-09	1.07E-09	9.14E-10	7.91E-10
SW	1.31E-09	1.05E-09	8.67E-10	7.30E-10	6.25E-10
WSW	1.51E-09	1.20E-09	9.85E-10	8.24E-10	7.02E-10
W	1.18E-09	9.41E-10	7.74E-10	6.50E-10	5.56E-10
WNW	1.62E-09	1.30E-09	1.08E-09	9.10E-10	7.82E-10
NW	1.96E-09	1.57E-09	1.30E-09	1.10E-09	9.39E-10
NNW	2.28E-09	1.85E-09	1.54E-09	1.30E-09	1.12E-09
N	2.39E-09	1.93E-09	1.59E-09	1.35E-09	1.16E-09

Source: Containment Building

TABLE 2A-5 ANNUAL AVERAGE X/Q VALUES FOR THE RADWASTE BUILDING (DECAYED AND DEPLETED)

Sector	Downwind Distance (KM) 0.4	0.8	1.2	1.6	2.4
NNE	2.86E-06	9.58E-07	5.59E-07	3.94E-07	2.40E-07
NE	2.30E-06	7.94E-07	4.74E-07	3.39E-07	2.11E-07
ENE	2.26E06	7.95E-07	4.75E-07	3.40E-07	2.12E-07
E	1.60E-06	5.70E-07	3.61E-07	2.63E-07	1.67E-07
ESE	1.63E-06	5.61E-07	3.49E-07	2.53E-07	1.61E-07
SE	1.46E-06	5.01E-07	3.11E-07	2.24E-07	1.41E-07
SSE	1.15E-06	3.80E-07	2.39E-07	1.73E-07	1.11E-07
S	1.04E-06	3.39E-07	2.12E-07	1.53E-07	9.71E-08
SSW	8.17E-07	2.87E-07	1.78E-07	1.29E-07	8.15E-08
SW	8.42E-07	3.23E-07	2.03E-07	1.46E-07	9.06E-08
WSW	1.05E-06	3.91E-07	2.44E-07	1.76E-07	1.09E-07
W	1.00E-06	3.42E-07	2.06E-07	1.45E-07	8.77E-08
WNW	1.49E-06	4.83E-07	2.89E-07	2.03E-07	1.24E-07
NW	1.41E-06	4.78E-07	3.03E-07	2.18E-07	1.36E-07
NNW	1.58E-06	5.17E-07	3.18E-07	2.27E-07	1.42E-07
N	1.54E-06	5.27E-07	3.27E-07	2.36E-07	1.47E-07

Source: Radwaste Building

TABLE 2A-5 ANNUAL AVERAGE X/Q VALUES FOR THE RADWASTE BUILDING (DECAYED AND DEPLETED)

	Downwind Distance (KM)				
Sector	3.2	4.0	4.8	5.6	6.4
NNE	1.67E-07	1.25E-07	9.90E-08	8.08E-08	6.77E-08
NE	1.49E-07	1.13E-07	9.04E-08	7.43E-08	6.27E-08
ENE	1.50E-07	1.14E-07	9.12E-08	7.52E-08	6.35E-08
E	1.19E-07	9.16E-08	7.35E-08	6.09E-08	5.17E-08
ESE	1.16E-07	8.91E-08	7.18E-08	5.97E-08	5.09E-08
SE	1.01E-07	7.78E-08	6.27E-08	5.21E-08	4.43E-08
SSE	7.98E-08	6.18E-08	5.00E-08	4.17E-08	3.56E-08
S	6.98E-08	5.39E-08	4.36E-08	3.63E-08	3.10E-08
SSW	5.84E-08	4.49E-08	3.61E-08	3.00E-08	2.55E-08
SW	6.34E-08	4.77E-08	3.76E-08	3.07E-08	2.56E-08
WSW	7.61E-08	5.73E-08	4.52E-08	3.69E-08	3.08E-08
W	6.07E-08	4.54E-08	3.57E-08	2.90E-08	2.43E-08
WNW	8.57E-08	6.41E-08	5.04E-08	4.10E-08	3.42E-08
NW	9.56E-08	7.22E-08	5.71E-08	4.66E-08	3.91E-08
NNW	1.00E-07	7.62E-08	6.07E-08	5.00E-08	4.22E-08
N	1.04E-07	7.93E-08	6.31E-08	5.19E-08	4.38E-08

Source: Radwaste Building

TABLE 2A-5 ANNUAL AVERAGE X/Q VALUES FOR THE RADWASTE BUILDING (DECAYED AND DEPLETED)

	Downwind Distance (KM)				
Sector	7.2	8.0	8.8	9.6	10.4
NNE	5.79E-08	5.03E-08	4.42E-08	3.93E-08	3.52E-08
NE	5.38E-08	4.69E-08	4.14E-08	3.70E-08	3.32E-08
ENE	5.47E-08	4.78E-08	4.23E-08	3.78E-08	3.41E-08
E	4.46E-08	3.91E-08	3.47E-08	3.11E-08	2.80E-08
ESE	4.41E-08	3.88E-08	3.46E-08	3.11E-08	2.82E-08
SE	3.84E-08	3.38E-08	3.01E-08	2.71E-08	2.45E-08
SSE	3.10E-08	2.73E-08	2.44E-08	2.20E-08	2.00E-08
S	2.70E-08	2.38E-08	2.13E-08	1.92E-08	1.74E-08
SSW	2.21E-08	1.94E-08	1.73E-08	1.55E-08	1.40E-08
SW	2.19E-08	1.90E-08	1.67E-08	1.48E-08	1.32E-08
WSW	2.63E-08	2.28E-08	2.00E-08	1.77E-08	1.58E-08
W	2.07E-08	1.79E-08	1.57E-08	1.39E-08	1.25E-08
WNW	2.92E-08	2.53E-08	2.22E-08	1.97E-08	1.76E-08
NW	3.34E-08	2.90E-08	2.55E-08	2.26E-08	2.03E-08
NNW	3.62E-08	3.16E-08	2.80E-08	2.50E-08	2.24E-08
N	3.76E-08	3.28E-08	2.89E-08	2.58E-08	2.32E-08

Source: Radwaste Building

TABLE 2A-5 ANNUAL AVERAGE X/Q VALUES FOR THE RADWASTE BUILDING (DECAYED AND DEPLETED)

Sector	Downwind Distance (KM) 11.2	12.0	12.8	13.6	14.4
NNE	3.18E-08	2.88E-08	2.63E-08	2.42E-08	2.23E-08
NE	3.00E-08	2.74E-08	2.50E-08	2.30E-08	2.13E-08
ENE	3.09E-08	2.82E-08	2.58E-08	2.38E-08	2.20E-08
E	2.55E-08	2.33E-08	2.14E-08	1.97E-08	1.83E-08
ESE	2.57E-08	2.36E-08	2.18E-08	2.02E-08	1.88E-08
SE	2.24E-08	2.05E-08	1.89E-08	1.75E-08	1.63E-08
SSE	1.83E-08	1.68E-08	1.55E-08	1.44E-08	1.34E-08
S	1.59E-08	1.46E-08	1.35E-08	1.25E-08	1.17E-08
SSW	1.27E-08	1.17E-08	1.07E-08	9.94E-09	9.23E-09
SW	1.19E-08	1.08E-08	9.87E-09	9.06E-09	8.36E-09
WSW	1.42E-08	1.29E-08	1.18E-08	1.08E-08	9.92E-09
W	1.12E-08	1.02E-08	9.28E-09	8.51E-09	7.84E-09
WNW	1.58E-08	1.44E-08	1.31E-08	1.20E-08	1.11E-08
NW	1.83E-08	1.66E-08	1.51E-08	1.39E-08	1.28E-08
NNW	2.03E-08	1.85E-08	1.70E-08	1.56E-08	1.44E-08
N	2.10E-08	1.91E-08	1.75E-08	1.61E-08	1.49E-08

Source: Radwaste Building

TABLE 2A-5 ANNUAL AVERAGE X/Q VALUES FOR THE RADWASTE BUILDING (DECAYED AND DEPLETED)

Sector	Downwind Distance (KM)				
	15.2	16.0	24.0	32.0	40.0
NNE	2.06E-08	1.92E-08	1.07E-08	6.99E-09	5.00E-09
NE	1.98E-08	1.84E-08	1.04E-08	6.87E-09	4.95E-09
ENE	2.05E-08	1.91E-08	1.09E-08	7.27E-09	5.28E-09
E	1.70E-08	1.59E-08	9.19E-09	6.16E-09	4.50E-09
ESE	1.76E-08	1.65E-08	9.80E-09	6.71E-09	4.98E-09
SE	1.52E-08	1.43E-08	8.44E-09	5.76E-09	4.25E-09
SSE	1.25E-08	1.18E-08	7.07E-09	4.86E-09	3.62E-09
S	1.09E-08	1.02E-08	6.13E-09	4.20E-09	3.12E-09
SSW	8.61E-09	8.06E-09	4.72E-09	3.19E-09	2.35E-09
SW	7.74E-09	7.19E-09	4.01E-09	2.63E-09	1.89E-09
WSW	9.17E-09	8.51E-09	4.67E-09	3.03E-09	2.15E-09
W	7.26E-09	6.74E-09	3.73E-09	2.42E-09	1.73E-09
WNW	1.03E-08	9.53E-09	5.29E-09	3.45E-09	2.47E-09
NW	1.19E-08	1.10E-08	6.15E-09	4.02E-09	2.88E-09
NNW	1.34E-08	1.25E-08	7.10E-09	4.71E-09	3.40E-09
N	1.38E-08	1.29E-08	7.27E-09	4.81E-09	3.47E-09

Source: Radwaste Building

TABLE 2A-5 ANNUAL AVERAGE X/Q VALUES FOR THE RADWASTE BUILDING (DECAYED AND DEPLETED)

	Downwind Distance (KM)				
Sector	48.0	56.0	64.0	72.0	80.0
NNE	3.80E-09	2.99E-09	2.42E-09	2.01E-09	1.70E-09
NE	3.78E-09	2.99E-09	2.43E-09	2.03E-09	1.72E-09
ENE	4.05E-09	3.22E-09	2.63E-09	2.19E-09	1.86E-09
E	3.46E-09	2.76E-09	2.26E-09	1.89E-09	1.61E-09
ESE	3.89E-09	3.13E-09	2.58E-09	2.17E-09	1.86E-09
SE	3.31E-09	2.66E-09	2.19E-09	1.84E-09	1.58E-09
SSE	2.83E-09	2.28E-09	1.88E-09	1.59E-09	1.36E-09
S	2.43E-09	1.96E-09	1.61E-09	1.36E-09	1.16E-09
SSW	1.82E-09	1.46E-09	1.20E-09	1.00E-09	8.58E-10
SW	1.44E-09	1.14E-09	9.24E-10	7.68E-10	6.51E-10
WSW	1.63E-09	1.28E-09	1.03E-09	8.54E-10	7.21E-10
W	1.31E-09	1.03E-09	8.33E-10	6.90E-10	5.82E-10
WNW	1.87E-09	1.47E-09	1.19E-09	9.89E-10	8.36E-10
NW	2.19E-09	1.73E-09	1.40E-09	1.16E-09	9.84E-10
NNW	2.61E-09	2.06E-09	1.68E-09	1.40E-09	1.19E-09
N	2.65E-09	2.10E-09	1.71E-09	1.43E-09	1.21E-09

Source: Radwaste Building

TABLE 2A-6 ANNUAL AVERAGE X/Q VALUES FOR THE TURBINE BUILDING (DECAYED AND DEPLETED)

	Downwind Distance (KM)				
Sector	0.4	0.8	1.2	1.6	2.4
NNE	5.74E-06	1.87E-06	9.56E-07	6.39E-07	3.61E-07
NE	4.95E-06	1.64E-06	8.35E-07	5.60E-07	3.19E-07
ENE	5.40E-06	1.79E-06	9.06E-07	6.05E-07	3.44E-07
E	4.52E-06	1.47E-06	7.51E-07	5.02E-07	2.87E-07
ESE	4.10E-06	1.30E-06	6.74E-07	4.52E-07	2.62E-07
SE	4.06E-06	1.27E-06	6.59E-07	4.40E-07	2.52E-07
SSE	2.97E-06	9.19E-07	4.80E-07	3.22E-07	1.87E-07
S	3.13E-06	9.46E-07	5.02E-07	3.36E-07	1.94E-07
SSW	2.23E-06	7.11E-07	3.69E-07	2.47E-07	1.42E-07
SW	2.19E0-6	7.38E-07	3.64E-07	2.40E-07	1.34E-07
WSW	2.71E-06	9.01E-07	4.44E-07	2.93E-07	1.63E-07
W	2.12E-06	6.76E-07	3.43E-07	2.27E-07	1.28E-07
WNW	3.07E-06	9.56E-07	4.91E-07	3.26E-07	1.84E-07
NW	3.70E-06	1.17E-06	5.90E-07	3.92E-07	2.21E-07
NNW	3.92E-06	1.23E-06	6.32E-07	4.21E-07	2.40E-07
N	3.73E-06	1.21E-06	6.17E-07	4.13E-07	2.34E-07

Source: Turbine Building

TABLE 2A-6 ANNUAL AVERAGE X/Q VALUES FOR THE TURBINE BUILDING (DECAYED AND DEPLETED)

	Downwind Distance (KM)				
Sector	3.2	4.0	4.8	5.6	6.4
NNE	2.39E-07	1.73E-07	1.33E-07	1.06E-07	8.72E-08
NE	2.13E-07	1.55E-07	1.20E-07	9.64E-08	7.97E-08
ENE	2.29E-07	1.67E-07	1.29E-07	1.03E-07	8.53E-08
E	1.91E-07	1.40E-07	1.08E-07	8.69E-08	7.20E-08
ESE	1.77E-07	1.31E-07	1.02E-07	8.25E-08	6.88E-08
SE	1.69E-07	1.24E-07	9.63E-08	7.77E-08	6.45E-08
SSE	1.27E-07	9.37E-08	7.33E-08	5.95E-08	4.96E-08
S	1.31E-07	9.60E-08	7.45E-08	6.01E-08	4.99E-08
SSW	9.56E-08	7.01E-08	5.44E-08	4.39E-08	3.65E-08
SW	8.76E-08	6.31E-08	4.83E-08	3.85E-08	3.16E-08
WSW	1.07E-07	7.74E-08	5.93E-08	4.72E-08	3.88E-08
W	8.45E-08	6.12E-08	4.70E-08	3.75E-08	3.09E-08
WNW	1.22E-07	8.82E-08	6.77E-08	5.41E-08	4.45E-08
NW	1.47E-07	1.06E-07	8.16E-08	6.52E-08	5.36E-08
NNW	1.60E-07	1.16E-07	8.96E-08	7.18E-08	5.93E-08
N	1.55E-07	1.13E-07	8.70E-08	6.97E-08	5.74E-08

Source: Turbine Building

TABLE 2A-6 ANNUAL AVERAGE X/Q VALUES FOR THE TURBINE BUILDING (DECAYED AND DEPLETED)

Sector	Downwind Distance (KM) 7.2	8.0	8.8	9.6	10.4
NNE	7.33E-08	6.28E-08	5.46E-08	4.80E-08	4.26E-08
NE	6.73E-08	5.79E-08	5.05E-08	4.45E-08	3.96E-08
ENE	7.21E-08	6.20E-08	5.40E-08	4.77E-08	4.24E-08
E	6.09E-08	5.24E-08	4.58E-08	4.04E-08	3.60E-08
ESE	5.85E-08	5.07E-08	4.45E-08	3.95E-08	3.54E-08
SE	5.48E-08	4.73E-08	4.14E-08	3.67E-08	3.27E-08
SSE	4.23E-08	3.67E-08	3.23E-08	2.87E-08	2.57E-08
S	4.23E-08	3.65E-08	3.20E-08	2.83E-08	2.53E-08
SSW	3.09E-08	2.67E-08	2.33E-08	2.06E-08	1.84E-08
SW	2.65E-08	2.27E-08	1.97E-08	1.73E-08	1.54E-08
WSW	3.25E-08	2.78E-08	2.41E-08	2.12E-08	1.88E-08
W	2.60E-08	2.22E-08	1.93E-08	1.70E-08	1.51E-08
WNW	3.74E-08	3.20E-08	2.78E-08	2.44E-08	2.17E-08
NW	4.51E-08	3.86E-08	3.35E-08	2.94E-08	2.61E-08
NNW	5.00E-08	4.29E-08	3.74E-08	3.29E-08	2.93E-08
N	4.84E-08	4.16E-08	3.62E-08	3.19E-08	2.83E-08

Source: Turbine Building

TABLE 2A-6 ANNUAL AVERAGE X/Q VALUES FOR THE TURBINE BUILDING (DECAYED AND DEPLETED)

	Downwind Distance (KM)				
Sector	11.2	12.0	12.8	13.6	14.4
NNE	3.80E-08	3.43E-08	3.10E-08	2.83E-08	2.59E-08
NE	3.55E-08	3.21E-08	2.91E-08	2.66E-08	2.45E-08
ENE	3.81E-08	3.44E-08	3.12E-08	2.86E-08	2.62E-08
E	3.23E-08	2.92E-08	2.66E-08	2.43E-08	2.24E-08
ESE	3.19E-08	2.90E-08	2.65E-08	2.43E-08	2.25E-08
SE	2.94E-08	2.67E-08	2.43E-08	2.23E-08	2.06E-08
SSE	2.32E-08	2.11E-08	1.93E-08	1.77E-08	1.64E-08
S	2.27E-08	2.06E-08	1.88E-08	1.72E-08	1.58E-08
SSW	1.66E-08	1.50E-08	1.37E-08	1.25E-08	1.15E-08
SW	1.37E-08	1.24E-08	1.12E-08	1.02E-08	9.36E-09
WSW	1.68E-08	1.51E-08	1.36E-08	1.24E-08	1.14E-08
W	1.35E-08	1.21E-08	1.10E-08	1.00E-08	9.18E-09
WNW	1.94E-08	1.74E-08	1.58E-08	1.44E-08	1.32E-08
NW	2.33E-08	2.09E-08	1.90E-08	1.73E-08	1.58E-08
NNW	2.62E-08	2.36E-08	2.14E-08	1.96E-08	1.79E-08
N	2.53E-08	2.29E-08	2.08E-08	1.89E-08	1.74E-08

Source: Turbine Building

TABLE 2A-6 ANNUAL AVERAGE X/Q VALUES FOR THE TURBINE BUILDING (DECAYED AND DEPLETED)

	Downwind Distance (KM)				
Sector	15.2	16.0	24.0	32.0	40.0
NNE	2.39E-08	2.21E-08	1.18E-08	7.47E-09	5.23E-09
NE	2.26E-08	2.09E-08	1.13E-08	7.28E-09	5.15E-09
ENE	2.42E-08	2.24E-08	1.22E-08	7.86E-09	5.57E-09
E	2.07E-08	1.92E-08	1.05E-08	6.78E-09	4.82E-09
ESE	2.08E-08	1.94E-08	1.09E-08	7.26E-09	5.27E-09
SE	1.90E-08	1.77E-08	9.83E-09	6.45E-09	4.63E-09
SSE	1.52E-08	1.41E-08	8.03E-09	5.34E-09	3.88E-09
S	1.47E-08	1.36E-08	7.55E-09	4.93E-09	3.53E-09
SSW	1.06E-08	9.89E-09	5.46E-09	3.56E-09	2.54E-09
SW	8.62E-09	7.97E-09	4.27E-09	2.73E-09	1.92E-09
WSW	1.05E-08	9.65E-09	5.10E-09	3.22E-09	2.24E-09
W	8.45E-09	7.81E-09	4.15E-09	2.63E-09	1.84E-09
WNW	1.21E-08	1.12E-08	5.96E-09	3.77E-09	2.64E-09
NW	1.46E-08	1.34E-08	7.12E-09	4.50E-09	3.14E-09
NNW	1.65E-08	1.53E-08	8.23E-09	5.26E-09	3.70E-09
N	1.60E-08	1.48E-08	8.00E-09	5.12E-09	3.61E-09

Source: Turbine Building

TABLE 2A-6 ANNUAL AVERAGE X/Q VALUES FOR THE TURBINE BUILDING (DECAYED AND DEPLETED)

Sector	Downwind Distance (KM)				
	48.0	56.0	64.0	72.0	80.0
NNE	3.90E-09	3.03E-09	2.42E-09	1.98E-09	1.65E-09
NE	3.87E-09	3.02E-09	2.42E-09	2.00E-09	1.67E-09
ENE	4.20E-09	3.28E-09	2.64E-09	2.17E-09	1.83E-09
E	3.64E-09	2.85E-09	2.30E-09	1.90E-09	1.60E-09
ESE	4.04E-09	3.21E-09	2.62E-09	2.18E-09	1.85E-09
SE	3.53E-09	2.78E-09	2.26E-09	1.87E-09	1.58E-09
SSE	2.98E-09	2.36E-09	1.93E-09	1.61E-09	1.37E-09
S	2.69E-09	2.11E-09	1.71E-09	1.42E-09	1.20E-09
SSW	1.93E-09	1.52E-09	1.23E-09	1.02E-09	8.57E-10
SW	1.44E-09	1.13E-09	9.03E-10	7.44E-10	6.24E-10
WSW	1.67E-09	1.29E-09	1.03E-09	8.38E-10	6.99E-10
W	1.37E-09	1.06E-09	8.46E-10	6.92E-10	5.78E-10
WNW	1.97E-09	1.52E-09	1.22E-09	9.96E-10	8.31E-10
NW	2.33E-09	1.80E-09	1.44E-09	1.17E-09	9.79E-10
NNW	2.77E-09	2.15E-09	1.72E-09	1.41E-09	1.18E-09
N	2.71E-09	2.11E-09	1.70E-09	1.39E-09	1.17E-09

Source: Turbine Building

TABLE 2A-7 ANNUAL AVERAGE D/Q VALUES FOR THE CONTAINMENT BUILDING

Sector	Downwind Distance (KM) 0.4	0.8	1.2	1.6	2.4
NNE	1.40E-08	5.71E-09	3.26E-09	2.11E-09	1.15E-09
NE	1.27E-08	5.11E-09	2.90E-09	1.87E-09	1.02E-09
ENE	1.20E-08	4.94E-09	2.89E-09	1.89E-09	1.05E-09
E	7.55E-09	3.32E-09	2.06E-09	1.40E-09	8.13E-10
ESE	7.96E-09	3.36E-09	2.03E-09	1.37E-09	7.84E-10
SE	7.06E-09	3.15E-09	1.95E-09	1.32E-09	7.64E-10
SSE	5.05E-09	2.21E-09	1.35E-09	9.07E-10	5.21E-10
S	3.93E-09	1.73E-09	1.04E-09	7.00E-10	4.01E-10
SSW	3.63E-09	1.57E-09	9.66E-10	6.56E-10	3.80E-10
SW	5.56E-09	2.57E-09	1.61E-09	1.10E-09	6.38E-10
WSW	7.55E-09	3.48E-09	2.18E-09	1.48E-09	8.61E-10
W	6.09E-09	2.77E-09	1.68E-09	1.13E-09	6.40E-10
WNW	7.64E-09	3.36E-09	1.99E-09	1.32E-09	7.38E-10
NW	7.50E-09	3.60E-09	2.21E-09	1.48E-09	8.51E-10
NNW	6.84E-09	3.04E-09	1.78E-09	1.17E-09	6.52E-10
N	8.96E-09	4.02E-09	2.36E-09	1.54E-09	8.51E-10

Source: Containment Building

TABLE 2A-7 ANNUAL AVERAGE D/Q VALUES FOR THE CONTAINMENT BUILDING

	Downwind Distance (KM)				
Sector	3.2	4.0	4.8	5.6	6.4
NNE	7.39E-10	5.26E-10	3.99E-10	3.07E-10	2.43E-10
NE	6.53E-10	4.65E-10	3.53E-10	2.72E-10	2.15E-10
ENE	6.83E-10	4.90E-10	3.75E-10	2.89E-10	2.28E-10
E	5.38E-10	3.92E-10	3.03E-10	2.34E-10	1.85E-10
ESE	5.16E-10	3.75E-10	2.90E-10	2.24E-10	1.77E-10
SE	5.04E-10	3.67E-10	2.84E-10	2.19E-10	1.73E-10
SSE	3.44E-10	2.50E-10	1.94E-10	1.50E-10	1.18E-10
S	2.64E-10	1.92E-10	1.48E-10	1.15E-10	9.07E-11
SSW	2.51E-10	1.83E-10	1.41E-10	1.09E-10	8.62E-11
SW	4.23E-10	3.09E-10	2.40E-10	1.85E-10	1.46E-10
WSW	5.68E-10	4.13E-10	3.20E-10	2.47E-10	1.95E-10
W	4.18E-10	3.02E-10	2.32E-10	1.79E-10	1.42E-10
WNW	4.80E-10	3.46E-10	2.65E-10	2.05E-10	1.62E-10
NW	5.58E-10	4.04E-10	3.11E-10	2.41E-10	1.91E-10
NNW	4.22E-10	3.02E-10	2.31E-10	1.78E-10	1.41E-10
N	5.50E-10	3.93E-10	3.00E-10	2.31E-10	1.83E-10

Source: Containment Building

TABLE 2A-7 ANNUAL AVERAGE D/Q VALUES FOR THE CONTAINMENT BUILDING

	Downwind Distance (KM)				
Sector	7.2	8.0	8.8	9.6	10.4
NNE	1.97E-10	1.64E-10	1.39E-10	1.19E-10	1.04E-10
NE	1.75E-10	1.45E-10	1.23E-10	1.05E-10	9.16E-11
ENE	1.85E-10	1.54E-10	1.30E-10	1.11E-10	9.67E-11
E	1.50E-10	1.24E-10	1.05E-10	9.00E-11	7.83E-11
ESE	1.43E-10	1.19E-10	1.00E-10	8.60E-11	7.48E-11
SE	1.41E-10	1.17E -10	9.85E-11	8.45E-11	7.36E-11
SSE	9.57E-11	7.94E-11	6.70E-11	5.74E-11	5.00E-11
S	7.37E-11	6.12E-11	5.17E-11	4.44E-11	3.87E-11
SSW	6.99E-11	5.80E-11	4.90E-11	4.20E-11	3.65E-11
SW	1.19E-10	9.87E-11	8.34E-11	7.15E-11	6.23E-11
WSW	1.58E-10	1.31E-10	1.11E-10	9.52E-11	8.29E-11
W	1.15E-10	9.57E-11	8.09E-11	6.95E-11	6.06E-11
WNW	1.32E-10	1.09E-10	9.25E-11	7.94E-11	6.92E-11
NW	1.56E-10	1.30E-10	1.10E-10	9.43E-11	8.24E-11
NNW	1.15E-10	9.58E-11	8.11E-11	6.97E-11	6.09E-11
N	1.49E-10	1.24E-10	1.05E-10	9.04E-11	7.89E-11

Source: Containment Building

TABLE 2A-7 ANNUAL AVERAGE D/Q VALUES FOR THE CONTAINMENT BUILDING

Sector	Downwind Distance (KM) 11.2	12.0	12.8	13.6	14.4
NNE	9.14E-11	8.14E-11	7.30E-11	6.59E-11	5.99E-11
NE	8.08E-11	7.20E-11	6.46E-11	5.83E-11	5.30E-11
ENE	8.53E-11	7.59E-11	6.80E-11	6.14E-11	5.57E-11
E	6.91E-11	6.14E-11	5.50E-11	4.97E-11	4.51E-11
ESE	6.59E-11	5.86E-11	5.25E-11	4.74E-11	4.30E-11
SE	6.49E-11	5.77E-11	5.18E-11	4.67E-11	4.24E-11
SSE	4.41E-11	3.92E-11	3.52E-11	3.17E-11	2.88E-11
S	3.42E-11	3.04E-11	2.73E-11	2.47E-11	2.25E-11
SSW	3.22E-11	2.86E-11	2.57E-11	2.31E-11	2.10E-11
SW	5.50E-11	4.90E-11	4.40E-11	3.98E-11	3.61E-11
WSW	7.32E-11	6.51E-11	5.84E-11	5.28E-11	4.79E-11
W	5.35E-11	4.77E-11	4.28E-11	3.87-E11	3.52E-11
WNW	6.12E-11	5.46E-11	4.90E-11	4.43E-11	4.03E-11
NW	7.30E-11	6.52E-11	5.87E-11	5.31E-11	4.84E-11
NNW	5.39E-11	4.81E-11	4.33E-11	3.92E-11	3.57E-11
N	6.99E-11	6.25E-11	5.62E-11	5.09E-11	4.64E-11

Source: Containment Building

TABLE 2A-7 ANNUAL AVERAGE D/Q VALUES FOR THE CONTAINMENT BUILDING

Sector	Downwind Distance (KM) 15.2	16.0	24.0	32.0	40.0
NNE	5.47E-11	5.02E-11	2.55E-11	1.59E-11	1.11E-11
NE	4.84E-11	4.44E-11	2.26E-11	1.40E-11	9.74E-12
ENE	5.09E-11	4.66E-11	2.36E-11	1.46E-11	1.01E-11
E	4.11E-11	3.77E-11	1.90E-11	1.18E-11	8.15E-12
ESE	3.92E-11	3.59E-11	1.81E-11	1.12E-11	7.71E-12
SE	3.88E-11	3.55E-11	1.80E-11	1.12E-11	7.76E-12
SSE	2.63E-11	2.41E-11	1.22E-11	7.56E-12	5.24E-12
S	2.05E-11	1.88E-11	9.62E-12	6.00E-12	4.18E-12
SSW	1.92E-11	1.76E-11	8.85E-12	5.47E-12	3.78E-12
SW	3.30E-11	3.03E-11	1.55E-11	9.65E-12	6.71E-12
WSW	4.38E-11	4.02E-11	2.04E-11	1.27E-11	8.83E-12
W	3.22E-11	2.96E-11	1.52E-11	9.49E-12	6.62E-12
WNW	3.69E-11	3.39E-11	1.74E-11	1.09E-11	7.60E-12
NW	4.43E-11	4.08E-11	2.12E-11	1.34E-11	9.42E-12
NNW	3.27E-11	3.00E-11	1.56E-11	9.81E-12	6.90E-12
N	4.25E-11	3.91E-11	2.03E-11	1.28E-11	9.02E-12

Source: Containment Building

TABLE 2A-7 ANNUAL AVERAGE D/Q VALUES FOR THE CONTAINMENT BUILDING

	Downwind Distance (KM)				
Sector	48.0	56.0	64.0	72.0	80.0
NNE	8.32E-12	6.52E-12	5.28E-12	4.40E-12	3.76E-12
NE	7.30E-12	5.70E-12	4.61E-12	3.83E-12	3.27E-12
ENE	7.56E-12	5.89E-12	4.75E-12	3.94E-12	3.35E-12
E	6.07E-12	4.71E-12	3.78E-12	3.13E-12	2.64E-12
ESE	5.73E-12	4.44E-12	3.57E-12	2.95E-12	2.49E-12
SE	5.78E-12	4.49E-12	3.61E-12	2.98E-12	2.52E-12
SSE	3.90E-12	3.03E-12	2.44E-12	2.01E-12	1.70E-12
S	3.13E-12	2.45E-12	1.98E-12	1.64E-12	1.40E-12
SSW	2.32E-12	2.19E-12	1.76E-12	1.46E-12	1.24E-12
SW	5.01E-12	3.90E-12	3.13E-12	2.59E-12	2.19E-12
WSW	6.58E-12	5.10E-12	4.09E-12	3.37E-12	2.84E-12
W	4.96E-12	3.86E-12	3.10E-12	2.56E-12	2.17E-12
WNW	5.71E-12	4.46E-12	3.60E-12	2.99E-12	2.54E-12
NW	7.10E-12	5.55E-12	4.49E-12	3.72E-12	3.16E-12
NNW	5.22E-12	4.10E-12	3.32E-12	2.77E-12	2.37E-12
N	6.81E-12	5.34E-12	4.32E-12	3.59E-12	3.05E-12

Source: Containment Building

TABLE 2A-8 ANNUAL AVERAGE D/Q VALUES FOR THE RADWASTE BUILDING

Sector	Downwind Distance (KM) 0.4	0.8	1.2	1.6	2.4
NNE	3.01E-08	1.11E-08	5.93E-09	3.67E-09	1.88E-09
NE	2.56E-08	9.38E-09	5.01E-09	3.10E-09	1.59E-09
ENE	2.52E-08	9.33E-09	5.03E-09	3.13E-09	1.62E-09
E	1.57E-08	6.16E-09	3.46E-09	2.19E-09	1.16E-09
ESE	1.62E-08	6.15E-09	3.40E-09	2.14E-09	1.12E-09
SE	1.45E-08	5.68E-09	3.18E-09	2.01E-09	1.06E-09
SSE	1.07E-08	4.06E-09	2.25E-09	1.42E-09	7.44E-10
S	8.28E-09	3.23E-09	1.80E-09	1.14E-09	6.00E-10
SSW	8.03E-09	3.09E-09	1.72E-09	1.08E-09	5.68E-10
SW	1.10E-08	4.50E-09	2.57E-09	1.64E-09	8.74E-10
WSW	1.39E-08	5.71E-09	3.25E-09	2.07E-09	1.10E-09
W	1.19E-08	4.69E-09	2.60E-09	1.63E-09	8.54E-10
WNW	1.52E-08	5.94E-09	3.26E-09	2.05E-09	1.07E-09
NW	1.45E-08	6.07E-09	3.45E-09	2.18E-09	1.16E-09
NNW	1.41E-08	5.56E-09	3.06E-09	1.92E-09	9.98E-10
N	1.71E-08	6.73E-09	3.69E-09	2.31E-09	1.20E-09

Source: Radwaste Building

TABLE 2A-8 ANNUAL AVERAGE D/Q VALUES FOR THE RADWASTE BUILDING

Sector	Downwind Distance (KM) 3.2	4.0	4.8	5.6	6.4
NNE	1.17E-09	8.15E-10	6.06E-10	4.64E-10	3.66E-10
NE	9.96E-10	6.92E-10	5.14E-10	3.94E-10	3.11E-10
ENE	1.01E-09	7.06E-10	5.26E-10	4.02E-10	3.17E-10
E	7.34E-10	5.16E-10	3.88E-10	2.97E-10	2.34E-10
ESE	7.10E-10	4.98E-10	3.73E-10	2.85E-10	2.25E-10
SE	6.72E-10	4.72E-10	3.54E-10	2.72E-10	2.14E-10
SSE	4.70E-10	3.30E-10	2.47E-10	1.89E-10	1.49E-10
S	3.80E-10	2.67E-10	2.01E-10	1.54E-10	1.21E-10
SSW	3.59E-10	2.52E-10	1.89E-10	1.44E-10	1.14E-10
SW	5.57E-10	3.93E-10	2.96E-10	2.27E-10	1.79E-10
WSW	6.98E-10	4.92E-10	3.70E-10	2.84E-10	2.23E-10
W	5.39E-10	3.78E-10	2.83E-10	2.17E-10	1.71E-10
WNW	6.73E-10	4.72E-10	3.53E-10	2.71E-10	2.13E-10
NW	7.37E-10	5.20E-10	3.92E-10	3.01E-10	2.37E-10
NNW	6.30E-10	4.41E-10	3.30E-10	2.53E-10	2.00E-10
N	7.56E-10	5.29E-10	3.96E-10	3.03E-10	2.39E-10

Source: Radwaste Building

TABLE 2A-8 ANNUAL AVERAGE D/Q VALUES FOR THE RADWASTE BUILDING

Sector	Downwind Distance (KM) 7.2	8.0	8.8	9.6	10.4
NNE	2.97E-10	2.46E-10	2.08E-10	1.78E-10	1.55E-10
NE	2.52E-10	2.09E-10	1.77E-10	1.51E-10	1.32E-10
ENE	2.57E-10	2.13E-10	1.80E-10	1.54E-10	1.34E-10
E	1.89E-10	1.57E-10	1.32E-10	1.13E-10	9.82E-11
ESE	1.82E-10	1.51E-10	1.27E-10	1.09E-10	9.47E-11
SE	1.73E-10	1.44E-10	1.21E-10	1.04E-10	9.02E-11
SSE	1.21E-10	1.00E-10	8.43E-11	7.22E-11	6.27E-11
S	9.81E-11	8.13E-11	6.86E-11	5.87E-11	5.10E-11
SSW	9.22E-11	7.64E-11	6.44E-11	5.52E-11	4.79E-11
SW	1.45E-10	1.20E-10	1.01E-10	8.66E-11	7.52E-11
WSW	1.81E-10	1.50E-10	1.26E-10	1.08E-10	9.40E-11
W	1.39E-10	1.15E-10	9.71E-11	8.32E-11	7.24E-11
WNW	1.73E-10	1.44E-10	1.21E-10	1.04E-10	9.04E-11
NW	1.92E-10	1.59E-10	1.35E-10	1.15E-10	1.00E-10
NNW	1.62E-10	1.34E-10	1.13E-10	9.72E-11	8.46E-11
N	1.94E-10	1.61E-10	1.36E-10	1.17E-10	1.02E-10

Source: Radwaste Building

TABLE 2A-8 ANNUAL AVERAGE D/Q VALUES FOR THE RADWASTE BUILDING

	Downwind Distance (KM)				
Sector	11.2	12.0	12.8	13.6	14.4
NNE	1.37E-10	1.21E-10	1.09E-10	9.78E-11	8.87E-11
NE	1.16E-10	1.03E-10	9.20E-11	8.29E-11	7.51E-11
ENE	1.18E-10	1.05E-10	9.36E-11	8.43E-11	7.64E-11
E	8.64E-11	7.67E-11	6.86E-11	6.18E-11	5.60E-11
ESE	8.33E-11	7.39E-11	6.61E-11	5.95E-11	5.39E-11
SE	7.94E-11	7.05E-11	6.31E-11	5.68E-11	5.15E-11
SSE	5.52E-11	4.90E-11	4.38E-11	3.94E-11	3.57E-11
S	4.49E-11	3.99E-11	3.57E-11	3.21E-11	2.91E-11
SSW	4.22E-11	3.74E-11	3.35E-11	3.01E-11	2.73E-11
SW	6.62E-11	5.88E-11	5.26E-11	4.74E-11	4.30E-11
WSW	8.28E-11	7.36E-11	6.59E-11	5.94E-11	5.39E-11
W	6.38E-11	5.67E-11	5.08E-11	4.58E-11	4.16E-11
WNW	7.96E-11	7.08E-11	6.34E-11	5.72E-11	5.19E-11
NW	8.85E-11	7.88E-11	7.07E-11	6.38E-11	5.80E-11
NNW	7.46E-11	6.64E-11	5.95E-11	5.37E-11	4.87E-11
N	8.96E-11	7.98E-11	7.15E-11	6.46E-11	5.86E-11

Source: Radwaste Building

TABLE 2A-8 ANNUAL AVERAGE D/Q VALUES FOR THE RADWASTE BUILDING

Sector	Downwind Distance (KM) 15.2	16.0	24.0	32.0	40.0
NNE	8.08E-11	7.40E-11	3.70E-11	2.28E-11	1.58E-11
NE	6.84E-11	6.27E-11	3.13E-11	1.92E-11	1.33E-11
ENE	6.96E-11	6.37E-11	3.17E-11	1.95E-11	1.35E-11
E	5.10E-11	4.67E-11	2.33E-11	1.43E-11	9.98E-12
ESE	4.91E-11	4.49E-11	2.23E-11	1.37E-11	9.48E-12
SE	4.69E-11	4.30E-11	2.15E-11	1.33E-11	9.22E-12
SSE	3.25E-11	2.98E-11	1.48E-11	9.08E-12	6.30E-12
S	2.66E-11	2.43E-11	1.22E-11	7.52E-12	5.26E-12
SSW	2.49E-11	2.28E-11	1.14E-11	6.98E-12	4.85E-12
SW	3.92E-11	3.59E-11	1.80E-11	1.11E-11	7.70E-12
WSW	4.91E-11	4.50E-11	2.26E-11	1.40E-11	9.70E-12
W	3.79E-11	3.47E-11	1.75E-11	1.08E-11	7.52E-12
WNW	4.73E-11	4.34E-11	2.19E-11	1.35E-11	9.41E-12
NW	5.29E-11	4.86E-11	2.47E-11	1.55E-11	1.08E-11
NNW	4.45E-11	4.08E-11	2.07E-11	1.29E-11	9.04E-12
N	5.35E-11	4.91E-11	2.49E-11	1.55E-11	1.09E-11

Source: Radwaste Building

TABLE 2A-8 ANNUAL AVERAGE D/Q VALUES FOR THE RADWASTE BUILDING

	Downwind Distance (KM)				
Sector	48.0	56.0	64.0	72.0	80.0
NNE	1.19E-11	9.36E-12	7.59E-12	6.36E-12	5.46E-12
NE	1.01E-11	7.94E-12	6.47E-12	5.44E-12	4.70E-12
ENE	1.02E-11	8.08E-12	6.60E-12	5.57E-12	4.82E-12
E	7.61E-12	6.05E-12	4.97E-12	4.21E-12	3.67E-12
ESE	7.20E-12	5.70E-12	4.67E-12	3.95E-12	3.43E-12
SE	7.01E-12	5.56E-12	4.55E-12	3.85E-12	3.34E-12
SSE	4.80E-12	3.81E-12	3.13E-12	2.66E-12	2.32E-12
S	4.06E-12	3.26E-12	2.70E-12	2.31E-12	2.03E-12
SSW	3.69E-12	2.92E-12	2.39E-12	2.02E-12	1.76E-12
SW	5.78E-12	4.52E-12	3.65E-12	3.04E-12	2.59E-12
WSW	7.27E-12	5.68E-12	4.58E-12	3.81E-12	3.25E-12
W	5.64E-12	4.40E-12	3.55E-12	2.95E-12	2.51E-12
WNW	7.07E-12	5.54E-12	4.47E-12	3.73E-12	3.18E-12
NW	8.24E-12	6.51E-12	5.30E-12	4.45E-12	3.83E-12
NNW	6.91E-12	5.49E-12	4.50E-12	3.81E-12	3.30E-12
N	8.30E-12	6.57E-12	5.37E-12	4.52E-12	3.91E-12

Source: Radwaste Building

TABLE 2A-9 ANNUAL AVERAGE D/Q VALUES FOR THE TURBINE BUILDING

Sector	Downwind Distance (KM) 0.4	0.8	1.2	1.6	2.4
NNE	5.08E-08	1.75E-08	9.00E-09	5.49E-09	2.75E-09
NE	4.36E-08	1.50E-08	7.70E-09	4.70E-09	2.36E-09
ENE	4.55E-08	1.57E-08	8.05E-09	4.91E-09	2.46E-09
E	3.40E-08	1.18E-08	6.05E-09	3.70E-09	1.86E-09
ESE	3.00E-08	1.03E-08	5.33E-09	3.26E-09	1.64E-09
SE	2.92E-08	1.01E-08	5.22E-09	3.19E-09	1.61E-09
SSE	2.04E-08	7.02E-09	3.61E-09	2.21E-09	1.11E-09
S	1.88E-08	6.49E-09	3.34E-09	2.04E-09	1.03E-09
SSW	1.59E-08	5.50E-09	2.84E-09	1.74E-09	8.77E-10
SW	2.19E-08	7.56E-09	3.90E-09	2.38E-09	1.20E-09
WSW	2.70E-08	9.39E-09	4.84E-09	2.96E-09	1.49E-09
W	1.99E-08	6.95E-09	3.60E-09	2.21E-09	1.12E-09
WNW	2.69E-08	9.31E-09	4.80E-09	2.93E-09	1.48E-09
NW	3.08E-08	1.08E-08	5.58E-09	3.42E-09	1.73E-09
NNW	2.92E-08	1.01E-08	5.23E-09	3.19E-09	1.61E-09
N	3.31E-08	1.15E-08	5.93E-09	3.63E-09	1.83E-09

Source: Turbine Building

TABLE 2A-9 ANNUAL AVERAGE D/Q VALUES FOR THE TURBINE BUILDING

	Downwind Distance (KM)				
Sector	3.2	4.0	4.8	5.6	6.4
NNE	1.70E-09	1.16E-09	8.57E-10	6.55E-10	5.18E-10
NE	1.45E-09	9.99E-10	7.36E-10	5.62E-10	4.44E-10
ENE	1.52E-09	1.04E-09	7.68E-10	5.87E-10	4.64E-10
E	1.15E-09	7.89E-10	5.82E-10	4.45E-10	3.51E-10
ESE	1.02E-09	7.01E-10	5.17E-10	3.96E-10	3.13E-10
SE	9.96E-10	6.86E-10	5.06E-10	3.88E-10	3.06E-10
SSE	6.87E-10	4.73E-10	3.49E-10	2.67E-10	2.11E-10
S	6.36E-10	4.38E-10	3.23E-10	2.47E-10	1.96E-10
SSW	5.42E-10	3.74E-10	2.76E-10	2.11E-10	1.67E-10
SW	7.43E-10	5.12E-10	3.78E-10	2.89E-10	2.28E-10
WSW	9.20E-10	6.33E-10	4.66E-10	3.57E-10	2.52E-10
W	6.90E-10	4.75E-10	3.51E-10	2.69E-10	2.12E-10
WNW	9.12E-10	6.28E-10	4.63E-10	3.54E-10	2.80E-10
NW	1.07E-09	7.39E-10	5.46E-10	4.18E-10	3.30E-10
NNW	9.90E-10	6.81E-10	5.02E-10	3.84E-10	3.03E-10
N	1.13E-09	7.77E-10	5.73E-10	4.38E-10	3.47E-10

Source: Turbine Building

TABLE 2A-9 ANNUAL AVERAGE D/Q VALUES FOR THE TURBINE BUILDING

Sector	Downwind Distance (KM) 7.2	8.0	8.8	9.6	10.4
NNE	4.21E-10	3.49E-10	2.95E-10	2.53E-10	2.20E-10
NE	3.61E-10	3.00E-10	2.53E-10	2.17E-10	1.89E-10
ENE	3.77E-10	3.13E-10	2.65E-10	2.27E-10	1.97E-10
E	2.86E-10	2.37E-10	2.00E-10	1.72E-10	1.49E-10
ESE	2.54E-10	2.11E-10	1.78E-10	1.53E-10	1.33E-10
SE	2.49E-10	2.07E-10	1.75E-10	1.50E-10	1.30E-10
SSE	1.71E-10	1.42E-10	1.20E-10	1.03E-10	8.98E-11
S	1.59E-10	1.32E-10	1.12E-10	9.57E-11	8.32E-11
SSW	1.35E-10	1.12E-10	9.50E-11	8.15E-11	7.09E-11
SW	1.86E-10	1.54E-10	1.30E-10	1.12E-10	9.72E-11
WSW	2.29E-10	1.90E-10	1.61E-10	1.38E-10	1.20E-10
W	1.73E-10	1.43E-10	1.21E-10	1.04E-10	9.06E-11
WNW	2.28E-10	1.89E-10	1.60E-10	1.37E-10	1.19E-10
NW	2.69E-10	2.23E-10	1.89E-10	1.62E-10	1.41E-10
NNW	2.47E-10	2.05E-10	1.73E-10	1.48E-10	1.29E-10
N	2.82E-10	2.34E-10	1.98E-10	1.70E-10	1.48E-10

Source: Turbine Building

TABLE 2A-9 ANNUAL AVERAGE D/Q VALUES FOR THE TURBINE BUILDING

	Downwind Distance (KM)				
Sector	11.2	12.0	12.8	13.6	14.4
NNE	1.94E-10	1.72E-10	1.54E-10	1.38E-10	1.25E-10
NE	1.66E-10	1.47E-10	1.32E-10	1.19E-10	1.07E-10
ENE	1.73E-10	1.54E-10	1.38E-10	1.24E-10	1.12E-10
E	1.31E-10	1.17E-10	1.04E-10	9.39E-11	8.51E-11
ESE	1.17E-10	1.04E-10	9.29E-11	8.36E-11	7.57E-11
SE	1.15E-10	1.02E-10	9.11E-11	8.20E-11	7.43E-11
SSE	7.90E-11	7.01E-11	6.27E-11	5.64E-11	5.11E-11
S	7.32E-11	6.50E-11	5.81E-11	5.23E-11	4.74E-11
SSW	6.23E-11	5.53E-11	4.95E-11	4.45E-11	4.04E-11
SW	8.55E-11	7.59E-11	6.79E-11	6.11E-11	5.54E-11
WSW	1.06E-10	9.38E-11	8.39E-11	7.56E-11	6.85E-11
W	7.97E-11	7.08E-11	6.34E-11	5.71E-11	5.18E-11
WNW	1.05E-10	9.31E-11	8.33E-11	7.50E-11	6.80E-11
NW	1.24E-10	1.10E-10	9.85E-11	8.87E-11	8.04E-11
NNW	1.14E-10	1.01E-10	9.02E-11	8.12E-11	7.36E-11
N	1.30E-10	1.15E-10	1.03E-10	9.29E-11	8.42E-11

Source: Turbine Building

TABLE 2A-9 ANNUAL AVERAGE D/Q VALUES FOR THE TURBINE BUILDING

Sector	Downwind Distance (KM) 15.2	16.0	24.0	32.0	40.0
NNE	1.14E-10	1.04E-10	5.16E-11	3.12E-11	2.12E-11
NE	9.79E-11	8.96E-11	4.42E-11	2.67E-11	1.81E-11
ENE	1.02E-10	9.35E-11	4.61E-11	2.79E-11	1.89E-11
E	7.75E-11	7.09E-11	3.50E-11	2.12E-11	1.44E-11
ESE	6.90E-11	6.31E-11	3.12E-11	1.89E-11	1.28E-11
SE	6.77E-11	6.20E-11	3.07E-11	1.86E-11	1.26E-11
SSE	4.65E-11	4.26E-11	2.10E-11	1.27E-11	8.64E-12
S	4.32E-11	3.95E-11	1.95E-11	1.18E-11	8.03E-12
SSW	3.68E-11	3.36E-11	1.66E-11	1.01E-11	6.84E-12
SW	5.04E-11	4.61E-11	2.28E-11	1.38E-11	9.37E-12
WSW	6.24E-11	5.71E-11	2.83E-11	1.72E-11	1.17E-11
W	4.72E-11	4.32E-11	2.15E-11	1.31E-11	8.89E-12
WNW	6.19E-11	5.67E-11	2.81E-11	1.70E-11	1.15E-11
NW	7.33E-11	6.71E-11	3.33E-11	2.03E-11	1.38E-11
NNW	6.70E-11	6.13E-11	3.04E-11	1.84E-11	1.25E-11
N	7.67E-11	7.02E-11	3.48E-11	2.11E-11	1.43E-11

Source: Turbine Building

TABLE 2A-9 ANNUAL AVERAGE D/Q VALUES FOR THE TURBINE BUILDING

Sector	Downwind Distance (KM) 48.0	56.0	64.0	72.0	80.0
NNE	1.54E-11	1.17E-11	9.22E-12	7.47E-12	6.19E-12
NE	1.32E-11	1.01E-11	7.93E-12	6.44E-12	5.36E-12
ENE	1.38E-11	1.05E-11	8.29E-12	6.74E-12	5.61E-12
E	1.05E-11	8.03E-12	6.35E-12	5.17E-12	4.31E-12
ESE	9.38E-12	7.17E-12	5.68E-12	4.64E-12	3.89E-12
SE	9.24E-12	7.06E-12	5.58E-12	4.55E-12	3.80E-12
SSE	6.33E-12	4.85E-12	3.84E-12	3.14E-12	2.64E-12
S	5.88E-12	4.49E-12	3.56E-12	2.90E-12	2.43E-12
SSW	5.00E-12	3.81E-12	3.01E-12	2.45E-12	2.04E-12
SW	6.83E-12	5.19E-12	4.09E-12	3.32E-12	2.75E-12
WSW	8.53E-12	6.49E-12	5.12E-12	4.15E-12	3.45E-12
W	6.50E-12	4.95E-12	3.91E-12	3.17E-12	2.63E-12
WNW	8.40E-12	6.39E-12	5.03E-12	4.08E-12	3.38E-12
NW	1.01E-11	7.67E-12	6.05E-12	4.92E-12	4.08E-12
NNW	9.13E-12	6.95E-12	5.48E-12	4.45E-12	3.70E-12
N	1.05E-11	7.99E-12	6.30E-12	5.11E-12	4.25E-12

Source: Turbine Building

APPENDIX 2B

Rock Foundation Treatment
Residual Heat Removal Complex
Fermi 2 Nuclear Power Plant
for
Detroit Edison Company

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REPORT

ROCK FOUNDATION TREATMENT

RESIDUAL HEAT REMOVAL COMPLEX

FERMI II NUCLEAR POWER PLANT

FOR

THE DETROIT EDISON COMPANY

INTRODUCTION

This report describes the rock foundation treatment program for the Residual Heat Removal Complex at the Fermi II Nuclear Power Plant located near Monroe, Michigan. The primary purpose of the rock foundation treatment program was to explore for solution cavities or features and if found grout them in order to minimize the potential for ground motion amplification in the event of an earthquake.

The foundation treatment consisted of two separate operations: rock surface preparation and clean-up (Part A) and rock grouting (Part B). Detailed descriptions of both operations are presented herein.*

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* Note: all references listed separately at end of report.

PART A

FOUNDATION ROCK SURFACE PREPARATION AND CLEAN-UP

Foundation Rock Surface Preparation and Clean-up

General

Upon the completion of the RHR complex excavation and prior to the placement of a concrete leveling mat for the grouting program, preparation and clean-up of the foundation rock surface was performed as recommended (Reference 1). All loose debris, loosely-chinked rock fragments, mud films and most clay was removed by high pressure jetting and by mechanical and hand equipment. The supervision and inspection of this program was carried out by Dames & Moore between February 19, 1974 and April 1, 1974.

Scope

The scope of our services during this phase of the foundation rock treatment was as follows:

1 - To supervise and inspect the clean-up of the foundation rock surface prior to placement of the concrete leveling mat;

2 - To prepare a geologic map of the rock surface features;

3 - To assist the AEC representative during his inspection of a cleaned portion of the foundation rock surface;

4 - To work closely on a daily basis with personnel of Ralph M. Parsons Company, the general contractor in order to coordinate the clean-up and leveling mat placement and to report progress to representatives of the Detroit Edison Company.

General Surface Geology

Lithology - The foundation rock surface consists of light brownish-gray, very fine-grained dolomite, a few areas of which are roughly textured and covered by black, paper-thin shale.

Much of the foundation rock surface is irregular, generally containing 2- to 4-foot diameter and 1/2- to 1- foot high mounds of medium to thin-bedded dolomite. These mounds or dome-like features are characterized by: (1) a wavy onionskin structure; (2) healed, massive brecciation due to primary sedimentary processes; and (3) vugs which vary from 1 inch to 1 foot in maximum dimension and contain celestite crystals. The northwest corner of the foundation is an exception to the general rock surface because there, the rock is evenly bedded and contains no mounds of brecciated dolomite.

The mounds are of sedimentary origin and were probably formed by the accumulation of layers of algae and lime mud in the original environment of deposition. In several places along the rock walls of the foundation, vertical zones of massive sedimentary breccia occur which are several feet wide and taper to a flattened top at bedding planes. These flattened tops are the result of truncation by primary erosional processes. One of these zones near column line intersection A8 is flanked and overlain by unbrecciated, layered, dolomite dipping downward from both sides. Below the brecciated zone the general dip of the strata appears to be uninterrupted, thus indicating a non-tectonic origin. The zone is well-cemented and exhibits no more fracturing than is evident throughout other parts of the excavation. Because of the similarity of the mounds observed both on the foundation floor and on the walls they are considered the same type of feature and sedimentary in origin.

Gray clay seams ranging from 1/8 inch to 2 inches in thickness fill some joints and some bedding plane fractures. This clay appears to be of the same physical character as that of the overlying glacial till. The fillings, therefore, are probably derived from the till. Areas of sedimentary breccia and clay fillings are shown on Plate A1, and detailed descriptions of the subsurface dolomite to a depth of 20 feet below the excavation surface are given on Plates B6 through B13.

Structure - Bedding plane attitudes vary from point to point in the foundation and in general seem to reflect the presence of the above mentioned breccia mounds. Despite local variations there is an apparent structural dip of a few degrees in a northerly direction. This compares favorably with the regional dip of a few degrees northwest towards the center of the Michigan Basin.

Fractures - The majority of the fractures in the foundation rock are tight, although some are filled with soft gray clay as described above. No displacements, tectonic breccias, or slickensided surfaces, other than slickensides associated with stylolites, were noted.

Most of the fractures are naturally occurring joints and can be grouped into three aprpproximately orthogonal sets. The dominant or major joint set trends from N21°-38°W and dips from

60°-80° to the southwest. Generally these joints vary in length from 5 to 30 feet but some are as much as 65 feet long. Spacing between joints is from 2 to 10 feet.

A bend of approximately 15° to the west of the major joint set occurs along a southwest-northeast zone from column line intersection A7 to the area of intersection E11. Since (1) many joints of the major set are continuous across this zone; and (2) no displacements or slickensides were noted along joints either parallel or transverse to the bend, therefore the bend only reflects a local variation in the orientation of the major joint set.

A minor set of joints trends from N54°-72°E and dips from 30°-60° to the northwest. Generally, these joints vary in length from 2 to 10 feet but some are as much as 30 feet long. Spacing between these joints is from 1 to 5 feet. In general, joints of the minor set are more irregular than those of the major set and certain ones terminate against major joints.

Bedding plane joints, which undulate but are essentially horizontal, are spaced from 6 inches to 2 feet apart. As seen in the rock walls of the sides of the foundation and in the sumps, these joints are generally tight but occassionally exhibit some minor openings which are often clay-filled as described above.

Also present are numerous relatively short, irregular fractures. Many of these, especially those radiating from the diamond-cored shot holes, can be attributed to the blasting program.

Procedures

A recommended procedure for rock surface preparation is described in Reference 1.

Following the initial program of blasting and mucking for the RHR Complex excavation, the rock surface was cleared of clay, rock fragments, and loosely-chinked rock by rubber-tired backhoes. At this point a veneer of gravel-to cobble-sized rock and clay remained. A high-pressure water hose, attached to a backhoe and moved laterally was then used for washing. This was subsequently followed by picks, shovels, brooms, hand-held water hoses and air-jet equipment for dental cleaning. Later, a three-man team working with a high-pressure water hose having a flattened nozzle was found to be very effective for the total removal of remaining surface debris. A ten-foot diameter area of thinly layered dolomite in the northwest section of the foundation was found to have open bedding plane fractures. A backhoe-mounted pneumatic hammer and picks were used to remove this section of rock which extended to a depth of 6 inches.

Following completion of the cleaning operation in a given area the rock surface was inspected and all features mapped. All open or closed fractures, joints, clay seams, and other structures or rock types were noted. These mapped features are shown on Plate A1, Foundation Rock Surface Features.

The foundation rock walls were inspected but not mapped. Photographs of the walls were taken instead by the Detroit Edison Company, and these are available for examination.

Conclusions

Based on our technical supervision and inspection of the rock surface preparation and clean-up, it is our opinion that the work has been carried out in accordance with project plans and specifications. During an AEC inspection of a cleaned portion of the excavation, it was determined that the clean-up had been done satisfactorily and that no detrimental structural features existed on the foundation surface. The surface was also free of any loose rock, mud films or clay which might prevent an effective bond with the concrete leveling mat, which was subsequently placed over the rock surface.

PART B

FOUNDATION ROCK GROUTING

Foundation Rock Grouting

General

Specifications and criteria for the foundation grouting program were prepared by Sargent & Lundy Engineers for the Residual Heat Removal Complex (Reference 3). Any modifications to the grouting procedure were effected by the Detroit Edison Company after consultation with representatives of Sargent and Lundy. Data on water pressure tests, drilling, grout takes, sand-cement-water ratios and grout pressures were recorded on a daily basis by the Lee Turzillo Contracting Company and regularly distributed to representatives of the Ralph M. Parson Company. The complete grouting program was observed by Dames & Moore between March 20, 1974, and May 1, 1974. Where pertinent, recommendations on the program were made by Dames & Moore to representatives of The Detroit Edison Company.

Purpose

The primary purpose of the rock foundation grouting program was to minimize the potential for ground motion amplification in the event of an earthquake through consolidation by grouting of any solution features in the foundation.

Scope

The scope of our services during this phase of the rock foundation treatment was as follows:

1 - To supervise the location and logging of eight exploratory test holes which were core drilled

prior to grouting operations;

2 - To observe the water pressure testing of the eight preliminary test holes;

3 - To observe grouting operations performed by the Lee Turzillo Contracting Company which included drilling, washing and grouting primary, secondary, tertiary and quaternary sets of holes;

4 - To supervise the location and logging of eight exploratory test holes which were core drilled following the grouting operations;

5 - To observe water pressure testing and grouting of the eight final test holes;

6 - To discuss on a daily basis progress of the foundation treatment program with representatives of the Ralph M. Parsons Company and The Detroit Edison Company.

Procedures

In order to evaluate conditions which might be encountered during the grouting operations, eight exploratory holes were core drilled, logged and water pressure tested prior to the commencement of grouting. The pressure testing was performed by setting an air inflatable packer 5 feet from the bottom of a hole, pressure testing that interval, and then moving the packer up the hole 5 feet at a time. The test intervals, therefore, ranged from 5 feet to 20 feet for the four tests in each exploratory hole. This method was the standard procedure used for all pressure testing in the exploratory holes although the original specifications called for the testing of discrete 5-foot intervals. When more than 80 percent of the grouting program had been completed, eight additional exploratory core holes were begun in order to compare final rock conditions with conditions before grouting. These final eight test holes were logged and pressure tested in the manner of the preliminary holes and the last of these holes were drilled following the end of the grouting operations. Flow rates from the water pressure tests performed on the 16 exploratory holes are presented in Table B2. The positions of all the exploratory holes are shown on Plates B1 through B5.

The sequence of grouting operations consisted of drilling, washing and grouting each grout hole. The elevation of the bases of the grout holes was selected (Reference 3) for the RHR Complex at 530 feet. A concrete leveling mat or slab at elevation 550 feet was placed over the excavated, cleaned rock surface. The leveling mat varied in thickness from approximately 6 inches to 2 feet due to the irregularity of the excavated rock surface. Grouting of primary and secondary holes was performed in two zones, hereafter referred to as first and second zones, extending to depths of 6 and 20 feet, respectively. Tertiary holes as well as the few quarternary holes were grouted in single stages to elevations 530 feet and 540 feet respectively. Primary holes were spaced 30 feet on centers and final closure was achieved by subsequently grouting necessary intermediate holes (secondary, tertiary, and some quarternary holes). The locations of all holes are presented in Plates B-1 through B-5, Foundation Treatment. The volume of grout injected into each hole during each sequence of grouting is shown on those plates. The grout takes shown on plates B-1 and B-2 would only be for primary holes, the grout takes shown on plates B-3 and B-4 would only show those for secondary holes and plate B-5 only shows grout takes corresponding to tertiary and quarternary holes. A detailed description of the grouting procedure is presented below.

Prior to grouting, 2 1/2 foot long, 4-inch diameter casings were drilled and cemented into the concrete leveling mat and rock to a depth of 2 feet leaving approximately 6 inches of stick-up. This step tended to reduce surface leakage around the pipes during subsequent grouting. Primary grout holes of the first zone were drilled on approximately 30-foot centers, 6 feet into concrete and rock, to elevation 544. Crawler mounted percussion drills were used to drill the 3-inch diameter grout holes. All holes were washed thoroughly with air and water prior to grouting. Grouting of each hole in the first zone (Plate B1) was done as a single stage with a 1.6:1 water/cement plus fly ash ratio under pressure from 5 to 12 psi. A few primary holes were grouted with a water/cement plus fly ash ratio of 1.2:1. In areas of high take, grout frequently flowed from the nearby holes, in which case the initial hole was temporarily sealed and the flowing holes injected to refusal.

Second zone grouting (Plate B2) was begun by extending the primary holes to a depth of 20 feet to elevation 530 feet. All holes were grouted to their full depth as a single stage with the mechanical packer set at the top of the hole and pressure held between 20 and 50 psi. A mix of 2:1 water/cement plus fly ash was generally used, although in the north and south sump areas the ratio was thickened to 1.2:1 or 1:1 water/cement plus fly ash.

Each secondary hole was located at the geometric center of four primary holes. Grouting of the secondary holes in the first zone (Plate B3) was done in the same manner as were the primary holes. Initially the mix was 3:1 water/cement plus fly ash, but when holes began taking grout the ratio was thickened to 1.8:1 and in a few cases to 1.2:1. Grouting of the second zone (Plate B4) was continued by extending the first zone secondary holes to a depth of 20 feet to elevation 530 feet. Grout mixes for the second zone, secondary holes were 1.2:1 water/cement plus fly ash, except in one case when a 1:1 ration was used.

Tertiary grout holes are at the center of the 15-foot square formed by two primary and two secondary holes. These holes were drilled 20 feet deep to an elevation of 530 feet and grouted as a single zone (Plate B5) rather than using the two-zone procedure as was done with the primary and secondary holes. The reason for this was the general very low take in grouting the second zone - secondary holes. A ratio of 1.2:1 water/cement plus fly ash was generally used. In the only area where grout takes were significant, five quarternary holes, each located in the center of the diamond formed by a primary, secondary, and two tertiary holes, were drilled and grouted to a depth of 10 feet. A 20-foot deep core hole completed this quarternary array and was grouted at the same time.

All grout holes were grouted to refusal. In holes in which grout interconnections occurred, packers were set and maintained until back pressure reduced to zero. Some grout leaks occurred in the north and south sumps, especially during the first zone primary grouting, and where significant these were dry packed by hand with cement. Subsequent first zone grouting indicated these areas were sealed.

As noted above in grouting the first and second zones, injection gage pressures ranged from 5 to 12 psi and from 20 to 50 psi, respectively. These pressures were changes made to the original specifications and were felt necessary by the contractor in order to properly move the grout and to counter any artesian pressures, which were indicated in some cases by slight water flows from a number of the open holes. The ground water surface in the general area of the plant is approximately 575 feet and is, therefore, 25 feet above the RHR foundation rock surface or 45 feet above the bases of the grout holes. Local artesian conditions may have existed despite the dewatering program. In a few instances pressure build-ups may have been indicated by water flows from previously grouted holes. These holes were each regrouted. To determine if heaving of the concrete leveling mat was occurring due to grout being forced between the concrete leveling mat and the rock, elevations on the concrete surface were checked by transit from time to time. No changes in elevations were observed. It was also noted in all eight final core-drilled exploratory holes that the concrete mat was tightly-bonded to the rock surface.

Table B1 summarizes the volume of grout injected into the foundation for the RHR Complex. There is a general decrease in unit take, both from first to second zone grouting and from primary to secondary to tertiary holes within these zones. The unit take of the secondary holes in the first zone is 94 percent of the take of the primary holes in that zone, and by comparison the secondary holes of the second zone showed a unit take which was 18 percent of that of the primary holes in that zone. The unit take and the tertiary holes is consistent with a decrease in grout take and seems to confirm the single zone grouting which was used at this point.

Visual inspection of the leveling mat following completion of the grouting program confirmed that virtually all water flow had been eliminated, including all artesian flow from each of three preliminary borings which predated the RHR excavation in the vicinity of holes S43, P6, and P48.

Conclusions

Exploration drilling both prior to and after grouting along with careful observation of the drilling of the grout holes and amount of grout take prove there are no continuous open solution features in the foundation of the RHR Complex.

References:

(1) Dames & Moore letter, "Recommended Procedure for Foundation Preparation, Residual Heat Removel (RHR) Complex, Enrico Fermi Atomic Power Plant - Unit 2", dated February 11, 1974.

(2) Dames & Moore "Report, Results of Rock Foundation Treatment, Fermi II Nuclear Power Plant, for The Detroit Edison Company", dated January 12, 1971.

(3) Sargent & Lundy "Specification 3071-135, Pressure Rock Grouting for Residual Heat Removal Complex, Enrico Fermi Atomic Power Plant - Unit 2, The Detroit Edison Company", dated September 21, 1973.

Table B1

SUMMARY OF GROUTING

Holes Drilled	Number of Holes	Holes With Take	% Holes With Take	Volume of Grout (cubic ft)	Unit Take (Total Holes-Cubic Feet of Grout per ft. of hole)
First Zone Grouting (Holes drilled 6 feet deep to elevation 544 feet)					
Primary	78*	40	51%	707.4	1.51
Secondary	78*	45	58%	663.2	1.42
Second Zone Grouting (Holes drilled 20 feet deep to elevation 530 feet - except for north and south sumps)					
Primary	90	58	64%	636.7	.51
Secondary	90	22	24%	115.8	.09
Single Zone Grouting (Holes drilled 20 feet deep to elevation 530 feet)					
Tertiary	171	29	17%	189.3	.06
(Holes drilled 10 feet deep to elevation 540 feet - except for Q1--20 feet deep)					
Quaternary	6	4	67%	29.3	.49
Exploratory Test Holes (Holes drilled 20 feet deep to elevation 530 feet)					
Pre-grouting	8	7	88%	93.4	.58
Post-grouting	8	7	88%	42.7	.27

* Does not include area of sumps.

TABLE B2

WATER PRESSURE TESTING
(Flow Rates in Gallons/Minute)

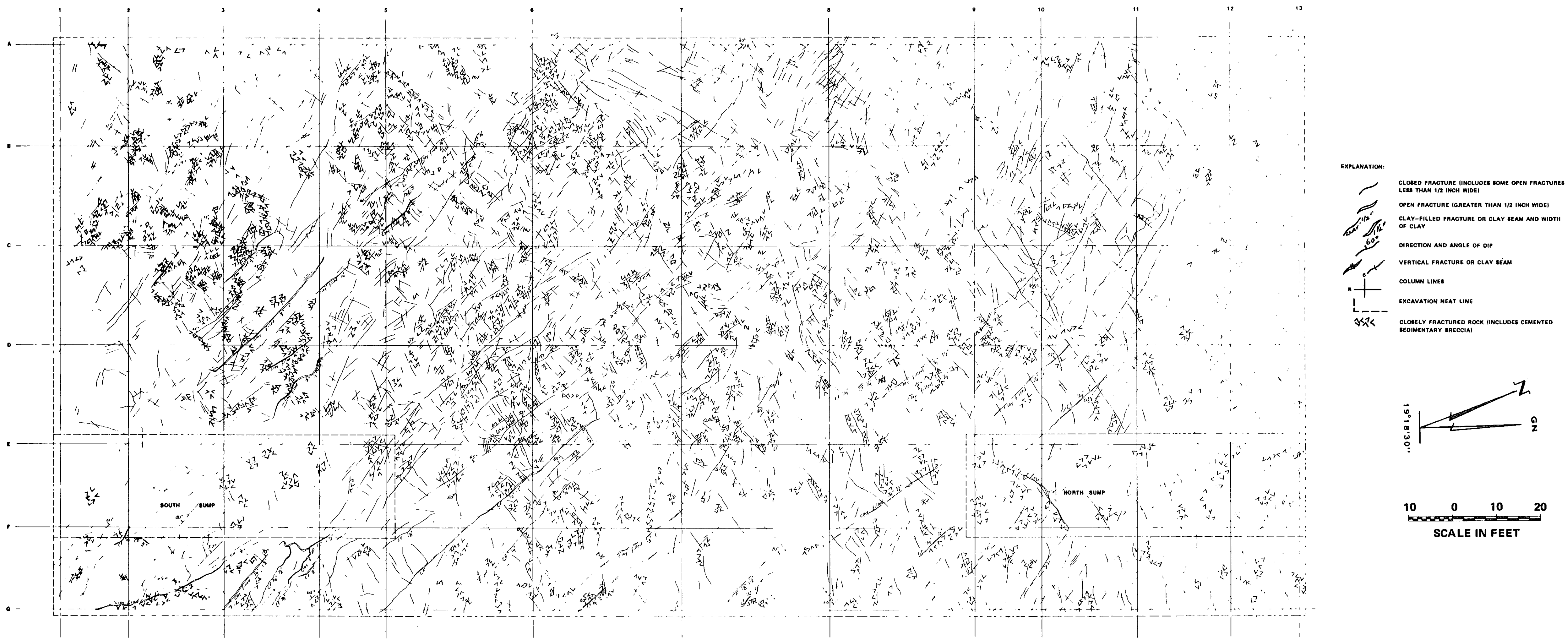
Test Hole Number	Intervals Tested (Elevations in Feet) (1) 530-535	(2) 530-540	(3) 530-545	(4) 530-550
		Pre-Grouting Exploratory Holes		
S44	.02	.41	.90 [5]	1.30 [3]
S21	.09	.92	.79	1.94
P15	.02	.17	.54	1.97
S75	.03	.00	1.22*	1.78*
P19	.00	.04	.22	.23
P37	.02	.08	1.01	2.08 [3]
S83	.22	.22	.62	.90 [5]
P77	.00	.03	.69	1.54 [2]
		Post-Grouting Exploratory Holes		
Q1	.00	.05	1.00**	.10
Q2	--	--	--	.70**
Q3	.10	.70	.50	.10
Q4	.20	.70	.70	.00 [5]
Q5	.00	.40	.60	.00 [4]
Q6	.00	.00	.00	--
Q7	.00	.81	.01	.78
Q8	.00	1.36	.83	.24

Note:

1. Each interval tested at constant pressure of 10 psi for 10 minutes unless otherwise noted by asterisk for a different pressure or number in upper right hand corner of block for different time.

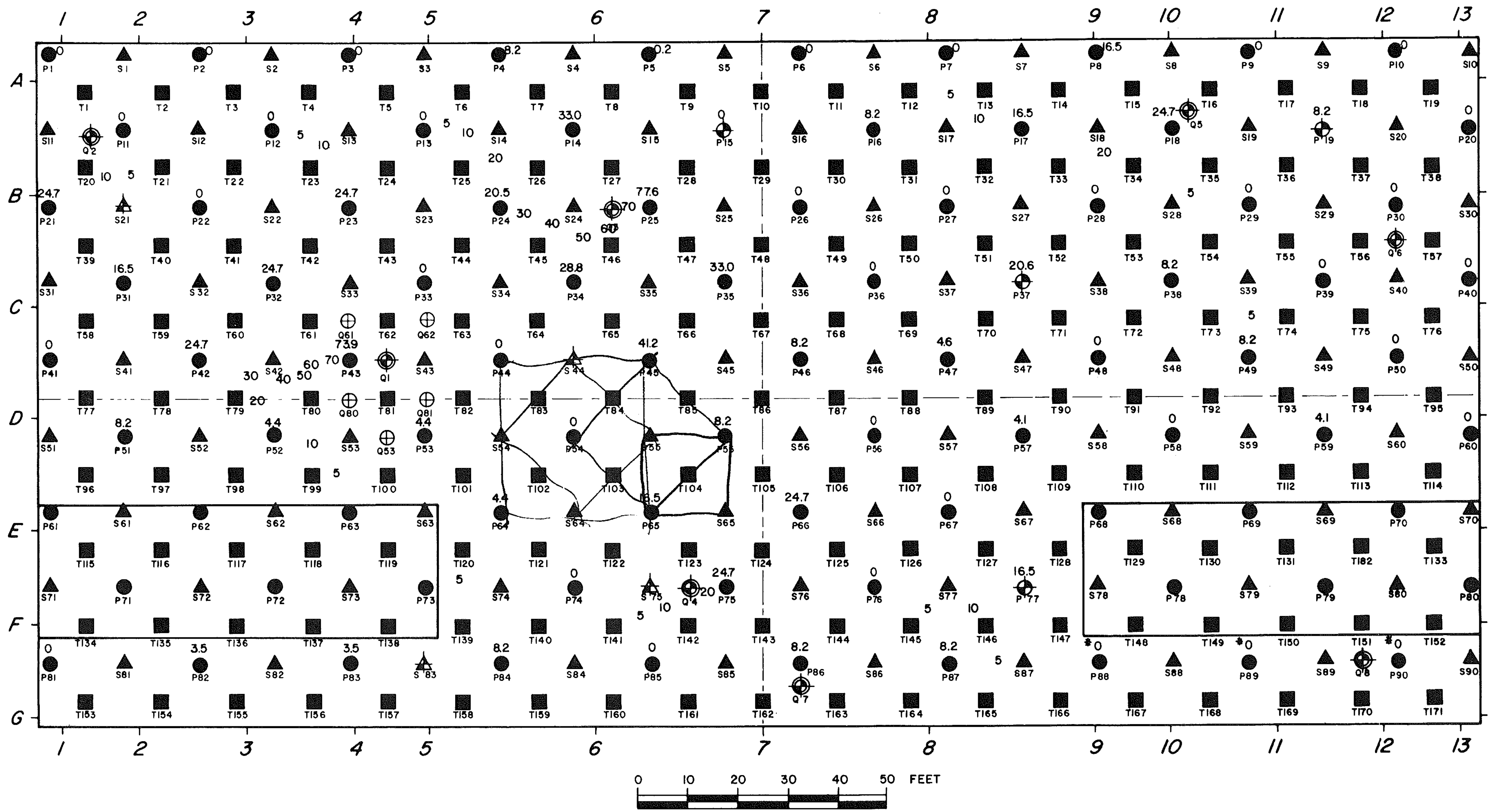
2. See Plates B1 - B5 for hole locations.

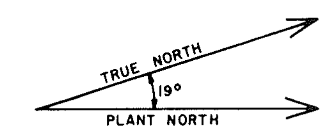
* 5 psi
** 0 psi



FOUNDATION ROCK SURFACE FEATURES
RESIDUAL HEAT REMOVAL COMPLEX

PLATE A–1





EXPLANATION

- PRIMARY GROUT HOLES
- SECONDARY GROUT HOLES
- TERTIARY GROUT HOLES
- QUATERNARY GROUT HOLES

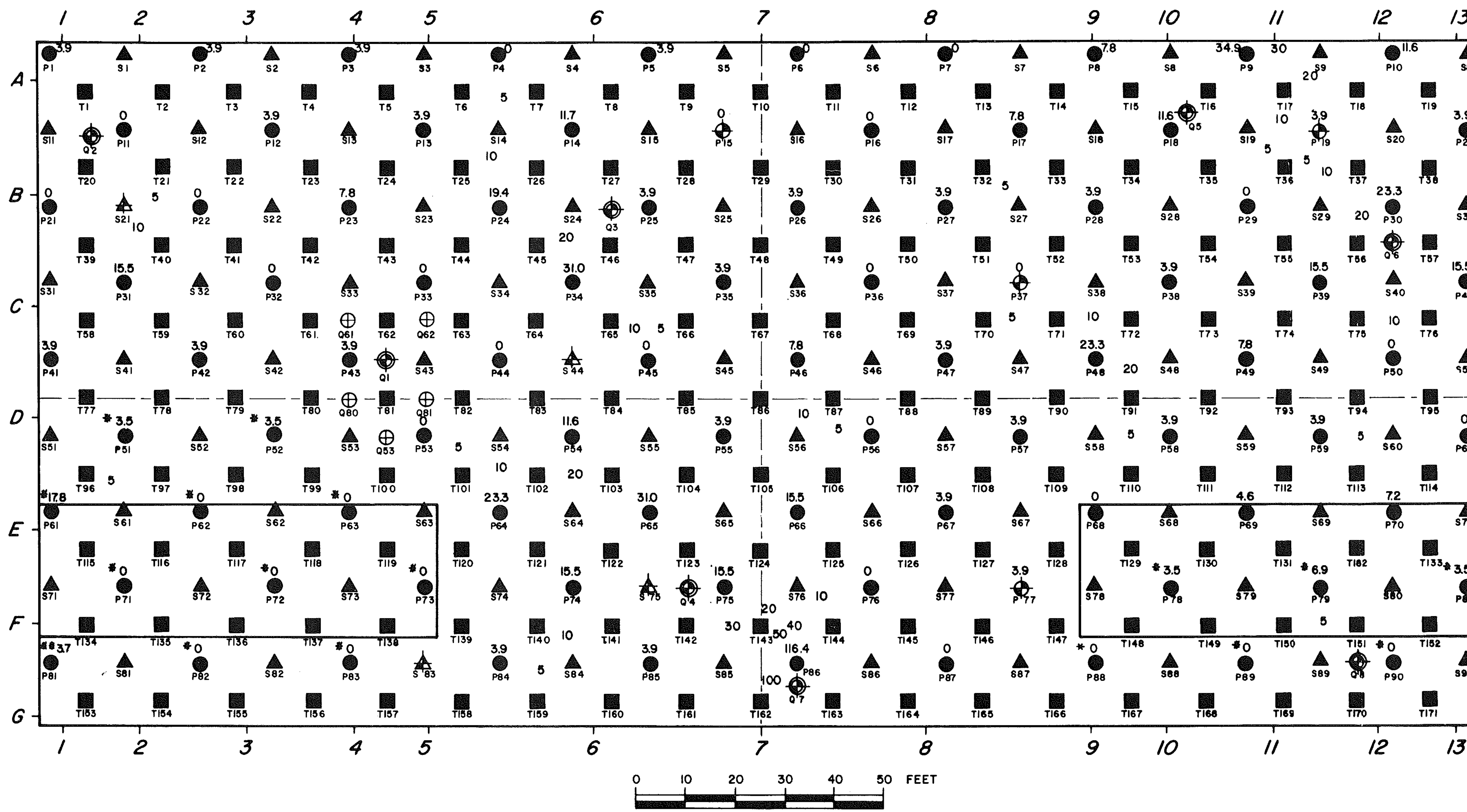
- 8.2 GROUT VOLUME IN CUBIC FEET-MIX WITH 1:1 (CEMENT:FLY ASH) AND 1.6:1 (WATER: CEMENT PLUS FLY ASH)
- *8.2 MIX WITH 1:1 (CEMENT:FLY ASH) AND 1.2:1 (WATER:CEMENT PLUS FLY ASH)
- 0 NO GROUT TAKEN BY ROCK

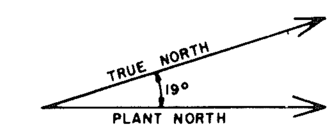
- OR PRE-GROUTING EXPLORATORY HOLES (SYMBOLS CORRESPOND TO EITHER A PRIMARY OR SECONDARY GROUT HOLE POSITION)
- POST-GROUTING EXPLORATORY HOLES
- 2 A BUILDING COLUMN LINES
- APPROXIMATE BUILDING AND EXCAVATION LINES
- BUILDING CENTER LINE

REFERENCE: MODIFIED FROM LEE TURZILLO CONTRACTING CO.
DRAWING NUMBER 2410-1
FEBRUARY 19, 1974

PRIMARY HOLES – FIRST ZONE GROUTING (0–6 FEET)

PLATE B–1





EXPLANATION

- PRIMARY GROUT HOLES
- SECONDARY GROUT HOLES
- TERTIARY GROUT HOLES
- QUATERNARY GROUT HOLES

3.9 GROUT VOLUME IN CUBIC FEET-MIX WITH 1.5:1 (CEMENT:FLY ASH) AND 2:1 (WATER: CEMENT PLUS FLY ASH)

*3.9 MIX WITH 1:1 (CEMENT:FLY ASH) AND 1.2:1 (WATER:CEMENT PLUS FLY ASH)

**3.9 MIX WITH 1:1 (CEMENT:FLY ASH) AND 1:1 (WATER:CEMENT PLUS FLY ASH)

0 NO GROUT TAKEN BY ROCK

OR PRE-GROUTING EXPLORATORY HOLES (SYMBOLS CORRESPOND TO EITHER A PRIMARY OR SECONDARY GROUT HOLE POSITION)

POST-GROUTING EXPLORATORY HOLES

2 A BUILDING COLUMN LINES

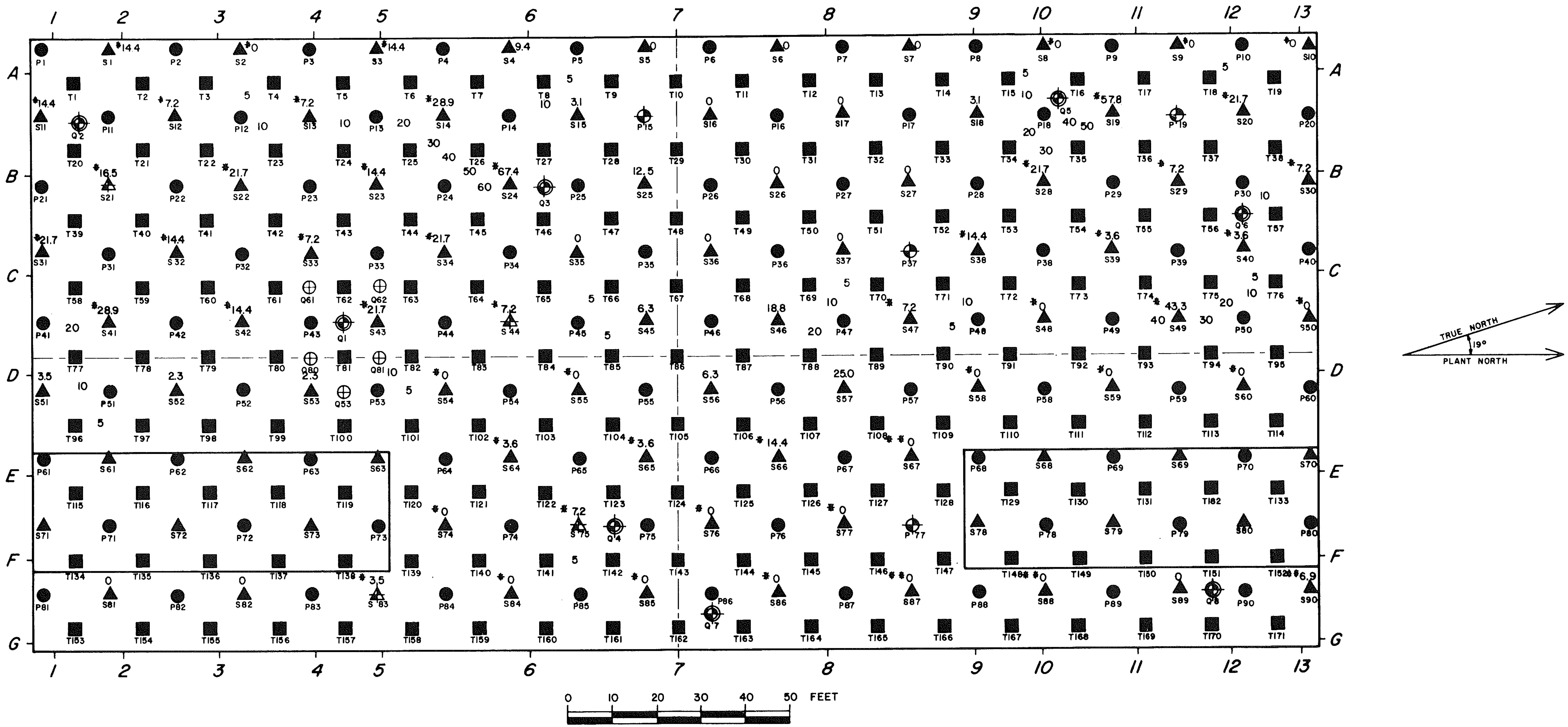
APPROXIMATE BUILDING AND EXCAVATION LINES

BUILDING CENTER LINE

REFERENCE: MODIFIED FROM LEE TURZILLO CONTRACTING CO. DRAWING NUMBER 2410-1 FEBRUARY 19, 1974

PRIMARY HOLES – SECOND ZONE GROUTING (6–20 FEET)

PLATE B–2



EXPLANATION

- PRIMARY GROUT HOLES
- SECONDARY GROUT HOLES
- TERTIARY GROUT HOLES
- QUATERNARY GROUT HOLES

7.2 GROUT VOLUME IN CUBIC FEET-MIX WITH 2:1 (CEMENT:FLY ASH) AND 3:1 (WATER: CEMENT PLUS FLY ASH)

*7.2 MIX WITH 1.5:1 (CEMENT:FLY ASH) AND 1.8:1 (WATER:CEMENT PLUS FLY ASH)

**7.2 MIX WITH 1:1 (CEMENT:FLY ASH) AND 1.2:1 (WATER:CEMENT PLUS FLY ASH)

0 NO GROUT TAKEN BY ROCK

OR PRE-GROUTING EXPLORATORY HOLES (SYMBOLS CORRESPOND TO EITHER A PRIMARY OR SECONDARY GROUT HOLE POSITION)

POST-GROUTING EXPLORATORY HOLES

2 A BUILDING COLUMN LINES

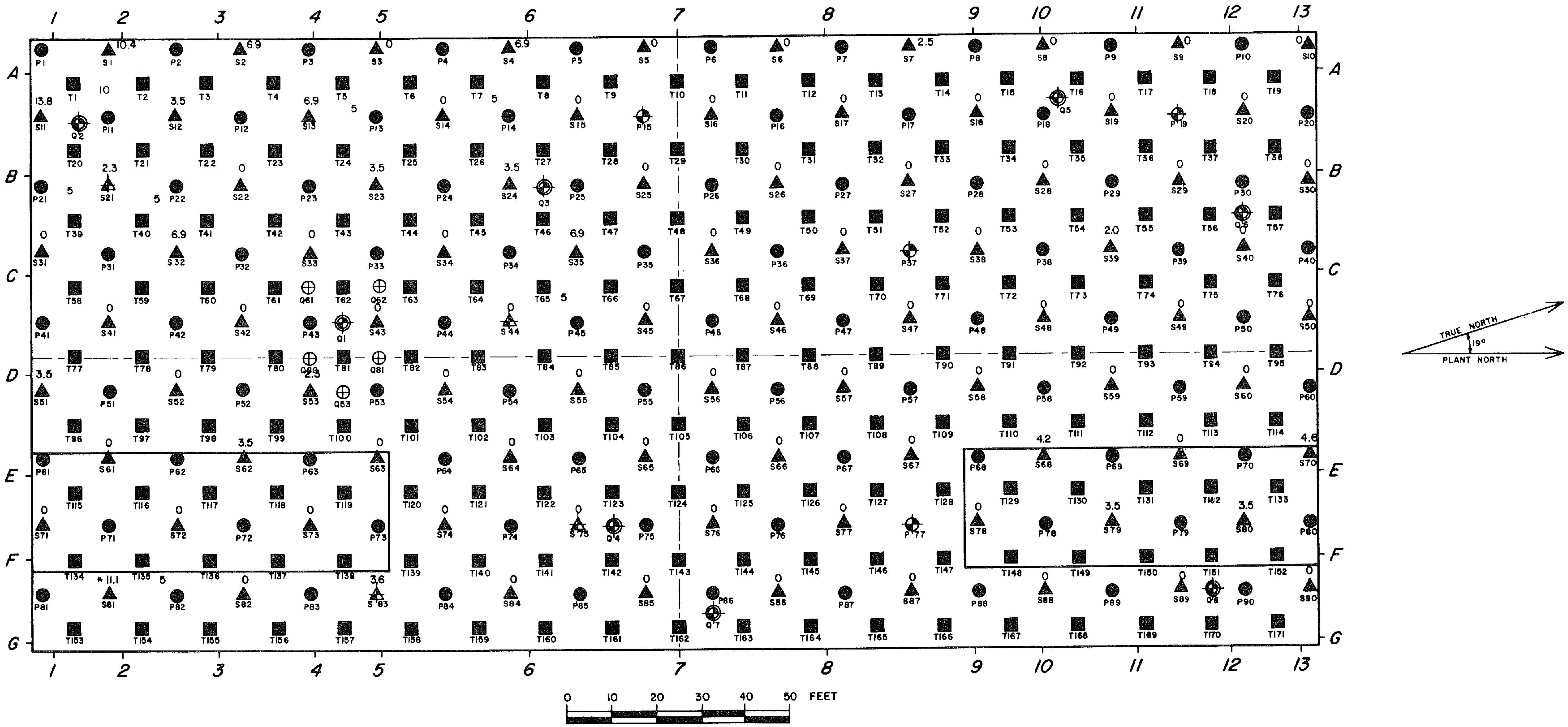
APPROXIMATE BUILDING AND EXCAVATION LINES

BUILDING CENTER LINE

REFERENCE: MODIFIED FROM LEE TURZILLO CONTRACTING CO. DRAWING NUMBER 2410–1 FEBRUARY 19, 1974

SECONDARY HOLES –
FIRST ZONE GROUTING (0–6 FEET)

PLATE B–3



EXPLANATION

- PRIMARY GROUT HOLES
- SECONDARY GROUT HOLES
- TERTIARY GROUT HOLES
- QUATERNARY GROUT HOLES

3.5 GROUT VOLUME IN CUBIC FEET-MIX WITH 1:1 (CEMENT:FLY ASH) AND 1.2:1 (WATER: CEMENT PLUS FLY ASH)

*3.5 MIX WITH 1:1 (CEMENT:FLY ASH) AND 1:1 (WATER:CEMENT PLUS FLY ASH)

0 NO GROUT TAKEN BY ROCK

PRE-GROUTING EXPLORATORY HOLES (SYMBOLS CORRESPOND TO EITHER A PRIMARY OR SECONDARY GROUT HOLE POSITION)

POST-GROUTING EXPLORATORY HOLES

BUILDING COLUMN LINES

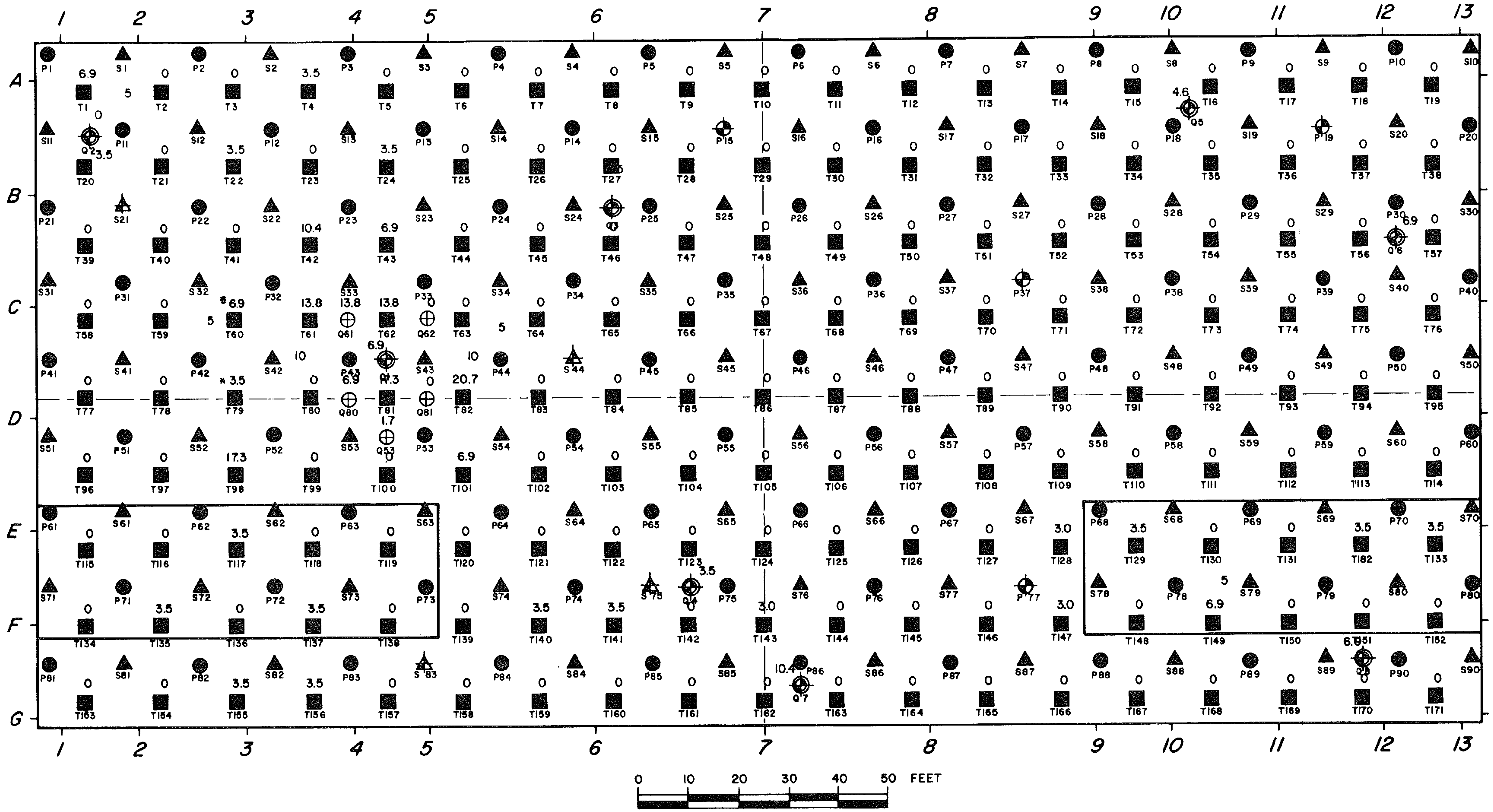
APPROXIMATE BUILDING AND EXCAVATION LINES

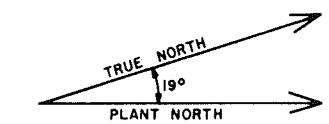
BUILDING CENTER LINE

REFERENCE: MODIFIED FROM LEE TURZILLO CONTRACTING CO.
DRAWING NUMBER 2410-1
FEBRUARY 19, 1974

SECONDARY HOLES –
SECOND ZONE GROUTING (6–20 FEET)

PLATE B–4





EXPLANATION

- PRIMARY GROUT HOLES
- SECONDARY GROUT HOLES
- TERTIARY GROUT HOLES
- QUATERNARY GROUT HOLES

6.9 OR 6.9 OR 6.9 — GROUT VOLUME IN CUBIC FEET-MIX WITH 1:1 (CEMENT:FLY ASH) AND 1.2:1 (WATER: CEMENT PLUS FLY ASH)

* 6.9 — MIX WITH 1.5:1 (CEMENT:FLY ASH) AND 1.5:1 (WATER:CEMENT PLUS FLY ASH)

0 — NO GROUT TAKEN BY ROCK

OR — PRE-GROUTING EXPLORATORY HOLES (SYMBOLS CORRESPOND TO EITHER A PRIMARY OR SECONDARY GROUT-HOLE POSITION)

POST-GROUTING EXPLORATORY HOLES

2 A — BUILDING COLUMN LINES

APPROXIMATE BUILDING AND EXCAVATION LINES

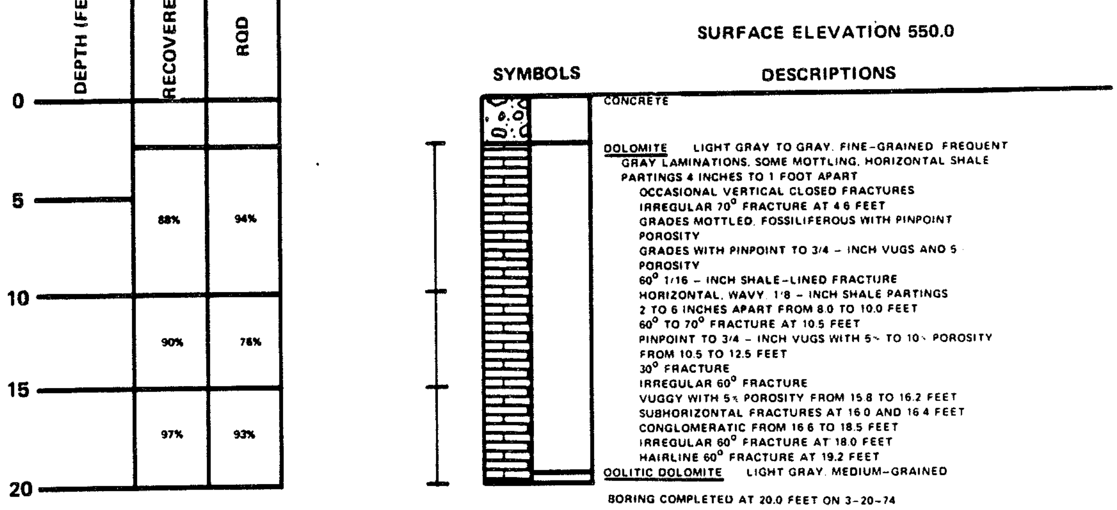
BUILDING CENTER LINE

**REFERENCE: MODIFIED FROM LEE TURZILLO CONTRACTING CO.
DRAWING NUMBER 2410–1
FEBRUARY 19, 1974**

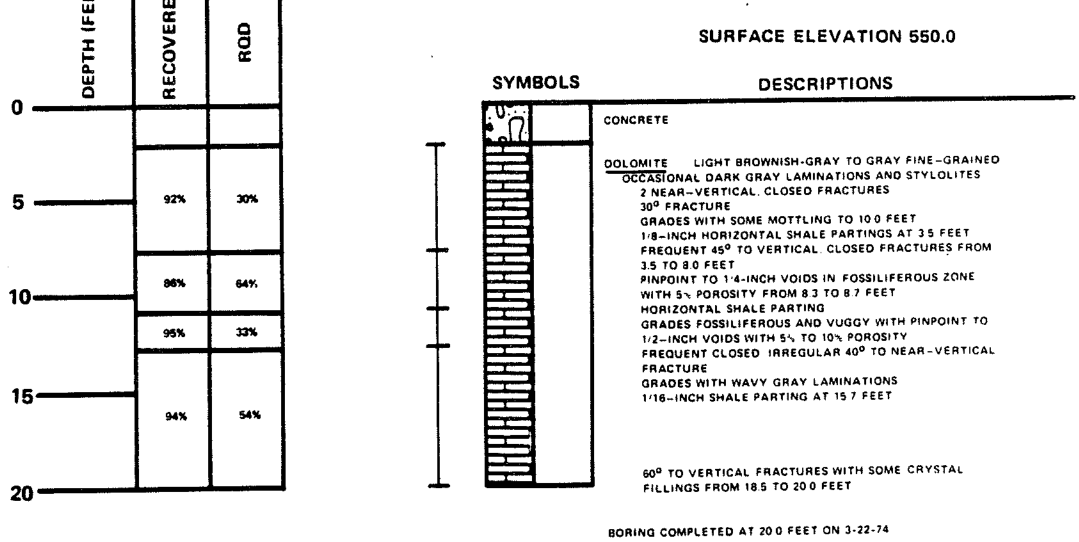
**TERTIARY AND QUATERNARY HOLES –
SINGLE ZONE GROUTING (0–20 FEET)**

PLATE B–5

BORING P–15



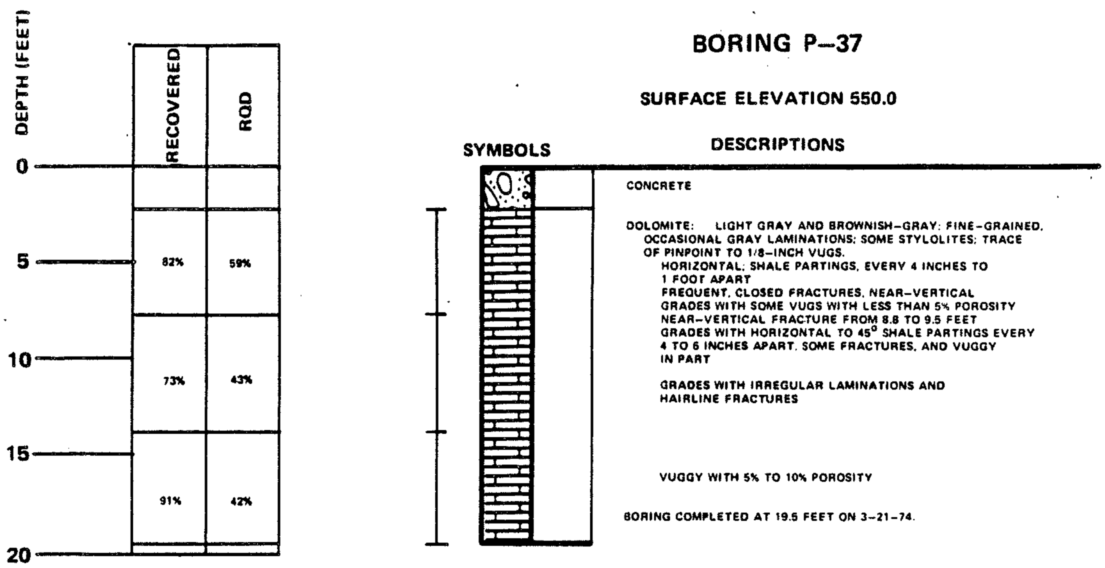
BORING P–19

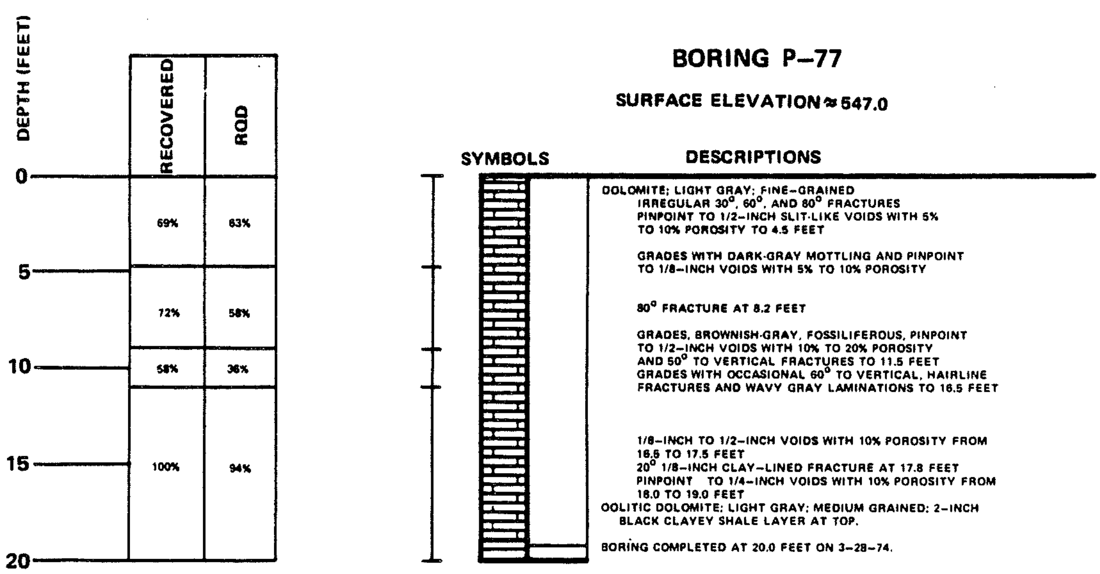


REFERENCE:
DAMES & MOORE REPORT
RESULTS OF ROCK FOUNDATION TREATMENT,
RESIDUAL HEAT REMOVAL COMPLEX,
ENRICO FERMI ATOMIC POWER PLANT UNIT 2,
JUNE 1974

LOG OF BORINGS

PLATE B–6





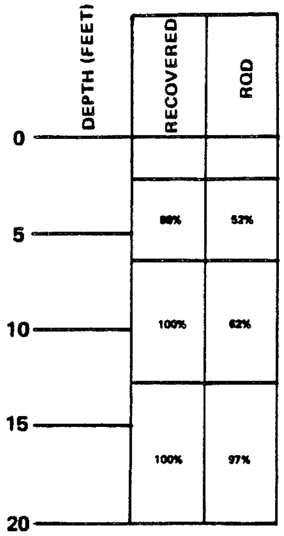
REFERENCE:
DAMES & MOORE REPORT,
RESULTS OF ROCK FOUNDATION TREATMENT,
RESIDUAL HEAT REMOVAL COMPLEX,
ENRICO FERMI ATOMIC POWER PLANT UNIT 2,
JUNE 1974

LOG OF BORINGS

PLATE B–7

BORING S-21

SURFACE ELEVATION 550.0

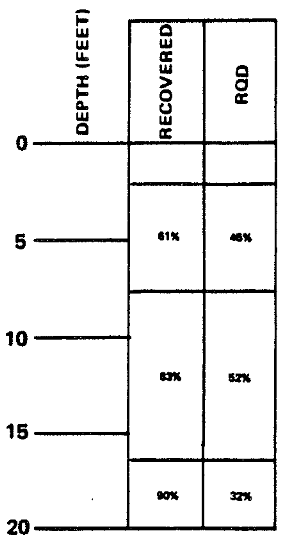


RECOVERED	RQD
88%	52%
100%	62%
100%	97%

SYMBOLS	DESCRIPTIONS
	CONCRETE
	DOLOMITE; LIGHT GRAY; FINE-GRAINED; PINPOINT TO 1/4-INCH VUGS WITH LESS THAN 5% POROSITY FREQUENT, IRREGULAR 45° TO VERTICAL FRACTURES HORIZONTAL SHALE PARTING AT 5.6 FEET GRADES TO DARK GRAY AND FOSSILIFEROUS WITH OCCASIONAL SHALE PARTING NEAR-VERTICAL IRREGULAR FRACTURE AT 6.5 FEET 50° FRACTURE AT 7.0 FEET PINPOINT TO 1/4-INCH VUGS WITH 5% POROSITY FROM 10.0 TO 11.5 FEET BROKEN AND VUGGY GRADES WITH IRREGULAR LAMINATIONS 60° TO 70° IRREGULAR FRACTURE FROM 16.4 TO 17.0 FEET VERTICAL 1/8" X 1 1/2" VUGS FROM 17.4 TO 17.7 FEET WITH 10% POROSITY 1/2-INCH BLACK CLAYEY SHALE LAYER AT 19.0 FEET
	OOLITIC DOLOMITE; LIGHT GRAY; FINE TO MEDIUM-GRAINED.
	BORING COMPLETED AT 20.0 FEET ON 3-25-74.

BORING S-44

SURFACE ELEVATION 550.0



RECOVERED	RQD
61%	46%
83%	52%
90%	32%

SYMBOLS	DESCRIPTIONS
	CONCRETE
	DOLOMITE; LIGHT GRAY TO BROWNISH-GRAY; FINE-GRAINED; OCCASIONAL SHALE PARTINGS; FOSSILIFEROUS; PINPOINT TO 1/4-INCH VUGS WITH 5% POROSITY IRREGULAR 50° FRACTURE NUMEROUS IRREGULAR NEAR-VERTICAL FRACTURES AND PINPOINT TO 1/8-INCH VUGS FROM 4.2 TO 8.5 FEET IRREGULAR 45° TO 70° FRACTURES 1 1/2-INCH, IRREGULAR VUG IRREGULAR 70° TO VERTICAL VUGGY FRACTURES IRREGULAR VUGGY FRACTURE FROM 18.4 TO 19.8 FEET LOWER 3 INCHES, OOLITIC DOLOMITE
	BORING COMPLETED AT 20.0 FEET ON 3-21-74.

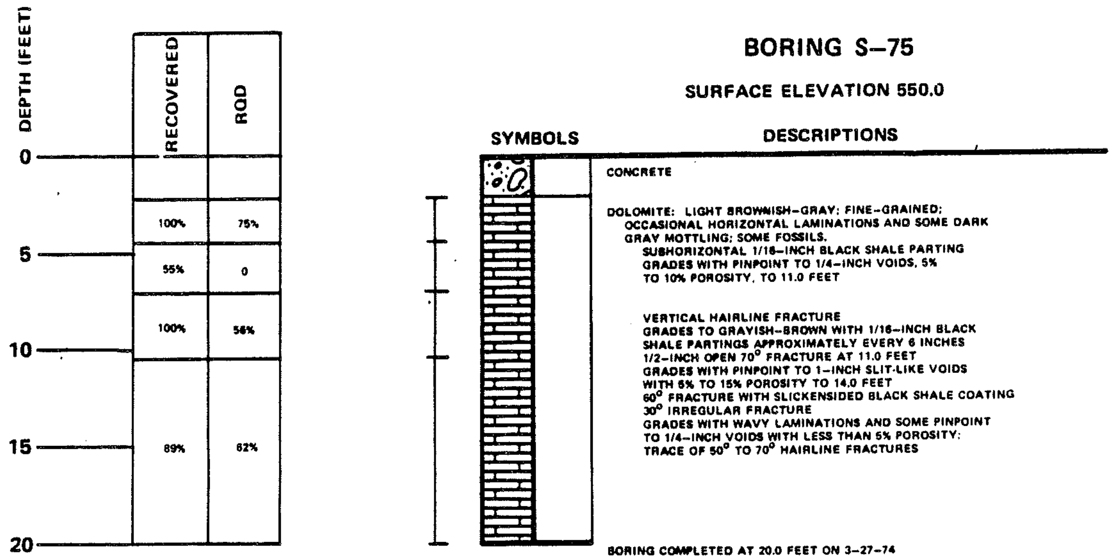
REFERENCE:
DAMES & MOORE REPORT,
RESULTS OF ROCK FOUNDATION TREATMENT
RESIDUAL HEAT REMOVAL COMPLEX,
ENRICO FERMI ATOMIC POWER PLANT UNIT 2,
JUNE 1974

LOG OF BORINGS

PLATE B-8

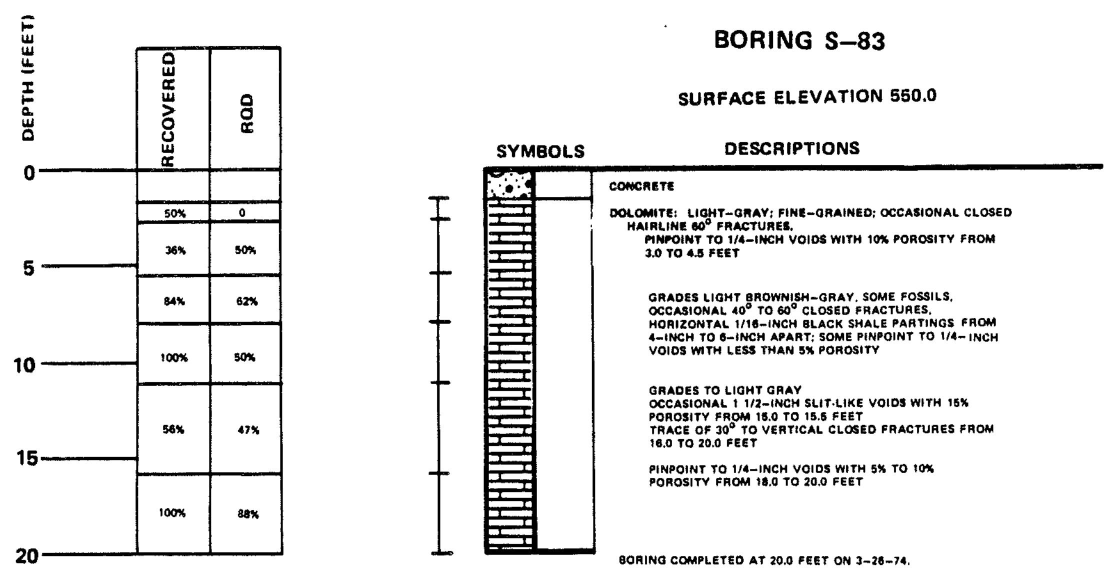
BORING S–75

SURFACE ELEVATION 550.0



BORING S–83

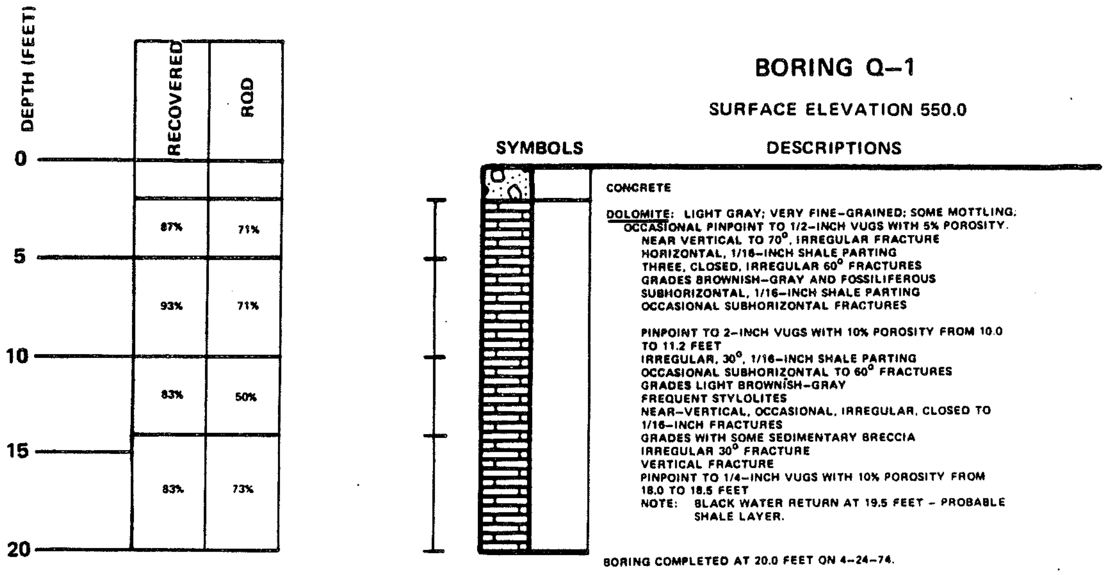
SURFACE ELEVATION 550.0

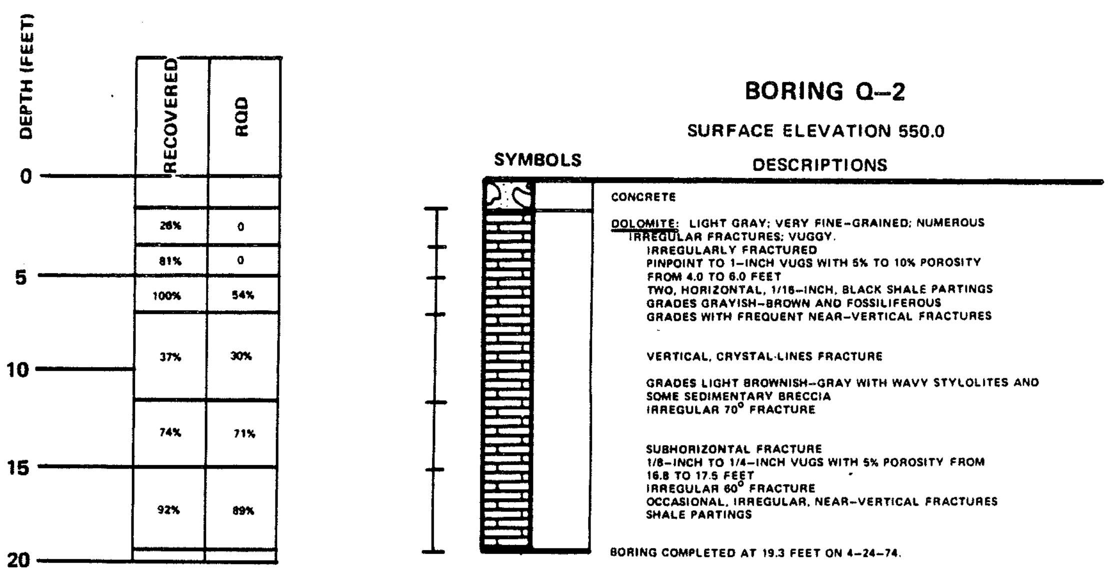


REFERENCE:
DAMES & MOORE REPORT
RESULTS OF ROCK FOUNDATION TREATMENT
RESIDUAL HEAT REMOVAL COMPLEX,
ENRICO FERMI ATOMIC POWER PLANT UNIT 2,
JUNE 1974

LOG OF BORINGS

PLATE B–9





REFERENCE,
DAMES & MOORE REPORT,
RESULTS OF ROCK FOUNDATION TREATMENT
RESIDUAL HEAT REMOVAL COMPLEX,
ENRICO FERMI ATOMIC POWER PLANT UNIT 2,
JUNE 1974

LOG OF BORINGS

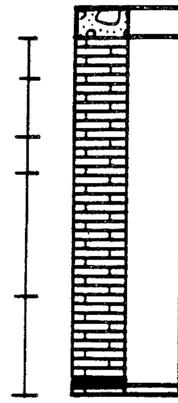
PLATE B–10

BORING Q–3

SURFACE ELEVATION 550.0

DEPTH (FEET)	RECOVERED	RQD
0		
	39%	0
5	75%	15%
	100%	72%
10	100%	72%
15	100%	73%
20		

SYMBOLS — DESCRIPTIONS



CONCRETE

DOLOMITE: LIGHT GRAY; VERY FINE–GRAINED; OCCASIONAL STYLOLITES; IRREGULARLY FRACTURED; 5% TO 10% VUGGY POROSITY.
- IRREGULAR FRACTURES
- 70° FRACTURES
- GRADES MOTTLED WITH SEDIMENTARY BRECCIA
- GRADES BROWNISH–GRAY AND FOSSILIFEROUS
- DARK GRAY, 2–INCH HORIZONTAL CLAY LAYER
- SEVERAL 70° TO VERTICAL FRACTURES
- TWO, SUBHORIZONTAL, BLACK SHALE PARTINGS
- 1/8–INCH TO 2–INCH VUGS WITH 5% TO 15% POROSITY FROM 9.5 TO 11.8 FEET
- NEAR–VERTICAL, CLOSED TO 1/16–INCH FRACTURE
- 1/16–INCH, BLACK SHALE PARTING
- IRREGULAR, 50° FRACTURE
- GRADES WITH WAVY STYLOLITES
- FOUR, IRREGULAR, SUBHORIZONTAL FRACTURES
- IRREGULAR, VERTICAL TO NEAR–VERTICAL FRACTURES
- TWO–INCH SHALE LAYER

OOLITIC DOLOMITE: LIGHT BROWNISH–GRAY; MEDIUM–GRAINED.

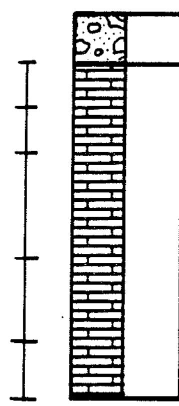
BORING COMPLETED AT 20.0 FEET ON 4–25–74.

BORING Q–4

SURFACE ELEVATION 550.0

DEPTH (FEET)	RECOVERED	RQD
0		
	68%	21%
5	100%	48%
10	97%	65%
15	51%	11%
	77%	60%
20		

SYMBOLS — DESCRIPTIONS



CONCRETE

DOLOMITE: LIGHT BROWNISH–GRAY; VERY FINE–GRAINED; NEAR–VERTICAL TO 70° IRREGULAR FRACTURES; OCCASIONAL STYLOLITES.
- PINPOINT TO 1/4–INCH VUGS WITH 5% POROSITY FROM 5.0 TO 5.5 FEET
- FREQUENT, IRREGULAR, 30° TO 70° FRACTURES
- GRADES MOTTLED GRAY
- PINPOINT TO 1/2–INCH VUGS WITH 10% POROSITY FROM 7.0 TO 7.9 FEET
- IRREGULAR VERTICAL FRACTURE
- GRADES BROWNISH–GRAY
- 1/16–INCH HORIZONTAL BLACK SHALE PARTING
- BLACK SHALE PARTING
- 30° FRACTURE
- 1/8–INCH TO 2–INCH VUGS WITH SOME CLAY FILLINGS AND 20% POROSITY FROM 11.5 TO 12.5 FEET
- NUMEROUS, IRREGULAR, NEAR-VERTICAL, CLOSED TO 1/4–INCH FRACTURES
- OCCASIONAL 40° TO 60° FRACTURES
- PINPOINT TO 1/4–INCH VUGS WITH 5% POROSITY FROM 18.0 TO 19.5 FEET

BORING COMPLETED AT 20.0 FEET ON 4–25–74

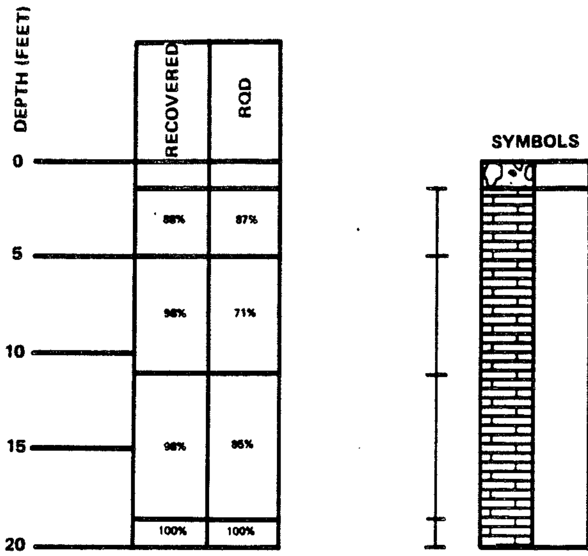
REFERENCE:
DAMES & MOORE REPORT
RESULTS OF ROCK FOUNDATION TREATMENT, RESIDUAL HEAT REMOVAL COMPLEX UNIT 2, JUNE 1974

LOG OF BORINGS

PLATE B–11

BORING Q-5

SURFACE ELEVATION 550.0



DESCRIPTIONS

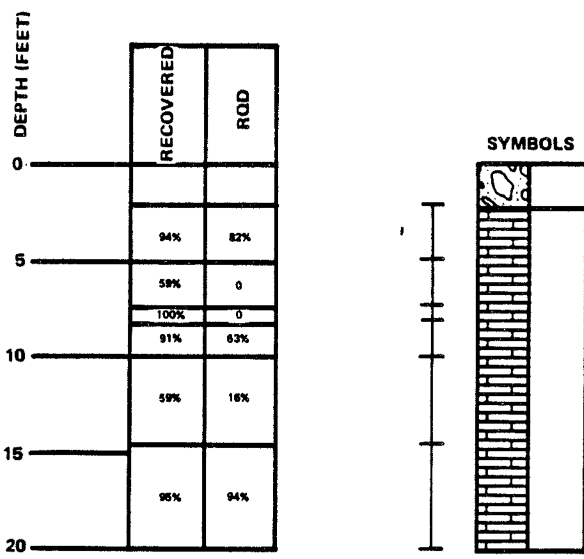
CONCRETE
DOLOMITE: LIGHT GRAY; VERY FINE-GRAINED; HORIZONTAL BLACK STYLOLITES EVERY 2 INCHES TO 6 INCHES APART.
TWO 1/16-INCH, HORIZONTAL, BLACK SHALE PARTINGS

SUBHORIZONTAL FRACTURE
SHALE PARTING
TWO, 80° FRACTURES
PINPOINT TO 1/2-INCH VUGS WITH 5% TO 15% POROSITY FROM 7.3 TO 9.3 FEET
GRADES WITH SOME GRAY MOTTLING AND SEDIMENTARY BRECCIA
GRADES BROWNISH-GRAY WITH NEAR-VERTICAL FRACTURES WITH BLACK SHALE LININGS
1/4 -INCH VUGS WITH 10% POROSITY FROM 10.5 TO 12.0 FEET
PINPOINT TO 1/2-INCH VUGS WITH 5% POROSITY FROM 12.0 TO 14.3 FEET
IRREGULAR, 1/16-INCH, 30° BLACK SHALE PARTING
OCCASIONAL, WAVY GRAY LAMINATIONS AND HAIRLINE FRACTURES
SUBHORIZONTAL FRACTURE

BORING COMPLETED AT 20.0 FEET ON 4-25-74.

BORING Q-6

SURFACE ELEVATION 550.0



DESCRIPTIONS

CONCRETE

DOLOMITE: LIGHT BROWNISH-GRAY; VERY FINE-GRAINED; OCCASIONAL DARK GRAY LAMINATIONS AND STYLOLITES.
80° FRACTURE
SEVERAL, NEAR-VERTICAL FRACTURES

80° FRACTURE
SUBHORIZONTAL, 1/16-INCH, BLACK SHALE PARTING
GRADES WITH DARK GRAY MOTTLING
20° FRACTURE
SUBHORIZONTAL PARTING
GRADES DARK GRAYISH-BROWN WITH SOME VUGS
BLACK SHALE PARTINGS EVERY 4 TO 6 INCHES APART
NOTE: 10.0 FEET - SOME WATER FLOW, APPROXIMATELY 2 GALLONS/MINUTE.
60° FRACTURE
NEAR-VERTICAL, IRREGULAR, 1/16-INCH, CRYSTAL-LINED FRACTURE
GRADES WITH IRREGULAR GRAY LAMINATIONS AND STYLOLITES

PINPOINT TO 1/4-INCH VUGS WITH 5% POROSITY

BORING COMPLETED AT 20.0 FEET ON 4-26-74.

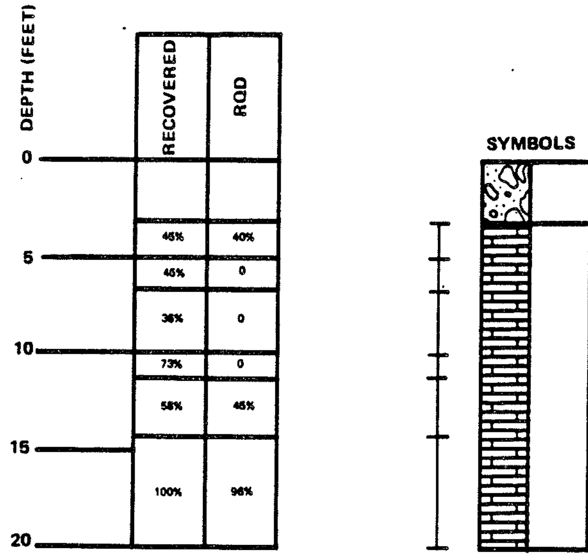
REFERENCE:
DAMES & MOORE REPORT
RESULTS OF ROCK FOUNDATION TREATMENT, RESIDUAL HEAT REMOVAL COMPLEX, UNIT 2, JUNE 1974

LOG OF BORINGS

PLATE B-12

BORING Q–7

SURFACE ELEVATION 550.0



DESCRIPTIONS

CONCRETE
NOTE: WATER FLOW FROM HOLE APPROXIMATELY 3 GALLONS/MINUTE

DOLOMITE: LIGHT GRAY: VERY FINE–GRAINED.
SEVERAL NEAR–VERTICAL, HAIRLINE TO 1/16–INCH FRACTURES
NOTE: SLIGHT WATER FLOW.
GRADES WITH DARK GRAY MOTTLING AND IRREGULAR VERTICAL FRACTURES

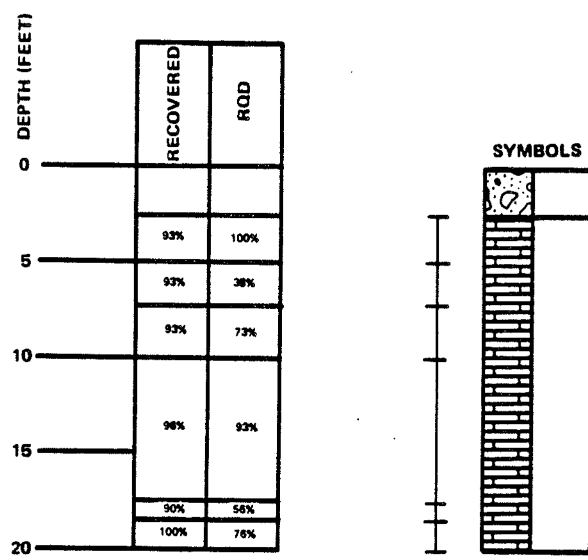
GRADES BROWNISH–GRAY, FOSSILIFEROUS WITH SOME SHALE PARTINGS AND VERTICAL FRACTURES
PINPOINT TO 1/4–INCH VUGS WITH 5% POROSITY
60° TO NEAR–VERTICAL FRACTURES
NOTE: 13.0 FEET – PROBABLE GROUT IN WATER RETURN.
HORIZONTAL FRACTURE
GRADES WITH WAVY GRAY LAMINATIONS
IRREGULAR 45° FRACTURE
NEAR–VERTICAL, CLOSED TO 1/16–INCH FRACTURE

PINPOINT TO 1/4–INCH VUGS WITH 5% TO 10% POROSITY, FROM 19.0 TO 20.0 FEET

BORING COMPLETED AT 20.0 FEET ON 4–29–74.

BORING Q–8

SURFACE ELEVATION 550.0



DESCRIPTIONS

CONCRETE

DOLOMITE: LIGHT GRAY; VERY FINE–GRAINED; OCCASIONAL GRAY, STYLOLITES; NEAR–VERTICAL HAIRLINE TO 1/16–INCH FRACTURES.
IRREGULAR 30° TO 60° FRACTURES
1/2–INCH VUGS WITH 5% TO 10% POROSITY FROM 3.2 TO 4.7 FEET
OCCASIONAL 60° FRACTURES
GRADES WITH GRAY MOTTLING
GRADES BROWNISH–GRAY WITH OCCASIONAL BLACK SHALE PARTINGS
SUBHORIZONTAL FRACTURE
50° FRACTURE
SEVERAL 30° TO 45° FRACTURES
1/16–INCH TO 1 1/2–INCH VUGS WITH 15% POROSITY FROM 12.5 TO 13.5 FEET
60° FRACTURE
IRREGULAR 60° FRACTURE
80°, CLOSED TO 1/16–INCH FRACTURE
HIGHLY FRACTURED
TRACE OF FINE CONGLOMERATE
IRREGULARLY FRACTURED

BORING COMPLETED AT 20.0 FEET ON 4–29–74.

REFERENCE:
DAMES & MOORE REPORT
RESULTS OF ROCK FOUNDATION TREATMENT
RESIDUAL HEAT REMOVAL COMPLEX, UNIT 2
JUNE 1974.

LOG OF BORINGS

Specification 3071-37
Issued: 11-27-70

A30-00-0-000SA-007

APPENDIX 2C

THE DETROIT EDISON COMPANY
SPECIFICATION

FILL MATERIALS,PLACEMENT AND COMPACTION

Enrico Fermi Atomic Power Plant
6400 Dixie Highway
Stony Creek, Monroe County,
Michigan.

THE DETROIT EDISON COMPANY
SPECIFICATION

SPECIFICATION 3071-37
PREPARED BY
ENGINEERING DESIGN &
SERVICES DEPARTMENT

Issued: 11-27-70

FILL MATERIALS, PLACEMENT AND COMPACTION

Enrico Fermi Atomic Power Plant
6400 Dixie Highway
Stony Creek, Monroe County,
Michigan.

PART 1 : GENERAL

1-01 GENERAL CONDITIONS

a. All work under this contract shall be governed by "The General Conditions of the Contract", Edison Specification 3071, this specification and the applicable drawings and bills of material.

b. The Contractor, including his suppliers and sub-contractors, shall conform to Edison Specification 3071-8B, "Field Contractor Quality Assurance Requirements for Construction, Installation and Erection of Quality Levels 1 and 2 Structures and Equipment. Quality Levels 1 and 2 will apply to this work as defined on the drawings and bills of material.

c. The term, Engineer, used herein shall mean the Architectural-Civil Design Division of Edison's Engineering Design and Services Department or its authorized representative.

1-02 SCOPE

a. Furnish all labor, supervision, and equipment necessary to perform the filling, compaction, and grading as described herein and as shown on the drawings.

b. Fill materials shall be from sources designated and approved by the Engineer.

PART 2 : PRODUCT

2-01 GENERAL

a. All fill materials shall be maintained free of foreign matter such as vegetation, organic matter, rubbish, metal scrap, and ice.

2-02 QUARRY RUN ROCK FILL

a. Material shall be shattered rock obtained by blasting or ripping in rock cuts. Shattered rock shall be reasonably well graded with a maximum size not to exceed ½ cubic yard.

b. No specific moisture content at time of placing is required.

c. Shattered rock shall be deposited on the fill and pushed over the end of the fill by means of bulldozers or other equipment into approximately horizontal layers not exceeding 3 feet in thickness. The final surface of the Quarry Run Rock Fill shall be so choked with small rock fragments and fines that there will be no infiltration of any soil which may subsequently be placed on this surface. Where insufficient rock fines are available to properly choke the surface, sand or fine gravel and sand shall be used.

2-03 CRUSHER RUN ROCK FILL - 6 INCH AND UNDER

a. Material shall be that obtained by crushing Quarry Run Rock (see 2-02 a) and shall be graded as follows:

Sieve Size - U.S. Standard	Percent Passing.
6 inch	95
3 inch	30- 75

Loss by washing 0-10 percent.

2-03 <u>CRUSHER RUN ROCK FILL - 6 INCH AND UNDER</u> Cont'd

b. No specific moisture content at time of placing is required.

c. <u>TYPE A</u>: Material shall be spread in approximately horizontal layers not exceeding 15 inches in thickness and compacted by 2 passes of a vibratory type compactor.

<u>TYPE B</u>: Material shall be spread in approximately horizontal layers not exceeding 15 inches in thickness and compacted by one pass of the treads of a crawler type tractor weighing 40,000 pounds or more.

2-04 CRUSHER RUN ROCK FILL - 1½ INCH AND UNDER

a. Material shall be that obtained by crushing Quarry Run Rock (see 2-02 a) and shall be graded as follows:

Sieve Size - U.S. Standard	Percent Passing.
2 inch	100
1½ inch	95-100
½ inch	25-50
No. 10	6-18
No. 200	3-10

b. The moisture content at time of placing shall be not greater than 12 percent.

c. <u>TYPE A</u>: Material shall be spread in approximately horizontal layers not exceeding 12 inches in thickness and compacted by a minimum of six passes of a vibratory type compactor to not less than 95 percent of the maximum unit weight.

<u>TYPE B</u>: Material shall be spread in approximately horizontal layers not exceeding 12 inches in thickness and compacted by one pass of the treads of a crawler type tractor weighing 40,000 pounds or more.

2-05 SELECT GRANULAR FILL

a. Material shall be graded as follows:

Sieve Size - U.S. Standard.	Percent Passing.
2½ inch	100
1 inch	60-100
No. 100	0-30

Loss by washing 0-7 percent.

b. The moisture content at time of placing shall not vary more than ± 2% of optimum.

c. Material shall be spread in approximately horizontal layers not exceeding 15 inches in thickness and compacted to not less than 95 percent of the maximum unit weight.

2-06 MISCELLANEOUS GRANULAR FILL

a. Material shall be graded as follows:

Sieve Size - U.S. Standard	Percent Passing.
3 inch	100

Loss by washing 0-15 percent.

b. The moisture content at time of placing shall not vary more than ± 1% of optimum.

c. Material shall be spread in approximately horizontal layers not exceeding 15 inches in thickness and compacted to not less than 95 percent of the maximum unit weight.

2-07 QUARRY SCREENINGS FILL

a. Material shall be screenings obtained from the crusher operation at the France Stone Quarry, Monroe, Michigan and shall be graded as follows:

Sieve Size - U.S. Standard	Percent Passing.
No. 4.	90-100
No. 10.	50-65
No. 40.	25-40
No. 200	20 maximum.

2-07 QUARRY SCREENINGS FILL Cont'd

b. The moisture content at time of placing shall not vary more than ± 2% of optimum.

c. TYPE A: Material shall be spread in approximately horizontal layers not exceeding 9 inches in thickness and compacted to not less than 100 percent of the maximum unit weight.

TYPE B: Material shall be spread in approximately horizontal layers not exceeding 9 inches in thickness and compacted to not less than 95 percent of the maximum unit weight.

2-08 SELECT CLAY FILL

a. Material shall be the sandy silty clay (till) obtained from site excavation below approximate elevation 565.

b. The moisture content at time of placing shall be no greater than optimum nor less than 2% below optimum.

c. TYPE A: Material shall be spread in approximately horizontal layers not exceeding 9 inches in thickness and compacted to not less than 100 percent of the maximum unit weight.

TYPE B: Material shall be spread in approximately horizontal layers not exceeding 9 inches in thickness and compacted to not less than 95 percent of the maximum unit weight.

2-09 MISCELLANEOUS CLAY FILL

a. Material shall be clay from on or off-site sources not meeting Select Clay Fill description.

b. The moisture content at time of placing shall not vary more than ± 2% of optimum.

c. Material shall be spread in approximately horizontal layers not exceeding 9 inches in thickness and compacted to not less than 95 percent of the maximum unit weight.

PART 3 : EXECUTION

3-01 FOUNDATION REQUIREMENTS

a. The foundation material on which the fill is to be placed shall be as specified on the drawings and its suitability shall be approved by the Engineer prior to placing fill.

b. The surface of the sandy silty clay till (below approximate elevation 565 in the main building area) on which fill is to be placed shall be graded as required to provide for drainage and eliminate ponding.

3-02 LAYER THICKNESS

a. Thickness of layers in excess of that specified will be permitted only after satisfactory demonstration by the Contractor that the required density can be obtained. Whenever the required density is not obtained after such permission is granted, the thickness of the layers shall be reduced upon instructions of the Engineer.

b. The thickness of the first layer of materials other than clay to be constructed on poorly drained soil may be increased to a maximum of 24 inches upon approval by the Engineer.

3-03 COMPACTION

a. One pass of the treads of a crawler type tractor is defined as the required number of successive tractor trips which, by means of sufficient overlap, will insure complete coverage of an entire layer by the tractor treads.

b. One pass of a vibratory compactor is defined as the required number of successive tractor trips which, by means of sufficient overlap, will insure complete coverage of an entire layer by the compacting device.

c. A vibratory compactor is defined as one of the following:

Plate type vibratory compactor, tractor mounted, as manufactured by International Vibrator or Jackson Vibrators, Inc.

Drum type vibratory compactor, tractor drawn, such as Hyster C200B, Vibro-Plus CH33, or equal as approved by the Engineer.

3-03 COMPACTION Cont'd

d. In areas inaccessable to large equipment, obtain required compaction with mechanical vibrators for granular fill, and with mechanical rammers for cohesive fill.

3-04 COLD WEATHER RESTRICTIONS

a. Frozen material shall not be placed in the fill. All ice and snow shall be removed from the surface of the foundation material before fill is placed thereon. In addition where the fill is to support a structure, all ground containing frost within limits of 1 on 1 slopes spreading outward in all directions from the bottom of structure footings shall be removed. In other areas ground containing more than 4 inches of frost shall be removed. Ground containing less than 4 inches of frost and not used for fill which will support structure footings need not be removed.

b. The placing of materials described in sections 2-07, 2-08 and 2-09 shall be limited to the period between May 1 and November 1 unless otherwise approved by the Engineer.

3-05 DRAINAGE

a. The surface of the fill shall be maintained with sufficient slope to provide for runoff of surface water from every point.

b. The working surface of fill described in Sections 2-07, 2-08 and 2-09 shall regularly be sealed with a smooth-wheel static roller at the close of each working day and shall be sealed during the day when practicable prior to rainfall.

c. Filling shall be conducted so that no obstruction to drainage from other sections of the fill area is created at any time. Sumps, if any, will be continuously maintained in effective operating condition.

d. The Contractor shall protect compacted fill and foundation material in excavated areas from becoming rutted or distorted. All rutting or distortion caused by the Contractor's operation shall be corrected by the Contractor at his expense before any succeeding layers are placed.

3-06 FILL AGAINST STRUCTURES

a. Fill shall not be placed against any portion of a structure until the required surface finishing and waterproofing of such portions have been completed. Waterproofing materials shall be protected as required to prevent damage which might occur from fill operations.

b. Fill which will cause a horizontal loading on an unshored portion of a structure shall not be placed until the concrete has attained at least 70 percent of its design strength.

c. Fill around isolated structures such as piers shall be placed on opposite sides at the same time to equalize horizontal loadings.

3-07 MAXIMUM UNIT WEIGHT

a. Maximum unit weight when used as a measure of compaction or density of cohesive soils having a loss by washing greater than 10 percent, shall be understood to mean the maximum weight per cubic foot as determined using the One-Point T-99 Test or the AASHO T-99 Test as described in the MDSH Density Control Handbook, August,1969.

b. The One-Point Michigan Cone Test or the Michigan Cone Test as described in the MDSH Density Control Handbook, August, 1969, modified as follows, will be used for determining the maximum unit weight for granular materials having a loss by washing of 10 percent or less:

For granular soils having a unit weight of 120 pounds per cubic foot or less, the unit weight will be determined at any moisture content between 6 percent and a point short of saturation.

For granular soils having a unit weight over 120 pounds per cubic foot, the unit weight will be determined at the moisture content, between 6 percent and a point short of saturation, which will give the maximum weight.

c. In-place density of materials shall be obtained using a volumeter which measures the volume of a hole by means of a rubber balloon and water under air pressure.

PART 4 : SPECIFICATIONS AND STANDARDS

4-01 EDISON SPECIFICATIONS

a. 3071, The General Conditions of the Contract.

b. 3071-8B, Field Contractor Quality Assurance Requirements for Construction, Installation and Erection of Quality Levels 1 and 2 Structures and Equipment.

4-02 MICHIGAN DEPARTMENT OF STATE HIGHWAYS

a. MDSH Density Control Handbook, August,1969.

APPENDIX 2D

Records of Laboratory Test Results on Rock Core Samples

ST. LOUIS SAN FRANCISCO LONDON, ENG. LOS ANGELES PITTSBURGH

ROBERT W. HUNT COMPANY ENGINEERS
CHICAGO 7, ILLINOIS

December 27, 1968

File No. 1187-2
Order B-13686

Report 3584
Page 1

Tests On Stone Cores

Job: No. 7605-002-16

Dames and Moore
309 West Jackson Boulevard
Chicago, Illinois 60606

Attention: Mr. D. G. Staggs

Gentlemen:

We report test results on four (4) stone cores obtained by our representative at your office on December 17, 1968 marked as shown in the following tabulations:

The sample cores were prepared for test by us.

Test core size: Diameter 2.00 inches Length 4.00 inches

Sample Core Designation			Compressive Strength		Modulus of Elasticity	Weight
Boring Number	Depth Feet	Classification	Maximum Load Lbs.	Per Square Inch Lbs.	At 50% of Maximum Load, Lbs. Per Square Inch	Per Cubic Foot Lbs.
20	27	Dolomite	49,200	15,661	13,346,000	154.02
32A	52	Oolite	30,400	9,677	4,359,000	145.29
28	106	Argillaceous Dolomite	28,400	9,040	2,601,000	162.12
4	58	Dolomite	24,500	7,799	- - -	137.80

Specific Gravity:

	Sample Core Designation			
Boring No.	20	32A	28	4
Depth, Ft.	27	52	106	58
Classification	Dolomite	Oolite	Argillaceous Dolomite	Dolomite
Specific Gravity:-	2.47	2.33	2.60	2.21

Respectfully submitted,
ROBERT W. HUNT COMPANY

G. E. Matoush

G.E. Matoush, Manager
Cement and Concrete Department

GEM:rek-4

ROBERT W. HUNT COMPANY, ENGINEERS
Chicago 7, Illinois

March 31, 1972

File No. 1187-2 Report 853
Order 13-C-6283 Page 1

Unconfined Compression Tests

Purchase Order No. PA 205

Job Number: 7605-020

Dames and Moore
1550 Northwest Highway
Park Ridg, Illinois 60068

Gentlemen:

We report results on unconfined compression test performed on Rock Core samples picked up by our representative on March 28, 1972 at your office.

Boring Identification		Compressive Strength Lbs. Per Square Inch
RHR-8	36.3'-37.0'	7536
RHR-3	29.2'-29.8'	8188
RHR-5	40.5'-41.6'	8333
RHR-7	33.9'-34.6'	7388
RHR-6	29.2'-29.8'	10,362
RHR-4	30.9'-31.5'	9928
RHR-2	39.1'-39.6'	9130

Respectfully submitted,
ROBERT W. HUNT COMPANY

G.E. Matoush, Manager
Cement and Concrete Department

GEM:rek- 4

(exact copy - not original)

ROBERT W. HUNT COMPANY, Engineers

DAMES AND MOORE Job: 7605-002-16

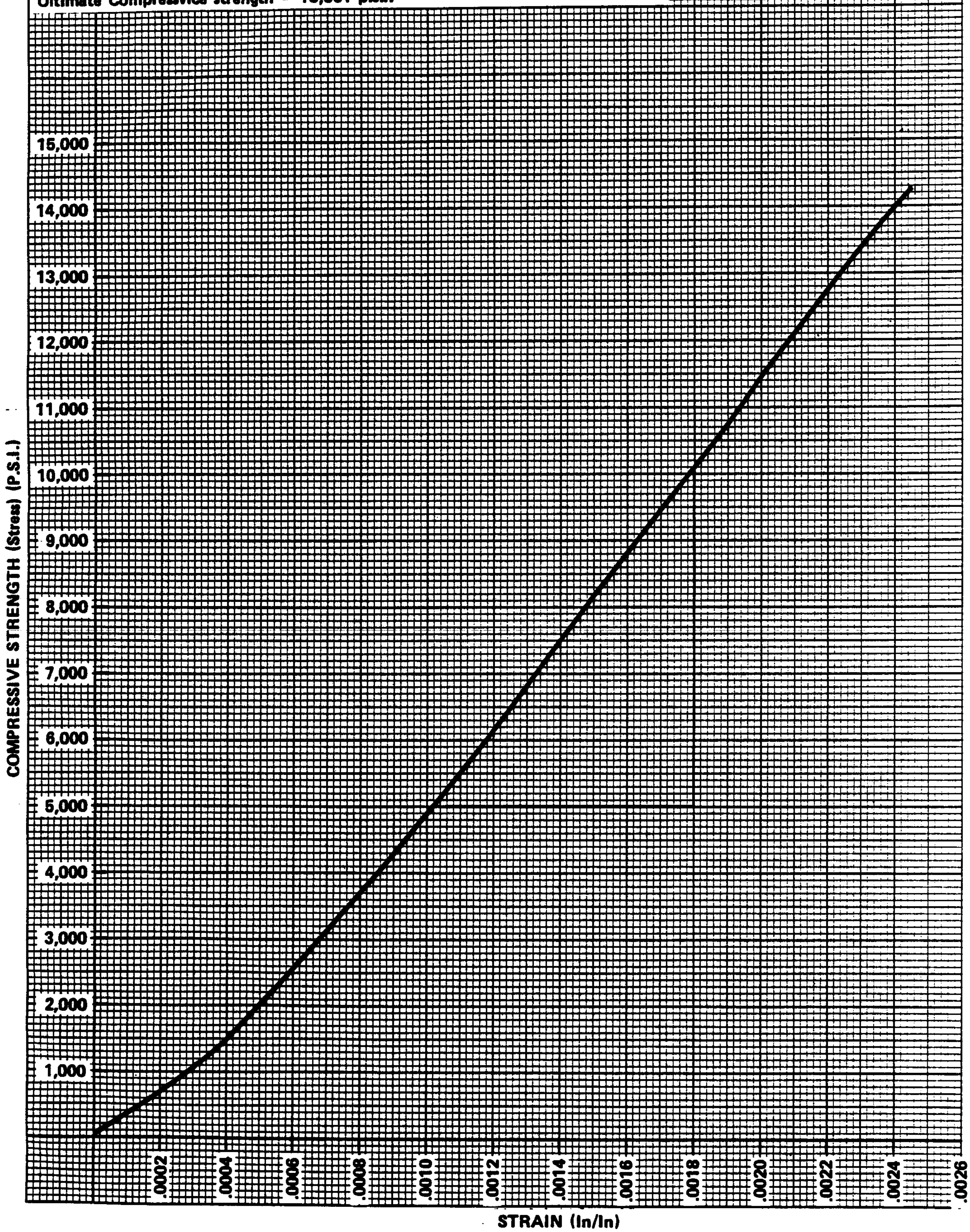
File No. 1187-2
Order B-11686

December 27, 1968

Report 3584
Page No. 2

Core Marking: Boring – 20 Depth – 27 feet Dolomite

Ultimate Compressvice strength – 15,661 p.s.i.



ROBERT W. HUNT COMPANY, Engineers

DAMES AND MOORE JOB: 7605-002-16

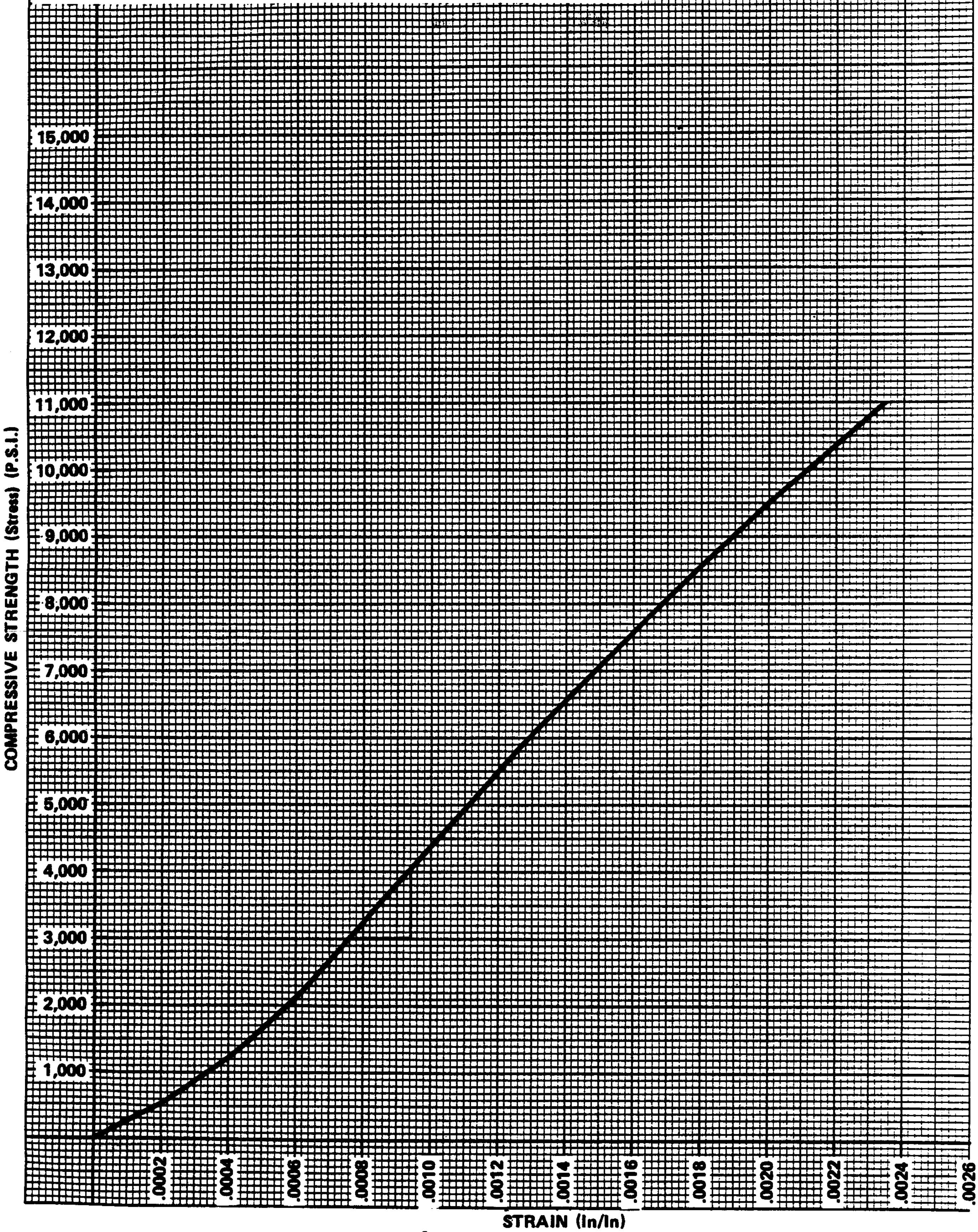
File No. 1187-2
Order No. B-13686

December 27, 1968

Report 3584
Page No. 3

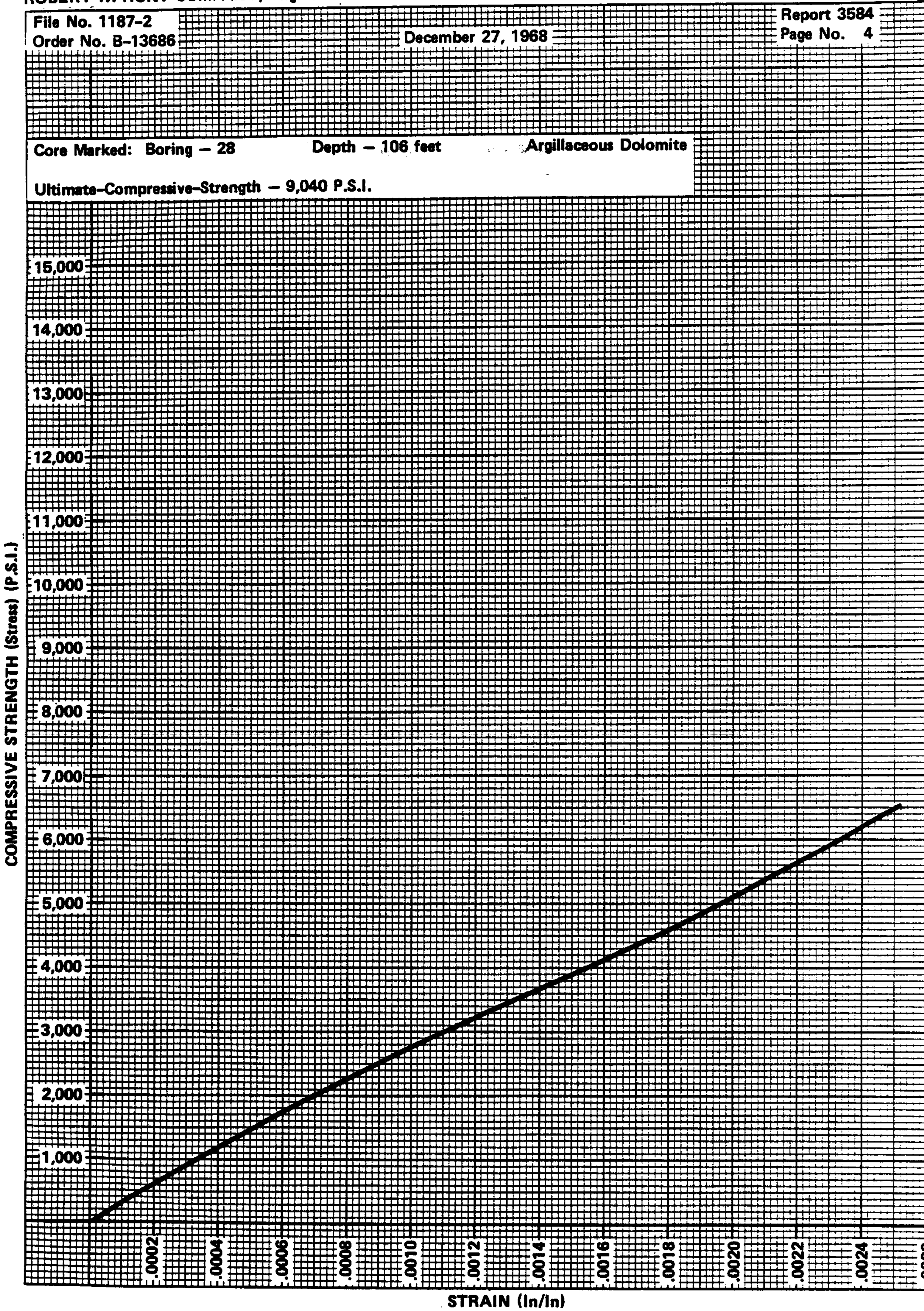
Core Marked: Boring – 32A Depth – 52 feet Oolite

Ultimate Compressive-Strength-9,677 p.s.i.



ROBERT W. HUNT COMPANY, Engineers

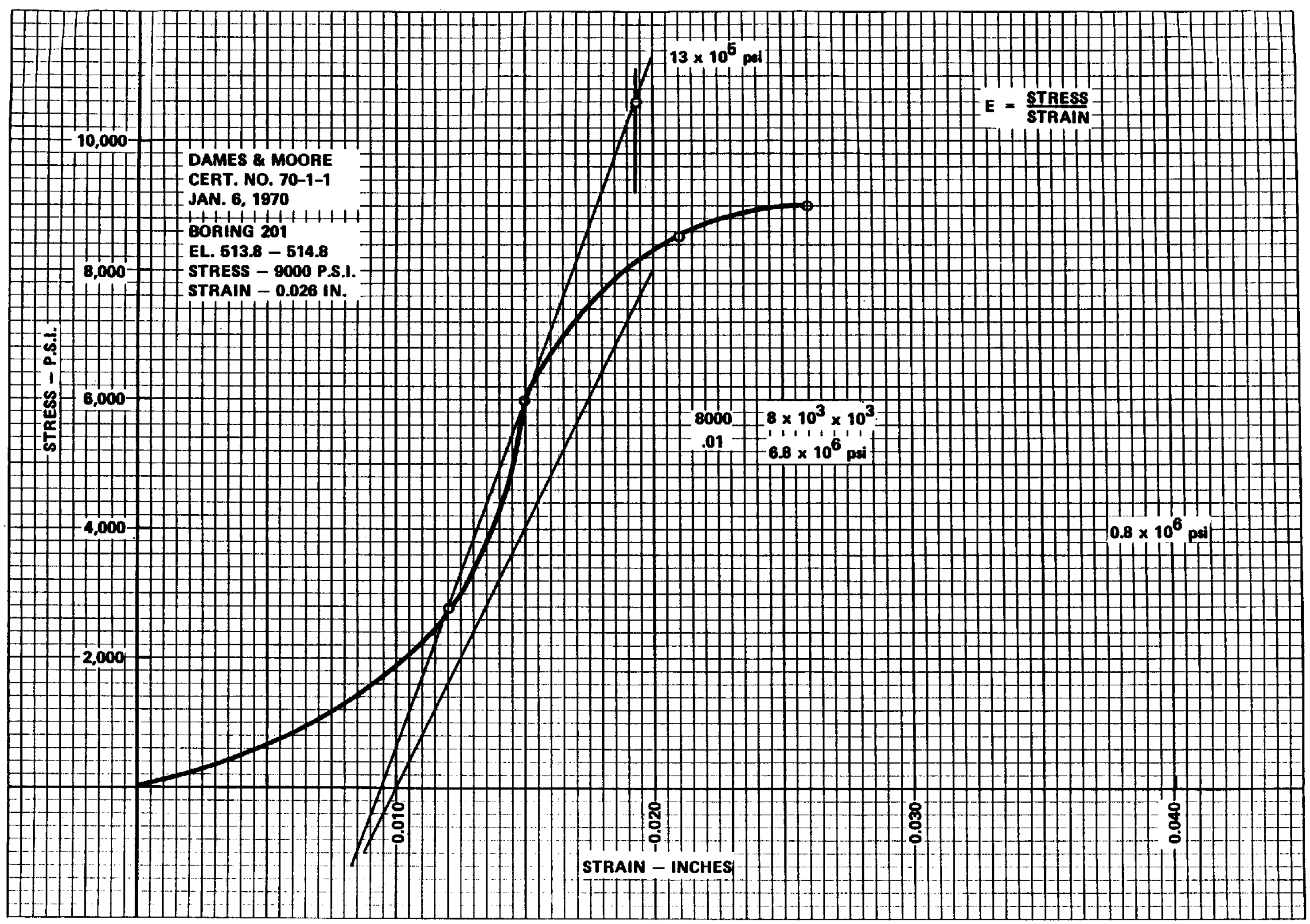
DAMES AND MOORE Job: 7605-002-16

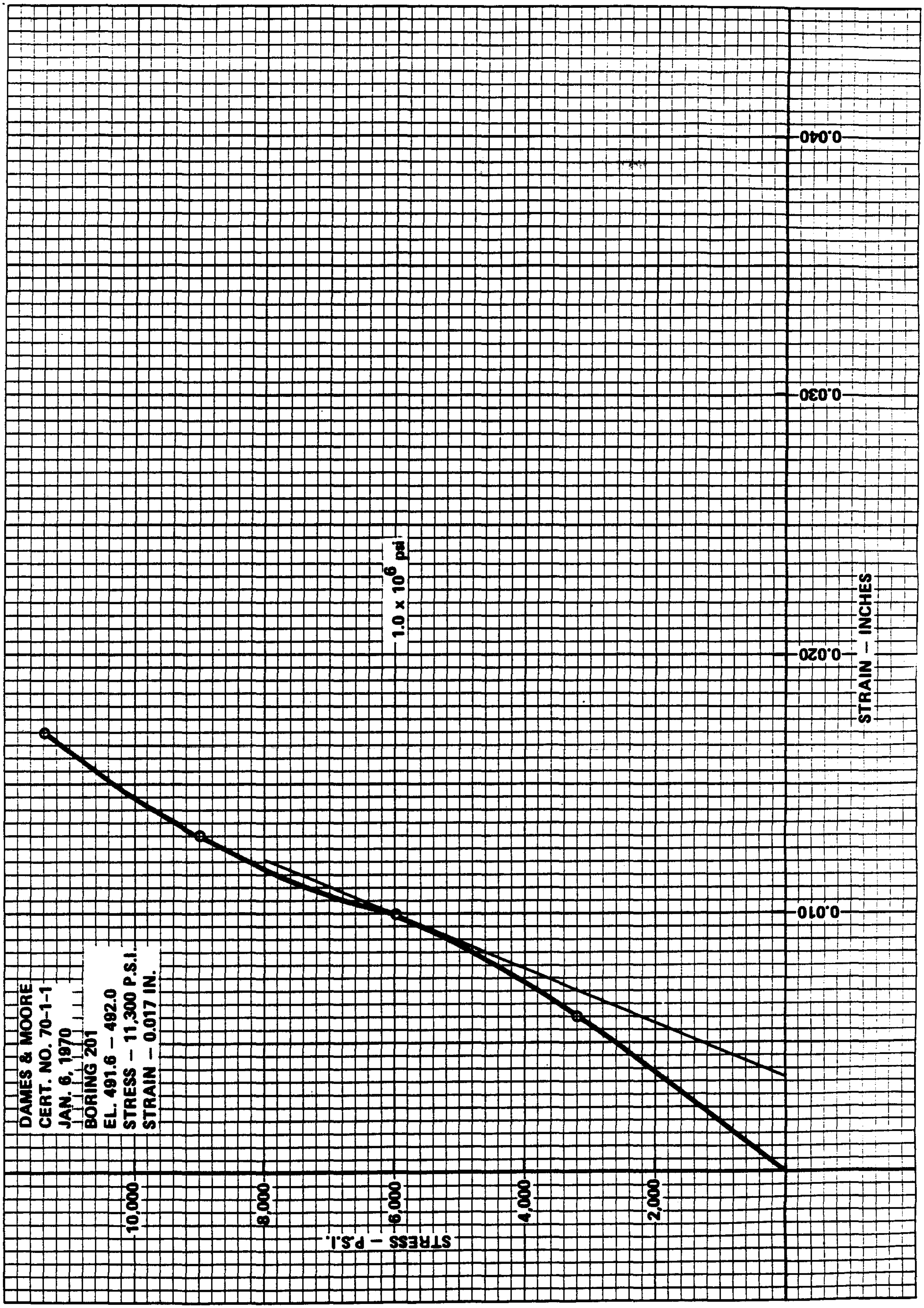


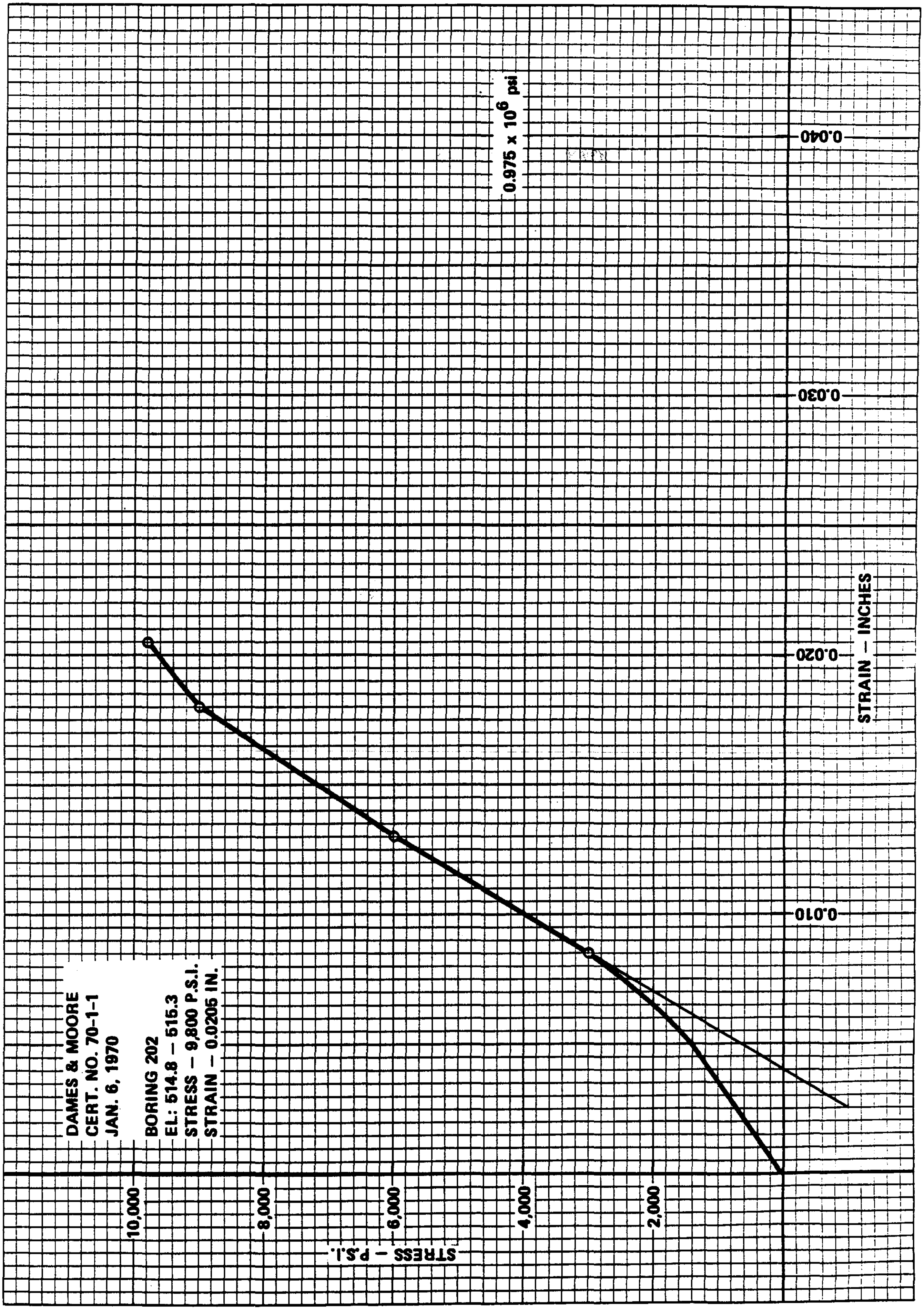
Dames & Moore
1414 Dexter Ave. No.
Seattle, 98109

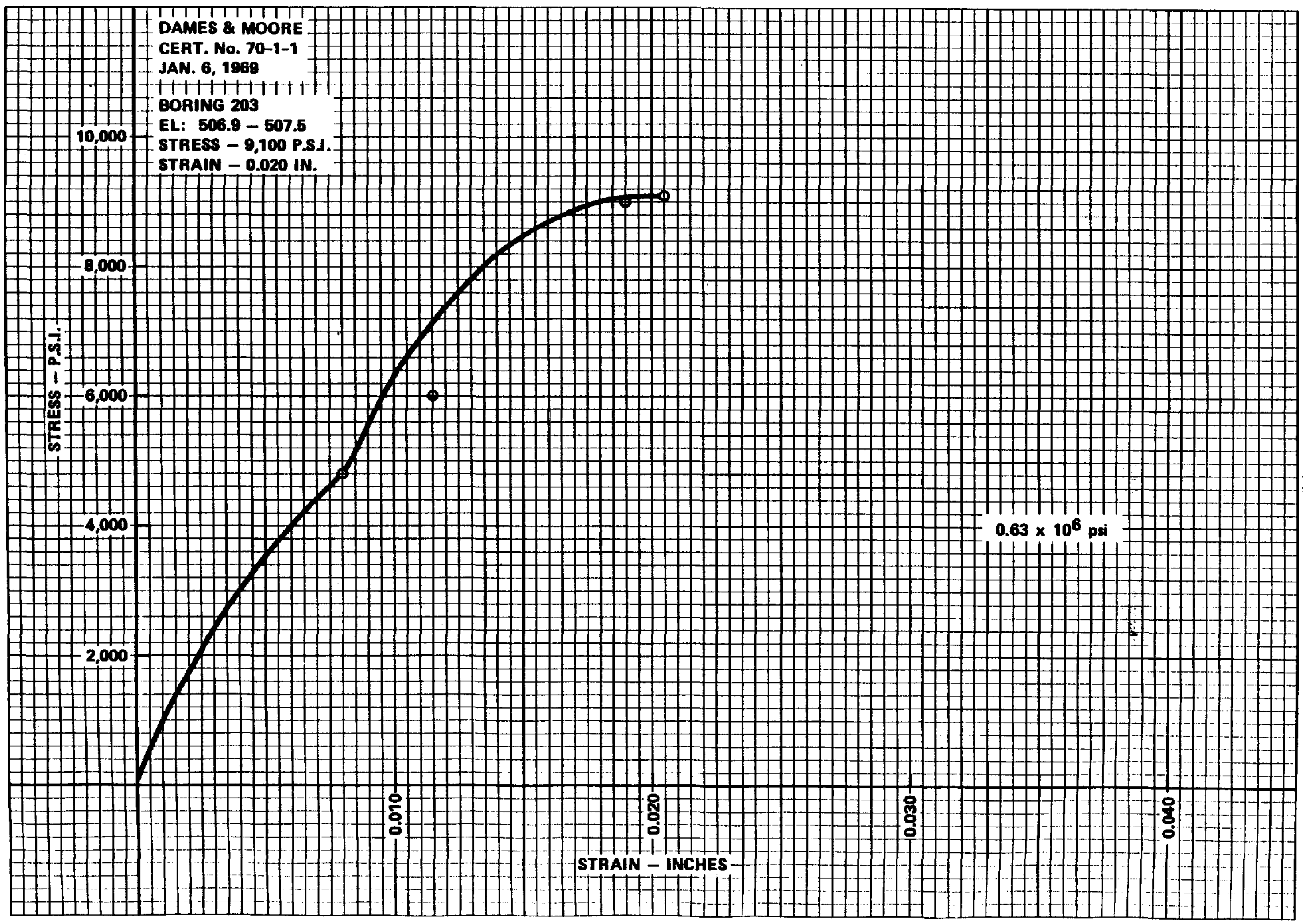
CERT. NO. 701-1
January 6, 1970

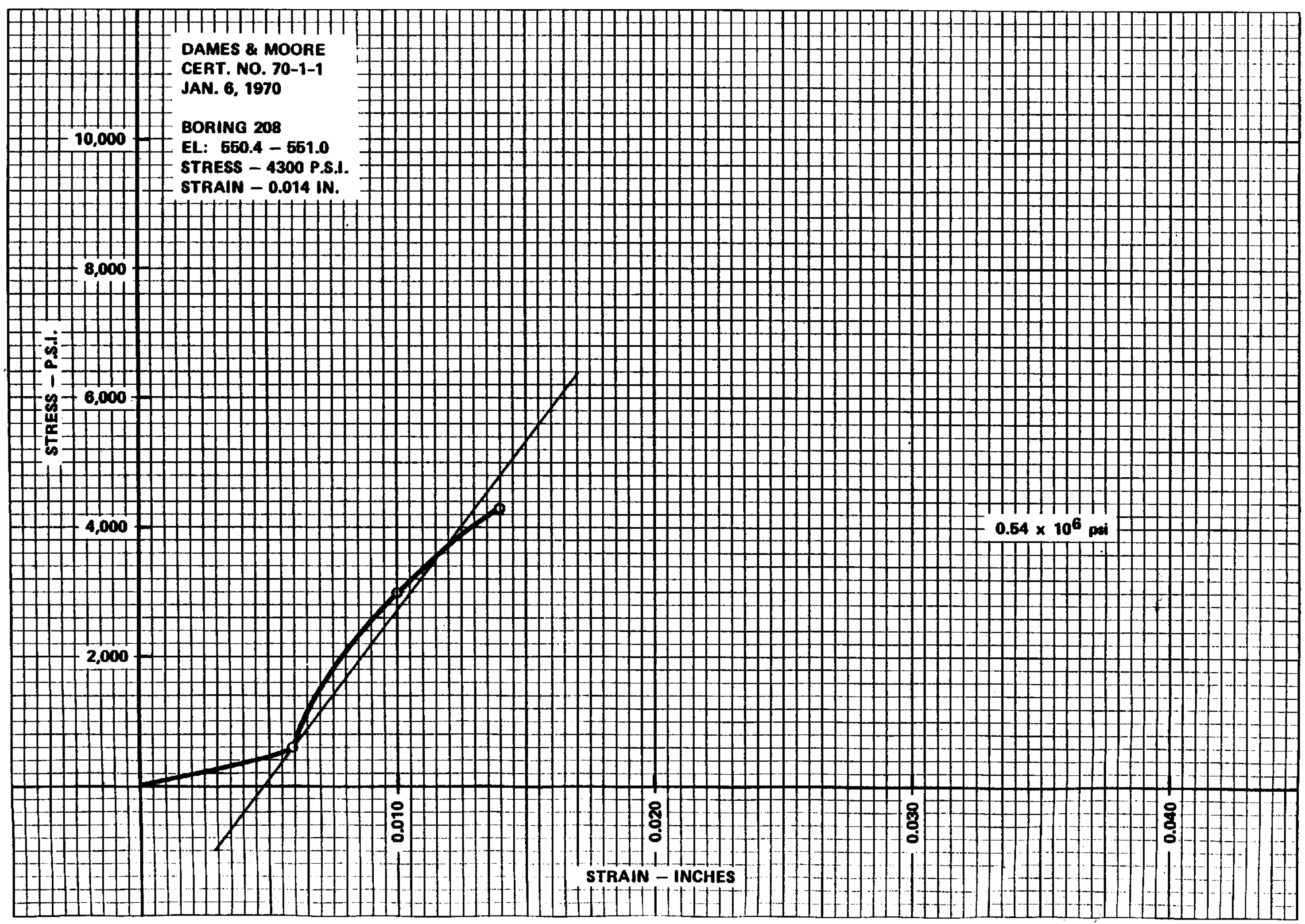
Boring No.	Sample Elev.	Diameter	Height	Area Sq./In.	Weight	Unit Wt. Lb. ft.^{3}	Gross Load	P.S.I.	PSF
201	514.8/ -513.9	2.050	4.269	3.301	1.231	151.0	29,700	9,000	1.29×10^6
201	492.0/ -491.6	2.050	4.324	3.301	1.400	169.5	37,400	11,300	1.62×10^6
202	515.3/ -514.8	2.040	4.282	3.269	1.185	146.3	32,000	9,800	1.41×10^6
203	507.5/ -506.9	2.051	4.265	3.304	1.257	154.2	30,000	9,100	1.31×10^6
211	532.9/ -531.8	2.050	4.315	3.301	1.205	146.2	19,400	5,900	0.85×10^6
213	543.8/ -543.1	2.050	4.312	3.301	1.230	149.3	18,700	5,700	0.82×10^6
208	551.0/ -550.4	2.050	4.343	3.301	1.203	145.0	14,200	4,300	0.62×10^6
210	546.5/ -545.5	1.862	4.256	2.723	1.028	153.3	22,700	6,900	0.99×10^6
211	549.2/ -548.7	2.050	4.272	3.301	1.392	170.6	62,200	18,800	2.70×10^6

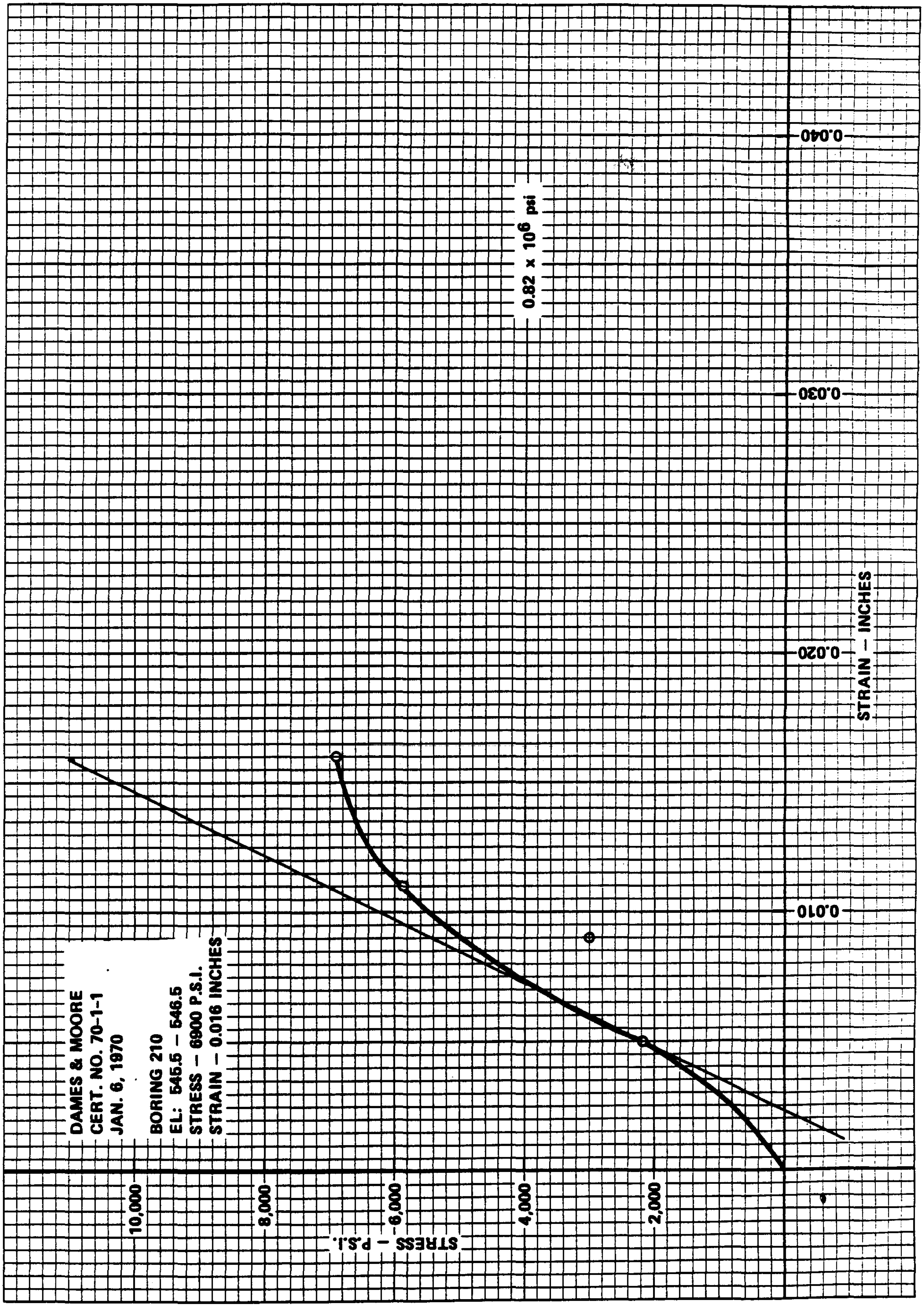

13 x 10^5 psi
E = STRESS / STRAIN
10,000
8,000
6,000
4,000
2,000
DAMES & MOORE
CERT. NO. 70-1-1
JAN. 6, 1970
BORING 201
EL. 513.8 – 514.8
STRESS – 9000 P.S.I.
STRAIN – 0.026 IN.
STRESS – P.S.I.
8000
.01
8 x 10^3 x 10^3
6.8 x 10^6 psi
0.8 x 10^6 psi
0.010
0.020
0.030
0.040
STRAIN – INCHES

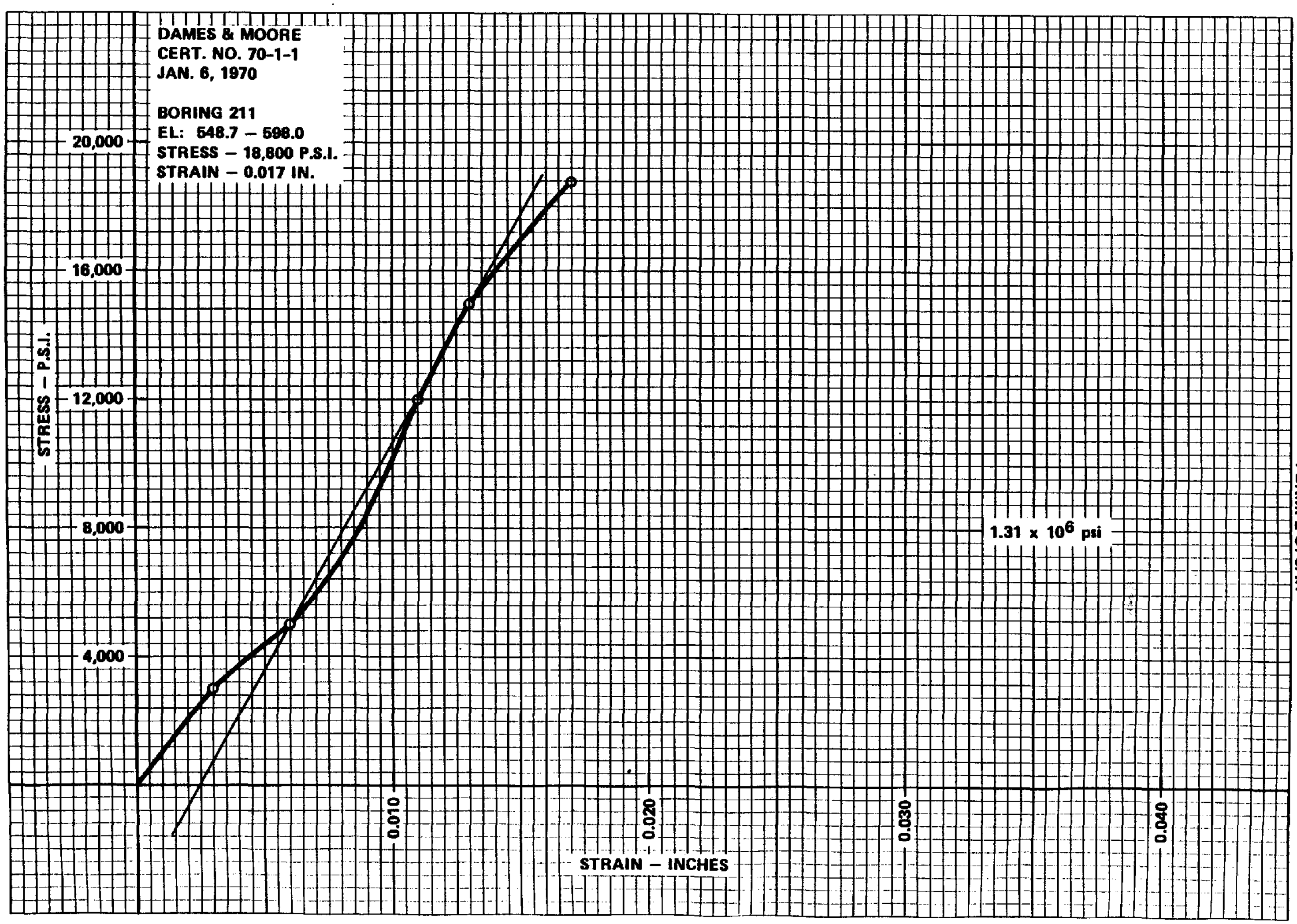

DAMES & MOORE
CERT. NO. 70-1-1
JAN. 6, 1970
BORING 201
EL. 491.6 — 492.0
STRESS — 11,300 P.S.I.
STRAIN — 0.017 IN.
1.0 x 10^6 psi
STRAIN — INCHES
0.010
0.020
0.030
0.040
STRESS — P.S.I.
10,000
8,000
6,000
4,000
2,000

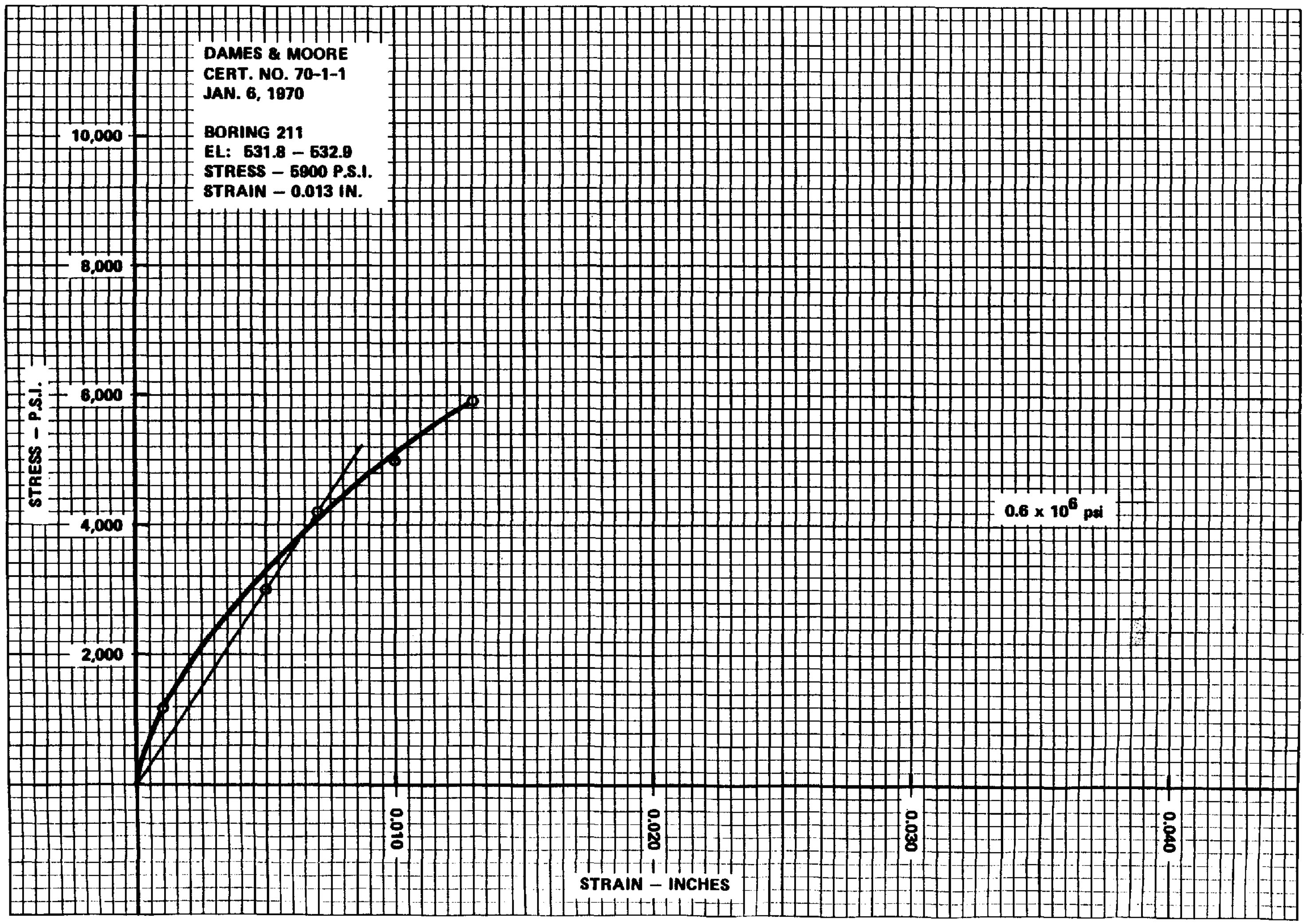

0.975 x 10^6 psi
0.040
0.030
0.020
0.010
STRAIN — INCHES
DAMES & MOORE
CERT. NO. 70-1-1
JAN. 6, 1970
BORING 202
EL: 514.8 — 515.3
STRESS — 9,800 P.S.I.
STRAIN — 0.0205 IN.
10,000
8,000
6,000
4,000
2,000
STRESS — P.S.I.

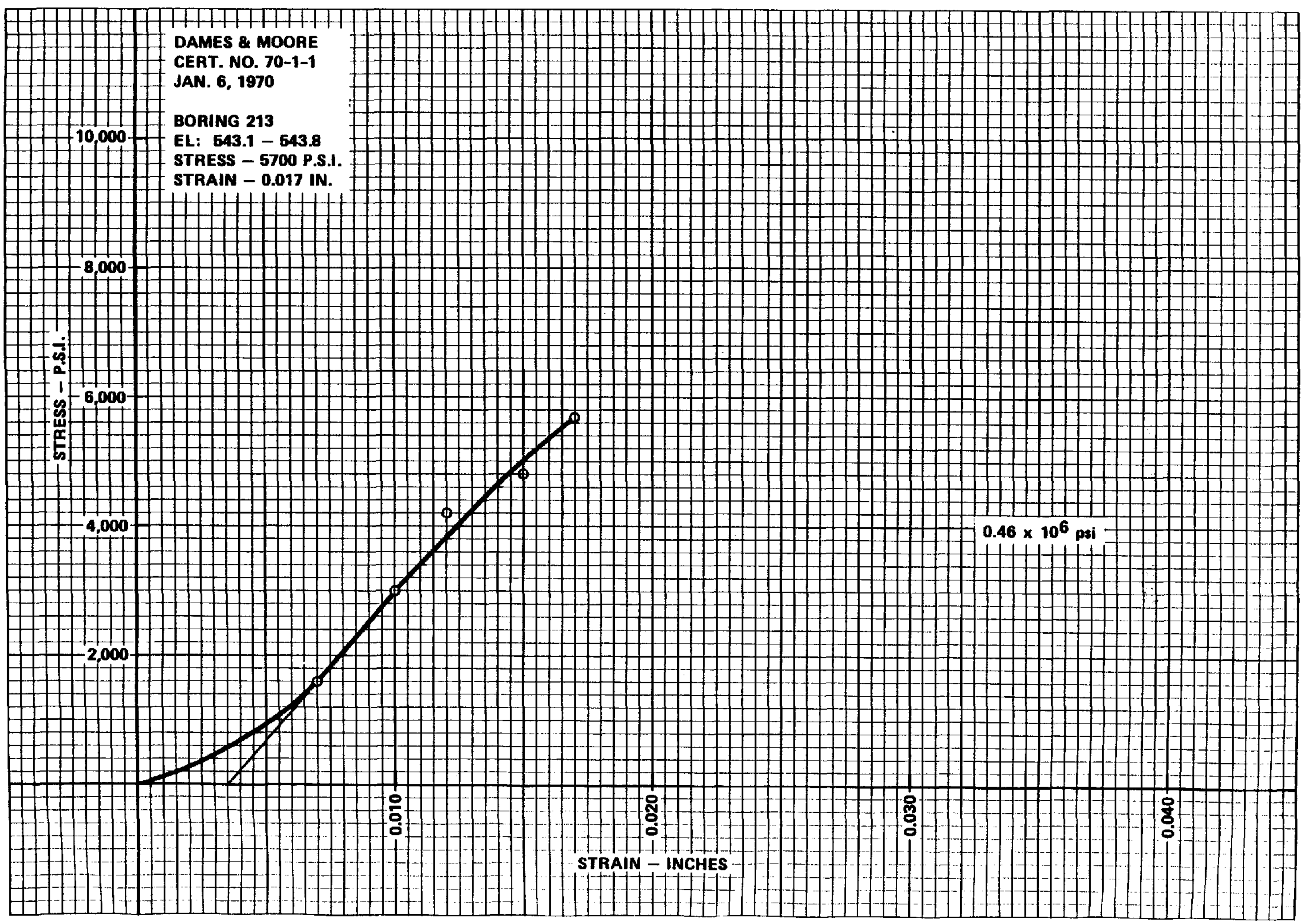

DAMES & MOORE
CERT. No. 70-1-1
JAN. 6, 1969
BORING 203
EL: 506.9 – 507.5
STRESS – 9,100 P.S.I.
STRAIN – 0.020 IN.
10,000
8,000
6,000
4,000
2,000
STRESS – P.S.I.
0.010
0.020
0.030
0.040
STRAIN – INCHES
0.63 x 10^6 psi


DAMES & MOORE
CERT. NO. 70-1-1
JAN. 6, 1970
BORING 208
EL: 550.4 – 551.0
STRESS – 4300 P.S.I.
STRAIN – 0.014 IN.
10,000
8,000
6,000
4,000
2,000
STRESS – P.S.I.
0.010
0.020
0.030
0.040
STRAIN – INCHES
0.54 x 10^6 psi


DAMES & MOORE
CERT. NO. 70-1-1
JAN. 6, 1970
BORING 210
EL: 545.5 – 546.5
STRESS – 6900 P.S.I.
STRAIN – 0.016 INCHES
0.82 x 10^6 psi
STRAIN – INCHES
0.010
0.020
0.030
0.040
STRESS – P.S.I.
10,000
8,000
6,000
4,000
2,000


DAMES & MOORE
CERT. NO. 70-1-1
JAN. 6, 1970
BORING 211
EL: 548.7 – 598.0
STRESS – 18,800 P.S.I.
STRAIN – 0.017 IN.
20,000
16,000
12,000
8,000
4,000
STRESS – P.S.I.
0.010
0.020
0.030
0.040
STRAIN – INCHES
1.31 x 10^6 psi


DAMES & MOORE
CERT. NO. 70-1-1
JAN. 6, 1970
BORING 211
EL: 531.8 – 532.9
STRESS – 5900 P.S.I.
STRAIN – 0.013 IN.
10,000
8,000
6,000
4,000
2,000
STRESS – P.S.I.
0.010
0.020
0.030
0.040
STRAIN – INCHES
0.6 x 10^6 psi


DAMES & MOORE
CERT. NO. 70-1-1
JAN. 6, 1970
BORING 213
EL: 543.1 – 543.8
STRESS – 5700 P.S.I.
STRAIN – 0.017 IN.
10,000
8,000
6,000
4,000
2,000
STRESS – P.S.I.
0.46 x 10^6 psi
0.010
0.020
0.030
0.040
STRAIN – INCHES

CHAPTER 3: DESIGN OF STRUCTURES, COMPONENTS, EQUIPMENT, AND SYSTEMS

3.1 CONFORMANCE WITH GENERAL DESIGN CRITERIA

3.1.1 Summary Description

This section contains an evaluation of the design basis of Fermi 2 as measured against the General Design Criteria (GDC) for Nuclear Power Plants, Appendix A of 10 CFR 50, effective May 21, 1971, and subsequently amended July 7, 1971. The General Design Criteria, which are divided into six groups, are intended to establish minimum requirements for the design of nuclear power plants.

The GDC were not written specifically for the BWR; rather, they were intended as a guide to the design of all water-cooled nuclear power plants. As a result, the criteria are generic in nature and subject to a variety of interpretations. For this reason, there are some cases where conformance to a particular criterion is not directly assessable. In these cases, the conformance of plant design to the interpretation of the criterion is discussed. In the discussion of each criterion, the section of the UFSAR where more detailed information is presented to demonstrate compliance with or exception to the criterion is referenced.

Based on the content herein, Edison concludes that the design of Fermi 2 is in accordance with and satisfies the GDC.

3.1.2 Criterion Conformance

3.1.2.1 Group I, Overall Requirements (Criteria 1-5)

3.1.2.1.1 Criterion 1 - Quality Standards and Records

Structures, systems, and components important to safety shall be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed. Where generally recognized codes and standards are used, they shall be identified and evaluated to determine their applicability, adequacy, and sufficiency and shall be supplemented or modified as necessary to assure a quality product in keeping with the required safety function. A Quality Assurance Program shall be established and implemented in order to provide adequate assurance that these structures, systems, and components will satisfactorily perform their safety functions. Appropriate records of the design, fabrication, erection, and testing of structures, systems, and components important to safety shall be maintained by or under the control of the nuclear power unit licensee throughout the life of the unit.

Criterion 1 Conformance - Structures, systems, and components important to safety are listed in Table 3.2-1. The total Quality Assurance Program is described in Chapter 17 and is applied to the items contained in Table 3.2-1. The Quality Assurance Program ensures sound engineering in all phases of design and construction through conformity to regulatory requirements and design bases described in the license application. In addition, the program ensures adherence to specified standards in fabrication and construction. It also includes the observance of proper preoperational and operational testing and maintenance procedures. Documentation of the foregoing is provided by keeping appropriate records. The total

Quality Assurance Program of Edison and its principal contractors is responsive to and satisfies the intent of the quality-related requirements of 10 CFR 50, including Appendix B.

Structures, systems, and components are first classified in Section 3.2 with respect to their location and service, and their relationship to the safety function to be performed. Recognized codes and standards are applied to the equipment in these classifications, as necessary, to ensure a quality product in keeping with the required safety function.

Documents are maintained that demonstrate that all the requirements of the Quality Assurance Program are being satisfied. This documentation shows that appropriate codes, standards, and regulatory requirements are observed, specified materials are used, correct procedures are used, qualified personnel are provided, and the finished parts and components meet the applicable specifications for safe and reliable operation. These records are available so that any desired item of information is retrievable for reference. These records will be maintained in accordance with the guidance of ANSI N45.2.9-1974, Requirements for Collection, Storage, and Maintenance of Quality Assurance Records for Nuclear Power Plants, and Regulatory Guide 1.88, Revision 2, as addressed in Appendix A.

The detailed Quality Assurance Program set forth in Chapter 17, and developed by Edison and its contractors, satisfies the requirements of Criterion 1.

For further discussion, see the following:

a. Chapter 3 - Design of Structures, Components, Equipment, and Systems

b. Section 4.2 - Fuel System Design

c. Section 5.2 - Integrity of Reactor Coolant Pressure Boundary

d. Section 5.4 - Reactor Pressure Vessel and Appurtenances

e. Section 5.5 - Component and Subsystem Design

f. Section 6.2 - Containment Systems

g. Section 6.3 - Emergency Core Cooling System

h. Section 7.2 - Reactor Protection System

i. Section 7.3 - Engineered Safety Feature Systems

j. Section 7.6 - Other Systems Required for Safety and Power Generation

k. Chapter 8 - Electrical Power Systems

l. Chapter 12 - Radiation Protection.

3.1.2.1.2 Criterion 2 - Design Bases for Protection Against Natural Phenomena

Structures, systems, and components important to safety shall be designed to withstand the effects of natural phenomena such as earthquakes, tornados, hurricanes, floods, tsunami, and seiches without loss of capability to perform their safety functions. The design bases for these structures, systems, and components shall reflect: (1) appropriate consideration of the most severe of the natural phenomena that have been historically reported for the site and surrounding area, with sufficient margin for the limited accuracy, quantity and period of time in which the historical data have been accumulated; (2) appropriate combinations of the effects of normal and accident conditions with the effects of the natural phenomena; and (3) the importance of the safety functions to be performed.

Criterion 2 Conformance - The design bases enumerated in this criterion are incorporated into the design of structures, systems, and components of Fermi 2. Among the natural phenomena considered are wind and tornado loadings, including static and dynamic water level loadings caused by floods, hurricanes, and other severe storms with wave runup effects; and seismic loadings. In each case the most severe of these phenomena is used as the design basis, together with appropriate combinations of normal and accident conditions. These design bases are developed from detailed analysis of the occurrence and history of these phenomena in the area surrounding the plant location. The method of incorporating these effects is discussed later in Chapter 3. The natural phenomena of the area are discussed in Chapter 2.

A detailed discussion can be found in the following:

a. Section 2.3 - Meteorology
b. Section 2.4 - Hydrological Engineering
c. Section 2.5 - Geology and Seismology
d. Section 3.2 - Classification of Structures, Components, and Systems
e. Section 3.3 - Wind and Tornado Loadings
f. Section 3.4 - Water Level (Flood) Design
g. Section 3.5 - Missile Protection
h. Section 3.7 - Seismic Design
i. Section 3.8 - Design of Category I Structures
j. Section 3.9 - Mechanical Systems and Components
k. Section 3.10 - Seismic Design of Category I Instrumentation and Electrical Equipment.

3.1.2.1.3 Criterion 3 - Fire Protection

Structures, systems, and components important to safety shall be designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions. Noncombustible and heat-resistant materials shall be used wherever practical throughout the unit, particularly in locations such as the containment and main control room. Fire detection and fighting systems of appropriate capacity and capability shall be provided and designed to minimize the adverse effects of fires on structures, systems, and components important to safety. Fire-fighting systems shall be designed to assure that their rupture or inadvertent operation does not significantly impair the safety capability of these structures, systems, and components.

Criterion 3 Conformance - The design of Fermi 2 is in full compliance with this criterion. The use of noncombustible and heat-resistant materials is maximized. Fire protection and detection measures of appropriate capacities are incorporated in the design, with particular emphasis given to areas containing safety systems, such as the Control Center, and components of engineered safety feature (ESF) systems. The fire protection system (FPS) does not, by rupture or inadvertent operation, prevent the safe shutdown of the plant. The FPS, described in Subsection 9.5.1, provides an adequate supply of water and/or chemicals to fire-fighting stations throughout the plant. The FPS meets the requirements of the applicable laws, codes, and requirements of the State of Michigan, and adheres to the NFPA standards and NEPIA recommendations (Subsection 9.5.1).

A diesel-driven fire pump and a motor-driven fire pump are each independently capable of satisfying plant fire-fighting water requirements. Standby carbon dioxide and Halon systems are provided for fire protection in the diesel generator area and electrical areas in the auxiliary building. The main and auxiliary transformers are protected with deluge fire-fighting equipment. In addition, portable fire extinguishers, hose reels, and hydrants are strategically located throughout the plant area.

Hydrogen, lubrication, and fuel-oil storage facilities are located, designed, and protected to minimize both the probability and effects of fire and explosion. The FPS is discussed in detail in Subsection 9.5.1.

Further discussion of fire protection can be found in the following:

a. Section 6.4 - Habitability Systems

b. Section 8.3 - Onsite Power Systems

c. Section 9.5 - Other Auxiliary Systems

d. Section 14.1 - Test Program.

3.1.2.1.4 Criterion 4 - Environmental and Missile Design Bases

Structures, systems, and components important to safety shall be designed to accommodate the effects of, and to be compatible with, the environmental conditions associated with normal operation, maintenance, testing and postulated accidents, including loss-of-coolant accidents. These structures, systems, and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit.

Criterion 4 Conformance - Safety-related systems, components, and structures have been designed to accommodate all normal or routine environmental conditions, and conditions associated with postulated accidents including a LOCA. Safety-related systems and components are designed to function properly in the most severe environmental conditions in which their functions are required.

Analyses are performed to determine the effects of missiles, pipe whip, and the jet force of fluid discharge, both inside and outside the primary containment. Where required, restraints, missile shields, additional separation, or additional structural strength are incorporated into the design to ensure proper functioning of safety-related plant features.

Further discussion of environmental and missile design bases can be found in Sections 3.3 through 3.12, and particularly in the following sections.

a. Section 3.5 - Missile Protection

b. Section 3.6 - Protection Against Dynamic Effects Associated with the Postulated Rupture of Piping

c. Section 3.11 - Environmental Design of Mechanical and Electrical Equipment

d. Section 10.2 - Turbine Generator.

3.1.2.1.5 Criterion 5 - Sharing of Structures, Systems, and Components

Structures, systems, and components important to safety shall not be shared between nuclear power units unless it is shown that their ability to perform their functions, including, in the event of an accident in one unit, an orderly shutdown and cooldown of the remaining units, is not significantly impaired by the sharing.

Criterion 5 Conformance - There are no safety-related systems or components that are shared with another unit.

3.1.2.2 Group II, Protection by Multiple Fission Product Barriers (Criteria 10-19)

3.1.2.2.1 Criterion 10 - Reactor Design

The reactor core and associated coolant, control, and protection systems shall be designed with appropriate margin to assure that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences.

Criterion 10 Conformance - The reactor core components consist of fuel assemblies, control rods, in-core ion chambers, and related items. The mechanical design is based on conservative application of stress limits, operating experience, and experimental test results. The fuel is designed to provide high integrity over a complete range of power levels including transient conditions. The core is sized with sufficient heat-transfer area and coolant flow to ensure that there is no fuel damage under normal conditions or anticipated operational occurrences.

The reactor protection system (RPS) is designed to monitor certain reactor parameters, sense abnormalities, and scram the reactor, thereby preventing fuel damage when trip points are exceeded. Scram trip setpoints are selected on the basis of operating experience and safety design. There is no case in which the scram trip setpoints allow the core to exceed the thermal-hydraulic safety limits. Power for the RPS is supplied by an independent high-inertia ac motor-generator set. Alternative electrical power is available to the RPS buses.

An analysis and evaluation has been made of the effects on core fuel following adverse plant operating conditions. The results of abnormal operational transients are presented in Chapter 15.

The reactor core and associated coolant, control, and protection systems are designed to ensure that the specified fuel design limits are not exceeded during conditions of normal or abnormal operation. Therefore, they meet the requirements of Criterion 10.

For further discussion, see the following:

a. Section 4.2 - Fuel System Design

b. Section 4.3 - Nuclear Design

c. Section 4.4 - Thermal and Hydraulic Design

d. Section 5.5 - Component and Subsystem Design

e. Section 6.3 - Emergency Core Cooling System

f. Section 7.2 - Reactor Protection System

g. Chapter 15 - Accident Analyses.

3.1.2.2.2 Criterion 11 - Reactor Inherent Protection

The reactor core and associated plant systems shall be designed so that in the power operating range the net effect of the prompt inherent nuclear feedback characteristics tends to compensate for a rapid increase in reactivity.

Criterion 11 Conformance - The reactor core is designed to have a reactivity response that regulates or damps changes, both in power level and in spatial distributions of power production, to a level consistent with safe and efficient operation.

The inherent dynamic behavior of the core is characterized in terms of (a) fuel temperature or Doppler coefficient, (b) moderator void coefficient, and (c) moderator temperature coefficient. The combined effects of these coefficients in the power range are termed the power coefficient. Doppler reactivity feedback occurs simultaneously with a change in fuel temperature and opposes the power change that caused it. Moreover, it contributes to system stability. Because the Doppler reactivity opposes load changes, it is desirable to maintain a large ratio between moderator void coefficient and Doppler coefficient for optimum load-following capability. The BWR has an inherently large moderator-to-Doppler coefficients ratio, which permits use of coolant flow rate for load following.

In a BWR, the moderator void coefficient is of importance while the BWR is operating at power. Nuclear design requires the void coefficient inside the fuel channel to be negative. The negative void reactivity coefficients provide an inherent negative feedback during power transients.

The reactor is designed so that the moderator temperature coefficient is small and positive in the cold condition; however, the overall power reactivity coefficient is negative.

The reactor core and associated coolant system are designed so that in the power operating range, prompt inherent dynamic behavior tends to compensate for any rapid increase in reactivity in accordance with Criterion 11.

For further discussion, see the following:

a. Section 4.3 - Nuclear Design

b. Section 4.4 - Thermal and Hydraulic Design.

3.1.2.2.3 Criterion 12 - Suppression of Reactor Power Oscillations

The reactor core and associated coolant, control, and protection systems shall be designed to assure that power oscillations which can result in conditions exceeding specified acceptable fuel design limits are not possible or can be reliably and readily detected and suppressed.

Criterion l2 Conformance - The reactor core is designed to ensure that no power oscillation will cause the fuel design limits to be exceeded. The power reactivity coefficient is the composite simultaneous effect of the fuel temperature or Doppler coefficient, moderator void coefficient, and moderator temperature coefficient, on the change in power level. It is negative and well within the range required for adequate damping of power and spatial xenon disturbances. Operating experience has shown that large BWRs are inherently stable against xenon-induced power instability. The large negative operating coefficient provides

a. Good load following with well-damped behavior and little undershoot or overshoot in the heat-transfer response

b. Load following with recirculation flow control

c. Strong damping of spatial power disturbances.

The RPS design provides protection from excessive fuel cladding temperatures and protects the nuclear system process barrier from excessive pressures that threaten the integrity of the system. Local abnormalities are sensed, and, if protection system limits are reached, corrective action is initiated through an automatic scram. High integrity of the protection system is achieved through the combination of logic arrangement, trip channel redundancy, power supply redundancy, and physical separation.

The reactor core and associated coolant, control, and protection systems are designed to suppress any power oscillations that could result in exceeding fuel design limits. These systems ensure that Criterion 12 is met.

For further discussion see the following:

a. Section 4.2 - Fuel System Design

b. Section 4.3 - Nuclear Design

c. Section 4.4 - Thermal and Hydraulic Design

d. Section 5.2 - Integrity of Reactor Coolant Pressure Boundary

e. Section 7.2 - Reactor Protection System

f. Section 7.7 - Control Systems Not Required for Safety

g. Chapter 15 - Accident Analyses.

3.1.2.2.4 Criterion 13 - Instrumentation and Control

Instrumentation shall be provided to monitor variables and systems over their anticipated ranges for normal operation, for anticipated operational occurrences, and for accident conditions as appropriate to assure adequate safety, including those variables and systems that can affect the fission process, the integrity of the reactor core, the reactor coolant pressure boundary, and the containment and its associated systems. Appropriate controls shall be provided to maintain these variables and systems within prescribed operating ranges.

Criterion 13 Conformance - The fission process is monitored and controlled for all conditions from source range through power operating range. The neutron monitoring system (NMS) detects core conditions that threaten the overall integrity of the fuel barrier caused by excess power generation and provides a signal to the RPS. Fission counters, located in the core, are used for the source range through power operating range. The detectors are located to provide maximum sensitivity to control rod movement during startup, and to provide optimum monitoring in the intermediate and power ranges.

The source range monitor (SRM) subsystem provides neutron flux information during reactor startup and low-flux-level operations. Detectors are inserted into the core for a reactor startup and withdrawn after neutron flux is indicated on the intermediate range monitor (IRM) subsystem. The SRM can provide detection of less than a 20-sec period under the worst possible startup conditions, and is capable of generating a trip signal to block rod withdrawal.

The IRM monitors neutron flux from the upper portion of the SRM to the lower portion of the power range monitor (PRM) subsystems. The IRM is capable of either generating a trip signal to block rod withdrawal or scram the reactor.

The local power range monitor (LPRM) subsystem consists of fission chambers located throughout the core, signal conditioning equipment, and trip functions. The LPRM signals are also used in the average power range monitor (APRM) subsystem, rod block monitor (RBM) subsystem, and Integrated Plant Computer System (IPCS). The RBM is designed to prevent local fuel damage as a result of a single rod withdrawal error under a condition of allowed RBM bypass.

The traversing in-core probe (TIP) subsystem provides a signal proportional to the axial neutron flux distribution of the core. This system provides a means of accurately calibrating the LPRM signal by correlation with the TIP signal.

The reactor protection system (RPS) protects the fuel barriers and the nuclear process barrier by monitoring plant parameters and causing a reactor scram when predetermined setpoints are exceeded.

The reactor manual control system (RMCS) consists of the electrical circuitry, switches, indicators, and alarm devices required for the manipulation of the control rods and surveillance equipment. Separation between the scram function and the normal rod control functions prevents failures in the reactor manual control circuitry from affecting the scram circuitry.

Reactor pressure vessel (RPV) instrumentation monitors the RPV temperatures, water levels, water flow rate, internal pressure, and water leakage detection from the top head flange. This information is used to assess conditions existing inside the RPV and to assess the physical condition of the RPV. Reactor pressure vessel temperatures are recorded on a multipoint recorder in the control center. Controlled heating and cooling rates allow thermal stress to be appropriately limited. Reactor pressure and vessel water level are also indicated in the control center, in addition to recirculation loop flow, core flow, and the differential pressure between the RPV annulus outside of the core and the core inlet plenum.

To provide protection against the consequences of accidents involving the release of radioactive materials from the fuel and nuclear system process barrier, the containment and reactor vessel isolation control system initiates automatic isolation of appropriate pipelines whenever monitored variables exceed pre-selected operational limits.

Nuclear system leakage limits are established so that appropriate action can be taken to ensure the integrity of the nuclear system process barrier. Nuclear system leakage rates classified as identified leakage rates flow to the equipment drain, and those classified as unidentified leakage rates flow to the floor drain sumps. The permissible total leakage rate limit to these sumps is based on NRC requirements. Leakage detection is in accordance with Regulatory Guide 1.45, Reactor Coolant Pressure Boundary Leakage Detection Systems. Flow integrators and recorders are used to determine the leakage by monitoring flow pumped from the drain sumps. The unidentified leakage rate as discussed in Subsection 5.2.7.4 is limited to a value that is less than the value that has been conservatively calculated to be a minimum leakage from a crack large enough to propagate rapidly. The limited leakage volume still allows time for identification and corrective action before integrity of the process barrier is threatened.

The sequence-of-events recorders receive inputs from plant variables, including the primary variables of the RPS. The inputs are scanned and monitored for change of state. The IPCS provides a quick and accurate determination of the core thermal performance. Data reduction, accounting, and logging functions of the IPCS further supplement procedural requirements for control rod manipulation during reactor startup and shutdown.

As previously indicated, adequate instrumentation is provided to monitor system variables in the reactor core, reactor coolant pressure boundary (RCPB), and reactor containment. Appropriate controls are provided to maintain the variables within the operating range and to initiate the necessary corrective action in the event of abnormal operational occurrence or accident. This arrangement of instrumentation and controls meets the requirements of Criterion 13.

For further discussion, see the following:

a. Section 4.2 - Fuel System Design

b. Section 5.2 - Integrity of Reactor Coolant Pressure Boundary

c. Section 5.5 - Component and Subsystem Design

d. Section 6.2 - Containment Systems

e. Section 7.2 - Reactor Protection System

f. Section 7.3 - Engineered Safety Feature Systems

g. Section 7.6 - Other Systems Required for Safety and Power Generation

h. Section 7.7 - Control Systems Not Required for Safety.

3.1.2.2.5 Criterion 14 - Reactor Coolant Pressure Boundary

The reactor coolant pressure boundary shall be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture.

Criterion 14 Conformance - The piping and equipment pressure parts, which extend through the outer isolation valve(s) but which are within the RCPB, are designed, fabricated, erected, and tested to provide a high degree of integrity throughout the plant lifetime. Systems and components within the RCPB are classified in Section 3.2 as Code Group A. The design requirements, codes, and standards applied to this Code Group ensure a quality product in keeping with the safety functions to be performed.

To minimize the possibility of brittle fracture within the RCPB, the fracture or notch properties and the operating temperature of ferritic materials are controlled to ensure adequate toughness when the system is pressurized to more than 20 percent of the design pressure. Subsection 5.2.4 describes the methods used to control toughness properties. Materials are to be impact tested in accordance with ASME Boiler and Pressure Vessel (B&PV) Code Section III, 1971. The fracture toughness temperature requirements of the RCPB materials also apply for the RCPB piping which penetrates the containment, up to and including the outermost isolation valve.

Piping and equipment pressure parts of the RCPB are assembled and erected by welding unless applicable codes permit flanged or screwed joints. The welding procedures used are designed to produce welds of complete fusion and free of unacceptable defects. All welding procedures, welders, and welding machine operators are qualified in accordance with the requirements of Section IX of the ASME B&PV Code for the materials to be welded.

Qualification records, including the results of procedure and performance qualification tests and identification symbols assigned to each welder, are maintained.

Subsection 5.2.3 contains the detailed material and examination requirements for the piping and equipment of the RCPB prior to and after its assembly and erection. Leakage testing and surveillance are accomplished as described in the evaluation against Criterion 30.

The design, fabrication, erection, and testing of the RCPB ensures an extremely low probability of failure or abnormal leakage, thus satisfying the requirements of Criterion 14.

For further discussion, see the following:

a. Chapter 3 - Design of Structures, Components, and Systems
b. Section 5.4 - Reactor Pressure Vessel and Appurtenances
c. Section 5.5 - Component and Subsystem Design
d. Section 5.2 - Integrity of Reactor Coolant Pressure Boundary
e. Section 15.0 - General (Accident Analyses)
f. Chapter 17 - Quality Assurance.

3.1.2.2.6 Criterion 15 - Reactor Coolant System Design

The reactor coolant system and associated auxiliary, control, and protection systems shall be designed with sufficient margin to assure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operation, including anticipated operational occurrences.

Criterion 15 Conformance - The reactor coolant system consists of the RPV and appurtenances, the reactor circulation system, the nuclear system pressure relief system, the main steam lines, the reactor core isolation cooling (RCIC) system, and the residual heat removal (RHR) system. These systems are designed, fabricated, erected, and tested to meet stringent quality requirements and appropriate codes and standards that ensure high integrity of the RCPB throughout the plant lifetime. The reactor coolant system is designed and fabricated to meet the requirements of the ASME B&PV Code Section III, as required by 10 CFR 50.55a, including special waiver provisions.

The auxiliary, control, and protection systems associated with the reactor coolant system act to provide sufficient margin to ensure that the design conditions of the RCPB are not exceeded during any condition of normal operation, including anticipated operational occurrences. As described in the evaluation of Criterion 13, instrumentation is provided to monitor essential variables to ensure that they are within prescribed operating limits. If the monitored variables exceed their predetermined settings, the auxiliary control and protection systems automatically respond to maintain the variables and systems within allowable design limits.

An example of the integrated protective action scheme, which provides sufficient margin to ensure that the design conditions of the RCPB are not exceeded, is the automatic initiation of the nuclear system pressure relief system on receipt of an overpressure signal. To accomplish overpressure protection, a number of pressure-operated relief valves are provided that can discharge steam from the nuclear system to the suppression pool. The nuclear system pressure relief system also provides automatic depressurization of the nuclear system in the event of a LOCA in which the RPV is not depressurized by the accident. The depressurization of the nuclear system in this situation allows operation of the low-pressure emergency core cooling systems (ECCS) to supply enough cooling water to adequately cool the core. In a similar manner, other auxiliary, control, and protection systems provide assurance that the design conditions of the RCPB are not exceeded during any conditions of normal operation, including anticipated operational occurrences.

The application of appropriate codes, standards, and high quality requirements to the reactor coolant system and the design features of its associated auxiliary, control, and protection systems, ensures that the requirements of Criterion 15 are satisfied.

For further discussion, see the following:

a. Chapter 3 - Design of Structures, Components, Equipment, and Systems

b. Section 5.2 - Integrity of Reactor Coolant Pressure Boundary

c. Section 5.4 - Reactor Pressure Vessel and Appurtenances

d. Section 5.5 - Component and Subsystem Design

e. Section 6.3 - Emergency Core Cooling System

f. Section 7.6 - Other Systems Required for Safety and Power Generation

g. Section 15.0 - General (Accident Analyses).

3.1.2.2.7 Criterion 16 - Containment Design

Reactor containment and associated systems shall be provided to establish an essentially leaktight barrier against the uncontrolled release of radioactivity to the environment and to assure that the containment design conditions important to safety are not exceeded for as long as postulated accident conditions require.

Criterion 16 Conformance - The primary containment, which includes the drywell and suppression pool, has been designed, fabricated, and erected so as to accommodate, without failure, the pressures and temperatures resulting from the double-ended rupture (or equivalent failure) of any coolant pipe within the primary containment. The primary containment encloses the reactor coolant system and associated instrumentation and controls. During accident conditions, valves which isolate systems that penetrate the primary containment become part of the containment barrier.

The secondary containment, a building that contains the primary containment as well as portions of the reactor process systems and refueling facilities, is maintained at a negative pressure under accident conditions to ensure against leakage. The interior atmosphere is processed to control emissions to the environs so that offsite dose levels are maintained well below the requirements of 10 CFR 100 or 10 CFR 50.67.

Periodic testing and inspection verify the integrity of the reactor containment. Further information on the reactor containment and associated systems can be found in the following:

a. Section 3.8 - Design of Category I Structures

b. Section 6.2 - Containment Systems

c. Section 14.1 - Test Program.

3.1.2.2.8 Criterion 17 - Electric Power Systems

An onsite electric power system and an offsite electric power system shall be provided to permit functioning of structures, systems, and components important to safety. The safety function for each system (assuming the other system is not functioning) shall be to provide sufficient capacity and capability to assure that (1) specific acceptable fuel design limits and design conditions of the RCPB are not exceeded as a result of anticipated operational occurrences, and (2) the core is cooled, and containment integrity and other vital functions are maintained in the event of postulated accidents.

The onsite electric power supplies, including the batteries, and the onsite electric distribution system, shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure.

Electric power from the transmission network to the onsite electric distribution system shall be supplied by two physically independent circuits (not necessarily on separate rights of way) designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accidents and environmental conditions. A switchyard common to both circuits is acceptable. Each of these circuits shall be designed to be available in sufficient time following a loss of all onsite alternating current power supplies and the other offsite electric power circuit, to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded. One of these circuits shall be designed to be available within a few seconds following a loss of coolant accident to assure that core cooling, containment integrity, and other vital safety functions are maintained. Provisions shall be included to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the onsite electrical power supplies.

Criterion 17 Conformance - The Fermi 2 onsite power system has four separate emergency diesel generators (EDGs), each of which supplies a separate bus. There are two independent and redundant divisions of ESF, each of which can be powered by a division pair of the

EDGs through their associated buses. The diesel generators are of sufficient capacity to provide minimum essential emergency loads, including a single failure, such as the loss of a diesel generator or essential bus. The diesel generators are located in a Category I structure with fire-barrier separation between diesel generators.

Also provided are separate battery power sources to supply power to the separate and redundant ESF dc loads and controls. The battery system consists of two redundant 260/130-V and 24/48-V supplies and chargers. The chargers can be supplied from offsite power or the EDGs, in emergency situations.

The offsite power sources consist of 120-kV and 345-kV independent systems with associated buses and transformers. These supply power to the 4160-V buses. The redundancy of buses within the plant and the division of critical loads between buses yield a system of high reliability and integrity.

The EDGs and batteries have been designed to allow periodic testing and inspection without interruption of normal plant operation. Fault detection and isolation provisions prevent the propagation of faults to alternative systems.

With the above electric system design, Criterion 17 is believed to be satisfied.

Further information on the electric power systems can be found in the following:

a. Section 3.10 - Seismic Design of Category I Instrumentation and Electrical Equipment

b. Chapter 8 - Electric Power.

3.1.2.2.9 Criterion 18 - Inspection and Testing of Electrical Power Systems

Electrical power systems important to safety shall be designed to permit appropriate periodic inspection and testing of important areas and features such as wiring, insulation, connections, and switchboards, to assess the continuity of the systems and the condition of their components. The system shall be designed with a capability to test periodically (1) the operability and functional performance of the components of the systems, such as onsite power sources, relays, switches, and buses, and (2) the operability of the systems as a whole, and, under conditions as close to design as practical, the full operation sequence that brings the systems into operation, including operation of applicable portions of the protection system, and the transfer of power among the nuclear power unit, the offsite power system, and the onsite power system.

Criterion 18 Conformance - Provisions are made in the design of the offsite and onsite power systems for the inspection and testing of appropriate areas of the system. The EDG system can be tested without interruption of normal operations. The battery system is also designed for periodic testing. The offsite power systems are normally operating; therefore, the status of both the offsite systems and the onsite systems is indicated in the main control room. All systems are designed for periodic inspection. Further information can be found in the following:

a. Chapter 8 - Electric Power

b. Section 14.1 - Test Program.

3.1.2.2.10 Criterion 19 - Main Control Room

A control room shall be provided from which actions can be taken to operate the nuclear power unit safely under normal conditions and to maintain it in a safe condition under accident conditions, including loss-of-coolant accidents. Adequate radiation protection shall be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent to any part of the body, for the duration of the accident.

Equipment at appropriate locations outside the control room shall be provided (1) with a design capability for prompt hot shutdown of the reactor, including necessary instrumentation and controls to maintain the unit in a safe condition during hot shutdown, and (2) with a potential capability for subsequent cold shutdown of the reactor through the use of suitable procedures.

Holders of operating licenses using an alternative source term under § 50.67, shall meet the requirements of this criterion, except that with regard to control room access and occupancy, adequate radiation protection shall be provided to ensure that radiation exposures shall not exceed 0.05 Sv (5 rem) total effective dose equivalent (TEDE) as defined in § 50.2 for the duration of the accident.

Criterion 19 Conformance - The design of the main control room allows continuous occupancy by operating personnel under all operating and accident conditions, including LOCA. All control stations, switches, controllers, and indicators necessary to safely operate and shut down the plant are located in the control center.

Shielding is provided to limit the exposure of control center personnel to a level significantly less than the 5 rem whole-body limit. The control center air conditioning system (CCACS) provides air filtration, recirculation, temperature, and/or humidity control, and has sufficient redundancy to ensure the availability of the system. Recirculation of main control room air is initiated upon a high radiation alarm, with makeup outside air provided to pressurize the control room and selected from the intake with the lower radiation level. Air-operated isolation and recirculation valves can be manually operated. Entrance and exit from the plant (and main control room) in emergency situations are controlled to limit personnel dose to less than 5 rem for the duration of the accident.

Because of the shielding and ventilation systems provided, evacuation of the main control room is a highly improbable event. If, for some reason, evacuation is required, safe shutdown of the reactor can be accomplished from a remote shutdown station. There are sufficient controls and indications at this station to bring the reactor safely to a hot shutdown condition. There is also the capability to bring the reactor to a cold shutdown condition from outside the main control room.

For use of the alternative source term under 10 CFR 50.67, the exposure limit is 5 rem TEDE. Specific accidents that apply the alternative source term per 10 CFR 50.67, and thus utilize the 5 rem TEDE limit, are identified in Section 1.2.1.2.2.3.

Further discussions concerning this criterion are in the following:

a. Section 6.4 - Habitability Systems

b. Section 7.5 - Safety-Related and Power Generation Display Instrumentation

c. Section 9.4 - Air Conditioning, Heating, Cooling, and Ventilation Systems

d. Section 12.1 - Shielding

e. Chapter 15 - Accident Analyses.

3.1.2.3 Group III, Protection and Reactivity Control Systems (Criteria 20 - 29)

3.1.2.3.1 Criterion 20 - Protection System Functions

The protection system shall be designed (1) to initiate automatically the operation of appropriate systems including the reactivity control systems, to assure that specified acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences and (2) to sense accident conditions and to initiate the operation of systems and components important to safety.

Criterion 20 Conformance - The RPS is designed to provide timely protection against the onset and consequences of conditions that threaten the integrity of the fuel barrier and the nuclear system process barrier. Fuel damage is prevented by initiation of an automatic reactor shutdown if monitored nuclear system variables exceed preestablished limits of anticipated operational occurrences. Scram trip settings are selected and verified to be far enough above or below operating levels so as to provide proper protection but not be subject to spurious scrams. The RPS includes the motor-generator power system, sensors, relays, bypass circuitry, and switches that signal the control rod system to scram. The scrams initiated by nuclear system variables, nuclear system high pressure, turbine stop valve closure, turbine control valve fast closure, and RPV low water level will prevent fuel damage following abnormal operational transients. Specifically, these process parameters initiate a scram in time to prevent the core from exceeding thermal-hydraulic safety limits during abnormal operational transients. Response by the RPS is prompt and the total scram time is short.

A fully withdrawn control rod (withdrawn to 144 in.) will traverse 90 percent of its full stroke in less than 3.5 sec, which is sufficient to ensure that acceptable fuel design limits are not exceeded.

In addition to the RPS, which provides automatic shutdown of the reactor to prevent fuel damage, protection systems are provided to sense accident conditions and initiate automatically the operation of other systems and components important to safety. Systems such as the ECCS are initiated automatically to limit the extent of fuel damage following a LOCA. Other systems automatically isolate the RPV or the containment to prevent the release of significant amounts of radioactive materials from the fuel and the nuclear system process barrier. The controls and instrumentation for the ECCS and the isolation systems are initiated automatically when monitored variables exceed preselected operational limits.

The design of the protection system satisfies the functional requirements as specified in Criterion 20.

For further discussion, see the following:

a. Section 4.2 - Fuel System Design

b. Section 5.2 - Integrity of Reactor Coolant Pressure Boundary

c. Section 5.5 - Component and Subsystem Design

d. Section 6.3 - Emergency Core Cooling System

e. Section 7.2 - Reactor Protection System

f. Section 7.3 - Engineered Safety Feature Systems

g. Section 7.6 - Other Systems Required for Safety and Power Generation

h. Chapter 15 - Accident Analyses.

3.1.2.3.2 Criterion 21 - Protection System Reliability and Testability

The protection system shall be designed for high functional reliability and inservice testability commensurate with the safety functions to be performed. Redundancy and independence designed into the protection system shall be sufficient to assure that (1) no single failure results in loss of the protection function and (2) removal from service of any component or channel does not result in loss of the required minimum redundancy unless the acceptable reliability of operation of the protection system can be otherwise demonstrated. The protection system shall be designed to permit periodic testing of its functioning when the reactor is in operation, including a capability to test channels independently to determine failures and losses of redundancy that may have occurred.

Criterion 21 Conformance - The RPS design provides assurance that, through redundancy, each channel has sufficient reliability to fulfill the single-failure criterion. No single component failure, intentional bypass, maintenance operation, calibration operation, or test to verify operational availability will impair the ability of the system to perform its intended safety function. Additionally, the system design ensures that when a scram trip point is exceeded there is a high scram probability. However, should a scram not occur, other monitored components will scram the reactor if their trip points are exceeded. There is sufficient electrical and physical separation between channels and between trip logics monitoring the same variable to prevent environmental factors, electrical transients, and physical events from impairing the ability of the system to respond correctly.

The RPS includes design features that permit inservice testing. This ensures the functional reliability of the system should the reactor variable exceed the corrective action setpoint.

The RPS initiates an automatic reactor shutdown if the monitored plant variables exceed preestablished limits. This system is arranged into two independently powered trip systems. Each trip system has three trip logics, two of which produce an automatic trip signal. The logic scheme is a one-out-of-two twice arrangement. The RPS can be tested during reactor operation. Manual scram testing is performed by operating one of the two manual scram controls. This tests one trip system. The total test verifies the ability to deenergize the scram pilot valve solenoids. Indicating lights verify that the actuator contacts have opened. This capability for a thorough testing program significantly increases reliability.

Control rod drive (CRD) operability can be tested during normal reactor operation. Drive position indicators and in-core neutron detectors are used to verify control rod movement. Each control rod can be withdrawn one notch and then reinserted to the original position without significantly perturbing the nuclear system. One control rod is tested at a time.

Control rod mechanism overdrive demonstrates rod-to-drive coupling integrity. Hydraulic supply subsystem pressures can be observed on control center instrumentation. Moreover, the hydraulic control unit scram accumulator and the scram discharge volume level are continuously monitored.

The main steam line isolation valves (MSIVs) may be tested during full reactor operation. They can be closed to 90 percent of full-open position without affecting reactor operation. If reactor power is reduced sufficiently, the isolation valves may be fully closed. Means are provided to evaluate valve stem leakage during reactor shutdown. During refueling operation, valve leakage rates can be determined.

Testing of the RHR system can be performed during normal operation. Main system pumps can be evaluated by taking suction from the suppression pool and discharging through test lines back to the suppression pool. System design and operating procedures also permit the testing of discharge valves into the reactor recirculation loops and into the containment spray headers. The low-pressure coolant injection (LPCI) mode can be tested after reactor shutdown. Each active component of the ECCS provided to operate in a design-basis accident (DBA) is designed to be operable for test purposes during normal operation of the nuclear system, except where such tests directly affect reactor operation.

The high functional reliability, redundancy, and inservice testability of the protection system satisfies the requirements specified in Criterion 21.

For further discussion, see the following:

a. Section 4.2 - Fuel System Design

b. Section 5.5 - Component and Subsystems Design

c. Section 6.2 - Containment Systems

d. Section 6.3 - Emergency Core Cooling System

e. Section 7.2 - Reactor Protection System

f. Section 7.3 - Engineered Safety Feature System

g. Section 14.1 - Test Program

h. Chapter 15 - Accident Analyses.

3.1.2.3.3 Criterion 22 - Protection System Independence

The protection system shall be designed to assure that the effects of natural phenomena, and of normal operating, maintenance, testing, and postulated accident conditions on redundant channels do not result in loss of the protection function, or shall be demonstrated to be acceptable on some other defined basis. Design techniques, such as functional diversity or diversity in component design and principles of operation, shall be used to the extent practical to prevent loss of the protection function.

Criterion 22 Conformance - The components of protection systems are designed so that the mechanical and thermal environment resulting from any emergency situation in which the components are required to function will not interfere with the operation of that function. Wiring for the RPS outside of the main control room enclosures is run in rigid metallic wireways. The RPS wireways in certain instances are shared by wiring from the corresponding containment and RPV isolation control system channel, but the wires from duplicate sensors on a common process tap are run in separate wireways. The system sensors are electrically and physically separated. Only one trip actuator logic circuit from each trip may be run in the same wireway.

The RPS is designed to permit maintenance and diagnostic work while the reactor is operating. This is accomplished without restricting the plant operation or hindering the output of these safety functions. The flexibility in design afforded the protection system allows operational system testing by the use of an independent trip channel for each trip logic input. When an essential monitored variable exceeds its scram trip point, it is sensed by at least two independent sensors in each trip system. An intentional bypass, maintenance operation, calibration operation, or test will result in a single channel trip. This leaves at least two trip channels per monitored variable capable of initiating a scram. Although each trip system contains two trip channels, only one channel in each trip system must trip to initiate a scram. Thus, the arrangement of two trip channels per trip system ensures that scram will occur as a monitored variable exceeds its scram setting.

The protection system meets the design requirements for functional and physical independence as specified in Criterion 22.

For further discussion, see the following:

a. Section 4.2 - Fuel System Design

b. Section 5.5 - Component and Subsystem Design

c. Section 7.2 - Reactor Protection System

d. Section 7.3 - Engineered Safety Feature Systems

e. Chapter 15 - Accident Analyses.

3.1.2.3.4 Criterion 23 - Protection System Failure Modes

The protection system shall be designed to fail into a safe state or into a state demonstrated to be acceptable on some other defined basis if conditions such as disconnection of the system, loss of energy (e.g., electric power, instrument air), or postulated adverse environments (e.g., extreme heat or cold, fire, pressure, steam, water, and radiation) are experienced.

Criterion 23 Conformance - The RPS is designed to fail into a safe state. Use of an independent trip channel for each trip logic allows the system to sustain any trip channel failure without preventing the other sensors monitoring the same variable from initiating a scram. A single sensor or trip channel failure will cause a channel trip. Only one trip channel in each trip system must be actuated to initiate a scram. Intentional bypass, maintenance operation, calibration operation, or test will result in a single channel trip. A failure of any one RPS input or subsystem component will produce a trip in one of two channels. This condition is insufficient to produce a reactor scram, but the system is ready to perform its protective function upon another trip.

The environmental conditions in which the instrumentation and equipment of the RPS must operate were considered in establishing the component specifications. Instrumentation specifications are based on the worst expected ambient conditions in which the instruments must operate.

The failure modes of the protection system are such that it will fail into a safe state as required by Criterion 23.

For further discussion, see the following:

a. Section 3.11 - Environmental Design of Mechanical and Electrical Equipment

b. Section 7.2 - Reactor Protection System

c. Section 7.3 - Engineered Safety Feature Systems

d. Chapter 8 - Electric Power.

3.1.2.3.5 Criterion 24 - Separation of Protection and Control Systems

The protection system shall be separated from control systems to the extent that failure of any single control system component or channel, or failure or removal from service of any single protection system component or channel which is common to the control and protection systems leaves intact a system satisfying all reliability, redundancy, and independence requirements of the protection system. Interconnection of the protection and control systems shall be limited so as to assure that safety is not significantly impaired.

Criterion 24 Conformance - There is separation between the RPS and the process control systems. Sensors, trip channels, and trip logics of the RPS are not used directly for automatic control of process systems. Therefore, failure in the controls and instrumentation of process systems cannot induce failure of any portion of the protection system. High scram reliability is designed into the RPS and hydraulic control unit for the CRD. The scram signal and the mode of operation overrides all other signals.

The containment and RPV isolation control systems are designed so that any one failure, maintenance operation, calibration operation, or test to verify operational availability will not impair the functional ability of the isolation control system to respond to essential variables. Corresponding isolation control system channels and RPS channels are not separated from each other, since common power supplies, relay cabinets, primary sensors, and wireways are used for both systems. However, because of the fail-safe design and the one-out-of-two taken twice logic, no single failure in either system can cause failure to scram or failure to isolate.

The protection system is separated from control systems as required in Criterion 24.

For further discussion, see the following:

a. Section 3.12 - Separation Criteria for Safety-Related Mechanical and Electrical Equipment

b. Section 4.2 - Fuel System Design

c. Section 7.2 - Reactor Protection System

d. Section 7.3 - Engineered Safety Feature Systems.

3.1.2.3.6 Criterion 25 - Protection System Requirements for Reactivity Control Malfunctions

The protection system shall be designed to assure that specified acceptable fuel design limits are not exceeded for any single malfunction of the reactivity control systems, such as accidental withdrawal (not ejection or dropout) of control rods.

Criterion 25 Conformance - The RPS provides protection against the onset and consequences of conditions that threaten the integrity of the fuel barrier and the nuclear system process barrier. Any monitored variable that exceeds the scram setpoint will initiate an automatic scram and not impair the remaining variables from being monitored. If one channel fails, the remaining portions of the RPS shall function.

The RMCS is designed so that no single failure can negate the effectiveness of a reactor scram. The circuitry for the RMCS is completely independent of the circuitry controlling the scram valves. This separation of the scram and normal rod control functions prevents failures in the reactor manual control circuitry from affecting the scram circuitry. Because each control rod is controlled as an individual unit, a failure that results in energizing any of the insert or withdrawal solenoid valves can affect only one control rod. The effectiveness of a reactor scram is not impaired by the malfunctioning of any one control rod.

The most serious rod withdrawal errors occur when the reactor is operating in the power region and the operator withdraws the maximum worth rod. Fuel damage in this event is prevented by the timely action of the rod block monitor, which acts to stop rod movement before safety limits are reached.

The design of the protection system ensures that specified acceptable fuel limits are not exceeded for any single malfunction of the reactivity control systems as specified in Criterion 25.

For further discussion, see the following:

a. Section 4.2 - Fuel System Design

b. Section 4.3 - Nuclear Design

c. Section 4.4 - Thermal and Hydraulic Design

d. Section 7.2 - Reactor Protection System

e. Section 7.6 - Other Systems Required for Safety and Power Generation

f. Section 7.7 - Control Systems Not Required for Safety

g. Chapter 15 - Accident Analyses.

3.1.2.3.7 Criterion 26 - Reactivity Control System Redundancy and Capability

Two independent reactivity control systems of different design principles shall be provided. One of the systems shall use control rods, preferably including a positive means for inserting the rods, and shall be capable of reliably controlling reactivity changes to assure that under conditions of normal operation, including anticipated operational occurrences, and with appropriate margin for malfunctions such as stuck rods, specified acceptable fuel design limits are not exceeded. The second reactivity control system shall be capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes (including xenon burnout) to assure acceptable fuel design limits are not exceeded. One of the systems shall be capable of holding the reactor core subcritical under all temperature conditions.

Criterion 26 Conformance - Two independent reactivity control systems using different design principles are provided. The normal method of reactivity control uses control rod assemblies that contain boron carbide (B_4C) powder in the Ultra-MD control rods, and a combination of B_4C and hafnium in the Duralife 140, Marathon C, and Ultra-HD control rods. Positive insertion of these control rods is provided by means of the control rod drive hydraulic system. The control rods are capable of reliably controlling reactivity changes during normal operation (e.g., power changes, power shaping, xenon burnout, normal startup, and shutdown) via operator-controlled insertions and withdrawals. The control rods are also capable of maintaining the core within acceptable fuel design limits during anticipated operational occurrences via the automatic scram function. The occurrence of a limited number of stuck rods during a scram will not adversely affect the capability to maintain the core within fuel design limits.

The circuitry for manual insertion or withdrawal of control rods is completely independent of the circuitry for reactor scram. This separation of the scram and normal rod control functions prevents failures in the reactor manual control circuitry from affecting the scram circuitry. Two sources of scram energy (accumulator pressure and reactor vessel pressure) provide needed scram performance over the entire range of reactor pressure (i.e., from operating conditions to cold shutdown). The design of the control rod system includes an appropriate margin for malfunctions such as stuck rods. Control rod withdrawal sequences and patterns are selected prior to operation to achieve optimum core performance and, simultaneously, low individual rod worths. Because of the carefully planned and regulated rod withdrawal sequence, prompt shutdown of the reactor can be achieved with the insertion of a small number of the many independent control rods. In the event that a reactor scram is necessary, the occurrence of a limited number of stuck rods will not hinder the capability of the control rod system to render the core subcritical.

The second independent reactivity control system is provided by the reactor coolant recirculation system. By varying reactor flow, it is possible to affect the type of reactivity changes necessary for planned, normal power changes (including xenon burnout). In the event that reactor flow is suddenly increased to its maximum value (pump runout), the core will not exceed fuel design limits because the power flow map defines the allowable initial operating states so that the pump runout will not violate these limits.

The control rod system is capable of holding the reactor core subcritical under all temperature conditions, even when the control rod of highest worth is assumed to be stuck in the fully withdrawn position. This shutdown capability of the control rod system is made possible by designing the fuel with burnable poison (Gd_2O_3) to control the high reactivity of fresh fuel. In addition, the standby liquid control system (SLCS) is available to add soluble boron to the core and render it subcritical.

The redundancy and capabilities of the reactivity control systems for Fermi 2 satisfy the requirements of Criterion 26.

For further discussion, see the following:

a. Section 4.2 - Fuel System Design

b. Section 7.4 - Systems Required for Safe Shutdown

c. Section 7.6 - Other Systems Required for Safety and Power Generation

d. Section 7.7 - Control Systems Not Required for Safety.

3.1.2.3.8 Criterion 27 - Combined Reactivity Control Systems Capability

The reactivity control system shall be designed to have a combined capability in conjunction with poison addition by the emergency core cooling system, of reliably controlling reactivity changes to assure that under postulated accident conditions and with appropriate margin for stuck rods the capability to cool the core is maintained.

Criterion 27 Conformance - There is no credible event applicable to the BWR which requires combined capability of the control rod system and poison additions by the emergency core cooling network. The primary reactivity control system for the BWR during postulated accident conditions is the control rod system. Abnormalities are sensed and, if protection system limits are reached, corrective action is initiated through an automatic scram. High integrity of the protection system is achieved through the combination of logic arrangement, trip channel redundancy, power supply redundancy, and physical separation. High reliability of reactor scram is further achieved by the separation of scram and manual control circuitry, individual control units for each control rod, and fail-safe design features built into the rod drive system. Response by the RPS is prompt, and the total scram time is short.

In reactor operation, there is a spectrum of possible control rod worths, depending on the reactor state and the control rod pattern chosen for operation. Control rod withdrawal sequences and patterns are selected to achieve optimum core performance and low individual rod worths. The RWM prevents rod withdrawal other than by the preselected rod withdrawal pattern. These functions assist the operator with an effective backup control rod monitoring routine that enforces adherence to established startup, shutdown, and low-power-level operations. As a result of this carefully planned procedure, prompt shutdown of the reactor can be achieved with scram insertion of less than half of the many independent control rods. If accident conditions require a reactor scram, this can be accomplished rapidly with appropriate margin for the unlikely occurrence of malfunctions such as stuck rods.

The reactor core design assists in maintaining the stability of the core under accident conditions as well as during power operation. Reactivity coefficients in the power range that contribute to system stability are (1) fuel temperature or Doppler coefficient, (2) moderator void coefficient, and (3) moderator temperature coefficient. The overall power reactivity coefficient is negative and provides a strong negative reactivity feedback under severe power transient conditions.

The design of the reactivity control systems ensures reliable control of reactivity under postulated accident conditions with appropriate margin for stuck rods. The capability of cooling the core is maintained under all postulated accident conditions. Thus, Criterion 27 is satisfied.

For further discussion, see the following:

a. Section 4.2 - Fuel System Design

b. Section 4.3 - Nuclear Design

c. Section 4.4 - Thermal and Hydraulic Design

d. Section 7.2 - Reactor Protection System

e. Section 7.6 - Other Systems Required for Safety and Power Generation

f. Section 7.7 - Control Systems Not Required for Safety

g. Chapter 15 - Accident Analyses.

3.1.2.3.9 Criterion 28 - Reactivity Limits

The reactivity control systems shall be designed with appropriate limits on the potential amount and rate of reactivity increase to assure that the effects of postulated reactivity accidents can neither (1) result in damage to the reactor coolant pressure boundary greater than limited local yielding nor (2) sufficiently disturb the core, its support structures or other reactor pressure vessel internals to impair significantly the capability to cool the core. These postulated reactivity accidents shall include consideration of rod ejection (unless prevented by positive means), rod dropout, steam line rupture changes in reactor coolant temperature and pressure, and cold water addition.

Criterion 28 Conformance - The control rod system design incorporates appropriate limits on the potential amount and rate of reactivity increase. Control rod withdrawal sequences and patterns are selected to achieve optimum core performance and low individual rod worths. The RWM prevents withdrawal other than by the preselected rod withdrawal pattern. These functions assist the operator with an effective backup control rod monitoring routine that enforces adherence to established startup, shutdown, and low-power-level operations control rod procedures.

The control rod mechanical design incorporates a hydraulic velocity limiter that prevents rapid rod ejection. This engineered safeguard protects against a high reactivity insertion rate by limiting the control rod velocity to less than 5 fps. Normal rod movement is limited to 6-in. increments, and the rod withdrawal rate is limited to 3 in./sec by the hydraulic valve.

The plant safety analysis (Chapter 15) provides detailed evaluations of the postulated reactivity accidents as well as abnormal operational transients. Analyses are included for rod dropout, steam line rupture, changes in reactor coolant temperature and pressure, and cold water addition. The initial conditions, assumptions, calculational models, sequences of events, and anticipated results of each postulated occurrence are covered. The results of these analyses indicate that none of the postulated reactivity transients or accidents result in damage to the RCPB. In addition, the integrity of the core, its support structures, or other RPV internals is maintained so that the capability of cooling the core is not impaired for any of the postulated reactivity accidents described in the plant safety analysis.

The design features of the reactivity control system, which limit the potential amount and rate of reactivity increase, ensure that Criterion 28 is satisfied for all postulated reactivity accidents.

For further discussion, see the following:

a. Chapter 3 - Design of Structures, Components, Equipment, and Systems

b. Section 4.2 - Fuel System Design

c. Section 4.3 - Nuclear Design

d. Subsection 4.5.3 - Control Rod Drive Housing Supports

e. Section 5.2 - Integrity of Reactor Coolant Pressure Boundary

f. Section 5.4 - Reactor Pressure Vessel and Appurtenances

g. Section 5.5 - Component and Subsystem Design

h. Section 7.6 - Other Systems Required for Safety and Power Generation

i. Chapter 15 - Accident Analyses.

3.1.2.3.10 Criterion 29 - Protection Against Anticipated Operational Occurrences

The protection and reactivity control systems shall be designed to assure an extremely high probability of accomplishing their safety functions in the event of anticipated operational occurrences.

Criterion 29 Conformance - The high functional reliability of the protection and reactivity control systems is achieved through the combination of logic arrangement, redundancy, physical and electrical independence, functional separation, fail-safe design, and inservice testability. These design features are discussed in Criteria 21, 22, 23, 24, and 26.

An extremely high probability of correct protection and reactivity control systems response to anticipated operational occurrences is maintained by a thorough program of inservice testing and surveillance. Active components can be tested or removed from service for maintenance during reactor operation without compromising the protection or reactivity control functions even in the event of a subsequent single failure. Components important to safety such as the CRD, MSIVs, and RHR pumps are tested during normal reactor operation. Functional testing and calibration schedules are developed using experience. These schedules represent optimized protection and reactivity control system reliability by considering both the failure probabilities of individual components and the reliability effects during individual component testing on the portion of the system not under going testing. The capability for inservice testing ensures the high functional reliability of protection and reactivity control systems should a reactor variable exceed the corrective action setpoint.

The capabilities of the protection and reactivity control systems to perform their safety functions in the event of anticipated operational occurrences meet the requirements of Criterion 29.

For further discussion, see the following:

a. Section 4.2 - Fuel System Design

b. Section 5.5 - Component and Subsystem Design

c. Section 6.2 - Containment Systems

d. Section 6.3 - Emergency Core Cooling System

e. Section 7.2 - Reactor Protection System

f. Section 7.3 - Engineered Safety Feature Systems

g. Chapter 15 - Accident Analyses.

3.1.2.4 Group IV, Fluid Systems (Criteria 30-46)

3.1.2.4.1 Criterion 30 - Quality of Reactor Coolant Pressure Boundary

Components which are part of the reactor coolant pressure boundary shall be designed, fabricated, erected, and tested to the highest quality standards practical. Means shall be provided for detecting and, to the extent practical, identifying the location of the source of reactor coolant leakage.

Criterion 30 Conformance - By using conservative design practices and detailed quality control procedures, the pressure-retaining components of the RCPB are designed and fabricated to retain their integrity during normal and postulated accident conditions. Accordingly, components that comprise the RCPB are designed, fabricated, erected, and tested in accordance with the recognized industry codes and standards listed in Sections 5.2, 5.4, and 5.5. Further, product and process quality planning is provided as described in Chapter 17 to ensure conformance with the applicable codes and standards and to retain appropriate documented evidence verifying compliance. Because the subject matter of this criterion deals with aspects of the RCPB, further discussion on this subject is treated in the response to Criterion 14, Reactor Coolant Pressure Boundary.

Means are provided for detecting reactor coolant leakage. The leak detection system consists of sensors and instruments to detect, annunciate, and in some cases, isolate the RCPB from potentially hazardous leaks before predetermined limits are exceeded. Small leaks are detected by temperature and pressure changes, increased condensate flow from the primary containment cooling system, increased frequency of sump pump operation, and measurement of fission product concentration. In addition to these, large leaks are detected by changes in flow rates in process lines and reactor water level. The allowable leakage rates are based on the predicted and experimentally determined behavior of cracks in pipes, the ability to make up coolant system leakage, the normally expected background leakage due to equipment design, and the detection capability of the various sensors and instruments. The total leakage rate limit is established so that, in the absence of normal ac power associated with a loss of feedwater supply, makeup capabilities are provided by the RCIC system. While the leak detection system provides protection from small leaks, the ECCS network provides protection for the complete range of discharges from ruptured pipes. Thus, protection is provided for the full spectrum of possible discharges. The RCPB and the leak detection system are designed to meet the requirements of Criterion 30.

For further discussion, see the following:

a. Chapter 3 - Design of Structures, Components, Equipment and Systems

b. Section 5.2 - Integrity of Reactor Coolant Pressure Boundary

c. Section 5.4 - Reactor Pressure Vessel and Appurtenances

d. Section 5.5 - Component and Subsystem Design

e. Section 7.6 - Other Systems Required for Safety and Power Generation

f. Section 15.0 - Accident Analyses

g. Chapter 17 - Quality Assurance.

3.1.2.4.2 Criterion 31 - Fracture Prevention of Reactor Coolant Pressure Boundary

The reactor coolant pressure boundary shall be designed with sufficient margin to assure that when stressed under operating, maintenance, testing, and postulated accident conditions (1) the boundary behaves in a nonbrittle manner and (2) the probability of rapidly propagating fracture is minimized. The design shall reflect consideration of service temperatures and other conditions of the boundary material under operating, maintenance, testing, and postulated accident conditions and the uncertainties in determining (1) material properties, (2) the effects of irradiation on material properties, (3) residual, steady-state, and transient stresses, and (4) size of flaws.

Criterion 31 Conformance - Brittle fracture control of pressure-retaining ferritic materials is provided to ensure protection against nonductile fracture. To minimize the possibility of brittle fracture failure of the RPV, it is designed to meet the requirements of ASME B&PV Code Section III, 1968 Edition through Summer 1969 addenda, which considers material properties; steady-state and transient stresses; and the size of flaws, and conforms very closely with Appendix G, which was added in the Summer 1972 Addenda (see Section 5.2 for a discussion of the degree of conformance.)

The nil ductility transition (NDT) temperature is defined as the temperature below which ferritic steel fails in a brittle rather than ductile manner. The RT_{NDT} temperature increases as a function of neutron exposure at integrated neutron exposures greater than 1.0 x 10^{17} n/cm^2 with neutrons of energies in excess of 1 MeV. Since the material RT_{NDT} temperature dictates the minimum operating temperature at which the reactor vessel can be pressurized, it is desirable for the NDT temperature to be low.

The reactor assembly design provides an annular space from the outermost fuel assemblies to the inner surface of the RPV that serves to attenuate the fast neutron flux incident upon the reactor vessel wall. This annular volume contains the core shroud, jet pump assemblies, and reactor coolant. Assuming plant operation at rated power, and end-of-life (EOL) cumulative Effective Full Power Years (EFPY) of 52 EFPY, the maximum fast neutron fluence at the inner surface of the RPV is calculated to be 1.03 x 10^{18} n/cm^2 (fast neutron fluence consists of neutrons having energies greater than 1 MeV) as detailed in Table 4.3-2. EOL RT_{NDT} temperature as calculated from the EOL fluence and chemical composition indicates a substantial margin against the occurrence of brittle fracture. For hydrostatic test, the RPV will not be pressurized until the RPV temperature exceeds the RT_{NDT} by at least 60°F

The RCPB piping, pumps, and valves are designed, maintained, and tested such that adequate assurance is provided that the boundary will behave in a nonbrittle manner throughout the life of the plant.

For further discussion, see the following:

a. Chapter 3 - Design of Structures, Components, Equipment, and Systems

b. Section 5.2 - Integrity of Reactor Coolant Pressure Boundary

c. Section 5.4 - Reactor Pressure Vessel and Appurtenances.

3.1.2.4.3 Criterion 32 - Inspection of Reactor Coolant Pressure Boundary

Components which are part of the reactor coolant pressure boundary shall be designed to permit (1) periodic inspection and testing of important areas and features to assess their structural and leaktight integrity, and (2) an appropriate material surveillance program for the reactor pressure vessel.

Criterion 32 Conformance - The RPV design and engineering effort includes provisions for inservice inspection. Removable plugs in the sacrificial shield and/or removable panels in the insulation provide access for examination of the vessel and its appurtenances. In addition, all of the remaining portion of the RCPB is provided with removable insulation. Inspection of the RCPB is in accordance with the ASME B&PV Code Section XI. The Inservice Inspection Plan, access provisions, and areas of restricted access are defined in Section 5.2.

Reactor pressure vessel material surveillance samples are located within the RPV to enable periodic monitoring of material properties with exposure. The program includes specimens of the base metal, heat-affected zone metal, and weld material. The samples are placed near the core midplane to obtain maximum exposures. Tests include tensile and impact testing. The test program is in accordance with ASTM El85-73 and the appropriate requirements of 10 CFR 50, Appendixes G and H. Subsequent to developing this surveillance program, the BWRVIP developed an integrated surveillance program (ISP) which replaces the Fermi specific surveillance program. This program is described in section 5.2.4.4.3.

The plant testing and inspection programs ensure that the requirements of Criterion 32 will be met.

For further discussion, see the following:

a. Chapter 3 - Design of Structures, Components, Equipment, and Systems

b. Section 5.2 - Integrity of Reactor Coolant Pressure Boundary

c. Section 5.4 - Reactor Pressure Vessel and Appurtenances

d. Section 5.5 - Component and Subsystem Design

e. Section 14.1 - Test Program.

3.1.2.4.4 Criterion 33 - Reactor Coolant Makeup

A system to supply reactor coolant makeup for protection against small breaks in the reactor coolant pressure boundary shall be provided. The system safety function shall be to assure that specified acceptable fuel design limits are not exceeded as a result of reactor coolant loss due to leakage from the reactor coolant pressure boundary and rupture of small piping or other small components which are part of the boundary. The system shall be designed to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished using the piping, pumps, and valves used to maintain coolant inventory during normal reactor operation.

Criterion 33 Conformance - Means provided for detecting reactor coolant leakage are discussed in the conformance to Criterion 30. As stated, the RCIC system provides makeup for small leaks, and the ECCS provides core cooling for the complete range of discharges from ruptured pipes. Protection is provided for the full spectrum of possible discharges to the extent that fuel clad temperature limits are not exceeded utilizing either onsite or offsite redundant power sources.

The plant is designed to provide ample reactor coolant makeup for protection against small leaks in the RCPB for anticipated operational occurrences and postulated accident conditions. The design of these systems meets the requirements of Criterion 33.

For further discussion, see the following:

a. Section 5.2 - Integrity of Reactor Coolant Pressure Boundary

b. Section 5.6 - Instrumentation Requirements

c. Section 6.3 - Emergency Core Cooling System

d. Section 7.6 - Other Systems Required for Safety and Power Generation.

3.1.2.4.5 Criterion 34 - Residual Heat Removal

A system to remove residual heat shall be provided. The system safety function shall be to transfer fission product decay heat and other residual heat from the reactor core at a rate such that specified acceptable fuel design limits and the design conditions of the reactor coolant pressure boundary are not exceeded.

Suitable redundancy in components and features, and suitable interconnections, leak detection, and isolation capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

Criterion 34 Conformance - The RHR system provides the means to

a. Remove decay heat and residual heat from the nuclear system so that refueling and nuclear system servicing can be performed

b. Supplement the fuel pool cooling and cleanup system capacity during shutdown to provide additional cooling capacity.

The RHR system is designed for three modes of operation:

a. Shutdown cooling

b. Containment cooling

c. LPCI.

The LPCI mode of operation, part of the ECCS, does not apply to Criterion 34 since its purpose is to reflood the core rather than remove decay heat.

The major equipment of the RHR system consists of two heat exchangers, four main system pumps, and four service water pumps. The equipment is connected by associated valves and piping, and the instrumentation and controls are provided for proper system operation. The main system pumps are sized on the basis of the flow required during the LPCI mode of operation, which is the mode requiring the maximum flow rate. The heat exchangers were sized on the basis of the required duty for the steam condensing function, which is the mode requiring the maximum heat exchanger capacity. However, Edison has decided to delete the steam condensing mode of the RHR system and has disconnected the equipment that would be necessary to use this mode of RHR.

One loop, consisting of a heat exchanger, two main system pumps in parallel, and associated piping, is located in one area of the reactor building. The other heat exchanger, pumps, and piping (forming a second loop) are located in another area of the reactor building to minimize the possibility of a single physical event causing the loss of the entire system. The two loops of the RHR system are cross connected by a single header, making it possible to supply either loop from the pumps in the other loop. Either of these redundant loops can fully meet the most limiting of the three modes of operation.

The division and redundancy in the RHR system apply to the electric power system also. As discussed in Section 8.3, the electric power system is divided into two separate, redundant divisions, each of which is independently capable of supplying power to one group of the redundant safety equipment and components required for safe shutdown at the plant. Each division is supplied by electrically and physically separate offsite power sources. Four 2850-kW standby diesel generators, two in each division, supply adequate power to their respective division in the event that offsite power is not available. The diesel generators, buses, and switchgear of Division I are electrically and physically separated such that no single failure could interrupt both divisions of electric power. Also, all of the above onsite emergency ac power equipment is housed in Category I structures that also provide protection against missiles and natural phenomena. The batteries, buses, and other equipment of the dc power systems are likewise divided into two redundant, separate, full-capacity divisions with the same equipment protection as provided for the ac power systems. Thus, the power from onsite and offsite power systems conforms to Criterion 34.

The RHR system is adequate to remove residual heat from the reactor core and ensure that fuel and RCPB design limits are not exceeded. Redundant offsite and onsite electric power systems are provided. The design of the RHR system, including its power supply, meets the requirements of Criterion 34.

For further discussion, see the following:

a. Section 5.5 - Component and Subsystem Design

b. Section 6.3 - Emergency Core Cooling Systems

c. Section 7.3 - Engineered Safety Feature Systems

d. Section 8.3 - Onsite Power Systems

e. Section 9.2 - Water Systems

f. Chapter 15 - Accident Analyses.

3.1.2.4.6 <u>Criterion 35 - Emergency Core Cooling</u>

A system to provide abundant emergency core cooling shall be provided. The system safety function shall be to transfer heat from the reactor core following any loss of reactor coolant at a rate such that (l) fuel and clad damage that could interfere with continued effective core cooling is prevented and (2) clad metal-water reaction is limited to negligible amounts.

Suitable redundancy in components and features, and suitable interconnections, leak detection, isolation, and containment capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

<u>Criterion 35 Conformance</u> - The ECCS consists of the following: (1) high pressure coolant injection system (HPCI), (2) automatic depressurization system (ADS), (3) core spray system, and (4) LPCI (an operating mode of the RHR system). The ECCS is designed to limit fuel cladding temperature over the complete spectrum of possible break sizes in the nuclear system process barrier, including a complete and sudden circumferential rupture of the largest pipe connected to the reactor vessel.

The HPCI system consists of a steam turbine, a constant-flow pump, system piping, valves, controls, and instrumentation. The HPCI system ensures that the reactor core is adequately cooled to prevent excessive fuel clad temperatures for breaks in the nuclear system that do not result in rapid depressurization of the RPV. The HPCI continues to operate until RPV pressure is below the pressure at which LPCI operation or core spray system operation maintains core cooling. Water to supply the HPCI and core spray systems is available from either the condensate storage tank or the suppression pool. The supply of water for LPCI operation is available from the suppression pool only.

In case the capability of the feedwater pumps, CRD pumps, RCIC, and HPCI is not sufficient to maintain the reactor water level, the ADS functions to reduce the reactor pressure so that flow from LPCI and the core spray system enters the RPV in time to cool the core and prevent excessive fuel clad temperature. The ADS uses five of the nuclear system pressure relief valves to relieve the high-pressure steam to the suppression pool.

Two independent loops are provided as a part of the core spray system. Each loop consists of a pair of centrifugal water pumps driven by electric motors, a spray sparger in the RPV above the core, piping and valves to convey water from the suppression pool to the sparger, and the associated instrumentation and controls instrumentation. In cases of low water level in the RPV or high pressure in the drywell, the core spray system automatically sprays water onto the top of the fuel assemblies in time, and at a sufficient flow rate, to cool the core and prevent excessive fuel temperature. The LPCI system starts from the same signals that initiate the core spray and operates independently to achieve the same objective by flooding the RPV.

In cases of low water level in the reactor or high pressure in the containment drywell, the LPCI mode of the RHR system pumps water into the RPV in time to flood the core and prevent excessive fuel temperature. Low-pressure coolant injection operation provides protection to the core in case of a large break in the nuclear system when the feedwater pumps and the HPCI system are unable to maintain RPV water level. Protection provided by LPCI also extends to a small break where the ADS has operated to lower the RPV pressure which would result in the LPCI and the core spray system starting to provide core cooling.

Results of the performance of the ECCS for the entire spectrum of liquid line breaks are discussed in Section 6.3.

3.1.2.4.7 Criterion 36 - Inspection of Emergency Core Cooling System

The emergency core cooling system shall be designed to permit appropriate periodic inspection of important components, such as spray rings in the reactor pressure vessel, water injection nozzles, and piping, to assure the integrity and capability of the system.

Criterion 36 Conformance - The ECCS is designed as discussed in Criterion 35. The engineering and design efforts for the ECCS include inservice inspection considerations. The spray rings within the vessel are accessible for inspection during each refueling outage. Removable plugs in the sacrificial shield and/or panels in the insulation provide access for examination of nozzles. Removable insulation is provided on the ECCS piping out to and including the first isolation valve outside containment. Inspection of the ECCS is in accordance with the intent of Section XI of the ASME Code. The Inservice Inspection Plan, access provisions, and areas of restricted access are defined in Section 5.2.

During plant operations, the pumps, valves, piping, instrumentation, wiring, and other components outside the primary containment can be visually inspected at any time. Components inside the primary containment can be inspected when the drywell is open for access. When the RPV is open, for refueling or other purposes, the spargers and other internals can be inspected. Portions of the ECCS that are part of the RCPB are designed to specifications for inservice inspection to detect defects. Particular attention is given to the reactor nozzles and the core spray and feedwater spargers. The design of the RPV and internals for inservice inspection and the plant testing and inspection program ensure that the requirements of Criterion 36 are met.

For further discussion, see the following:

a. Section 4.2 - Fuel System Design

b. Section 5.2 - Integrity of Reactor Coolant Pressure Boundary

c. Section 5.4 - Reactor Pressure Vessel and Appurtenances

d. Section 7.3 - Engineered Safety Feature Systems.

3.1.2.4.8 Criterion 37 - Testing of Emergency Core Cooling System

The emergency core cooling system shall be designed to permit appropriate periodic pressure and functional testing to assure (1) the structural and leaktight integrity of its components, (2) the operability and performance of the active components of the system, and (3) the operability of the system as a whole and, under conditions as close to design as practical, the performance of the full operational sequence that brings the system into operation, including operation of applicable portions of the protection system, the transfer between normal and emergency power sources, and the operation of the associated cooling water system.

Criterion 37 Conformance - The ECCS consists of the HPCI system, ADS, LPCI mode of the RHR system, and core spray system. Each of these systems is provided with sufficient test connections and isolation valves to permit appropriate periodic functional testing that ensures the structural and leaktight integrity of its components.

The HPCI, LPCI, and core spray systems are designed to permit periodic testing to ensure the operability and performance of the active components of each system.

The pumps and valves of these systems will be tested periodically to verify operability. Flow-rate tests will be conducted on the core spray, LPCI, and HPCI systems. The ADS logic will be tested on a routine basis. Operability of the safety/relief valves will be tested when they are removed on a periodic schedule for valve testing and overhaul.

The complete ECCS will be subjected to tests in order to verify the performance of the full operational (Section 14.1) sequence that brings each component system into operation. The operation of the associated cooling water systems is discussed in the evaluation of Criterion 46. It is concluded that the requirements of Criterion 37 are met.

For further discussion, see the following:

a. Section 5.2 - Integrity of Reactor Coolant Pressure Boundary

b. Section 6.3 - Emergency Core Cooling System

c. Section 7.3 - Engineered Safety Feature Systems

d. Chapter 8 - Electric Power

e. Section 14.1 - Test Program.

3.1.2.4.9 <u>Criterion 38 - Containment Heat Removal</u>

A system to remove heat from the reactor containment shall be provided. The system safety function shall be to reduce rapidly, consistent with the functioning of other associated systems, the containment pressure and temperature following any loss-of-coolant accident and maintain them at acceptably low levels.

Suitable redundancy in components and features, and suitable interconnections, leak detection, isolation, and containment capabilities shall be provided to assure that for onsite electrical power system operation (assuming offsite power is not available) and for offsite electrical power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

<u>Criterion 38 Conformance</u> - In the event of a LOCA within the reactor containment, the pressure suppression system will rapidly condense the steam to prevent containment overpressure. The containment feature of pressure suppression employs two separate compartmented sections of the primary containment: the drywell that houses the nuclear system and the suppression chamber containing a large volume of water. Any increase in pressure in the drywell from a leak in the nuclear system is relieved below the surface of the suppression chamber water pool by connecting vent lines, thereby condensing steam being released to the drywell. Any pressure buildup in the suppression chamber is equalized with the drywell by a vent line and vacuum breaker arrangement. Cooling systems remove heat from the reactor core, the drywell, and water in the suppression chamber during accident conditions. Thus, continuous cooling of the primary containment is provided.

The ECCS is actuated to provide core cooling in the event of a LOCA. Low water level in the RPV or high pressure in the drywell will initiate the ECCS to prevent excessive fuel temperature. Sufficient water is provided in the suppression pool to accommodate the initial energy that can transiently be released into the drywell from the postulated pipe failure.

The suppression chamber is sized to contain this water, in addition to the water displaced from the reactor primary system, together with the free air initially contained in the drywell.

Either or both RHR system loops, which include the heat exchangers, can be manually activated to remove energy from the containment in the containment cooling mode. The redundancy and capability of the offsite and onsite electric power systems to provide power for the RHR system are presented in the Criterion 34 Conformance Evaluation.

The pressure suppression system is capable of rapid containment pressure and temperature reduction following a LOCA so that design limits are not exceeded. Redundant offsite and onsite electric power systems provide assurances that system safety functions can be accomplished. The design of the containment heat removal system meets the requirements of Criterion 38.

For further discussion, see the following:

a. Section 5.5 - Component and Subsystem Design

b. Section 6.2 - Containment Systems

c. Section 6.3 - Emergency Core Cooling System

d. Section 7.3 - Engineered Safety Feature Systems

e. Chapter 8 - Electric Power

f. Chapter 9 - Auxiliary Systems

g. Chapter 15 - Accident Analyses.

3.1.2.4.10 Criterion 39 - Inspection of Containment Heat Removal System

The containment heat removal system shall be designed to permit appropriate periodic inspection of important components, such as the torus, sumps, spray nozzles, and piping to assure the integrity and capability of the system.

Criterion 39 Conformance - Provisions are made to facilitate periodic inspection of active components and other important equipment of the containment pressure-reducing systems. During plant operations, the pumps, valves, piping, instrumentation, wiring, and other components outside the primary containment can be visually inspected at any time, and will be inspected periodically. Components inside the primary containment can be inspected when the drywell is open for access. The testing frequencies of most components will be correlated with the component inspection.

The pressure suppression chamber is designed to permit appropriate periodic inspection. Space is provided outside the chamber for inspection and maintenance. There are two hatches that permit access to the suppression chamber for inspection.

The containment heat removal system is designed to permit periodic inspection of major components both outside and inside the primary containment as discussed in Section 14.1. This design meets the requirements of Criterion 39.

For further discussion, see the following:

a. Section 5.5 - Component and Subsystem Design
b. Section 6.2 - Containment Systems
c. Section 6.3 - Emergency Core Cooling System
d. Section 7.3 - Engineered Safety Feature Systems
e. Section 9.2 - Water Systems
f. Section 14.1 - Test Program.

3.1.2.4.11 Criterion 40 - Testing of Containment Heat Removal System

The containment heat removal system shall be designed to permit appropriate periodic pressure and functional testing to assure (1) the structural and leaktight integrity of its components, (2) the operability and performance of the active components of the systems, and (3) the operability of the system as a whole, and, under conditions as close to the design as practical, the performance of the full operational sequence that brings the system into operation, including operation of applicable portions of the protection system, the transfer between normal and emergency power sources, and the operation of the associated cooling water system.

Criterion 40 Conformance - The containment heat removal function is accomplished by the containment cooling mode of the RHR system. This mode consists of the suppression pool cooling subsystem and containment spray subsystem.

The RHR system is provided with sufficient test connections and isolation valves to permit periodic pressure testing. The containment spray mode is subjected to a periodic air test.

The pumps and valves of the RHR system will be operated periodically to verify operability. The containment spray mode is not fully testable, but the operation of the initiation signal and components can be verified. The suppression pool cooling mode is not automatically initiated, but operation of the components is periodically verified. The operation of associated cooling water systems is discussed in the response to Design Criterion 46. It is concluded that the requirements of Criterion 40 are met.

For further discussion, see the following:

a. Section 5.5 - Component and Subsystem Design
b. Section 7.3 - Engineered Safety Feature Systems
c. Chapter 8 - Electric Power
d. Section 14.1 - Test Program.

3.1.2.4.12 Criterion 41 - Containment Atmosphere Cleanup

Systems to control fission products, hydrogen, oxygen, and other substances which may be released into the reactor containment shall be provided as necessary to reduce, consistent with the functioning of other associated systems, the concentration and quantity of fission products released to the environment following postulated accidents, and to control the concentration of hydrogen or oxygen and other substances in the containment atmosphere following postulated accidents, to assure that containment integrity is maintained.

Each system shall have suitable redundancy in components and features, and suitable interconnections, leak detection, isolation, and containment capabilities to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) its safety function can be accomplished, assuming a single failure.

Criterion 41 Conformance - Fission products or other materials that leak into the drywell following postulated accidents are mostly contained in the drywell. Those that leak to the reactor building are processed by the standby gas treatment system (SGTS). The SGTS draws air from the reactor building and discharges it through a high-efficiency particulate air (HEPA) filter and deep-bed charcoal filters to reduce the levels of radiation before exhausting the air to the environment. The SGTS is designed to meet Category I requirements and can be powered from either the onsite or offsite power sources. An on-line continuous gas monitoring system allows operating personnel to evaluate the drywell atmospheric conditions, including hydrogen and oxygen concentration. To counteract the buildup of combustible gases to unacceptable limits, the drywell is rendered inert with nitrogen gas. For further details, see Sections 6.2 and 9.3.6.

3.1.2.4.13 Criterion 42 - Inspection of Containment Atmosphere Cleanup Systems

The containment atmosphere cleanup systems shall be designed to permit appropriate periodic inspection of important components such as filter frames, ducts, and piping to assure the integrity and capability of the systems.

Criterion 42 Conformance - All parts of the systems described for Criterion 41 can be inspected periodically (except small lengths of piping or ducting passing through concrete shielding) for visible indications of damage or potential failure. Access is provided to all active components for inspection and maintenance. Section 6.2, Containment Systems, includes a description of the preoperational and inservice performance inspection programs to ensure the integrity and capability of the containment atmosphere cleanup systems. For further details, see Section 6.2.

3.1.2.4.14 Criterion 43 - Testing of Containment Atmosphere Cleanup Systems

The containment atmosphere cleanup systems shall be designed to permit appropriate periodic pressure and functional testing to assure (1) the structural and leaktight integrity of its components, (2) the operability and performance of the active components of the systems such as fans, filters, dampers, pumps, and valves and (3) the operability of the systems as a whole and, under conditions as close to design as practical, the performance of the full operational sequence that brings the systems into operation, including operation of applicable portions of the protection system, the transfer between normal and emergency power sources, and the operation of associated systems.

Criterion 43 Conformance - The integrity of the containment atmosphere cleanup systems is verified by preoperational and inservice testing. Testing (including filter dioctyl phthalate penetration testing [DOP] and freon testing) for the SGTS is discussed in Section 6.2. Inspection and testing of the containment are also discussed in Sections 6.2 and 14.1.

Testability of the power sources is described in Chapter 8. For further discussion, see the following:

a. Section 6.2 - Containment Systems

b. Chapter 8 - Electric Power

c. Section 14.1 - Test Program.

3.1.2.4.15 Criterion 44 - Cooling Water

A system to transfer heat from structures, systems, and components important to safety to an ultimate heat sink shall be provided. The system safety function shall be to transfer the combined heat load of these structures, systems, and components under normal operating and accident conditions.

Suitable redundance in components and features, and suitable interconnection, leak detection, and isolation capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished assuming a single failure.

Criterion 44 Conformance - The RHR service water (RHRSW) system, the emergency equipment service water (EESW) system, and the EDG service water system are designed in accordance with Criterion 44 to transfer heat from structures, systems, and components important to safety, to the ultimate heat sink under normal operating and accident conditions. The systems have suitable redundancy to accommodate a single failure without hindering the safety function of the systems. Appropriate leak-detection capability is provided. The RHRSW system is provided to remove heat from the RHR system during plant shutdown and post-accident conditions. The EDG service water system removes heat rejected by the EDG when operating and the EESW provides cooling water for equipment required to operate during and following an accident, as needed.

Electric power for the operation of each system may be supplied from offsite or onsite power sources, with distribution arranged such that a single failure will not prevent the system from performing its safety function.

For discussion of the above systems, see the following:

a. Subsection 5.5.7 - Residual Heat Removal System

b. Chapter 8 - Electric Power

c. Section 9.2 - Water Systems.

3.1.2.4.16 Criterion 45 - Inspection of Cooling Water System

The cooling water system shall be designed to permit appropriate periodic inspection of important components, such as heat exchangers and piping, to assure the integrity and capability of the system.

Criterion 45 Conformance - The systems discussed under Criterion 44 Conformance are designed to permit periodic inspection and/or monitor system integrity. Where physical inspection is not possible (e.g., buried pipes) periodic integrity testing, such as hydrostatic testing, is performed. Periodic inspection requirements are also established. For further details, see Section 9.2, Water Systems.

3.1.2.4.17 Criterion 46 - Testing of Cooling Water System

The cooling water system shall be designed to permit appropriate periodic pressure and functional testing to assure, (1) the structural and leaktight integrity of its components, (2) the operability and the performance of the active components of the system, and (3) the operability of the system as a whole and, under conditions as close to design as practical, the performance of the full operational sequence that brings the system into operation for reactor shutdown and for loss of coolant accidents, including operation of applicable portions of the protection system and the transfer between normal and emergency power sources.

Criterion 46 Conformance - The service water systems discussed in the conformance to Criterion 44 are designed to conform to the requirements of Criterion 46. Provisions are made for testing the actuation of the systems from both normal and emergency power sources, and for monitoring the integrity of components. Initial and periodic testing of these systems is described in Section 14.1. For further details, see the following:

a. Section 9.2 - Water Systems

b. Section 14.1 - Test Program.

3.1.2.5 Group V, Reactor Containment (Criteria 50-57)

3.1.2.5.1 Criterion 50 - Containment Design Basis

The reactor containment structure, including access openings, penetrations, and the containment heat removal system shall be designed so that the containment structure and its internal compartments can accommodate, without exceeding the design leakage rate and, with sufficient margin, the calculated pressure and temperature conditions resulting from any loss-of-coolant accident. This margin shall reflect consideration of (1) the effects of potential energy sources which have not been included in the determination of the peak conditions, such as energy in steam generators and energy from metal-water and other chemical reactions that may result from degraded emergency core cooling functioning; (2) the limited experience and experimental data available for defining accident phenomena and containment responses, and (3) the conservatism of the calculational model and input parameters.

Criterion 50 Conformance - The reactor containment structures, including access openings, penetrations, and the containment heat removal system are designed with sufficient margin to meet the intent of Criterion 50. The design includes consideration of metal/water reactions and other chemical reactions subsequent to the postulated LOCA. The primary reactor containment consists of the drywell, pressure suppression chamber, and interconnecting vent pipes and vent header.

The containment was initially designed for 56 psig at 281°F. Subsequently, the containment has been analyzed for the envelope of conditions representing the spectrum of LOCAs by Chicago Bridge and Iron Company (CBI), the design fabricator, and is considered adequate without exception. Metal temperatures are not expected to reach the maximum temperature of 340°F, except for localized impingement areas. Continued integrity of the primary containment is ensured by initial and periodic testing and inspection.

Further discussion of containment design may be found in the following:

a. Section 3.8 - Design of Category I Structures

b. Section 6.2 - Containment Systems

c. Section 14.1 - Test Program.

3.1.2.5.2 Criterion 51 - Fracture Prevention of Containment Pressure Boundary

The reactor containment boundary shall be designed with sufficient margin to assure that under operating, maintenance, testing, and postulated accident conditions (1) ferritic materials behave in a non-brittle manner and (2) the probability of rapidly propagating fracture is minimized. The design shall reflect consideration of service temperatures and other conditions of the containment boundary material during operation, maintenance, testing, and postulated accident conditions and the uncertainties in determining (1) material properties (2) residual, steady-state, and transient stresses, and (3) size of flaws.

Criterion 51 Conformance - Operational, test, and postulated accident temperatures are combined with appropriate pressures and other loads in the load-combination equations of Section 3.8. The resulting loads are used in determining the required material properties and construction methods according to the ASME B&PV Code, and AISC requirements, as well as specific material requirements imposed by other codes, standards, and special considerations. All of these codes, standards, special requirements, and analytical techniques used in determining the adequacy of containment material fracture toughness, are given in Section 3.8. Methods of ensuring compliance with these codes are covered by the Quality Assurance Program discussed in Chapter 17.

For further discussion of containment design, refer to the following:

a. Section 3.8 - Design of Category I Structures

b. Section 6.2 - Containment Systems.

3.1.2.5.3 Criterion 52 - Capability for Containment Leakage Rate Testing

The reactor containment and other equipment which may be subjected to containment test conditions shall be designed so that periodic integrated leakage rate testing can be conducted at containment design pressure.

Criterion 52 Conformance - Provisions for containment leakage rate testing conform to Criterion 52. Section 6.2 discusses the provisions for containment leakage rate testing which conform to this criterion as well as to 10 CFR 50, Appendix J, Option B. Containment leak rate testing is discussed in the following:

a. Section 3.8 - Design of Category I Structures

b. Section 6.2 - Containment Systems.

3.1.2.5.4 Criterion 53 - Provisions for Containment Testing and Inspection

The reactor containment shall be designed to permit (1) appropriate periodic inspection of all important areas, such as penetrations, (2) an appropriate surveillance program and (3) periodic testing at containment design pressure of the leak-tightness of penetrations which have resilient seals and expansion bellows.

Criterion 53 Conformance - The reactor containment design permits access to penetrations and other important areas for implementation of the surveillance program described in the Technical Specifications. Penetrations and resilient seals and bellows are inspected visually, and leaktightness is verified by periodic containment pressure tests. The frequency of inspection will be consistent with the leakage rate for the individual units. Initial leak rate tests of the containment vessel and necessary action were performed to ensure that the actual leak rate was below the design values. Provisions in containment design for the performance of the tests are described in Section 6.2, Containment Systems.

3.1.2.5.5 Criterion 54 - Piping Systems Penetrating Containment

Piping systems penetrating primary reactor containment shall be provided with leak detection, isolation, and containment capabilities having redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating these piping systems. Such piping systems shall be designed with a capability to test periodically the operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

Criterion 54 Conformance - Piping systems penetrating the containment are designed to withstand a pressure at least equal to the containment maximum internal pressure. All piping systems penetrating the containment are provided with isolation valves.

Proper valve closing time is achieved by appropriate selection of valve, operating type, and operator size. Isolation valve closing time was verified during the functional performance tests prior to reactor startup. The design of piping systems penetrating reactor containment includes provisions for appropriate testing of isolation valves and valve leakage.

Major leaks in the pipe are located by increased temperature, radiation, and/or drain sump flow. Provisions are made to permit leakage testing of the isolation valves. For further discussion, see Section 6.2, Containment Systems.

3.1.2.5.6 Criterion 55 - Reactor Coolant Pressure Boundary Penetrating Containment

Each line that is part of the reactor coolant pressure boundary and that penetrates primary reactor containment shall be provided with containment isolation valves as follows, unless it can be demonstrated that the containment isolation provisions for a specific class of lines, such as instrument lines, are acceptable on some other defined basis:

a. one locked closed isolation valve inside and one locked closed isolation valve outside containment, or

b. one automatic isolation valve inside and one locked closed isolation valve outside containment, or

c. one locked closed isolation valve inside and one automatic isolation valve outside containment. A simple check valve may not be used as the automatic isolation valve outside containment, or

d. one automatic isolation valve inside and one automatic isolation valve outside containment. A simple check valve may not be used as the automatic isolation valve outside containment.

Isolation valves outside containment shall be located as close to containment as practical and upon loss of actuating power, automatic isolation valves shall be designed to take the position that provides greater safety.

Other appropriate requirements to minimize the probability or consequences of an accidental rupture of these lines or of lines connected to them shall be provided as necessary to assure adequate safety. Determination of the appropriateness of these requirements, such as higher quality in design, fabrication, and testing, additional provisions for inservice inspection, protection against more severe natural phenomena, and additional isolation valves and containment shall include consideration of the population density, use characteristics, and physical characteristics of the site environs.

Criterion 55 Conformance - Conformance to this criterion is discussed on a line-by-line basis in Subsection 6.2.4.2.2.2. It is shown that Fermi 2 conforms to this criterion to the extent that it is consistent with the safety requirements of the various systems. Several lines required to be open for injecting liquids following accidents use testable check valves for isolation (feedwater, SLCS, and ECCS discharge lines).

3.1.2.5.7 Criterion 56 - Primary Containment Isolation

Each line that connects directly to the containment atmosphere and penetrates primary reactor containment shall be provided with containment isolation valves as follows, unless it can be demonstrated that the containment isolation provisions for a specific class of lines, such as instrument lines, are acceptable on some other defined basis:

a. one locked closed isolation valve inside and one locked closed isolation valve outside containment, or

b. one automatic isolation valve inside and one locked closed isolation valve outside containment, or

c. one locked closed isolation valve inside and one automatic isolation valve outside containment. A simple check valve may not be used as the automatic isolation valve outside containment, or

d. one automatic isolation valve inside and one automatic isolation valve outside containment. A simple check valve may not be used as the automatic isolation valve outside containment.

Isolation valves outside containment shall be located as close to the containment as practical and upon loss of actuating power, automatic isolation valves shall be designed to take the position that provides greater safety.

Criterion 56 Conformance - Conformance to this criterion is discussed in Subsection 6.2.4.2.2.3. This criterion requires one isolation valve inside the containment and one outside. Fermi 2 is based on the design basis that placing isolation valves inside the suppression chamber would reduce the reliability of the connecting systems. Justification for this configuration is included in Subsection 6.2.4.2.2.3.1.

3.1.2.5.8 Criterion 57 - Closed System Isolation Valves

Each line that penetrates primary reactor containment and is neither part of the reactor coolant pressure boundary nor connected directly to the containment atmosphere shall have at least one containment isolation valve which shall be either automatic, or locked closed, or capable of remote manual operation. This valve shall be outside the containment and located as close to the containment as practical. A simple check valve may not be used as the automatic isolation valve.

Criterion 57 Conformance - Piping forming a closed loop within the containment is provided with isolation valves in accordance with Criterion 57. Each line that penetrates the primary reactor containment and is neither part of the RCPB nor connected directly to the containment atmosphere has at least one containment isolation valve that is either automatic or locked closed, or capable of remote manual operation. This valve is located outside the containment but as close to the containment as practicable.

Containment isolation valves and the associated tables and figures are discussed in Section 6.2, Containment Systems.

3.1.2.6 Group VI, Fuel and Radioactivity Control (Criteria 60-64)

3.1.2.6.1 Criterion 60 - Control of Releases of Radioactive Materials to the Environment

The nuclear power unit design shall include means to control suitably the release of radioactive materials in gaseous and liquid effluents and to handle radioactive solid wastes produced during normal reactor operation, including anticipated operational occurrences. Sufficient holdup capacity shall be provided for retention of gaseous and liquid effluents containing radioactive materials, particularly where unfavorable site environmental conditions can be expected to impose unusual operational limitations upon the release of such effluents to the environment.

Criterion 60 Conformance - An extensive system, including filtration, evaporation, and demineralization, has been designed for liquid waste treatment. Offgas from the steam-jet air ejector is processed by appropriate holdup in charcoal delay beds. Liquid wastes are normally processed (dewatered, solidified, etc.) and packaged in suitable containers for eventual disposition in licensed burial grounds. Should any condition exist that could prevent safe release of liquid waste, the liquid radwaste system has ample tankage to permit deferring the release. This system is designed to be able to receive anticipated surges in liquid waste volumes. The offgas system is capable of safely processing, for release, considerably more radioactive gas than would be expected during normal plant conditions and anticipated operational occurrences. For additional information, refer to Chapter 11.

Fermi 2 potable water was originally supplied from the onsite Fermi 1 water treatment plant and pumped through the Fermi 2 distribution system. Under this condition, the system was not subject to the requirements of Design Criterion 60. In 1995, the Fermi 2 water supply was connected to the Frenchtown Township Water Treatment Plant (FTWTP) system, and the Fermi 1 plant was abandoned.

The Fermi 2 potable water supplies the makeup demineralizer system and the sanitary, drinking, kitchen, and safety shower systems. The makeup demineralizer system is the only interconnection between the potable water and systems having the potential for containing radioactive material. At this interconnection, the potable water system is protected by an air gap, an NRC accepted design provision to prevent the inadvertent contamination of the FTWTP system with radioactive material.

3.1.2.6.2 Criterion 61 - Fuel Storage and Handling and Radioactivity Control

The fuel storage and handling, radioactive waste, and other systems which may contain radioactivity shall be designed to assure adequate safety under normal and postulated accident conditions. These systems shall be designed (1) with a capability to permit appropriate periodic inspection and testing of components important to safety, (2) with suitable shielding for radiation protection, (3) with appropriate containment, confinement, and filtering systems, (4) with a residual heat removal capability having reliability and testability that reflect the importance to safety of decay heat and other residual heat removal, and (5) to prevent significant reduction in fuel storage coolant inventory under accident conditions.

Criterion 61 Conformance

New-Fuel Storage - New fuel may be placed in the fuel storage pool or placed in dry storage in the new-fuel storage vault located inside the secondary containment (reactor building). The geometric design of the storage racks precludes accidental criticality (see Criterion 62 Conformance Evaluation). Use of the new fuel storage vault is subject to the restrictions discussed in Section 9.1.1.2.1.

Spent-Fuel Handling and Storage - The handling of new- and spent-fuel assemblies for reactor refueling is within the reactor building. Fuel storage pool water is allowed to flood the reactor well to provide shielding above the reactor and spent fuel. Fuel pool water is circulated through the fuel pool cooling and cleanup (FPCC) system to maintain fuel pool temperature, purity, clarity, and level. Storage racks preclude accidental criticality (see Criterion 62 Conformance Evaluation).

Reliable decay heat removal is provided by the closed-loop FPCC system. It consists of two circulating pumps, two heat exchangers, two filter-demineralizers, two skimmer surge tanks, and the required piping, valves, and instrumentation. The pool water is circulated through the system; suction is taken from surge tanks, flow passes through the heat exchanger and filters, and is discharged through diffusers at the bottom of the fuel pool and reactor well. Pool water temperature is maintained below 125°F when removing the maximum normal heat load from the pool with the reactor building closed cooling water temperature at its maximum. If it appears that the pool temperature will exceed 150°F, the FPCC system can be connected to the RHR system.

This increases the cooling capacity of the FPCC system and ensures that the temperature will not exceed 150°F.

There are no connections to the fuel storage pool that could allow the fuel pool to be drained below the pool gate between the reactor well and fuel pool. The high and low level switches indicate pool-water-level changes in the main control room and pump room. Pool-water-level indication is painted on the pool walls. Fission product concentration in the pool water is minimized by use of the filter-demineralizer. This minimizes the release of fission products from the pool to the reactor building environment.

No testing is planned because at least one pump, heat exchanger, and filter-demineralizer are continuously in operation while fuel is stored in the pool. Duplicate units are operated periodically to handle abnormal heat loads or to replace a unit for servicing. Routine visual inspection of the system components, instrumentation, and trouble alarms are adequate to verify system operability.

Dry Spent Fuel Storage - Storage of spent fuel at the Fermi Independent Spent Fuel Storage Installation (ISFSI) is governed by the regulations in 10 CFR 72 that are applicable to Part 72 general licensees, and the Certificate of Compliance (CoC) for the spent fuel storage cask. Furthermore, in accordance with the provisions of 10 CFR 50.68(c), while a spent fuel transportation package approved under 10 CFR 71 or a spent fuel storage cask approved under 10 CFR 72 is in the spent fuel pool:

1. The requirements of 10 CFR 50.68(b) do not apply to the fuel located within that package or cask, and
2. The requirements of 10 CFR 71 or 10 CFR 72, as applicable, and the requirements of the package or cask CoC apply to the fuel within that package or cask.

Radioactive Waste System - The radioactive waste systems provide all equipment or connections for portable systems necessary to collect, process, and prepare for disposal all radioactive liquid, gaseous, and solid waste produced as a result of reactor operation. Liquid radwastes are classified, contained, and treated as high or low conductivity, chemical, sludges, or concentrated wastes. Processing includes filtration, ion exchange, analysis, and dilution. Liquid wastes are also decanted, and sludge is accumulated for disposal as solid radwaste. Wet solid wastes are packaged in approved disposal containers. Dry solid radwastes are packaged in strong, tight containers. Gaseous radwastes are monitored, processed, recorded, and controlled so that radiation doses to persons outside the controlled area are below those allowed by applicable regulations.

Accessible portions of the reactor and radwaste buildings have sufficient shielding to maintain dose rates within the limits set forth in 10 CFR 20. The radwaste building is designed to preclude accidental release of radioactive materials to the environs.

The radwaste systems are used on a routine basis and do not require specific testing to ensure operability. Performance is observed by radiation monitors during operation.

The fuel storage and handling, and radioactive waste systems are designed to ensure adequate safety under normal and postulated accident conditions. The design of these systems meets the requirements of Criterion 61.

For further discussion, see the following:

a. Section 5.5 - Component and Subsystem Design

b. Section 6.2 - Containment Systems

c. Section 9.1 - Fuel Storage and Handling

d. Section 9.3 - Process Auxiliaries

e. Chapter 11 - Radioactive Waste Management

f. Chapter 12 - Radiation Protection

g. Section 14.1 - Test Program.

3.1.2.6.3 Criterion 62 - Prevention of Criticality in Fuel Storage and Handling

Criticality in the fuel storage and handling system shall be prevented by physical systems or processes, preferably by use of geometrically safe configurations.

Criterion 62 Conformance - Appropriate plant fuel handling and storage facilities are provided to preclude accidental criticality for new and spent fuel. Criticality in fuel storage is prevented by the geometrically safe configuration of the storage rack. There is sufficient spacing between the assemblies to ensure that the array, when fully loaded, is substantially subcritical. Fuel elements are limited by rack design to only toploading and fuel assembly positions. The fuel racks are Category I structures.

New fuel may be stored underwater in the spent fuel pool or placed in dry storage in the top-loaded new-fuel storage vault subject to the restrictions discussed in Section 9.1.1.2.1. This vault contains a drain to prevent the accumulation of water. The new-fuel storage vault racks (located inside the secondary containment) are designed to prevent an accidental critical array, even in the event that the vault becomes flooded or subjected to seismic loadings. The 6.625 in. by 11.5 in. center-to-center new-fuel assembly spacing limits the effective multiplication factor of the array to not more than 0.90 for new dry fuel. The effective neutron multiplication factor of the reactor (k_{eff}) will not exceed 0.95 if the new fuel is flooded.

Spent fuel is stored under water in the spent fuel pool. The high-density spent-fuel racks are constructed of stainless steel and include sheets of Boraflex or Boral, which are neutron attenuators. Sheets of Boraflex are used in all walls of the racks that contain Boraflex. For the racks that contain Boral, Boral panels are not needed on the exterior walls of modules facing non-fuel regions. In addition, Boral panels are used on only one exterior surface of the modules that face each other across the small water gap between the modules. The remaining conventional (low-density) spent-fuel racks are constructed of aluminum.

The spent-fuel storage racks are Category I structures designed to ensure that a k_{eff} not greater than 0.95 is maintained when the racks are fully loaded with fuel of the highest anticipated reactivity and flooded with unborated water at room temperature (68°F). The calculated k_{eff} includes a margin for uncertainty in k_{eff} calculations and in mechanical tolerances, statistically combined, so that the true k_{eff} will be less than 0.95 with a 95 percent probability at a 95 percent confidence level.

Refueling interlocks include circuitry that senses conditions of the refueling equipment and the control rods. These interlocks reinforce operational procedures that prohibit making the reactor critical. The fuel handling system is designed to provide a safe, effective means of transporting and handling fuel and is designed to minimize the possibility of mishandling or improper operation.

The use of conventional and of geometrically safe configurations for new-fuel storage and conventional and high-density storage racks for spent-fuel storage and the design of fuel handling systems preclude accidental criticality in accordance with Criterion 62.

For further discussion, see the following:

a. Section 7.6 - All Other Systems Required for Safety and Power Generation

b. Section 9.1 - Fuel Storage and Handling.

Dry Spent Fuel Storage - Storage of spent fuel at the Fermi Independent Spent Fuel Storage Installation (ISFSI) is governed by the regulations in 10 CFR 72 that are applicable to Part 72 general licensees, and the Certificate of Compliance (CoC) for the spent fuel storage cask. Furthermore, in accordance with the provisions of 10 CFR 50.68(c), while a spent fuel transportation package approved under 10 CFR 71 or a spent fuel storage cask approved under 10 CFR 72 is in the spent fuel pool:

1. The requirements of 10 CFR 50.68(b) do not apply to the fuel located within that package or cask, and

2. The requirements of 10 CFR 71 or 10 CFR 72, as applicable, and the requirements of the package or cask CoC apply to the fuel within that package or cask.

3.1.2.6.4 Criterion 63 - Monitoring Fuel and Waste Storage

Appropriate systems shall be provided in fuel storage and radioactive waste systems and associated handling areas, (1) to detect conditions that may result in loss of residual heat removal capability and excessive radiation levels, and (2) to initiate appropriate safety actions.

Criterion 63 Conformance - Appropriate systems have been provided to meet the requirements of this criterion. A malfunction of the FPCC system, which could result in loss of RHR capability and excessive radiation levels, is alarmed in the main control room. Alarmed conditions include low fuel pool cooling water pump discharge pressure, high/low level in the fuel storage pool and skimmer surge tanks, and flow in the drain lines between fuel pool gates between fuel pool and reactor well. System temperature is also continuously monitored and alarmed in the main control room. The reactor building ventilation radiation monitoring system detects abnormal amounts of radioactivity and initiates appropriate action to control the release of radioactive material to the environs.

Area radiation and tank and sump levels are monitored and alarmed to give indication of conditions that may result in excessive radiation levels in radioactive waste system areas. These systems satisfy the requirements of Criterion 63.

For further discussion, see the following:

a. Section 7.6 - Other Systems Required for Safety and Power Generation

b. Section 9.1 - Fuel Storage and Handling

c. Section 11.2 - Liquid Radwaste System

d. Section 11.3 - Gaseous Radwaste System

e. Section 11.5 - Solid Radwaste System

f. Section 11.7 - Onsite Storage Facility.

3.1.2.6.5 Criterion 64 - Radioactivity-Release Monitoring

Means shall be provided for monitoring the reactor containment atmosphere, spaces containing components for recirculation of loss of coolant accident fluids, effluent discharge paths, and the plant environs for radioactivity that may be released from normal operations, including anticipated operational occurrences, and from postulated accidents.

Criterion 64 Conformance - Means have been provided for monitoring radioactivity releases resulting from normal and anticipated operational occurrences.

The following station releases are monitored:

a. Gaseous releases from the offgas system and the gland seal exhaust delay pipe

b. Liquid discharge to the circulating water pond decant line

c. Reactor building ventilation

d. Radwaste building ventilation

e. Turbine building ventilation

f. Deleted

g. Onsite storage building ventilation.

In addition, the drywell containment atmosphere is monitored by onsite monitors.

For further discussion of the means and equipment used for monitoring radioactivity releases, see the following:

a. Section 5.2 - Integrity of Reactor Coolant Pressure Boundary

b. Section 7.6 - Other Systems Required for Safety and Power Generation

c. Section 11.4 - Process and Effluent Radiation Monitor Systems.

3.2 CLASSIFICATION OF STRUCTURES, COMPONENTS, AND SYSTEMS

Certain structures, components, and systems of the nuclear plant are considered important to safety because they perform safety actions required to avoid or mitigate the consequences of abnormal operational transients or accidents. The purpose of this section is to classify structures, components, and systems according to the importance of the safety functions they perform. In addition, design requirements are placed on such equipment to ensure the proper performance of safety actions, when required.

3.2.1 Seismic Classification

Plant structures, systems, and components important to safety are designed to withstand the effects of a safe-shutdown earthquake (SSE) and remain functional if they are necessary to ensure

a. Integrity of the reactor coolant pressure boundary (RCPB)

b. Capability to shut down the reactor and maintain it in a safe condition

c. Capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposures comparable to the guideline exposures set forth in 10 CFR 50.67 or 10 CFR 100.

Plant structures, systems, and components, including their foundations and supports, designed to remain functional in the event of an SSE and an operating-basis earthquake (OBE), are designated as Category I, as generically indicated in Table 3.2-1. A detailed tabulation of all Fermi 2 facility Category I equipment items is provided in the Central Component System (CECO). In this tabulation, each equipment item is described, facility installation locations are noted, the aseismic qualification basis is summarized, and the representative qualification documentation is identified. The CECO list is updated to reflect the facility item's aseismic status on a continual basis. The method of seismic qualification of some items is indicated in Table 3.2-2.

The Fermi 2 design fully conforms to the requirements of Regulatory Guide 1.29, Revision 3, Seismic Design Classification.

The radwaste system for the Fermi 2 plant is excluded from Category I criteria since the conservatively calculated offsite whole-body dose from radwaste system failure does not exceed 0.5 rem as specified in Regulatory Guide 1.29. The dose-rate considerations and analyses are discussed in Chapter 11, particularly in Subsections 11.2.3 and 11.3.3.

The recirculation pumps of a BWR plant are not considered essential for safe plant shutdown under either normal or abnormal conditions, even though Paragraph (h) of the Regulatory Position of this guide implies that reactor coolant pumps are required for safety. Thus, the pump seal purge system is not designed to meet Category I requirements with the exception of the components required for containment isolation. However, the pump seal and motor cooling water system are Category I, consistent with the structural design of the pumps and the recirculation system.

All Category I structures, systems, and components have been analyzed under the loading conditions of the SSE and OBE. Since the two earthquakes vary in intensity, the design of

Category I structures, components, and systems to resist each earthquake and other loads is based on levels of material stress or load factors, whichever is applicable, and yield margins of safety appropriate for each earthquake. The margin of safety provided for Category I structures, components, and systems for the SSE is sufficiently large to ensure that their safety functions are not jeopardized. For further details of specific seismic design criteria, refer to

a. Sections 3.7 and 3.9 for mechanical design criteria

b. Sections 3.7 and 3.8 for structural design criteria

c. Sections 3.7 and 3.10 for electrical design criteria

d. Sections 3.7 and 3.10 for instrumentation and control design criteria.

3.2.2 System Quality Group Classification

System Quality Group classifications as defined in Regulatory Guide 1.26 have been determined for each water-, steam-, or radioactive waste-containing component of those applicable fluid systems relied upon to

a. Prevent or mitigate the consequences of accidents and malfunctions originating within the RCPB

b. Permit shutdown of the reactor and maintain it in the safe-shutdown condition

c. Contain radioactive material.

A tabulation of Quality Group classification for each component so defined is shown in Table 3.2-1. Figures 3.2-1 and 3.2-2 depict the relative locations of these components along with their Quality Group classification.

Regulatory Guide 1.26 was still under development at the completion of the AEC staff review of the Fermi 2 construction permit application. Thus, the minimum code requirements for each Quality Group classification were those proposed by Edison and accepted by the AEC staff as evidenced in Subsection 3.3.3 and Table 3.3-3 of the AEC Safety Evaluation Report (Reference 1) resulting from their review. The substance of the table is shown in Table 3.2-3. Subsequent to issuance of the construction permit, Edison requested waiver from the requirements of 10 CFR 50.55a, which became effective July 12, 1971. The differences between the code requirements of Section 50.55a and those actually used, which were those required at the time of procurement of the component, are shown in Table 3.2-4. These differences were the subject of a waiver requested by Edison and approved by the AEC (Reference 2) except for Valve B31-F023. Reference 2 listed the purchase order date as October 1970 and code applied as NPVC, 70, for Valve B31-F023 in error. The correct data are November 1969 and NPVC, 68, as listed in Table 3.2-4.

3.2 CLASSIFICATION OF STRUCTURES, COMPONENTS, AND SYSTEMS

REFERENCES

1. "Safety Evaluation by the Division of Reactor Licensing, USAEC in the Matter of the Detroit Edison Company, Enrico Fermi Atomic Power Plant Unit 2, Docket 50-341," dated May 17, 1971.

2. Edison Letter EF2-17172, dated May 31, 1973, and AEC letter to Edison dated July 12, 1973. Re: Waiver of the code requirements of 10 CFR Part 50.55a.

TABLE 3.2-1 STRUCTURES, SYSTEMS, AND COMPONENTS CLASSIFICATION[a]

Principle Component[b]	Scope of Supply[c]	Location[d]	Category[e]	Quality Group Classification[f]	Quality Assurance Requirements[g]	Principal Construction Code[h]	Remarks
I. Reactor system							
1. Reactor pressure vessel	GE	C	I	A	S	III-A	
2. Reactor Vessel support	GE	C	I	N/A	S	None	
3. Reactor Vessel appurtenances pressure retaining portions	GE	C	I	A	S	III-A	
4. CRD housing support	GE	C	I	N/A	S	None	i
5. Reactor internal structures, engineered safety features	GE	C	I	N/A	S	None	
6. Control rods	GE	C	I	N/A	B	None	
7. Control rod drives	GE	C	I	N/A	S	III-A	
8. Core support	GE	C	I	N/A	S	None	
9. Power range detector hardware	GE	C	I	N/A	S	III-A	j
10. Fuel assemblies	GE	C	I	N/A	B	None	
11. Reactor vessel stabilizer truss	GE	C	I	N/A	S	None	
II. Nuclear boiler system							
1. Vessels, level instrumentation chambers	GE	C	I	A	S	III-A	
2. Piping, relief valve discharge	E	C	I	B	B	III-2	
3. Piping, relief valve discharge inside vent line	E	C	I	D+	B	B31.1.0	
4. Relief valve discharge T-quenchers	E	C	I	C	B	III-3	
5a. Piping, main steam, from reactor inboard drywell penetration process pipe connectors	GE	C	I	A	S	B31.7-1	
5b. Piping, main steam, drywell penetration process pipe and piping to outboard MSIVs	E	C, R	I	A	B	III-1	

TABLE 3.2-1 STRUCTURES, SYSTEMS, AND COMPONENTS CLASSIFICATION[a]

Principle Component[b]	Scope of Supply[c]	Location[d]	Category[e]	Quality Group Classification[f]	Quality Assurance Requirements[g]	Principal Construction Code[h]	Remarks
6. Pipe supports, main steam	GE	C	I	N/A	S	B31.7-1	
7. Pipe restraints, main steam	E	C, R	I	N/A	B	None	
8. Piping, other within outer-most isolation valves	E	C, R	I	A	B	III-1	j
9. Piping, instrumentation beyond outermost isolation valves	E	R, T	N/A	D	S	B31.1.0	j
10. Relief valves	GE	C	I	A	S	NPVC-1	
11. Valves, main steam isolation valves	GE	C, R	I	A	S	NPVC-1	
12. Valves, other, isolation valves and within	E	C, R	I	A	B	III-1	j
13. Valves, instrumentation beyond outermost isolation valves	E	R, T	N/A	D	S	B16.5	j
III. Reactor recirculation system							
1. Piping	GE	C	I	A	S	B31.7-1	j
2. Pipe suspension recirculation line	GE	C	I	N/A	S	B31.7-1	
3. Pipe restraints recirculation line	GE	C	I	N/A	S	None	
4. Pumps	GE	C	I	A	S	NPVC-1	z
5. Valves	GE	C	I	A	S	NPVC-1	j
6. Motor, pump	GE	C	I	N/A	S	None	
IV. CRD hydraulic system							
1. Valves	GE, E	R	I	B	S	III-2	j
2. Valves, other	GE, E	R	N/A	D	S	B16.5	j
3. Piping, scram discharge volume lines	E	R	I	B	B	III-2	
4. Piping, insert and withdraw lines	E	C. R	I	B	B	III-2	
5. Piping, other	E	R	N/A	D	S	B31.1.0	j
6. Hydraulic control unit	GE	R	I	N/A	S	None	l

TABLE 3.2-1 STRUCTURES, SYSTEMS, AND COMPONENTS CLASSIFICATION[a]

Principle Component[b]	Scope of Supply[c]	Location[d]	Category[e]	Quality Group Classification[f]	Quality Assurance Requirements[g]	Principal Construction Code[h]	Remarks
V. Standby Liquid control system							
1. Standby liquid control tank	GE	R	I	D	BM	API 650	m
2. Pump	GE	R	I	C	BM	NPVC-3	
3. Pump motor	GE	R	I	N/A	BM	None	
4. Valves, explosive	GE	R	I	C	BM	NPVC-3	
5. Valves, isolation and within	E	C, R	I	A	B	III-1	j
6. Valves, beyond isolation valves	E	R	I	C	B	III-3	j
7. Piping, within isolation valves	E	C,R	I	A	B	III-1	j
8. Piping, beyond isolation valves	E	R	I	C	B	III-3	j
VI. Neutron monitoring system							
1. Piping, TIP	GE	R	I	N/A	S	None	
2. Valves, isolation, TIP subsystem	GE	R	I	N/A	S	None	
3. Instrumentation and control rod block monitoring	GE	R	II/I	N/A	S	None	
4. APRM	GE	R	I	N/A	S	IEEE 344, IEEE 323	
VII. Reactor protection system							
1. Electrical trip	GE	R, T	I	N/A	B	IEEE 344, IEEE 323	
VIII. Process radiation monitoring system							
1. Main steam line radiation monitors, fuel pool ventilation exhaust radiation monitors	GE	R	I	N/A	B	IEEE 344, IEEE 323	
2. Control center emergency air inlet radiation monitors	E	A	I	N/A	B	IEEE 323	

TABLE 3.2-1 STRUCTURES, SYSTEMS, AND COMPONENTS CLASSIFICATION[a]

Principle Component[b]	Scope of Supply[c]	Location[d]	Category[e]	Quality Group Classification[f]	Quality Assurance Requirements[g]	Principal Construction Code[h]	Remarks
3. Control center normal make-up air radiation monitors	E	A	II/I	N/A	B	IEEE 323	
1. Torus Hardened Vent Radiation Monitor System	E	A	II/I	N/A	S	IEEE 344	
IX. Residual heat removal system							
1. Heat exchangers, primary side	GE	R	I	B	S	III-C	
2. Heat exchangers, secondary side	GE	R	I	C	S	VIII & TEAM-C	
3. Piping, within outer most isolation valves	E	C, R	I	A	B	III-1	j
4. Piping, beyond outer most isolation valves	E	R	I	B	B	III-2	j
5. Pumps	GE	R	I	B	S	NPVC-2	
6. Pump motors	GE	R	I	N/A	S	None	
7. Valves, isolation, LPCI line and SDC suction	E	C, R	I	A	B	III-1	
8. Valves, isolation, torus suction, containment spray, head spray and test lines	E	C, R	I	B	B	III-2	j, x
9. Valves, beyond isolation valves	E	R	I	B	B	III-2	
X. Core spray system							
1. Piping, within outermost isolation valves	E	C, R	I	A	B	III-1	j
2. Piping, beyond outermost isolation valves	E	R	I	B	B	III-2	j
3. Pumps	GE	R	I	B	S	NPVC-2	
4. Pump motors	GE	R	I	N/A	S	None	
5. Valves, isolation and within	E	C, R	I	A	B	III-1	j

TABLE 3.2-1 STRUCTURES, SYSTEMS, AND COMPONENTS CLASSIFICATION[a]

Principle Component[b]	Scope of Supply[c]	Location[d]	Category[e]	Quality Group Classification[f]	Quality Assurance Requirements[g]	Principal Construction Code[h]	Remarks
6. Valves, beyond outermost isolation valves	E	R	I	B	B	III-2	j
XI. High-pressure coolant injection system							
1. Steam turbine	GE	R	I	N/A	S	None	n
2. Piping, suction line from condensate storage tank isolation valve	E	R,O	I	B	B	III-2	j
3. Piping, turbine steam supply and discharge	E	R	I	B	B	III-2	
4. Piping, return test line to condensate storage tank downstream of second isolation valve	E	R,O	N/A	D	S	B31.1.0	
5. Piping, within outermost isolation valve	E	C,R	I	A	B	III-1	
6. Piping, suppression pool suction and pump discharge	E	R	I	B	B	III-2	j
7. Main pump	GE	R	I	B	S	NPVC-2	
8. Booster pump	GE	R	I	B	S	NPVC-2	
9. Valves, beyond outermost isolation valves	E	R	I	B	B	III-2	
10. Valves, outer isolation and within	E	C,R	I	A	B	III-1	j
11. Valves, beyond isolation valves, motor operated	E	R	I	B	B	III-2	j
XII. Reactor core isolation cooling system							
1. Piping, within outermost isolation valves	E	C,R	I	A	B	III-1	j
2. Piping, beyond outermost isolation valves	E	R	I	B	B	III-2	j

TABLE 3.2-1 STRUCTURES, SYSTEMS, AND COMPONENTS CLASSIFICATION[a]

Principle Component[b]	Scope of Supply[c]	Location[d]	Category[e]	Quality Group Classification[f]	Quality Assurance Requirements[g]	Principal Construction Code[h]	Remarks
3. Piping, return test line to condensate storage tank downstream of second isolation valve and vacuum pump discharge line to containment isolation valves	E	R,O,A	I,N/A	D	S	B31.1	j
4. Pumps	GE	A	I	B	S	NPVC-2	
5. Valves, isolation and within	E	C,R	I	A	B	III-1	j
6. Valves, other	E	R	I	B	B	III-2	j
7. Turbine	GE	A	I	N/A	S	None	n
8. Piping, suction line from condensate storage tank	E	R,O	I	B	B	III-2	j
XIII. Fuel service equipment							
1. Fuel preparation machine	GE	C,R	II/I[y]	N/A	S	None	
2. General-purpose grapple	GE	C,R	II/I	N/A	S	None	
XIV. Reactor pressure vessel service equipment							
1. Steam line plugs	E	C	I	N/A	S	None	
2. Dryer and separator sling and head strongback	GE	C	I	N/A	S	None	
3. Head Strongback Carousel	GE	C	I	N/A	S	None	
XV. In-vessel service equipment							
1. Control rod grapple	GE	C	II/I	N/A	S	None	
2. Reactor Cavity Work Platform	E	R	II/I	N/A	B	None	
XVI. Refueling equipment							
1. Refueling equipment platform assembly	GE	C	II/I	N/A	S	None	
2. Refueling bellows	E	C	I	B	S	III-2	aa
XVII. Storage equipment							

TABLE 3.2-1 STRUCTURES, SYSTEMS, AND COMPONENTS CLASSIFICATION[a]

Principle Component[b]	Scope of Supply[c]	Location[d]	Category[e]	Quality Group Classification[f]	Quality Assurance Requirements[g]	Principal Construction Code[h]	Remarks
1. Defective- fuel storage container	GE	R	I	N/A	S	None	
2. High-density fuel storage racks	E	R	I	N/A	B	III-NF	
XVIII. Radwaste System							
1. Tanks, atmospheric vessels	E	W	N/A	D	S	API-620 & 650 VIII	o
2. Heat exchangers and evaporators	E	W	N/A	C,D	S	VIII & TEMA-C	p
3. Piping and valves	E	C,R,W	N/A	D	S	B31.1.0	
4. Pumps	E	W	N/A	C,D	S	III-3, B31.1.0	j,p
5. Piping and valves, containment isolation	E	C,R	I	B	B	III-2	p
6. Valves, flow control and filter system	E	W	N/A	C,D	S	III-3, B16.5	p
7. Valves, other	E	W	N/A	D	S	B16.5	
XIX. Reactor water cleanup							
1. Vessels: filter demineralizer	GE	R	N/A	C	S	III-C	
2. Heat exchangers, regenerating nonregenerating: tube side, Nonregenerating: shell side	GE GE GE	R R R	N/A N/A N/A	D D D	S S S	III-C, TEMA-R III-C, TEMA-R VIII, TEMA-R	
3. Piping, within outermost isolation valves	E	C,R	I	A	B	III-1	
4. Piping, beyond outermost isolation valves	E	R,T,W	N/A	C,D	S	III-3 B31.1.0	j,k
5. Pumps (recirculation, precoat, and holding)	GE	R	N/A	D	S	NPVC-3	
6. Valves, isolation valves and within	E	C,R	I	A	B	III-1	j,q,r
7. Valves, beyond reactor isolation valves	GE E	R R,T,W	N/A N/A	C D	S S	NPVC-3 B16.5	j j

TABLE 3.2-1 STRUCTURES, SYSTEMS, AND COMPONENTS CLASSIFICATION[a]

Principle Component[b]	Scope of Supply[c]	Location[d]	Category[e]	Quality Group Classification[f]	Quality Assurance Requirements[g]	Principal Construction Code[h]	Remarks
XX. Fuel pool cooling and cleanup system							
1. Vessels, filter-demineralizers	GE	W	II/I	C	S	VIII	
2. Vessels, other	E	W	II/I	N/A	S	None	
3. Heat exchangers	GE	R	II/I	C,	S	VIII, TEMA-R	
4. Piping	E	W,R	N/A, I/I, I	C,B,D	S	III-3, B31.1.0	j
5. Pumps	GE	R	II/I	C	S	NPVC-3	
6. Valves	E	R	N/A, II/I, I	C,B,D	B	III-3, B16.5	J
XXI. Control center panels	GE, E	A	I	N/A	S,B	IEEE	t
XXII. Local panels and racks	GE, E	R,A,H	I	N/A	S,B	IEEE	t
XXIII. Offgas system							
1. Tanks, drains and condensate receiver	E	T	N/A	D	S	VIII	
2. Heat exchangers	E	T	N/A	D	S	AEG-VIII, TEMA-C	
3. Piping	E	T	N/A	D	S	B31.1.0,	
4. Pumps, ring water vacuum	E	T	N/A	D	S	MANF. STD	
5. Valves, flow control	E	T	N/A	D	S	B31.1.0	
6. Valves, other	E	T	N/A	D	S	B31.1.0	
7. Pressure vessels, ring water buffer tanks	E	T	N/A	D	S	AEG-VIII	
XXIV. RHR service water system							
1. Piping	E	H,O,R	I	C	B	III-3	
2. Pumps	E	H	I	C	B	III-3	
3. Pumps motors	E	H	I	N/A	B	None	
4. Valves	E	H,R	I	C	B	III-3	
5. Mechanical draft cooling towers, including structure fans, and related hardware	E	H	I	N/A	B	None	

TABLE 3.2-1 STRUCTURES, SYSTEMS, AND COMPONENTS CLASSIFICATION[a]

Principle Component[b]	Scope of Supply[c]	Location[d]	Category[e]	Quality Group Classification[f]	Quality Assurance Requirements[g]	Principal Construction Code[h]	Remarks
XXV. Plant service and cooling water systems							
1. Piping and valves forming part of primary containment boundary	E	C,R	I	B	B	III-2	
XXVI. Noninterruptable air and pneumatic supply systems							
1. Vessels, accumulators supporting safety-related systems	E	C,R	I	C	B	III-3	
2. Piping and valves	E	C,R	I	C	B	III-3	
3. Control air compressors	E	A	I	D	B	VIII, B31.1.0	
4. Control air dryers	E	A	I	D	B	VIII, B31.1.0	
5. Receiver tanks	E	A	I	C	B	III-3	
6. Control air aftercooler	E	A	I	D	B	VIII, B31.1.0	
7. Isolation valves	E	A,R	I	C	B	III-3	
8. Pressure regulating valves	E	A,R	I	C	B	III-3	
XXVII. Diesel generator systems							
1. Day tanks, fuel oil storage and day tanks	E	H	I	C	B	III-3	
2. Piping and valves, fuel oil system	E	H	I	C	B	III-3 (see Fig. 9.5-4, 5 and 6)	
3. Pumps, fuel oil system	E	H	I	N/A	B	None	
4. Pumps, piping, valves and heat exchangers, diesel service water system	E	H	I	C	B	III-3	
5. Jacket and air coolant piping, valves, and heat exchangers	E	H	I	C	B	III-3 (see Fig. 9.5-7)	
6. Pump motors, diesel service water system	E	H	I	N/A	B	None	
7. Diesel generators	E	H	I	N/A	B	None	
8. Starting air receivers piping and valves, combustion air intake piping	E	H	I	C	B	III-3	

TABLE 3.2-1 STRUCTURES, SYSTEMS, AND COMPONENTS CLASSIFICATION[a]

Principle Component[b]	Scope of Supply[c]	Location[d]	Category[e]	Quality Group Classification[f]	Quality Assurance Requirements[g]	Principal Construction Code[h]	Remarks
9. Lube oil cooler	E	H	I	C	B	III-3	
10. Exhaust piping	E	H	I	D	S	B31.1.0	
11. Skid-mounted lube oil system	E	H	I	N/A	S		
12. Starting Air Receivers Safety Relief Valves	E	H	I	D	B	VIII, B31.1.0	
XXVIII. Primary containment atmosphere control system							
1. Piping and valves from primary containment through outer isolation valve	E	R	I	B	B	III-2	
XXIX. Standby gas treatment system							
1. Containment pressure boundary piping and valves	E	R	I	B	B	III-2	
2. Piping, downstream to secondary containment suction valves	E	R,A	NA	D	S	B31.1.0	
3. Piping and valves, secondary containment suction valves to filter unit ductwork	E	R,A	I	D	B	B31.1.0	
4. Cooling and exhaust fan	E	A	I	N/A	B		
5. Filter unit and associated duct and valves	E	A	I	N/A	B		
6. Exhaust vent stack	E	A,O	I	N/A	B	AISC	
7. Piping and valves, inlet header to torus vent stack	E	R,O	I	D	B	B31.1.0	
XXX. Emergency equipment cooling water system							
1. All components with safety functions, except as listed in XXV	E	R	I	C	B	III-3	
XXXI. Emergency equipment area cooling system							

TABLE 3.2-1 STRUCTURES, SYSTEMS, AND COMPONENTS CLASSIFICATION[a]

Principle Component[b]	Scope of Supply[c]	Location[d]	Category[e]	Quality Group Classification[f]	Quality Assurance Requirements[g]	Principal Construction Code[h]	Remarks
1. All components with emergency equipment cooling coils safety function	E	R,A	I	C	B	III-3	
2. RHR complex HVAC system components with safety fuction	E	H	I	N/A	B		
XXXII. Power conversion system							
1. Main steam piping from outboard MSIVs to third MSIVs	E	R,T	II/I	D	S	B31.1.0	
2. Main steam branch-line piping and valves downstream of outboard MSIVs (for branch lines between outboard and third MSIVs)	E	R,T	II/I	D	S	B31.1.0	
3. Feedwater piping, beyond outermost isolation valves	E	R,T	N/A	D	S	B31.1.0	
4. Feedwater piping, within outermost isolation valve	E	C,R	I	A	B	III-1	
5. Valves, isolation valves and within, feedwater	E	C,R	I	A	B	III-1	
6. Valves, beyond outermost isolation valves, feedwater	E	R,T	N/A	D	S	B16.5	
							r
XXXIII. Condensate storage and transfer system							u, s
1. Condensate storage tank	E	O	N/A	D	S	USAS B96.1	s
2. Piping and valves, except HPCI/RCIC suction	E	M	N/A	D	S	B31.1.0, B16.5	s
3. Other components	E	M	N/A	D	S	(see Table 3.2-2)	
XXXIV. Auxiliary ac power system							
1. All components with safety function	E	A,R,H	I	B, N/A	B	IEEE 308/IEEE 344	

TABLE 3.2-1 STRUCTURES, SYSTEMS, AND COMPONENTS CLASSIFICATION[a]

Principle Component[b]	Scope of Supply[c]	Location[d]	Category[e]	Quality Group Classification[f]	Quality Assurance Requirements[g]	Principal Construction Code[h]	Remarks
2. Primary electrical penetrations	E	R,C	I	B	B	IEEE 336 III-NE IEEE 317	v
3. Diesel generator packages including auxiliaries (e.g., governor, voltage regulator, excitation system, and control and relay protection equipment) not listed in XXVII	E	H	I	N/A	B		
4. 4160V switchgear	E	A,H	K	N/A	S		
5. 480V load centers	E	A,H	K	N/A	S		
6. 480V motor control centers	E	A,R,H	I	N/A	S		
7. Conduit and tray supports (installation containing class 1E cables and other installations whose failure may damage other safety-related items)	E	A11	I	N/A	S		
8. Transformers	E	A,H	K	N/A	S		
9. Valve operators	E	A11	I	N/A	S		
10. Protective relays and control panels	E	H,R	I	N/A	S		
11. 120V ac instrument power supply and distribution equipment	E	A	K	N/A	S		
12. Fire-rated penetrations	E	A11	I	N/A	S		
XXXV. DC power systems							
1. All components with safety function	E	A,R,H	I	N/A	B	IEEE 308	
a. 260/130V batteries, battery racks, battery chargers, and dc distribution equipment	E	A,R,H	K	N/A	S		

TABLE 3.2-1 STRUCTURES, SYSTEMS, AND COMPONENTS CLASSIFICATION[a]

Principle Component[b]	Scope of Supply[c]	Location[d]	Category[e]	Quality Group Classification[f]	Quality Assurance Requirements[g]	Principal Construction Code[h]	Remarks
b. Conduit and tray supports (installations containing class 1E cables and other installations whose failure may damage other safety-related items)	E	A11	I	N/A	S		
XXXVI. Civil structures							
1. Primary containment	E	R	I	B	B	III-B	
2. Reactor auxiliary building	E	R,A	I	N/A	B	ACI-318, AISC	
3. Auxiliary building steel framed penthouse components that are not required to support the crane or the secondary containment	E	A	II/I	N/A	S	AISC	
4. Steam tunnel	E	T	I	N/A	B	ACI 318, AISC	
5. Radwaste building	E	W	N/A	N/A	S	ACI 318, AISC	
6. Circulating water pump house	E	P	N/A	N/A	S	ACI 318, AISC	
7. Control center complex (including cable spreading room)	E	A	I	N/A	B	ACI 318, AISC	
8. RHR complex	E	H	I	N/A	B	ACI 318, AISC	
9. Radiation shielding	E	R,A,C	I	N/A	B	ACI 318, AISC	
Sacrificial shielding wall							
Reactor building							
Auxiliary building							
Control center complex							
Masonry wall, safety related							
10. Support truss (pipe break)	E	C	I	N/A	S		
11. ISFSI Equipment Storage Building	E	I	N/A	N/A	B	ACI 318, AISC	
12. ISFSI Storage Pad	E	J	I	N/A	APP 17.2A	ACI 349	
13. ISFSI Fabrication Pad	E	K	N/A	N/A	APP 17.2A	ACI 318	

TABLE 3.2-1 STRUCTURES, SYSTEMS, AND COMPONENTS CLASSIFICATION[a]

Principle Component[b]	Scope of Supply[c]	Location[d]	Category[e]	Quality Group Classification[f]	Quality Assurance Requirements[g]	Principal Construction Code[h]	Remarks
14. ISFSI Transfer Pad	E	L	N/A	N/A	APP 17.2A	ACI 318	
15. Original Cat. I 4160-V Ductbanks between RHR Complex & Auxiliary Bldg.	E	O	I	N/A	B	ACI 318	
16. Second Set of Cat. I 4160-V Ductbanks between RHR Complex & Auxiliary Bldg.	E	O	I	N/A	B	ACI 349-01 & ACI 318-05	
17. ISFSI Cask Transfer Facility	E	N	N/A	N/A	APP 17.2A	ACI 318	
18. FLEX Storage Facility #1 & #2	E	O	N/A	N/A	N/A	ACI 318 & AISC	
XXXVII. Post-LOCA hydrogen control system							
1. All components with safety function	E	R	I	B	B	III-2	
XXXVIII. Reactor building crane	E	R	I	N/A	S	EOCI	
XXXIX. Control center air conditioning system							
1. Condenser coil and associated piping	E	A	I	C	B	III-3	
2. Chilled water piping	E	A	I	D	B	B31.1.0	
3. Piping, chilled water makeup	E	R,A	N/A	D	S	B31.1.0	
4. Isolation dampers	E	R,A	I	N/A	B		
5. Cooling units for equipment room	E	A	I	N/A	B		
6. Chillers	E	A	I	D	B	VIII	
7. Multizone units	E	A	I	N/A	B		
8. Supply fans	E	A	I	N/A	B		
9. Recirculation, emergency makeup air filter units	E	A	I	N/A	B		
10. Recirculation air filter units and fans	E	A	I	N/A	B		

TABLE 3.2-1 STRUCTURES, SYSTEMS, AND COMPONENTS CLASSIFICATION[a]

Principle Component[b]	Scope of Supply[c]	Location[d]	Category[e]	Quality Group Classification[f]	Quality Assurance Requirements[g]	Principal Construction Code[h]	Remarks
11. Chilled water pumps	E	A	I	D	B		
12. Return fans	E	A	I	N/A	B		
13. Associated ductwork	E	A	I	N/A	B		
14. Associated motors	E	R,A	I	N/A	B	None	
XL. Shore barrier	E	O	I	N/A	B	None	
XLI. MSIV leakage control system	(Not Required per License Amendment No. 160)						
XLII. Postaccident sampling							
1. Sample isolation valves and piping	E	R	I	A,B	B	III-1,2	
2. Sampling station and tubing downstream of isolation valves	GE, E	A	N/A	C,D	S	III-3, B31.1	j
XLIII. Cable and associated hardware with safety function	GE, E	All	N/A	N/A	B	IEEE/ICC/ WG-12-32 I333 323	t
XLIV. Locally mounted instrumentation with safety function (not rack or panel mounted)	GE, E	R,A,H	I	N/A	S,B	IEEE	
XLV. Fire detection, suppression, and extinguishing systems, emergency lighting, and breathing apparatus	E	All	N/A	N/A	N/A	N/A	s

Note a

Safety-related instrumentation and control systems and components are identified in Chapter 7 and will be subject to the operational QA Program requirements.

Note aa

The reactor refueling bellows was designed, fabricated, and installed as ASME Class 2 but was not N-stamped.

Note b

A module is an assembly of interconnected components that constitutes an identifiable device or piece of equipment. For example, electrical modules include sensors, power supplies, and signal processors; mechanical modules include turbines, strainers, and orifices.

Note c

GE = Supplied by General Electric

E = Supplied by the Detroit Edison Company.

Note d

Location abbreviations are:

A = Auxiliary building

C = Part of, or within, primary containment

H = RHR complex

I = Independent Spent Fuel Storage Installation (ISFSI) Equipment Storage Building

J = Independent Spent Fuel Storage Installation (ISFSI) Storage Pad

K = ISFSI Fabrication Pad

L = ISFSI Transfer Pad

M = Any other location

N = ISFSI Cask Transfer Facility

O = Outdoors onsite

P = Circulating water pump house

R = Reactor building

T = Turbine building

W = Radwaste building

Note e

I = The equipment is constructed in accordance with the seismic requirements for the SSE and OBE as described in Section 3.7.

K = The equipment is constructed in accordance with the seismic requirements as described in Section 3.10.

NA = The seismic requirements for the SSE are not applicable to the equipment.

II/I = The equipment is constructed in accordance with the seismic requirements of Category II/I described in Section 3.7.

Note f

The structure, system, or component is constructed in accordance with the codes listed in Table 3.2-3.

Note g

B = The structure, system, or component meets the QA requirements of 10 CFR 50, Appendix B, in accordance with the QA Program described in Chapter 17.

S = Items ordered with specific QA requirements identified in the purchase documents. This includes items purchased prior to the issuance of 10 CFR 50, Appendix B (35 FR 10499, June 27, 1970). For example, this would include items purchased under the contract with General Electric (the NSSS supplier), which was effective August 15, 1968.

BM = The system or component will be maintained according to the requirements of 10 CFR 50, Appendix B, but was not originally procured according to Appendix B.

App 17.2A = ISFSI Storage Pad and ISFSI Cask Transfer Facility are ITS-C; See UFSAR Appendix 17.2A

Note h

Notation for principal construction codes is:

III-A,B,C,1,2,3 - ASME Boiler and Pressure Vessel Code Section III, Class A,B,C,1,2, or 3 or Subsection NE, Class NE. (Pre-1971 versions of the code used the Class A,B,C, designation while 1971 and later versions used the Class 1,2,3 designation. Equipment was ordered throughout a period requiring use of both designations)

VIII - ASME Boiler and Pressure Vessel Code Section VIII, Pressure Vessels, Division I

B31.7-1,2,3 - ANSI Nuclear Power Piping Code Class 1, II, III

B31.1.0 - ANSI B31.1.0 Standard Code for Pressure Piping, Power Piping

NPVC - 1,2,3 Draft ASME Code for Pumps and Valves for Nuclear Power, Class I,II,III

IEEE 308-1971 - IEEE Criteria for Class 1E Electric System, for Nuclear Power Generating Station

IEEE 317-1971 - IEEE Standard for Electric Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations

IEEE 344-1971 - Guide for Seismic Qualification of Class I Electrical Equipment for Nuclear Power Generating Stations.

IEEE/ICC/WG-12-32 - Proposed Guide for Type Tests of Class I Cables and Connections Installed Inside the Containment of Nuclear Generating Stations

TEMA-C,R - Tubular Exchanger Manufacturer Association, Class C,R

ACI 318 - Building Code Requirements for Reinforced Concrete 1963 and 1971. Note: Code Year 2005 used for ISFSI structures and the second set of Category I 4160-V underground ducts, manholes and cable vault structures only.

ACI 349-01 – Code Requirements for Nuclear Safety-Related Concrete Structures and Commentary

AEG-VIII - Manufactured in West Germany in accordance with ASME Boiler and Pressure Vessel Code Section VIII, Division I, but not code stamped. Code compliance certified by third-party inspectors

AISC - Specification for the Design Fabrication and Erection of Structural Steel for Buildings

API 650 - Welded steel tanks for oil storage

API 620 - Specifications for Welded Steel Storage Tanks

B96.1 - USAS B96.1 - Welded aluminum alloy field-erected storage tanks

B16.5 - ANSI B16.5 - Steel pipe flanges and flanged fittings

EOCI - Electric Overhead Crane Institute.

(Other Civil and Structural Codes are given in Section 3.8.)

Note i

Maintenance on all components within the reactor internal structures will be performed in accordance with 10 CFR 50, Appendix B.

Note j

1. All instrument lines that are connected to the RCPB and are not utilized to actuate safety systems are Quality Group D from the outer isolation valve or the process shutoff valve (root valve) to the sensing instrumentation

2. All other instrument lines:

    - Through the root valve; shall be of the same classification as the system to which they are attached

    - Beyond the root valve, if used to actuate a safety system; shall be of the same classification as the system to which they are attached

    - Beyond the root valve; if not used to actuate a safety system, are Quality Group D.

3. All sample lines from the outer isolation valve or the process root valve through the remainder of the sampling system are Quality Group D

4. Portions of instrument lines (regardless of the originating quality group) passing through primary containment are part of a penetration assembly that is part of containment. As such, these lines are Quality Group B, consistent with the Containment Quality Group. This is in accordance with Regulatory Guide 1.11 and Note 2(a) referenced from 10 CFR 50.55a(d)(2).

Note k

The recirculation pumps of a BWR plant are not considered essential for safe plant shutdown under either normal or abnormal conditions, even though Paragraph (h) of the Regulatory Position of Regulatory Guide 1.29 implies that reactor coolant pumps are required for safety. Thus, the pump seal purge system is not designed to meet Category I requirements with the exception of the components required for containment isolation. However, the pump seal and motor cooling water system are Category I, consistent with the structural design of the pumps and the recirculation system.

Note l

The hydraulic control unit (HCU) is a GE factory-assembled engineered module of valves, tubing, piping, and stored water which controls a single control rod drive (CRD) by the application of precisely timed sequences of pressures and flows. Control is accomplished by slow insertion or withdrawal of the control rods for power control, and rapid insertion for reactor scram

Although the HCU, as a unit, is field installed and connected by process piping, many of its internal parts differ markedly from process piping components because of the more complex functions they must provide. Thus, although the codes and standards invoked by the Group A, B, C, D pressure integrity quality levels clearly apply at all levels to the interfaces between the HCU and the connecting conventional piping components (e.g., pipe nipples, fittings, simple hand valves, etc.), it is considered that they do not apply to the specialty parts (e.g., solenoid valves, pneumatic components, and instruments)

The design and construction specification for the HCU invoke such codes and standards as can be reasonably applied to individual parts in developing required quality levels, but these codes and standards are supplemented with additional requirements for these parts and for the remaining parts and details. For example: (1) all welds are LP inspected, (2) all socket welds are inspected for gap between pipe and socket bottom, (3) all welding is performed by qualified welders, and (4) all work is done per written procedures

Quality Group D is generally applicable because the codes and standards invoked by that group contain clauses that permit the use of manufacturer's standards and proven design techniques which are not explicitly defined within the codes of Quality Groups A, B, or C. This is supplemented by the QC techniques described above.

Note m

The standby liquid control system storage tank is Group D plus the following additional QC:

a. Spot radiographic inspection was performed on all vertical and horizontal shell butt welds and on all bottom butt welds. Methods, techniques, and acceptance standards were in accordance with the requirements of API 650

b. Liquid-penetrant inspection was performed on all tank nozzle welds below and including the overflow nozzle both internal and external to the tank. All fillet and socket welds received a random liquid penetrant examination. Methods, technique, and acceptance standards were in accordance with the ASME B&PV Code Section VIII, Division I.

Note n

The RCIC and HPCI turbines do not fall within the applicable design codes. To ensure that the turbine is fabricated to the standards commensurate with their safety and performance requirements, GE has established specific design requirements for this component. These requirements are given in the appropriate GE internal documents.

Note o

The radwaste system for Fermi 2 is excluded from Category I criteria because the conservatively calculated offsite whole-body dose from radwaste system failure does not exceed 0.5 rem as specified in Regulatory Guide 1.29. The dose-rate considerations and analyses are discussed in Chapter 11, particularly Subsections 11.2.3 and 11.3.3.

Note p

Section VIII of ASME B&PV Code and ANSI B31.1.0 apply downstream of the outermost isolation valves.

Note q

Three valves, one inside and two outside the containment, are placed in the RWCU influent line. The RWCU effluent line has two valves, one inside and one outside containment. The RWCU system beyond the third isolation valve G3352F119 on the influent line up to the outside containment isolation valve G3352F220 on the effluent line is constructed in accordance with the applicable codes of Code Group D.

Note r

The first valve capable of timely actuation in branch lines connected to the main steam lines between the outermost containment isolation valve and the third isolation valve, meets all of the pressure integrity requirements of Group D plus the following additional requirements:

1. Pressure-retaining components of all cast parts of valves are subject to volumetric examination or surface examination methods. Ultrasonic examination to equivalent standards is used as an alternate to radiographic methods. If size or configuration does not permit effective volumetric examination, magnetic-particle or liquid-penetrant methods are substituted

2. All inspection records are retained for the life of the plant. These records include data pertaining to the qualification of inspection personnel, examination procedures, and examination results. A certification has been obtained from the vendors of the turbine stop valves and turbine bypass valves stating that all cast pressure-retaining parts of a size and configuration for which volumetric examination methods are effective have been examined by radiographic methods by qualified personnel. Ultrasonic examination to equivalent standards may be used as an alternative to radiographic methods.

Note s

The spring-loaded piston operator of the valve is held open by air pressure during normal operation. Fail-open solenoid valves are used to release air pressure and to permit the check valve piston operators to close. The valves are remote manually operated from the main control room using signals that indicate loss of feedwater flow.

The classification of the feedwater line from the reactor pressure vessel through the third isolation valve is Quality Group A. The remainder of these systems is Quality Code Group D.

Note t

The specific IEEE construction codes used for a particular component may be found in the purchase document referenced in the Master Instrument List.

Note u

The outermost valve of the three isolation valves in the feedwater lines is similar to a boiler feed pump check valve.

Note v

The condensate storage tank is designed, fabricated, and tested to meet the intent of API 650. In addition, the specifications for the tank require that

1. All shell joints are full penetration and fusion welds
2. All shell joints are radiographed 100 percent
3. Shell to bottom joint is 100 percent liquid penetrant examined.

Note w

Fire detection, suppression, and extinguishing systems, emergency lighting, and breathing apparatus impacting safety-related areas of the plant are periodically inspected, maintained, and tested for proper operation per the Operational QA Program Requirements.

Note x

Residual heat removal (RHR) head spray line between reactor pressure vessel and bulkhead penetration is removed. Therefore, head spray portion of RHR shutdown cooling is no longer part of the reactor coolant pressure boundary. Also, an in-line blank orifice plate isolates the head spray piping from the RHR System. The head spray piping and its associated components have been downgraded to Quality Group B (piping and components between and including isolation valves E1150F022 and E1150F023) or Quality Group D (all other head spray piping and components that are not part of the RHR System pressure boundary).

Note y

The fuel preparation machines are used for removing and replacing channels on fuel assemblies and fuel bundle inspection. They are not required to prevent or mitigate the consequences of postulated accidents. Therefore, they are classified QA level non-Q and seismic category II/I. They were originally supplied by GE as passive, safety-related components, seismically qualified to the Fermi 2 design basis OBE and SSE seismic events.

Note z

The reactor recirculation pumps are upgraded to the 4th generation design. The modified RCPB components were designed and manufactured to ASME III, Class 1, 1989, No addenda.

TABLE 3.2-2 CATEGORY I MECHANICAL COMPONENTS: METHOD OF SEISMIC QUALIFICATION

Components	Testing	Analysis	Remarks
General			
Category I piping		X	
NSSS valves (by GE)	X	X	See note a
BOP valves (by Edison)	X	X	See note b
Penetration assemblies		X	
Specific			
Reactor vessel and internals		X	
Control rods		X	
Control rod drives and housings		X	
Fuel assemblies		X	
Safety/relief valves		X	
Air accumulators		X	
Main steam isolation valves	X	X	See note a
Recirculation pumps and motors		X	Nonessential; see note c
Recirculation valves		X	
CRD hydraulic control units	X		
Standby liquid control tank		X	
SLCS pump and motor		X	
RHR heat exchangers		X	
RHR pumps		X	
RHR pump motors		X	
Core spray		X	
Core spray pump motors		X	
HPCI steam turbine		X	
HPCI pumps		X	
RCIC steam turbine		X	
RCIC pumps		X	
Refueling platform		X	See note e
Refueling bellows		X	Nonessential; see note c

TABLE 3.2-2 CATEGORY I MECHANICAL COMPONENTS: METHOD OF SEISMIC QUALIFICATION

Components	Testing	Analysis	Remarks
Fuel storage racks		X	
RHR service water pumps		X	
RHR service water pump motors		X	
RHR cooling towers		X	
Control air compressors		X	
Control air dryers	X		
Control air aftercoolers	X		
Control air receiver tanks		X	
Control air afterfilter	X		
Diesel generator day tanks		X	
Fuel oil tanks		X	
Fuel oil pumps		X	
Diesel generator service water pump		X	
Diesel generator pump motors		X	
Diesel generators		X	
Standby gas treatment filter units		X	
EECW heat exchangers		X	
EECW pumps and motors		X	
EECW makeup pumps and motors		X	
EECW service water pump and motors		X	
ECCS equipment area cooling units		X	
EECW makeup tanks		X	
Primary containment		X	
Reactor building crane		X	
Post-LOCA hydrogen control system	X	X	See note d
Drywell coolers		X	
Drywell cooler fans		X	
Floor and equipment drain sumps		X	
Floor and equipment drain sump pumps		X	

TABLE 3.2-2 CATEGORY I MECHANICAL COMPONENTS: METHOD OF SEISMIC QUALIFICATION

Components	Testing	Analysis	Remarks
Reactor building HVAC isolation dampers		X	
Control center multizone units		X	
Return air fans		X	
Chillers		X	
Chilled water pumps and motors		X	
Emergency makeup air filter		X	
Recirculation air filter		X	
Recirculation air filter fans		X	
Fan-coil units		X	
Battery room fans		X	

[a] Prototype test was conducted for the main steam isolation valves (Atwood and Morrill type, furnished by GE).

[b] Prototype tests were conducted for Limitorque motor operators, including operability tests.

[c] Components that are listed as nonessential are not required to operate during or after a safe-shutdown earthquake but have to retain their integrity for pressure-retaining functions.

[d] Prototype tests were conducted for the hydrogen control and recombiner system, and seismic analysis was conducted as part of the stress analysis of pressure-retaining components and piping.

[e] The refueling platform has been reclassified as Seismic Category II/I.

TABLE 3.2-3 MINIMUM CODE REQUIREMENTS FOR QUALITY GROUP CLASSIFICATION

Component	Group A	Group B	Group C	Group D
Pressure vessels	ASME B&PV Code Section III, Class A	ASME B&PV Code Section III, Class C	ASME B&PV Code Section VIII, Division I	ASME B&PV Code Section VIII, Division I or equivalent
0-15 psig storage tanks	None	API-620	API-620	API-620 or equivalent
Atmospheric storage tanks	None	API-650, ANSI B96.1	API-650, ANSI B96.1	API-650, ANSI B96.1 or equivalent
Piping	ANSI B31.7, Class I	ANSI B31.7, Class II	ANSI B31.7, Class III	ANSI B31.1.0 or equivalent
Pumps and valves	ASME Code for Pumps and Valves Class I	ASME Code for Pumps and Valves Class II	ASME Code for Pumps and Valves Class III	Valves-ANSI B31.1.0 or Equivalent Pumps-ASME Code for pumps. Valves Class III or equivalent

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These code requirements were established and agreed to by the AEC during the Construction Permit Review (AEC Staff Safety Evaluation Report, Table 3.3.3) and do not, in all cases, conform to the codes indicated in Regulatory Guide 1.26. However, as noted under Principal Construction Code, Table 3.2-1, many of the construction codes actually used exceed the above and meet the Regulatory Guide 1.26 requirements. For example, the primary electrical penetrations conform to ASME B&PV Code Section III, Subsection NE, Class NE.

These requirements were supplemented and modified as shown in Table 3.2-4 and explained in Subsection 3.2.2.

For code definitions, see Note h of Table 3.2-1.

TABLE 3.2-4 CODE STATUS OF CLASS I (A) PRIMARY PRESSURE BOUNDARY COMPONENTS

Component Description	Quantity	Plant Identification System Number	Purchase Order Date	Code Applied	Code Required per 10 CFR 50, 55a
Reactor pressure vessel[a]	1	B11-A001	Jan. 67	ASME III[b] 69S[c]	ASME III, 70S
RPV head nozzle	1	B11-D072[i]	May 71	ASME III, 70S	ASME III, 70S
CRD housinga	185	B11-D141, 142, 143, 144	Aug. 70	ASME III, 69W[d]	ASME III, 70S
CRD[e]	185	B11-D146	July 70	ASME III, 69W	ASME III, 70S
In-core housing	55	B11-D190, 198	Sept. 70	ASME III, 69W	ASME III, 70S
Jet pump instrument penetration	2	B11-D235	Jan. 71	ASME III, 70S	ASME III, 70S
Safety/relieve valve	15	B21-F013	Jan. 71[f]	NPVC, 70	ASME III, 71
MSIV inboard	4	B21-F022	Oct. 69	NPVC, 68[g]	ASME III, 71
MSIV outboard	4	B21-F028	Oct. 69	NPVC, 68	ASME III, 71
Primary steam piping	1	B21-G001	Sept. 70	B31.7, [h]69	ASME III, 71S
Main steam flow element	2	B21-N005	Jan. 71	B31.7, 69	ASME III, 71S
Recirc. pump[j]	2	B31-C001	Dec. 69	NPVC, 68	ASME III, 71
Recirc. gate valve	2	B31-F023	Nov. 69	NPVC, 68	ASME III, 71
Recirc. gate valve	4	B31-F031	Nov. 69	NPVC, 68	ASME III, 71
Recirc. piping	2	B31-G001	June 70	B31.7, 69	ASME III, 71S
Recirc. flow element	2	B31-N013	Jan. 71	B31.7, 69	ASME III, 71S

[a] Upgraded from 1965 ASME Code, 1969 Summer Addendum edition except for specific nozzle and attachment magnetic-particle tests (refer to AEC Question 2.5.1 and Edison PSAR Amendment 11 dated September 15, 1970).

[b] ASME III = ASME Boiler and Pressure Vessel Code Section III.

[c] S = Summer Addendum to the Code.

[d] W = Winter Addendum to the Code

[e] Pressure boundary components only

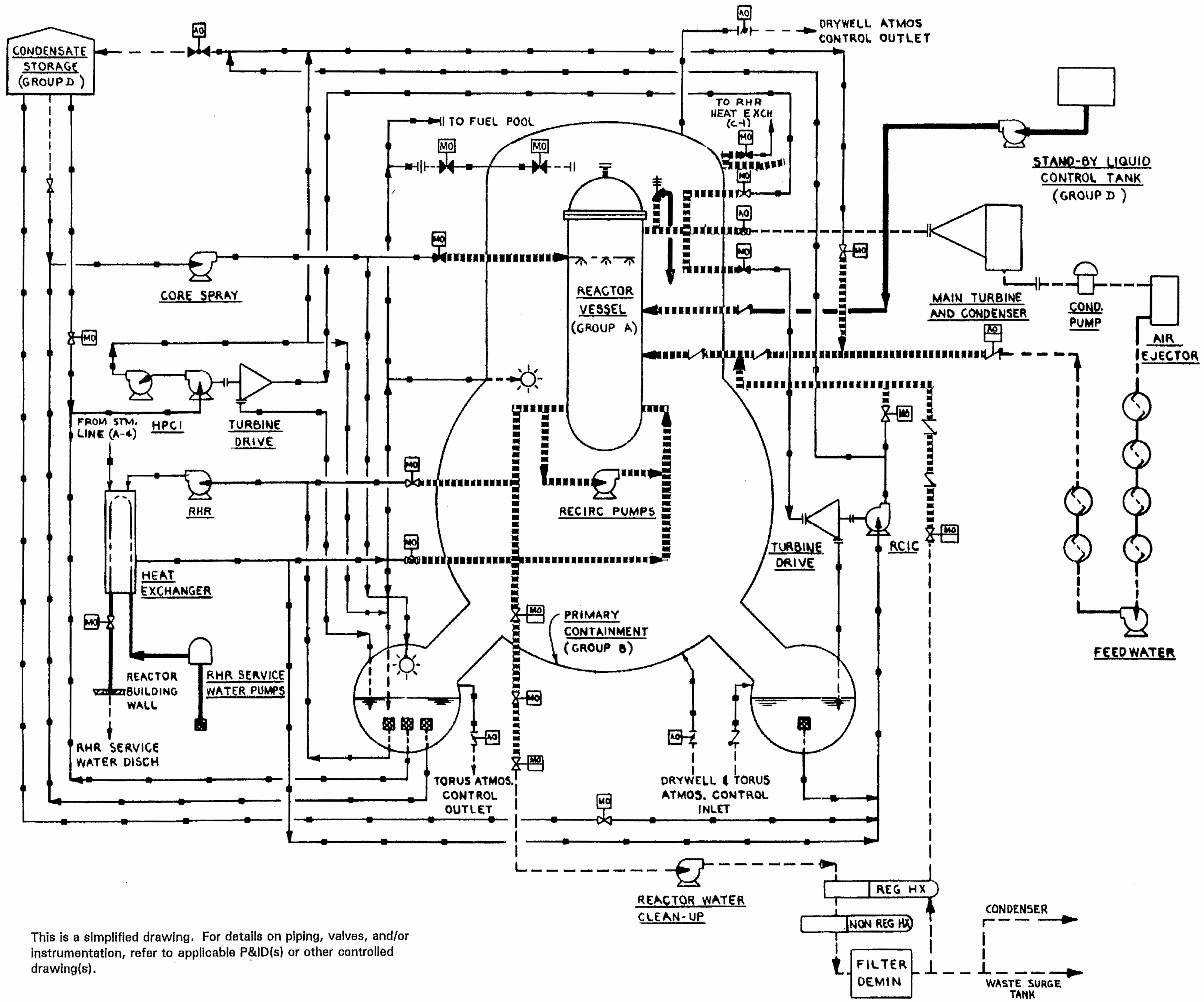
[f] The purchase order was revised on 4/18/77 to delete Dresser as the vendor and replace it with Target Rock. The original procurement requirements and codes remained applicable.

[g] NPVC = ASME Draft Code for Pumps and Valves for Nuclear Power.

[h] B31.7 = ANSI B31.7 Code for Nuclear Power Piping.

[i] GE master part number B11-D072 is deleted

[j] Upgraded to 4th Generation Design. Cover Assembly Per ASME III, 1989.



LEGEND:

GROUP A	IIIIIIIIIIIIIIII
GROUP B	—●——●—
GROUP C	————
GROUP D+ (D PLUS)	// // // //
GROUP D	- - - - - - - -
UNCLASSIFIED	— — — —
AIR SUPPLY	— ⫲ ⫲ ⫲ ·

This is a simplified drawing. For details on piping, valves, and/or instrumentation, refer to applicable P&ID(s) or other controlled drawing(s).

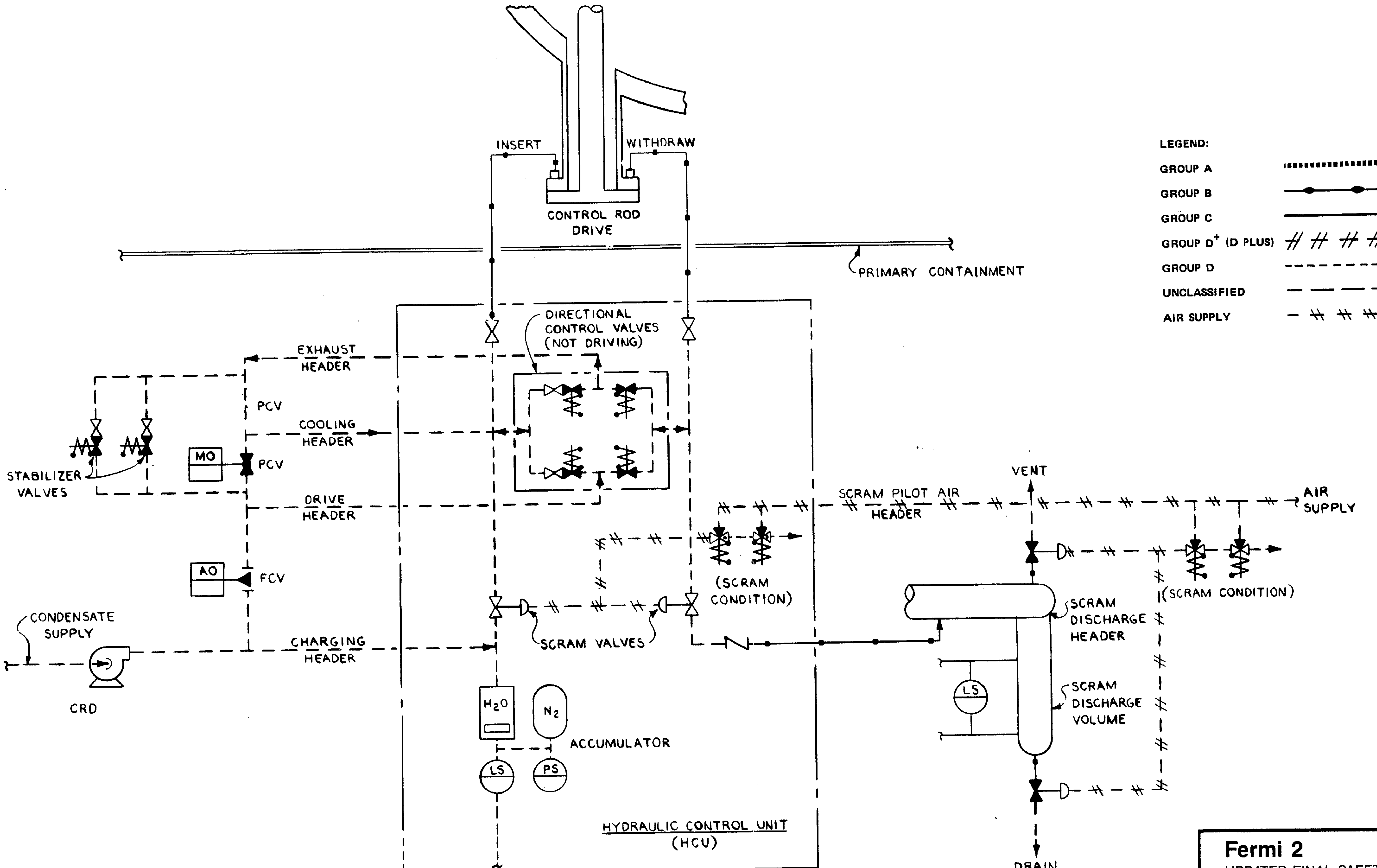
BASED ON GENERAL ELECTRIC COMPANY DWG. NO. 117C4559AB

Fermi 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 3.2-1

GROUP CLASSIFICATION DIAGRAM
NUCLEAR BOILER SYSTEM

REV 22 04/19



LEGEND:

GROUP A	
GROUP B	
GROUP C	
GROUP D$^+$ (D PLUS)	
GROUP D	
UNCLASSIFIED	
AIR SUPPLY	

Fermi 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 3.2-2

GROUP CLASSIFICATION DIAGRAM
CONTROL ROD DRIVE SYSTEM

BASED ON GENERAL ELECTRIC COMPANY DWG. NO. 117C4559AB

3.3 WIND AND TORNADO LOADINGS

3.3.1 Wind Loadings

3.3.1.1 Design Wind Velocity

For service load conditions, the Category I structures of Fermi 2 are designed to withstand a 90 mph fastest-mile sustained wind velocity, 30 ft above ground level. This wind velocity has a l00-year recurrence interval.

3.3.1.2 Basis for Wind Velocity Selection

The wind velocity and recurrence interval is based on ASCE Paper No. 6038 by H. C. S. Thom (Reference 1). The 90-mph velocity for the Fermi site was read from Figure 5 of this paper. Figure 3.3-1 is a reproduction of Figure 5 of ASCE Paper No. 6038. This paper is referenced in the ANSI A58.1-1972 Code (Reference 2) for selecting basic wind speeds for locations in the United States.

The design of 90 mph is conservative for the Fermi 2 site when compared to measured values recorded at Detroit City Airport and Toledo, Ohio. As discussed in Subsection 2.3.1, the fastest-mile wind recorded was 77 mph at Detroit City Airport.

3.3.1.3 Vertical Velocity Distribution and Gust Factor

The relationships to determine the vertical velocity distribution of the wind are obtained from page 1139 of ASCE Paper No. 3269 (Reference 3) for coastal areas and are as follows:

for $V_{30} \leq 60$ mph

$$V_z = V_{30}\left(\frac{z}{30}\right)^{0.3} \qquad (3.3\text{-}1)$$

for $V_{30} > 60$ mph

$$V_z = V_{30}\left(\frac{z}{30}\right)^{x} \qquad (3.3\text{-}2)$$

where

V_{30} = basic wind velocity (mph) at height 30 ft above ground level (grade)

x = factor which varies from 0.3 when V_{30} = 60 mph to 0.143 when V_{30} = 130 mph (Reference 3)

V_z = wind velocity (mph) at height (z) above grade

z = distance above grade in feet

Thus, at heights between 100 and 150 ft above grade, the height of the upper portion of the reactor building, the wind velocity is calculated to be 123.5 mph. Gust factors have also been determined by the methods given on pages 1124 through 1198 in ASCE Paper No. 3269 (Reference 3). For all Category I structures, the gust factor varies linearly from 1.1 at grade level to 1.0 at 400 ft. However, a gust factor of 1.1 was used for the full height of both the reactor/auxiliary building and the residual heat removal (RHR) complex except for the blow-away siding design during the design tornado, where a factor of 1.0 was used.

3.3.1.4 Determination of Applied Forces

The design wind velocity specified in Subsection 3.3.1.1 is translated into an equivalent static pressure according to the provisions outlined on pages 1150-1151 in ASCE Paper No. 3269 (Reference 3). The dynamic pressure is the product of one-half the air density and the square of the resultant design velocity, and represents the kinetic energy per unit volume of moving air. For standard air and velocity, V_z, in mph, pressure in pounds per square foot is given by

$$q = 0.002558\ V_z^2 \qquad (3.3\text{-}3)$$

The equivalent static pressure to be applied to the structure is given by

$$p = q \times C_D \qquad (3.3\text{-}4)$$

where

p = average pressure, pounds per square foot

C_D = average pressure coefficient

q = dynamic pressure, pounds per square foot

Positive and negative average pressure coefficients of 0.9 and 0.5, respectively, which include the appropriate shape and drag coefficients, are applied to the walls of rectangular flat-topped structures. An average pressure coefficient of 0.8 is used for roof suction. Table 3.3-1 lists the equivalent static pressure as a function of height above grade for rectangular flat-topped Category I structures.

3.3.2 Tornado Loadings

If tornadic winds traverse the site, the reactor is capable of being shut down and secured in a safe-shutdown mode. Some minor superstructure damage could be incurred by the reactor/auxiliary building. Damage could occur to other nonseismic structures suchas the turbine building, condensate storage tanks, and incoming power lines, without affecting the ability to shut down the reactor and maintain integrity of containment and essential heat removal systems during and following a tornado that might traverse the site. Simultaneous damage to all of these items is not expected. However, as a design objective, the reactor is capable of being safely shut down and maintained in a safe-shutdown condition with the loss of all such nonseismic structures. Components that directly affect the ultimate safe shutdown of the plant are located either under the protection of reinforced concrete or underground.

Where structural failure could affect the operation and functions of the primary containment and reactor primary system, and for structures affecting equipment necessary for safe shutdown of the reactor, tornado effects are considered in the design of these structures.

3.3.2.1 Applicable Design Parameters

For extreme environmental load conditions, the Category I structures housing the systems required for a safe shutdown of the plant in the event of a tornado are designed to withstand the effects of a tornado by providing either sufficiently strong structures or appropriate venting. With the exception of the 4160-V RHR cable vaults, manholes, and ductbanks, the design parameters of the Fermi 2 design-basis tornado are

a. A rotational wind velocity of 300 mph
b. A translational wind velocity of 60 mph
c. An external pressure drop of 3 psi at the rate of 1 psi/sec.

Although the Fermi 2 design was established before the issuance of Regulatory Guide 1.76, Design Basis Tornado for Nuclear Power Plants (April 1974), the above parameters compare well with this guide. The rotational and translational wind velocities given in the guide are slightly different (290 mph and 70 mph, respectively). However, the total maximum velocity is the same. Likewise, although the rate of pressure drop given in the guide is faster (2 psi/sec), the magnitude of the pressure drop is the same.

The tornado missile design of the 4160-V RHR cable vaults and the manholes and ductbanks between these cable vaults and the Reactor/Auxiliary building cable vaults is based on criteria established in Regulatory Guide 1.76, Revision 1 (March 2007) and tornado missile analysis methods specified in NUREG-0800, Standard Review Plan 3.5.3 Revision 3, dated March 2007.

The Design Basis Tornado wind characteristics in accordance with Regulatory Guide 1.76 Revision 1 (March 2007) are as follows:

a. A maximum wind velocity of 230 mph
b. A maximum rotational wind velocity of 184 mph
c. A translational wind velocity of 46 mph
d. An external pressure drop of 1.2 psi at the rate of 0.5 psi/sec

Tornado wind velocity and pressure drop corresponding to the tornado generated missiles is used to evaluate the adequacy of the 4160-V RHR cable vaults and the manholes and ductbanks between these cable vaults and the Reactor/Auxiliary building cable vaults.

3.3.2.2 Determination of Forces on Structures

All tornado wind pressure and differential pressure effects are considered static in application since the natural period of the building structures and their exposed elements are short compared with the rise in time of the applied design pressures.

The tornado wind rotational velocity varies linearly with radius (r) from zero at the center to a maximum at a distance R_c from the center and inversely with r as r increases beyond R_c. That is

$$v = \frac{c}{r} \text{ for } r > R_c \text{ (Reference 4)} \qquad (3.3\text{-}5)$$

where

V = velocity, fps

r = radial distance from center of tornado, ft

c = a constant for tornadoes empirically established at 10^5 ft^2/sec (Reference 4)

At the design rotation velocity of 300 mph (440 fps), r = R_c and is 227 ft, as determined from the above equation. The resulting rotational velocity is shown in Figure 3.3-2. The total velocity profile is obtained by algebraically adding 60 mph translational velocity to the rotational velocity profile. This is also shown in Figure 3.3-2. This results in a maximum velocity of 360 mph on the strong side of the tornado and a maximum velocity of 240 mph on the weak side. The rotational velocity distribution also varies according to the elevation above ground level reaching a maximum 300 mph at a point approximately 225 ft above ground (Reference 5), which is approximately 75 ft above the top of the reactor building. However, no reduction in rotational wind velocities is used, and therefore the analysis is conservative.

The maximum differential pressure of 3 psi occurs as a result of vortex action at the center of the tornado. Differential pressure as a function of cyclonic radius for the model (Reference 4) is given by the expressions:

$$p(r) = \rho V_c^2 \left[1.0 - 0.5\left({}^{r}/_{R_c}\right)^2\right] \text{ for } r < R_c \qquad (3.3\text{-}6)$$

$$p(r) = 0.5\,\rho V_c^2 \left({}^{R_c}/_{r}\right)^2 \text{ for } r \geq R_c \qquad (3.3\text{-}7)$$

where

p(r) = pressure drop, lb/ft^2

ρ = mass density of air = 0.002376 $lb\text{-}sec^2/ft^4$

V_c = maximum rotational velocity = 440 fps

The standard value of air density is assumed because, although the air density is expected to be reduced, its effect may be offset by the presence of dust. The pressure diagram resulting from the evaluation of the above equations is presented in Figure 3.3-3.

The tornado velocity is converted to an equivalent static pressure according to the procedures given in ASCE Paper No. 3269 (Reference 3), conservatively considering no variation with height and a gust factor of 1.0. This pressure is then combined with the barometric pressure.

When a flat object is placed in a tornado wind, the load on it is equal to the sum of the windward pressure and leeward pressure as the barometric pressure drop on both faces cancels out. However, when an unvented, enclosed object is placed in a tornado wind, the total windward pressure equals the leeward velocity pressure plus the barometric pressure drop. The total pressure diagrams for the vented and unvented cases are shown in Figure 3.3-4.

Most structures are unvented. However, the reactor/auxiliary building above the fifth floor is designed to vent as discussed in Subsection 3.3.2.3.2.

Category I structures have been designed to withstand the effects due to simultaneous action of tornado wind velocity pressures, atmospheric pressure drop, and a single tornado-generated missile.

The 4160-V RHR cable vaults, manholes, and ductbanks have been designed to simultaneous action of tornado wind velocity pressure, pressure drop, and a single tornado-generated missile in accordance with Regulatory Guide 1.76 Revision 1 (March 2007) and NUREG-0800, Standard Review Plan 3.5.3 Revision 3, dated March 2007.

Design tornado loads were found by making use of the following expression:

$$W_T = (p + C_p q)A + M_T \qquad (3.3\text{-}8)$$

where

W_T = design tornado load

p = atmospheric pressure drop

q = wind velocity pressure

C_p = pressure coefficient described in Subsection 3.3.1.4

A = exposed area under consideration

M_T = effects of single tornado-generated missile

Both overall (overturning, sliding) and local effects of tornado-generated loads W_T have been investigated. Structure under consideration was placed at various locations in the tornado wind field, and the governing combination of p and q was selected for each particular effect.

The effects of tornado missiles are local in nature. Accordingly, they have been taken into account in the design of structural elements and disregarded in case of overturning and sliding.

3.3.2.3 Ability of Category I Structures To Perform Despite Failure of Structures Not Designed for Tornado Loads

3.3.2.3.1 General

Superficial structural damage can be tolerated by the reactor/ auxiliary building and the RHR complex. Nonseismic structures such as the turbine building, condensate storage tanks, and incoming power distribution system can withstand some structural damage without affecting the safe-shutdown capabilities of Category I structures and equipment. As indicated in Table 3.3-2, systems required for a safe shutdown of the reactor are housed in well-protected structures.

3.3.2.3.2 Reactor/Auxiliary Building Above the Fifth Floor (Blow-Away Siding)

The panels and roof above the refueling floor are designed to release (blow away) during the design-basis tornado, as described in Section 3.8, while the remainder of the exposed frame is designed for the full tornado load. The design and analyses of these panels under tornado loadings have been presented to and accepted by the AEC by Reference 6. Further design requirements imposed on this portion of the reactor building are as follows:

a. For the design-basis tornado, and assuming that panels equivalent to 10 percent of the surface area of the panels are caught and do not release, the stress levels of the structural steel frame of this portion of the reactor building must not exceed 95 percent of the yield stress

b. With all siding in place, the reactor building will be capable of withstanding a 200-mph tornado wind at stress levels limited to 95 percent of the yield strength of the steel.

This additional load limitation provides a range of pressure within which the siding is designed to blow off.

For the reactor building above the refueling floor, the maximum load on the projected area of the exposed steel supporting frame with 10 percent of the siding is 464 lb/ft^2 during the design- basis tornado, while the maximum load on the structure for the 200-mph tornado with the siding all intact is -98 lb/ft^2 (suction) on the leeward side and 46 lb/ft^2 on the windward side. Surface pressure for the remainder of the reactor and auxiliary buildings and the RHR complex is included in the loading combinations considered in Section 3.8.

A postulated explosion of the 20,000-gallon liquid hydrogen tank at the HWC gas facility may also cause some damage to the roof and siding of the reactor building above the refueling floor. The hydrogen tank has been located sufficiently far from the reactor building to assure that blast forces from an explosion would be less than the pressure forces from a design basis tornado. Therefore, the tornado analysis bounds the effects of a hydrogen-tank explosion at the roof and siding above the refueling floor.

3.3.2.3.3 Fuel Pool Exposure

In the unlikely event of a tornado of sufficient severity to cause the panels above the refueling floor to release, the spent-fuel pool would be exposed. This concern was identified by the AEC as Post Construction Permit Open Item No. 9. The AEC had requested additional spent-fuel protection, but agreed later that no additional protection was required (Reference 7).

With the siding blown off during the design-basis tornado, the refueling floor would be exposed. However, based on the GE publication, "Tornado Protection for the Spent Fuel Storage Pool," APED-5696, Class-I (November 1968), there is no credible mechanism by which a significant amount of water could be sucked from the fuel pool by a tornado. The fuel stored in the spent-fuel storage pool would be protected by approximately 22 ft. 6 in. of water covering the tops of the fuel storage racks and by the racks themselves.

3.3.2.3.4 Crane and Crane Support Structures

The reactor building superstructure steel frame and anchor bolts are designed for the design-basis tornado described in Subsection 3.3.2.2 at a stress level of 95 percent of yield. Therefore, there would be no danger of failure of the columns supporting the crane bridge and trolley. Moreover, the crane and trolley are restrained from motion in the horizontal direction when not in use by "dead-man" safety pins.

The crane is provided with electrically operated locking bars effectively connecting the unloaded crane to the runway when not in use and capable of withstanding a design-basis tornado wind force of 410 lb/ft^2 due to a 360-mph resultant wind velocity. Restraints are provided on the crane bridge and trolley to prevent either from leaving their respective rails due to horizontal and vertical displacement in the event of a design-basis earthquake. For further details, see Subsection 3.7.3.18. Vent holes are provided in girders and other enclosed structures such as trolley frame, trucks, and electrical cabinets of such size to withstand an atmospheric pressure reduction of 1.0 psi/sec, maximum reduction of 3 psi, due to the design-basis pressure transient.

3.3.2.3.5 Other Venting

Because of the depressurization that can occur when the very low- pressure area within the funnel of a tornado engulfs a structure, structures housing equipment necessary for safe shutdown must either be designed for the depressurization, or be vented. In the Fermi 2 design, all such structures, with the exception of the steam tunnel, are designed for the depressurization. Venting of the steam tunnel is accomplished by blowout panels that are designed to release in the event of external depressurization.

3.3.2.3.6 Residual Heat Removal Complex

The RHR complex cooling towers are exposed to the flight of potential missiles. However, as discussed in Section 3.5, the probability of damage is negligible.

All systems contained in the RHR complex are divided into two separate and redundant groups, Division I and Division II, with a thick wall between the two divisions that serves as a missile barrier. This further reduces the probability of safety-related systems not being able to perform their functions. The RHR complex is described in Section 9.2.

3.3.2.3.7 Tornado Failure of Nonseismic Structures

Protection against the possibility of failure of Category I structures due to the tornado-induced failure of nonseismic structures is provided by the inherent structural integrity of the Category I structures to mitigate other postulated, equally severe events. Further, the site building arrangement (see Figure 1.2-5), as well as the history and probability of tornadoes likely to occur at the site, minimizes the probability of a tornado engulfing a nonseismic structure.

3.3.2.3.7.1 Probability of Occurrence

The probability of a design-basis tornado occurring at the 1000-acre Fermi site is 4.075×10^{-5}, or a recurrence interval of 24,500 years (Subsection 2.3.1.3.2). This probability is significantly further diminished by factoring in the horizontal surface area occupied by the Fermi 2 Category I structures - approximately 1 acre.

3.3.2.3.7.2 Category I - Nonseismic Structure Arrangement

Category I structures are located with respect to nonseismic structures in a manner that minimizes, if not eliminates, the probability of failure of a Category I structure due to the tornado-induced failure of the nonseismic structure. The impingement of a nonseismic structure upon a Category I structure, or the generation of missiles from a nonseismic structure, are the only unlikely events that could be postulated to occur.

Some temporary trailers and miscellaneous construction material may be stored near Category I structures to support plant outages.

There is a refuel outage building adjacent to the south wall of the reactor building and a small prefabricated metal building housing nitrogen inerting equipment immediately west of the reactor building. In addition, approximately 30 ft west of the RHR complex, there is a 345-kV switchyard. To the north is a reinforced-concrete cooling tower.

To the east is the turbine house-radwaste building, which consists of a reinforced-concrete structure and steel superstructure. The failure of other nonseismic structures further eastward of the turbine house-radwaste building would not affect the Category I structures, as missiles or impingement caused by their failure would affect only the reinforced-concrete turbine house. The turbine house can absorb energy resulting from either another nonseismic structure failure, or its own partial failure.

3.3.2.3.7.3 Turbine Building

The improbable direct strike of a tornado on the turbine building could result in a worst-case event where portions of the metal siding and support columns and girders deform and impinge against the thick, heavily reinforced concrete wall of the adjacent reactor/auxiliary building (see Figure 1.2-20). This impingement could result in superficial structural damage, but would not prevent the reactor from being brought into a safe-shutdown mode.

The collapse of the turbine building roof would not affect the operation of any safety-related equipment. There is no safety- related equipment in the turbine building that would be required to operate if the roof were to collapse.

A postulated explosion of the 20,000-gallon liquid hydrogen tank at the HWC gas facility may also cause some damage to the roof and siding of the turbine building above the operating floor. The hydrogen tank has been located sufficiently far from the turbine building to assure that blast forces from an explosion would be minimized, and that stop and control valve closure inputs to the reactor protection system would remain functional. However, even if trip function (direct scram) is postulated to fail, other diverse signals, such as reactor pressure and high neutron flux, will scram the reactor. Therefore the consequences of a turbine trip with a postulated failure of direct scram are bounded by the design basis earthquake event.

3.3.2.3.7.4 Category I Buildings

The Fermi 2 Category I buildings are designed for the postulated severe loading conditions in appropriate loading combinations (Section 3.8). Their construction generally consists of thick, heavily reinforced concrete walls. A spectrum of missiles was selected, approved by the NRC, and used as a design basis for these buildings. As discussed in 3.3.2.3.7.2, the arrangement of nonseismic structures with respect to Category I buildings minimizes the effect of a nonseismic structure failure on Category I buildings.

3.3 WIND AND TORNADO LOADINGS

REFERENCES

1. H. C. S. Thom, "New Distributions of Extreme Winds in the United States," Journal of the Structural Division, ASCE, Vol. 94, (ST 7), pp. 1787-1801, July 1968.
2. ANSI A581-1972, Building Code Requirements for Minimum Design Loads in Buildings and Other Structures.
3. Task Committee on Wind Forces, Committee on Loads and Stresses, Wind Forces on Structures, Final Report, Paper No. 3269, Vol. 26 Transactions, ASCE, 1961.
4. J. M. McLaughlin, Sargent & Lundy, Design of Nuclear Power Plants for Tornados, Tornado Phenomenology and Related Protective Design Measures, Conference at the University of Wisconsin, April 26-28, 1970, page 5.
5. J. A. Dunlop, and K. Wiedner, "Nuclear Power Plant Tornado Design Considerations," Journal of the Powers Division, Proceedings of the ASCE, pp. 407-417, March 1971.
6. Detroit Edison Company, Technical Report, PSAR Open Item No. 7, "Tornado Winds-Refueling Floor Siding and Superstructure," May 8, 1973. Submitted to and approved by the AEC, Docket No. 50-341, per letter of August 2, 1973 from AEC to Edison.
7. Letter from AEC to Edison, June 11, 1974 responding to Edison letters EF 2-l8679, August 9, 1973, and EF 2-19171, August 14, 1973.

TABLE 3.3-1 EQUIVALENT STATIC WIND PRESSURE

Used in the Design of Category I Structures

Height Above Grade (ft)	Positive Pressure (1b/ft^2)	Negative Pressure (1b/ft^2)	Total Pressure (1b/ft^2)
0 to 50	22.8	12.7	35.5
50 to 100	34.9	19.4	54.3
100 to 150	42.5	23.6	66.1
150 to 200	47.9	26.6	74.5

TABLE 3.3-2 SYSTEMS REQUIRED TO ATTAIN SAFE SHUTDOWN IN THE EVENT OF A TORNADO

Systems	Location
Emergency equipment cooling water system	Reactor/auxiliary building
Emergency equipment service water system	RHR complex
Reactor core isolation cooling system	Reactor/auxiliary building
Emergency diesel generator system	RHR complex
Residual heat removal system (shutdown cooling)	Reactor/auxiliary building
RHR service water system	RHR complex, reactor/auxiliary building
Reactor protection system	Reactor/auxiliary building

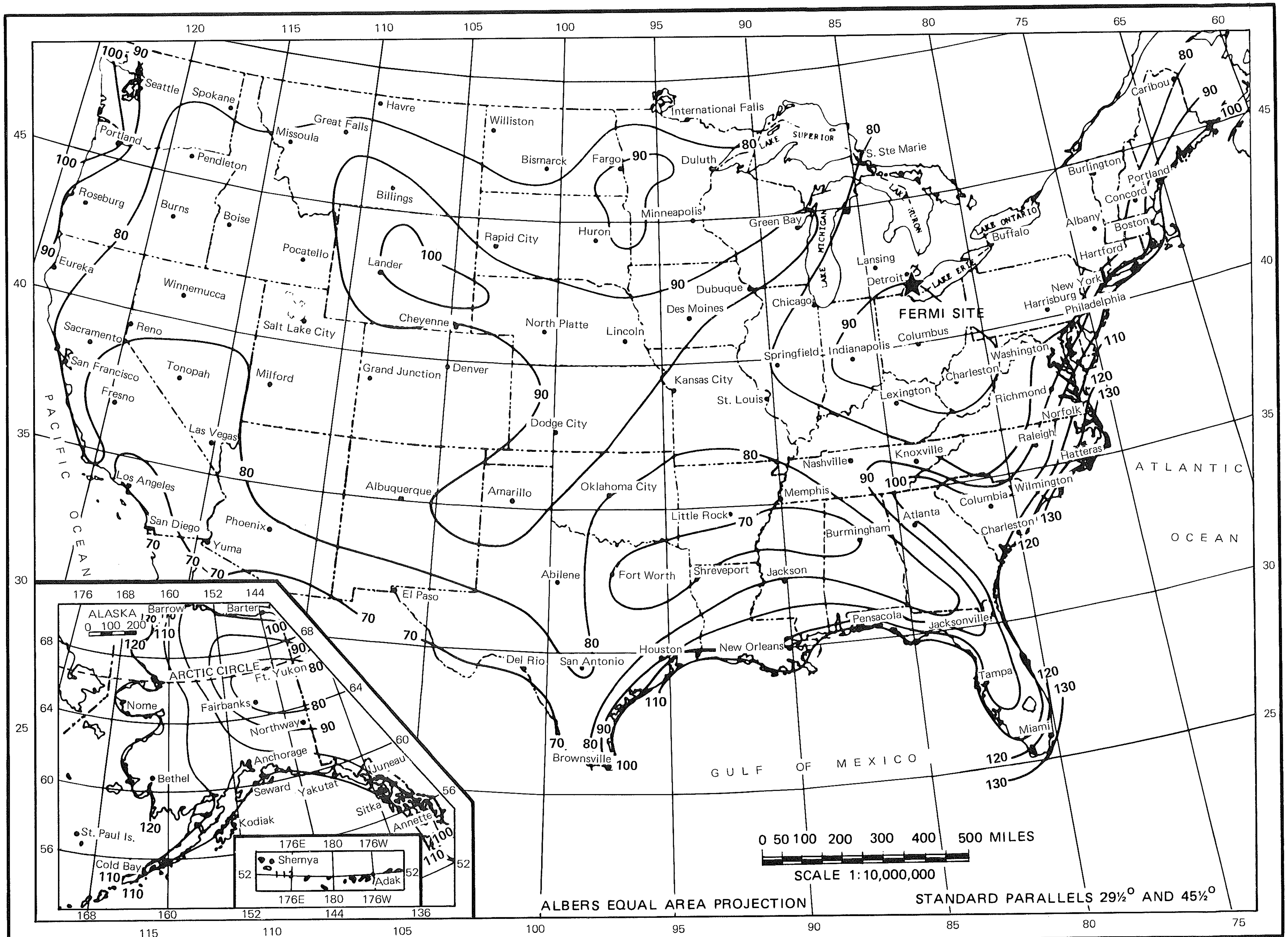


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FIGURE 3.3-1

ISOTACH 0.01 QUANTILES IN MILES PER HOUR ANNUAL EXTREME – 30 FT ABOVE GROUND 100-YEAR MEAN RECURRENCE INTERVAL

REFERENCE: ASCE PAPER NO. 6038, FIGURE 5, JULY, 1968 (REFERENCE 1)

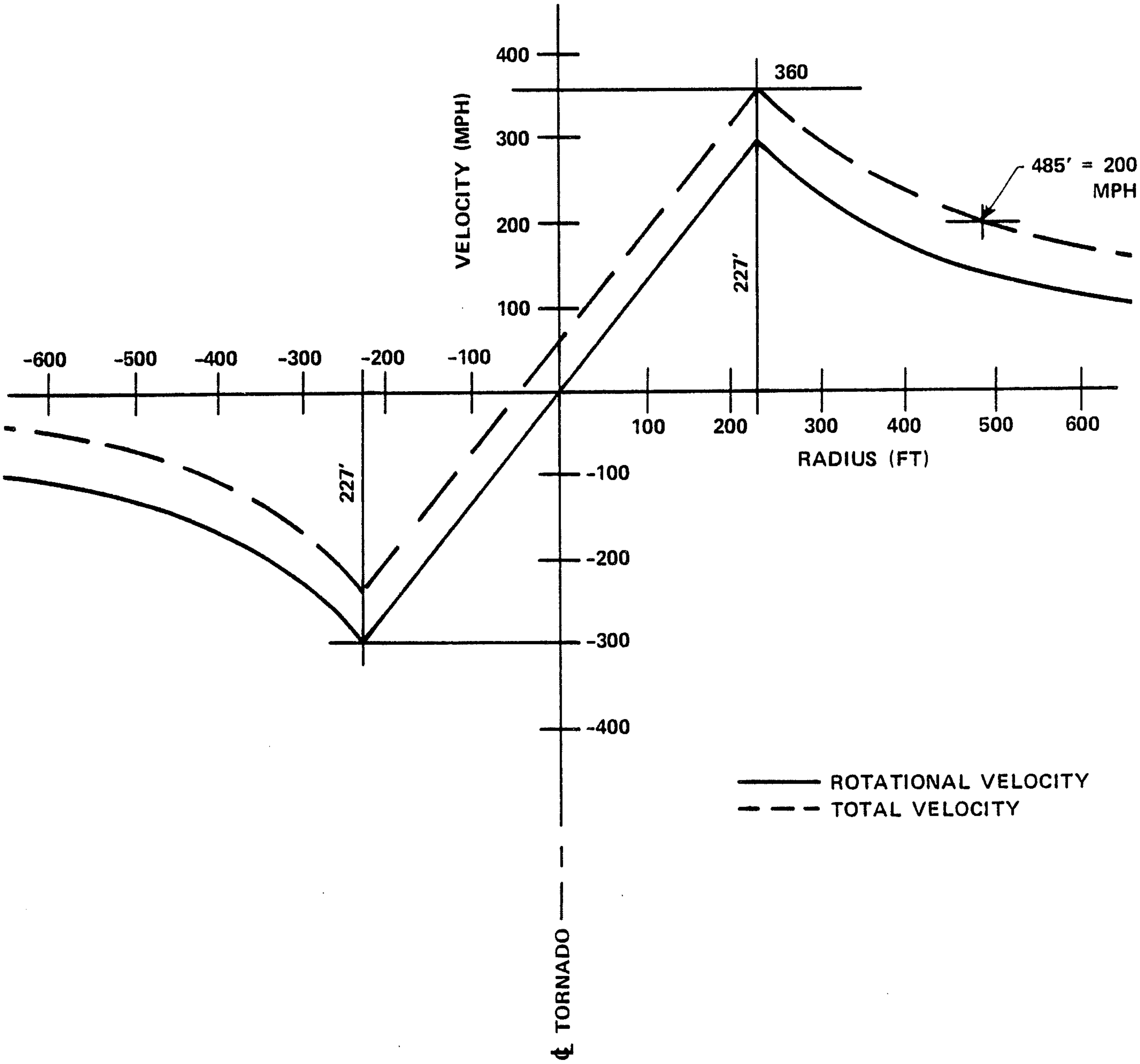

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FIGURE 3.3-2

TORNADO VELOCITY VERSUS DISTANCE

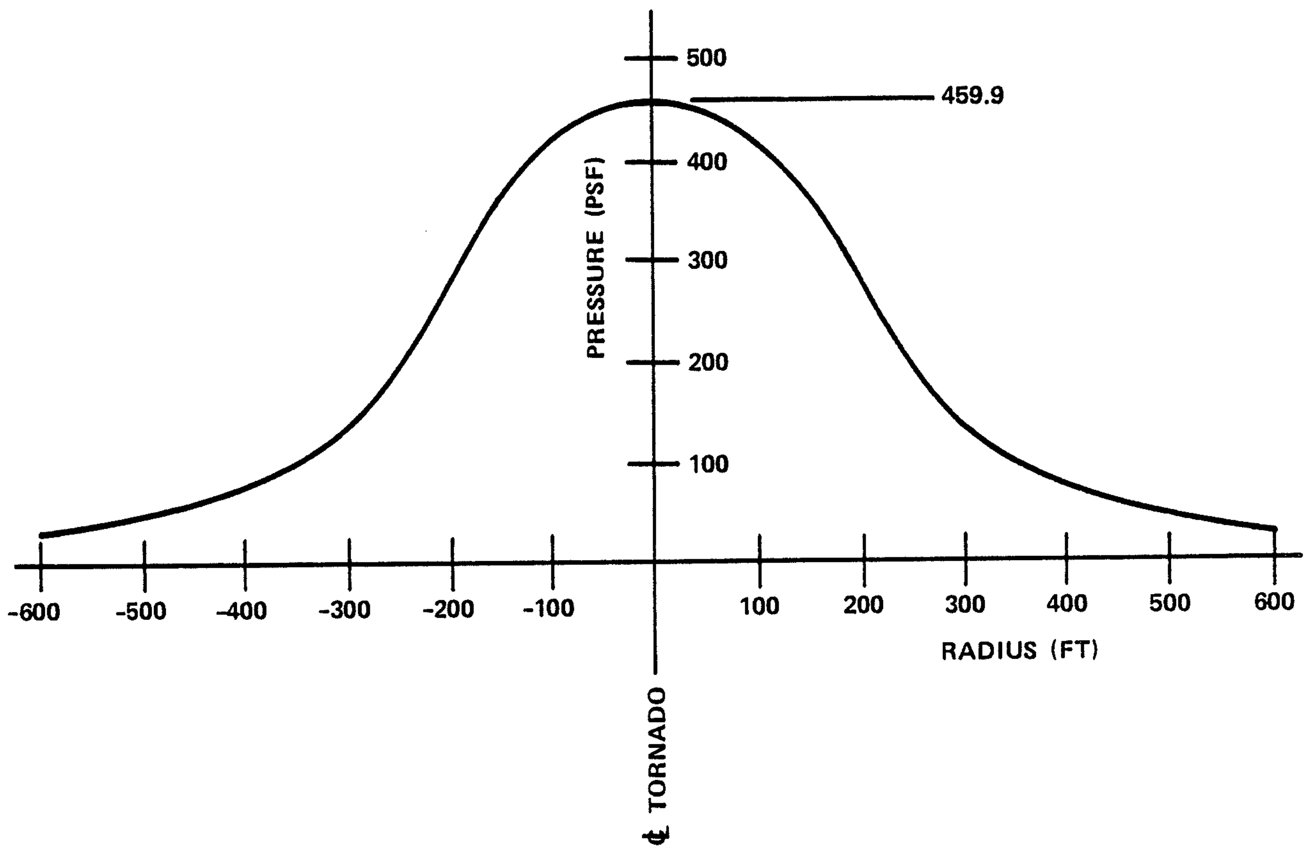

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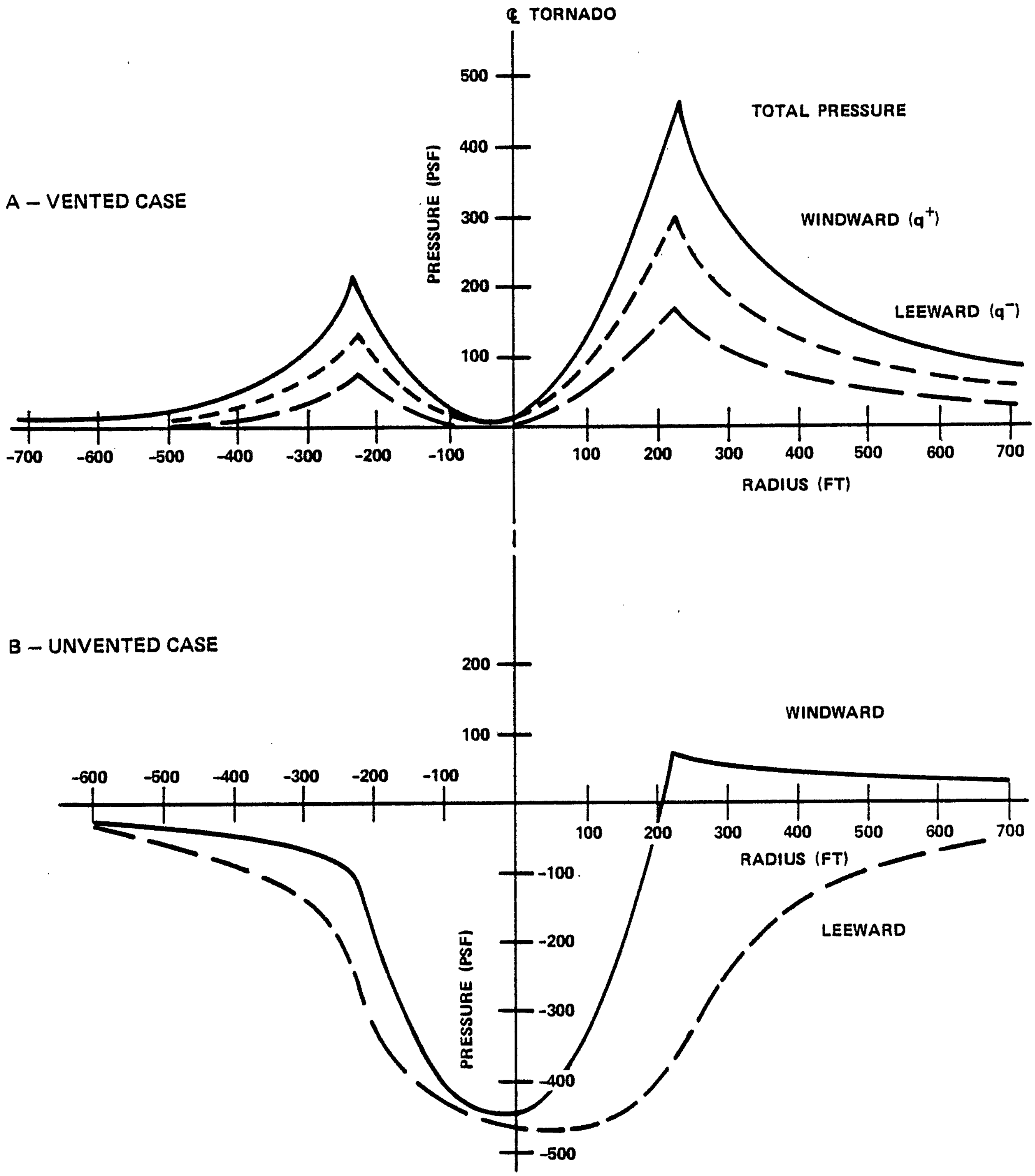
FIGURE 3.3-3

TORNADO PRESSURE DROP VERSUS DISTANCE



REFERENCE: TASK COMMITTEE ON WIND FORCES, COMMITTEE ON LOADS AND STRESSES, WIND FORCES ON STRUCTURES, FINAL REPORT, PAPER NO. 3269, VOL. 26 TRANSACTIONS, ASCE 1961.

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FIGURE 3.3-4

TORNADO WIND PRESSURE – VENTED AND UNVENTED

3.4 WATER LEVEL (FLOOD) DESIGN

3.4.1 Flood Elevations

From consideration of several types of hypothetical flooding, it was found that the maximum stillwater elevation that could occur at the site is 586.9 ft (New York Mean Tide, 1935), and results from the probable maximum meteorological event (PMME), with a storm path along the axis of Lake Erie (N 67.5° E). Flood design is discussed in Subsection 2.4.2 and the maximum elevation determination in Subsection 2.4.5.

All Category I components are protected from the adverse effects of the maximum flood elevation by their location within reinforced-concrete Category I structures, as described in this section and in Chapter 2.

As stated in Subsection 2.4.2, Fermi 2 Category I structures and components are designed against flooding up to a minimum elevation of 588 ft, or 1.1 ft above the maximum stillwater elevation.

3.4.2 Phenomena Considered in Design Load Calculations

Category I structures and components are designed for the static and hydrodynamic forces associated with wind-generated waves as specified in Subsection 2.4.5. The effects of a tsunami are not considered because the site is located in an area designated as having potentially minor seismic activity. Any seismic disturbance would be local and would result in only minor excitations in Lake Erie. Tsunami considerations are discussed in Subsection 2.4.6.

3.4.3 Flood Force Application

The pressure induced by the maximum stillwater elevation is considered to be hydrostatic. A lateral pressure distribution below the flood line on the walls of the Category I structures is determined. From this, the uplift pressure on the Category I structure basement slabs and flotation potential is then calculated. This pressure is included in the load combinations considered in the design of the slabs. Pressures induced by wave action are discussed in Subsection 2.4.5.

3.4.4 Flood Protection

Flood protection for Fermi 2 Category I structures and components includes waterproofing the structure, designing the structure to withstand the hydrostatic and hydrodynamic forces associated with flooding, maximum usage of watertight seals and penetrations below the maximum flood elevation, and locating the Category I components within the reinforced-concrete Category I structures.

3.4.4.1 Reactor Building Structure

The Category I reactor/auxiliary building, which houses safety-related systems and components, is designed against flooding to Elevation 588.0 ft, or 1.1 ft above the PMME stillwater flood elevation of 586.9 ft. All doors and penetrations through the outside walls below the design flood elevation are of watertight design.

As stated in Subsection 2.4.2.2.2, there are only a few essential penetrations in the exterior walls of the reactor/auxiliary building. All of these penetrations below Elevation 588.0 ft are watertight.

The presence of the turbine building prevents waves and wave runup above the sill elevations on the east wall of the reactor/ auxiliary building, thereby preventing flooding of the building. The south wall of the reactor/auxiliary building has two large openings and several waterproofed pipe-sleeved openings. The large openings are an air-locked rail car door and an air-locked personnel door. Both of these air-locked doors are completely waterproofed to preclude wave runup flooding.

In addition, all watertight doors have signs on both sides stating that the door is to be secured closed except for immediate use.

The several watertight sleeve openings, the walls of the building, and the watertight doors are designed to withstand the hydrostatic head of the maximum flood level. Maximum wave effects and forces are discussed in Subsection 2.4.5.4.

Leakage is not expected through the several watertight access openings and the waterproofed sleeved openings in the reactor/ auxiliary building.

The walls of the reactor/auxiliary building are waterproofed below the finished grade elevation of 583.0 ft.

Waterstops on all construction joints and water seal rings on all penetrations are provided on all openings below the maximum flood level. The waterstops are joined to form a continuous watertight seal. Joint preparation and joint sealants are in conformance with the recommendations and the guidelines of American Concrete Institute (ACI) standards. All work is inspected by qualified personnel to ensure that leakage is kept to a minimum.

All interior floor drain systems inside the reactor/auxiliary building are independent of the yard storm drainage system, and therefore no potential water backflow into the structure is anticipated during the design flood condition. Shore protection is not required to preclude flooding of this structure.

3.4.4.2 Residual Heat Removal Complex Structure

The residual heat removal (RHR) complex is watertight to Elevation 590.0 ft. There are no openings on the north, south, and west walls. All pipe and electrical penetrations on the east wall below Elevation 590.0 ft are waterproofed. However, if any amount of leakage should occur, it would go directly into an RHR Complex compartment. Then, it is pumped to the Circulating Water Reservoir.

The remaining openings to be considered would be the access doors on the east wall. These doors are normally closed and locked, and have their thresholds at Elevation 590.0 ft. They are of steel construction and are shielded behind reinforced-concrete missile walls. The insignificant amount of runup above the flooded elevation of 586.9 ft may find its way through the door threshold and door jambs, at Elevation 590.0 ft, and be diverted into the floor drain system in the building. The leakage through the gaps of the doors could never exceed the drain capacity of the Elevation 590.0-ft floor drain system. The structure is also designed to withstand the wave action associated with this flooding. (Refer to Subsection 2.4.2.2.3, Residual Heat Removal Complex Flood Criteria.)

The RHR complex is described in Subsection 9.2.5.

The RHR complex reservoir is floodproof. The reservoir overflow is a nonsiphon floodproof post. All active equipment that could be damaged by water (pump motors, switchgear, diesel generators) is located above the maximum water flood level.

Moreover, all interior floor drains are independent of the yard storm drain system. Thus, there is no potential for backflow flooding. Walls of the RHR complex below grade level are watertight.

3.4.4.3 Category I Yard Structures

The Category I piping and electrical ducts between the RHR complex and the reactor building are below the site flood elevation of 586.9 ft during the PMME. The RHR supply, RHR return, and emergency equipment service water pipelines to both divisions will continue to function during the flood.

There are two sets of Category I ductbanks between the RHR complex and the Reactor/Auxiliary building, with a Division I and Division II ductbank in each set. In each case, the buried cable ducts between the RHR complex and the Reactor/Auxiliary building provide adequate cable separation to maintain independence of redundant circuits.

The first set of ductbanks was installed during plant construction. The physical separation of the two redundant, below-grade circuits is 30 ft at the point the cable ducts leave the southeast corner of the reactor building. The ducts make a sweeping bend, with a minimum separation of 20 ft between them. After the bend, the ducts parallel the reactor building in a westerly direction, with 24 ft of separation. This separation is constant until the ducts pass under the rail car air lock, where the separation widens until the ducts enter (still below grade) the RHR complex.

Each circuit is separately housed in a cast-in-place, rectangular reinforced-concrete duct. The duct is covered by successive layers of compacted-rock fill placed up to the finished site nominal grade of 583 ft. The duct runs vary in elevation from 573 ft minimum to 580 ft maximum. Since the maximum ground-water elevation is 576 ft, the cables are not specifically designed for continuous underwater service. For low voltage power, control and instrumentation cables, there is no long term mechanism for water related insulation degradation due to lack of voltage stressor or a credible common mode failure mechanism. Therefore, low voltage cables perform their design functions while their external surface remains continuously wetted due to surrounding water. 4160-V essential power circuits are not routed within these ductbanks.

The second set of 4160-V RHR cable vaults, ductbanks and associated manholes is installed above the maximum ground water elevation of 576.0 ft with ducts sloped to the manholes, such that circuits contained are not subject to continuous wetting. These are also cast-in-place, rectangular reinforced concrete ductbanks, but are located with the ductbank top approximately six inches below the surface and manhole covers at grade level. 4160-V essential power circuits are routed within these ductbanks. Although the manholes and cable vaults may be subject to flooding during the duration of the PMME, the 4160-V essential bus tie cables are qualified for wet conditions in excess of six months, which is greater than this duration.

The minimum elevation for cable termination in either the RHR complex or the reactor building is 588.7 ft, which is above the site probable stillwater elevation of 586.9 ft.

3.4.4.4 Internal Flood Protection

3.4.4.4.1 General

Category I and nonseismic structures are provided with equipment and floor drainage systems designed to collect and remove all waste liquids from their points of origin to a suitable disposal area in a controlled and safe manner. All collected liquid waste is routed to sumps in each of the respective buildings, where it is allowed to accumulate for periodic discharge to the radwaste building for treatment. Abnormal sump water levels (high-high or low-low) are annunciated in the control room. The locations of the sumps and sump pumps, the capacity of each sump and sump pump, and the design bases for equipment and floor drainage systems of each building are described in Subsection 9.3.3.

To prevent backflow flooding through the equipment and floor drainage systems, the following considerations were included in the system design:

a. Independence of building systems to negate the possibility of abnormal occurrences in one building from affecting normal operation in other buildings

b. Check valves and manual isolation valves in each sump pump discharge line to prevent backflow to the sump.

c. Redundant check valves and a manual isolation valve located in both the equipment drain and floor drain 6-inch transfer lines near the secondary containment boundary to prevent backflow into secondary containment.

3.4.4.4.2 Design Analyses

The potential for backflow flooding through the equipment and floor drainage systems due to the PMME flood is evaluated as follows:

a. The PMME is postulated to have occurred and the associated flooding in the turbine building will be consistent with the site water-level accumulation during the incident

b. Flood water would enter the equipment or floor drainage piping system through the collector tanks and their overflow lines in the radwaste building. These overflow lines are provided for routing the collection tank overflow to the radwaste building sumps. The collection tanks are in the basement (approximate Elevation 557 ft) of the radwaste building. As the floodwaters rise, the collection tanks would be filled through the overflow line and the system piping would be backfilled to the check valves in the 6-inch transfer lines.

c. Redundant check valves and a manual isolation valve in both the floor and equipment drain transfer lines are located near the secondary containment boundary just before the pipe exits into the turbine building. The design configuration allows for periodic leak testing of the check valves and this combined with redundancy of the check valves, and the presence of a manual isolation valve ensures that no single active failure will result in backflow flooding into the reactor building such that the safe shutdown capability of the reactor through the emergency core cooling system (ECCS) would be affected.

3.4.4.5 Shore Barrier

Neither the reactor/auxiliary building nor the RHR complex depends on a shore barrier to preclude flooding of the structures.

Although the Category I structures do not require protection against flooding from wave runup, a shore barrier is included in the Fermi 2 plant design to protect other portions of the plant from wave effects. The design of the shore barrier was approved by the AEC by Reference 1. The shore barrier was designed by Dames & Moore, specialists in applied earth sciences.

The shore barrier is a rubble mound revetment with a cover of armor stone, which fronts the Fermi 2 unit as shown in Figure 2.4-22. It has a toe elevation of 572 ft, a crest elevation of 583 ft, and a lakeward-side slope of 2:1 (horizontal to vertical). The design allows for the possibility of a 6 percent to 8 percent displacement of stone during the PMME. The design of the barrier is further discussed in Subsection 2.4.5 and shown in cross section in Figure 2.4-22. The barrier preserves the integrity of the plant site fill placed to Elevation 583 ft as well as protecting the main plant portion of the site against wave forces. The purpose and design of the barrier are also discussed in Subsection 2.4.5.7.

The surveillance requirements and limiting conditions for operation of the shore barrier are contained in the Technical Requirements Manual.

3.4.4.6 Condensate Storage Tanks

The condensate storage tanks are not seismic structures. However, a seismic analysis was performed for the condensate storage tanks using the Fermi 2 design-basis earthquake with the tank in the fully loaded condition. The maximum shell stresses were found to be well within the allowable limits. Tank rupture is not anticipated. For added conservatism, a containing barrier has been built around the tanks, and modifications to the site grade have been made in the immediate vicinity of the tanks. This will prevent any of the condensate liquid from reaching the distant yard drainage system should leakage occur. The Category I structures are located approximately 600 ft west of the condensate storage tanks.

3.4 WATER LEVEL (FLOOD) DESIGN

REFERENCE

1. Letter from W. R. Butler, AEC, to C. M. Heidel, Detroit Edison, Subject: Beach Barrier Design, dated April 16, 1974

3.5 MISSILE PROTECTION

Protection against the hypothetical effects of missiles is provided in accordance with the following damage limit criteria:

a. The integrity of the containment system is maintained

b. The capability for shutdown of the reactor and maintenance of core cooling capability is maintained

c. A missile accident that is not a LOCA does not initiate a LOCA.

Where possible, missile protection is achieved through basic plant component arrangement such that, if a missile-generating failure should occur, the direction of the flight of the missile would be away from Category I structures or other critical system components. Examples of such arrangements are shown in Figure 3.5-1, Sheets 1 through 6, which show the general arrangement of piping, pumps, motor, valves, and other equipment in the drywell indicating component missile protection by separation. Where it is impossible to provide protection through selective plant layout and where the structures available do not provide sufficient missile protection, barriers are provided to prevent potential missiles from damaging critical systems and structures.

An analysis of potential missiles and the missile protection provided follows. Although it is not given in the order specified in Regulatory Guide 1.70, the information requested in the guide is presented. The reason for the change in order is to present a more comprehensive discussion of the missile protection included in the Fermi 2 design.

3.5.1 Missile Selection (Sources)

3.5.1.1 Missiles From Pressurized Equipment

3.5.1.1.1 Missiles Considered

Potential missiles from pressurized equipment that were investigated include the following:

a. Valve bonnets (large and small)

b. Valve stems

c. Thermowells

d. Vessel head bolts

e. Pieces of pipe

f. High-pressure gas cylinders.

3.5.1.1.2 Design Evaluation

Using conservative assumptions, it has been determined that the potential missiles from items a. through e. above, originating from fluid lines, cannot achieve sufficient energy to penetrate the drywell, critical system components, or missile shields to the extent that safe reactor shutdown would be impaired. An added conservatism exists because of the separation criteria and barriers described in Subsections 3.5.3 and 3.5.4. The probability of incapacitating more than one of the redundant reactor protection system (RPS) safe-shutdown and engineered safety feature (ESF) system components by a single missile is negligible. The driving force for these potential missiles is assumed to come from the kinetic energy of the water or steam.

In the event of a break in a fluid-carrying component, the velocity of the exiting fluid is determined. The drag force of the fluid that propels a missile is proportional to the product of the fluid mass density and velocity squared. By applying this drag force to each potential missile, the missile attaining the most kinetic energy is determined. Damage resulting from impact of this missile is then analyzed. Small missiles are assumed to achieve maximum fluid velocity instantly, which is conservative because a missile requires a finite time to accelerate to this velocity after being dislodged. In addition, missiles in a horizontal trajectory tend to fall out of the fluid jet. Therefore, the driving force acts for a shorter time and the missile probably achieves a velocity lower than its maximum.

High-pressure gas cylinders on the Fermi 2 site that are capable of generating potentially high-energy missiles are as follows:

a. Hydrogen gas storage cylinders

b. Service gas storage cylinders (welding gases, nitrogen, and spare breathing air)

c. Emergency breathing air cylinders

d. Oxygen and hydrogen reagent cylinders

e. Hydrogen and oxygen storage vessels at the HWC Gas Supply Facility

The hydrogen and service gas storage cylinders are located more than 300 ft from the reactor building. Any potential missiles must first pass through the first floor of the turbine building and through several concrete walls (with a combined thickness of more than 5 ft) before reaching the reactor building wall. There is insufficient energy stored in these cylinders for any potential missile to penetrate these walls.

Emergency breathing air cylinders are stored in seismically qualified storage racks located along the north wall of the reactor building ventilation room. The concrete walls of this room are sufficient to prevent any potential missiles from reaching critical locations outside of this room. Equipment inside this room can be damaged by potential missiles, but this will not prevent a safe reactor shutdown. A design-basis earthquake (DBE) will not initiate emergency breathing air cylinder damage because the cylinders are secured in seismically qualified storage racks.

The primary containment hydrogen monitors require supplies of hydrogen and oxygen to act as reagent gases. These cylinders are located adjacent to each monitor, thereby minimizing the tubing run to each instrument. The cylinders, regulators, piping, and racks are seismically designed and installed. The racks are also designed to restrain the cylinders to prevent them from becoming missiles if punctured.

Using the barrier and procedures of Subsections 3.5.3 and 3.5.4, respectively, results of the investigation showed that additional missile barriers for potential missiles from pressurized equipment are not required. With the assumption of maximum missile velocity and minimum missile energy required for perforation, the results are conservative.

The HWC gas supply facility is located approximately 1100 feet northwest of the nearest safety-related structure (the RHR Complex). The hydrogen and oxygen storage tanks and the gaseous hydrogen tube bank are designed to remain in position during the design basis earthquake. Since the site for the HWC Gas Storage Facility was chosen to provide the required separation from safety-related structures, a release from this location would not affect plant safety. Potential blast effects from tank ruptures are enveloped by the existing analyses of the design basis tornado and design basis earthquake.

3.5.1.2 Missiles From Rotating Equipment

3.5.1.2.1 Missiles Considered

Potential missiles from rotating equipment, which could require a missile barrier, include

a. High-pressure turbine rotor segment

b. Low-pressure turbine rotor segment

c. Recirculation pump or motor segment

d. Emergency diesel generator (EDG) segment.

All probable paths of flight of these potential missiles have been investigated.

3.5.1.2.2 Design Evaluation

As stated in Subsection 10.2.3, after the low pressure (LP) turbine rotor replacement during RF05, there is no design basis turbine missile at Fermi 2. The HP turbine rotor was replaced in RF07. The new HP turbine rotor, which was reviewed for overspeed capability, was found to be higher in overspeed than the maximum theoretical overspeed of the unit (LP rotors and generator). Moreover, the seventh stage blades of the HP turbine rotor are smaller in length and lighter in weight that the eighth stage blades of the LP turbine rotors. Based on this, it is concluded that the HP turbine rotor missile analysis is bounded by the LP turbine missile analysis. The HP turbine rotor and generator rotor missiles cannot completely breach their respective outer casings. The new HP and LP turbine rotors are of monoblock construction. The monoblock rotors have higher speed capability than the maximum attainable speed of the turbine generator units. Per General Electric, the supplier of the new rotors, the probability of missiles being generated is well below 10 to the -8 power.

The most substantial piece of nuclear steam supply system (NSSS) rotating equipment is the reactor recirculation system (RRS) pump and motor. This potential missile source is addressed in detail in References 3 and 4.

It is concluded in Reference 3 that destructive pump overspeed can result in certain types of missiles. A careful examination of shaft and coupling failures shows that the fragments will not result in damage to the containment or to vital equipment.

a. Low-Energy Missiles (Kinetic Energy Less Than 1000 ft-lb)

Low-energy-level missiles may be created at motor speeds of 300 percent of rated as a result of failure of the end structure of the rotor. The structure consists of the retaining ring, the end ring, and the fans. Missiles potentially generated in this manner will strike the overhanging ends of the stator coils, the stator coil bracing, support structures, and two walls of 1/2-in.-thick steel plate. Because of the ability of these structures to absorb energy, it is concluded that missiles would not escape this structure. It is at this point that frictional forces would tend to bring the overspeed sequence to a stop

b. Medium-Energy Missiles (Kinetic Energy Less Than 20,000 ft-lb)

   In the postulated event that the body of the rotor were to burst, medium-energy missiles could be created. The likelihood that these missiles would escape the motor is considered less than the likelihood of escape for the low-energy missiles described above, because of the additional amount of material constraining missile escape, such as the stator coil, field coils, and stator frame directly adjacent to the rotor

c. The Motor As a Potential Missile

   Since bolting is capable of carrying greater torque loads than the pump shaft, pump bolt failure is precluded. Since pump shaft failure decouples the rotor from the overspeed driving blowdown force, only those cases with peak torques less than those required for pump shaft failure (five times rated) will have the capability of driving the motor to overspeed. When missile-generation probabilities are considered along with a discussion of the actual load-bearing capabilities of the system, it is evident that these considerations support the conclusion that it is unrealistic that the motor would become a missile.

It is concluded in Reference 4 that destructive overspeed of the pump and motor could occur as a result of a full double-ended pipe break LOCA in the recirculation pump suction line. In the event of motor failure, the motor stator and frame structure would prevent the release of any missiles as indicated above. In the event of pump destructive overspeed, impeller missiles could be produced. However, they will not penetrate the pump case. They could be ejected from the open end of the broken pipe. However, pipe restraints have been installed to prevent potential missile points in the pipe from developing. (See Subsection 5.5.1.4.)

Potential missiles from an EDG would be small auxiliary items knocked loose from the engine exterior by blows from within. Analysis has shown that the maximum velocity of these missiles would be 40 fps, with a maximum mass of 5 lb each. These missiles are of lower energy than potential tornado-generated missiles. As the external walls of the EDG rooms are constructed to withstand the tornado-generated missiles, missiles ejected from an EDG will be contained within that EDG room and therefore cannot incapacitate another EDG in the other division.

3.5.1.3 Tornado-Generated Missiles

3.5.1.3.1 General

Tornado forces and the design-basis tornado are discussed in Section 3.3. Objects lying in the path of tornadoes may be picked up by the tornado due to aerodynamic lift force or due to the rapid pressure reduction that may have injected the object into the tornado wind field. The objects that are potential missiles vary in size, shape, and number. The design-basis missiles selected for consideration in the Fermi 2 design are a 4-in. x 12-in. x 12-ft plank with a density of 40 lb/ft^3, and a 4000-lb passenger car traveling at 50 mph at a maximum of 25 ft above grade elevation. The design-basis missiles are given in Subsection 12.2.1.7.1 of the PSAR.

For the Category I 4160-V electrical ductbanks between the RHR cable vaults and the Reactor/Auxiliary building cable vaults, the top of the ductbanks is located approximately six inches below grade, the top of the manholes is located at grade level, and RHR cable vaults are located above grade. The design for this ductbank system is based on Regulatory Guide 1.76 Revision 1 (March 2007) (Reference 17) and, as such, the design is evaluated for the design-basis tornado missiles described in Regulatory Guide 1.76 Revision 1.

3.5.1.3.2 Additional Analyses

The missile barriers listed in Subsection 3.5.3 provide protection against tornado generated missiles; however, three areas received additional analysis to ensure resistance to tornado generated missiles. They are the spent fuel pool, the fan blades of the cooling towers in the Residual Heat Removal (RHR) complex, and the miscellaneous penetrations and openings in the exterior walls of the Reactor/Auxiliary Building and RHR Complex.

3.5.1.3.2.1 Spent Fuel Pool - Reactor Building

As the siding above the refueling floor is designed to release in the event of a design-basis tornado, potential damage to fuel in the spent fuel pool from tornado-generated missiles is of concern. The AEC noted this concern in its Safety Evaluation Report on the Construction Permit (Reference 2). The concern was identified as Post Construction Permit Open Item No. 9. This concern has also been the subject of analyses submitted to the AEC by GE (Reference 5). The Edison position on this open item was submitted to the AEC in August 1973 (Reference 6). The Edison position was based on the GE report (Reference 5) and a study of the probability of a tornado striking the site and showed that the probability of damage to fuel in the spent fuel pool by a tornado-borne missile is extremely small (7×10^{-10} per year) and that no additional protection is required. The AEC waived the requirement to provide tornado protection of the spent fuel pool in June 1974 (Reference 7) based on its own independent assessment. The AEC cited the low probability of a tornado, the lower likelihood that objects could be lifted to the elevation of the fuel pool and become missiles, and the expectation that where spent fuel damage were to occur, the associated offsite exposure radiological consequences would likely be within 10CFR100 limits.

3.5.1.3.2.2 Residual Heat Removal Complex Mechanical Draft Cooling Towers

A study was performed to determine the probability that both cooling tower divisions can be rendered out-of-service by tornado- generated missiles entering the fan discharge stack (Reference 8). The result of this study, as determined below, is that this probability is very small and is conservatively estimated between 10^{-9} and 10^{-10} per year. The RHR cooling towers and their missile protection features are described in Subsection 9.2.5.

In the cooling tower study, several potential design-basis tornado missiles are considered. These represent the complete range of all possible missiles that may be potential threats to the safety of the cooling towers:

a. A 4-in. x 1-ft x 12-ft wood plank

b. A 13.5-in.-diameter x 35-ft-long utility pole

c. A 1-in.-diameter x 3-ft-long steel rod

d. A 6-in.-diameter x 15-ft-long schedule 40 steel pipe

e. A 12-in.-diameter x 15-ft-long schedule 40 steel pipe.

Other missiles cited in the literature, such as a 2-in. x 4-in. x 1-ft wood piece, a 9-in. brick, a 6-in. x 12-in. x 2-in.-thick concrete slab, a 1-ft block concrete, and a "standard" automobile are not able to reach the level of the cooling towers if they are injected at ground level or at elevations of 200 ft or less (Reference 9).

Each design-basis missile was then analyzed for its ability to impact the cooling tower fan blades.

Using the three-dimensional wind flow field proposed by Bates and Swanson (Reference 10), the vertical impact velocities of the design-basis missiles at different roof elevations have been calculated assuming the objects are injected into the tornado wind field at different elevations. The results are shown in Table 3.5-1.

None of the missiles except the wood plank picked up at ground level or injected at 50-ft or 100-ft elevations, is able to reach the level of the cooling tower. The steel rod injected at 50 ft and other objects injected into the tornado wind field at higher elevations (250 ft) may be hurled into the cooling towers, but only a few missiles could be of this type.

Even if a missile lands in the cooling tower, it will not damage the cooling tower fan blades. The Marley Company, the manufacturer of the Fermi 2 RHR complex mechanical draft cooling towers, has calculated that the fan blades would safely withstand the impact from an object weighing 17 lb falling freely from an elevation of 250 ft. This is equivalent to a kinetic energy of about 8.5×10^4 ft-lb. Therefore, the fan blades are able to withstand the impact from smaller missiles; e.g., design-basis missile c. listed above (1-in.-diameter x 3-ft-long steel rod).

The number of missiles assumed to impact a cooling tower is then determined. The number of missiles that are injected into the tornado field depends on factors such as the number of "loose" objects lying in an area of a 3000-ft radius circle around the RHR complex, which contains the cooling towers. Therefore, the number of missiles injected into the tornado funnel cannot be decided with any degree of certainty. It is assumed that of all the potentially damaging objects available, two of them will be picked up by the design-basis tornado at just the right time and location to become a missile.

The cooling tower system is designed such that it can function even if one tower division is damaged and rendered out of operation. Therefore, for the cooling tower system to be out of service, both tower divisions must be damaged simultaneously by tornado missiles. For this to happen, the following sequence of events must occur:

a. A tornado strikes a point in the plant site. Based on the meteorological data and on Thom's model, the probability of this event is calculated as 7×10^{-4} per year

b. An object which is accelerated horizontally does not bounce and is ejected into the tornado at a 45° angle. This probability is conservatively estimated at 10^{-1}

c. The object maintains the orientation inside the tornado and exposes its maximum cross-sectional area to the full wind force. Since objects will tend to tumble, the probability of this event is conservatively estimated at 10^{-1}

d. The object is thrown into a cooling tower division. Objects of the type being considered here could land anywhere within 100 ft of the tornado funnel. This is a circular area of 500 ft diameter. The area of the cooling tower fan discharges in the RHR complex is about 850 ft^2. Therefore, the probability of a missile landing in a cooling tower division is approximately 4.3×10^{-3}. This is multiplied by two because it was assumed earlier that the two objects would be injected into the tornado wind field

e. The missiles land simultaneously in both tower divisions. The probability of this joint occurrence is calculated as the product of the probability of one missile landing in one tower division and the probability of the second missile landing in the other tower division simultaneously. Using the concept of statistical independence of these events, the probability of the joint event is conservatively estimated to be between 10^{-9} and 10^{-10} per year.

The draft ANSI standard on Plant Design Against Missiles (Reference 11) recommends that no protective measures be required if the combined probability of missile ejection and subsequent unacceptable damage is less than 10^{-7} per year. As the probability of tornado damage to the cooling tower unit calculated above is considerably lower than the acceptable limit, and because certain components and portions of the tower structure are hardened against tornado missiles and the fan blades can be replaced after a tornado (as described in subsection 9.2.5.2.2), it is concluded that no missile protective covers are required for the cooling towers. It may be noted that the probability evaluated herein is very conservative because most tornadoes have velocities lower than 300 mph. Some missiles, even though hurled into the towers, may lose part of their kinetic energy if they strike the walls. Such missiles are not effective in damaging the fan blades.

The 8-lb steel-rod missile could damage the fan blades if the velocity were high enough (i.e., slightly higher than listed in Table 3.5-1). The latest probability study on damage to the towers indicated a probability of 5×10^{-18} per year for all four cooling tower fans to be damaged by 20 steel-rod (rebar) missiles.

3.5.1.3.2.3 Exterior Walls/Roofs - Reactor/Auxiliary Building/RHR Complex

The exterior walls/roofs of the Reactor, Auxiliary, and Residual Heat Removal Complex buildings have been designed to resist the impact of tornado-generated missiles such that the safety related systems and components required for safe shutdown as identified in Tables 3.3-2 and 3.5-2 are generally protected. A limited number of these Seismic Category I systems and components located outside of (or otherwise not protected by these) Seismic Category I structures are evaluated based on a probabilistic missile damage analysis (Reference 19). The specific targets for which no tornado missile protection was required based on the risk analysis are listed in Table 3.5-3. The specific acceptance criterion for tornado damage for the unprotected systems and components required for safe-shutdown following a tornado event is that the cumulative sum of the mean damage probabilities for these systems and components be less than 10^{-6} per year as established in References 27 and 28. The aggregate mean damage probability corresponding to the scope of equipment identified in Table 3.5-3 is less than 10^{-6} per yr, which satisfies the regulatory acceptance criterion.

The manner in which these targets were identified and selected for evaluation is described under the "Scope" section below. The use of TORMIS as an appropriate tool for evaluating tornado missile risk was generically accepted by the NRC in Reference 23 subject to site-specific approval of the first application. The "Analysis" section below describes the manner and degree to which the Fermi 2 analysis meets the constraints of the original NRC SER (Reference 23) or was otherwise found to be acceptable in the site-specific SER approving its use (Reference 25).

3.5.1.3.2.3.1 Scope

The exterior walls/roofs of the Reactor, Auxiliary, and Residual Heat Removal Complex buildings have been designed to resist the impact of tornado-generated missiles such that the safety related systems and components required for safe shutdown identified in Tables 3.3-2 and 3.5-2 are generally protected. A limited number of these Seismic Category I systems and components located outside of (or otherwise not protected by these) Seismic Category I structures are evaluated as not requiring unique tornado missile protection by burial or barriers on the basis of a probabilistic missile damage analysis.

Table 3.5-3 identifies the specific features evaluated in the probabilistic tornado missile analysis. The specific targets included in this table represent wall penetrations and doors in the exterior surfaces of these structures. Generally, specific safety-related targets are not associated with any particular penetration; hence, the tornado missile hazard associated with these penetrations and openings is limited to and characterized by the probability of missile penetration of the target itself. However, specific safety-related targets can be associated with missiles penetrating the reactor building railroad air lock doors, the first floor auxiliary building south wall entrance, and the EDG removable wall panels.

Unprotected safety-related equipment not identified in UFSAR Table 3.3-2 as being required for safe reactor shutdown following a tornado was not included as targets. Examples include Control Room Emergency Filtration system south emergency makeup intake, the south portion of the Auxiliary Building rooftop and the Standby Gas Treatment equipment located on the refuel floor. In addition, the RHR Mechanical Draft Cooling Towers which are specifically licensed for post-tornado repair and restoration (See UFSAR Section 3.5.1.3.2.2) and the Spent Fuel Pool which was evaluated on the basis of an alternative risk analysis (See Section 3.5.1.3.2.1) were both excluded from the scope of analysis.

Other features that were excluded for this risk analysis are the buried underground cable vaults between the RHR complex and the auxiliary building, the EDG fuel oil tank vents and the EDG exhaust stacks, which are located on the roof of the RHR complex. Both of these rooftop features are provided with tornado missile shield protection specifically designed to prevent vertically travelling missiles from entering the RHR complex and damaging the EDG fuel oil tanks and diesel engines.

3.5.1.3.2.3.2 Analysis

The mean cumulative damage probability for the targets identified in Table 3.5-3 was evaluated using TORMIS, a Monte Carlo based program for simulating tornados that was developed from the NRC approved EPRI version of this program (References 20, 21, 22). Major inputs to the analysis include:

a. the regional probabilities of the occurrence of tornados
b. the location and size of eligible targets
c. location and number of potential missile sources

Given these inputs, TORMIS computes the hit and damage probabilities associated with each target. These probabilities are post-processed to generate the aggregate risk associated with all targets. The term “target damage” is used in a general sense to mean any damage (or “loss of function”) criteria caused by a tornado missile hitting the target. Target damage is not necessarily the same as target hit, but hit can equal damage for fragile equipment. The “damage” probabilities included in this analysis consisted of using the built-in TORMIS penetration, spall, and perforation equations for selected steel and concrete targets. In addition, the missile size, impact orientation, and velocity vector orientation were used to compute the probabilities of missiles entering “pipe-penetration” type openings. The TORMIS feature for overall structural response damage modeling capability was not used for this analysis.

In Reference 23, the NRC approved use of the (EPRI) TORMIS methodology subject to the following constraints:

1. Data on tornado characteristics should be employed for both broad regions and small areas around the site. The most conservative values should be used in the risk analysis or justification provided for those values selected.
2. The EPRI study proposes a modified tornado classification, Modified F (F')-scale for which the velocity ranges are lower by as much as 25% than the velocity ranges originally proposed in the Fujita (F)-scale. Insufficient documentation was provided in the studies in support of the reduced F'-scale. The F-scale tornado classification should therefore be used in order to obtain conservative results.
3. Reductions in tornado wind speed near the ground due to surface friction effects are not sufficiently documented in the EPRI study. Such reductions were not consistently accounted for when estimating tornado wind speeds at 33 feet above grade on the basis of observed damage at lower elevations. Therefore, users should calculate the effect of assuming velocity profiles with ratios Vo (speed at ground level) ÷ V33 (speed at 33 feet elevation) higher than that in the EPRI study. Discussion of sensitivity of the results to changes in the modeling of the tornado wind speed profile near the ground should be provided.
4. The assumptions concerning the locations and numbers of potential missiles presented at a specific site are not well established in the EPRI studies. However, The EPRI methodology allows site specific information on tornado missile availability to be incorporated in the risk calculation. Therefore, users should provide sufficient

information to justify the assumed missile density based on site specific missile sources and dominant tornado paths of travel.

5. Once the EPRI methodology has been chosen, justification should be provided for any deviations from the calculation approach.

Also, as generically approved in Reference 23 (and clarified through Reference 26), the TORMIS methodology is not approved for proposing:

a. elimination of existing tornado barriers

b. technical specification (TS) changes, or

c. plant modifications

The description of the Fermi 2 site-specific TORMIS analysis was reviewed against the criteria established in References 23 and 26 and was approved in Reference 25 based on the following characteristics:

1. Definition of the Fermi 2 TORMIS Tornado Sub-Region

A site-specific analysis was performed to generate a tornado hazard curve data set for the TORMIS analysis. The tornado data retained in the National Climatic Data Center Storm Events Data Base (NCDC, 2006) files for the years 1950-2005 were used to analyze both broad and small regions around Fermi 2 in order to identify a suitable representative sub-region for the site. Tornado occurrences were mapped for the large region, a 15º longitude x 15º latitude area centered on the Fermi 2 site, and statistical tests were performed using 1º x 1º and 3º x 3º blocks to identify a suitably homogeneous sub-region. The historical records of tornado occurrences within the sub-region tornado were used to establish the tornado occurrence rate, (Enhanced-Fujita) EF-scale intensities, path length, width, and direction variables to be specified as input for use in the TORMIS analysis.

The statistical analysis of the sub-region data established a mean occurrence rate of 3.1E-4 per year over the 56-year period. In accordance with the TORMIS methodology, backwards averaging was used to estimate a detrended occurrence rate to correct for changes in the annual reporting trends. The adjusted mean occurrence rate was determined to be 4.002E-4/year based on the 30-year backwards average.

2. Tornado Windspeed Intensity

The analysis utilizes the original Enhanced Fujita (EF) scale windspeeds as per Reference 24. Though the 1983 NRC SER called for the use of the F-scale of tornado intensity for assigning tornado windspeeds to each intensity category (F1-F5), the EF-scale was subsequently adopted in the positions of NRC Reg. Guide 1.76 Revision 1 that are based on Reference 24.

3. Characterization of Tornado Windspeed as a Function of Height Above Ground Elevation

The Fermi 2 TORMIS simulations were performed with the TORMIS rotational velocity Profile 3, which has increased near ground windspeeds over Profile 5; the profile used in the 1981 EPRI TORMIS reports. Hence, the Fermi 2 runs were made with higher near ground windspeeds than in the EPRI study. A sensitivity study was conducted by running the original EPRI profiles and comparing the results. The most conservative profile with highest near ground windspeeds was conservatively used.

4. Missile Characterization and Site-Structure Models

Walkdowns of the Fermi 2 site were performed to characterize the missile sources and plant configuration. This information was developed into the plant modeling inputs for the TORMIS analysis that describe the facility by specifying the geometry, location, and material properties of the structures/components and the location of potential missile sources. Missile sources (buildings, houses, storage areas, vehicles, etc.) were catalogued and modeled to a distance of approximately 2,500 feet. This is done by specifying missile origin zones around the facility and a statistical description of missile types, based on the facility survey. The site surveys were conducted just prior to refueling outages to maximize the estimated population of available missiles and missiles sources. The Fermi 2 site missiles include the 20 standard TORMIS missiles in Reference 21, including structural sections, pipes, wood members, other construction materials, and an automobile category. In addition to the 20 standard TORMIS missile types, three Fermi 2 specific missiles were created for the analysis, one to represent scaffold clamps of which there were a large number present during the site walkdown, one to represent the sections of metal siding that enclose the upper portions of the Reactor and Turbine Buildings, and the third to represent the large number of concrete block also identified during the site walkdowns. The TORMIS analysis used over 200,000 missiles in the simulations of EF5 tornadoes striking Fermi 2.

5. Deviations from the Original EPRI Methodology

The Fermi 2 analysis is performed using an update of TORMIS developed from the original EPRI NP-2005 source code. With some exceptions, this version of TORMIS implements the original NRC SER approved methodology. Revisions of the original NRC-approved version of the code generally implement changes necessary to enable continued use of the program on modern computing platforms and to enable analysis of larger problems. Specifically, the original main frame based random number generator has been replaced with a new machine independent algorithm and the code was re-dimensioned to allow larger numbers of missiles and surfaces.

The updated TORMIS program implements an algorithm for evaluating the risk of damage to piping penetrations credited in the Fermi 2 analysis that was not present in the original NRC approved methodology. The method consists of identifying the minimum required missile size, angle of orientation and angle of incidence at impact necessary for a missile to be capable of passing through a pipe penetration target. Missiles that are too large, not oriented correctly, or that impinge obliquely on a target are screened out based on these criteria. This method eliminates from the calculated cumulative risk those impacts which would not realistically have resulted in missile penetration of a pipe penetration target.

3.5.1.3.3 Conclusion

As a result of these studies, the tornado-generated missiles to be considered in barrier design are the wood plank and the automobile, previously described.

3.5.1.4 Site-Related Missiles

3.5.1.4.1 Airplanes

Airports in the vicinity of the Fermi 2 site are listed in Table 2.2-2 and shown in Figure 2.2-1. Table 2.2-2 also lists the proximity to the site, number of and type of aircraft, and other physical and operations data. As discussed in Section 2.2, the nearest airport (2 miles away) cannot accommodate aircraft large enough to be a hazard to Fermi 2 and the nearest major airport is too far away (19 miles north-northwest of the site) to be considered a potential hazard with regard to large-aircraft takeoff and landing. In addition, there are no nearby military airports that could be expected to accommodate aircraft with bomb or explosive loads.

3.5.1.4.2 Military Activities

There are no military facilities within 10 miles of the plant. There are two restricted areas in Lake Erie, 20 and 27 miles from the plant, which are used as impact areas for small arms, ground artillery, and anti-aircraft artillery from Camp Perry and from the test-firing range at Erie Industrial Park. However, restriction to weapon horizontal-firing range and direction, as well as the nature of the projectiles, preclude a threat to the plant.

3.5.1.5 Primary Containment Internal Missiles

The potential for missiles inside the containment due to gravitational effects from unrestrained equipment is possible only during maintenance situations. All equipment and components located inside the containment and associated with reactor operation and safety are restrained. Equipment moved into the containment for maintenance operations (including hoists) is controlled by administrative procedures and is removed when personnel leave the maintenance site or prior to returning to reactor operation. Where possible and practical, maintenance equipment used inside the containment is temporarily restrained. In view of the above, any missiles due to gravitational effects are expected to be relatively small and any resulting damage is anticipated to be minor.

3.5.2 Selected Missiles

As a result of the investigations described in Subsection 3.5.l, the missiles to be considered in barrier design are the tornado generated missiles. These missiles are those considered as a design basis in the PSAR and approved by the AEC as documented in the AEC Safety Evaluation Report (Reference 2). For the Category I 4160-V electrical ductbanks between the RHR cable vaults at the RHR complex and the Reactor/Auxiliary building, the tornado missiles identified in Regulatory Guide 1.76 Revision 1 (Reference 17) are considered.

3.5.2.1 Tornado-Generated Missiles

The tornado-generated missiles are a 4-in. x 12-in. x 12-ft wood plank with a density of 40 lb/ft^3, traveling end-on at a velocity of 255 mph with a contact area of 48 in.^{2}; and a 4000 lb passenger car traveling through the air at 50 mph at a maximum 25 ft above grade elevation. The car has a contact area of 20 ft^2. In the case of tornado-generated missiles, it is assumed that only walls and other vertical exposed surfaces are subject to impacts. Roof structures would be subject only to free-falling ballistic-type projectiles (e.g., wood or stone debris) without high tornadic wind force components. If penetration of the roof structures should occur, such penetration would not constitute a hazard, since the projectile would have very low energy, and the concrete floors and walls protect safety-related equipment for safe shutdown.

The following Design Basis Tornado missiles from Table 2 of Regulatory Guide 1.76 Revision 1 (March 2007) (Reference 17) are considered for the Category I 4160-V RHR cable vaults and the manholes and ductbanks between these cable vaults and the Reactor/Auxiliary building cable vaults:

a. 6.625” diameter x 15 ft long Schedule 40 steel pipe weighing 287 lbs and traveling horizontally at 135 fps

b. 4,000 lb, 16.4 ft x 6.6 ft x 4.3 passenger car traveling horizontally through the air at 135 fps at a maximum height of 30 ft above ground

c. 1” diameter solid steel sphere, weighing 0.147 lb and traveling horizontally at 26 fps

Vertical missiles are all missiles listed above with a vertical velocity equal to 67% of their horizontal speed.

In addition, the following missiles addressed in the Safety Evaluation Report are also evaluated for penetration resistance and regeneration of secondary missiles:

a. 1” diameter x 3 ft long steel rod weighing 8 lbs, traveling horizontally at 250 fps

b. 13.5” diameter x 35 ft long utility pole weighing 1490 lbs, traveling at 247 fps

Vertical missiles are all missiles listed above with a vertical velocity equal to 67% of their horizontal speed.

3.5.3 Missile Barriers and Loadings

Structures, shields, and barriers designed to withstand missile effects are given in Table 3.5-2 according to the equipment protected. In addition to these barriers, the steel plate primary containment vessel is completely enclosed in and surrounded by a reinforced-concrete structure as described in Subsection 3.8.4. This concrete structure, in addition to serving as a radiation shield for personnel in the reactor building, provides a major structural barrier for the protection of the containment and reactor system against missiles that may be generated external to the primary containment.

The suppression chamber has no source of internal or external missile generation. The vent pipes connecting the suppression chamber to the drywell are protected by jet deflectors. The vent discharge headers and piping are designed to withstand the jet reaction force caused by flow discharge into the suppression pool. The control rod drive (CRD) mechanisms are located in a concrete vault below the reactor pressure vessel.

3.5.4 Barrier Design Procedures

3.5.4.1 Overall Structural Response

To determine the capability of the missile barriers provided, the impact and penetration of potential missiles must be determined. Since the missile mass is small compared with the mass of any Category I structure, the only meaningful overall structural response is that of the structural element impacted by the missile. The overall response of the structural element is investigated by designing the element for the forces transmitted to it by the missile.

3.5.4.2 Edge Impact

For edge impact, punching shear stress was checked after obtaining the maximum force impacted to the element by the missile. The punching shear stress is given by the following expressions:

$$Qs = \frac{mV_o}{t_d s} \quad \text{(for rigid missles)} \qquad (3.5\text{-}2)$$

$$Qs = \frac{F_1}{s} \quad \text{(for nonrigid missles)} \qquad (3.5\text{-}3)$$

where

F_1 = maximum contact force = $1.14WV_o$

and

t_d = impact time = $\frac{2D}{V_o}$

D' = penetration depth calculated by modified Petry Formula (Subsection 3.5.4.7)

V_o = initial velocity of missile

m = mass of missile

s = perimeter of area enclosed by a border extending one-half of the panel thickness beyond contact area

W = weight of missile

3.5.4.3 Central Impact

For central impact in the case of rigid missiles, the maximum force impacted to a structural element is calculated by the following expression:

$$F = \frac{mV_o2}{2D'} \qquad (3.5\text{-}4)$$

and

$$t_d = \text{duration of force} = \frac{2D'}{V_o} \qquad (3.5\text{-}5)$$

After the force F and its duration t_d are obtained, the element is designed for this dynamic load. For central impact in the case of nonrigid missiles, the panel is modeled as a single degree of freedom system with equivalent mass and equivalent stiffness. The equation of motion for impact is solved to get maximum deflection of the element. This deflection is compared with allowable (or ductility ratio) to arrive at a satisfactory design.

3.5.4.4 Impact Analytical Procedures

The impact of the missile is considered plastic because of the local unrecoverable deformations of either the missile or the target or of both. The velocity of the missile and the target (concrete panel) after the impact, V_a, is determined from the consideration of conservation of linear momentum and is expressed by the following equation:

$$M_m V_i = M_m V_a + M_e V_a \qquad (3.5\text{-}6)$$

where

M_m = mass of missile

V_i = velocity of impact

M_e = effective mass of target

For the Category I 4160-V RHR cable vaults and the manholes and ductbanks between these cable vaults and the Reactor/Auxiliary building cable vaults, overall structural response is based on the dynamic response of the structures and impulse-load time history. A simplified method based on idealization of the structure to an equivalent single-degree-of freedom system is utilized.

The procedure used in determining impactive force and time duration of the impact follows the guidance in Reference 16.

The impactive force and time duration of a hard missile, such as the 6" diameter schedule 40 steel pipe, is determined by the expression shown in Section 3.5.4.3. The impactive force and time duration for soft missiles, such as the automobile and wood plank, is determined by the Riera formula, as outlined in Reference 16.

3.5.4.5 Punching Shear Analytical Procedure

Reinforced-concrete panels are checked for the punching shear failure and the flexural yielding failures. The effective mass, M_e, of the panel for the case of punching shear failure is obtained as follows:

$$M_e = (A + d)(B + d)dw \qquad (3.5\text{-}7)$$

where

A, B = dimensions of missile

d = thickness of panel

w = density of target material

3.5.4.6 Flexural Failure Analytical Procedure

The effective mass for the case of flexural failure of a panel is defined as that mass which must be concentrated at the point of impact on an equivalent weightless slab so that it will have the same kinetic energy as the actual slab when the point of impact is subjected to unit velocity.

For a flexural failure, the energy transferred to the slab is compared with its energy capacity at an appropriate ductility ratio. For a punching shear failure, the shear capacity at the critical section is compared with the shear force transferred to the slab.

3.5.4.7 Depth of Penetration Analytical Procedure

The depth of penetration into concrete walls is calculated using the Modified Petry Formula (Reference 12). The concrete barrier thickness was selected to prevent secondary missiles formed by scabbing from damaging both divisions of protected systems safe shutdown equipment.

Concrete wall/slab thickness provided for the Category I 4160-V RHR cable vaults, manholes, manhole covers, and ductbanks between these cable vaults and the Reactor/Auxiliary building cable vaults are more than the minimum acceptable barrier thickness required as shown in Table 1 of NUREG-0800, Standard Review Plan 3.5.3 Revision 3, dated March 2007 (Reference 18).

Modified Petry Formula (Reference 12) is used to determine the concrete protective cover thickness to prevent penetration and regeneration of secondary missiles for the two additional tornado missiles identified in the Safety Evaluation Report.

The method of calculation used to determine the energy required to penetrate a steel plate is based on extensive tests conducted by the Stanford Research Institute (Reference 13). During these tests, rod-shaped missiles were impacted against square steel plates having clamped edges. The results of the tests are described by the following expression for minimum energy per unit diameter of missile required for perforation of a steel plate:

$$\frac{E}{D} = U\left(0.344T^2 + \frac{W}{W_s}0.032T\right) \qquad (3.5\text{-}8)$$

where

E = critical energy required for penetration, ft-lb

D = diameter of missile, in.

U = ultimate tensile strength of steel plate, lb/in.^{2}

T = plate thickness, in.

W = length of side of square window in the target frame between the rigid supports, in.

W_s = test constant = 4 in.

No composite section (concrete with steel plate backing or the like) has been used for missile-resistant structural elements.

The impact of a turbine-generator missile on the reactor building or auxiliary building is discussed and references are cited in Subsection l0.2.3. The impact of a turbine missile on the RHR complex has also been evaluated.

3.5.5 Missile Barrier Features

The missile barriers listed in Table 3.5-2 provide adequate protection against potential tornado-generated missiles. In addition, it has been shown that the probability of missile damage to either fuel in the spent-fuel pool or the RHR cooling tower fans, both of which could be exposed to such damage, is extremely small. Together with the redundancy and separation provided, the missile protection provided for Fermi 2 is adequate.

The general arrangement of piping and equipment in the drywell showing the separation of redundant systems is given in Figure 3.5-1, Sheets 1 through 6.

For assumed failures of the high pressure coolant injection (HPCI) system, the automatic depressurization system (ADS) functions to reduce the reactor pressure to a value low enough to allow the low pressure coolant injection (LPCI) and core spray systems to pump water to the reactor pressure vessel (RPV) in time to cool the core consistent with the design basis. (See Subsection 6.3.2.2.2.) The ADS uses five of the 15 safety/relief valves (SRVs) of the nuclear boiler pressure-relief system to achieve the automatic blowdown to the suppression pool. Protection from simultaneous damage to the HPCI steam line inside the containment and to the SRVs designated for ADS function due to pipe whip or fragments of pipes is provided by physical separation. The HPCI steam source is provided from main steam line A, while only the SRVs on main steam lines C and D are considered available for performance of the ADS function.

3.5 MISSILE PROTECTION

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3.5 MISSILE PROTECTION

REFERENCES

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26. NRC Regulatory Issue Summary 2008-14.

27. Position on the Use of Probabilistic Risk Assessment In Tornado Missile Protection Licensing Actions, ADAMS Accession Number ML080870287.

28. NUREG-0800, Standard Review Plan, Section 2.2.3, Evaluation of Potential Accidents (ADAMS Accession Number ML070460336.

TABLE 3.5-1 MISSILE TRAJECTORY DATA FOR TORNADO MISSILES NEAR THE RESIDUAL HEAT REMOVAL COMPLEX COOLING TOWERS

Missile	Initial Elevation (ft)	Peak Elevation (ft)	Vertical Velocity at Impact (fps)
a. 4-in. x 1-ft x 12-ft-long wood plank	0	734	97
	50	739	97
	100	732	97
	250	702	96
b. 13.5-in. diameter x 35-ft-long utility pole	0	0	-
	60	60	-
	100	100	-
c. 1-in. diameter x 3-ft-long steel rod	0	2	-
	50	662	133
	100	664	132
	250	604	128
d. 6-in. diameter x 15-ft-long Schedule 40 steel pipe	0	-	-
	50	50	-
	100	100	-
	250	268	96
e. 12-in. diameter x 15-ft-long Schedule 40 steel pipe	0	-	-
	50	50	-
	100	100	-
	250	250	77

TABLE 3.5-2 EQUIPMENT PROTECTED FROM MISSILES AND ASSOCIATED MISSILE BARRIERS

A. REACTOR AND AUXILIARY BUILDINGS

Equipment Protected	Missile Barriers
1. All items whose failure could affect the operation and functions of the primary reactor containment and those that are necessary for safe shutdown of the reactor	1. a. All exterior concrete walls b. Reactor building fifth floor concrete slab c. Auxiliary building concrete roof slab d. Auxiliary building fifth floor concrete slab e. Reactor building fifth floor equipment hatch cover
2. Air conditioning equipment for the control center	2. a. Auxiliary building concrete roof slab b. Walls between auxiliary and turbine building c. Shield barrier at the Auxiliary Building / Turbine Building third floor portal. (see Note 1)
3. Reactor pressure vessel	3. Shield plug over reactor pressure vessel
4. Main control room, battery room ESF switch-gear room, emergency closed cooling water system, residual heat removal system, relay room, control rod drive units	4. Combined thickness of walls and/or floors of the reactor and auxiliary buildings above and including the fourth floor. Removable exterior precast panel in Division I Switchgear Room South Wall is protected by a 1-inch steel plate.

Note 1: There are two EECW lines in the Auxiliary Building which are potentially susceptible to tornadic induced missiles coming from the Turbine Building through the connecting portal on the third floor.

B. RHR COMPLEX BUILDING

Equipment Protected	Missile Barriers
All items whose failure could affect the operation and functions of the primary containment and those that are necessary for safe shutdown of the reactor (including the EDGs)	a. All exterior concrete walls b. All concrete roof slabs except the RHR complex cooling tower discharges c. Isolation walls between redundant systems

C. Category I 4160-V RHR cable vaults and the manholes and ductbanks between these cable vaults and the Reactor/Auxiliary building cable vaults

Equipment Protected	Missile Barriers
All items whose failure could affect the operation and functions of the primary containment and those that are necessary for safe shutdown of the reactor (including the EDGs)	a. All ductbanks b. All concrete walls c. All concrete roof slabs d. Access covers at RHR cable vaults e. Manholes

TABLE 3.5-3 List of Unprotected Plant Targets Accepted Based on TORMIS Analysis

DESCRIPTION	BUILDING / SITE LOCATION
Pipe penetration P-150	AB
Pipe penetration P-151	AB
Pipe penetration P-152	AB
Pipe penetration P-153	AB
Electrical penetration E-11117	AB
Electrical penetration E-11116	AB
Instrumentation penetration I-5504	AB
Instrumentation penetration I-5505	AB
Ventilation penetration V-521	AB
Electrical Penetration E-5654	AB
Pipe penetration P-139	AB
Pipe penetration P-140	AB
Pipe penetration P-141	AB
Pipe penetration P-142	AB
Pipe penetration P-143	AB
Electrical penetration E-11153	AB
Electrical penetration E-11154	AB
Pipe penetration P-136	AB
Pipe penetration P-137	AB
Pipe penetration P-138	AB
Electrical penetration E-1270	AB
Electrical penetration E-1271	AB
Electrical penetration E-1272	AB
Electrical penetration E-1273	AB
Pipe penetration P-10765	AB
Electrical penetration E-15132	AB
Electrical penetration E-11054	AB
Pipe penetration P-10766	AB
Class 1E Electrical Cables East of Door R1-15 (Safety related electrical cables East of R1-15)	AB
Electrical penetration E-5757	RB
Pipe penetration P-5609	RB
Pipe penetration P-5624	RB
Pipe penetration P-5625	RB
Pipe penetration P-17305	RB
Pipe penetration P-17319	RB
Outer Railroad Air Lock Door R1-1	RB
Electrical penetration E-5543	RB

TABLE 3.5-3 List of Unprotected Plant Targets Accepted Based on TORMIS Analysis

DESCRIPTION	BUILDING / SITE LOCATION
Electrical penetration E-10764	RB
Pipe penetration P-156 (Area around pipe protected by flange)	RB
Pipe penetration P-156 (Pipe in opening)	RB
Electrical penetration E-5521	RB
Pipe penetration P-158	RB
Pipe penetration P-157	RB
Pipe penetration P-161	RB
Pipe penetration P-162	RB
Instrumentation penetration I-5657	RB
Pipe penetration P-160	RB
Pipe penetration P-12343	RB
Pipe penetration P-159	RB
Removable Panel (EDG-11)	RHR
Removable Panel (EDG-12)	RHR
Removable Panel (EDG-13)	RHR
Removable Panel (EDG-14)	RHR
Door to Motor Drive for Cooling Tower Fan (North End, East Tower, Top Door)	RHR
Door to Motor Drive for Cooling Tower Fan (North End, East Tower, Bottom Door)	RHR
Door to Motor Drive for Cooling Tower Fan (North End, West Tower, Top Door)	RHR
Door to Motor Drive for Cooling Tower Fan (North End, West Tower, Bottom Door)	RHR
Door to Motor Drive for Cooling Tower Fan (South End, East Tower, Top Door)	RHR
Door to Motor Drive for Cooling Tower Fan (South End, East Tower, Bottom Door)	RHR
Door to Motor Drive for Cooling Tower Fan (South End, West Tower, Top Door)	RHR
Door to Motor Drive for Cooling Tower Fan (South End, West Tower, Bottom Door)	RHR
Roof Penetration MK-142	RHR
Roof Penetration MK-144	RHR
West Wall Penetration MK-219	RHR
West Wall Penetration MK-220	RHR
West Wall Penetration MK-221	RHR
West Wall Penetration MK-222	RHR
West Wall Penetration MK-344	RHR

TABLE 3.5-3 List of Unprotected Plant Targets Accepted Based on TORMIS Analysis

DESCRIPTION	BUILDING / SITE LOCATION
West Wall Penetration MK-345	RHR
West Wall Penetration MK-346	RHR
West Wall Penetration MK-347	RHR
Doors R3-13 (Security Door RBD17) & R3-28	AB
Door R3-12 (Security Door RBD21)	AB
Concrete Block Wall #215	AB
Refuel Floor Equipment Hatch Cover (A/B – 10/11)	RB
Inner Railroad Air Lock Door R1-2 (effectively modeled as intersection with targets 57, 58, 59, and 60)	RB
Class 1E Equipment West of Interior Access Door R1-12	AB
Safety-related piping behind Railroad Air Lock Doors (Div. 2 EESW supply & return & RHR Containment Spray)	RB
Safety-related piping behind Railroad Air Lock Doors (Div. 1 EESW supply & FPCCU supply & return)	RB
Safety-related piping behind Railroad Air Lock Doors (RHR Containment Spray – vertical)	RB
Safety-related piping behind Railroad Air Lock Doors (RHR Containment Spray – horizontal)	RB

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Refer to Plant Drawing DW GEN ARRANGE

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FIGURE 3.5-1, SHEET 1

GENERAL ARRANGEMENT OF PIPING AND EQUIPMENT IN THE DRYWELL

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FIGURE 3.5-1, SHEET 2

GENERAL ARRANGEMENT OF PIPING AND EQUIPMENT IN THE DRYWELL

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FIGURE 3.5-1, SHEET 3

GENERAL ARRANGEMENT OF PIPING AND EQUIPMENT IN THE DRYWELL

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FIGURE 3.5-1, SHEET 4

GENERAL ARRANGEMENT OF PIPING AND EQUIPMENT IN THE DRYWELL

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FIGURE 3.5-1, SHEET 5

GENERAL ARRANGEMENT OF PIPING AND EQUIPMENT IN THE DRYWELL

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FIGURE 3.5-1, SHEET 6

GENERAL ARRANGEMENT OF PIPING AND EQUIPMENT IN THE DRYWELL

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3.6 PROTECTION AGAINST DYNAMIC EFFECTS ASSOCIATED WITH THE POSTULATED RUPTURE OF PIPING

Fermi 2 is designed with appropriate protection against the consequences of a LOCA. Specifically included are an emergency core cooling system (ECCS) to protect the core from the thermal-hydraulic consequences of a LOCA; a containment system to protect the public from the radiological consequences of a LOCA; and a system of restraints, equipment, piping arrangements with physical separation of redundant components, and protective shields to limit damage escalation from the dynamic effects (i.e., blowdown jet forces and pipe whip) associated with a LOCA.

The design provisions and corresponding criteria for the emergency core cooling and containment systems are covered in Chapter 6. Subsection 3.6.1 describes the measures that have been used to ensure that the containment vessel and all essential equipment within the containment, including components of the reactor coolant pressure boundary (RCPB), engineered safety feature (ESF) systems, and equipment supports, are adequately protected against the postulated LOCA dynamic effects.

The measures taken for protection against dynamic effects associated with the postulated rupture of high- and moderate-energy fluid piping outside the containment are described in Subsection 3.6.2.

Detailed analytical methods and computer codes are discussed in Subsection 3.6.3.

3.6.1 Protection Against Dynamic Effects Associated With the Postulated Rupture of Piping Inside the Containment

3.6.1.1 Systems in Which Design-Basis Pipe Breaks Occur

3.6.1.1.1 Break Location Criteria

All piping that is part of the RCPB and that is subject to reactor pressure continuously during normal plant operation, is considered as a potential initiator of a pipe break, and is analyzed for its dynamic effects damage potential. Piping that is never or only infrequently (i.e., during test operations) subject to reactor pressure is not considered as an initiator of a pipe break. Initial pipe-break events are not assumed to occur in pump and valve bodies because of their greater wall thickness and their location in the low-stress portions of the piping systems.

3.6.1.1.2 Longitudinal and Circumferential Breaks

The following types of breaks were postulated in the RCPB piping systems: (1) circumferential breaks were postulated in piping having a nominal diameter greater than 1 in. and (2) longitudinal breaks were postulated in piping having a nominal diameter greater than 4 in.

Except where limited by structural design features, a circumferential break results in pipe severance with full separation. The break was assumed perpendicular to the longitudinal axis of the pipe at the break location. The fluid discharge coefficient at the break was determined from analytical or experimental work.

A longitudinal break results in an axial split without severance. For design purposes, the longitudinal break was assumed to be rectangular in shape, with an area equal to the largest piping cross-sectional flow area at the point of break.

3.6.1.1.3 Major Piping Systems Considered for Dynamic Effects of Postulated Pipe Breaks

The major piping systems inside the containment considered for protection against dynamic effects of the postulated ruptures of piping are the piping associated with the following systems:

a. Main steam system-inside and outside the containment

b. Recirculation system

c. Feedwater system

d. High-pressure coolant injection (HPCI) system

e. Reactor core isolation cooling (RCIC) system

f. Core spray (CS) systems

g. Residual heat removal (RHR) supply and return lines.

These and other minor non-safety class system (see Subsection 3.6.1.1.4) pipe-break analyses have been submitted to the AEC in References 1 through 11.

References 1 through 11 describe the Fermi 2 conservative design against the dynamic effects of postulated pipe ruptures inside the containment and they show that the requirements of 10 CFR 50, Appendix A, and 10 CFR 100, as well as the intent of Regulatory Guide 1.46, are in fact met. Supplemental analyses have also been completed to establish as-built compliance with these criteria.

In addition, a detailed analysis of a postulated line break in the region of a reactor vessel nozzle safe-end and its effects on the sacrificial shield wall was performed in response to ACRS concerns and was submitted to the AEC (References 12 and 13).

There are no ASME Boiler and Pressure Vessel (B&PV) Code Section III, Class 2 and 3, high-energy piping systems located inside the primary containment.

3.6.1.1.4 Consideration of Other Systems (Non-Safety Class Systems)

Certain "other" systems (see Section 3.2) and components are not required for the safe shutdown of the reactor nor are they required for the limitation of the offsite release in the event of a LOCA. However, while none of this equipment is needed during or following a LOCA, some dynamic effects must be considered where a non-safety class system or component failure could initiate or escalate a LOCA in one of the following systems or components:

a. Reactor water cleanup (RWCU) system

b. RPV vent line

c. Main steam drains

d. Standby liquid control system.

3.6.1.2 Design-Basis Pipe-Break Criteria

The following definitions are used for piping run terminology.

Main Run - Piping interconnecting terminal ends. All branch lines from the main run are considered branch runs, with the exception of the following:

a. Free-ended branch lines throughout which there is no significant restraint to thermal expansion are considered part of the main run

b. All ASME B&PV Code Section III, Class 1, branch lines that are included with the main run piping in the code stress analysis computer mathematical model are considered part of the main run.

Piping Run - A main or branch run.

Terminal End - Piping originating at the structure or components (such as vessel and equipment nozzles and structural piping anchors) that acts as a rigid constraint to the thermal expansion. Typically, the anchors assumed for the piping code stress analysis are considered terminal ends. In-line fittings, such as valves, not assumed to be anchored in the piping code stress analysis, are not terminal ends. The branch connection to the main run is one of the terminal ends of a branch run, except where the branch run was classified as part of a main run as defined above.

Break Location in ASME B&PV Section III, Class 1 Piping Runs

Postulated pipe-break locations are selected in accordance with the intent of Regulatory Guide 1.46; NRC Branch Technical Position (BTP) APCSB 3.1, Appendix B; and as expanded in NRC BTP MEB 3-1. For ASME Section III, Class 1 piping systems, the postulated break locations are as follows:

a. The terminal ends of the pressurized portions of the run

b. At intermediate locations between the terminal ends where the maximum stress range between any two load sets (including zero load set), according to Subarticle NB- 3600 of ASME Section III for upset plant conditions and an independent operating-basis earthquake (OBE) event transient, exceeds the following:

1. If the stress range calculated using Equation 10 of the Code exceeds 2.4 S_m but is not greater than 3 S_m, no breaks will be postulated unless the cumulative usage factor exceeds 0.1

2. If the stress ranges, as calculated by Equation 12 or 13 of the Code, exceed 2.4 S_m, or if the cumulative usage factor exceeds 0.1 when Equation 10 exceeds 3 S_m.

c. Arbitrary intermediate pipe breaks no longer need to be postulated, per Generic Letter 87-11

3.6.1.2.1 Core Cooling Requirements

The designed emergency core cooling system (ECCS) capability can be maintained provided that dynamic-effect consequences do not exceed the following break area, break combination, and maintenance of minimum core cooling requirements.

3.6.1.2.1.1 Maximum Allowable Break Areas

The maximum allowable break areas are as follows:

a. For breaks involving recirculation piping, the total effective area of all broken pipes, including the effective area of the recirculation line break, shall not exceed the total effective area of the design-basis double-ended recirculation line break (see Subsection 6.2.1.3). By limiting the total area of all broken pipes involving recirculation loops to an area less than or equal to that of the design-basis accident (DBA) (circumferential break of recirculation loop), no accident could be more severe than the DBA

b. For breaks not involving recirculation piping, the effects are much less severe than recirculation line breaks. Hence, the total break area can be allowed to be larger than the recirculation breaks. Therefore, the total break area shall not exceed the sum of one feedwater header pipe area, one steam line (upstream of flow limiter) pipe area, and one core spray pipe area.

3.6.1.2.1.2 Break Combinations

In addition to the pipe-break-area restrictions, breaks involving one recirculation loop shall not result in loss of function or damage to the other recirculation loop or loss of coolant from the other loop in excess of that which would result from a break of the attached cleanup connection on the suction side of the loop.

3.6.1.2.1.3 Required Cooling Systems

To ensure compliance with Appendix A of 10 CFR 50, General Design Criteria for Nuclear Power Plants, the following cooling system requirements, including all required support systems, must be met after an additional single active safety system failure:

a. For breaks not involving recirculation piping, at least two low-pressure coolant injection (LPCI) pumps or one core spray system shall be available for core cooling

b. For breaks involving recirculation piping, at least one core spray line and two LPCI pumps or two core spray lines shall be available for core cooling

c. For a steam line break with a total effective break area of less than 0.4 ft^2, either the HPCI or automatic depressurization system (ADS) shall be available for reactor depressurization. At least (n-l) ADS valves must be available (n = total number of ADS valves)

d. For liquid breaks such as cleanup suction or combination of liquid and steam breaks whose total break area is less than 1.0 ft^2 and in which the ADS system is required for depressurization, at least (n-l) ADS valves must be available

e. For breaks smaller than the equivalent flow area of one open ADS valve, at least (n-l) ADS valves must be available. However, the required number of ADS valves will be one less for each additional steam break area equivalent to the area of one open ADS valve.

3.6.1.2.2 Containment System Integrity

The following shall be considered in addressing the LOCA dynamic effects with respect to containment system integrity:

a. Leaktightness of the primary containment fission product barrier shall be ensured throughout any LOCA, unless analyses show that offsite dose consequences are within 10 CFR 50.67 guidelines or 10 CFR 100 guidelines

b. For lines that penetrate the drywell and are normally closed during operation, the inboard isolation valve shall be as close as practical to the reactor pressure vessel. This arrangement reduces the length of pipe subject to a pipe break

c. For lines that penetrate the primary containment and are open during normal operation, the outboard isolation valve shall be as close as practical to the primary containment.

3.6.1.2.3 Control Rod Insertion Capability

To maintain the ability to insert the control rods in the event of a pipe break, the control rod drive (CRD) withdrawal lines shall be protected from the dynamic effects so that no more than one in any nine-rod array is allowed to be completely crimped (totally blocked). Complete severance of withdrawal lines will not affect the rod-insert function. Protection for the CRD insertion lines is not required since a reactor pressure of 600 psig or higher can adequately insert the control rods.

3.6.1.3 Design Loading Combinations

Design criteria, design stress limits, and various loading combinations for safety class system components and equipment, including the RCPB system components, are described in detail in Subsection 3.9.2. Design criteria, design stress limits, and loading combinations for various types of pipe-whip restraints and support systems for Fermi 2 are described in Subsection 3.6.1.5 (see also References 1 through 11).

A description of analytical methods and computer codes used is given in Subsections 3.6.1.4 and 3.6.1.7, respectively.

3.6.1.4 Dynamic Analyses

3.6.1.4.1 Analytical Methods

3.6.1.4.1.1 General Description of Analytical Methods

The prediction of time-dependent and steady-thrust reaction loads caused by blowdown of subcooled, saturated, and two-phase fluid from a ruptured pipe is used in design and evaluation of dynamic effects of pipe breaks. Unsteady loads result from depressurization wave propagation that causes the various sections of pipe to be loaded with time-dependent forces. Steady blowdown thrust loads are all equivalent to a corresponding thrust applied normal to the plane of the break and opposite to fluid blowdown velocity. These loads can be computed for each section of the piping system, and corresponding external restraints can be provided if it is necessary to limit the movement of the piping system. A detailed description of the analytical assumptions and methods used to compute these blowdown loads is given in Section A of Reference 1 and in References 2 and 5.

A schematic diagram representing modeling of physical systems in pipe-whip analysis is given in Figure 3.6-1.

3.6.1.4.1.2 Blowdown Types and Associated Thrust Loads

The blowdown types and associated thrust loads considered in the analyses are summarized in this subsection.

The two components of the thrust reaction load considered are

a. Blowdown thrust - This thrust is caused by fluid acceleration from the break and static pressure in the break itself

b. Wave thrust - This thrust is caused by momentum transfer associated with decompression and compression waves (sonic waves) propagating in the various pipe sections. It is assumed that simple pipe bends and turns (without flow-area change) do not attenuate the traveling pressure waves or cause reflections.

Only the wave thrust produces reaction loads on bound pipe segments, whereas blowdown thrust applies only to the broken pipe segment. In the initial phase of a blowdown caused by a pipe rupture, both the wave and blowdown thrusts are present and they are additive. However, when the steady blowdown phase is reached, the wave thrust becomes zero and all bound pipe segment reaction loads disappear.

In designing protective devices to minimize the effects of pipe rupture, the jet impingement loads on surrounding mechanical system components, equipment, and structures were also considered to ensure that the effects of pipe rupture would not propagate to other vital plant systems.

3.6.1.4.1.3 Circumferential Breaks and Associated Thrust Loads

When analyzing a case where a single straight segment of broken pipe is attached to a pressure vessel, the magnitudes of both blowdown and wave thrust loads are computed. Depending on the state of the fluid in the piping system, nonflashing liquid or vapor phase, the resulting thrust loads will be different, as shown in Figures 3.6-2 and 3.6-3, respectively.

However, bends, friction, and flashing of near-saturated water all affect the blowdown characteristics. Therefore, for actual analyses, these factors were taken into account and the resulting time-dependent thrust force diagrams are modified as shown in Figure 3.6-4 for steam lines. Figure 3.6-4 shows a typical timethrust diagram for a line containing steam. After the initial wave thrust has died down, the blowdown thrust approaches the steady-state value.

a. Friction effects - Thrust reaction forces are attenuated by pipe friction that exerts its most direct effect on the blowdown rate. Figure 3.6-5 shows the steady-state thrust as a function of the friction coefficient (K = FL/D) for steam and saturated water. Reference 2, Section II-F, summarizes the methods used for including friction effects

b. Flashing effects - The effects of phase change are much less important for vapor flows than for low-quality saturated liquid/vapor mixtures. Therefore, methods for predicting time-dependent and steady blowdown properties of vapors are relatively straightforward. However, methods for predicting time-dependent blowdown of saturated mixtures must provide somewhat higher than expected loads for design purposes. Refer to Reference 14, Paragraph 4.2, for analytical development

c. Traveling speed of wave thrust - Flow disturbances propagate at sonic speed relative to the fluid. The sonic speed is important in predicting time-dependent flow properties before steady blowdown rates are reached. For development of sonic velocities used in the Fermi 2 design, refer to Reference 1 and Reference 2, Section II-C.

3.6.1.4.1.4 Longitudinal Breaks and Associated Thrust Loads

In the case of a longitudinal break of a pipe, the blowdown flow will come from both the upstream and the downstream directions except for lines with a dead end. For longitudinal breaks in dead-end lines, the analysis is similar to the analysis of circumferential breaks. If the longitudinal break area is sufficiently small, flow rate will be limited by the break itself; however, if the break is large, flow rate will be limited by the sum of upstream and downstream pipe areas or any applicable restriction area. The geometric character of a longitudinal pipe fracture is still relatively uncertain. Therefore, it is reasonable to consider an ideal, short nozzle-type break rather than a sharp-edged orifice-type break that would reduce the computed reaction thrust. A longitudinal break is shown in Figure 3.6-6. Figures 3.6-7 and 3.6-8 show thrusts for longitudinal breaks. In Fermi 2 piping system analyses, it is postulated that a longitudinal break area is equal to the pipe flow cross-sectional area. Refer to Reference 1, Section I of Reference 2, and Reference 14 for details on the analysis of thrust loads for longitudinal breaks.

3.6.1.4.1.5 Jet Impingement Loads

Jet impingement loads result from blowdown flow that forms a jet of fluid and imparts impact forces to pipes or other mechanical and structural target objects in its path. Analysis for components subject to jet impingement loads is described in Section D of Reference 1.

3.6.1.4.2 Modeling of Physical Systems

3.6.1.4.2.1 Circumferential Break Model

The circumferential break pipe/restraint system is modeled in the analyses such that the pipe immediately upstream of the elbow is loaded as a beam whose point of fixity is usually taken at a fitting or at the nonpiping component element such as a pump, vessel, or containment penetration. The weights of these pipes are small compared to the blowdown thrust loads; therefore, gravitational forces are neglected in the model. However, the mass of all piping, fittings, valves, or any other concentrated weight is considered in the dynamic analysis to account for the inertial effects of these masses. A schematic diagram of pipe/restraint is shown in Figure 3.6-9 for the circumferential break case.

The weight of the beam section, L, shown in Figure 3.6-9 is treated as a distributed mass. If a concentrated weight exists in the beam between the restraint and the break, it is treated in the model as an additional point mass transferred to the beam end at the break location line of action. The restraint closest to the broken end is assumed to carry the total dynamic load. No credit is taken for additional restraints, if any, along the pipe that would reduce the loading on the primary restraint.

3.6.1.4.2.2 Longitudinal Break Model

Figure 3.6-l0 shows a model in which a longitudinal break occurs along the bend of an elbow. The model elements are generally similar to those of the circumferential break. However, an additional element, the equivalent beam restraint, L_3, is present as shown in the figure. This element shares the applied load with the beam element from the instant the break occurs. The applied load in the longitudinal break case has two components. The first component, F_{BA}, acts parallel to the axis of the equivalent beam restraint as a compression force if the equivalent beam restraint ends in a true point of fixity; that is, a vessel, containment penetration, etc. If the equivalent beam restraint does not end at a point of fixity, the force F_{BA} will load some other combination of beams and equivalent beam restraint. The second component, F_{BB}, acts perpendicular to the equivalent beam restraint, L_3, and the beam, L. The equivalent beam restraint is treated in the model as a beam spring whose force is directly opposite to the thrust load. The mass, however, is treated as an additional equivalent point mass along with any other concentrated loads it may contain, applied to the end of the beam section.

3.6.1.4.2.3 Pipe Response Modes of the Model

The five pipe response modes of the model are as follows:

a. First response mode - The first mode of response is the free movement of the piping system before it contacts the restraint. In this mode, the energy that is not dissipated as deformation energy of the beam in the circumferential break and of the beam and equivalent beam restraint in the longitudinal break, becomes kinetic energy of the beam system

b. Second response mode - This response mode is initiated the instant the pipe hits the restraint. Analysis of this response mode requires a complex mathematical model because of the multilink response of the system involved. In this mode the thrust force, restraint force, and pipe-bending resistance moments all have to be considered to compute the accelerations, velocities, and displacements at the broken end of the pipe

c. Third response mode - In this mode the restraint and the bound end of the pipe have ceased to move, but the free end of the pipe is still in motion. During this period, the forces and moments of the various load elements, the energy balance, and the kinetic energy are computed as a function of the displacement. If the kinetic energy is computed to be zero or negative, the free end of the pipe is assumed to be stationary

d. Fourth response mode - In this mode the movement at the free end of the beam relative to the bound end is zero, and the computation process continues as in the third mode

e. Fifth response mode - In this mode the steady-state response of the piping system is computed. The computed steady-state load is compared to the maximum allowable restraint load.

The five modes of response listed above describe the computational process used in the dynamic analysis of pipe rupture thrusts and corresponding effects on the pipe-whip restraints. Details of the computer code used in this analysis are given in Reference 5. The results of the analyses are reported in Reference 1.

3.6.1.5 Protective Measures

Protection against the dynamic effects of a pipe rupture is provided in the form of pipe-whip restraints, equipment shields, and physical separation of piping, equipment, and instrumentation.

Detailed analyses of pipe restraints and restraint support systems, and test results of the pipe restraints installed in Fermi 2 are described in References 1 and 9, respectively, which were submitted to the AEC as topical reports. Supplemental analyses were also performed for the as-built configuration.

3.6.1.5.1 Pipe Restraint Design

3.6.1.5.1.1 Design Criteria

Pipe restraints, as differentiated from piping supports, are designed to function and carry loads for an extremely low probability of gross failures in the RCPB and other vital safety system piping. The RCPB piping integrity does not depend on the piping restraints during normal, upset, emergency, or faulted conditions as defined in paragraph NB-3113, Section III, of the ASME B&PV Code, but relies on piping supports to maintain the piping design stress values and/or piping integrity.

The pipe restraints (that is, those devices that serve only to control the movement of a ruptured pipe following gross failure) are subjected to once-in-a-lifetime loading. Local pipe and restraint deformations that occur upon impact do not further affect the integrity of the RCPB. For the purpose of design, the pipe-break event is considered to be a faulted condition and the pipe, its restraints, and structure to which the restraint is attached, are analyzed accordingly.

Piping within the broken loop shall no longer be considered part of the RCPB. Plastic deformation in the pipe is considered as a potential energy absorber. Limits of strain can be imposed that are similar to strain levels allowed in restraint plastic members. Piping systems are designed so that plastic instability does not occur in the pipe at the design dynamic and static loads.

Therefore, the design objectives governing the extent of permissible damage resulting from postulated dynamic effects of pipe whip are as follows:

a. The integrity of the primary containment system must be maintained

b. Safe shutdown and maintenance of core cooling integrity must be ensured.

To ensure the previous general design criteria of pipe restraints, the following specific design requirements must be met.

a. The restraints shall in no way increase the RCPB stresses by their presence during any mode of reactor operation or condition

b. The restraint system shall function to stop the movement of a pipe failure (gross loss of piping integrity) without allowing damage to critical components or missile generation.

3.6.1.5.1.2 Types of Pipe Restraint Components

To establish a design basis relating to material selection, fabrication, inspection, installation, quality assurance, and applicable design limits, three types of restraint hardware are defined. In addition, the structural and civil components are considered as a separate type.

a. Type I - Restraint energy absorption members - Those members that, under the influence of impacting pipes (pipe whip), will absorb energy by significant plastic deformation (e.g., U-bolts, rods, cables)

b. Type II - Restraint connecting members - Those components that form a direct link between the restraint plastic members and the structure (e.g., clevises, brackets, pins)

c. Type III - Restraint connecting member structural attachments - Those fasteners that provide the method of securing the restraint connecting members to the structure (e.g., weld attachments, bolts)

d. Type IV - Structural and civil components - Those steel and concrete structures that ultimately must carry the restraint load (e.g., sacrificial shield, trusses).

3.6.1.5.1.3 Loading Basis for Pipe Restraints

For the purpose of designing the pipe restraints as defined in Subsection 3.6.1.5.1.2, the following faulted loading combinations are used:

a. Dynamic Loading

1. Blowdown thrust of the pipe section that impacts the restraint

2. Dynamic inertia loads of the moving pipe section that is accelerated by the blowdown thrust and impacts the restraint.

b. Static Loading

1. Maximum steady-state blowdown thrust following initial dynamic loading when pipe movement ceases

2. Effective piping weight on the restraint, if significant.

3.6.1.5.1.4 Design Basis for Pipe Restraints

The four types of pipe restraints are

Type I

a. Materials - All materials that are used to absorb energy through significant plastic deformation shall conform to

1. ASME B&PV Code Section III, Subsection NB, Class 1 Components, or

2. ASTM specifications with consideration for brittle fracture control.

b. Inspection - Inspection and identification of material shall conform to

1. ASME B&PV Code Section III, Subsection NB, Class 1 Components (Section V, Non-Destructive Examination Methods), or

2. ASTM specification procedures, including volumetric and surface inspection.

c. Design limits

1. Design local strain - The permanent deformation in metallic ductile materials shall be limited to 50 percent of the minimum actual uniform elongation based on restraint material tests for stainless steel restraint bars

2. Design steady-state load - The maximum restraining load will be limited to:

(a) 80 percent of the minimum calculated static ultimate restraint strength at the drywell design temperature for bar-type restraints

(b) 75 percent of certified minimum breaking strength for cables determined on the basis of tests (Reference 14).

3. Dynamic material mechanical properties - The material selected must exhibit tensile impact properties that are not less than

(a) 70 percent of the static percent elongation

(b) 80 percent of the statistically determined minimum total energy absorption.

Type II

a. Materials - Material selection shall conform to ASTM Specifications, including considerations for brittle fracture control

b. Inspection - Inspection shall conform to ASME/ASTM requirements or process qualification and finished parts surface inspection per ASTM methods

c. Design limits - Design limits shall be based on the following stress limits:

1. Primary stresses shall be limited to the higher of

(a) 70 percent of S_u , where S_u = minimum ultimate strength by tests or ASTM Specification

(b) $S_y + 1/3 (S_u - S_y)$, where S_y = minimum yield strength by tests or ASTM Specification.

Type III

a. Fasteners

1. Materials - Fastener materials shall conform to ASTM and ASME requirements

2. Inspection - All fasteners shall be inspected or certified per applicable ASTM and ASME specifications

3. Design limits - Same as Type II.

b. Welds

1. Materials - Weld material for attachment to carbon steel structures shall conform to AWS/ASME specification per:

(a) AWS A5.1, A5.5, or A5.17, low hydrogen electrode for metal arc welding, or

(b) AWS A5.18 or A5.20 filler metal for MIG or TIG welding.

2. Procedures - Procedures and welders shall be qualified per AWS Code D1.0 - latest edition for welding in building structures

3. Design limits - Design limits shall be based on the following stress limits:

The maximum primary weld stress intensity (two times maximum shear stress) will be limited to three times AWS or AISC allowable weld shear stress.

Type IV

Design requirements for structural equipment are not codified to the same extent as for the mechanical and electrical equipment. The industry recognizes this inadequacy and is actively working in this area. For example, standards for concrete containment are being developed by both the ASME and the American Concrete Institute (ACI). It is also impractical to "qualify" a structure as is done for electrical or instrument components. It is therefore current practice within the industry for structural requirements to be developed and specified by a qualified structural engineer, and for those requirements and methods of implementing the design to be reviewed by the NRC. Structures are designed to respond to conditions associated with the specific structure including operational and accident loadings, seismic loadings, wind loadings, and tornado loadings.

The design-basis approach of categorizing components is consistent in allowing less stringent inspection requirements for those components subject to lower stresses. Considerable strength margins exist in Types II through IV even to the limit of load capacity (fracture) of a Category I component. It is recognized that impact properties in all components must be considered since brittle-type failures could reduce the restraint system effectiveness. For details of load combinations, design limits, stress criteria, and materials specifications, see Section 3.8.

3.6.1.5.1.5 Design Basis for Seismic Guide

The normal function of a seismic guide is to support a piping system and limit deflection under seismic loading. Because of the limited space in the area of the inboard main steam isolation valve (MSIV), it was necessary in this particular case to combine the function of a seismic guide with the function of a pipe-whip restraint. Details are described in Reference 1.

The seismic guide is designed with a low clearance to maintain small deflections during seismic events, so that the containment penetration and the inboard MSIV will not be subjected to high stresses. To limit the pipe motion within the confines of available space in the event of a pipe rupture, the existing seismic guide was redesigned to include the function of a low-clearance pipe-whip restraint.

The seismic guide contains 40 crushable energy-absorbing stainless steel tubes with a 1-in. outside diameter, a 0.156-in.-thick wall, and a 10-in. length. These tubes will not be in contact with the pipes under normal and/or seismic events. However, in the event of a pipe rupture requiring the pipe-whip restraint to function, the pipe is free to work on the crushable tubes, thus dissipating its kinetic energy to the tubes.

3.6.1.5.1.6 Verification Tests for Pipe-Whip Restraints

The dynamic test program conducted by Edison with the assistance of GE verifies the adequacy of the Fermi 2 pipe-whip restraint designs. The concept of large-clearance design with plastic deformation of restraint material to absorb the kinetic energy of a whipping pipe has been proven in these tests, which are described in Reference 9.

The overall conclusion can be drawn from the results of the actual tests that sufficient conservatism exists in the analysis methods used to initially predict the effectiveness of the design concept in restraining vital piping without hindering their normal expansion and contraction in the course of plant operation. Therefore, it is concluded that the pipe-whip restraint designs are effective, with sufficient margins to meet all of the safety design requirements.

3.6.1.5.1.7 Design Basis for Recirculation System Restraints

Restraints for the recirculation system piping are the GE cable-type restraints. These restraints are discussed in Reference 14.

3.6.1.5.2 Separation and Protective Provisions for Safety- Related Systems and Equipment

3.6.1.5.2.1 Separation Criteria

Separation of safety-related mechanical and electrical systems and equipment is provided such that the General Design Criteria of 10 CFR 50 are fulfilled by providing the protection against the single-failure criterion. That is, all safety-related systems and equipment are arranged such that a single failure of any active component in a redundant system does not result in a loss of capability of the system to perform its safety function (see Section 3.12).

3.6.1.5.2.2 System Separation

The mechanical and electrical systems and equipment separation are as follows:

a. Mechanical systems and equipment - Piping for a redundant safety system is run independent of its counterpart. Supports, restraints, and mechanical components of redundant piping of the same system are not shared in common, unless it can be shown that such sharing does not significantly impair their ability to perform their safety functions.

   The systems and equipment that meet the separation criteria are as follows:

   1. LPCI
   2. CS
   3. HPCI
   4. ADS
   5. RCIC.

b. Electrical systems and equipment - The electrical portions of the following systems are affected by the separation criteria:

   1. Reactor protection
   2. HPCI
   3. CS
   4. RHR
   5. Emergency closed cooling water (ECCW)

6. RCIC.

The corresponding electrical equipment includes

1. Instrument channels
2. Trip systems
3. Trip actuators
4. Standby power sources
5. Average power range monitor
6. Intermediate range monitor.

These systems and equipment have also been designed and fabricated in accordance with the intent of IEEE Standard 279-1971 and IEEE Standard 308-1971, as applicable.

3.6.1.5.2.3 Physical Separation

The physical separation for mechanical and electrical systems and equipment is as follows:

a. Mechanical systems and equipment

   1. Mechanical equipment and piping, including control safety conduit and tubing and containment penetrations for safety-related systems, are physically separated to meet the single-failure criterion

   2. The ADS is physically separated from the HPCI system such that no portion of the HPCI influent line or HPCI steam supply line is located within the jet impingement damage distance or pipe-whip damage distance of any component considered essential to the ADS operation

   3. Provisions are made to ensure that no single failure could incapacitate both the HPCI and RCIC systems.

b. Electrical systems and equipment

   Electrical equipment and wiring for the reactor protection system (RPS) and the ECCS subsystems are physically separated under separate divisions, designated as Divisions I and II, to conform to the requirements of the single-failure criterion by arrangement and/or protective barriers.

3.6.1.5.3 Protective Shields and Jet Deflectors

Jet deflectors are provided in the drywell at the inlet of each vent pipe to prevent possible damage from jet forces, which might accompany a pipe break in the drywell. In addition, piping and electrical penetrations in the primary containment are either designed to withstand or are shielded from the jet impingement forces arising from the rupture of the largest local pipe or connection. Details of the piping penetration jet deflectors are discussed in Subsection 3.8.2.1.3.1. The sacrificial shield and the containment floor also act as shields for the pipe-whip and jet impingement forces arising from a break in the unrestrained portions of the pipe inside the drywell.

3.6.1.6 Pipe-Whip Restraint Support System

Pipe-whip restraints are provided at required locations along the length of pipes under pressure to withstand forces arising from whipping of the pipes in the event of a postulated pipe rupture. These restraints are designed so that the energy dissipated during whipping of the pipe after rupture is absorbed by plastic yielding of the restraints; this provision of absorption of energy by plastic yielding results in further reduction of the reactive force due to whipping. Depending upon the location of the restraints and configuration of the piping network, the restraints are attached directly to the sacrificial shield, through trusses to the sacrificial shield, directly to the reactor pressure vessel (RPV) pedestal, or through trusses to the RPV pedestal and drywell floor. The design of the pipe-whip restraint support system (PWRSS) is described in Reference 1.

3.6.1.6.1 Design Criteria

3.6.1.6.1.1 Design Basis

The structural analysis of the components of the PWRSS is performed using linear elastic methods. The stresses resulting from such an analysis for the load combinations involving pipe rupture forces are limited to Φfy, where f_y is the maximum stress resulting in first yielding of the structure as specified in AISC and ACI specifications, and Φ is the reserve strength factor, which depends on the type of structure and ranges in value from 0.85 to 0.95. The reserve strength factors are used to ascertain that the structure does not reach first yield under the specified load combinations. This factor also includes the effect of strength variation in materials and workmanship.

An underlying assumption in the design of the PWRSS is that only one pipe-rupture event can take place in any given instant.

The design forces for the PWRSS are derived from the results of the dynamic pipe-whip analyses, described in the preceding subsections, and expressed as equivalent static loads. In deriving these equivalent static loads, consideration is given to the following parameters:

a. Time dependence of pipe-rupture loads

b. Flexibility and damping of the components of the PWRSS

c. Second-order effects in the restraints, such as strain hardening and variation of material properties with rate of strain.

3.6.1.6.1.2 Load Combinations and Allowable Stresses

The load combinations described here involve only the loads due to pipe-whip forces and corresponding allowable stresses. The values of allowable stresses are the maximum possible values. The actual limiting values for design are dependent on the type, function, and method of construction of the particular structure; and hence, if necessary, the values of allowable stresses are suitably reduced. The load combinations and allowable stresses given are applicable to all components of the PWRSS.

a. Load Combinations for Design of PWRSS Components

Load Combination category	D	L	T_a	P_a	R	E	E'	M
Abnormal/severe environment	1.0	1.0	1.0	1.0	1.0	1.0		
Abnormal/extreme environmental	1.0	1.0	1.0	1.0	1.0		1.0	1.0

NOTES:

1. Loads not applicable to a particular structure under consideration may be deleted.

2. If for any load combination the effect of any load other than D reduces the total load, it shall be deleted from the combination.

NOTATION

D = Dead load of structure plus any other permanent loads

L = Conventional floor live loads and movable equipment loads

T_a = Thermal effects that may occur during an accident

P_a = Pressure loads that may occur during an accident

R = Statically equivalent forces arising out of effects that include jet impingement, dynamic rupture load associated with whipping pipe, and accidental thermal pipe reaction

E = Operating-basis earthquake (OBE) effects

E' = Safe-shutdown (formerly design-basis) earthquake (SSE) effects

M = Effects of missile impact

b. Allowable Stresses

1. Concrete

(a) Compression

Membrane	$0.60f_c'$
Membrane plus flexural	$0.75\ f_c'$
Local compression	$0.90\ f_c'$

(b) Shear

Permissible nominal shear stress and design of necessary shear reinforcement are as per the provisions in Chapter 11 of ACI 318-71, Building Code Requirements for Reinforced Concrete

(c) Membrane Shear

The principal stresses resulting from membrane shear and normal stresses are computed for all combinations. If the principal tension is greater than $3\sqrt{f'_c}$ in localized areas, then reinforcing steel is provided to carry the total tensile force

In addition to the specific requirements stated above, all the other provisions of ACI 318-71 apply.

2. Reinforcing Steel

   Tension $0.9\ f_y$

   Compression (load carrying) $0.9\ f_y$

3. Structural Steel

   The allowable stresses are 1.6 times those given in AISC specifications. The following requirements are also satisfied:

   (a) Allowable shear stress = $\frac{0.95\ F_y}{\sqrt{3}}$

   (b) Allowable shear stress in fillet welds = 1.6 times those given in AISC specifications.

   (c) Allowable tensile stress in a plane perpendicular to the plate thickness = $\frac{2}{3} F_y$

NOTATION

f'_c = Specified compressive strength of concrete, psi

f_y = Specified yield strength of reinforcement

F_y = Specified yield strength of structural steel

3.6.1.6.1.3 Components of Pipe-Whip Restraint Support System

The primary components in the PWRSS are

a. Pipe-whip restraints

b. Sacrificial shield

c. Trusses

d. Reactor support pedestal

e. Drywell floor.

A schematic representation of interactions among various components of the PWRSS is given in Figure 3.6-11; the relative locations of the components are shown in Figure 3.6-12.

Some descriptions of structures, analytical methods, loads, and stresses for the design of PWRSS are given in Reference 15.

3.6.1.7 Computer Programs Used in Analysis and Design of Pipe- Whip Restraints and Restraint Support Systems

The computer programs used in the analysis and design of pipe-whip restraints and restraint support systems are:

a. PDA - PDA (Pipe Dynamic Analysis Program for Pipe Rupture Movement) was developed by GE to solve nonlinear, two-dimensional dynamic equations of pipe-whip and the restraining device motions. This program is used to generate the time-dependent forcing functions for the design of pipe-whip restraint devices. For a detailed program description refer to Reference 5

b. INDIA - INDIA (Interaction Diagram for Reinforced Concrete Members) was developed and is maintained by Sargent & Lundy (S&L). It has been designed to plot the bending moment-axial load interaction diagram for reinforced-concrete members

   Interaction diagrams can be obtained for any of the criteria of design, ultimate strength, yield strength, or working stress. Both compression and tension axial loads are considered, as well as positive and negative moments

   The program output includes a listing of the results for the specified design criterion. The interaction diagram is plotted, if so desired

c. KALSHEL - KALSHEL (Kalnins' Shell of Revolution) was developed by A. Kalnins of Lehigh University and is maintained by S&L. The program analyzes thin axisymmetric shells of revolution for arbitrary load conditions. It is based on a computation scheme set forth in the publication by A. Kalnins, "Analysis of Shells of Revolution Subjected to Symmetrical and Nonsymmetrical Loads," Journal of Applied Mechanics, ASME, Vol. 31, September, 1969, pp. 467-476. For the solution, the general boundary value problem of a rotationally symmetric shell is transformed into a new system of first-order ordinary differential equations. An Adams method of numerical integration is used as a basis for the solution of transformed equations

   The shell wall may vary in thickness along the meridian and may consist of up to four layers of different isotropic or orthotropic materials. Branch shells may be connected to the main shell. Surface loads and live loads in the radial, tangential, and/or meridional directions and meridional moments may be considered in the analysis. Temperature distributions that may be considered to vary linearly across the thickness may also be considered. All loads may be asymmetric

   The program output includes the shell displacements in the radial, tangential, and meridional directions, meridional rotations, meridional moment, hoop moment, meridional force, hoop force, transverse shear force, and twist shear force. Outer fiber stresses calculated from the stress resultants may also be obtained. Sargent & Lundy has modified the program to sum the displacement and stress resultants of the individual Fourier harmonics along meridians at specified angles

d. <u>SLSAP</u> - SLSAP (Sargent & Lundy Structural Analysis Program) was developed by E. L. Wilson of the University of California, Berkeley, and is maintained by S&L. The program uses the stiffness matrix method to analyze two-and three-dimensional frames, trusses, and grids, three-dimensional elastic axially symmetrical solids, plates, and shells for arbitrary static loads. Dynamic analyses for frequencies and mode shapes, spectral analysis, and numerical integration analyses are also possible

   The program allows materials with arbitrary elastic constants, combined loading, rigid members, elastic supports, and a combination of different element types

   The program output includes displacement and rotations of all joints or nodes, forces or stresses in members or elements, frequencies and mode shapes, and dynamic response in terms of displacements and forces

e. <u>SOR-III</u> - SOR-III (Shell of Revolution) was developed by Knolls Atomic Power Laboratory for the AEC. It is maintained by S&L. The program analyzes thin shells of revolution subjected to axisymmetric loading by numerically integrating the governing differential equations using a generalized Adams-Moulton method

   Arbitrary distribution of normal, tangential, and moment surface loadings, as well as edge forces and deflections, may be considered in the axisymmetric loadings. Input of boundary conditions allows for the consideration of elastic support conditions. The effect of temperature variations along the meridian or across the thickness is also considered

   The program output includes shell displacements, outer fiber stresses and strains, and stress resultants

f. <u>STRESS-II</u> - STRESS-II (Structural Engineering Systems Solver) was developed by Massachusetts Institute of Technology and is maintained by University Computing Company. It uses the stiffness matrix method to analyze plane and space trusses and frames and plane grids

   The structure can be analyzed for arbitrary joint loads, member loads, temperature changes, and joint displacements. A plotting feature is available with the program

   The output includes joint displacements, equilibrium check, and reactions and member forces

g. <u>TEMCO-III</u> - TEMCO-III (Reinforced Concrete Sections Under Eccentric Loads and Thermal Gradients) was developed and is maintained by S&L. It analyzes reinforced-concrete sections subjected to combined external loads and thermal gradients. The analysis may be done assuming either a cracked or an uncracked section. Temperature effects are induced in the section by reactions created by translational or rotational restraints

   The analysis may be done for separate or combined action of tensile or compressive axial force, shear force, bending moment, and thermal gradients

The program output includes the location of the neutral axis, stresses in the steel and concrete, and an equilibrium check

h. Additional computer program descriptions are given in Section 3.13.

3.6.2 Protection Against Dynamic Effects Associated With the Postulated Rupture of Piping Outside Containment

The evaluation of pipe breaks of high-energy systems outside the containment includes the main steam and feedwater lines, the HPCI system, the RCIC system, the RWCU system, reactor building heating steam lines, and the CRD system.

Evaluation of the effects of through-wall leakage cracks in moderate-energy piping systems is also reported in this section. The evaluation takes into account the potential damaging effects of either water flooding or spraying from the pipe crack, and considers the overall capability of achieving reactor shutdown and maintaining a cold-shutdown condition.

The plot plan with the relative sizes of major structures is shown in Figure 1.2-5. The reactor portion of the reactor/ auxiliary building, including the primary containment, contains most of the Level I systems and components. Areas within the auxiliary portion of the reactor/auxiliary building that contain Level I systems and components are

a. Main control room and associated heating, ventilating and air conditioning (HVAC) room

b. Switchgear room

c. DC power supply rooms

d. Relay rooms

e. Cable spreading rooms

f. Standby gas treatment compartments

g. HVAC rooms.

The standby ac power system, residual heat removal service water (RHRSW) pumps and emergency equipment service water (EESW) pumps are housed in the RHR complex, a physically separate structure.

The reactor/auxiliary building is mounted on a common foundation in which the reactor portion is separated from the auxiliary portion by a sealed wall. The sealed wall between the reactor building and auxiliary building is for secondary containment purposes. Piping systems whose operating pressure and temperature conditions are consistent with a high-energy classification, as defined in Subsection 3.6.2.1.2.1, are listed in Subsection 3.6.2.1.3.

In all cases investigated, conservatism was exercised in determining the consequences resulting from the postulated pipe break. These results were in turn used to develop design provisions that would provide the necessary protection to mitigate any adverse effects on the ability to achieve a safe reactor shutdown. These design provisions are detailed in the sections describing the adverse conditions they were intended to mitigate, and are summarized in Section 3.6.2.4. The modifications to plant design called out herein provide assurance against unacceptable consequences of the postulated pipe breaks.

The reactor/auxiliary building floor plans are shown in Figures 3.6-13 through 3.6-19. The floor plans include a room, area, and compartment number system that is referred to throughout this section, particularly in the discussion on the environmental effects of high-energy pipe breaks and the moderate-energy pipe breaks. By cross reference, an easy method is provided for following the discussion.

3.6.2.1 Design-Basis Pipe Break Evaluation

The design-basis pipe break was postulated to occur in all high-energy piping systems defined in Subsection 3.6.2.1.2.1. Throughwall leakage cracks were postulated to occur in all moderate-energy piping systems defined in Subsection 3.6.2.1.2.l.

3.6.2.1.1 Approach To Evaluation

The approach to the evaluation of postulated breaks in high-energy fluid systems and through-wall leakage cracks in moderate energy fluid systems is described in this section. The approach takes into consideration the rules and guidance provided in the following:

a. AEC letter dated December 15, 1972, and the errata sheet dated January 12, 1973 (Reference 16)

b. AEC letter dated July 12, 1973 (Reference 17)

c. Branch Technical Position ASB 3-1 (formerly BTP APCSB 3-1), "Protection Against Postulated Piping Failures in Fluid Systems Outside Containment," July 1981 (Reference 18)

d. Branch Technical Position MEB 3-1, "Postulated Rupture Locations in Fluid System Piping Inside and Outside Containment," July 1981 (Reference 19)

In instances where the provisions of the above documents differ, to the extent practical based on the stage of design and construction of the plant, the evaluation methods are based on the guidance provided in the Items c. and d. Branch Technical Positions.

3.6.2.1.1.1 High-Energy Fluid Systems

A summary of the basic approach used in the evaluation of the consequences of high-energy pipe breaks is as follows:

a. Pipe-break locations are as given in Subsection 3.6.2.1.2.2

b. Evaluation of the direct consequences of the break on systems and components required for a safe cold shutdown, taking into consideration the effects of pipe whip, jet impingement, flooding, and environmental conditions (temperature, pressure, and humidity)

c. Evaluation of the ability of Category I structures to withstand the effects of the pipe break, taking into consideration the effects of pipe whip, jet impingement, flooding, pressure, and temperature in combination with the specified seismic event loads and normal plant loads

d. A determination of the remaining systems and components available to ensure and maintain a safe cold shutdown. This determination is made in accordance with Subsection 3.6.2.1.4 and Table 3.6-1. In making this determination, the following assumptions were made with regard to the operability of these systems and components:

1. If the pipe break directly results in a turbine-generator trip or an RPS trip (scram), offsite power is assumed to be unavailable.
2. A single component failure is assumed to occur in addition to the postulated pipe break and any other system or component failures resulting as a direct consequence of this pipe break.
3. Operator action is assumed l0 minutes after pipe break.

e. Assurance that the escape of steam, water, and heat from structures enclosing the ruptured pipe does not prevent occupation of the main control room, nor does it impair the ability of instrumentation, electric power supplies, components, and controls to initiate, actuate, and complete a safety action. In this regard, a loss of redundancy, but not the loss of a function, is permissible.

3.6.2.1.1.2 Moderate-Energy Fluid Systems

A summary of the basic approach used in the evaluation of the consequences of moderate-energy through-wall leakage cracks is given below.

a. For piping systems located in areas containing systems and components important to safety, through-wall leakage cracks were postulated at the most adverse locations to determine the effects from both water spray and flooding. In areas where safety systems and components are not located, the effects of flooding in other areas were considered

b. Evaluation of direct consequences of leakage cracks on systems and components, taking into account the effects of resulting water spray and flooding

c. A determination was made of systems and components available to ensure and maintain a safe cold shutdown

   This determination was made in accordance with Subsection 3.6.2.1.4 and Table 3.6-1. In making this determination, the following assumptions were made with regard to the operability of these systems and components:

   1. If water spray or flooding from the pipe crack directly results in a turbine-generator trip or an RPS trip (scram), offsite power was assumed to be unavailable
   2. A single component failure was assumed to occur in addition to the system or component failures resulting from water spray or flooding. In the event the pipe crack is assumed to occur in one of two or more redundant trains of a dual-purpose essential system, failure of components in the other train or trains of that system was not assumed

3. Operator action was assumed l0 minutes after the pipe crack.

d. It is established that water spray or flooding does not prevent occupation of the main control room, nor does it impair the ability of instrumentation, electric power supplies, components, and controls to initiate, actuate, and complete a safety action

e. In the event a safe shutdown cannot be ensured considering those systems failed or assumed to have failed as a consequence of the leakage cracks, plant modifications were instituted or protection was provided to those systems or components.

3.6.2.1.2 Design-Basis Pipe Break Criteria

3.6.2.1.2.1 Definition of High-Energy Fluid Systems

High-energy fluid systems include those systems that under normal or upset plant conditions are pressurized during operation and one of the following conditions exists:

a. The maximum operating temperature exceeds 200°F

b. The maximum operating pressure exceeds 275 psig.

A fluid system meeting the above definition less than 2 percent of the time is not considered a high-energy fluid system.

Moderate-energy fluid systems include those that during normal plant conditions are either in operation or maintained pressurized under conditions where both of the following conditions exist:

a. The maximum operating temperature is 200°F or less

b. The maximum operating pressure is 275 psig or less.

3.6.2.1.2.2 Design-Basis High-Energy Break/Crack Locations

Break locations are postulated outside the containment in accordance with the following criteria:

a. ASME B&PV Code Section III, Class 1, pipe breaks are postulated to occur at the following locations in each piping run or branch run:

1. The terminal ends

2. Any intermediate locations between terminal ends, where the maximum stress range as calculated by Equation 10, and either Equation 12 or 13, of NB-3653, derived on an elastically calculated basis under the loadings associated with normal and upset plant conditions, exceeds 2.4 S_m

3. Any intermediate location between terminal ends where the cumulative usage factor derived from the pipe fatigue analysis and based on all normal, upset, and testing plant conditions exceeds 0.1

4. Arbitrary intermediate pipe breaks no longer need to be postulated, per Generic Letter 87-11

b. ASME B&PV Code Section III, Class 2 and 3, pipe breaks are postulated to occur at the following locations in each piping run or branch run:

1. The terminal ends

2. Any intermediate location between terminal ends, where the stresses as calculated by Equations 9 and 10 of NC/ND-3652, derived on an elastically calculated basis under the loadings associated with normal and upset plant conditions, exceed 0.8 (1.2 S_h + S_a)

3. Arbitrary intermediate pipe breaks no loner need to be postulated, per Generic Letter 87-11

c. In situations where detailed stress analyses of ASME B&PV Code Section III, Class 2 and 3, piping systems are not used to select postulated break locations, and, in the case of those high-energy systems outside the containment that are not analyzed to ASME III Code requirements, break locations are conservatively assumed to occur at all fitting welds where a break has the potential of causing unacceptable damage to systems and/or components necessary to effect and/or maintain a safe shutdown.

d. The break analysis of seismically analyzed non-ASME class piping is postulated according to the requirements for ASME Class 2 and 3 piping.

For those portions of the piping passing through the primary containment penetrations and extending to the first outboard isolation valve, pipe breaks were not postulated since the piping was conservatively designed and restrained beyond the valve such that, in the event of a postulated pipe break outside the containment, the transmitted pipe loads will neither impair the operability of the valve nor affect the integrity of the piping of the containment penetration.

Design criteria for piping between the primary containment and outboard isolation valves provide for maximum stresses considering all normal and upset conditions as calculated by the equations in Paragraph NB-3653 of ASME B&PV Code Section III, which may not exceed the following limits:

a. If Equation 10 results in $S < 2.4\ S_m$, no other requirement need be met

b. If Equation 10 results in $S > 2.4\ S_m$, then Equations 12 and 13 must result in $S < 2.4\ S_m$ and Equation 14 must yield a value of $U < 0.1$.

3.6.2.1.2.3 Design-Basis Break Types and Orientation

The following high-energy breaks are postulated at the locations described in Subsection 3.6.2.1.2.2:

a. Circumferential breaks in piping runs and branch runs exceeding 1 in. nominal pipe size

b. Longitudinal breaks in piping runs and branch runs 4 in. nominal pipe size and larger

c. Longitudinal breaks are not postulated at terminal ends.

Longitudinal breaks are considered parallel to the axis of the pipe and oriented at any point around the pipe circumference.

Circumferential breaks are considered to be perpendicular to the axis of the pipe.

The break area is equal to the internal cross-sectional area of the ruptured pipe in the case of circumferential breaks and longitudinal breaks. Longitudinal breaks extend a distance of one diameter on each side of the break location.

3.6.2.1.2.4 Design-Basis Through-Wall Leakage Cracks

Through-wall leakage cracks in piping exceeding 1 in. nominal pipe size were generally postulated at the most adverse locations in moderate-energy piping systems located in areas that contain systems and components important to safety, but in which no high-energy systems are present. However, through-wall leakage cracks need not be postulated in portions of piping where the calculated stresses satisfy BTP MEB 3-1 (reference 19) exclusion criteria. These through-wall leakage cracks were assumed to be half the pipe diameter in length and half the pipe wall thickness in width.

3.6.2.1.3 Identification of Energy Systems

The high- and moderate-energy systems included in this evaluation are identified below.

3.6.2.1.3.1 High-Energy Piping Systems

The piping systems located inside the reactor/auxiliary building but outside the primary containment and meeting the definition of high-energy systems, defined in Subsection 3.6.2.1.2.1, are

a. Main steam

b. Feedwater

c. High-pressure coolant injection system steam supply

d. Reactor core isolation cooling system steam supply

e. Reactor water cleanup

f. Control rod drive insert and withdrawal lines and charging line

g. Reactor building heating steam lines.

The piping systems listed below have normal/upset pressure and/or temperature conditions that fall into the high energy category; however, since these systems are operated less than 2 percent of the time, they are not considered high-energy systems. This is consistent with the definitions presented in Subsection (3.6.2.1.2.1).

These systems are

a. Residual heat removal system

b. Core spray system

c. Reactor core isolation cooling system discharge

d. High pressure coolant injection system discharge.

3.6.2.1.3.2 Moderate-Energy Systems

Appropriate portions of the following piping systems meeting the definition of moderate-energy systems as defined in Subsection (3.6.2.1.2.1) were evaluated:

a. Residual heat removal system

b. Core spray system

c. High-pressure coolant injection system

d. Fire protection system

e. Reactor core isolation cooling system

f. Fuel pool cleanup system

g. Reactor building closed cooling water system

h. Service water

i. Emergency equipment cooling water

j. Reactor water cleanup system

k. Control rod drive system

l. Torus water management system

m. Chilled water system

n. Reactor building heating steam system

o. Supplemental cooling chilled water system.

3.6.2.1.4 Identification of Systems and Components Required for Safe Shutdown

The systems and components that contribute to attaining and maintaining a safe shutdown are listed in Table 3.6-1. The listing is broken down into two categories. The first, General Requirements, indicates those systems or components that are required regardless of the piping break being evaluated. The second, Specific Requirements, indicates the additional systems and components required for specified pipe breaks (i.e., main steam line, feedwater line, etc.).

These systems and components were evaluated with respect to the effects of a postulated break of a high- or moderate-energy fluid system.

3.6.2.1.5 Assessment of Acceptability

3.6.2.1.5.1 Components and Equipment

From the approach to evaluation defined in Subsection 3.6.2.1.1, the component and/or equipment was evaluated and an assessment made of its acceptability to the hypothetical accident by the following:

a. The loss of function of a component is acceptable if an analysis can show that a redundant component or backup system is available to perform the component's safety function and to ensure safe reactor shutdown

b. An evaluation of a component's capability to perform is based on its ability to function in the environmental conditions of flooding present after the postulated pipe break

c. An evaluation of a component's capability to perform is based on its ability to withstand the impact forces of an impacting pipe. Throughout the evaluation, the impacted component is conservatively assumed incapable of performing its function. An exception to this assumption is the case where one pipe impacts another pipe of equal or greater size and equal or greater wall thickness

d. An evaluation of a component's capability to perform is based on its ability to withstand the environmental conditions of pressure, temperature, and humidity during blowdown compared to the allowable pressure, temperature and humidity conditions of the equipment design specifications and/or test qualifications

e. An evaluation of a component's capability to perform is based on its ability to function in the conditions of high-energy jet impingement.

3.6.2.1.5.2 Structures

In accordance with the approach to evaluation (Subsection (3.6.2.1.1), plant structures and structural components have been analyzed to demonstrate ability to withstand the pipe whip impact, jet impingement, temperature, pressurization, and flooding hydrostatic loads resulting from postulated ruptures. Plant structures include those located within the reactor/auxiliary building. The overall criteria governing acceptability of structural loads resulting from postulated ruptures are as follows.

a. Damage to any structure caused by consequences of a postulated rupture, either directly or indirectly through failure of an adjacent structure, may not impair the function of any systems or equipment required to place and maintain the reactor in a cold-shutdown condition

b. The design leaktightness of the primary containment shall be preserved in the event of a postulated rupture

c. The structural integrity of the main control room to achieve a safe cold shutdown shall be preserved in the event of a postulated rupture.

The criteria for acceptability of loads on structural components resulting from postulated ruptures are given in Subsection (3.8.4.5.1).

A dynamic response amplification factor of 2.0 was used to account for the dynamic effects of impact loading when used in conjunction with a static evaluation. In those cases where a dynamic evaluation was performed, the amplification factor was explicitly determined through the dynamic analysis techniques.

In the analysis of structural components such as single beams or slabs whose failure would not jeopardize the overall structural integrity, the effects of direct stress, flexure, shear, buckling, and of the reversal of normal design loads due to pipe rupture were considered. These analyses were generally performed using limit analysis techniques, such as collapse load analysis for beams and frames and yield line theory for concrete slabs, which account for resistance of structural elements into their plastic range. The allowable loads were determined on the basis of the maximum ductility factors in Table 3.6-2, derived from Reference 20. The maximum deflections under the applied loads did not exceed the applicable ductility factor times the deflection at first yield in the structure.

Maximum section strength of concrete structures was computed using the ultimate strength design method. Maximum section strength of steel members was based on the assumption of elastic-perfectly-plastic material properties and the plastic design criteria in References 21 and 22. Material yield strength was multiplied by the dynamic increase factors specified in Table 3.6-3, derived from Reference 23 for analyses under rapidly applied pipe rupture loads. Statistical variation in material properties and elevated temperature effects was accounted for in a conservative manner.

The methods used in the structural analyses are presented in Subsection 3.6.3.

3.6.2.1.6 Identification of Analysis Requirements

Not all postulated pipe-break locations in the main steam or feedwater lines were subjected to a dynamic pipe whip analysis since, under certain conditions, the loss of a component is acceptable (Subsection 3.6.2.1.5.1).

The pipe ruptures are assumed at locations where the consequence of the pipe whip, either due to the longitudinal or the circumferential pipe ruptures, has the worst potential effect with respect to a particular system or component required for safe shutdown (Table 3.6-1). All areas of postulated pipe break were conservatively examined. For areas where the damage levels were acceptable, a further evaluation was not required. For areas where a damage potential existed and this damage would preclude the safe shutdown of the reactor, these areas were so listed and further evaluated.

One or more of the exclusion criteria defined in Table 3.6-4 and listed below were used to locate areas where no damage potential exists from pipe whip or jet impingement, or where damage would not preclude the safe reactor shutdown or maintenance of primary containment:

a. Separation

b. Distance

c. Redundancy

d. Backup

e. Self-elimination

f. Size

g. Low pressure

h. Barrier

i. Testing condition

j. Scarcity of usage

k. Safe area

l. Minimum size

3.6.2.2 High-Energy Pipe Break Analyses

The high-energy pipe-break analyses for those systems identified in Subsection 3.6.2.1.3.1 are reported in this section.

3.6.2.2.1 Main Steam Line Break in Steam Tunnel

The evaluation of the consequences of a break in the main steam line was carried out as described below.

Breaks of main steam lines in the turbine building were not subject to detailed evaluation because the equipment located in the Turbine Building steam tunnel is either not required for safe shutdown or has been analyzed and found to be able to perform its shutdown function in the conditions present after a break. The only consequences of such a break would be the backflow of steam into the auxiliary building comparable to that resulting from a break in the steam tunnel.

3.6.2.2.1.1 Review of Potential Damage

A review of the potential damage resulting from the break of a main steam line was carried out in accordance with Subsection 3.6.2.1.6 to identify the need for a dynamic pipe whip or jet impingement analysis. The review took into consideration the equipment required to ensure a safe shutdown as discussed in Subsection 3.4 and summarized in Table 3.6-1. The results of this review are documented in Reference 24.

3.6.2.2.1.2 Pipe Break Analysis

The main steam lines outside the containment are routed in an enclosed concrete tunnel through the auxiliary building and into the turbine building, as shown in Figure 3.6-20. The steam tunnel, which serves to isolate the main steam lines from most of the plant safety-related equipment, is provided with relief doors to alleviate pressures that would result in the event of a pipe rupture. In accordance with the criteria given in Subsection 3.6.2.1.2.2, longitudinal and circumferential design-basis ruptures were postulated at each end of each elbow in the main steam lines between the outboard isolation valves and the steam tunnel exit to the turbine building. Critical crack breaks were also postulated at all adverse locations in this piping. As an alternative to postulating ruptures between the containment and outboard isolation valves, the piping was designed to meet the normal operating stress criteria presented in Subsection 3.6.2.1.2.2, and was provided with rigid restraints to limit transmission of bending and torsional loads through the valves in the event of a downstream rupture. The postulated rupture locations are shown in Figure 3.6-20.

Analyses were performed to assess quantitatively the pipe whip, jet impingement, compartment pressure and steam environment effects of these postulated ruptures. Since the routing of all four main steam lines in the tunnel is nearly identical, in most cases the analyses were performed for only one line and the results extrapolated to the other three. The predicted rupture effects were evaluated to identify cases in which unacceptable damage to structures, systems or components required for shutdown could result. Finally, designs were developed for modifications required to prevent the occurrence of any unacceptable damage.

A description of the rupture effects analyses, the damage evaluations, and the required modifications for the main steam lines in the steam tunnel is given in the following sections.

3.6.2.2.1.2.1 Short-Term Blowdown Analysis

Blowdown analyses were performed for postulated main steam line breaks using the methods presented in Reference 25. The resulting thrust time-histories were then used as input for subsequent pipe whip and jet impingement analyses, using the methods outlined in Subsection 3.6.3.

To determine conservatively the thrusts resulting from the postulated ruptures, the following assumptions were made:

a. The reservoir pressures in the main steam system were assumed to be 1060 psia

b. On the reactor side of the breaks, the flow limiters were assumed to be the only resistance to flow

c. On the turbine side of the breaks, the lines between the break and the header were considered the only resistance to flow.

For the analyses, the RPV and the main steam header were assumed to be reservoirs. Since the routing of the four main steam lines in the area of interest is essentially the same, only one line was analyzed. The analyses were carried out for a time sufficient to allow for the use time of all restraint reactions. Typical thrust time histories resulting from the analyses are shown in Figure 3.6-21.

3.6.2.2.1.2.2 Pressurization and Environmental Analyses

These analyses were performed to predict maximum compartment pressures and steam environment conditions resulting from postulated design-basis ruptures in the steam tunnel. The tunnel is provided with two sets of pressure relief doors for venting. The upper set of pressure relief doors opens into the turbine building; the lower set opens into the first floor of the auxiliary building.

The environmental analyses were evaluated for uprated power conditions. Changes in the governing parameters were used to scale the affected environmental conditions. This resulted in a small increase in peak temperatures and pressure.

Immediately after a postulated main steam line break in the steam tunnel, saturated steam will flow from the break. However, due to the rise in reactor water level during blowdown, a flashing two-phase mixture of steam and water will soon begin to flow out of the break. The mass flow rate of the two-phase mixture is considerably higher than that of the saturated steam and continues until terminated by the closure of the MSIV.

The steam exiting from the break will pressurize the tunnel, and the pressure relief doors will be forced open by the pressure differential between the tunnel and the adjacent compartments. Within a few milliseconds, a mixture of steam and air will be flowing through the upper and lower sets of pressure relief doors into the turbine building and the first floor auxiliary building.

The operating condition analyzed is based on MSIV closure time of 10.5 sec. The break mass used in the calculation is shown in Figure 3.6-22 (Reference 26). Flow from the upstream side of the break was calculated assuming critical flow at the flow limiter of the broken line. Flow from the downstream side of the break is supplied by the 52 in. manifold which is in turn supplied by the three unbroken steam lines. Flow through the downstream side of the break is limited by critical flow at the end of the broken pipe.

A break in one of the main steam lines in the steam tunnel would affect only the steam tunnel, first floor Auxiliary Building, and the Turbine Building (Figure 3.6-23). Break mass and energy would be vented directly to the first floor Auxiliary Building through the lower steam tunnel pressure relief doors and then to the Turbine Building through large openings in the east wall of the first floor Auxiliary Building. Mass and energy would also be released directly from the steam tunnel to the Turbine Building second floor through the upper pressure relief doors.

Isolation of the main steam line break would be initiated almost immediately as the pressure drop across the flow restrictor for the broken line exceeds the setpoint of redundant pressure differential trip units, which send a signal to the nuclear steam supply systems (NSSS). The NSSS deenergize the main steam isolation valve solenoids for the broken and unbroken lines initiating valve closure. In addition, redundant steam tunnel high temperature leak detection trip units would also initiate MSIV closure.

The environmental responses for the steam tunnel and first floor Auxiliary Building due to a main steam line break are discussed in this section. The Turbine Building second floor confined area is included in the main steam line break model. However, the environmental response of this area is not discussed since failure of the safety related instrumentation and third MSIVs located in the Turbine Building will not prevent safe shutdown of the plant.

The plot of break flow versus time used in the computer model is shown in Figure 3.6-22. The "steps" in this plot correspond to the times at which a two-phase mixture reaches the upstream and downstream ends of the break. As can be seen in the plot, closure of the isolation valve does not begin to affect the break flow until approximately 8.6 seconds. The MSIV is closed at 10.5 seconds. However, the break flow is continuous to 13.0 seconds due to expansion of the inventory of steam and water in the piping downstream of the MSIV.

Pressure response versus time plots are shown in Figures 3.6-24 and 3.6-27 for the steam tunnel and Auxiliary Building first floor. The peak pressure value of 5.1 psig occurs in the steam tunnel at 8.6 seconds after the break. The time corresponds to the end of the highest plateau of the break flow curve. The pressure profile decreases from this peak to a negative pressure at 13.0 seconds due to condensation of the steam on cooler wall and floor surfaces.

The peak first floor Auxiliary Building pressure of 0.9 psig occurs at approximately 0.8 second after the break.

The plots of temperature versus time for the steam tunnel and first floor Auxiliary Building are shown in Figures 3.6-25 and 3.6-28, respectively. The temperatures in both rooms climb to the saturation temperature for the given room pressure as the air is exhausted through the vent openings. The peak temperatures are 228°F and 215°F for the steam tunnel and first floor Auxiliary Building, respectively. The relative humidity in both rooms reaches 100 percent within 0.5 second and remains at this level for the duration of the evaluation. Plots of humidity versus time are shown in Figures 3.6-26 and 3.6-29. The effect of the resultant temperature and humidity on safe shutdown equipment has been evaluated.

3.6.2.2.1.2.3 Pipe Whip Evaluation

Analyses were performed to assess pipe whip consequences on safety-related structures, systems, and components in the steam tunnel. Since most considerations and potential problems in this area are common to the main steam and feedwater lines, these systems will be discussed together in this section.

The calculated blowdown thrust forces for main steam and feedwater ruptures are given earlier in this subsection. The methods used in the pipe whip analyses are given in Subsection 3.6.3. Details of the structural evaluation for pipe whip impact are also given in Subsection 3.6.3; a brief summary of results of this evaluation follows:

a. Loads from pipe whip impact from main steam and feedwater line breaks could cause failure of the lower tunnel floor at elevation 583 ft 6 in.

b. Loads from pipe whip impact from a main steam line break could cause failure of the 4-ft 4-in. west wall between the steam tunnel and reactor building.

c. Pipe whip from a break of either line could induce unacceptable stresses in the isolation valves on the pipe between the valves and the primary containment

d. The remaining steam tunnel walls, the upper tunnel floor at elevation 626 ft 6 in., and the tunnel ceiling are all adequately designed to withstand pipe whip impact.

Designs were developed for main steam and feedwater line pipe whip restraints as described later in this subsection. The restraints are intended to prevent occurrence of the unacceptable consequences identified in Items a and b above. In addition, the combined action of the pipe whip restraints and the anchor framework just outside of main steam and feedwater flued heads (anchor framework is designed for pipe-break loads) prevents damage to the isolation valves, to the containment penetrations, and to the containment shell, caused by the transmission of bending and torsional loads through the piping in the event of a postulated rupture.

3.6.2.2.1.2.4 Jet Impingement Evaluation

Jet impingement effects were postulated for the main steam and feedwater line breaks in the vicinity of the isolation valves. The dynamic force on each valve was calculated in accordance with the methods presented in Subsection 3.6.3 and a stress evaluation of each valve and its interconnected piping was undertaken. It was determined that, although the MSIVs and feedwater check valves could safely withstand the dynamic impingement force, the HPCI, steam drain, and RCIC isolation valves' motor operator linkage and structure would be subjected to stress levels above the allowable value of 2 S_m (42,000 psia). In addition, the tunnel floor at elevation 583 ft 6 in. would fail as a result of jet impingement. A direct jet impingement would cause failure of the lower pressure relief doors; however, the jet would not cause failure to the 4-ft 4-in. shield wall outside the doors in the auxiliary building. The pressure relief doors are not required for safe shutdown.

To protect against the loss of function of the HPCI, RCIC, and steam drain isolation valves as a result of the postulated pipe break, jet impingement barriers were incorporated as a part of the pipe restraint system as shown in Figure 3.6-30, Sheets 1 through 3. A jet impingement barrier is also provided to protect the tunnel floor.

3.6.2.2.1.2.5 Structural Evaluation

Steam Tunnel Description

The lower portion of the steam tunnel (Figures 3.6-31 and 3.6-32) is 32 ft 9 in. long by 30 ft 0 in. wide with a 2-ft-thick slab floor at elevation 583 feet 6 in. All floor and wall slabs are doubly reinforced. The lower floor slab contains No. 7 steel reinforcing bars at 12 in. and is supported on 27WF160 and 27WF145 I-beams spaced 7°30' running in a radial pattern from the containment center. The north and south walls are reinforced concrete 4 ft 8 in. thick containing No. 9 steel reinforcing bars at 12 in. The west wall (next to the containment) is 4 ft 4 in. thick with No. 7 steel reinforcing bars at 12 in. The east wall contains 20 pressure relief panels 3 ft 6 in. by 5 ft 6 in. Directly outside the pressure relief panels, in the auxiliary building, is a 4-ft 4-in.-thick reinforced-concrete wall containing No. 8 steel reinforcing bars at 12 in. Joining this wall are 3-ft-thick side walls containing No. 7 steel reinforcing bars at 12 in. This outside structure provides radiation shielding.

Entrance to the lower portion of the steam tunnel may be made through a personnel door or through an equipment passage. The 3 x 7 ft personnel door is accessible to the outside through a side alcove. It is a seal-tight steel door, designed to withstand a 2.5 psig inward pressure and an outward pressure greater than 7 psi. The 6 x 8 ft equipment passage may be opened from the inside only by removing solid concrete shield blocks, unbolting a 3/8-in. steel plate, and then removing concrete shielding plank from the side of the aisle. This closure was designed for a 2.5 psi inward pressure and outward pressure greater than 7 psi (Reference 26).

Effects of Pipe Whip and Jet Impingement

The evaluation of tunnel structural elements for pipe whip impact and jet impingement loads was based on the criteria given in Subsection 3.6.2.1.5.2 and the methods given in Subsection 3.6.3.

The calculated blowdown thrust forces for main steam and feedwater ruptures, the methods for determination of jet impingement loads from these thrust forces, and the methods used in the pipe whip analyses are also given in Subsection 3.6.3. Yield line theory was used for analysis of concrete slabs (References 28 through 31).

Pipe Whip Restraints and Jet Impingement Shields

The main steam, feedwater, and HPCI steam piping in the steam tunnel are equipped with two restraint assemblies. These assemblies, acting in conjunction with the anchor framework just outside the main steam, feedwater, and HPCI steam flued heads, prevent the occurrence of the unacceptable consequences identified earlier in this section. Final designs are shown in Figure 3.6-30, Sheets 1 through 3, and are discussed below.

The restraint assemblies each consist of an assembly of six elastically designed plane frames situated around the main steam, feedwater, and HPCI steam piping immediately adjacent to the drywell penetrations, and an assembly of six energy-absorbing U-bolt devices situated on the main steam and feedwater lines directly above and east of the lower frames. The lower framework assembly is equipped with jet impingement shielding. Functions of these assemblies are listed below.

a. The lower assembly frames act as normal operating pipe supports and as pipe whip restraints. Lateral and vertical pipe motion is prevented; axial motion is permitted. The assembly frames are shimmed to fit around the pipes, allowing for out-of-roundness and diametric expansion

b. The lower assembly frames and shields prevent the following:

    1. Pipe whip onto, and subsequent failure of, the steam tunnel floor at elevation 583 ft 6 in.

    2. Jet impingement onto, and subsequent failure of, the steam tunnel floor at elevation 583 ft 6 in., and the HPCI, RCIC, and steam drain isolation valves

    3. Overloading of the isolation valves, piping between the isolation valves and the drywell penetrations, the drywell penetrations, and the containment shell, caused by transmission of pipe-rupture loads by the main steam, feedwater, and HPCI steam piping, acting individually or with the upper assembly.

c. The upper assembly restraints clear the pipes during all normal operating conditions, and act only in the event of a rupture. They prevent the following:

    1. Pipe whip onto, and subsequent failure of, the north, south, and west walls of the steam tunnel, adjacent to their locations

    2. Overloading of the isolation valves, piping between the isolation valves and drywell penetrations, the drywell penetrations, and the containment shell as described in Item b above. These restraints act with the lower assembly.

Final design of the lower and upper assemblies was based on the criteria given in Subsection 3.6.2.1.5.2, and the methods given in Subsection 3.6.3. The material used for the lower assembly members and the U-bolt attachment structures in the upper assembly is ASTM A 588 steel. The energy-absorbing U bolts used in the upper assembly are made of A479, type 304, stainless steel. Blowdown thrusts used for the design are shown in Figures 3.6-33 and 3.6-34. A value of 1.26 PA (where P is the operating pressure of the line and A is the flow area of the pipe) was used for the design blowdown thrust for all HPCI steam piping restraints. The thrusts were assumed to act instantaneously and to remain constant for the duration of the blowdown event.

Effect of Tunnel Pressurization on Steam Tunnel Structures

As indicated in Subsection 3.6.2.2.1.2.2, the calculated pressure resulting from a main steam line break in the steam tunnel was 5.1 psig for an MSIV closure time of 10.5 sec. The pressure resulting from the conservative 10.5 sec closure time of the MSIVs does not have an adverse effect on the structures.

The lower floor at elevation 583 ft 6 in. is the critical structure in the tunnel. It was designed for the load combinations and acceptance criteria shown in Table 3.6-5. The floor slab has been evaluated for a maximum pressure of 5.1 psig and found to be adequate.

All other structural elements of the steam tunnel will withstand higher pressures.

3.6.2.2.2 Feedwater Line Breaks in Steam Tunnel

The evaluation of the consequence of a break in the feedwater lines was carried out as described below.

3.6.2.2.2.1 Review of Potential Damage

As in the case of the main steam line break, a review of the potential damage caused by a feedwater line break was made to identify the need for a dynamic pipe whip or jet impingement analysis. The results of this review are documented in Reference 24.

In view of these results, a dynamic pipe whip and jet impingement analysis was carried out.

3.6.2.2.2.2 Feedwater Break Analysis

The feedwater lines outside the containment are routed in the same concrete tunnel through the Auxiliary Building and into the Turbine Building. In accordance with the criteria given in Subsection 3.6.2.1.2.2, longitudinal and circumferential design-basis ruptures were postulated at each end of each elbow in the feedwater lines between the outboard isolation check valves and the steam tunnel exit to the turbine building. Critical crack breaks were postulated at all adverse locations in this piping. As an alternative to postulating ruptures between the containment and outboard isolation check valves, the piping was designed to meet the normal operating stress criteria presented in Subsection 3.6.2.1.2.2, and was provided with restraints to limit transmission of bending and torsional loads through the valves in the event of an upstream rupture. The postulated rupture locations are shown in Figure 3.6-35.

Analyses were performed to assess quantitatively the pipe whip, jet impingement, and flooding effects of these postulated ruptures. Since the routing of the two feedwater lines in the tunnel is nearly identical, in most cases the analyses were performed for only one line and results extrapolated to the other line. The predicted rupture effects were evaluated to identify cases in which unacceptable damage to structures, systems, or components required for shutdown could result. Finally, designs were developed for modifications required to prevent occurrence of unacceptable damage.

A description of the rupture effects analyses, the damage evaluations, and the required modifications for the feedwater lines in the steam tunnel is given in the following sections.

3.6.2.2.2.2.1 Short-Term Blowdown Analysis

Blowdown analyses were performed for the postulated feedwater line breaks using the methods presented in Reference 25. The resulting thrust time-histories were then used as input for subsequent pipe whip and jet impingement analyses using the methods outlined in Subsection 3.6.3.

To determine conservatively the thrusts resulting from the postulated ruptures, the following assumptions were made:

a. The reservoir pressures for the feedwater line were assumed to be 1135 psia

b. Only the so-called "slower wave" (Reference 25) was considered in evaluating "wave force" (Reference 25) components on the open segments of piping.

As the routing of the two feedwater lines in the area of interest is essentially the same, only one line was analyzed.

As a result of check-valve closure, the thrust time-histories have the following characteristics.

a. Reactor side circumferential break thrusts do not reach a steady value that is larger than the initial value because the check valves between the breaks and the RPV close during the blowdown event

b. Longitudinal break thrusts have the same steady-state values as pump side circumferential break thrusts at the same location because check-valve closure prevents feeding of the break from the reactor side.

The analyses were carried out for a period of time sufficient to allow for the rise time of all restraint reactions. Typical thrust time-histories resulting from the analyses are shown in Figures 3.6-33 and 3.6-34.

3.6.2.2.2.2.2 Flooding Analysis

This subsection presents the analysis of flooding effects due to a postulated feedwater pipe rupture outside containment. The various locations that could be flooded are discussed as well as the assumptions and flow events following postulated pipe breaks. The results of the analysis are presented last.

Figure 3.6-36 shows the bottom floor of the steam tunnel and the first floor of the Auxiliary Building. The lower west portion of the steam tunnel is shown in Figure 3.6-35. The tunnel is provided with a lower pressure relief door composed of steel panels that individually swing up on hinges. Along the east wall of the Auxiliary Building first floor are large openings to the Turbine Building. The bottoms of these openings are located 6 ft above the floor.

Figure 3.6-37 shows a block diagram of the main features of the feedwater system. During normal plant operation, the condensate is pumped from the hotwell through various subsystems such as polishing demineralizers and the feedwater heaters to the reactor.

The entire feedwater system is classified as high energy. The two feedwater lines are routed from the reactor feed pumps on the first floor of the Turbine Building up to the No. 6 feedwater heaters located on the Turbine Building third floor. The feedwater lines are headered together downstream of the No. 6 heaters and then branch again into two parallel lines to drop down through the third floor slab into the second floor where they enter the steam tunnel.

The lines penetrate the steam tunnel upper pressure relief doors and continue parallel to the main steam lines until they enter primary containment.

As with the main steam lines, only that portion of the feedwater lines on the reactor side of the upper pressure relief doors is considered for pipe break. Feedwater breaks upstream of the doors are not evaluated since no safety-related equipment is located in the Turbine Building except for the third set of MSIVs which are not required for mitigation of break effects. Adequate seals exist to prevent Turbine Building breaks from affecting the Reactor and Auxiliary Buildings.

The analysis of the feedwater line break scenario assumes failure of the feedwater startup control valve in the open position. This single failure was selected to maximize flooding in affected areas of the plant. The feedwater line break would not be isolated until the condensate and heater feed pumps trip on low hotwell level. Operator action was not considered for the 8-1/2 minutes during which water flows through the postulated pipe break.

The basic flood model for the feedwater line break in the steam tunnel is shown in Figure 3.6-38. The fluid released from the feedwater break would be dispersed over the steam tunnel floor. A portion of the break fluid would flash to steam and pressurize the steam tunnel for a short period following the break.

The water dispersed over the steam tunnel floor would begin to drain to the northeast corner room sump. However, the break flow will greatly exceed the capacity of the floor drains and the steam tunnel flood depth would continue to increase. At a flood elevation of 584 ft 9 in. water would begin to flow through the equipment drain in the steam tunnel to the southeast corner room sump. As the steam tunnel flood depth continues to rise, the head of water would open the pressure relief doors allowing break fluid to enter first floor Auxiliary Building.

The first floor Auxiliary Building floor drains have been capped. Therefore, flow through the drain lines in this room does not occur.

As the first floor Auxiliary Building flood depth continues to increase, flow through numerous equipment drains whose funnels are at various elevations would occur. The equipment drains from first floor Auxiliary Building header join those from the steam tunnel, which lead to the southeast corner room.

The steam tunnel and first floor Auxiliary Building are watertight to flood depths of 10 and 4 feet, respectively. Therefore, these are the only rooms directly affected by flooding. Flooding in other rooms results only from floor and equipment drain flow. Floor and equipment drains flow to the northeast and southeast corner rooms, respectively, will exceed the capacity of the sumps. Therefore, the flood depth in these rooms will continue to increase. If the flood depths increase to a certain level, flooding of the torus and HPCI rooms will occur.

Table 3.6-6 indicates break flow rate and the sequence of events following a feedwater line break in the steam tunnel. The table is based on the assumption that the feedwater startup control valve failed in the open position. The sequence of events after the break is discussed below.

Immediately following the break, feedwater flow increases to 43,000 gpm, tripping the reactor feed pumps on low suction pressure (300 psig). Tripping the reactor feed pumps does not decrease the break flow because the heater feed, heater drain, and condensate pumps are capable of maintaining this flow rate. This flow rate remains constant until 57 seconds after the break when the fast closure reactor feedwater pump discharge valves are closed. Flow is then diverted through the startup level control valve and the break flow is reduced to 21,800 gpm. At 64.0 seconds, the heater number 5 level control valves are fully closed and heater drain pump flow is isolated from the break. As a result, the break flow decreased to 20,000 gpm and remains at this level until 447 seconds, at which time the condensate and heater feed pumps trip on low hotwell level totally isolating the break. The inventory of water in the piping downstream of the reactor feed pumps is then assumed to be discharged from the break over a one-minute period. The steam tunnel drains to the southeast corner room through equipment drains and the northeast corner room through floor drains.

The steam tunnel and Auxiliary Building first floor, where the Reactor Building closed cooling water (RBCCW) heat exchanger room is located, reach peak flood depths of 4 ft 6 in. and 3 ft 10 in., respectively. The steam tunnel and RBCCW heat exchanger room flood elevations then begin to decrease due to flow through the steam tunnel floor and equipment drains (DRN). The RBCCW heat exchanger room drains to the southeast corner room of the Auxiliary Building.

The northeast corner room peak flood depth of 7 ft is reached due to floor drain flow into the sump. Equipment drain flow causes flooding in the southeast corner room to a depth of 14 ft approximately 10 hours after the line break, at which point water would begin to spill into the torus and HPCI rooms. The torus room flood depth reached 14.8 in. and the HPCI room would reach a peak flood depth of 78.8 in. based on worst case door failure combinations for the given room.

The safe shutdown path considers systems necessary to scram the reactor, depressurize the reactor, and to establish and maintain core cooling utilizing the residual heat removal (RHR) system. For feedwater line breaks, the availability of offsite power maximizes the consequential effects of flooding. Therefore, offsite power was assumed to be available. If offsite power is not available, the condensate and heater feed pumps will trip, thus ending the break scenario sooner. No water will be lost from the reactor, whether offsite power is available or not, since the feedwater check valves are designed to close immediately. HPCI will restore water level to compensate for the loss of feedwater flow. The vessel can be manually depressurized by using the main steam safety relief valves. After pressure reduction, the operator places the RHR system (Division 1 or Division 2) in the low pressure coolant injection mode. The residual heat removal service water (RHRSW) system is used as the heat sink in the RHR cooling mode.

The evaluation shows the first floor Auxiliary Building (RBCCW heat exchanger room), the northeast corner room (Division 1 core spray and reactor core isolation cooling (RCIC)), the southeast corner room (Division 2 core spray), high pressure coolant injection (HPCI) and the torus room flooded. Under these conditions the plant can achieve safe shutdown by using the main steam safety relief valves and both divisions of RHR.

3.6.2.2.2.2.3 Effects of Feedwater Jet Impingement and Pipe Whip

The analyses of the effects of pipe whip and jet impingement for feedwater line rupture in the steam tunnel have been discussed previously, in conjunction with the analyses for main steam line ruptures in the steam tunnel, in Subsections 3.6.2.2.1.2.3 and 3.6.2.2.1.2.4.

3.6.2.2.2.2.4 Structural Evaluation

The evaluation of structural components for ability to withstand loads resulting from postulated feedwater line ruptures in the steam tunnel closely parallels that previously described in Subsection 3.6.2.2.1.2.5 for postulated main steam line ruptures, and details will not be repeated here.

The pipe whip impact and jet impingement loads resulting from a postulated feedwater line rupture could cause failure of the lower tunnel floor at elevation 583 ft 6 in.; however, the restraints described in Subsection 3.6.2.2.1.2.5 are intended to prevent this failure. The tunnel walls, upper floor at elevation 626 ft 8 in., and ceiling are adequately designed to withstand the pipe whip impact and jet impingement loads that would result from the postulated feedwater line ruptures.

The 1.9 psig maximum lower tunnel floor hydrostatic pressure that could result from flooding after a postulated feedwater line break is less than the 5.1 psig steam pressure that would follow a postulated steam line break with a 10.5 sec MSIV closure. It has been previously determined that the lower tunnel floor is adequately designed to withstand this pressure. Pressurization effects from flashing feedwater are also bounded by the main steam line break.

The structural evaluation also indicated that the auxiliary building is adequately designed to withstand the 1.7 psig hydrostatic pressure resulting from maximum possible flooding on the first floor.

3.6.2.2.3 High Pressure Coolant Injection System

The evaluation of the consequences of a pipe break in the HPCI system was carried out as described below and in references 24, 33 and 64.

The only portion of the HPCI system piping that is classified as high energy is the HPCI turbine steam supply line. This line exits from the primary containment into the steam tunnel near the main steam and feedwater lines. The line then drops through the steam tunnel floor to the torus area, where it is routed adjacent to the torus before entering the HPCI pump room (room SB7), where the line connects to the HPCI turbine.

Figure 3.6-39 shows the HPCI turbine steam supply line and its relation to building structures and components.

3.6.2.2.3.1 Review of Potential Damage

As in the case of the main steam and feedwater line breaks, a review of the potential damage resulting from a break in the HPCI steam line was carried out in accordance with Subsection 3.6.2.1.6 to identify the need for a dynamic pipe whip or jet impingement analysis. The review took into consideration the equipment required to ensure a safe shutdown, as discussed in Subsection 3.6.2.1.4 and listed in Table 3.6-1.

This review, combined with other considerations such as existing pipe restraints, established the following areas of concern with respect to pipe whip and/or jet impingement:

a. Effect on the HPCI isolation valve and containment penetration

b. Effect on the torus in the vicinity of the HPCI line in the torus room.

In addition, the environmental effects investigation was limited to a break in the HPCI room.

3.6.2.2.3.2 Pipe-Break Analysis

The criteria given in Subsection 3.6.2.1.2.2 have been applied in determining the locations of the postulated pipe breaks. The terminal end break locations are defined at the connection to the outboard containment isolation valve and the connection to the HPCI turbine stop valve. The Class 1 piping between the containment and the outboard isolation valve is designed to meet the normal operating stress criteria presented in Subsection 3.6.2.1.2.2. The detailed stress analysis of the piping determined that the predicted stresses at all locations between the terminal ends are substantially less than the stress limits established in Subsection 3.6.2.1.2.2. Therefore, no arbitrary intermediate pipe breaks were postulated per Generic Letter 87-11.

The postulated break locations in the HPCI steam supply line are included in Figure 3.6-39. With the criteria of Subsection 3.6.2.1.2.3.c, only circumferential-type breaks are postulated at each break. As required, analyses were performed to assess quantitatively the pipe whip, jet impingement, and environmental effects of these postulated ruptures.

3.6.2.2.3.2.1 Blowdown Analyses

Blowdown analyses were performed for postulated HPCI turbine steam supply line breaks using the PRTHRUST program as discussed in Subsection 3.6.3. To conservatively maximize blowdown thrust forces for input to the pipe whip and jet impingement calculations, the full-size 10-in. line was assumed to be initially at rated reactor pressure conditions (1060 psia saturated steam, zero flow). The primary containment isolation valves were assumed to be in their normal operating position, and the HPCI turbine stop valve was assumed to be closed.

The analyses were carried out for a period of approximately 0.5 sec, a time sufficient to develop maximum pipe whip and jet impingement response. It should be noted that this length of time is insufficient to allow activation of operable components, and the balance of plant systems (other than the broken system) continue to operate in the normal way.

The blowdown thrust was calculated as a function of time for circumferential breaks at each of the locations indicated in Figure 3.6-39. These results were then used in jet impingement and pipe whip analyses according to the methods described in Subsection 3.6.3 and discussed below.

Characteristically, the thrust is equal to line pressure times area at the instant of rupture, and increases thereafter as fluid is accelerated from the break. Within a short time, however, choking takes place at the break, and thrust drops sharply as the line pressure decays. The HPCI turbine side-break forces decay to zero as the steam in the line is depleted. Reactor side-break forces decay to a quasi-steady-state thrust, controlled by choking in the shutoff valve in the 1-in. bypass line around the outboard isolation valve.

A "longer-term" blowdown analysis was conducted as the initiating calculation of the environmental conditions resulting from a postulated break in a high energy piping system as described in Subsection 3.6.3.

A preliminary hand calculation showed that a full blowdown of the 10-in. steam line, under the assumption of loss of offsite power and failure of the dc isolation valve, together with a startup time of 10 sec for the diesel generator to initiate closure of the ac isolation valve, would result in unacceptably high pressures and temperatures in the reactor building. To avoid this situation, a 1-in. bypass line and shutoff valve around the outboard isolation valve were incorporated into the system with the normal mode of the outboard isolation valve in the closed position, as shown in Figure 3.6-39. The analysis incorporated the 1-in. bypass line.

The following assumptions were made for the "longer-term" blowdown analysis:

a. The line is initially at rated reactor pressure conditions of 1060 psia and saturated steam

b. The inboard steam line isolation valve and bypass line isolation valve are in their normally open positions

c. The outboard isolation valve is in its normally closed position

d. The HPCI turbine stop valve is closed

e. The dc valve in the 1-in. bypass line fails to close

f. Choke flow through the bypass line takes place until the inboard isolation valve is closed by operator action or high area temperature.

Immediately after the postulated break, steam from the downstream side of the outboard isolation valve is rapidly released from the break, and choke flow through the 1-in. bypass line continues to release steam until the inboard isolation valve is closed.

3.6.2.2.3.2.2 Environmental Analysis

Environmental analyses were performed using the "CVPT-REPORT" and “KITTY6” programs (described in Subsection 3.6.3) to predict the maximum compartment pressures, temperatures, and humidities resulting from postulated design-basis ruptures of the HPCI steam supply line. The steam line traverses three compartments: the steam tunnel, the torus room, and the HPCI pump room. The environmental analyses were evaluated for uprated power conditions.

The Steam Tunnel (Room 109)

No specific analysis was performed for HPCI steam line breaks in the steam tunnel, as the resulting conditions are bounded by the main steam line breaks discussed in Subsection 3.6.2.2.1 on the basis of mass flow and steam conditions.

Torus Room (Room SB2)

There are no postulated HPCI steam line breaks in the torus area.

HPCI Pump Room (Room SB7)

An environmental analysis was performed for a postulated break in the HPCI pump room, and the environmental response of affected compartments was determined. The analytical model showing the control volumes and the flow paths is provided in References 33 and 64.

Results of Analysis for HPCI Line Break in HPCI Room

After the postulated break, the HPCI pump room (SB7) would rapidly fill with steam and vent to room B7 and southeast corner room (SB6 and B6). Room B6 is connected via a stairwell to the first floor which, in turn, is connected to the second, third, and fourth floors via staircases and the equipment hatchway.

The compartmental (control volume) pressure and humidity responses are provided in Reference 33, and the temperature responses are provided in Reference 64. An evaluation has been performed to include the effect of power uprate. Maximum calculated pressure and temperature are 1.23 psig and 183°F in the HPCI pump room.

3.6.2.2.3.2.3 Pipe Whip Evaluation

Consideration was given to the effects of HPCI steam line pipe whip on safety-related structures, systems, and components in the steam tunnel, torus area, and the HPCI room. Where required, analyses were performed to assess pipe whip consequences. See Reference 24.

Effects in Steam Tunnel (Room l09)

Without a pipe whip restraint, the HPCI line pipe whip in the steam tunnel could potentially damage the outboard isolation valve and the primary containment penetration. However, this was anticipated in consideration of the restraints for the steam and feedwater lines in the tunnel, and restraints were provided for the HPCI line as well. The restraint design is discussed in Subsection 3.6.2.2.1.2.5.

Effects in Torus Room (Room SB2)

There are no postulated HPCI steam line breaks in the torus area.

Effects in HPCI Room (Room SB7)

The shutdown capability for the HPCI steam line break in the HPCI pump room is demonstrated in Reference 24.

The concrete structural components within the room were found to be adequately designed to withstand pipe whip impact loads.

Damage Evaluation

Damage evaluation and modifications instituted as a result of the pipe whip evaluation are discussed in Subsection 3.6.2.2.3.2.5.

3.6.2.2.3.2.4 Jet Impingement Evaluation

As in the case of pipe whip, the evaluation was carried out for each area through which the HPCI steam line passes. The evaluation and results are described in Reference 24.

Effects in Steam Tunnel (Room 109)

Jet impingement could adversely affect the HPCI outboard isolation valve. However, the jet impingement shields provided for protection against main steam line breaks would also protect against the HPCI line breaks.

With the inclusion of the 1.75-in. jet deflector plate provided for the main steam line break, jet impingement would not adversely affect any of the concrete structures.

Effects in Torus Room (Room SB2)

There are no postulated HPCI steam line breaks in the torus area.

Effects in HPCI Pump Room (Room SB7)

The shutdown capability for the HPCI steam line break in the HPCI pump room is demonstrated in Reference 24.

The concrete structural components were found to be adequately designed to withstand jet impingement loads.

Damage Evaluation

Damage evaluation and modifications instituted as a result of the jet impingement evaluation are discussed in Subsection (3.6.2.2.3.2.5).

3.6.2.2.3.2.5 System, Component, and Structural Damage Evaluation

An evaluation (Reference 24) was made of the direct damage resulting from HPCI steam line pipe whip or jet impingement. The evaluation included effects on various systems, components, and structures, as well as impact on the ability to achieve a safe shutdown. Plant features that mitigate the consequences of HPCI steam line breaks are described below.

Steam Tunnel (Room 109)

As indicated in Subsection 3.6.2.2.3.2.3, provision of HPCI steam line pipe restraints was incorporated into the steam line/ feedwater line restraint system. The restraints, together with the piping sleeve provided where the steam line passes through the steam tunnel floor, preclude unacceptable damage to the HPCI isolation valve or the primary containment penetration. Incorporated with the restraints is a shield to protect the isolation valve from jet impingement.

Torus Room (Room SB2)

There are no postulated HPCI steam line breaks in the torus area.

Evaluation of Environmental Effects on Systems, Components, and Structures

The equipment, including active and passive components, listed in Table 3.6-1 as required for attaining and maintaining a safe-shutdown condition after a postulated break in the HPCI steam line, was evaluated for its functional capability under the pressure, temperature, and humidity conditions resulting from the pipe break. It was determined that the environmental conditions would not adversely affect the operation of the required systems.

HPCI steam line breaks in the steam tunnel or HPCI pump room would not result in a reactor protection system (RPS) trip because the bypass line around the outboard isolation valves would severely minimize the RPV inventory loss. Normal shutdown procedures would be used in the case of HPCI steam line breaks.

It is concluded, therefore, that with the bypass line around the outboard isolation valve (Subsection 3.6.2.2.3.2.1) and the pipe whip restraints (Subsection 3.6.2.2.3.2.5) incorporated into the design, a break in the HPCI steam supply line will not jeopardize the ability to attain and maintain a safe shutdown.

3.6.2.2.4 Reactor Core Isolation Cooling System

The evaluation of the consequences of a break in the RCIC system was carried out as described below and in References 24, 33 and 64.

The only portion of the RCIC piping system that is classified as high energy is the RCIC steam supply line. This line exits from the primary containment into the steam tunnel near the main steam and feedwater lines. The line then drops through the steam tunnel floor to the torus area, where it is routed adjacent to the torus before entering the north core spray and RCIC pump room. Figure 3.6-41 shows the RCIC steam supply line configuration and its relation to building structures and components.

3.6.2.2.4.1 Review of Potential Damage

A review of the potential damage resulting from a break in the RCIC steam supply line was carried out in accordance with Subsection 3.6.2.1.6 to identify the need for a dynamic pipe whip or jet impingement analysis. The review took into consideration the equipment required to ensure a safe shutdown as discussed in Section 3.6.2.1.4 and Table 3.6-1.

In addition, the environmental effects investigation was conducted for a break in the northeast corner room, as discussed in Subsection 3.6.2.2.4.2.

3.6.2.2.4.2 Pipe-Break Analysis

The criteria given in Subsection 3.6.2.1.2.2 have been applied in determining the locations of the postulated pipe breaks. The terminal end break locations are defined at the connection to the outboard containment isolation valve and the connection to the RCIC turbine stop valve. The Class 1 piping between the containment and the outboard isolation valve is designed to meet the normal operating stress criteria presented in Subsection 3.6.2.1.2.2. The detailed stress analysis of the piping determined that the predicted stresses at all locations between the terminal ends are less than the stress limits established in Subsection 3.6.2.1.2.2. Therefore, no intermediate break locations have been postulated between the terminal ends.

The postulated break locations in the RCIC steam supply line are included in Figures 3.6-41 and 3.6-42. With the criteria of Subsection 3.6.2.1.2.3, Item c., only circumferential-type breaks are postulated at each break location. As required, analyses were performed to assess quantitatively the pipe whip, jet impingement, and environmental effects of these postulated ruptures.

3.6.2.2.4.2.1 Blowdown Analysis

For the pipe whip analysis, blowdown thrust loads at all critical break locations, as identified above, were calculated using an ideal gas model to determine the forcing functions. For jet impingement analyses, the exit plane thrust was calculated as 1.26 PA, where P is the fluid saturation pressure and A is the pipe flow area.

A "longer-term" blowdown analysis was conducted to determine the environmental conditions resulting from a postulated break in a high-energy piping system, as described in references 33, 64, and 65.

The following assumptions were made for the "longer-term" blowdown analysis:

a. The line is initially at rated reactor pressure conditions of 1060 psia and saturated steam

b. The line isolation valves are in their normally open position

c. The RCIC turbine stop valve and the motor-operated bypass valve are closed

d. The dc-powered isolation valve fails to close

e. The ac-powered isolation valve closes 29 sec after the line break. Closure time includes diesel generator startup and valve closure time, Reference 65.

f. Choked flow occurs at the most limiting restriction.

Immediately after the postulated break, the flow from the upstream side of the break increases rapidly to the critical flow for the break, and decreases with closing of the isolation valve. Steam flow rate as a function of time after the postulated break is provided in References 33 and 65.

3.6.2.2.4.2.2 Environmental Analysis

Environmental analyses were performed using the "CVPT-REPORT" and “KITTY6” programs (described in Subsection 3.6.3) to predict maximum compartment pressures, temperatures, and humidities resulting from postulated design-basis ruptures of the RCIC steam supply line. The steam line traverses three compartments: the steam tunnel, the torus room, and the RCIC pump room. The environmental analyses were evaluated for uprated power conditions.

The Steam Tunnel (Room 109)

No specific analysis was performed for RCIC steam line breaks in the steam tunnel, as the resulting conditions are bounded by those produced by the main steam line breaks discussed in Subsection 3.6.2.2.1.2.2 on the basis of mass flow and steam conditions.

Torus Room (Room SB2)

There are no postulated RCIC steam line breaks in the torus room.

RCIC Pump Room (Room SB5)

An environmental analysis was performed for postulated RCIC line breaks in the northeast corner room, and the environmental response of affected compartments was determined. The environmental analysis model showing the control volumes and the flow paths are provided in References 33 and 64.

Results of Environmental Analysis

For RCIC Steam Line Break in Torus Room

There are no postulated RCIC steam line breaks in the torus area.

For RCIC Steam Line Break in the RCIC Pump Room

After the postulated break, the RCIC pump room SB5 would rapidly fill with steam and, via a stairwell, vent to the basement of the reactor building, which in turn is connected to the first, second, third, and fourth floors via staircases and the equipment hatchway. Steam is also vented from the first floor to remaining corner rooms (B1/SB1, B3/SB3, B6/SB6) via staircases and equipment hatches. Each corner room vents to the torus room through pressure relief seals that open at 0.1 psid. Steam is also vented from the torus room to the pipe tunnel through open penetrations and from the RCIC pump room via pressure relief seals which open at 0.1 psid. A vent opening between the pipe tunnel and the first floor auxiliary building is provided and is designed to open at 0.33 psid to vent steam to the auxiliary building and subsequently to the turbine building.

The compartmental (control volume) pressure and humidity responses are provided in Reference 33, and the temperature responses are provided in Reference 64. Calculated pressure and temperature are 0.48 psig and <237°F in the RCIC pump room.

3.6.2.2.4.2.3 Pipe Whip Evaluation

Analyses were performed (Reference 24) to assess pipe whip consequences on safety-related structures, systems, and components in the main steam tunnel, in the event of a postulated design basis break of the RCIC steam line.

Blowdown thrust loads were calculated using the methods discussed in Subsection 3.6.2.2.4.2.1. The methods used in conducting the pipe whip analysis, and the details of the structural evaluation for pipe whip impact, are given in Subsection 3.6.3.

A summary of the results of the pipe whip evaluation for each room traversed by the RCIC steam line is presented below.

Effects in Steam Tunnel (Room 109)

Loads due to pipe whip could damage the outboard RCIC steam isolation valve. The containment penetration assembly would not be damaged, due to the existence of a separate containment penetration flued head support structure.

Effects in Torus Room (Rooms SB2 and B2)

There are no postulated RCIC steam line breaks in the torus area.

Effects in RCIC Pump Room

An evaluation of the effects of pipe whip is described in Reference 24.

Effects on Structural Components

The reinforced-concrete structures were found to be adequately designed to withstand pipe whip impact loads when analyzed in accordance with Subsection 3.6.3.

3.6.2.2.4.2.4 Jet Impingement Evaluation

As in the case of pipe whip, an evaluation (Reference 24) was carried out for each room traversed by the RCIC steam line. The jet impingement loads from the calculated thrust forces were determined by the methods described in Subsection 3.6.3.

Effects in Steam Tunnel

Jet impingement loadings due to a break in the RCIC steam line in the steam tunnel could damage the top works of the RCIC outboard isolation valve and render it inoperative.

Effects on Structural Components

The reinforced-concrete structures were found to be adequately designed to withstand jet impingement loads when analyzed by the methods described in Subsection 3.6.3.

3.6.2.2.4.2.5 System, Component, and Structural Damage Evaluation

An evaluation (Reference 24) was made of the direct damage resulting from the RCIC steam line break on various systems, components, and structures as well as its impact on the ability to attain a safe shutdown. The plant features that mitigate the consequences of RCIC steam line breaks are described below.

Steam Tunnel

The RCIC outboard isolation valve could be damaged by either pipe whip or jet impingement. Referring to Table 3.6-1, it is seen that a general requirement for a safe shutdown is to maintain the integrity of the primary containment. If the inboard isolation valve is assumed to fail in accordance with assumption d.2. of Subsection 3.6.2.1.1.1 and the outboard valve is damaged, the primary containment would be lost, representing an unacceptable condition.

To mitigate this condition, the RCIC steam line in the steam tunnel is equipped with a steel-plate pipe restraint that will prevent pipe whip from imposing unacceptably high loadings on the outboard isolation valve. The restraint design concurrently provides protection against jet impingement on the isolation valve top works, thereby ensuring its operability.

Torus Room

There are no postulated RCIC steam line breaks in the torus area.

Pipe Whip Restraints and Jet Impingement Shields

Designs for pipe whip restraints and jet impingement shields to protect from unacceptable damage resulting from RCIC steam line breaks in the steam tunnel are described below.

Steam Tunnel

The design for the pipe whip restraint and the jet impingement shield is as follows. The restraint is of the close-clearance plate type and, together with the piping sleeve previously provided where the pipe passes through the steam tunnel floor, serves to prevent the line from deflecting excessively in either the torsional or bending modes and hence prevents the development of excessive stresses in the outboard RCIC steam line isolation valve or in the piping between the isolation valve and the primary containment penetration flued head. Due to its configuration, this restraint also serves to protect the RCIC outer isolation valve from jet impingement.

Torus Room

There are no postulated RCIC steam line breaks in the torus area.

3.6.2.2.4.3 Evaluation of Ability To Attain and Maintain a Safe Shutdown

A break in the RCIC steam supply line in the steam tunnel may result in activation of the high-temperature signal in the steam tunnel, with concurrent closure of the MSIVs and subsequent RPS trip (scram). Therefore, this evaluation assumes loss of offsite power, as indicated in Subsection 3.6.2.1.1.1.

All of the systems and components listed in Table 3.6-1 as required for a safe shutdown will be operable. All required redundant components will be available, with the exception of Division I core spray, which is assumed to have failed, together with the RCIC system for the pipe break in the RCIC pump room.

As a result of reactor scram and primary containment isolation, reactor shutdown cannot be attained by normal shutdown procedures for a break in the steam tunnel, although they could and probably would be used for the break in the RCIC pump room.

The RCIC system will be automatically isolated by activation of one of the three signals listed in Table 3.6-1. Reactor depressurization can be achieved through use of the HPCI system to maintain water level and remotely operated relief valves to depressurize the RPV.

On depressurization, Division II core spray and LPCI would be available to maintain water level. Suppression pool cooling and maintaining a long-term safe shutdown can be accomplished by operation of the RHR system.

Applying the single failure criterion, operable redundant or backup systems are available to ensure that each required function is carried out. If HPCI is unavailable, depressurization can be accomplished by the ADS alone, while coolant water inventory is maintained at an acceptable level. Division II core spray or LPCI independently can maintain acceptable water levels after depressurization, and redundancy in RHR will ensure suppression pool cooling and the ability to maintain a long-term safe shutdown.

It is concluded, therefore, that a break in the RCIC steam supply line will not jeopardize the ability to attain and maintain a safe shutdown.

3.6.2.2.5 Reactor Water Cleanup System (RWCU)

The reactor water cleanup (RWCU) system removes water from the reactor recirculation system for decontamination by a demineralizer system and then returns the water to the reactor through the feedwater system. The RWCU line leaves the containment, entering the second floor of the reactor building, as shown in Figure 3.6-43. From this area, the line divides into two smaller lines that feed the RWCU recirculation pumps. The water is pumped through heat exchangers to a demineralizer system. The cleaned-up water is reheated by the heat exchangers and enters the feedwater system in the steam tunnel after being routed through a pipe chase to the torus area.

3.6.2.2.5.1 Review of Potential Damage

As in the preceding evaluations, a review of the potential damage resulting from a break in the RWCU piping system was carried out in accordance with Subsection 3.6.2.1.6 to identify the need for a dynamic pipe whip or jet impingement analysis.

Based on this review, the following concerns were identified regarding pipe whip and jet impingement:

a. Effect on outboard isolation valves and the primary containment penetration in room 224

b. Effects on the RWCU line isolation valves that connect to the feedwater line in the steam tunnel

c. Effects on the torus and other Category I systems and components in the torus room.

In addition, the environmental conditions and effects resulting from an RWCU line break required evaluation.

3.6.2.2.5.2 Pipe-Break Analysis

The criteria given in Subsection 3.6.2.1.2.2 have been applied in determining the locations of the postulated pipe breaks. The Class 1 piping between the containment and the outboard isolation valve is designed to meet the normal operating stress criteria presented in Subsection 3.6.2.1.2.2.

The postulated break locations in the seismically analyzed portion of the RWCU water line are included in Figure 3.6-44. With the criteria of Subsection 3.6.2.1.2.3, Item c., only circumferential-type breaks are postulated at each break. As required, analyses were performed to assess quantitatively the pipe whip, jet impingement, and environmental effects of these postulated ruptures.

3.6.2.2.5.2.1 Blowdown Analysis

A short-term blowdown analysis was performed for a rupture of an RWCU line downstream of the outboard isolation valve in room 224 and in room 219, using hand calculation methods to determine thrust loads for use in evaluating the potential damage due to pipe whip and jet impingement. Although pipe breaks are no longer postulated in room 224, this break analysis bounds other postulated breaks in room 219. To conservatively maximize blowdown thrust, the lines were assumed to be at the reactor recirculation line normal operating conditions.

Initially, the thrust would be equal to the line pressure at the time of the break times the break area. The thrust would then rapidly rise to a steady-state force of 1.26PA, where P is the fluid saturation pressure (910 psia) and A is the break area. The steady-state force would equal 27,300 lb and was taken as a constant value in the subsequent damage evaluation.

Similar evaluations were conducted for the postulated break in the torus room. Blowdown force for a postulated rupture of the RWCU line at anchor G33-3245-G34 was performed using Fauske's two-phase flow model (Reference 35). To conservatively maximize the blowdown forces, the line was assumed to be at maximum operating temperature and pressure (532°F and 1244 psia).

A "longer-term" blowdown analysis was conducted to determine the environmental conditions resulting from a postulated break in the RWCU system. Although a pipe break immediately downstream of the RWCU suction line outboard isolation valve is no longer postulated, this break analysis was used as a bounding case for other postulated breaks.

The following assumptions were made for the "longer-term" blowdown analysis:

a. The line is initially at 1060 psia and 534°F.

b. Deleted

c. The ac-powered isolation valve closes 23 sec after detection of the line break. This time includes instrument and loop response time and valve closure time. References 64 and 65.

Immediately after the postulated break, the flow rate from the upstream side of the break will consist of an initially high flow rate during the inventory blowdown followed by a smaller rate during steady-state blowdown. This flow rate is provided in References 33 and 65.

3.6.2.2.5.2.2 Environmental Analysis

Environmental analyses were performed using the "CVPT-REPORT" or “KITTY6” programs (described in Subsection 3.6.3) to predict the maximum compartment pressures, temperatures, and humidities resulting from postulated design-basis ruptures of the RWCU high-energy line. The environmental analyses were evaluated for uprated power conditions.

RWCU Pump Rooms (Rooms 217 and 218)

An environmental analysis was performed for an RWCU line break in pump room B, and the environmental response of affected compartments was determined. The environmental response for a break in pump room A would be similar. The environmental analysis model showing the control volumes and flow paths is provided in Reference 33.

RWCU Holdup and Heat Exchanger Rooms (Rooms 224 and 219)

An environmental analysis was performed for an RWCU line break in the hold-up pipe room 224. Although pipe breaks in room 224 are no longer postulated, this break analysis bounds all other postulated breaks in room 219; therefore, was maintained as a bounding analysis. No analysis was performed for the heat exchanger room 219. The environmental analysis models showing the control volumes and flow paths are provided in References 33 and 64.

Torus Room (SB2)

An environmental analysis was performed for an RWCU line break in the torus room. RWCU system isolation is automatically initiated following the break. The redundant

RWCU system flow comparator instrumentation is assumed to fail. However, the torus room RWCU leak detection thermocouple setpoints are reached.

Steam Tunnel (Room 109)

No pipe breaks are postulated for the RWCU line in the steam tunnel. Conditions in the steam tunnel are bounded by the main steam line breaks discussed in subsection 3.6.2.2.1.

Results of Analysis for RWCU Break in Room 218

Both pump rooms feature a stacked brick wall on the east side for shielding purposes only. On collapse of the stacked brick wall, break mass and energy is vented to the second floor, which is connected via staircases and the equipment hatchway to the first, third, and fourth floors of the reactor building. No essential equipment is located in the missile path of the collapsing wall. The maximum calculated temperature in pump room B was 214°F at a pressure of 0.97 psig. All other areas are bounded by the RWCU break in room 224.

Results of Analysis for RWCU Break in Room 224

Although pipe breaks in room 224 are no longer postulated, this break analysis bounds breaks in room 219. The heat exchanger (219) and holdup (224) rooms feature a common stacked brick wall on the west side, 24 in. thick, for shielding purposes only. Break mass and energy is vented to the reactor building on collapse of the stacked brick wall in the same manner as room 218. The maximum temperatures and pressures calculated for the hold-up pipe room and heat exchanger room were <216°F and 9.7 psig and <215°F and 1.18 psig. The reactor building second floor temperature and pressure calculated were 156°F and 1.14 psig. All other areas showed equal or lower temperatures and pressures.

The maximum pressure of 9.7 psig predicted for room 224 exceeded the capacity of the wall between the hold-up room and the heat exchanger room. The short term environmental analysis was updated to bound the actual RWCU breaks in the RWCU heat exchanger room (instead of a bounding break of the largest pipe in the worst location) and to recompute the differential pressure across the wall between the hold-up room and the heat exchanger room. The computer code COMPARE was utilized in the analysis. The revised analysis calculated a maximum differential pressure of 1.5 psid across the wall which is acceptable.

Results of Analysis for RWCU Break in Torus Room

A steady-state temperature of 191°F with 100 percent humidity would result in the torus room. The pressures in the reactor building are bounded by the RCIC steam line break environmental conditions, as discussed in Subsection 3.6.2.2.4.

3.6.2.2.5.2.3 Pipe Whip Evaluation

Consideration was given to the effects of RWCU-water-line pipe whip on safety-related structures, systems, and components in the rooms where the high-energy portion of the water lines coexists with such structures and equipment. The results of these evaluations are reported in Reference 24.

3.6.2.2.5.2.4 Jet Impingement Evaluation

As in the case of pipe whip, an evaluation was carried out to assess how jet impingement resulting from a break in the RWCU high-energy water line would affect safety-related structures, systems, and components. The results of these evaluations are reported in Reference 24.

3.6.2.2.5.2.5 Evaluation of System, Component, and Structural Damage

An evaluation was made of the damage resulting directly from the RWCU water line break. The evaluation included effects on various systems, components, and structures as well as impact on the ability to achieve a safe shutdown. The RWCU line in the torus room was provided with pipe whip restraints to protect the torus from the effects of design-basis breaks. A review of the consequences of pipe whip and jet impingement loadings resulting from a postulated break in the RWCU piping determined that no important structural element would be damaged by pipe whip or jet impingement.

Pipe Whip Restraints and Jet Impingement Shields

Design of restraints was based on the criteria given in Subsection 3.6.2.3.2 and the methods given in Subsection 3.6.2.1.5. The restraints provided for the RWCU pump discharge line in the torus room direct the thrust loads resulting from postulated breaks into the reactor building walls and prevent the broken line from impacting the torus. An analysis to determine member sizes was made assuming a conservative steady-state thrust loading, applied instantaneously and assumed to be constant for the entire blowdown event. A dynamic impact factor of 2 was assumed to account for the sudden nature of the loading.

Evaluation of Environmental Effects on Systems, Components, and Structures

Equipment, including active and passive components, listed in Table 3.6-1 as required for attaining and maintaining a safe-shutdown condition after a postulated break in the RWCU system was evaluated with respect to its functional capability under the pressure, temperature, and humidity conditions resulting from the pipe break. It was determined that the environmental conditions would not adversely affect the operation of the required systems.

The structural framing of the reactor/auxiliary building was analyzed in accordance with the methods described in Subsection 3.6.3 for the effects of RWCU water line breaks. The interior walls and slabs of the compartment were analyzed for the effects of pressurization in accordance with the methods described in Subsection 3.6.3, and were found to be acceptable. The maximum differential pressure between the external walls and atmospheric pressure is well within the 3-psig tornado design pressure differential.

In view of the above, no adverse consequences due to environmental effects of the RWCU line break have been identified.

3.6.2.2.5.3 Evaluation of Ability To Attain and Maintain a Safe Shutdown

A break in the RWCU water line would not result in a turbine generator trip or an RPS trip. Therefore, this evaluation assumes that offsite power is available.

Referring to Table 3.6-1, all systems and components listed as required for a safe shutdown will be operable, as will all redundant components. No single component failure can be assigned that would preclude attaining and maintaining a safe shutdown.

It is concluded, therefore, that a break in the RWCU water line will not jeopardize the ability to attain and maintain a safe shutdown.

3.6.2.2.6 Control Rod Drive System

An evaluation of the consequences of a pipe break in the control rod drive (CRD) system was carried out as described below.

Those portions of the CRD system piping outside the containment that are classified as high energy are the 1-in. insert and 3/4-in. withdraw lines running from the hydraulic control units to the drives, and the 2-in. water charging line.

The piping from the hydraulic control units to the scram discharge system is pressurized to high-energy conditions less than 0.1 percent of the system operating time. The balance of the time this portion of piping is vented to the atmosphere. Accordingly, in conformance to NRC guidance, it is permissible to treat this portion of the piping as moderate-energy piping. The consequences of a break in moderate-energy lines are addressed in Subsection 3.6.2.3. In response to additional NRC comments on a break in this portion of piping, GE published two generic evaluations (References 36 and 37), and the BWR Owners Group submitted a report on scram discharge pipe integrity (Reference 38). The applicability of these evaluations to Fermi 2 was addressed in Reference 39, along with additional plant-unique information as needed to address the NRC comments. The conclusion of the studies indicates that the mechanical quality, maintenance procedures, operator actions, and existing system performance are sufficient to satisfactorily guarantee scram discharge piping system integrity. In addition, even if a break were to occur, it was shown that the break would contribute negligibly to the risk of core uncovering.

3.6.2.2.6.1 Review of Potential Damage

As in the case of the previously discussed systems, a review of the potential damage resulting from a break in any of the CRD piping was conducted in accordance with the methods described in Subsection 3.6.2.1.6. The review took into account the equipment required for a safe shutdown, as discussed in Subsection 3.6.2.1.4 and Table 3.6-1.

This review (Reference 24) established that there would be no adverse consequences resulting from any break of the CRD piping.

Environmental effects were not analyzed for a break in the CRD line because of the highly subcooled nature of the water. There would be no flashing of the liquid that escapes the postulated break and consequently no adverse environmental response.

3.6.2.2.6.2 Pipe-Break Analyses

3.6.2.2.6.2.1 Blowdown Analyses

Blowdown thrust loads used to assess the effects of pipe whips were generated by conservative hand calculational methods, as described in Subsection 3.6.3.

3.6.2.2.6.2.2 Environmental Analyses

Effects related to the spraying or flooding of components in the area of a CRD line break have been considered and are included in the analysis of moderate-energy systems provided in Subsection 3.6.2.3.

3.6.2.2.6.2.3 Pipe Whip Evaluation

Analyses were performed to assess the pipe whip consequences on the safety-related structures, systems, and equipment that might be damaged as a result of a design-basis break in the CRD piping.

Blowdown thrust loads were hand-calculated, as discussed in Subsection 3.6.2.2.6.2.1. The methods used in the structural evaluation for pipe whip impact are discussed in Subsection 3.6.3.

As a result of the review of the consequences of pipe whip caused from breaks in the CRD system piping, it was determined that no safety-related structural elements would be damaged by a whipping pipe.

3.6.2.2.6.2.4 Jet Impingement Evaluation

Because of the highly subcooled condition of the water in the CRD piping outside the primary containment, the line would depressurize almost instantaneously after a design-basis break. The flow rate out of the break would be limited by the capacity of the CRD pumps (260 gpm at 0-ft head), and flow velocity from the break will not exceed 11 fps. As a result, no unacceptable consequences due to jet impingement loadings could be identified for a design-basis break in the CRD system outside the primary containment.

The effects of crack breaks in this piping are the effects expected from breaks in moderate-energy systems, that is, spraying and flooding.

3.6.2.2.6.2.5 Evaluation of System, Component, and Structural Damage

An evaluation was made of the direct damage resulting from a break in the CRD piping system on various systems, components, and structures, and its impact on the ability to achieve a safe shutdown. This evaluation was made by reference to Subsections 3.6.2.1.4 and 3.6.2.1.5, and Table 3.6-1. No adverse consequences were identified.

3.6.2.2.6.3 Evaluation of Ability To Attain and Maintain a Safe Shutdown

There would be no adverse consequences resulting from a break in the CRD piping that could preclude attaining and maintaining a safe shutdown.

3.6.2.2.7 Reactor Building Heating System

An evaluation of the consequences of a pipe break in the reactor building heating system was carried out as described below. The piping of this system is routed through most of the floors and rooms in the reactor and auxiliary buildings. Only the steam lines of the building heating system are classified as high energy.

3.6.2.2.7.1 Review of Potential Damage

As in the case of the previously discussed systems, a review (Reference 24) of the potential damage resulting from a break in any of the building heating steam lines was conducted in accordance with the methods described in Subsection 3.6.1. The review took into account the equipment required for a safe shutdown, as discussed in Subsection 3.6.2.1.4 and Table 3.6-1.

The pressure in the reactor building heating steam lines (15 psig) is less than that which can cause a pipe to whip from postulated breaks. Subsequently, blowdown analyses, pipe whip evaluations and jet impingement evaluations were not performed. The effects of cracks in this piping are the same as those expected from breaks in moderate-energy systems; that is, spraying. An evaluation of the spraying effects on various systems, components, and structures did not identify any adverse consequences. The environmental effects of temperature and humidity were also analyzed for a break in the building heating steam lines. Secondary containment isolation valves are provided in the steam supply lines to isolate the steam source on indication of a break.

3.6.2.2.7.2 Evaluation of Ability To Attain and Maintain a Safe Shutdown

The loss of the building heating system does not affect the safe shutdown capability of the reactor.

3.6.2.2.8 Non-Safety-Grade Systems

A review of plant safety with regard to high-energy pipe breaks was performed using the format established by the BWR Owners Group in response to H. R. Denton's letter, Potential Unreviewed Safety Question on Interaction Between Non-Safety-Grade Systems and Safety-Grade Systems.

From this review, Edison has concluded that no identified safety action would be negated by the failure of non-safety equipment resulting from the environmental effects of a high-energy pipe break. The only minor area of concern is the temperature effects of the pipe break on the level instrumentation sensing lines, and this has been addressed and resolved in the generic BWR report, NEDO-24708.

This review indicates that no previously established safety limits would be violated by the environmental effects.

It is desirable that operator action be taken to quickly mitigate the effects of the failures in most cases.

The specific systems and areas considered are included in Table 3.6-8.

3.6.2.3 Moderate-Energy Pipe-Break Evaluation

Moderate-energy piping systems, as defined in Subsection 3.6.2.1.2.1 and listed in Subsection 3.6.2.1.3.2 have been evaluated (Reference 24) for postulated through-wall leakage cracks (refer to Subsection 3.6.2.1.1.2 for the method and Subsection 3.6.2.1.2.4 for the design bases for the crack size and location). The components and/or equipment required for the safe shutdown of the reactor were evaluated and, if necessary, provided with measures to protect and ensure their operability. The evaluation for the moderate-energy piping systems encompasses an analysis of both flooding and spraying effects.

The consequences of flooding would depend on the crack size, crack flow rate, drainage rate of the compartment, and the location within the compartment of the components required for safe shutdown. An accumulation rate (defined as the crack flow rate minus the drainage rate) was determined for each compartment, and the potential for water accumulation in each compartment was examined. If accumulation posed a flooding threat to components or equipment, an examination was undertaken to determine the possibility of damaging each component within that compartment and the acceptability of such damage. Where drain paths exist such that water accumulation may occur in adjacent compartments, an evaluation of the components and equipment damage in those compartments was carried out.

The consequences of spraying would depend on the spray distance and the spray angle. The spraying distance was determined for the highest-pressure line within each compartment in which components and/or equipment are located.

In many cases, numerous break locations were selected within each compartment so as to maximize the effect on any one component and/or equipment within that compartment. An examination of each component and/or equipment required for safe reactor shutdown was completed to determine the acceptability of damage. In either analysis, whether for the case of flooding or for the case of spraying, the basic problem was to establish whether the effect of a postulated leakage crack has the potential of preventing the safe shutdown of the reactor when combined with a random failure of a single component.

3.6.2.3.1 Analytical Procedure

A step-by-step procedure was used to determine which of the components within the reactor/auxiliary building and the residual heat removal (RHR) complex could have the potential of being damaged by either flooding or spraying. The steps include listing components and/or equipment required for safe shutdown, located in areas affected by spray or flooding. On the basis of the crack flow rates (Subsection 3.6.2.3.3.) and spray distances (Subsection 3.6.2.3.3.) for each postulated crack, a determination was made as to which of these components could fail as a result of spray or submergence. Finally, the ability to achieve safe shutdown was evaluated, assuming a single active failure in addition to the failures caused by spray and flooding (Subsection 3.6.2.1.1.2).

3.6.2.3.2 Evaluation Guidelines

The basic guidelines used in evaluating the effects of flooding or spraying were as follows:

a. All water pipes were assumed to have the required pressure to produce a spray that would reach the most distant walls in direct line of the spray; if unacceptable damage would result, this assumption was reviewed and validated

b. All valve operator motors have NEMA 4 enclosures and were not assumed to fail from water spray

c. All motors other than valve operators were evaluated on an individual basis. If they were in open drip-proof enclosures, they were assumed to fail when exposed to a spray

d. All motors were assumed to fail if submersed due to flooding, except the subbasement floor drain sump motors

e. Cables are waterproof and would be unaffected by flooding or water spray

f. Motor control centers and switchgear were assumed to fail if sprayed or if submersed due to flooding

g. Essential instruments that are NEMA 4 rated were not assumed to fail from water spray

h. All instruments were assumed to fail if submersed due to flooding

i. Essential local terminal boxes that are NEMA 4 rated were not assumed to fail from spraying effects

j. All terminal boxes were assumed to fail if submersed due to flooding.

3.6.2.3.3 Analytical Methods

As indicated in the analytical procedures (Subsection 3.6.2.3.1) for flooding and spraying, calculations must be performed to find the crack flow rate and the spraying distance for postulated through-wall leakage cracks. The methods used to determine these parameters are described in Reference 24.

3.6.2.3.4 Results of Evaluation

From the evaluations of flooding and spraying effects, it was possible to identify certain components and/or equipment that required protective measures to prevent their loss of function as a result of the pipe crack.

3.6.2.3.4.1 Protective Measures To Mitigate Flooding Effects

3.6.2.3.4.1.1 Residual Heat Removal Complex

The QA Level I components located in the RHR complex are

a. Standby diesel generators (four)

b. RHR service water pumps (four)

c. Emergency equipment service water system (EESWS) pumps (two)

d. Diesel generator service water (DGSW) pumps (four)

e. RHR cooling towers (four)

f. 4160-V switchgear, 480-V switchgear, and motor control centers

g. Standby diesel generator heating, ventilation and air conditioning (HVAC) systems.

Because of the structural arrangement and openings for drainage, a moderate-energy pipe rupture in those areas cannot cause a flooding problem.

3.6.2.3.4.1.2 Reactor/Auxiliary Building

Subbasement Flooding

The floor drains, open stairwells, and other openings (equipment hatches, pipe chases, and various penetrations) provide ample access to the subbasement for any water that would leak from a postulated pipe crack occurring on any floor of the reactor/ auxiliary building. Therefore, the analysis of damage from flooding in the subbasement covers floods that would result from pipe breaks on other floors as well as from breaks in the subbasement.

Flooding in the subbasement can occur in the torus room (room SB2), any of the corner rooms (rooms SB1, SB3, SB5, or SB6) or the HPCI room (room SB7). The maximum flooding rate in the torus room would result from an RHR pump discharge line. Other moderate-energy lines in the torus room would have a lower leakage rate, and thus an evaluation of the RHR leak represents the envelope for leaks from other systems. Secondary containment isolation valves are provided in the torus water management system (TWMS) return line to the torus to isolate the condensate systems on indication of leakage (see Figure 9.2-13).

The maximum flooding rate in a corner room would result from an RHR return line. Other moderate-energy lines in the corner rooms would have a lower leakage rate. Flooding in a corner room due to leakage from an operating system in that room would be self-contained and self-limiting since it would stop when the pump stops due to submergence of the pump motors. For the case of a leak in one RHR division corner room while the other division is in operation, the presence of a leak would be readily identified by the sump level indication and the system would be turned off.

Leaks of a magnitude great enough to cause flooding would be detected by water line pressure and flow instrumentation, leak-detection instrumentation, or the activation of the sump pumps and sump overflow alarms.

Shutdown Capability Evaluation

Indications that there is water leakage into the subbasement in excess of specified limits call for an immediate controlled shutdown. Since there would be no turbine generator or RPS trip resulting from a moderate-energy pipe break, offsite power would be available and shutdown would be carried out by normal shutdown procedures.

In cases of moderate-energy piping leakage, operator action would be required to identify the leaking system and the location of the leak. Instrumentation of various types is available to allow the operator to identify the leaking system. In most cases, location of the leak would require a search of the areas traversed by the identified leaking system. Some of the safety-related equipment in the subbasement prone to damage by flooding is the equipment in the specific corner rooms indicated in Figure 3.6-13 and the various pump suction valves in the torus room. If a leak in an RHR pump discharge line resulted in flooding in the torus room and the flooding proceeded at the fastest rate, more than 2 hr would be required to flood the motor operators of the RHR suction valves; thus the operator would have adequate time to locate and terminate the leak without damage to any safety-related system or component.

In applying the single-component failure criterion, the only system required for normal shutdown that could be made inoperable is the RHR system. Should a leak develop in one division of the RHR, and the single-failure criterion were applied to the RHR divisional cross-tie valve, both divisions of the RHR would be disabled since continued operation of the nonleaking division would force water out of the leaking division and there would be no method of determining the leaking division. In this event, the primary system would be held at low-pressure hot standby until the malfunctioning valve were repaired and closed so that the leaking division could be identified. Once this were accomplished, the system could be taken down to a cold shutdown using the redundant RHR division, where the single-failure criterion is not applied in accordance with Subsection 3.6.2.1.1.2.

Loss of equipment in any single corner room together with an assumed single failure would not preclude attaining and maintaining a safe shutdown.

Basement

The basement consists of the four corner rooms enclosing various instrument racks. The flow rate from pipe cracks in any room in the basement would be relatively small; in all cases the water would drain to the subbasement rooms, and the evaluation for the subbasement flooding applies.

First Floor

Water accumulation could occur in a few areas on this floor; however, no safe-shutdown equipment is located in these areas. In other areas, sufficient floor drains and/or other openings (doors and stairwells) are provided to limit the accumulation to a few inches in depth. The water that leaked on this floor would eventually flow down to the subbasement, and the evaluation for the subbasement flooding applies.

Where RBCCW supplemental cooling supply and return piping to the Division I EECW loop passes along the floor between the control rod drive hydraulic control units, the HCUs have been evaluated for the impact of spray and jet impingement and found not to be impacted as a result of postulated cracks in this piping.

Second Floor

In general, the water that leaked on this floor from a postulated pipe crack in moderate-energy piping would drain to the subbasement area through the floor openings and/or stairwells, where its effect would be smaller than that of the postulated pipe crack in the subbasement.

Moderate-energy lines located in room 209 have the potential of damaging nearby electrical equipment as a result of postulated pipe cracks. These lines were shrouded to preclude this possibility.

Third Floor

The third floor contains the control room complex (room 308), motor control center (room 320), RPS motor-generator sets (rooms 32l and 322), switchgear (room 323), and batteries (rooms 325 and 326). The doors from room 3l8 provide access to the control room complex and to the switchgear room through the motor control center room. These rooms contain equipment that is sensitive to moisture and is required for the safe reactor shutdown.

Room 320 contains emergency equipment cooling water (EECW) supply and return lines that are routed near the motor control center cabinets, divisional cable trays, and fire protection system elements. The lines are shrouded to prevent these items from being sprayed and to prevent any significant water accumulation in room 320 in the event of a leakage crack in the lines. Room 318 contains no safety-related equipment. Water from a crack in either the EECW lines or fire protection header located in this room would spread directly to the turbine building. No significant accumulation of water in room 318 will be experienced. The closure strips that have been installed at the bottom of doors leading from room 318 into room 308 or room 320 will prevent water from spreading into the control room. In addition, small leakage allowed through the door in room 320 will not affect the equipment.

Fourth Floor

The secondary containment ventilation room (room 416) contains four pipes of about equal potential for causing flood damage. Two pathways are available for the spread of water; the open stairway (room 319) leading down to room 318, and the equipment hatch located over room 320. Water retained on the floor of room 416 will spread over the large floor area. No significant accumulation will be experienced.

Water descending the stairway will spread over the floor surface of room 318 into the turbine building. No significant accumulation will be experienced.

Water could leak into room 320 via the small holes in the equipment hatch. The water would spread over the room 320 floor surface and into adjacent rooms (rooms 321, 322, 323, 325, and 326). These rooms contain safety-related equipment that could be affected by water spray or accumulation. Therefore, a perimeter curb has been installed around the hatch. Also, a plastic cover has been installed over the hatch. The fire-protection line that is routed over the hatch area has also been shrouded. These measures will prevent water from leaking into room 320.

Fifth Floor

There is little effect on reactor safe shutdown from a postulated pipe crack in a moderate-energy piping system on this floor. Sufficient floor drains and openings to floors below (staircases and equipment hatches) have been provided to prevent flooding from postulated leaks. The water from this floor going to floors below has less effect than that of a postulated pipe crack on those floors. However, the following are some of the rooms that have been modified to mitigate the effect of a postulated pipe crack on this floor.

A maximum flow rate of 78 gpm from a postulated pipe crack of a moderate-energy reactor building closed cooling water (RBCCW) line is postulated in room 509. A floor drain is provided to prevent any water accumulation; however, there are duct penetrations leading to the control room below. To mitigate any possibility of water flowing through these penetrations, each penetration was sealed after its installation. A pipe crack can also lead to water flow down the stairwell leading to room 3l9 and thus to room 318.

3.6.2.3.4.2 Protective Measures To Mitigate Spraying Effects

3.6.2.3.4.2.1 Residual Heat Removal Complex

The safety-related components and equipment located in the RHR complex were discussed in Subsection 3.6.2.3.4.1.1. Water spray can adversely affect some safety-related equipment. Because of the separation arrangement, however, this damage would be limited to one division in any one system. Since the single-failure criterion is not applied to a redundant train of a dual-purpose system damaged by a pipe crack, the ability to achieve and maintain a safe shutdown is not jeopardized.

3.6.2.3.4.2.2 Reactor/Auxiliary Building

Following the procedure presented in Subsection 3.6.2.3.1, components and equipment required to ensure a safe shutdown and having the potential of being damaged as a result of a water spray from a moderate-energy pipe crack were identified. See Subsection 3.6.2.3.4.1.2.

3.6.2.4 Conclusions

3.6.2.4.1 High-Energy Piping Systems

Following the criteria described in Subsection 3.6.2.1, the main steam, feedwater, HPCI steam, RCIC steam, RWCU, building heating steam line, and CRD systems were evaluated for the effects of pipe rupture outside primary containment. This evaluation, described in Subsection 3.6.2.2, encompassed the effects of pipe whip, jet impingement, flooding, and environmental effects. The conclusions that were reached are described below.

3.6.2.4.1.1 Pipe Whip Effects

The effects of the unrestrained motion of segments of the afore-mentioned piping systems, due to thrust loads developed at postulated piping breaks, have been investigated. Pipe restraint designs have been installed that will mitigate the adverse effects of the pipe whip.

3.6.2.4.1.2 Jet Impingement Effects

The effects of jet impingement from the postulated piping breaks have been investigated. To mitigate the consequences of jet impingement, several postulated break locations are equipped with jet impingement shields to protect the affected systems, structures, and equipment.

3.6.2.4.1.3 Environmental and Flooding Effects

The environmental effects, including flooding and the effluent of a steam/air mixture, of postulated high-energy piping breaks have been investigated. It has been concluded that the components and equipment required for effecting and maintaining a safe shutdown are protected and the main control room will remain habitable.

3.6.2.4.1.4 Pressurization Effects

The pressurization effects of a postulated high-energy line break on the main steam tunnel, reactor/auxiliary building structures, and certain components and equipment have been investigated. The components and equipment required to effect and maintain a safe shutdown are protected and the main control room will remain habitable.

3.6.2.4.2 Moderate-Energy Piping Systems

Following the criteria described in Subsection 3.6.2.1, moderate-energy piping systems were evaluated for the effects of throughwall leakage cracks. This evaluation, described in Subsection 3.6.2.3, encompassed the effects of flooding and spraying. The conclusions reached are described below.

In the event of substantial flooding in the torus room, resulting primarily from an RHR pump discharge line leak, but including other lines as well, operator action is required to terminate the leakage. Maintenance work would be required to achieve and maintain a cold shutdown if the single-component failure criterion were applied to the cross-tie valve between the two RHR divisions.

Flooding into the third floor control room or switchgear room containing equipment required for a safe shutdown has been evaluated. Provisions were made to ensure that such flooding cannot occur either directly from other areas of the third floor or by leakage through penetrations from above. In addition, moderate-energy lines presently located in the third floor switchgear room are shrouded to preclude the possibility of spraying and flooding.

3.6.3 Analysis Methods and Procedures

The methods and procedures used for the evaluation of pipe breaks of high-energy systems outside containment are presented in Subsections 3.6.3.1 through 3.6.3.4.

3.6.3.1 Blowdown and Environmental Effects Analyses

An analysis was performed to predict system blowdown response for each of the postulated high-energy line ruptures. The blowdown information is used to determine pipe whip forces and jet impingement characteristics, and may also be used as input in a number of other thermal-hydraulic analyses, depending on the requirements and problems anticipated for a particular break. In cases where structural damage could result from overpressure caused by rupture, the blowdown flow results are input in a compartment pressurization analysis. In situations where building temperature and humidity in the postbreak environment could damage required electrical, instrumentation, or control equipment, the blowdown flow results are input in a building environment analysis. Postulated ruptures resulting in release of significant amounts of subcooled water were evaluated for effects of flooding in the building housing the broken lines.

The criteria and methods to be used for the thermal-hydraulic analyses are described below.

3.6.3.1.1 Blowdown Analysis

The blowdown analyses may be characterized as either short term or long term in nature, depending on the purpose for which the results are used. Thrust data required for pipe whip analysis can be obtained in short-term analyses (about 500 msec real time) since maximum piping response is reached within this time. Mass and energy flow data required for compartment pressurization, environmental, and flooding analyses must be based on longer term blowdown information since the severity of these effects may increase with continuing flow from the break.

Typically, the duration of short-term analyses is insufficient to allow activation of operable components (other than check valves), and the balance of plant systems (other than the inoperable system) continue to operate in the normal way. For the long-term analyses, consideration must be given to action of operable components, interaction of other systems with the broken system, and the effects of shutdown of the reactor.

The following general criteria govern the blowdown analysis:

a. Analyses shall consider flow from both sides of the break

b. Discharge coefficients shall equal 1.0 for all breaks

c. Credit shall be taken for flow limiters, line restrictions, and pipe friction as applicable

d. Breaks shall be assumed to occur instantaneously

e. The initial conditions for a break shall be the worst-case operational condition.

3.6.3.1.2 PRTHRUST Program

The blowdown analyses were performed using the computer program PRTHRUST (Reference 40). The PRTHRUST program is a modification of RELAP3 (Reference 41), the AEC's presently accepted LOCA analysis code (Reference 42) for the specific requirements of pipe rupture analysis. In PRTHRUST, the fluid system is mathematically modeled as an assemblage of control volumes interconnected by flow paths. Characteristics of control volume include the state of the contained fluid and possible energy addition. Control volumes are used to model such components as pressure vessels, steam generators, heat exchangers, and the piping volumes. Flow paths are used to interconnect control volumes and may include operable valves, check valves, fills, and pumps. The program allows actuation of operable devices, such as valves, to be triggered at a specific time or based on a physical signal such as pressure or flow at a point in the system. The variation in pump performance under transient conditions is considered. A core model is available for cases in which transient reactor performance effects blowdown.

Initial values for the problem are taken as steady-state operating conditions for the system. The transient is initiated by instantaneously opening a leak in the system. The solution proceeds by step-by-step integrations of the governing fluid equations with time. The requirement for conservation of mass and energy in a volume is satisfied at each time step. State properties in the volumes are calculated using thermodynamic state equations and the ASME steam tables (Reference 43) for subcooled, saturated or superheated fluids. The flow rate for flow paths between volumes is calculated using both the one-dimensional momentum equation and Moody's two-phase choked flow model (Reference 44). The lesser of the two flows is assumed to govern.

The PRTHRUST program output includes time-history values of mass flow, pressure, temperature, enthalpy, and other thermodynamic quantities at specified points in the system and at the break. This information is suitable for input in subsequent jet impingement, compartment pressurization, environmental, and flooding analyses as required.

The program also calculates break thrust as a function of time. This calculation is facilitated by placement of control volume(s) in the model between the break and the piping elbow(s) nearest the break, and is carried out using the following equation.

$$T = T_{pt} + T_{mt} + T_a = (P_t - P_e)A + \frac{\rho A V^2}{g} + \frac{\Delta(MV)}{\Delta t g} \qquad (3.6\text{-}5)$$

where

T	=	total thrust at break
T_{pt}	=	pressure thrust
T_{mt}	=	momentum thrust
T_a	=	thrust due to fluid acceleration
P_t	=	throat pressure at break
P_e	=	ambient pressure
A	=	break area
ρ	=	density
V	=	velocity
g	=	Newton's constant
M	=	mass
t	=	time

Throat pressure is given by the Moody correlation (Reference 44) for choked flow, and is taken as equal to ambient pressure for nonchoked flow. The momentum change term is equal to zero for steady flow.

3.6.3.1.3 Building Pressurization and Environmental Analyses

In cases where compartment pressure or steam environment resulting from a postulated rupture could result in damage to structures, systems, or equipment required for safe shutdown, an analysis was performed to assess the magnitude of these effects. Only the worstcase break in each compartment was analyzed.

The mass and energy input from the break was determined by a long-term blowdown analysis, assuming the most adverse reactor operating conditions. The analyses of longterm compartment pressures and environment are generally performed using the CONTEMPT-LT or KITTY6 computer program. Where expedient, however, conservative hand calculated mass and energy balance is used. The failure point of all components (doors, vents, walls, etc.) that may alter fluid flow paths are determined and the effects of such failures considered in the analyses. The initial positions of all doors or other movable vents are assumed to be in the most adverse normal condition. A discharge coefficient of 0.6 is conservatively assumed for all vent areas unless another value can be justified analytically.

3.6.3.1.4 CONTEMPT-LT Computer Program

The CONTEMPT-LT computer program (Reference 45) predicts the time-history of pressure, temperature, and humidity response in a group of interconnected compartments, resulting from a high energy pipe break in one compartment. Input break characteristics are the mass and energy flows computed in the blowdown analyses. In the program, compartments are represented by control volumes, and are interconnected by flow paths representing the venting areas. Venting to the outside may also be considered. Vents may be opened at a specified pressure to represent active components or failure of components such as doors.

Each control volume is separated into variable liquid and vapor regions. While each region is assumed to be uniform temperature, the liquid and vapor temperature may be different. Mass and energy transfer between the two regions is permitted, based on condensation and/or evaporation correlations, as applicable. The program solution is by step-by-step integration of the mass conservation and energy equations with time.

The program also includes the capability to perform one-dimensional heat conduction calculations. This capability can be used to account for the heat sinking effect of various building components by specifying appropriate initial and boundary conditions. The effect of building venting and leakage can be accounted for through use of available correlations for flow through small and large openings.

The CONTEMPT-LT output includes values of building pressure, temperature, and relative humidity in each compartment as a function of time.

3.6.3.1.5 Flooding Analyses

The analyses for flooding effects were carried out using hand calculational methods. Input was taken from mass and energy flow results of blowdown analyses for pressurized water lines. Consideration was also given to flooding caused by steam condensation as determined in the building environment analyses described in the preceding section. The flooding analysis for a particular compartment was performed only for the worst-case break for that compartment, although possible secondary effects, such as rupture of a second line by a whipping pipe, were considered.

The most adverse system operating conditions were assumed at the time of the break. In determining the mass of water released, failure of the active component leading to the maximum release was assumed.

The flooding analysis method was based on determination of compartment free volumes as functions of elevation, along with available drainage capability and flow-path characteristics between connecting compartments.

Using this information along with calculated water flow rates, the maximum water level and rate of water-level rise was determined for each compartment.

3.6.3.1.6 CVPT-REPORT Computer Program

The CVPT-REPORT computer program is used for the determination of compartment pressure and environmental response due to a postulated instantaneous pipe rupture in a high-energy piping system.

CVPT-REPORT is a design and analysis tool that can treat one compartment or 16 interconnected compartments of a completely arbitrary arrangement. Interconnecting paths modeled as orifices or pipe sections are accepted by the program. The break flow rate from the postulated break is determined by the program throughout the incident by considering input conditions of reactor vessel steady-state fluid conditions, pipe losses to the break point, flow restrictions, and isolation valve actuation cycles, including closing times and flow choking.

The CVPT-REPORT program uses a step-by-step integration method of the mass conservation and energy equations with time to obtain the environmental response of each compartment during the incident. State properties in the compartments are calculated using thermodynamic uniform-flow, uniform-state equations and the ASME steam tables for wet, saturated, or superheated steam. The flow rate for flow paths between compartments is calculated using the Darcy formula for compressible flow through orifices or a formula for compressible isothermal flow in pipelines. For postulated breaks where the process fluid is saturated or superheated steam, the mass flow rate out of the break is calculated by using a formula for the choked flow of a compressible gas through an isentropic nozzle. For cases where the process fluid is saturated liquid, the mass flow rate out of the break is determined by using the Darcy formula for the discharge of fluid through valves. The heat-transfer effect to the compartment walls is considered through incorporation of the Uchida heat transfer coefficients for a range of air-to-steam ratios (Reference 46).

The CVPT-REPORT program output includes time-history response of mass flow rate, and the pressure, temperature, and humidity of each compartment. This information is suitable for input into any subsequent long-term analysis or structural and component damage analysis.

3.6.3.1.7 KITTY6 Computer Program

The KITTY6 computer program is used to determine transient temperature and pressure responses in various areas of the reactor building for the HELB and LOCA accident cases. This problem is a transient heat transfer problem which depends upon the initial conditions, the boundary conditions and the characteristics of the system. The problem is solved numerically using the computer program KITTY6.

KITTY6 calculates node properties and path heat flow and mass flow rates for transients in user specified solid and/or fluid channel configurations. Paths between nodes may be used to model conductive, convective and radiative heat transfer and mass and enthalpy transport. In the compressible fluid system (CFS) of the model, elevation effects may be accounted for, compressible fluid flow paths may be represented as either of inertial or non-inertial (pseudo-steady) types, and limitation of flow path rates to the choking flows may be elected. Water and as many as five noncondensible gas species may be treated in the CFS. Provided the configuration specification, material properties, boundary conditions, internal heat generation rates, selected fluid flow rates and required printout times, KITTY6 computes and prints the node properties (temperature, pressure, density, composition and mass flow rates), and path mass and energy flow rates at user specified time intervals.

KITTY6 was utilized to re-evaluate environmental conditions resulting from HPCI, RCIC and RWCU breaks as referenced in the previous sections. The original short-term analyses for these breaks were not impacted by the revised environmental analyses.

3.6.3.2 Jet Impingement Analysis

This section defines analytical methods used for performing the jet impingement evaluation. The effects of jet impingement were considered for all longitudinal design-basis, longitudinal crack, and circumferential crack breaks. The jet impingement effects resulting from fluid discharge from both ends of the severed pipe were considered for all circumferential design-basis breaks, unless it could be shown that the two ends are sufficiently restrained to prevent offset after rupture. The sweep of the jet was considered for all design-basis breaks subject to pipe whip.

The break opening configuration for postulated design-basis breaks is defined in Subsection 3.6.1.1.2. The fluid jet is assumed to fan out to form a circular or prismatic cone issuing from the break opening. Jet impingement pressure on a target struck by the jet is calculated by determining total thrust at the break, and assuming this total integrated thrust remains constant at any plane of interest in the cone.

The axis of the jet is parallel to the pipe axis for design-basis circumferential breaks and perpendicular to the pipe axis for all other break types. The characteristics of the jet shapes for the various postulated break types are shown in Figure 3.6-45.

3.6.3.2.1 Total Thrust Load

The calculation of thrust on the pipe after rupture was described in the blowdown analysis. Using the principle of conservation of momentum, the steady-state jet thrust can be equated to the thrust on the pipe. This conclusion has been confirmed by Moody (Reference 47).

The total jet thrust for breaks can be equated to the maximum in the quasi-steady-state region of the thrust time curve. The rise time for the jet thrust can be taken as the time to reach this quasi-steady-state peak. The initial peak in the thrust-time curve, which is caused by acceleration of fluid from the pipe, does not influence the jet impingement load on a target. A graph showing determination of total thrust from the PRTHRUST results is shown in Figure 3.6-46.

3.6.3.2.2 Coning Angle

The fluid jets from steam or flashing water breaks were assumed to fan out with a constant half angle of l2.5°. The experimental basis for this assumption is found in Reference 48, which includes photographs of jets of both steam (about l00 psia saturated) and water (at 2250 psia and 550°F). For subcooled, nonflashing breaks, a jet divergence angle of l0° was assumed.

3.6.3.2.3 Jet Temperature

The jet temperature will vary with distance from the jet source. However, jet temperature will not exceed the stagnation temperature based upon an isenthalpic expansion of jet fluid. The jet temperature limits are

For steam line breaks:

$$T_j = 330°F \tag{3.6-6}$$

For liquid line breaks:

$$T_j = 240°F \text{ maximum} \tag{3.6-7}$$

$$= \text{Fluid temperature if less than } 240°F \tag{3.6-8}$$

where

T_j = jet stagnation temperature (°F)

3.6.3.2.4 Target Loading

The normal load applied to a target by the jet issuing from a postulated break may be expressed as

$$F = T\frac{A_i}{A_j} S_F D_{LF} \tag{3.6-9}$$

where

T = total thrust of jet (lb_f)

A_i = cross-sectional area of jet intercepted by target structure

A_j = total cross-sectional area of jet at target structure

S_F = shape factor

D_{LF} = dynamic load factor

The total thrust T has been defined previously in the blowdown analysis. The ratio A_i/A_j represents the proportion of the total mass flow interrupted by the target structure. The dynamic load factor D_{LF} accounts for the rapid application of the load. A dynamic load factor of two should be used in the absence of an analysis justifying a lower value.

The shape factor S_F depends on the projected section and orientation of the target struck by the jet and is a measure of the target's potential for changing the momentum of the jet.

Typical shape factors for perpendicular impingement at turbulent flow conditions are

a. 0.5 to 0.6 for piping spans up to ten diameters

b. 0.4 for spherical shapes

c. 0.2 for ellipsoidal shapes (stream lined)

d. 1.25 for flat plates.

The force determined using the above formula and factors represents the integral of a uniform pressure applied normally to the target impinged upon by the jet.

3.6.3.3 Pipe Whip Analysis

A pipe whip analysis was carried out for each of the design-basis ruptures postulated in high-energy lines identified as requiring this type of analysis. This analysis serves initially to identify situations in which whipping pipes could cause unacceptable damage to systems, equipment, or structures, and later to develop locations and design loads for restraints required to prevent unacceptable pipe whips. The steps in the pipe whip analysis are as follows:

a. An analysis is performed to predict piping response to the rupture thrust load. This analysis determines whether maximum moments and torque in the piping exceed values necessary to cause plastic hinging and whether a sufficient number of plastic hinges form to effect a plastic failure mechanism or pipe whip

b. If pipe whip takes place, the trajectory of the whipping pipe is traced to identify impact on systems, equipment, or structures. Mechanical, HVAC, electrical, instrumentation, and control components are considered to fail upon impact by whipping pipes, unless stress analyses justify otherwise. Structural components are evaluated to determine whether pipe whip impact causes failure in accordance with the methods described in this section and in Subsection 3.6.3.4

c. Locations selected for pipe restraints prevent the occurrence of unacceptable pipe whips. Sizing analyses were performed to determine stiffness and strength characteristics of these restraints.

d. Finally, a dynamic response analysis of the complete piping system and identified restraints was performed. This analysis verified the fact that unacceptable pipe whips do not occur in the restrained system, and provided maximum reaction loads for use in final design of the restraints.

The criteria for the pipe whip evaluation, and the analytical formulation of the analyses described above, is given in the following sections.

3.6.3.3.1 Criteria for Analysis

The following general criteria were applied in the pipe whip evaluation:

a. The dynamic nature of the piping thrust load shall be considered. In the absence of analytical justification to the contrary, a dynamic load factor of 2.0 shall be used

b. Nonlinear (elastic-plastic strain hardening) pipe and restraint material properties shall be considered. Pipe whip shall be considered to take place on attainment of a hinge mechanism in which maximum fiber strain reached 50 percent of that strain corresponding to maximum stress in a one-dimensional tensile test

c. Pipe whip was considered to result in unrestrained motion of the pipe along a path governed by the hinge mechanism and the direction of the vector thrust of the break force. A maximum of 180° rotation was assumed to take place about any hinge

d. The effect of rapid strain rate on material properties was considered. In the absence of justification to the contrary, a l0 percent increase in yield and ultimate stress under dynamic load was assumed

e. Variations between lower- and upper-bound material properties were considered in the most conservative fashion. For example, use of lower-bound properties provided a conservative prediction of pipe whip, while use of upper-bound properties was conservative for determination of maximum restraint loads. In the absence of data justifying the contrary, lower bounds were taken as minimum guaranteed properties, with a 40-percent statistical increase for upper-bound properties

f. Where possible, required pipe whip protection was provided by designing normal operating pipe restraints to withstand pipe rupture loads. Pipe whip restraints required at locations where resultant piping thermal stress would preclude use of rigid supports were designed with an initial clearance sufficient to allow. free thermal expansion of the pipe. The clearance restraints used a deformable energy-absorbing component retained by a support substructure. Energy-absorbing components were designed to withstand pipe impact without exceeding 50 percent of ultimate capacity. Rigid supports and support substructures were designed in accordance with the criteria given in Subsection 3.6.2.1.5.

3.6.3.3.2 <u>Preliminary Pipe Whip Evaluation</u>

The methods in this section were used to determine whether pipe whip takes place for a given postulated rupture, and to determine the kinetic energy of whipping pipes on impact with a target.

A pipe whip occurs when a hinge mechanism forms in the system that has a structural resistance less than the applied thrust force. The mechanisms consist of straight runs of pipe connected by fittings (elbows, etc.) that yield under a combination of internal moment and torsion. The condition for formation of a plastic hinge at a given location in a piping system is

$$\left(\frac{iM^2}{M_{ult}} + \frac{T}{T_{ult}}\right) \; 2 \geq 1 \qquad (3.6\text{-}10)$$

where

M = applied moment

= $\sqrt{M_l^2 + M_2^2}$

M_1, M_2 = moment components in plane perpendicular to pipe centerline

M_{ult} = ultimate moment

i = stress intensification factors for elbows, tees, etc.

T = applied torque

T_{ult} = ultimate torque

The ultimate moment and torque are limited by the allowable 50 percent uniform ultimate strain. Expressions for these quantities, based on assumed elastic-linear strain-hardening material properties, are given by the following:

$$M_{ult} = \sigma_y Z_p + (\sigma_{ult} - \sigma_y) Z_e \qquad (3.6\text{-}11)$$

$$T_{ult} = t_y z_{tp} + (t_{ult} - t_y) Z_{te} \qquad (3.6\text{-}12)$$

where

σ_{ult} = tensile stress corresponding to 50 percent of strain at maximum tensile stress

σ_y = tensile yield stress

Z_p = plastic bending section modulus

= $(4/3)(r_o^3 - r_i^3)$

Z_e = elastic bending section modulus

= $\frac{\pi(r_o^4 - r_i^4)}{4r_o}$

t_y = shear yield stress

= $\sigma_y/2$ (maximum shear theory)

t_{ult} = ultimate shear stress

= $\sigma_{ult}/2$

Z_{te} = elastic torsion section modulus

= $\frac{\pi(r_o^4 - r_i^4)}{2r_o}$

Z_{tp} = plastic torsion section modulus

= $\frac{2\pi}{3}(r_o^3 - r_i^3)$

r_o = pipe outside radius

r_i = pipe inside radius

Formation of a sufficient number of hinges produces a mechanism that moves under the action of the blowdown force and is resisted by the constant limit load and inertia of the mechanism. The resulting motion may be determined using simple kinematic formulas.

As an example, the motion resulting from a postulated longitudinal break at joint B is to be determined for the piping system shown in Figure 3.6-47.

The structural resistance (R_e) can be determined by subjecting the mechanism to a virtual displacement (w). Equating the work done by the limit load to the strain energy dissipated in the yield hinges (all hinges assumed to have the same plastic moment) results in

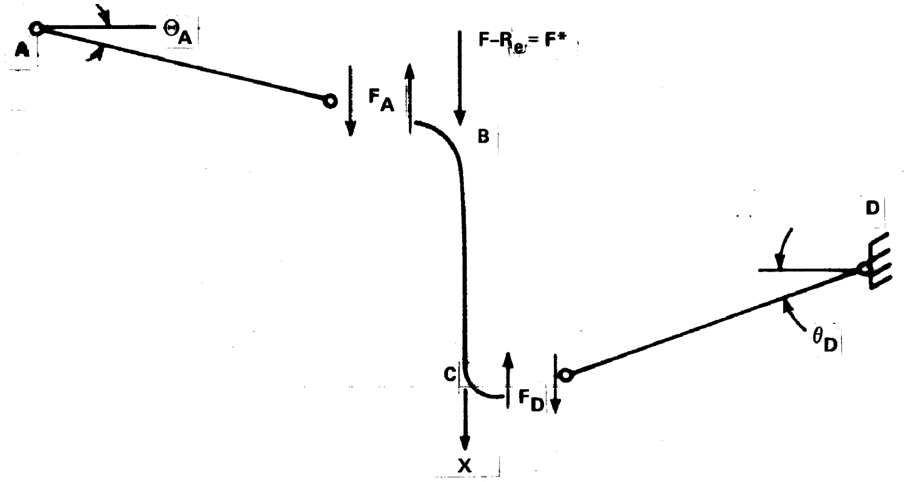
$$R_e(w) = 2M_p\theta_A + 2M_p\theta_D \qquad (3.6\text{-}13)$$

Substituting $\theta_A = {}^{w}/_{L_A}$, $\theta_D = {}^{w}/_{L_C}$, and eliminating w yields

$$R_e = 2M_p\left(\frac{1}{L_A} + \frac{1}{L_C}\right) \qquad (3.6\text{-}14)$$

If the blowdown force exceeds R_e, the system is unstable and pipe whip takes place. Section A-B will rotate clockwise about point A, and Section C-D will rotate counterclockwise about point D; in other words, the trajectory is determined assuming the runs are inextensional.

Impact velocity is determined by writing the dynamic equilibrium equations for the hinge mechanism subject to the action of the net force (blowdown force less structural resistance).



For Section A-B

$$F_AL_A = I_{AB}\ddot{\theta}_A \qquad (3.6\text{-}15)$$

For Section B-C

$$F - R_e - F_A - F_D = M_{BC}\ddot{X} \qquad (3.6\text{-}16)$$

For Section C-D

$$F_DL_C = I_{CD}\ddot{\theta}_D \qquad (3.6\text{-}17)$$

where

I = rotational mass moment of inertia of pipe about one end

$= \frac{ML^2}{3}$

M = mass of pipe

L = length of pipe

Substituting the expression for mass moment of inertia and $\theta = \chi L$, and combining the three equations, results in

$$F^* = F - R_e = \left[\frac{M_{AB}}{3} + M_{BC} + \frac{M_{CD}}{3}\right]\ddot{\chi} = M^*\ddot{\chi} \quad (3.6\text{-}18)$$

where

F^* = apparent force

M^* = apparent mass of mechanism

Having the force F^* and the apparent mass M^*, the velocity and kinetic energy at any displacement d is given by

$$V_d = \sqrt{2\frac{F^*}{M^*}d} \quad (3.6\text{-}19)$$

and the kinetic energy is given by

$$(KE)_d = \frac{M^*V_d^2}{2} = F^*d \quad (3.6\text{-}20)$$

= Work done during displacement

The formulation described above can be altered very simply to evaluate the case of a circumferential (guillotine) break at point C. In this case, the limit load for Section C-D is given by

$$R_e = \frac{M_p}{L_{CD}} \quad (3.6\text{-}21)$$

where

F^* = $F - R_e$ as before

M^* = $\frac{1}{3}M_{CD}$

and the equations for velocity and kinetic energy at any displacement can be applied as before.

The formulation above can thus be used to evaluate whether pipe whip takes place, the trajectory of the whip if formed, and the kinetic energy of the whipping pipe on impact with a target.

3.6.3.3.3 Preliminary Design of Pipe Whip Restraints

The preliminary design of pipe whip restraints designed to maintain contact with the pipe during all operating conditions were carried out using the SAP IV computer program (Reference 49). The preliminary design of pipe whip restraints designed with an initial clearance between pipe and restraints were carried out using the RAP computer program (Reference 50). The descriptions of these programs and methods for their use are given below.

3.6.3.3.4 RAP Computer Program

The RAP program performs a time-step integration solution of the dynamic equilibrium equation for a mass (the pipe) subjected to a force-time-history (the blowdown force) impacting a bilinear strain-hardening viscous-damped spring (the restraint). The pipe mass assumed in RAP is the apparent mass of the whip mechanism as described in the preceding section. The solution makes use of kinematic relationships among accelerations, velocities, and displacements at the beginning and end of each time step to reduce the second-order differential equation of motion to a form that may be solved algebraically over the time increment (References 50 and 51).

The incremental equilibrium equation for the system shown in Figure 3.6-48 is the following:

$$M\Delta\ddot{X} + C\Delta\dot{X} + K\Delta X = \Delta F \qquad (3.6\text{-}22)$$

where

M = effective mass of pipe

C = viscous damping coefficient

K = restraint stiffness

F = applied blowdown force

X = displacement

Δ = an increment of succeeding quantity

· = superscript indicating derivative w.r.t. time

In addition, if the acceleration of the mass is assumed to change linearly over a time step, the following relationships can be written:

$$\Delta\ddot{X}_{N+1} = \frac{6}{DT^2}\Delta X_{N+1} - \frac{6}{DT}\dot{X}_N - 3\ddot{X}_N \qquad (3.6\text{-}23)$$

$$\Delta\dot{X}_{N+1} = \frac{3}{DT}\Delta X_{N+1} - 3\dot{X}_N - \frac{DT}{2}\ddot{X}_N \qquad (3.6\text{-}24)$$

where the subscript "N" represents a quantity taken at the "Nth" time step and DT is the length of the time step. If Equations 3.6-23 and 3.6-24 are substituted into Equation 3.3-22, the result is

$$\left\{\frac{6M}{DT^2} + \frac{3C}{DT} + K\right\}\Delta X_{N+1} = \Delta F + \left\{\frac{6M}{DT} + 3C\right\}\dot{X}_N + \left\{3M + \frac{DT(C)}{2}\right\}\ddot{X}_N \qquad (3.6\text{-}25)$$

which can be solved for ΔX_{N+l}, since $\dot{X}_N$ and $\ddot{X}_N$ are known initial conditions at the beginning of the time step. Having ΔX_{N+l}, Equations 3.6-23 and 3.6-24 can be used to determine the change in acceleration and velocity during the time increment. At each step during the incremental process, the status of the restraint is checked to determine whether it is detached, elastically loading, plastically loading, or elastically unloading, and appropriate changes are made to the initial gap, yield deflection, and restraint stiffness.

3.6.3.3.5 SAP IV Computer Program

SAP IV (Reference 49) is a finite element computer program for linear elastic analysis of arbitrary three dimensional structures. The program includes a variety of beam, plate, shell, and solid elements. The program can consider applied static loads, thermal expansion, seismic response spectra, and time-history dynamic loads. The program numerical techniques and core storage allocation methods have been designed to permit analysis of largescale problems at reasonable cost, although smaller problems can be solved with no loss in efficiency.

3.6.3.3.6 Final Analysis of Piping System and Restraints

The final system analysis was performed to verify that the restraints selected fulfill their intended function in preventing unacceptable pipe whips, and to provide final design loads on the restraints. The final system analysis was carried out using the PIPERUP computer program (Reference 52).

The PIPERUP computer program performs nonlinear dynamic analysis of piping systems subjected to rupture thrust forces. PIPERUP can be used both to predict formation of pipe whips and to determine loads on piping anchors and pipe whip restraints. The program is based on the finite element method of analysis, with the piping represented as an assemblage of straight and curved beam elements, and the restraints as axial and rotational springs. The solution is a time-step integration of the system equations of motion.

Piping element stiffness is arranged to permit representation of elastic and linear strain-hardening material properties. Each element is initially represented as a combination of these sub-elements, whose sum stiffness equals the elastic stiffness of the pipe. If at a given time-step the element internal forces are detected to exceed the yield capacity of the pipe, one of the subelements is hinged, such that the stiffness of the remaining two subelements corresponds to the strain-hardening modulus of the material. The analysis is then continued; if the internal forces are later detected to exceed the ultimate capacity of the pipe, the second subelement is hinged, leaving a single subelement with a very small stiffness. Prediction of the yield and ultimate hinge transitions is based on a formulation derived in accordance with the von Mises theory, which considers biaxial bending and torsional stresses. In the event that unloading occurs from the plastic region, such unloading is along the elastic line (isotropic strain-hardening model). Prediction of a plastic collapse mechanism, or pipe whip, is based on detection of excessive deflections.

The modeling of restraints in the analysis can include initial gaps, and elastic and linear strain-hardening stiffnesses. The effects of impact on restraint loading are accounted for automatically in the solution technique.

Program output includes time-history values of deformation, internal loads, material strains, restraint reactions, and identification of pipe whip mechanisms.

3.6.3.4 Structural Analysis

Structural analyses were performed to assess the ability of essential plant structures and structural components to withstand loads resulting from postulated ruptures. These analyses included

a. Analysis of structural components and structures for pipe whip impacts and jet impingements

b. Analysis of structural components for compartment pressure, temperature, and hydrostatic flooding loads

c. Analysis of piping anchor structures for pipe-break loads

d. Analysis of structures and structural support systems for pipe whip restraint and jet impingement barrier reaction loads.

The criteria governing acceptability of postulated rupture loads on essential structures and structural components have been given in Subsection 3.6.2.1.5. As indicated in that section, the structural analyses are generally performed using limit analysis techniques, such as collapse load analysis for beams and frames and yield line theory for concrete slabs, which account for resistance of structural elements into their plastic range. The description of these techniques follows.

3.6.3.4.1 Characteristics of Pipe Rupture Loads

The structural loads resulting from pipe rupture can, in general, be categorized as either impulsive or impactive in nature. The time variation of impactive dynamic loads is dependent on the initial kinetic energy of the impacting body, and on the stiffness and inertial resistance of the impacting body and the structure to which the loads are applied. The time variation of impulsive dynamic loads is determined independently by factors other than structural mass or stiffness. The jet impingement, compartment pressure, and pipe restraint reaction loads resulting from pipe rupture are impulsive, while loads applied by whipping pipes are impactive. In situations where the applied force-time function is known, structural response can be computed accurately using time-history analysis techniques. This is, in fact, the case for all impulsive loads, and for certain impactive load cases. It is also possible to obtain simplified conservative solutions for many cases of practical interest. The analysis for impactive loads can be made using energy and momentum balance methods. The solution for impulsive loads can also be obtained using energy methods, or by equivalent static analysis using dynamic load factors.

3.6.3.4.2 Energy Balance Methods

Solution for structural response by energy methods is predicated on the equality:

Work Done on System = Energy Absorbed by System

The energy is absorbed as strain energy by the structure, and is equal to the area under the resistance-displacement curve (Figure 3.6-49) for the structure under load, or

$$E_S = \int_0^{X_m} R(X)dx \qquad (3.6\text{-}26)$$

where

E_s = strain energy absorbed

$R(X)$ = resistance-displacement function at point of loading

dx = deflection

X_m = maximum deflection under load

If the assumption of elastic-perfectly plastic-material properties are made, the energy absorbed is given by (see Figure 3.6-49)

$$E_s = R_e \left(X_m - \frac{1}{2} X_e \right)$$

where

R_e = resistance at yield

X_e = deflection at yield

For an elastic-plastic structure subject to initial loads, the energy absorbed is given by (see Figure 3.6-49)

$$E_s = [R_e - R_o] \left[x_m - \frac{x_e + x_o}{2} \right] \qquad (3.6\text{-}27)$$

where

R_o = equivalent resistance required for initial loads

x_o = displacement associated with R_o

3.6.3.4.3 Evaluation of Resistance-Displacement Functions

The evaluation of structure-resistance-displacement functions can be carried out using standard limit analyses techniques for most cases of practical interest. Acceptable methods for determination of resistance-displacement functions are demonstrated in two commonly encountered examples, as follows:

a. Point load on fixed-fixed beam - The resistance load at full yield for a fixed-fixed beam loaded at the center (Figure 3.6-50) can be determined using the principle of virtual work (References 53 and 54).

$$R_e = \frac{8M_P}{L} \qquad (3.6\text{-}28)$$

where

M_P = maximum section strength

L = length of beam

The deflection at yield X_e is given by

$$X_e = \frac{R_e L^3}{192EI} \qquad (3.6\text{-}29)$$

where

E = Young's modulus

I = section moment of inertia

For a steel beam, M_p is given by (see Reference 22)

$$M_p = F_y z \tag{3.6-30}$$

where

F_y = yield stress

z = plastic section modulus

For a concrete beam, M_p is given by (see Reference 55)

$$M_p = 0.9\left[(A_S - A'_s)F_y\left(d - a/2\right) + A'_s F_y (d - d')\right] \tag{3.6-31}$$

where

A_s = tensile steel reinforcing area

A'_s = compressive steel reinforcing area

F_y = steel yield stress (may be increased by dynamic increase factors)

$d - d'$ = distance between tensile and compressive reinforcing

$a = \frac{(p-p')F_y d}{0.85 f'_c}$

The above formula is predicated on the assumption that the beam is under-reinforced, or

$$(p - p') \leq 0.75 p_b \tag{3.6-32}$$

where

p = ratio of tensile steel

p' = ratio of compressive steel

p_b = balanced steel ratio

Computation of deflection for a concrete beam shall be based on the average moment of inertia for the cracked and uncracked sections, which may be approximated by (Reference 31)

$$I_a = \frac{bd^3}{2}(5.5p + 0.083) \tag{3.6-33}$$

where

b = width of beam

d = effective depth

All information necessary to quantify resistance- displacement curves for the fixed-fixed beam shown in Figure 3.6-50 is now present. Although the resistance of the beam in this example was governed by bending capability of the section, it should be noted that bending/shear interaction may substantially influence resistance of other systems, particularly where loads are applied near supports. Methods that may be used for other beam configurations and for frames are described in References 22, 53, and 54.

b. Point load on concrete slab - The resistance- displacement functions for concrete slabs may be found using yield line theory. As an example, typical yield line patterns for rectangular slabs under point loads are shown in Figure 3.6-51 (Reference 55). The yield load for a complete circular fan-type failure in an isotropically reinforced rectangular slab with equal tensile and compressive reinforcing steel is given by Reference 56.

$$R_e = 4\pi M_p \quad (3.6\text{-}34)$$

and the deflection at yield is given by

$$X_e = \frac{\alpha R_e a^2}{EI_a}(1 - \gamma^2) \quad (3.6\text{-}35)$$

The term α is dependent on the slab length-to-width ratio and may be obtained from Reference 57. Concrete slabs should also be checked for punching shear failure (see Reference 56) particularly where loads are applied close to edge supports.

3.6.3.4.4 Time-History Analysis Methods

The preceding section has described simplified analysis methods in which the energy absorption capability of the affected structure or structural component is compared to the initial kinetic energy of an impacting body or to the work done by an impulsive force. Application of the simplified methods generally requires use of conservative assumptions concerning the nature of the motive force and the strength of the structure. If necessary, the degree of conservatism can be reduced by use of a more accurate time-history analysis solution. Available time-history solutions range from simple single degree of freedom (first mode) approximations to highly detailed elasto-plastic finite element models. Nearly all time-history methods compute response to a specified force-time function, although a few solutions are available for specified initial structural velocities. Determination of forcing functions for impulsive loads is discussed in Subsection 3.6.3.4.7 and for impactive loads in Subsection 3.6.3.4.8.

3.6.3.4.5 Single Degree of Freedom Solutions

Methods are presented in Reference 31 for time-history analysis of single degree of freedom systems. Figures 2.7 through 2.9 of Reference 31 may be used to determine peak response to applied rectangular pulse, triangular pulse and ramp forcing functions for elastic systems. Where Figures 2.7 through 2.9 of Reference 31 are used to compute peak response, such response remained within elastic limits for the materials. Figures 2.23 through 2.26 of Reference 31 may be used to determine peak response to applied rectangular pulse, triangular pulse, and ramp forcing functions for elasto-plastic systems. Where Figures 2.23 through 2.26 of Reference 31 are used to compute peak response, the assumed resistance-displacement function was computed in accordance with methods described for the evaluation of resistance-displacement functions. It should be noted that the validity of the one degree of freedom response curves in Reference 31 is predicated on the assumption that dominant response occurs in the structure fundamental mode. The validity of this assumption was verified by application of the curves using the second structure mode. If peak response in the second mode exceeds 10 percent of that in the fundamental mode, a more detailed representation of the structure was used, as described below.

3.6.3.4.6 Numerical Methods of Structural Analysis

For structural problems in which the assumptions required to perform simplified analysis are excessively inaccurate or conservative, more general techniques are available in the form of automated discretization techniques. The two most common discretization techniques are finite element, wherein the structural continuum is modeled as an assemblage of discrete regions, and finite difference wherein the differential equations governing structural behavior are satisfied at discrete points. In either case, the result of the discretization process is a system of equations, generally of a size well beyond the scope of hand computations.

SAP (Structural Analysis Program) (Reference 49), a finite element computer program, was used to perform linear elastic dynamic analysis of complex structures and structural components.

3.6.3.4.7 Analysis for Impulsive Loads

As indicated previously, the analysis for impulsive loads can be carried out using energy balance techniques. As an example, the work done by an instantaneously applied constant magnitude impulsive force F in displacing a structure from rest to a maximum displacement X_m can be equated to the energy absorbed by the structure.

$$FX_m = R_e\left(\frac{X_e}{2} + (X_m - X_e)\right) \qquad (3.6\text{-}36)$$

The structure does not fail if the maximum displacement X_m is less than the ultimate displacement, or

$$X_m \leq \mu X_e \qquad (3.6\text{-}37)$$

By substituting and rearranging the two equations, we obtain the minimum required structural resistance as

$$R_e \geq \frac{F\mu}{\mu - {}^{1}/_{2}} \qquad (3.6\text{-}38)$$

where

R_e = resistance at yield

F = applied force

μ = allowable ductility ratio

It should be noted that this solution is always conservative in that it neglects both decrease in response due to finite rise time of the impulsive force, and the strain-hardening resistance of the structure. A more definitive solution may be obtained using the time-history analysis methods. Since the rise time of most impulsive loads (jet impingement and compartment pressure) resulting from pipe rupture substantially exceeds the fundamental period of the target structures, a one degree of freedom analysis is normally sufficient. Where time-history methods are used to compute response to impulsive loads, acceptability of maximum response will be governed by the ductility ratios.

3.6.3.4.8 Analysis for Impactive Loads

Overall structural response to impactive loads, such as whipping pipes, is dependent on the initial kinetic energy of the impacting body and the inertial (mass) and stiffness characteristics of the impacting body and target structure. It is appropriate to categorize impact problems in terms of the relative "hardness" (stiffness and inertial resistance) of the impacting body and target structure. Where the target structure is harder than the impacting body, the loading applied to the structure will be determined by the collapse of the impacting body. Where the impacting body is harder than the target structure, the loading on the target structure will be determined by the course of embedment of the body into the structure. Both of these cases approach what is termed plastic impact in mechanics. However, if the hardness of the impacting body and target structure is nearly equal, an elastic impact occurs. The solution for pipe impact problems may be obtained by energy/momentum balance methods, by time-history analysis methods, or by a combination of these two methods.

3.6.3.4.8.1 Analysis Using Energy and Momentum Balance

The analysis using energy and momentum balance is based on equating energy imparted to the target structure after impact to the maximum resultant strain energy. Using conservation of momentum to determine target velocity after impact we obtain

$$V_t = \frac{V_s m(1+e)}{M+m} \qquad (3.6\text{-}39)$$

where

V_t = target velocity after impact

m = effective mass of striking body (pipe)

M = effective mass of target structure

e = coefficient of restitution

V_s = velocity of striking body

Knowing target velocity after impact, the kinetic energy of the target after impact E_t is given by

$$E_t = \frac{MV_t^2}{2} \qquad (3.6\text{-}40)$$

Solution for maximum response is then found by equating the initial kinetic energy plus the work done by external forces to the strain energy at maximum displacement. For an elastic-perfectly-plastic system subject to impact, and an instantaneously applied constant magnitude force F, this equation is

$$\frac{MV_t^2}{2} + FX_m = R_e\left(\frac{X_e}{2} + (X_m - X_e)\right) \qquad (3.6\text{-}41)$$

The structure does not fail if the maximum deflection X_m obtained from the equation above is less than the ultimate deflection, or

$$X_m \leq \mu X_e \quad (3.6\text{-}42)$$

Alternatively, the structure survives if energy absorption required is less than the structure's energy absorption capability, that is,

$$\frac{MV_t^2}{2} + F\mu X_e \leq \left(R_e X_e \left(\mu - \frac{1}{2}\right)\right) \quad (3.6\text{-}43)$$

The acceptability of pipe whip impact can be conservatively evaluated for all cases based on the above equations and the following conservative assumptions:

a. Impact is elastic (e = 1)

b. The effective mass of the whipping pipe equals one-third of the mass between adjacent hinge(s) making up the pipe whip mechanism (Reference 59) for sections of pipe impacting side-on, and full mass for sections of pipe impacting end-on

c. The velocity of the pipe at impact is taken either from the piping dynamic analysis or determined using kinematic relationships

d. The effective mass of the target corresponds to that of a circular plug through the target thickness with diameter equal to pipe diameter plus target thickness (Reference 60). If the target is a beam, plug width may not exceed beam width

e. The resistance-displacement function for the target structure is computed using the energy balance methods

f. Acceptability of impact is governed by the allowable ductility factor in Table 3.6-2.

The simplified method is conservative both in assuming elastic impact (ignoring energy absorbed in local plastic deformation of the pipe and target structure on impact), and in assuming a lower limit target effective mass. A more definitive analysis is obtained by using more complex time-history analysis methods, as described in the following section.

3.6.3.4.8.2 Combined Time-History and Energy Balance Methods

In these methods, a time-history forcing function characterizing impact is established based on local deformation of the impacting body or target structure during impact. By taking into account local deformation during impact, the conservatism noted in the preceding section in assuming fully elastic impact is removed. By applying the computed forcing function in a structure dynamic response analysis, a realistic value of structure effective mass can be determined, based on the failure mechanism determined for the structure.

The case of a "hard" body impacting a relatively "soft" structure has been treated in Reference 61. This case would correspond, for example, to a heavy-walled pipe striking a thin shell.

The case of a relatively "soft" body striking a "hard" structure would correspond to a whipping pipe striking a massive concrete structure. The formulation for this analysis was derived from methods presented for evaluation of response to aircraft impact in Reference 62 and 63, and is presented below.

The force applied during impact includes a component due to blowdown thrust and an impulse component. The blowdown thrust component is simply that calculated in the thermal-hydraulic analysis previously described. The impulse component is that portion of the wall reaction that removes the kinetic energy from the pipe. It can be calculated by considering the change in momentum as the pipe crushes from length L + ΔX to length L, as shown in Figure 3.6-52.

Impulse = Change in momentum

$$F\Delta t = M_p(V - \Delta V) - \left(M_p V + \mu_S \Delta X V\right) \tag{3.6-44}$$

$$F\Delta t = -M_p \Delta V - \mu_S \Delta X V \tag{3.6-45}$$

$$F = -M_p \frac{\Delta V}{\Delta t} - \mu_S \frac{\Delta X}{\Delta t} V \tag{3.6-46}$$

$$F = -M_p a - \mu_S V^2 \tag{3.6-47}$$

Taking a force balance on the uncrushed portion of pipe

$$M_p a = K_p = \text{Crushing strength of pipe} \tag{3.6-48}$$

Then the force on the wall, F_W is

$$F_W = -F = K_p + \mu_S V^2 \tag{3.6-49}$$

where

F = $F(t)$ = impulse reaction applied to structure after impact

K_P = $K_P(x)$ = crushing strength of pipe

μ_S = $\mu_S(x)$ = mass of pipe stopped per unit of deflection

X = $X(t)$ = total distance crushed

t = time

V = velocity of uncrushed portion of pipe

M_P = mass of uncrushed portion of pipe

a = acceleration of uncrushed portion of pipe

This equation can be conservatively evaluated to find the impact force time-history based on the following assumptions:

a. The impulse reaction is applied to a target structure area with a maximum dimension not exceeding pipe diameter

b. Pipe crushing strength is based on local collapse of the pipe walls up to the point where the pipe is fully "flattened." Pipe crushing strength after "flattening" is limited to the lesser of piping or target ultimate compressive stress

c. The mass of pipe stopped can be calculated using geometric considerations up to the point where the pipe is fully "flattened." The mass of the pipe stopped after "flattening" is equal to one-third of the mass between adjacent plastic hinges for sections of pipe impacting side-on and full mass for sections of pipe impacting end-on

d. The impulse force drops to zero when the integral impulse force by time applied is equal to the initial momentum of the impacting pipe.

A typical force-time history after impact, generated in the above fashion, is shown in Figure 3.6-53. The force is equal to the blowdown force at first contact between the pipe and structure, and begins to increase thereafter as the pipe crushes. Once the pipe is fully crushed, the force rises to the limit of pipe or wall compressive strength. Once the pipe momentum is exhausted, the force drops again to the level of the blowdown thrust.

The force-time history thus determined is then applied in a time-history response analysis previously described. The time-history analysis is carried out up to formation of a plastic collapse mechanism in the target structure (up to limit load). Acceptability of the target structure response is determined using an energy balance as follows.

Work done on structure + kinetic energy of structure

= Maximum strain energy of structure

$$\int_{X_e}^{X_m} F dz + {}^1\!/_2\, MV^2 = R_e(X_m - X_e) \qquad (3.6\text{-}50)$$

where

F = applied force (see Figure 3.6-53)

Z = deflection

X_e = deflection at onset of collapse (from time-history analysis)

X_m = maximum deflection

M = effective mass of target structure (see Table 5-l from Reference 59, and Table 3.6-8)

V = velocity of target structure at onset of collapse (from time-history analysis)

R_e = limit resistance of structure

As long as F falls below R_e, the pipe kinetic energy will be reduced during impact with the structure by conversion to strain energy. Acceptability is again governed by

$$X_m \leq \mu X_e \qquad (3.6\text{-}51)$$

where μ is taken from Table 3.6-2.

3.6 PROTECTION AGAINST DYNAMIC EFFECTS ASSOCIATED WITH THE POSTULATED RUPTURE OF PIPING

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TABLE 3.6-1 SYSTEMS AND COMPONENTS REQUIRED FOR SAFE SHUTDOWN

Component or System

General Requirements

- Primary containment
- Pressure relief device
  - Safety/relief valves
  - Pressure suppression pool (passive)
- Main control room complex and control room air conditioning including intake radiation monitoring equipment
- Electrical power
  - Offsite power
  - Standby ac power
  - Emergency dc power
- Scram protection (reactor protection system)
- Control rod drive system (portion required for scam)
  - a. Turbine control valve fast signal, or
  - b. Reactor low water level signal, etc.[a]
- Core cooling
- Incident detection circuitry (start ECCS)
- RHR torus cooling mode (one loop)
- RHR service water to available RHR heat exchanger
- Core water to:
  - Diesel generator jacket cooling
  - RBCCW or EECW available to RHR pump motors
  - RBCCW or EECW available to RHR room coolers
- Instrumentation
  - Reactor water level indication
  - Temperature indication
- Control air system (noninterruptible portion – 1 division)

TABLE 3.6-1 SYSTEMS AND COMPONENTS REQUIRED FOR SAFE SHUTDOWN

Specific Requirements

For Main Steam Line Break

Flow restrictors (passive)

Isolation system control; incident detection circuitry

a. High temperature in main steam line tunnel
b. High steam line flow, or
c. Reactor low water level

Main steam line isolation valves

Feedwater check valves

Core cooling

a. HPCI
b. RHR plus remote-operated SRVs

Equipment cooling water (RBCCW or EECW) to room coolers

For Feedwater Line Break

Feedwater check valves

Isolation system control: incident detection circuitry

a. High temperature in main steam line tunnel, or
b. Reactor low water level

Main steam line isolation valves

Core cooling

a. HPCI
b. RHR

Equipment cooling water (RBCCW or EECW) to RHR room coolers

For High Pressure Coolant Injection System (HPCI) Steam Line Break

Isolation system control; incident detection circuitry

a. High temperature in HPCI steam line chase, or
b. High HPCI steam line flow, or
c. HPCI turbine steam line low pressure

HPCI isolation valves

Core cooling

a. RHR plus remote-operated SRVs

TABLE 3.6-1 SYSTEMS AND COMPONENTS REQUIRED FOR SAFE SHUTDOWN

RBCCW or EECW to room coolers

For Reactor Core Isolation Cooling System (RCIC)

Steam Line Break

Isolation systems control; incident detection circuitry

a. High temperature in RCIC steam line chase, or

b. High RCIC steam line flow, or

c. RCIC turbine steam line low pressure

RCIC isolation valves

Core cooling

a. HPCI plus remote-operated relief valves

b. RHR

RBCCW or EECW to HPCI room coolers

For Reactor Water Cleanup System (RWCU) Line Break

Isolation system control; incident detection circuitry

a. Flow imbalance, or

b. Low reactor water level, or

c. High temperature in RWCU pipe chase

RWCU isolation valves

Core cooling

a. HPCI and remote-operated relief valves, or

b. RHR plus remote-operated relief valves

RBCCW or EECW to HPCI room cooler

RBCCW or EECW to RCIC room cooler

---

[a] RPS trip signals resulting from loss of coolant:

1. Reactor vessel low water level
2. Main steam isolation valve closure
3. Primary containment (drywell) high pressure.

TABLE 3.6-2 MAXIMUM DUCTILITY FACTORS

1. Tension reinforced concrete beams and slabs (flexure controls design)
   $\mu = \frac{0.05}{p}$; $\mu \leq 12.5$

2. Doubly reinforced concrete beams and slabs (flexure controls design)
   $\mu = \frac{0.05}{p-p'}$; $\mu \leq 15.0$

3. Concrete beams and slabs in region requiring shear reinforcement
   a. Shear carried by concrete and stirrups — $\mu = 1.3$
   b. Shear carried completely by stirrups — $\mu = 3.0$

4. Concrete columns — $\mu = 1.3$

5. Structural steel tension members — $\mu = 0.5 \frac{\varepsilon_u}{\varepsilon_y}$

6. Structural steel flexural members
   a. Open sections (I, WF, T, etc.) — $\mu \leq 12.5$
   b. Closed sections (pipe, box, etc.) — $\mu \leq 25.0$
   c. Members where shear governs design — $\mu \leq 6.0$

7. Structural steel columns
   $\mu \leq 1.0$ for $\ell/r < 30$
   $\mu \leq 3.0$ for $30 \leq \ell/r \leq 60$
   $\mu \leq 6.0$ for $\ell/r > 60$

Notes

A_s = Area of tension reinforcement
A'_s = Area of compressive reinforcement
b = Width of section
d = Depth of section to reinforcement
p = Percentage tensile reinforcement
p' = Percentage compression reinforcement
$\mathcal{E}u$ = Uniform ultimate strain of material
$\mathcal{E}y$ = Strain at yield of material
ℓ = Effective length of column
r = Radius of gyration
(See AISC-69 Specifications)

TABLE 3.6-3 DYNAMIC INCREASE FACTORS (DIF)

I.	Reinforced or Prestressed Concrete	DIF
	Concrete	
	Compression	1.25
	Diagonal tension and direct shear (punch out)	1.0
	Bond	1.0
	Reinforcing Steel	
	Tension	1.2
	Compression	1.2
	Diagonal tension and direct shear (stirrups)	1.0
II.	Structural Steel	
	Flexure and tension	1.2
	Compression	1.2
	Shear	1.0

TABLE 3.6-4 REASONS FOR EXCLUSIONS

Index No.	Reasons	Explanation
(R1)	Separation	System in separate compartment.
(R2)	Distance	System separated by distance but in the same compartment.
(R3)	Redundancy	System function can be performed by two or more identical units.
(R4)	Back-up	System function can be replaced by the function of a different system.
(R5)	Self-eliminating	Pipe rupture caused damage only to the system itself.
(R6)	Size criteria	Pipe of an equal or larger diameter and equal or heavier wall thickness than the broken pipe is considered not damaged.
(R7)	Low pressure	Pressure inside the pipe is too low to cause a pipe whip.
(R8)	Barrier	System protected by barrier.
(R9)	Testing condition	Pipe line used only at testing condition or emergency condition, etc.
(R10)	Scarcity of usage	Duration of operation of the pipe is less than 2 percent of the duration of reactor operation.
(R11)	Safe area	Pipe routing in area where no system related with safe shutdown is located.
(R12)	Minimum size	Pipe smaller than 4 in. is not required for the analysis of longitudinal pipe break or pipe equal to or less than 1 in. is not required for the analysis of circumferential break.

[a] Index number used for permanent identification of components excluded from further consideration.

TABLE 3.6-5 LOADING COMBINATIONS FOR ELASTIC DESIGN OF STEEL STRUCTURES AND ULTIMATE STRENGTH OF CONCRETE STRUCTURES (STEAM TUNNEL)[a]

Load Combination Number	Overall Loading Equation[b]
	Elastic Design of Steel Structures
1	$1.5\ S = D + L + T_a + R_a + P_a$
2	$1.5\ S = D + L + T_a + R_a + P_a + 1.0\ (Y_j + Y_r + Y_m) + Feqo$
3	$1.5\ S = D + L + T_a + R_a + P_a + 1.0\ (Y_j + Y_r + Y_m) + Feqs$
	Ultimate Strength of Concrete Structures
1	$U_1 = D + L + T_a + R_a + 1.0\ P_a$
2	$U_1 = D + L + T_a + R_a + 1.0\ P_a + 1.0\ (Y_r + Y_j + Y_m) + 1.0\ Feqo$
3	$U_1 = D + L + T_a + R_a + 1.0\ P_a + 1.0\ (Y_r + Y_j + Y_m) + 1.0\ Feqs$

Symbols

D	Dead load of the structure, including any permanent equipment loads
Feqo	Loads generated by operating-basis earthquake
Feqs	Loads generated by the safe-shutdown earthquake
L	Live loads
P_a	Compartmental pressure due to pipe break
R_a	Pipe reaction under thermal conditions due to pipe rupture and including pipe reactions during normal operating conditions
T_a	Thermal loads due to pipe rupture and including thermal loads during normal operating conditions
Y_j	Jet impingement due to pipe rupture
Y_m	Missile effects due to pipe rupture
Y_r	High-energy pipe break reactions
S	Section strength based on elastic design methods and the allowable stresses as described in the AISC
U_1	Section strength based on ultimate strength design methods as described in ACI 318-63

[a] Loads not applicable to a particular system under consideration may be deleted.

[b] Effects for time-dependent loads will be superimposed accordingly.

TABLE 3.6-6 FLOW AND EVENTS POSTULATED FOR FEEDWATER BREAK

Approximate Time (sec)	Flow Rate (gpm)	Event
0		Break
0+	43,000	o Feedwater flow jumps to 43,000 GPM o RFP tripped on low suction pressure
7	43,000	o Reactor water level (L3) trip initiates a SCRAM trip o SCRAM trip initiates closure of feedwater pump discharge valves o Post SCRAM feedwater control automatically put into service
14	43,000	Steam tunnel leak detection system temperature exceeded.
22	43,000	After an 8.0 second instrument channel response time MSIV closure is initiated.
26	43,000	Vessel water level (L2) trip initates HPCI and RCIC operation. RCIC is not taken credit for in the scenario, since it is not environmentally qualified and because the NE corner room is affected by flooding.
32	43,000	After a 10 second MSIV closure time, the MSIVs are fully closed.
56	43,000	After the HPCI initiation signal, HPCI reaches rated flow within 30 to 60 sec. Fifty-six sec corresponds to the assumption of a 30 sec response time.
57	21,800	After an 8-second delay (in addition to the 30-second post scram delay) and a 12-second closure time, fast closure valves V12-2531 and V12-2532 are closed and all flow is forced through the start up level control valve.
64	20,000	The number 5 feedwater heater level control valves are closed and flow through the heater drain pumps is isolated from the break.
117	20,000	The RFP slow closure discharge valves are fully closed (V12-2503, V12-2504). This has no effect on the break flow but is noted to provide assurance that failure of the fast closure valves would not be as severe as failure of the start up control valve. Closure of these valves requires 80 seconds plus a 30 second delay.

TABLE 3.6-6 FLOW AND EVENTS POSTULATED FOR FEEDWATER BREAK

Approximate Time (sec)	Flow Rate (gpm)	Event
279	20,000	Reactor water level is restored by HPCI, which would close the startup control valve had it not been assumed to fail. Two hundred seventy-nine sec corresponds to the assumption of a 30 sec response HPCI time. This time may be up to 30 sec longer, assuming a 60 sec HPCI response time.
447	20,000	Condensate and heater feed pumps trip on low hotwell level and pumped flow is assumed to decrease to zero.
		The water inventory (13725 gal.) downstream of the RFPs is assumed to be discharged from the break over 1 minute period by gravity flow.
507	0	The water inventory in the piping is totally discharged.
	185,734 gallons	

TABLE 3.6-7 FEEDWATER LINE BREAK IN STEAM TUNNEL MAXIMUM FLOOD HEIGHT

Affected Area	Flood Elevation, ft	Flood Depth, in.
Steam Tunnel	587.98	53.7
RBCCW Room	587.31	45.8
NE Corner Room	546.74	80.9
SE Corner Room	554.08	169.0
Torus Room	541.23	14.8
HPCI Room	546.57	78.8

Note: This table lists maximum flood heights for each area, maximum heights do not occur simultaneously for all rooms.

TABLE 3.6-8 NON-SAFETY SYSTEMS NOT INVOLVED IN THE HIGH-ENERGY PIPE ANALYSIS

Rod worth minimizer

Plant process computer

Area radiation monitors

Transient recording and analysis (TRA)

Offgas

Radwaste solidification

Heat-tracing

Fuel-handling equipment

Fuel pool cooling

Maintenance monorails and hoists

Seismic measurement equipment

Turning gear

Generator

Generator hydrogen seal oil

Generator cooling

Generator buses

Generator excitation

Demineralized water

Sampling

Plant heating

Heating and process steam

Security

Communications

Integrated leak-rate test

Cooling tower

Screen wash

Circulating water screens and trash rakes

Hot machine shop

Switchyard

Tornado roof vents

Plant lighting

TABLE 3.6-9 EQUIVALENT MASS FOR COLLAPSED SECTIONS

Member	m_e
Beam or one way slab uniformly distributed load	
Restrained at supports	0.667 m
Simple at supports	0.667 m
Beam or one way slab concentrated load at center	
Restrained at supports	0.333 m
Simple at supports	0.333 m
Rectangular slab (b x a) [a, b] uniformly distributed load	
Restrained at four sides	$\frac{1}{2}\ \Sigma m_{\Delta} + \frac{(4b-3a)}{6b-4a}\ \Sigma m_{▱}$
Simple at four sides	$\frac{1}{2}\ \Sigma m_{\Delta} + \frac{(4b-3a)}{6b-4a}\ \Sigma m_{▱}$
Rectangular slab with concentrated load	$\frac{1}{6}\ \Sigma m_{\Delta}$

(a) $\frac{b}{2} \leq a \leq b$

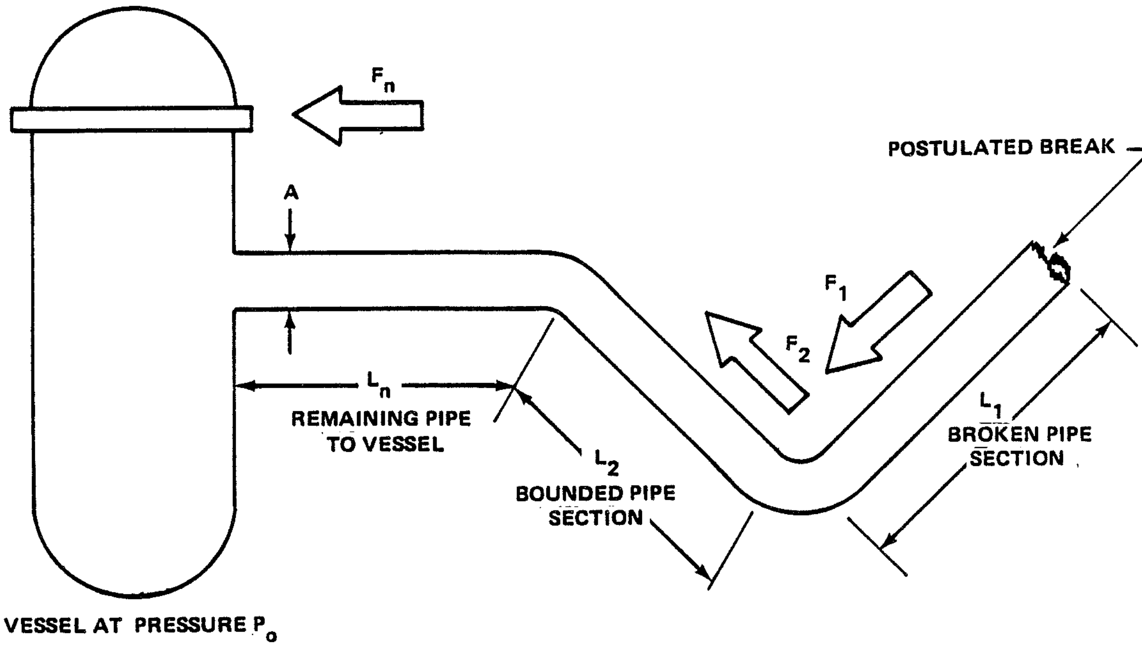
(b) $\frac{b}{2} \geq 1.0$

Notes

M = total mass of beam or slab

m_{Δ} = mass of triangular sections in yield line pattern

$m_{▱}$ = mass of trapezoidal sections in yield line pattern



A	UNIFORM PIPE FLOW AREA
F_1	BROKEN PIPE REACTION
F_2 —F_n	BOUNDED PIPE REACTIONS

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FIGURE 3.6-1

PRESSURE VESSEL AND BROKEN PIPE CIRCUMFERENTIAL BREAK

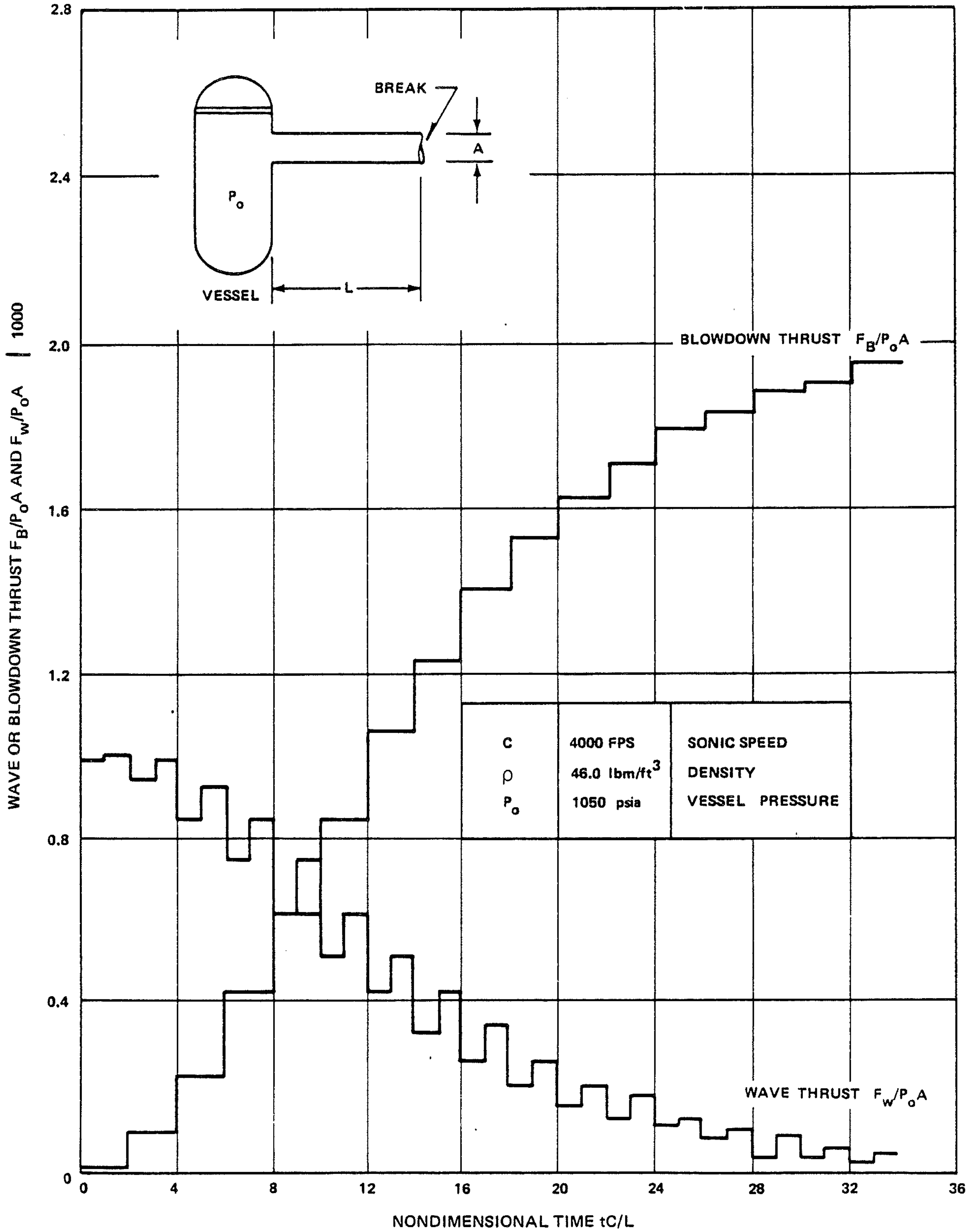

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FIGURE 3.6-2

THRUST COMPONENTS, SINGLE STRAIGHT PIPE, NONFLASHING LIQUID

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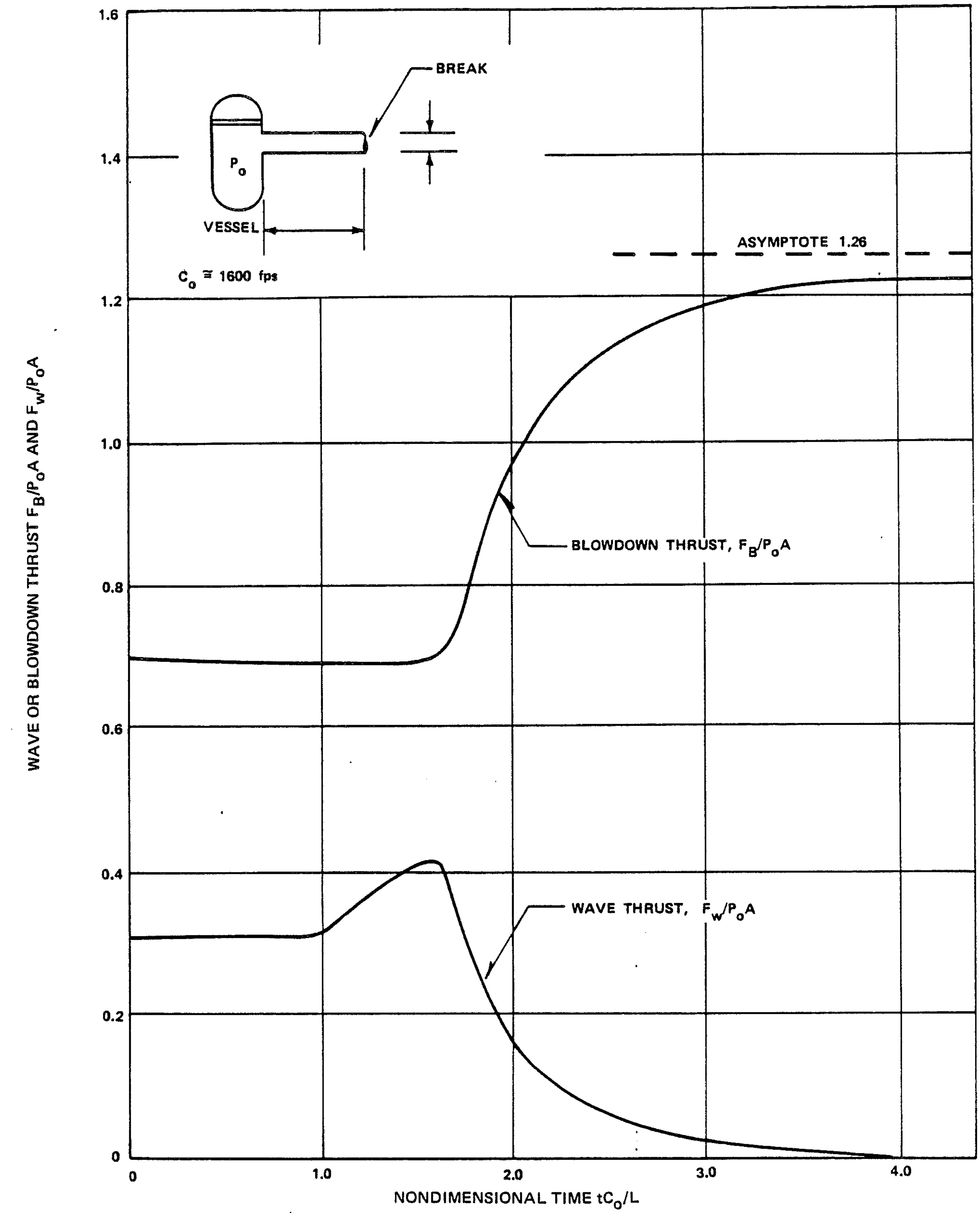

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FIGURE 3.6-3

THRUST COMPONENTS, SINGLE STRAIGHT PIPE, STEAM

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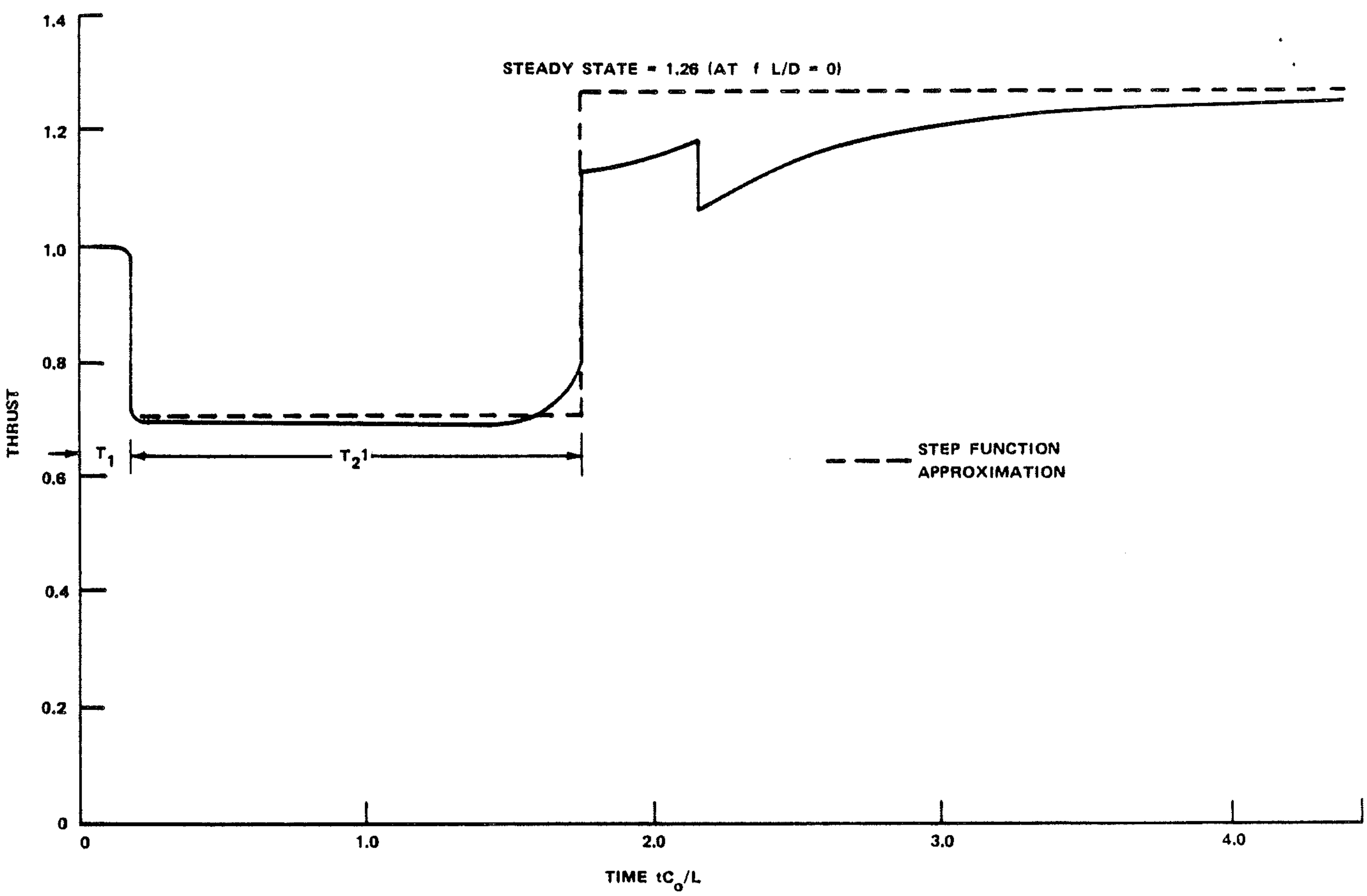

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FIGURE 3.6-4

TIME-THRUST DIAGRAM FOR A LINE CONTAINING STEAM – CIRCUMFERENTIAL BREAK

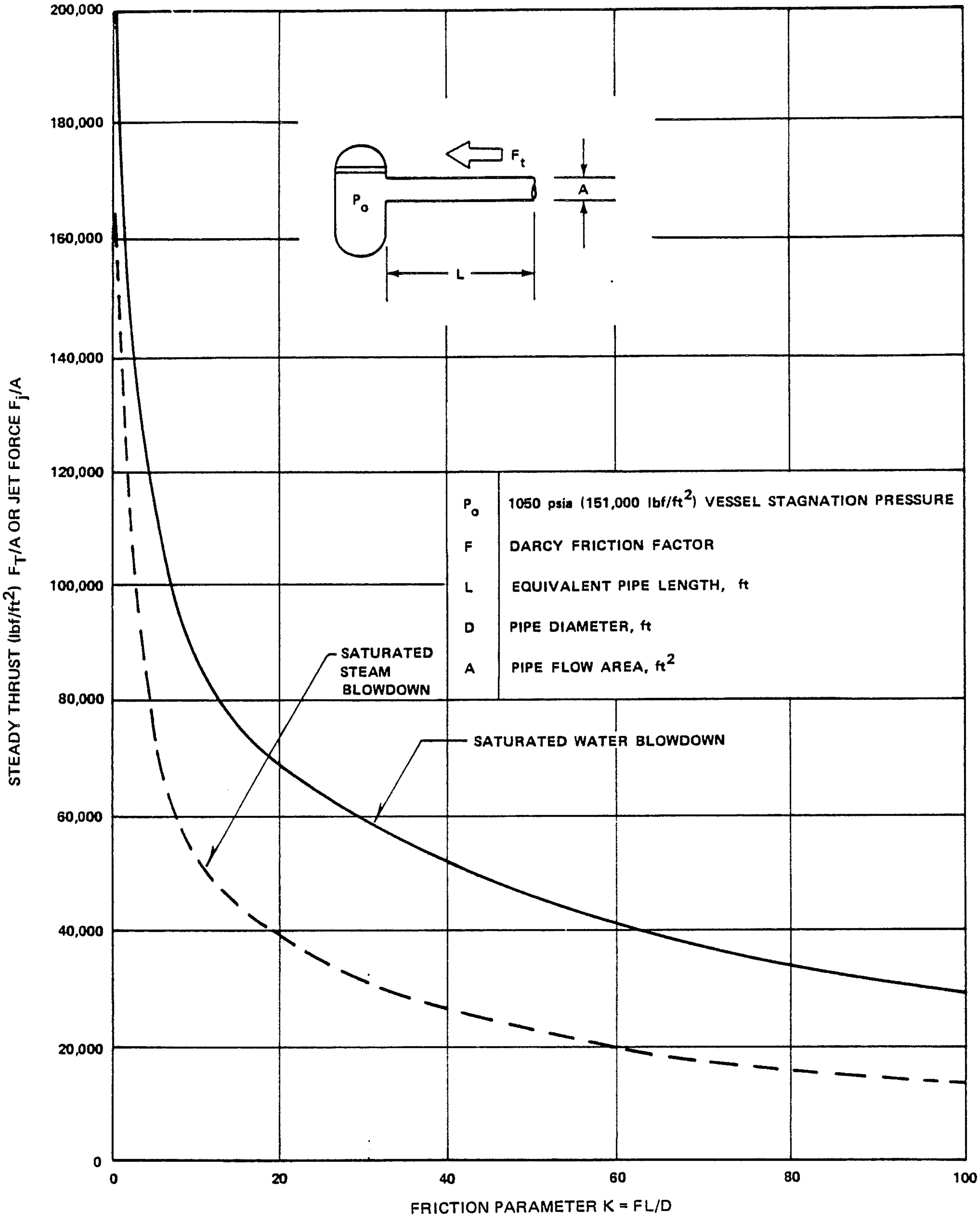

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FIGURE 3.6-5

STEAM-WATER TOTAL STEADY THRUST PER UNIT AREA

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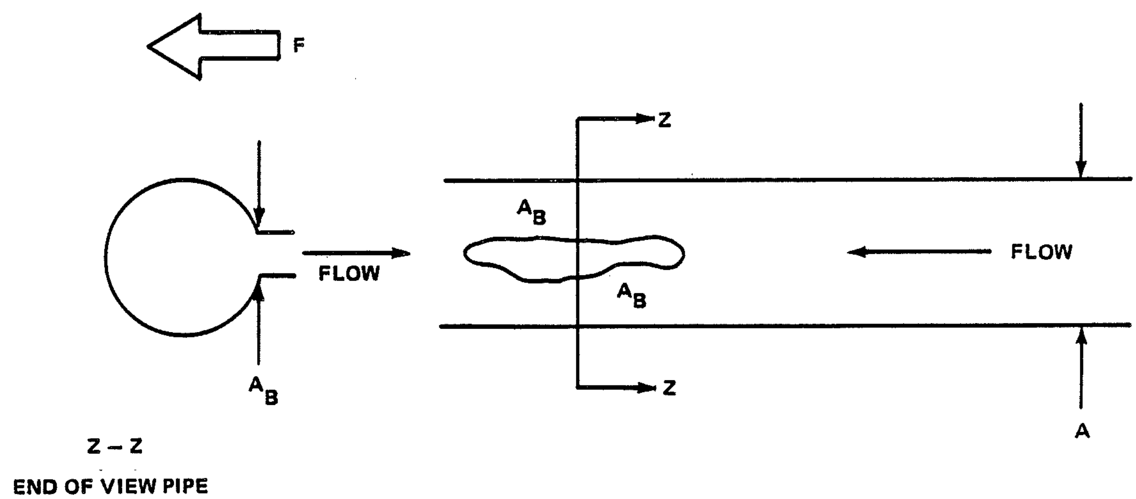

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FIGURE 3.6-6

LONGITUDINAL BREAK

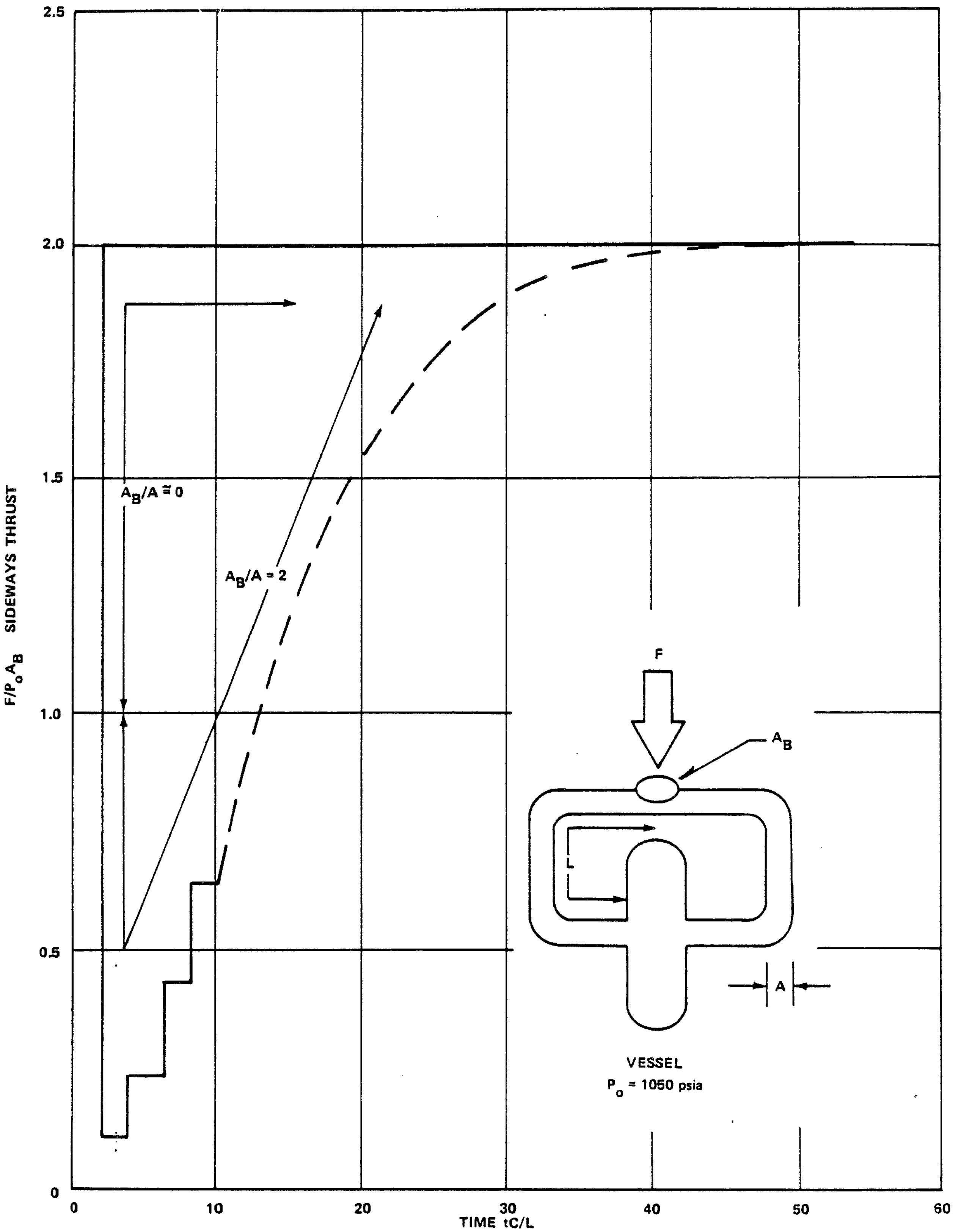

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FIGURE 3.6-7

THRUST FOR LONGITUDINAL BREAK IN WATER PIPE

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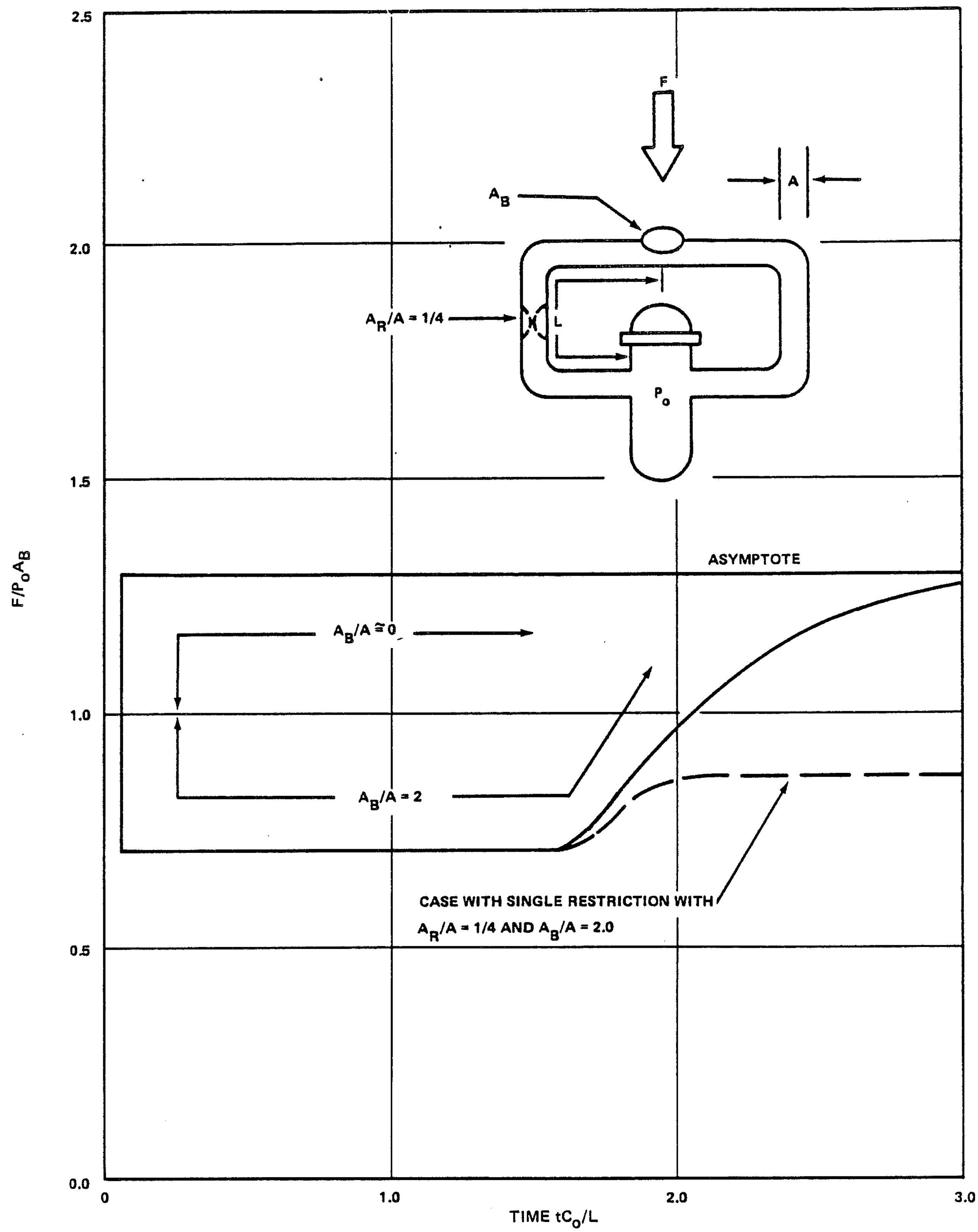

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FIGURE 3.6-8

THRUST FOR LONGITUDINAL BREAK IN STEAM PIPE EXCLUDING EFFECTS OF FRICTION

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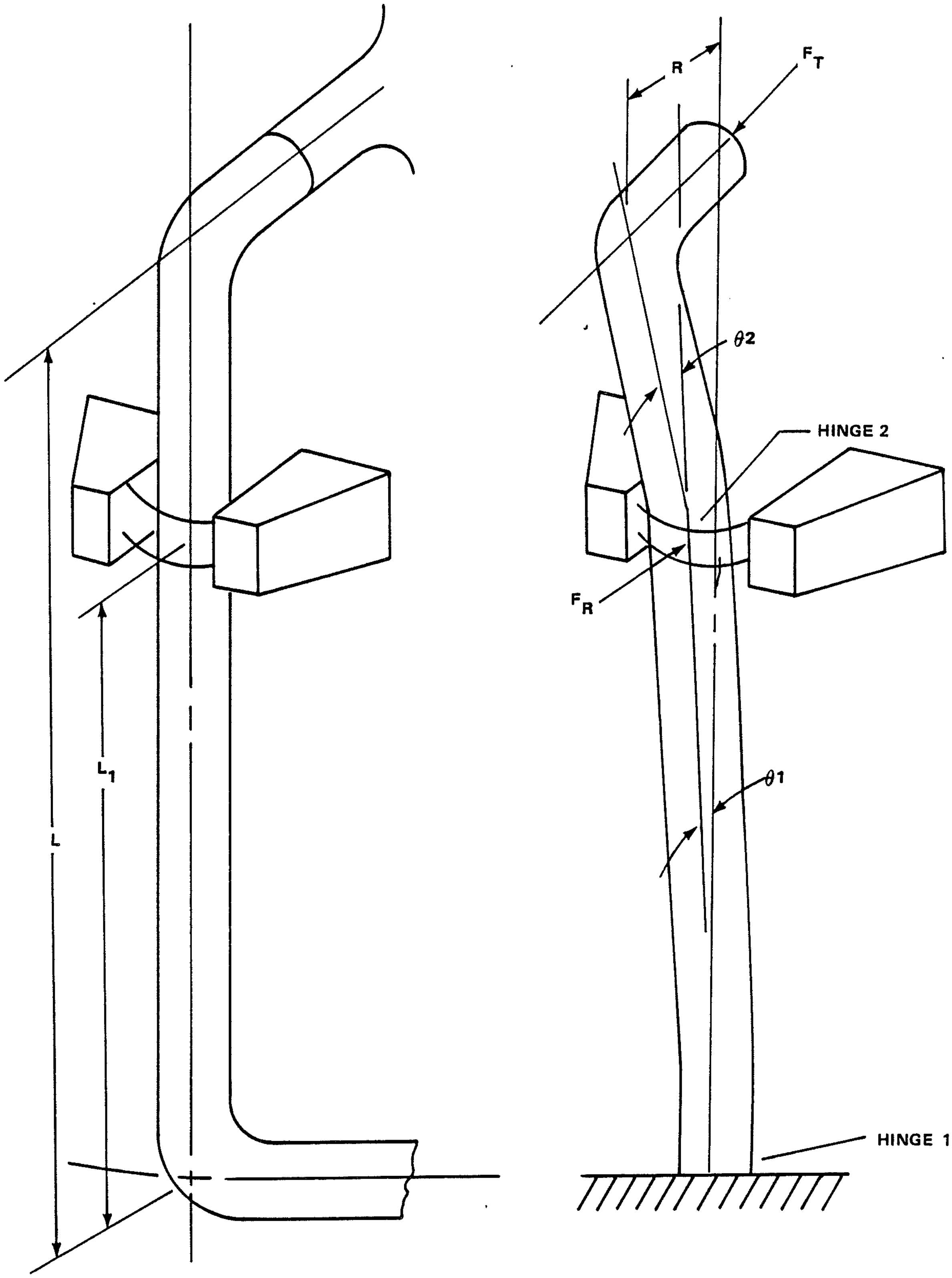

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FIGURE 3.6-9

PIPE/RESTRAINT CIRCUMFERENTIAL BREAK MODEL

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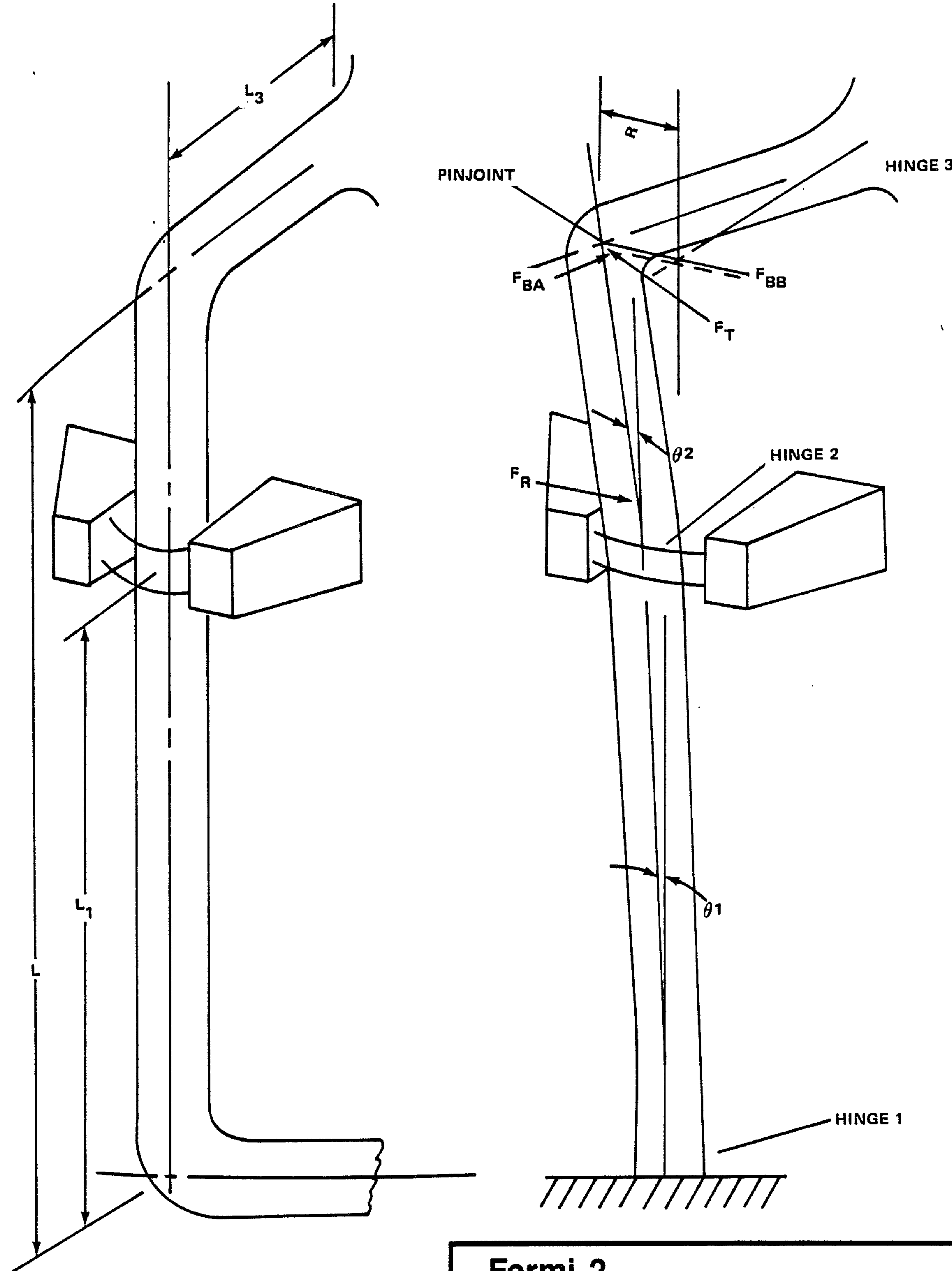

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FIGURE 3.6-10

PIPE/RESTRAINT LONGITUDINAL BREAK MODEL

GENERAL ELECTRIC COMPANY DRAWING

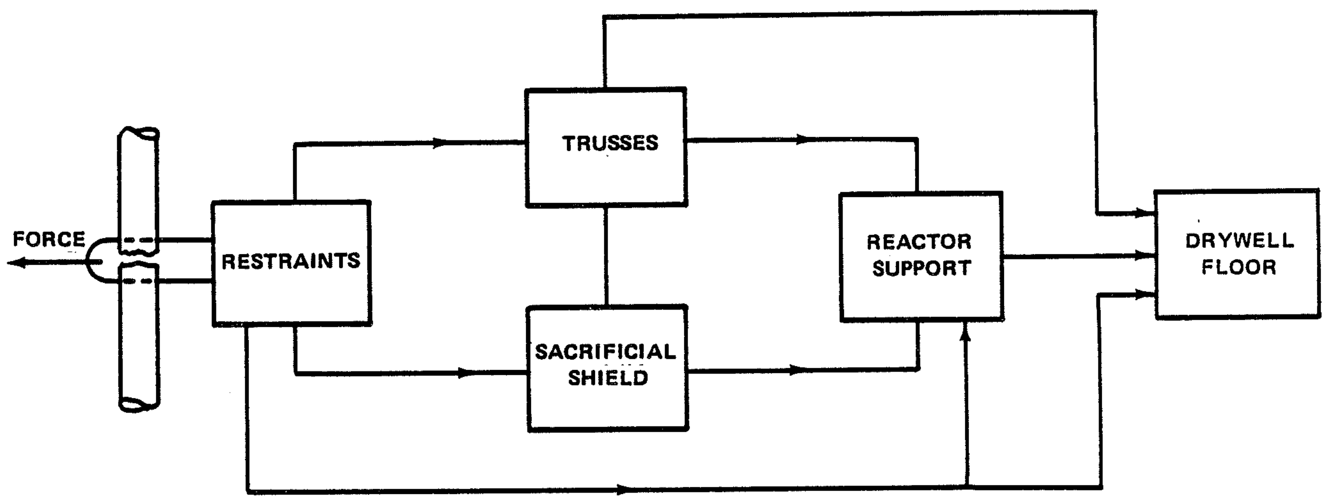

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FIGURE 3.6-11

PIPE WHIP RESTRAINT SUPPORT SYSTEM SCHEMATIC

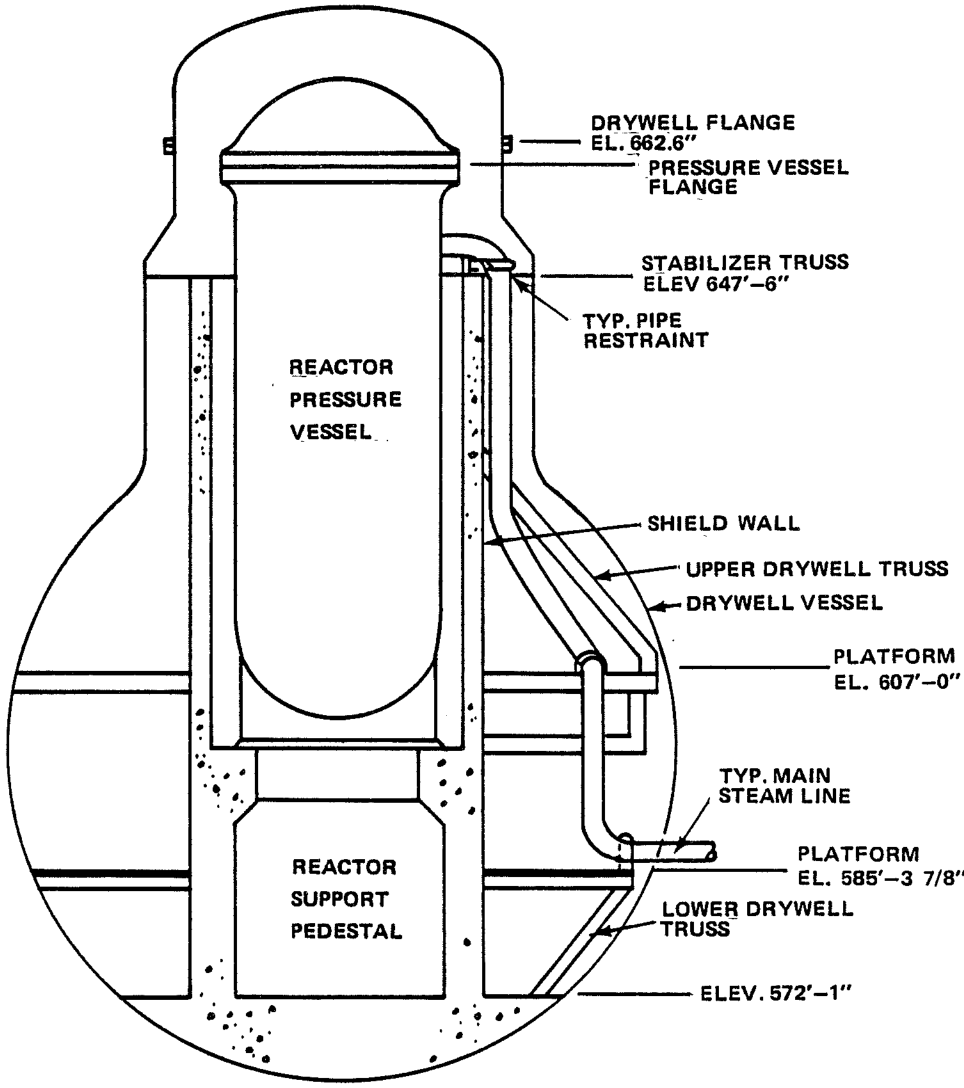

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FIGURE 3.6-12

PIPE WHIP RESTRAINT SUPPORT SYSTEM
DRYWELL SECTION

Figure Intentionally Removed
Refer to Plant Drawing RX BLDG ROOM LOCATIONS

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FIGURE 3.6-13

SELECTIVE ROOM LOCATIONS
REACTOR BUILDING SUBBASEMENT
ELEVATION 540.0 FT

Figure Intentionally Removed
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FIGURE 3.6-14

SELECTIVE ROOM LOCATIONS
REACTOR BUILDING BASEMENT
ELEVATION 565.0 FT

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FIGURE 3.6-15

SELECTIVE ROOM LOCATIONS
REACTOR BUILDING FIRST FLOOR
ELEVATION 583.5 FT

Figure Intentionally Removed
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FIGURE 3.6-16

SELECTIVE ROOM LOCATIONS
REACTOR BUILDING SECOND FLOOR
ELEVATION 613.5 FT

Figure Intentionally Removed
Refer to Plant Drawing RX BLDG ROOM LOCATIONS

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FIGURE 3.6-17

SELECTIVE ROOM LOCATIONS
REACTOR BUILDING THIRD FLOOR
ELEVATIONS 643.5 FT AND 641.5 FT

Figure Intentionally Removed
Refer to Plant Drawing RX BLDG ROOM LOCATIONS

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FIGURE 3.6-18

SELECTIVE ROOM LOCATIONS
REACTOR BUILDING FOURTH FLOOR
ELEVATION 659.5 FT

Figure Intentionally Removed
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FIGURE 3.6-19

SELECTIVE ROOM LOCATIONS
REACTOR BUILDING FIFTH FLOOR
ELEVATIONS 677.5 FT AND 684.5 FT

Figure Intentionally Removed
Refer to Plant Drawing STEAM TUNNEL SKETCH

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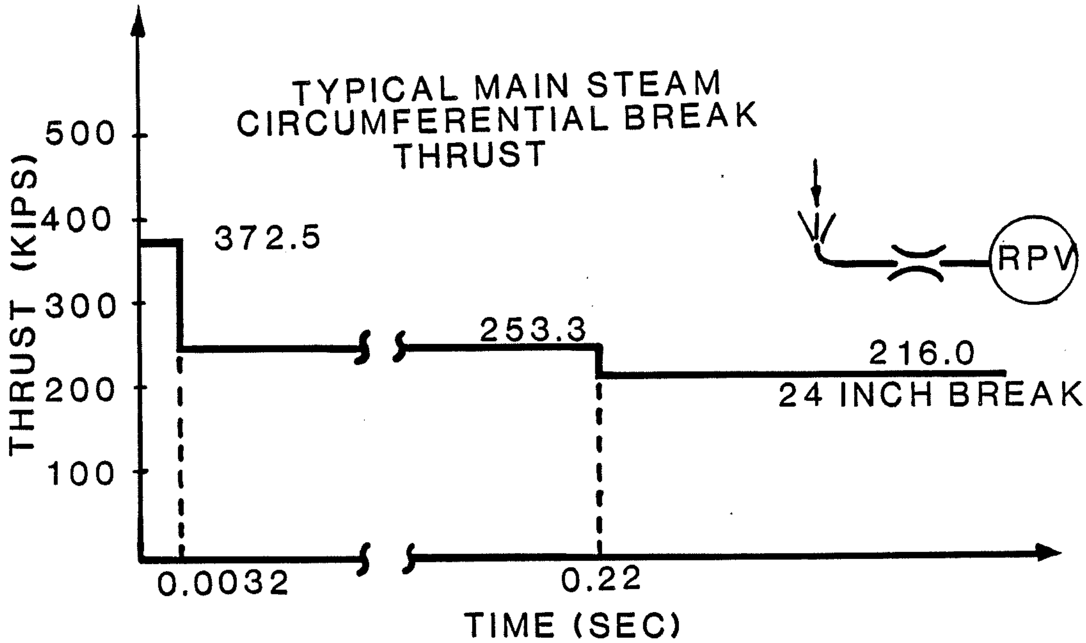
FIGURE 3.6-20

MAIN STEAM PIPING IN STEAM TUNNEL



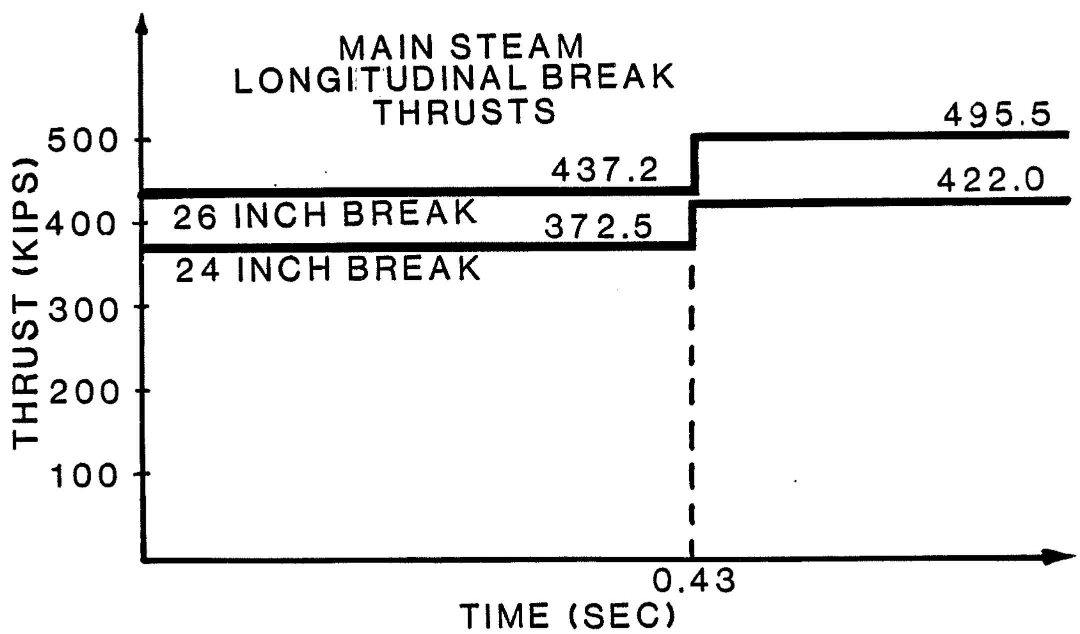


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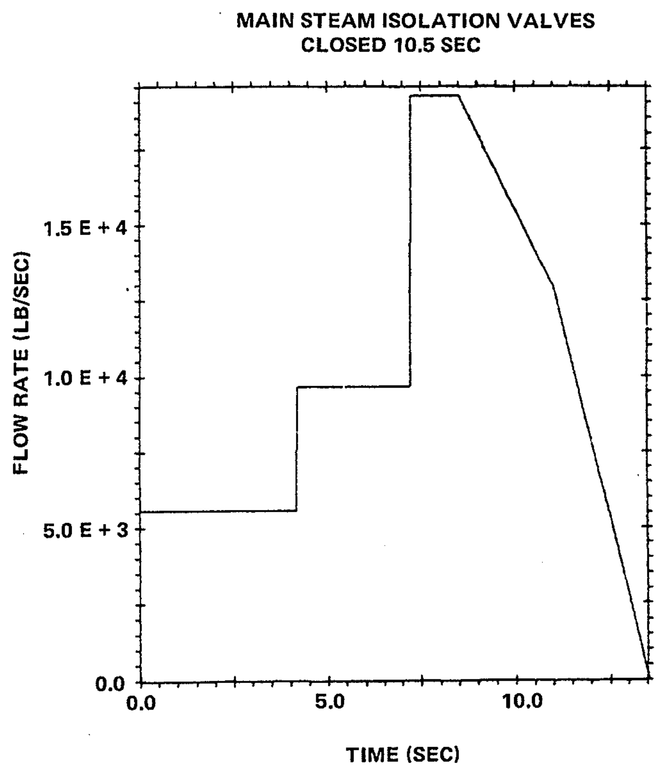
FIGURE 3.6-21

TYPICAL THRUST TIME HISTORIES
MAIN STEAM LINE BREAK



Note: The above blowdown history corresponds to 1050 psia dome pressure. For 1060 psia dome pressure (power uprate conditions), the blowdown rate will be 1% higher.

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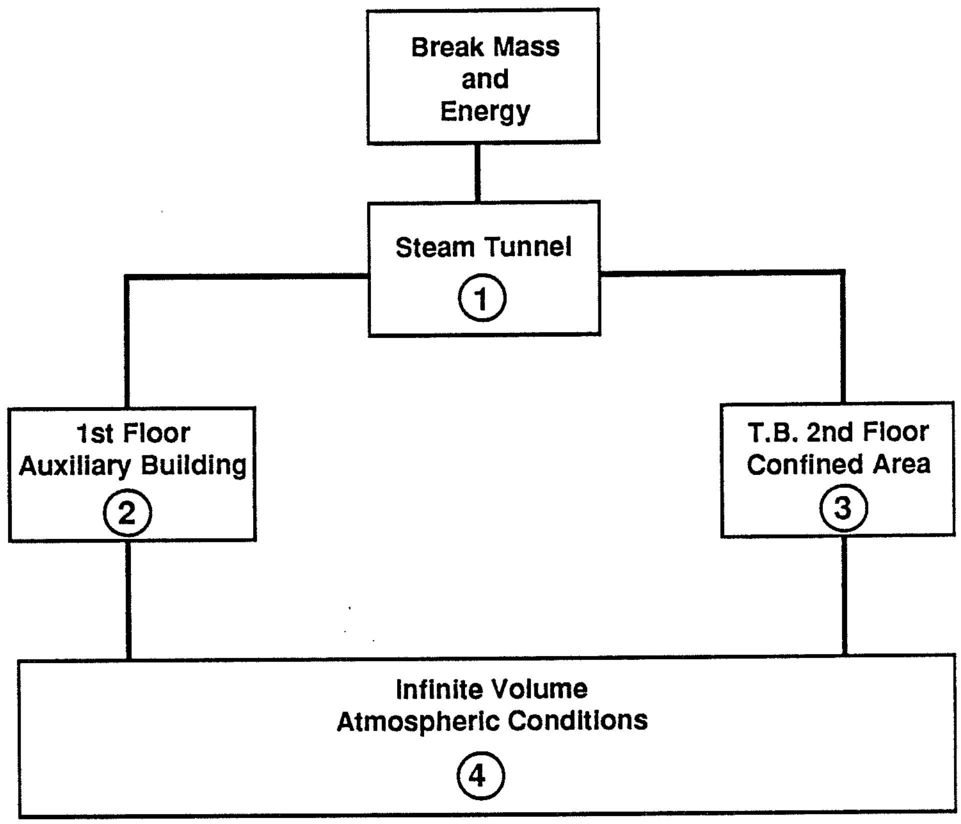
FIGURE 3.6-22

BREAK FLOW RATES AFTER MAIN STEAM LINE BREAK



NOTES:

◯ Indicates Control Volume Number

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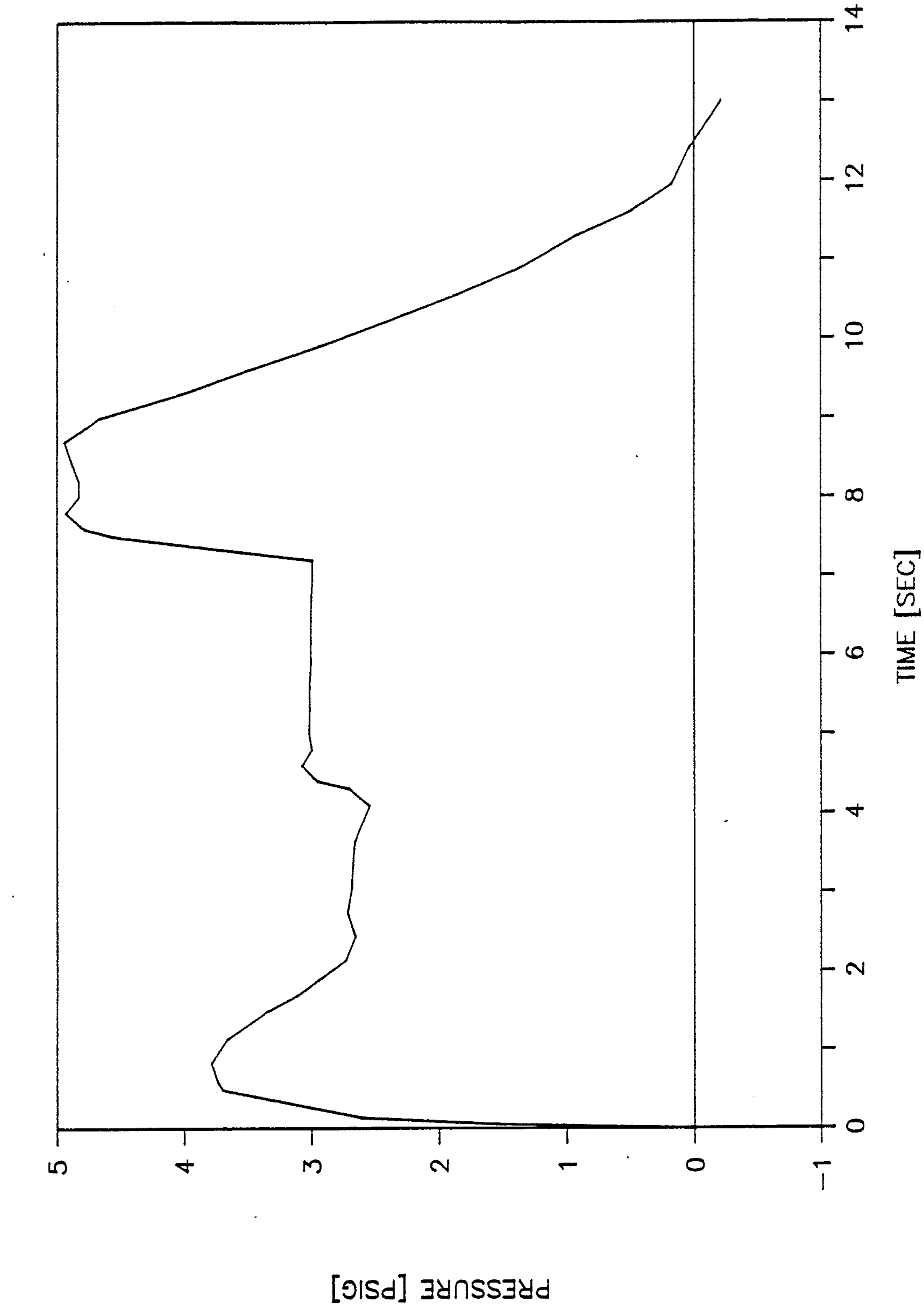
FIGURE 3.6-23

MAIN STEAM LINE BREAK IN THE STEAM TUNNEL - MATHEMATICAL MODEL



Note: The pressure transient corresponds to 1050 psia steam dome pressure. For 1060 psia dome pressure (power uprate conditions), the peak pressure will be 5.1 psig.

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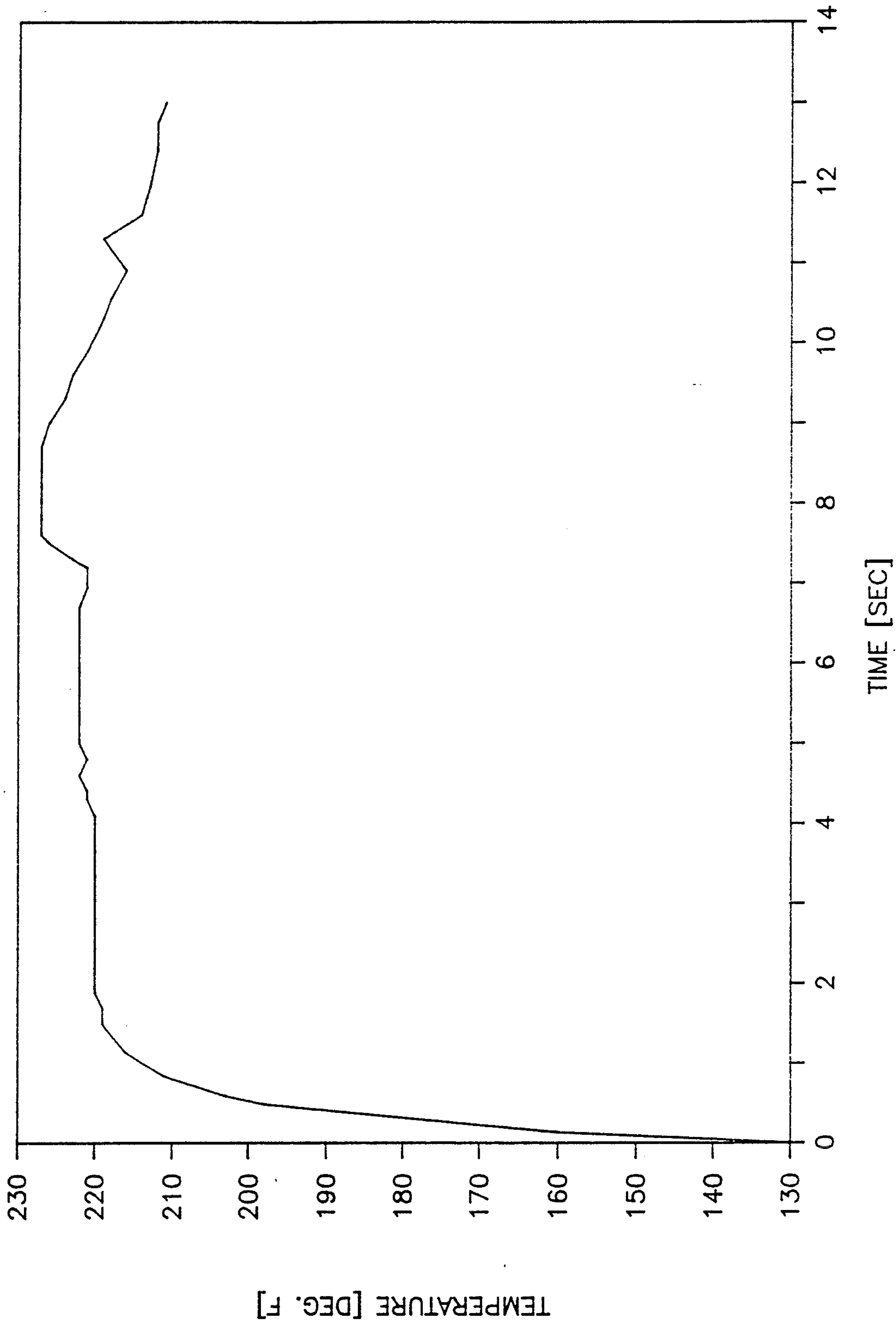
FIGURE 3.6-24

STEAM TUNNEL PRESSURE AFTER STEAM LINE BREAK



Note: The temperature transient corresponds to 1050 psia steam dome pressure. For 1060 psia dome pressure (power uprate conditions), the peak temperature will be 228°F.

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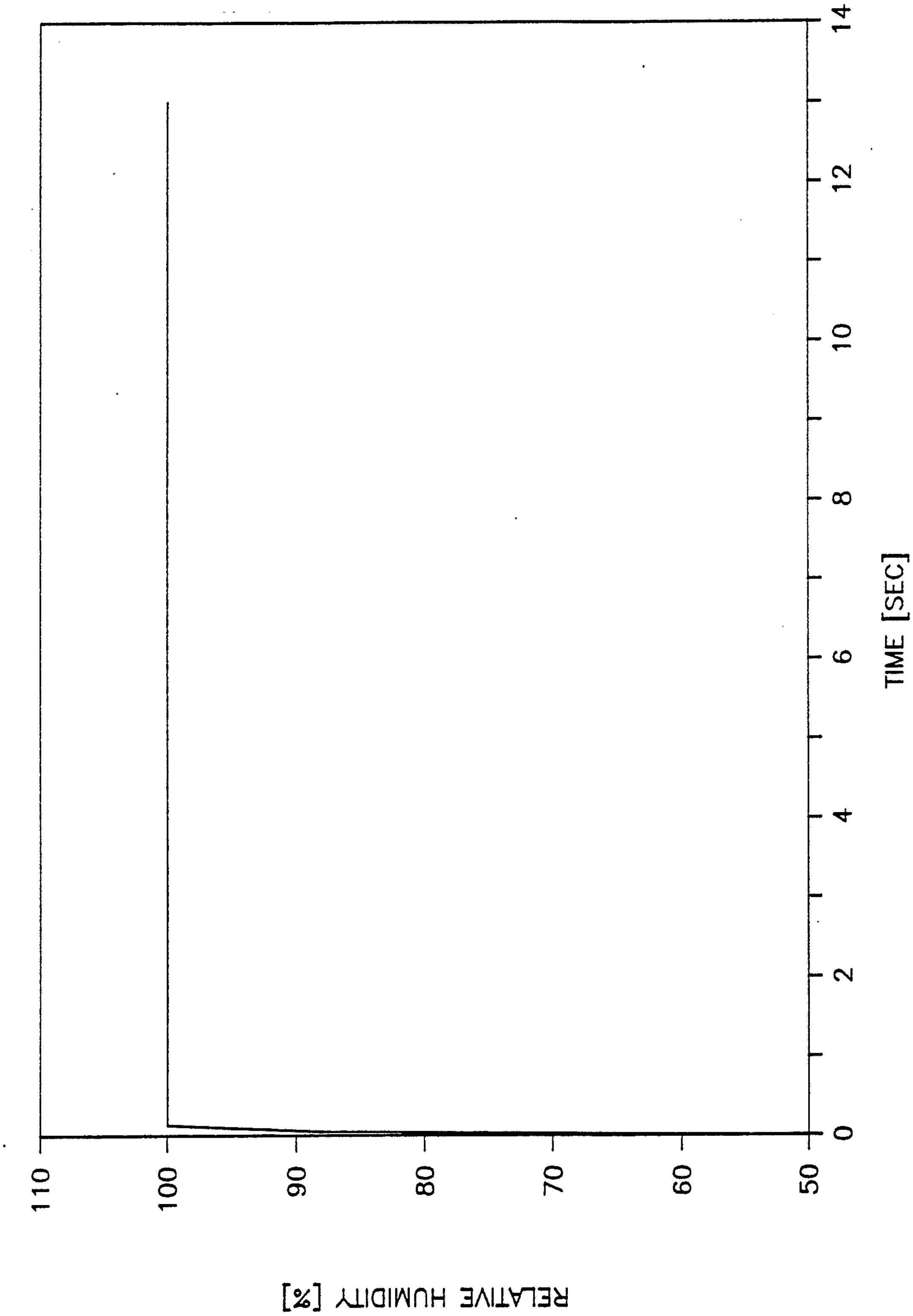
FIGURE 3.6-25

STEAM TUNNEL TEMPERATURE AFTER MAIN STEAM LINE BREAK



Note: The relative humidity profile corresponds to 1050 psia steam dome pressure. For 1060 psia dome pressure (power uprate conditions), the profile remains the same.

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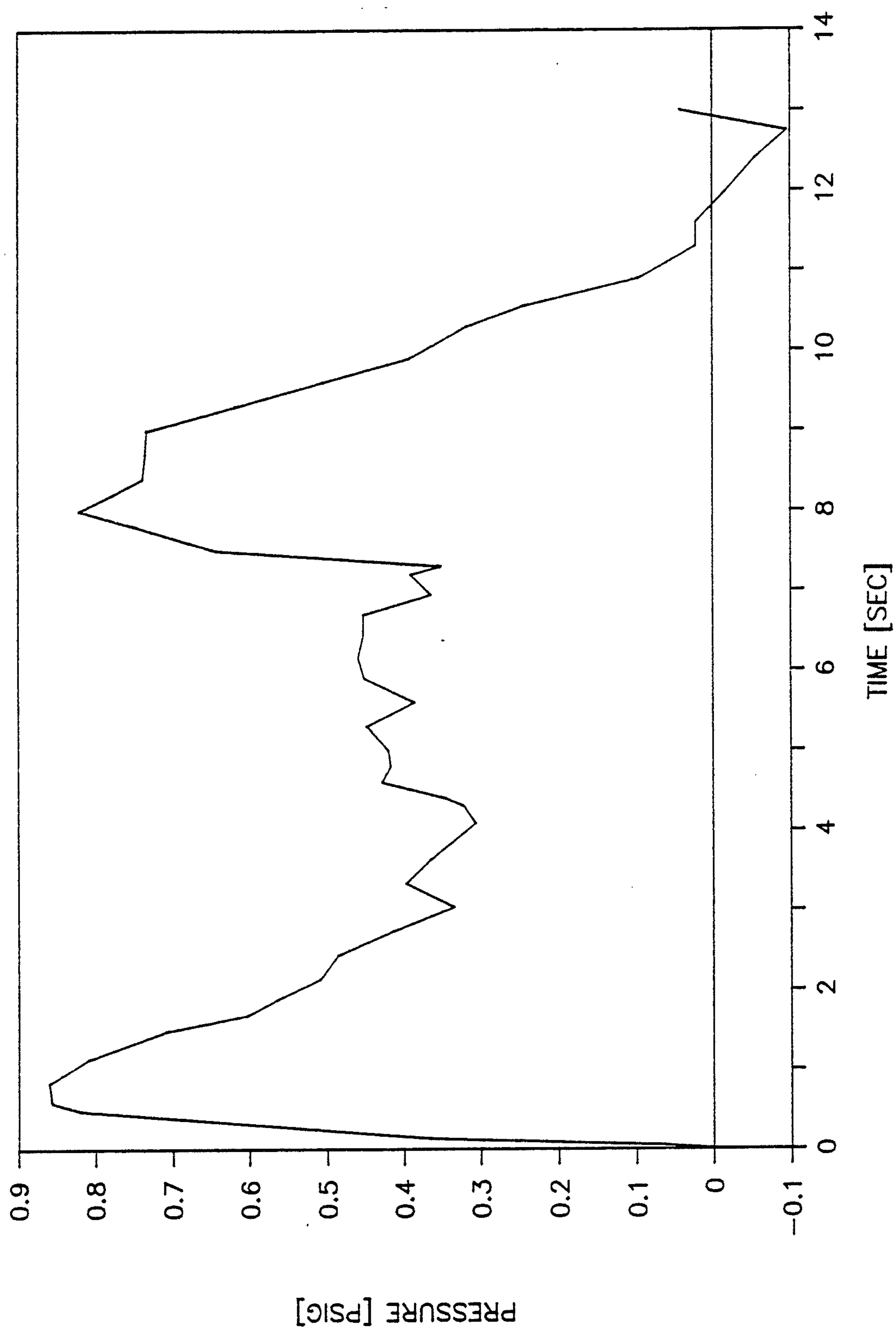
FIGURE 3.6-26

STEAM TUNNEL RELATIVE HUMIDITY AFTER MAIN STEAM LINE BREAK



Note: The pressure profile corresponds to 1050 psia steam dome pressure. For 1060 psia dome pressure (power uprate conditions), the peak pressure will be 0.9 psig.

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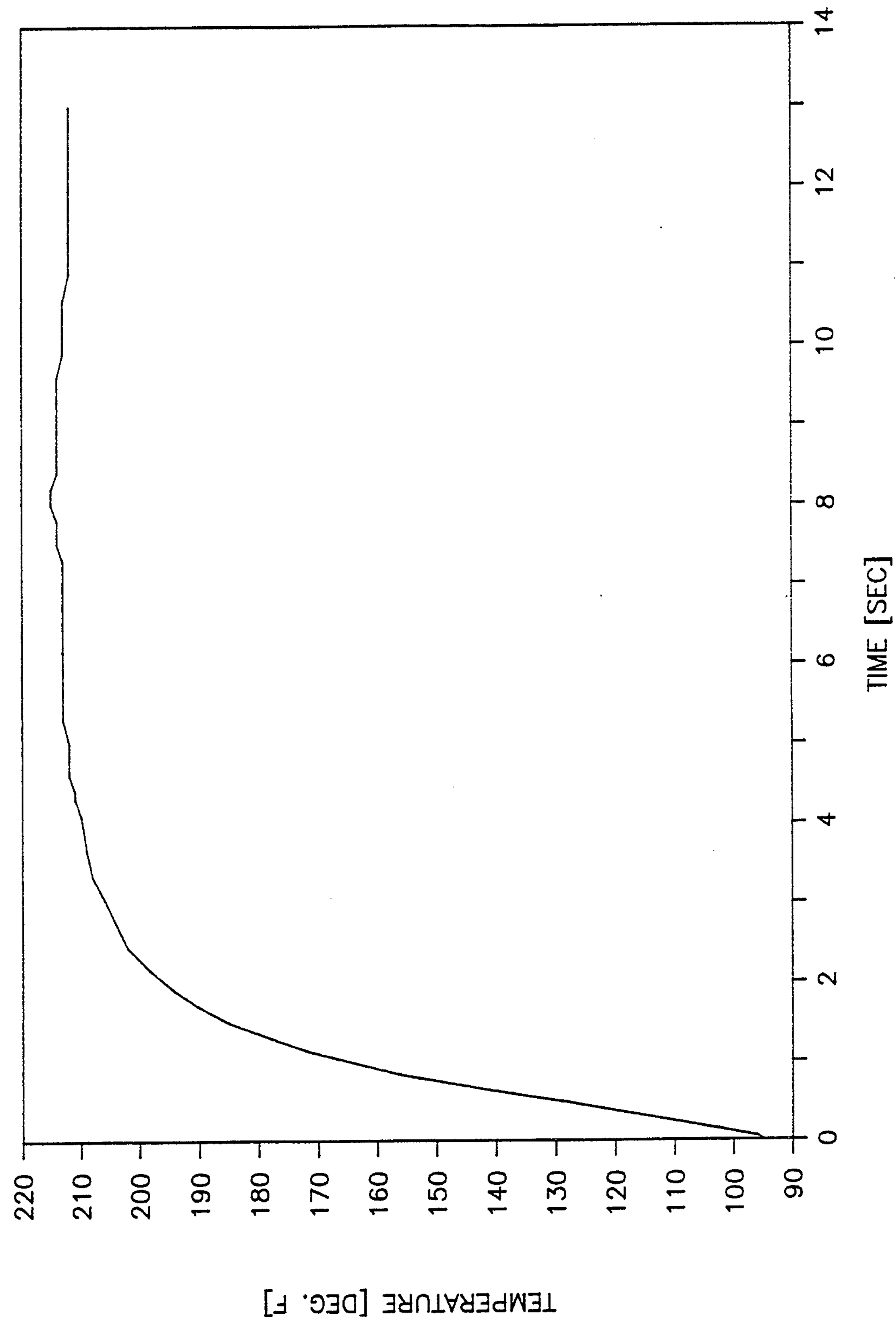
FIGURE 3.6-27

FIRST FLOOR AUXILIARY BUILDING PRESSURE AFTER MAIN STEAM LINE BREAK



Note: The temperature profile corresponds to 1050 psia steam dome pressure. For 1060 psia dome pressure (power uprate conditions), the temperature profile is practically unaffected.

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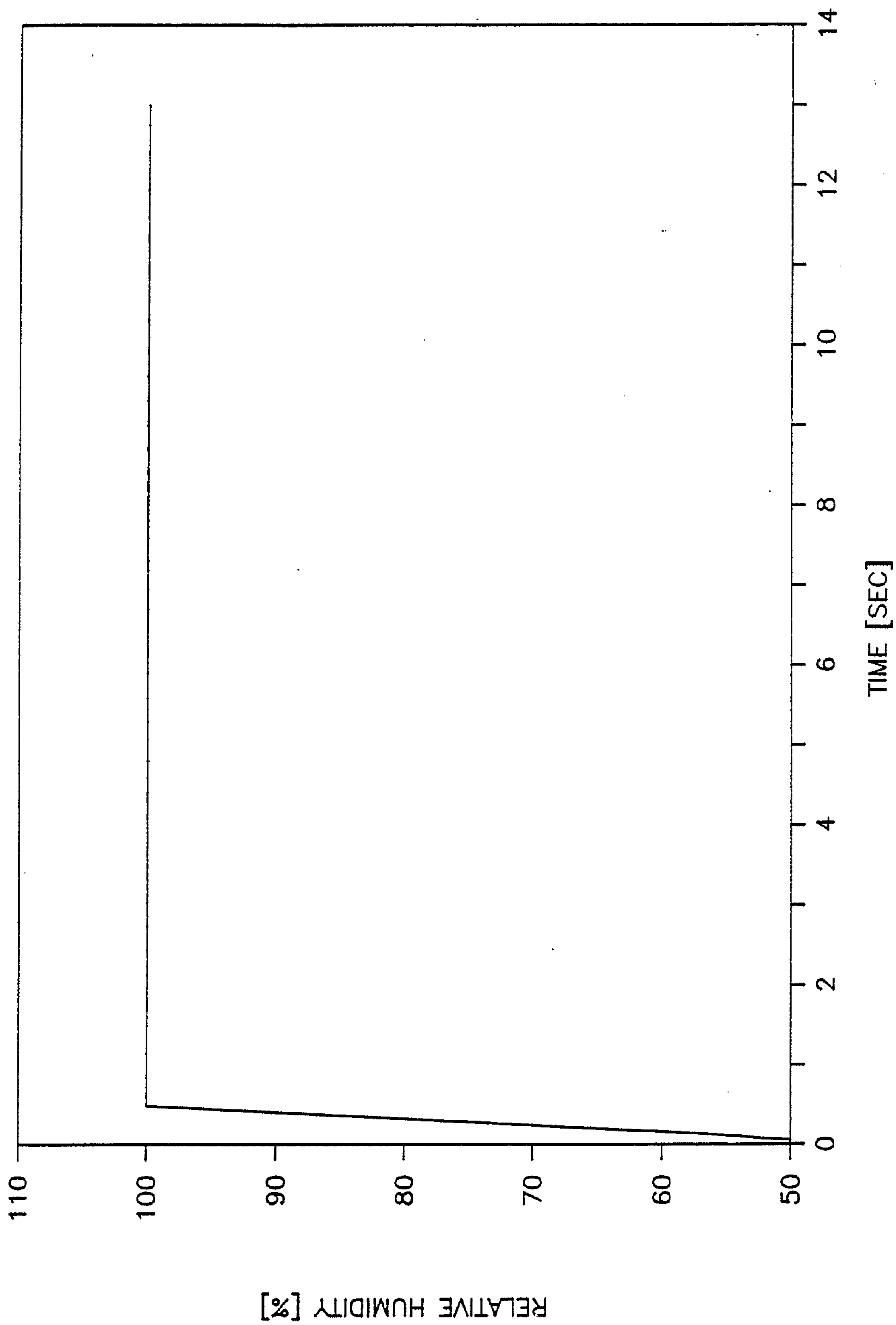
FIGURE 3.6-28

FIRST FLOOR AUXILIARY BUILDING TEMPERATURE AFTER MAIN STEAM LINE BREAK



Note: The relative humidity profile corresponds to 1050 psia steam dome pressure. For 1060 psia dome pressure (power uprate conditions), the relative humidity profile is practically unaffected.

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FIGURE 3.6-29

FIRST FLOOR AUXILIARY BUILDING RELATIVE HUMIDITY AFTER MAIN STEAM LINE BREAK

Figure Intentionally Removed
Refer to Plant Drawing C-2546

Figure Intentionally Removed
Refer to Plant Drawing C-2539

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FIGURE 3.6-30, SHEET 2

RESTRAINT STRUCTURE IN STEAM TUNNEL

Figure Intentionally Removed
Refer to Plant Drawing C-2538

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FIGURE 3.6-30, SHEET 3

RESTRAINT STRUCTURE IN STEAM TUNNEL

Figure Intentionally Removed
Refer to Plant Drawing STEAM TUNNEL SKETCH

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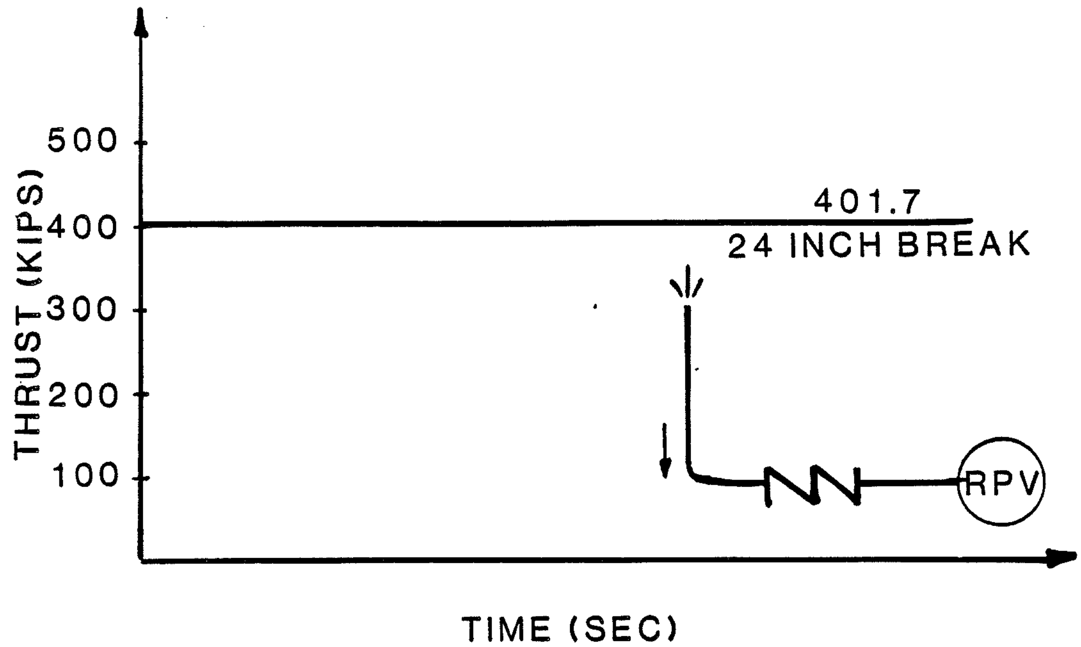
FIGURE 3.6-31

STEAM TUNNEL – PLAN VIEW

Figure Intentionally Removed
Refer to Plant Drawing STEAM TUNNEL SKETCH

FIGURE 3.6-32

STEAM TUNNEL



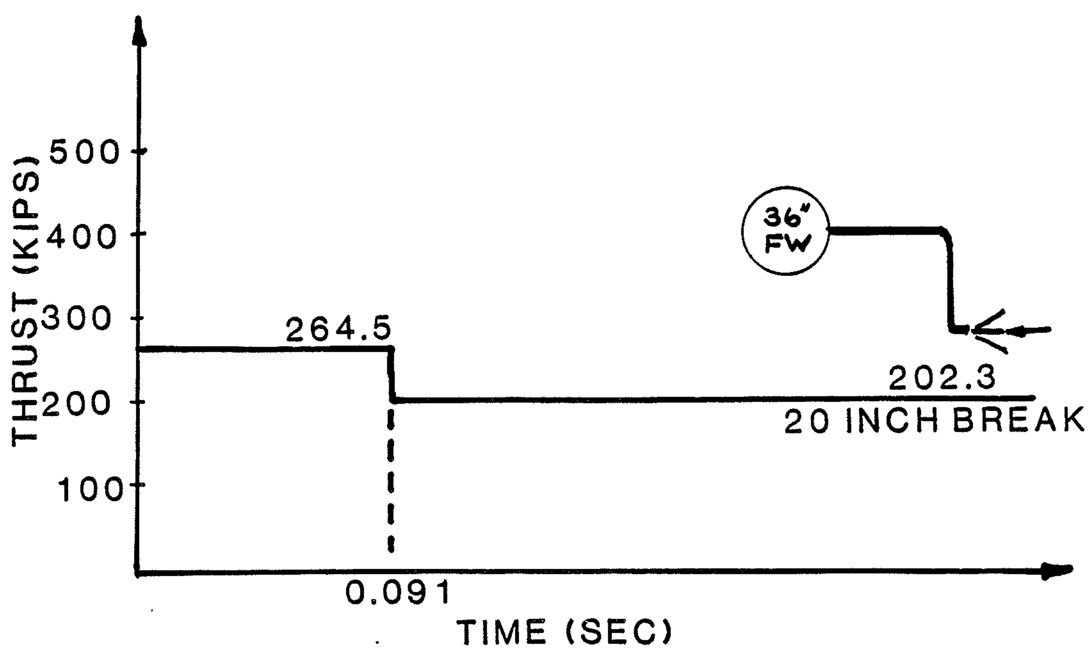


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FIGURE 3.6-33

TYPICAL FEEDWATER CIRCUMFERENTIAL BREAK THRUST

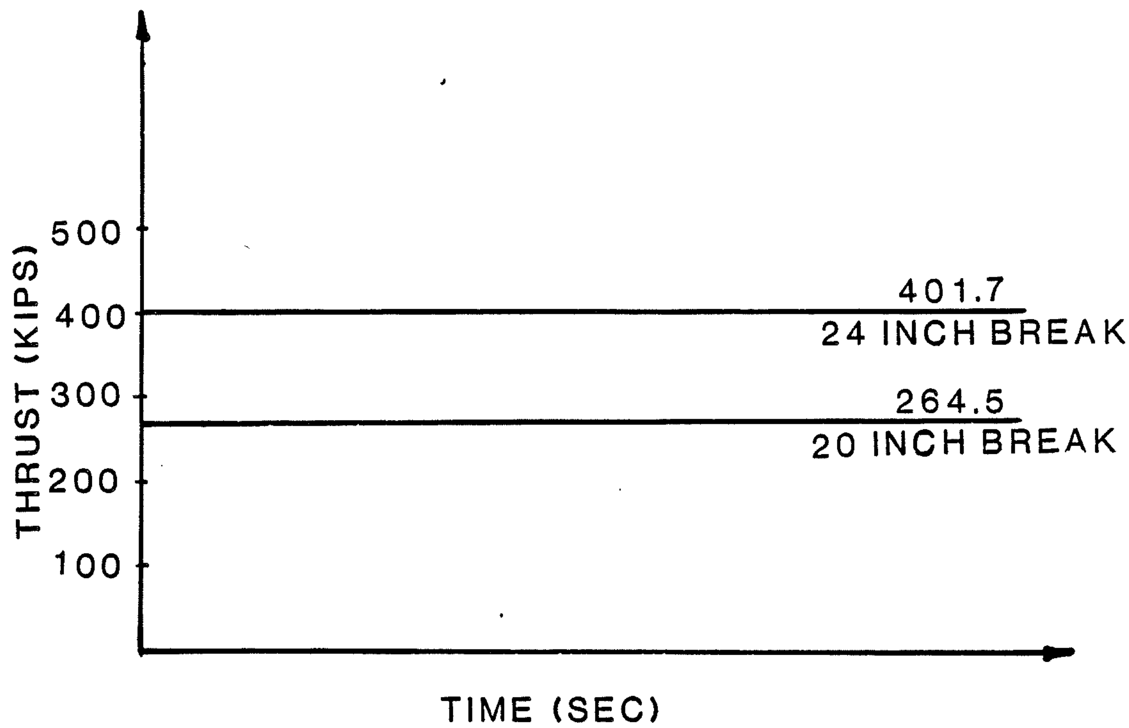

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FIGURE 3.6-34

FEEDWATER LONGITUDINAL BREAK THRUSTS

Figure Intentionally Removed
Refer to Plant Drawing STEAM TUNNEL FW PIPE

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FIGURE 3.6-35

FEEDWATER PIPING IN STEAM TUNNEL

Figure Intentionally Removed
Refer to Plant Drawing AUX BLDG FIRST FLOOR

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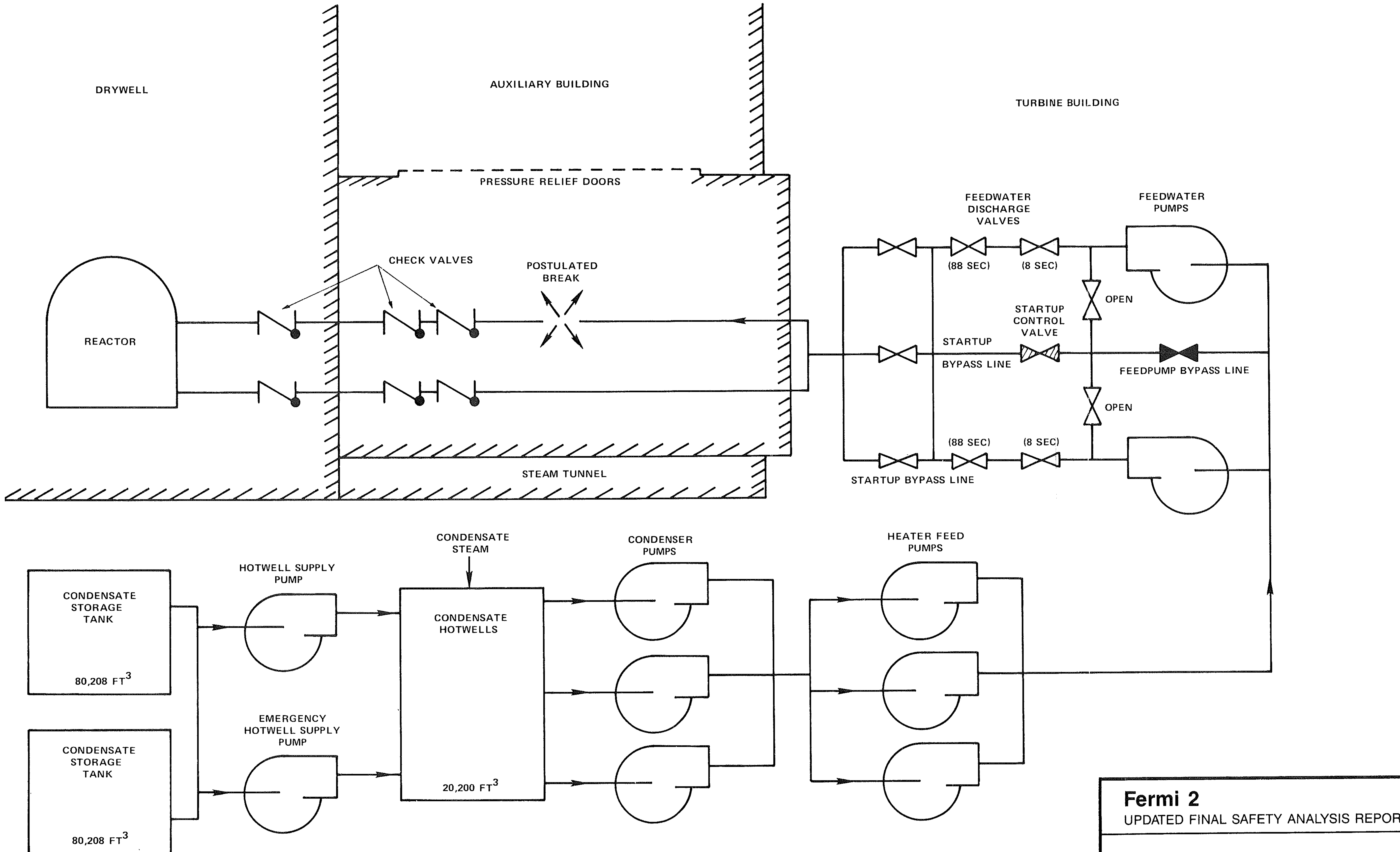
FIGURE 3.6-36

REACTOR/AUXILIARY BUILDING FIRST FLOOR



NUCLEAR SERVICES CORPORATION DRAWING

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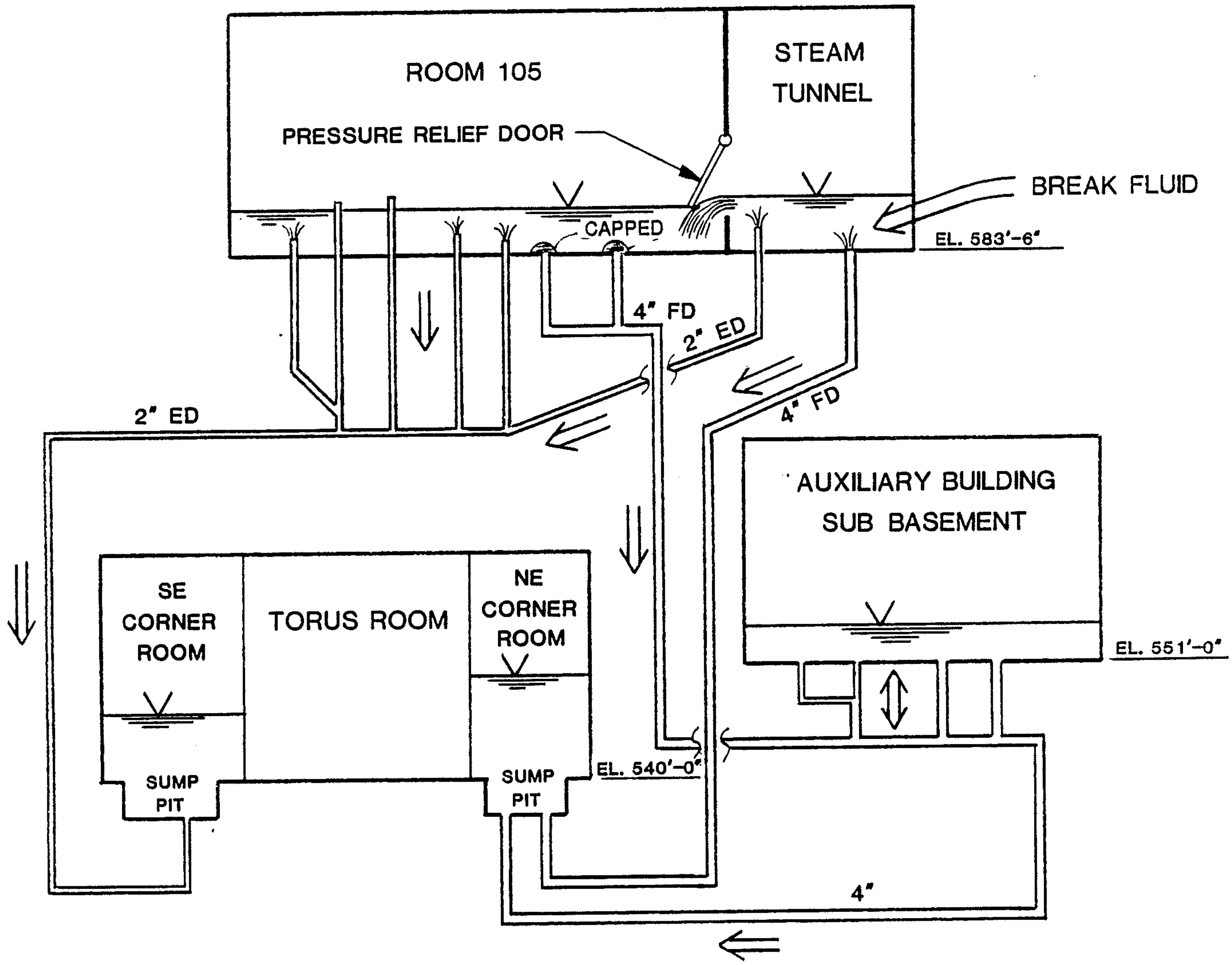
FIGURE 3.6-37

TYPICAL FEEDWATER LINE BLOWDOWN FORCE MODEL – CIRCUMFERENTIAL BREAK



NOTES:

1. ⇒ INDICATES FLOW DIRECTION
2. THIS FIGURE IS NOT TO SCALE
3. ⊻ INDICATES WATER SURFACE
4. FD - FLOOR DRAIN
   ED - EQUIPMENT DRAIN

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FIGURE 3.6-38

STEAM TUNNEL AND AUXILIARY BUILDING FIRST FLOOR FLOODING LEVEL VERSUS TIME FEEDWATER LINE BREAK

Figure Intentionally Removed
Refer to Plant Drawing HPCI SKETCH

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FIGURE 3.6-39

HIGH-PRESSURE COOLANT INJECTION STEAM SUPPLY LINE ROUTING

Figure Intentionally Removed
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FIGURE 3.6-40

PIPE-WHIP RESTRAINT LOCATIONS ON
HIGH-PRESSURE COOLANT INJECTION
STEAM LINE

Figure Intentionally Removed
Refer to Plant Drawing RCIC SKETCH

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FIGURE 3.6-41

REVISED ROUTING OF REACTOR CORE ISOLATION COOLING STEAM LINE

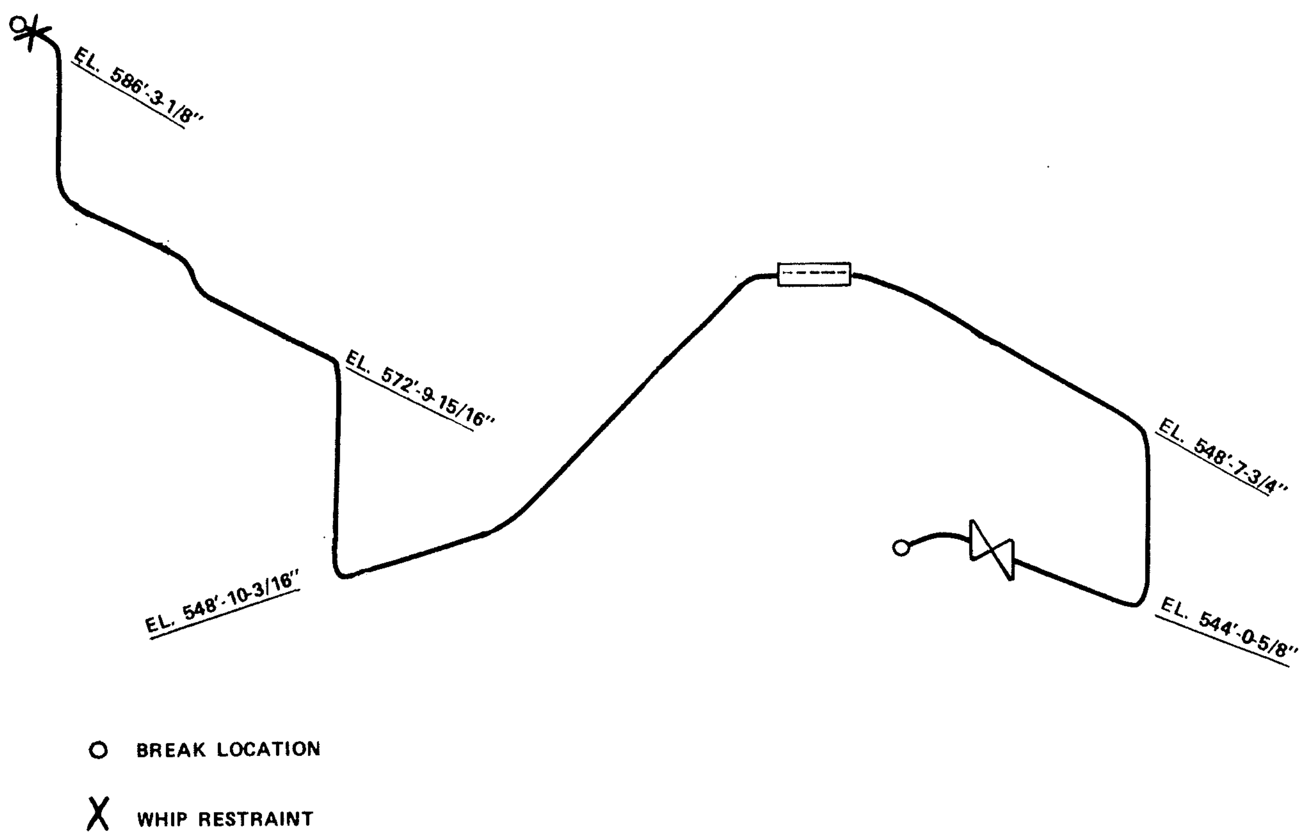

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FIGURE 3.6-42

REACTOR CORE ISOLATION COOLING STEAM LINE PIPE BREAK AND RESTRAINT LOCATIONS

Figure Intentionally Removed
Refer to Plant Drawing RWCU SKETCH

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FIGURE 3.6-43

REACTOR WATER CLEANUP LINE ROUTING AND MODIFICATIONS ON REACTOR BUILDING SECOND FLOOR

Figure Intentionally Removed
Refer to Plant Drawing RWCU SKETCH

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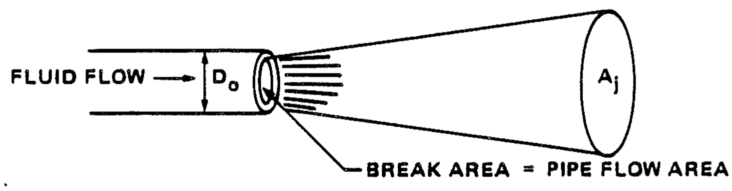
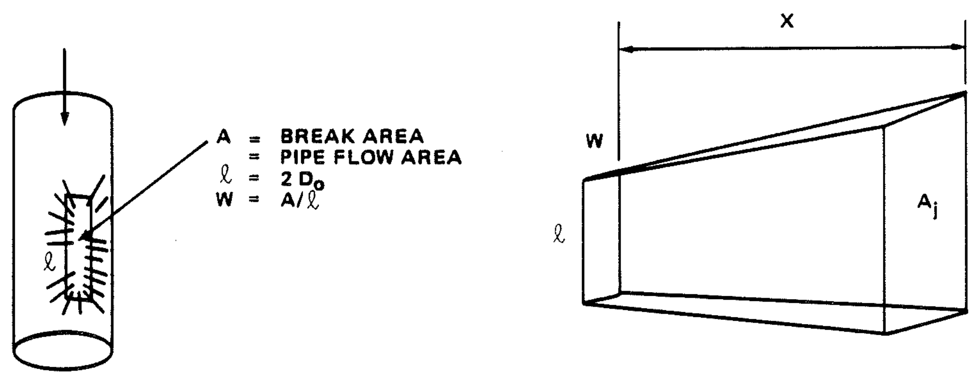
FIGURE 3.6-44

REACTOR WATER CLEANUP PUMP DISCHARGE RESTRAINT LOCATIONS AND REVISED ROUTING

(a) DESIGN BASIS CIRCUMFERENTIAL BREAK



(b) DESIGN BASIS LONGITUDINAL BREAK



(c) CRITICAL CRACK BREAK

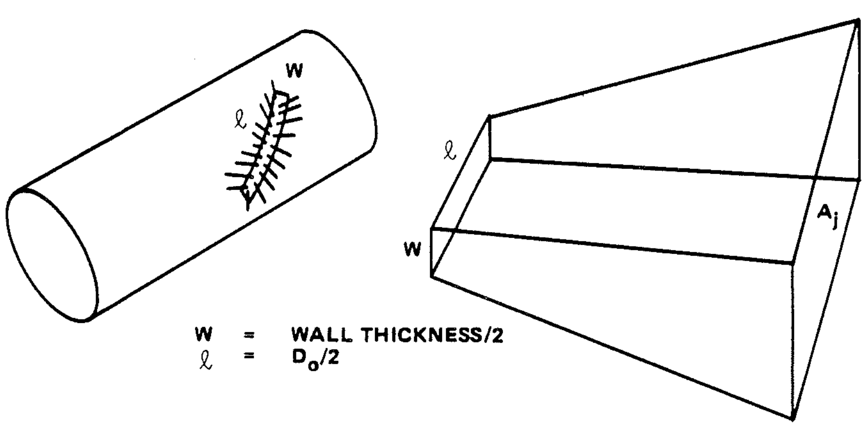


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FIGURE 3.6-45

JET CHARACTERISTICS

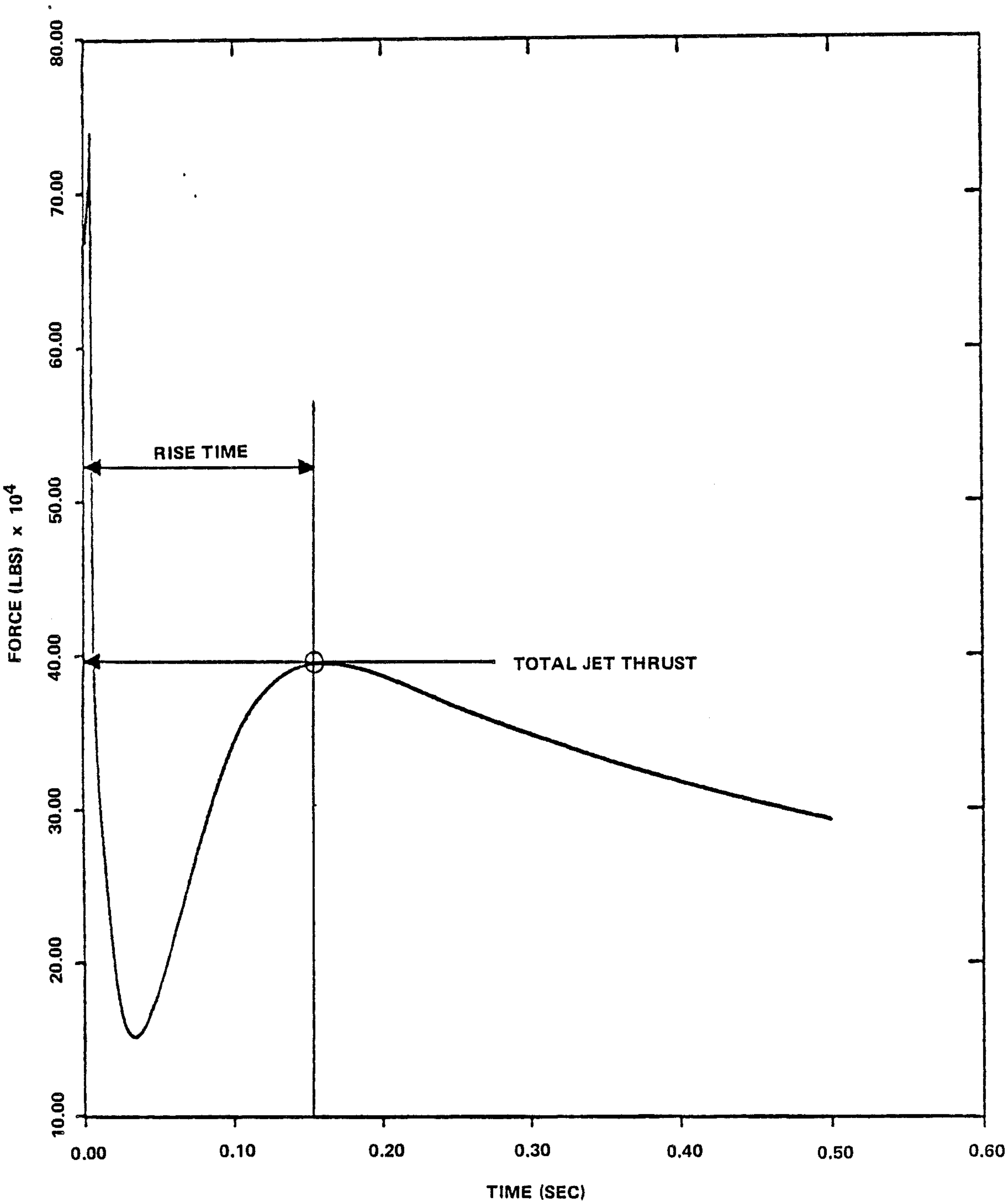

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FIGURE 3.6-46

DETERMINATION OF TOTAL JET THRUST

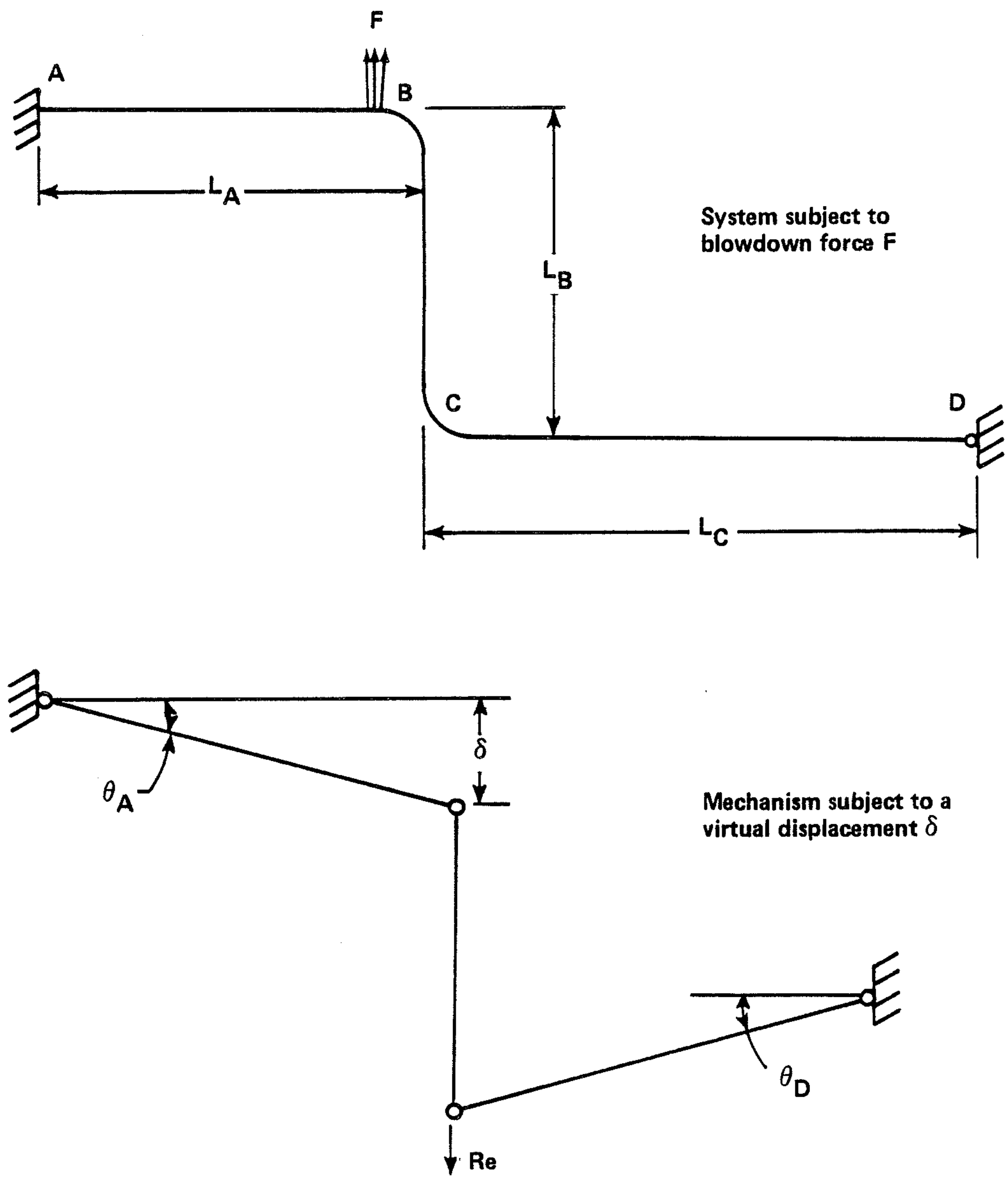

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FIGURE 3.6-47

MOTION AT POSTULATED LONGITUDINAL BREAK

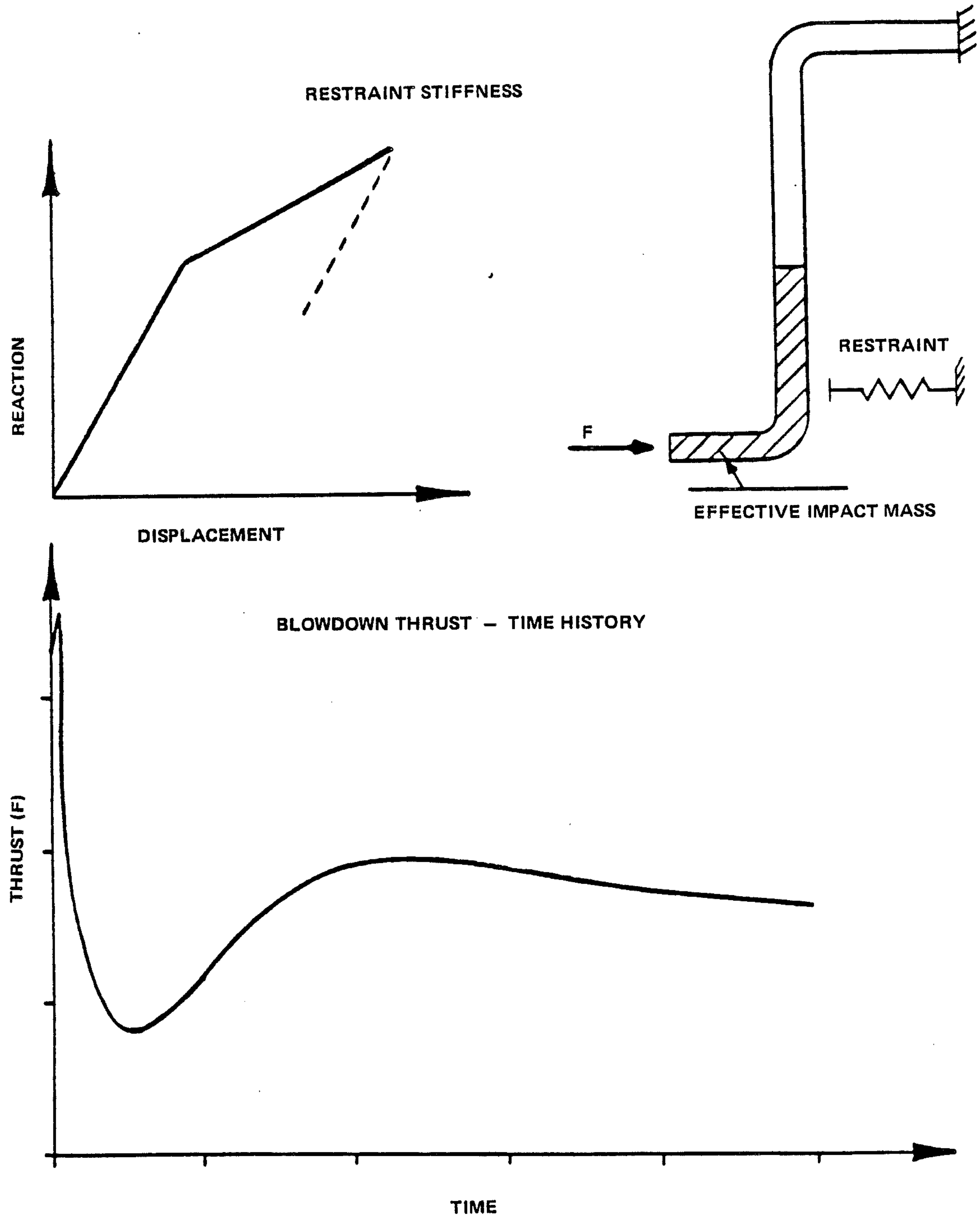

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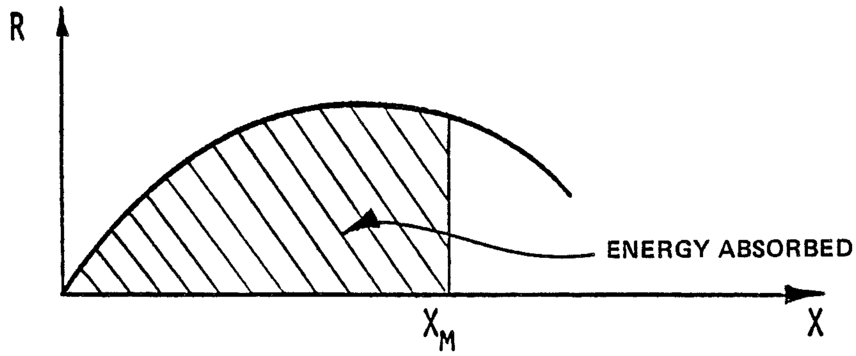
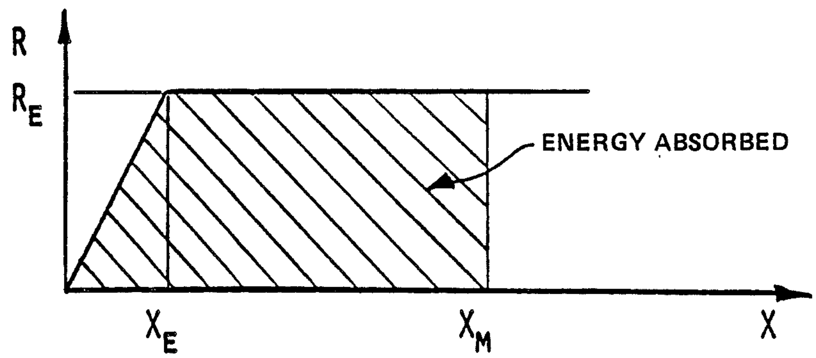
FIGURE 3.6-48

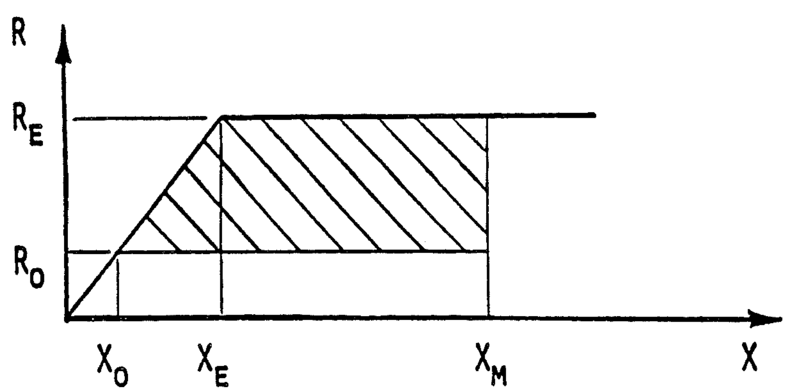
RESTRAINT IMPACT



A) NONLINEAR STRUCTURAL SYSTEM



B) ELASTO-PLASTIC STRUCTURAL SYSTEM



C) ELASTO-PLASTIC SYSTEM WITH INITIAL LOADS

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FIGURE 3.6-49

RESISTANCE-DISPLACEMENT CURVES

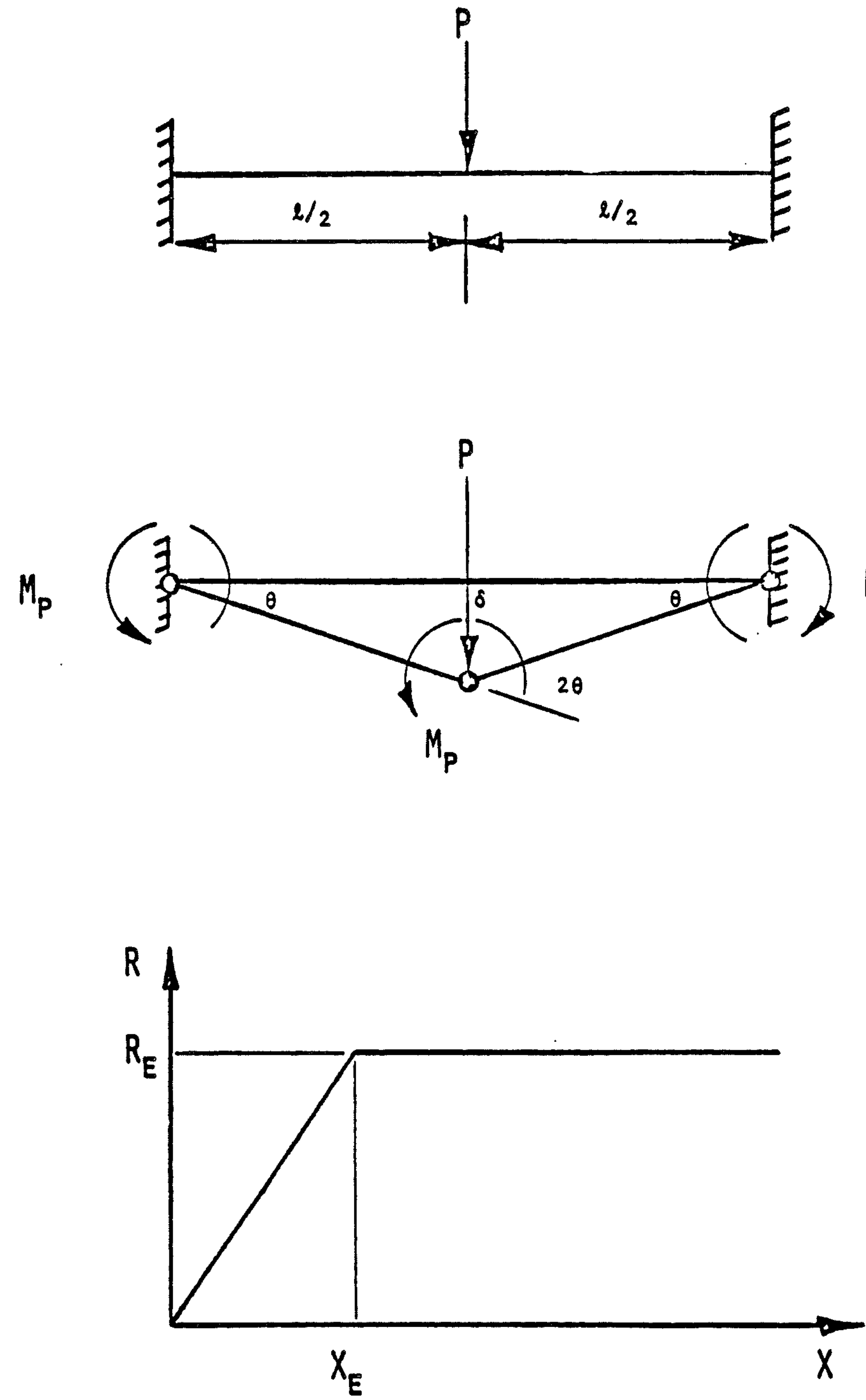

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FIGURE 3.6-50

RESISTANCE-DISPLACEMENT FOR FIXED-FIXED BEAM

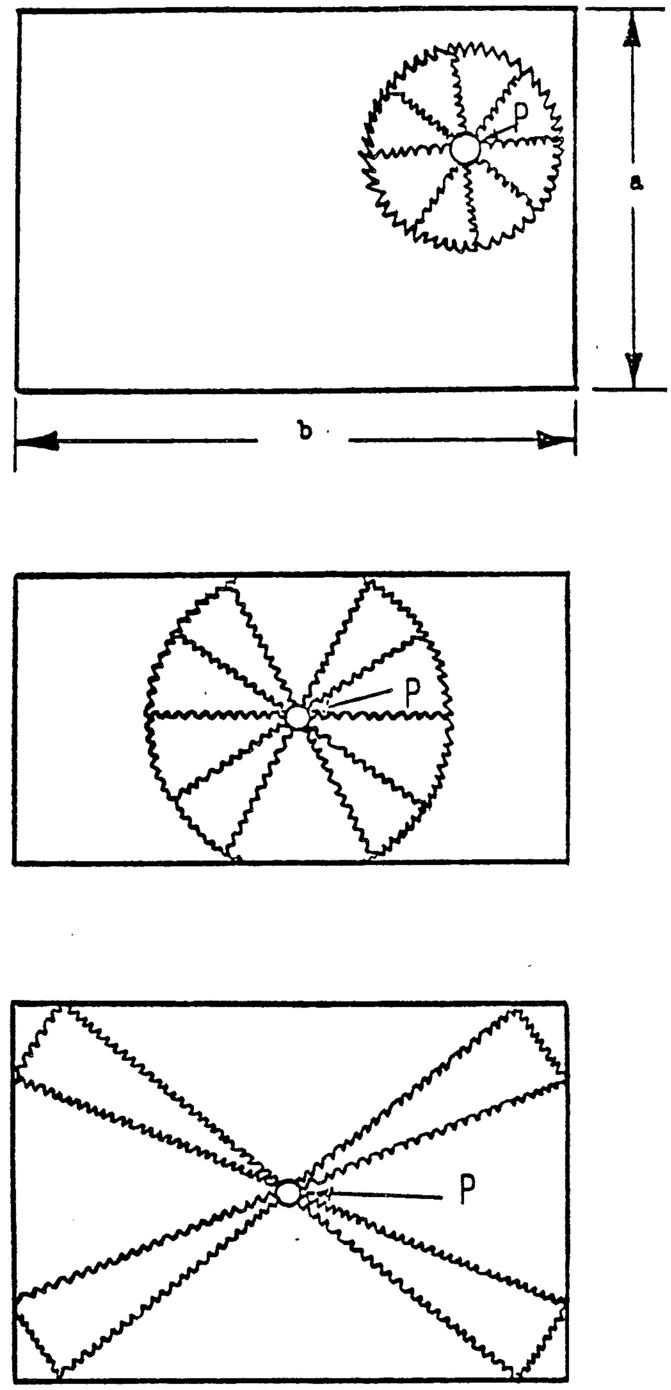

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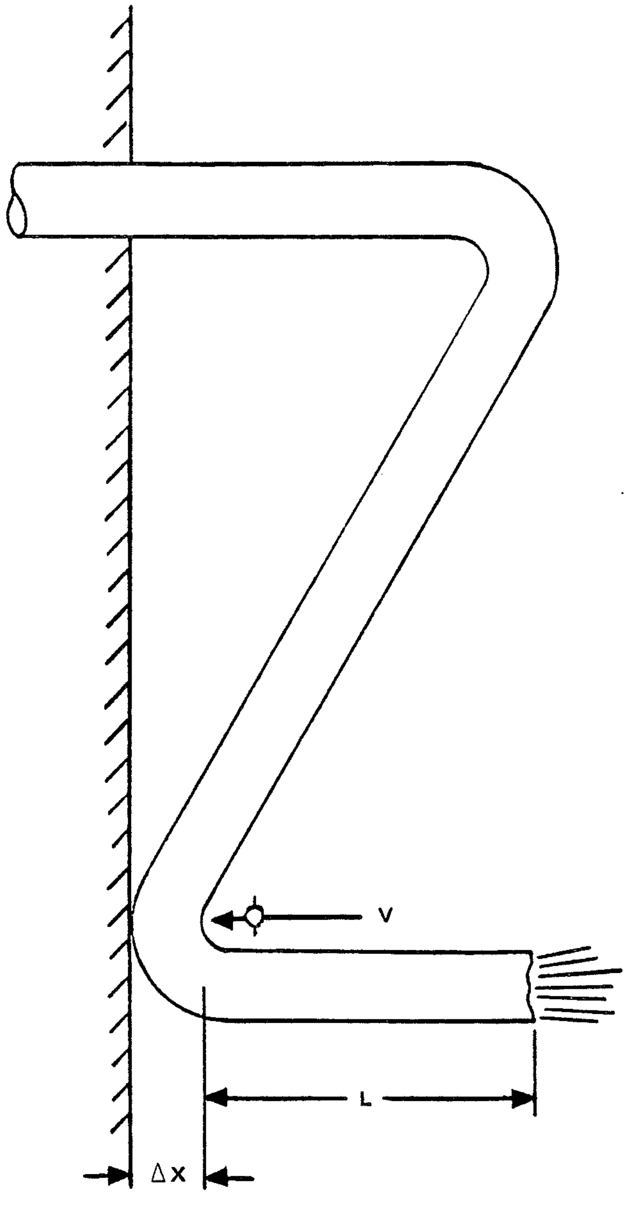
FIGURE 3.6-51

YIELD LINE PATTERNS FOR SLABS SUBJECT TO POINT LOADS



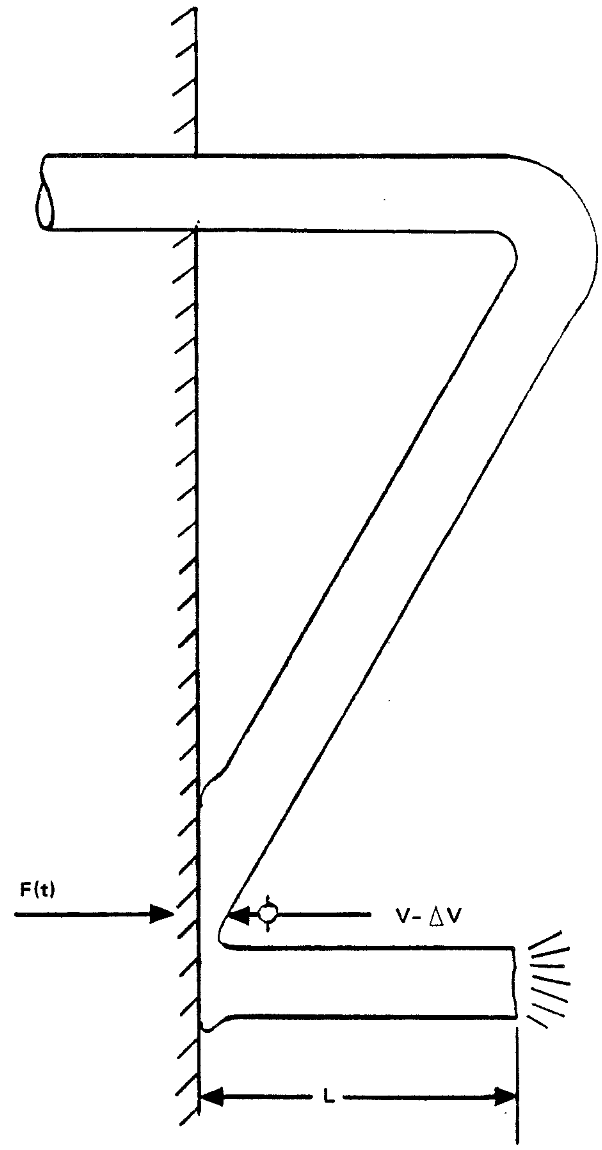


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FIGURE 3.6-52

CALCULATION OF IMPACT TIME-HISTORY

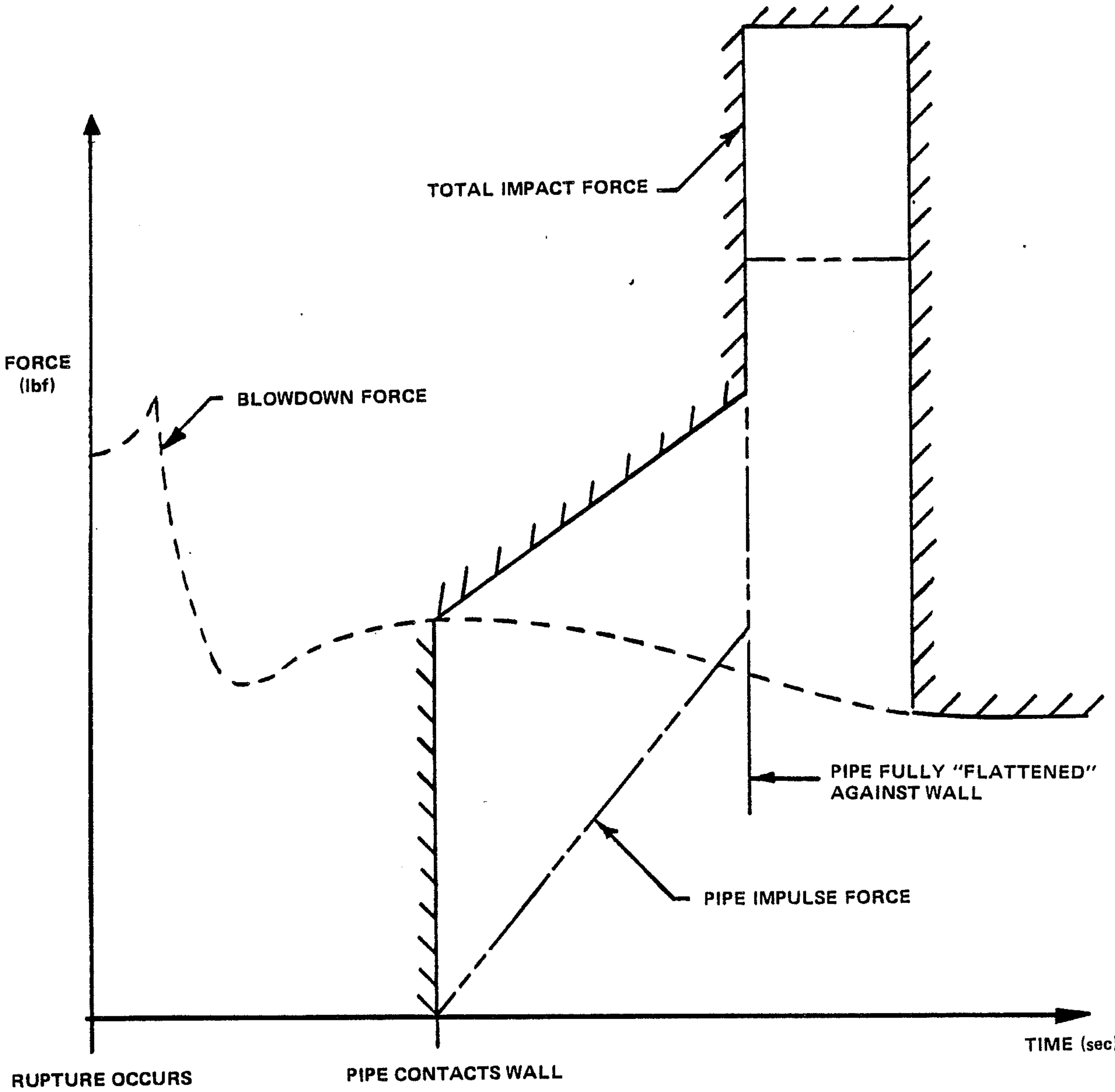

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FIGURE 3.6-53

IMPACT TIME-HISTORY

3.7 SEISMIC DESIGN

For purposes of seismic design, structures, systems, and components are categorized as follows:

Category I: Safety-Related Structures, Systems, and Components

Plant structures, systems, and components, including their foundations and supports, that are required to be designed to remain functional in the event of a safe-shutdown earthquake (SSE) as described in Regulatory Guide 1.29, are designated Category I. A detailed discussion on the design Category I structures and components is provided in the following sections.

Category II/I: Non-Safety-Related Items in a Safety-Related Envelope

Non-safety-related components--control, electrical, mechanical, or structural--in a safety-related envelope are designated Category II/I. The continued functioning of these items is not required, but their failure could reduce the functioning of plant Category I items. Hangers and supports for Category II/I components carrying safety-related items are Category I.

Category II/I items are designed to maintain their structural and mounting integrity. For normal (operating) loads, the maximum stresses in components are required to remain within code-specified allowable limits. Components may be stressed beyond the yield limit stress during SSE loading. A reasonable limit, depending on material capability, is placed on the allowable ductility ratio. Test and/or analysis may be performed to establish Category II/I component ductility levels to be satisfactory under postulated loads.

Nonseismic: Non-Safety-Related Structures and Associated Non-Safety-Related Components

Structures and components designated as Nonseismic are designed by the appropriate state-of-the-art methods.

3.7.1 Seismic Input

3.7.1.1 Design Response Spectra

The design-basis earthquake (DBE) as referred to in the Preliminary Safety Analysis Report (PSAR) and other documents is referred to herein as the SSE.

The results of the seismological studies performed by Dames & Moore (D&M) for Fermi 2 are summarized below.

Confirmatory site-specific earthquake evaluations were recently completed by Weston Geophysical to reaffirm the acceptability of the established Fermi 2 facility aseismic design bases.

Site-specific spectra were developed from real time-history data representing quakes with a magnitude never to be exceeded at the site and subsurface conditions similar to those at the site.

The site is located in one of the seismically stable regions in the United States. As shown by Figure 3.7-1, no earthquake epicenter has been located closer than about 15 miles and only nine earthquakes have been reported within 50 miles of the site since the beginning of the 19th century. None of these shocks were greater than Intensity V on the Modified Mercalli Scale (Table 3.7-1). Twelve earthquake epicenters of Intensity V or greater have been reported within 50 to 100 miles of the site and another 27 of Intensity V or greater were located at distances between 100 and 200 miles. These more distant shocks ranged up to Intensity VIII.

The closest reported earthquake of Intensity V or greater was in the 1877 shock west of Detroit, Michigan. This earthquake caused no damage near its epicenter and was not felt in the vicinity of the site. The remaining eight earthquakes, within 50 miles of the site, were of Intensity IV or smaller and none were larger than Intensity III at the site. The largest regional shocks occurred in 1937 near Lima, Ohio, in 1977 near Celina, Ohio, in 1980 near Sharpsburg, Kentucky, and in 1986 near Perry, Ohio. Although these shocks may have had epicentral intensities as great as VIII, none were greater than Intensity IV shocks at the site. The effect of these shocks in Michigan was not great and no damage resulted.

Although several shocks have been felt at the site within about the past two centuries, the maximum intensity at the site has not exceeded IV. None of the recorded earthquakes caused any damage at or near the site (Subsection 2.5.2).

With few exceptions, the significant earthquakes reported in the region can be associated with well-defined geologic structural zones (Subsection 2.5.2). To the north and east of the site, earthquakes are scarce and appear to be related to anticlinal structure in northern Michigan. To the west of the site, earthquake activity has consisted of infrequent minor shocks that can be related to faulting in southern Wisconsin and northern and central Illinois. To the south, earthquakes are believed to be related to the confluence of the Findlay, Cincinnati, and Kankakee Arches. There are no known faults within 25 miles of the site.

The site response spectra for the operating-basis earthquake (OBE) and the SSE, for the horizontal direction, are shown in Figures 3.7-2 and 3.7-3. Vertical ground motion for the SSE and OBE are taken as 2/3 (0.667) of the maximum horizontal ground acceleration. The maximum ground acceleration for horizontal motion for the SSE is 0.15g and for the OBE is 0.08g. These earthquakes for the stable Fermi site are very conservative and were selected jointly between Edison and the AEC staff and have received their acceptance (see Safety Evaluation by DRL, May 17, 1971). Earthquake history and other pertinent information on site geology and seismology are included in Section 2.5.

3.7.1.2 Design Response Spectra Derivation

3.7.1.2.1 General

The shapes of the OBE and SSE spectra essentially conform to the 1940 El Centro, California spectra with minor embellishments to accommodate the 1949 Olympia, Washington, and the 1935 Helena, Montana, experiences. The spectra are anchored at horizontal zero period accelerations of .08 and .15g respectively with corresponding vertical accelerations of .05 and .10g.

Internal equipment response spectra were derived based on detailed time-history analysis of the buildings subjected to numerous time-history base excitations. Time histories were employed in addition to those used to describe the shape of the basic ground spectra to ensure a broadband frequency content for equipment aseismic qualification purposes. In this regard, scaled earthquake records were used for generating the internal equipment response spectra. These internal building location spectra are arrived at by averaging the results obtained from four scaled earthquake records. The four earthquakes and their horizontal time-history records are the following:

a. N-S - El Centro, Calif., May 18, 1940

b. N-S - El Centro, Calif., December 30, 1934

c. S-80-W - Olympia, Wash., April 13, 1949

d. N-21-E - Taft, Calif., July 21, 1952.

Ground response spectra for a system with 2 percent of critical damping have been generated for each of the previous earthquake records.

In the generation of the ground spectra for each record, 60 periods from 0.1 sec to 1.0 sec were considered.

To determine what time duration of each record is required to ensure that maximum responses on the floor slab were obtained, response spectra were generated for each record using different time lengths of the records, all starting from zero time. The durations of the record required to give maximum responses in the period range of interest have been determined to be as follows:

a. 1940 El Centro - 7 sec

b. 1934 El Centro - 13 sec

c. 1949 Olympia - 20 sec

d. 1952 Taft - 10 sec.

Each earthquake record was scaled so that the area under the acceleration response spectra, obtained from the record duration previously indicated, between the periods 0.1 sec and 1.0 sec, equaled the area under the recommended OBE spectra between the corresponding periods for a 2 percent-damped system. The ground accelerations obtained by the previous scaling procedure, used to simulate the horizontal OBE, are as follows:

a. 1940 El Centro - 0.053g

b. 1934 El Centro - 0.078g

c. 1949 Olympia - 0.077g

d. 1952 Taft - 0.062g.

Response spectra from the earthquake records scaled to simulate the horizontal OBE were plotted over the recommended OBE spectra and are presented in Figures 3.7-4 through 3.7-7. The maximum ground accelerations for SSE were obtained by multiplying the previous values by two. The resulting ground response spectra for OBE and SSE are shown in Figures 3.7-2 and 3.7-3, respectively. The vertical components of the four previously described earthquakes were used to generate vertical spectra. Again the duration of each record required to give maximum responses in the period range of interest was determined. The durations of each record used in generating response spectra are as follows:

a. 1940 El Centro - 10.0 sec

b. 1934 El Centro - 10.8 sec

c. 1949 Olympia - 12.5 sec

d. 1952 Taft - 12.5 sec.

To determine the scaled vertical ground acceleration, a_{VS}, the following relationship has been used:

$$a_{VS} = a_{HS} * \frac{a_V * A_V}{a_H * A_H} \quad (3.7\text{-}1)$$

where

a_{HS} = scaled horizontal ground acceleration

a_V = actual vertical ground acceleration

a_H = actual horizontal ground acceleration

A_V = actual area of vertical ground response spectrum (0.lg maximum, acceleration)

A_H = actual area of horizontal ground response spectrum (0.1g maximum, acceleration)

Maximum vertical ground accelerations used to generate vertical internal building spectra for OBE are as follows:

a. 1940 El Centro - 0.0204g

b. 1934 El Centro - 0.0240g

c. 1949 Olympia - 0.0256g

d. 1952 Taft - 0.0395g.

Maximum vertical ground accelerations for SSE were obtained by multiplying the previous values by a factor of two. The OBE vertical spectra are shown in Figure 3.7-8. The SSE vertical spectra are shown in Figure 3.7-9.

3.7.1.2.2 Supplementary Seismic Evaluation

In response to requests for information from the NRC Geosciences Branch, a site-specific ground response spectrum was developed, exhibiting a significantly higher ground response than the SSE ground response. Structures, systems, and components required for cold shutdown have been reevaluated for this higher site-specific earthquake, and the plant's capability to safely shut down has been confirmed. A detailed description of the evaluation program, analytical results, and conclusions can be found in the Supplementary Seismic Evaluation Report, Detroit Edison Report No. EF2-53,332 (Reference 1). Additional information on certain details of the analysis (provided in response to NRC questions) and the results of additional analyses performed subsequent to the Reference 1 report are listed in Reference 2.

Site-specific ground motion spectra were developed from real time-history data as previously described. Category I structures were then proven to adequately resist this excitation by means of a response spectrum evaluation equivalent in technique to that initially used for facility design purposes.

Internal equipment spectra were, however, generated from a synthesized ground motion time history, rather than the averaged real time histories used for original internal spectral generation purposes.

These supplementary evaluations reaffirmed the original facility aseismic design basis acceptability.

3.7.1.2.3 Response Spectra and Seismic Analysis Methods Used for Piping Snubber Reduction

OBE and SSE seismic loads for drywell piping snubber reduction purposes were analyzed using the following method:

> ASME Code Case N-411-1 damping values were applied with the uniform support motion response spectra analysis method in accordance with Regulatory Guide 1.84, Revision 27. Closely spaced modes were combined in accordance with Regulatory Guide 1.92.

This method included high-frequency modes per NUREG-1061, Volume 4, recommendations. The total combined response of high-frequency modes is combined by the Square Root of the Sum of the Squares (SRSS) method with the total combined response from lower-frequency modes to determine the overall structural peak response. When Code Case N-411-1 was used for earthquake loads, it was not mixed with Regulatory Guide 1.61 damping criteria for the same load case. Seismic inertia and anchor movement loads were combined by the SRSS method.

New building response spectra using Regulatory Guide 1.60 ground motion input were developed using the containment model used for the Cycle 3 fuel load. Direct generation of response spectra and Code Case N-397 spectra broadening techniques were not used in developing the new response spectra. The horizontal OBE spectra was anchored at 0.08g and the SSE spectra was anchored at 0.15g. Response spectra peaks were broadened by +15 percent.

These methods and spectra were applied in the seismic analysis of selected drywell piping systems in order to reduce the number of snubber supports.

3.7.1.3 Critical Damping Values

The damping values (expressed as a percentage of critical damping) of common structures and equipment in the Fermi 2 plant are listed in Table 3.7-2. The damping values used for the Fermi 2 project are in some cases higher than those specified in Regulatory Guide 1.61. These higher values were taken from Reference 3, prior to the issuance of Regulatory Guide 1.61. The damping values for HVAC systems, as delineated in Reference 19, were used for the CCHVAC System and SGTS duct and duct support revalidation effort. The specified systems and subsystems which were not listed were classified within one of the items in the table. Other damping values have been used when justified by specific data such as data obtained by testing.

3.7.1.4 Bases for Site-Dependent Analysis

No site-dependent analysis was necessary for Fermi 2 since the Fermi site is founded on bedrock (Subsection 3.7.1.6).

3.7.1.5 Soil-Supported Category I Structures

As described in Section 2.5 and Subsection 3.7.1.6, all Category I structures are supported directly on bedrock.

3.7.1.6 Soil-Structure Interaction

Structures Founded on Rock

Category I structures at Fermi 2 are founded on bedrock. A study was completed for Fermi 2 structures founded on rock (Reference 4) in which it was shown that for the Fermi site, soil-structure interaction was insignificant. The findings of this study are in agreement with the conclusions drawn by other researchers who report that soil-structure interaction is significant only when the shear wave velocity of the soil is less than 1000 fps (References 5 and 6). Since the shear wave velocity of the rock at the Fermi site is 7600 fps, it can be safely assumed, in accordance with the literature (References 5 and 6) and finite element analysis undertaken (Reference 4), that the Fermi 2 medium behaves as a rigid foundation. Therefore, the spectra developed for the bedrock represent the response to the base excitation.

3.7.2 Seismic System Analysis

3.7.2.1 Seismic Analysis Methods

3.7.2.1.1 General Description

The calculation of the dynamic response of a nuclear power plant complex subjected to an earthquake loading can generally be divided into two broad areas of analysis. The first is the analysis of major buildings and structures which house and/or support Category I systems and components. The second is the analysis of Category I systems and components. This subsection deals with the first area of analysis: seismic system analysis.

The necessity for division into two categories is that it is not practical to accomplish the analysis of major structures, systems, and components contained therein in a single dynamic analysis. The analysis is completed in steps. Major seismic systems, such as Category I structures, are modeled and analyzed. The motion of major structures, obtained from their analysis, is then used as the forcing function in the dynamic analysis of smaller Category I systems and components.

The classification of major buildings and structures, and Category I systems and components, is complicated by the fact that all systems and components that possess sufficient mass and stiffness to influence the dynamic behavior of major buildings and structures must be incorporated in the analysis of the major buildings and structures.

Seismic systems are defined as those systems in contact with the ground and thus are excited directly by the site response spectra, or the equivalent time-history motion. For each seismic system, there is a corresponding dynamic model. Seismic systems are discussed in this subsection and they include the reactor/ auxiliary building, residual heat removal (RHR) complex, buried piping, and buried electrical ducts. Subsystems are those in contact with or coupled to the seismic system and thus are excited by the response spectra derived from the system analysis. Subsystem analysis is discussed in Subsection 3.7.3, where the specific analyses for piping, reactor pressure vessel (RPV) and its internals, components, cable tray supports, cranes, racks, ventilation ducts, and tanks are contained in Subsections 3.7.3.6, 3.7.3.15, 3.7.3.16, 3.7.3.17, and 3.7.3.19.

The following criteria are used for system and subsystem decoupling.

a. If the mass of a component or equipment is less than 1 percent of the mass of its supporting structure, the component or equipment is treated as a subsystem and its mass may not be included in the system model

b. If the mass of a component or equipment is between 1 and 10 percent of the mass of its supporting structure, an approximate model of the component or equipment is included in the system model. Later, detailed subsystem analyses are made for this component or equipment

c. If the mass of a component or equipment is more than 10 percent of the mass of its supporting structures, a detailed model of the component or equipment is included in the system model.

3.7.2.1.2 Analysis of Building Structure Systems

To determine the exact dynamic forces acting on a structure, the accelerations (and, therefore, the displacements) of every mass particle must be evaluated. As any real structure's mass is distributed over the spatial extent of the structure, an infinite number of coordinates is required to describe the motion of every mass particle when the structure is subjected to a dynamic load. Calculation of time-dependent displacements at every point in a complex structure is impossible, but the analysis can be simplified by the judicious selection of a limited number of displacement components or coordinates. In dynamic structural analysis, two different assumptions are used to specify the deflected shape of a structure. These are referred to as the lumped-mass approach and the distributed-coordinate approach. The lumped-mass approach is the most convenient and versatile method to use in analyzing complex structural configurations found in a nuclear power plant. This approach was used in the seismic analysis of the Fermi 2 plant structures.

In the lumped-mass idealization, it is assumed that the entire mass of the structure is concentrated at a number of discrete points. A six-degree-of-freedom lumped mass would be general, in the sense that the discrete mass would possess all possible degrees of freedom. But in many structures, certain degrees of freedom may be neglected because the mass-stiffness configuration of the structure is such that these neglected degrees of freedom would not give rise to significant inertia forces if they were considered.

Recognition of the degrees of freedom in a structure that do not contribute to its dynamic response simplifies the modeling of the degrees of freedom that do contribute to the dynamic response of the structure. A series of computer programs, developed and validated for the analysis of nuclear power plant structures, are used to analyze Category I building structures. The criteria used in developing these programs are (1) consideration of the degrees of freedom encountered in the dynamic analysis of a nuclear power plant; (2) ease of inputting mass-stiffness properties from the structural drawings; and (3) ease of using output in structural design. The three programs used in the dynamic analysis of major structures are

a. Dynamic Seismic Analysis of Shear Structures (DSASS)

b. Matrix Analysis of Seismic Stress (MASS-IV)

c. Dynamic Analysis of Structures (DYNAS).

Each of these programs was used in the analysis of a specific type of structure. The program DYNAS can be used for the analysis of any type of structure, system, or equipment. All three programs use the modal method of analysis of a lumped-mass model, but the stiffness properties that interconnect the masses are read in the programs differently, because each program considers different degrees of freedom of the masses. The forcing function can either be acceleration spectra or a time-dependent base acceleration record. The descriptions of these programs are presented in Section 3.13.

The seismic motion of all Category I structures has been determined by applying the earthquake ground motions to appropriate dynamic models. In general, interaction between Category I and nonseismic structures has been eliminated by providing separate foundations for the structures. Also, rattlespace between abutting buildings has been provided so that seismic motion between buildings will be unimpeded.

Throughout the analysis of building structures, the coordinate directions are defined as the x, y, and z axes. The x and y axes denote the two principal horizontal directions and the z axis denotes the vertical direction.

3.7.2.1.2.1 <u>Criteria Used in Modeling Techniques</u>

<u>Horizontal Analysis</u>

The site response spectra presented in Figures 3.7-2 and 3.7-3 have been interpreted as one horizontal component of the OBE and the SSE, respectively.

These spectra are based on the free field vibratory accelerations, before plant structures are in place, at the elevation of the foundation of the structure being analyzed.

Action of the two horizontal components of the ground motion has been considered by analyzing the dynamic models for excitations parallel to the principal horizontal axes of the model. The model used is a discrete-lumped-mass, dynamic model having coupled modes; that is, a static force in one principal direction results in modal displacements in the other principal direction. For models in which the displacements of the two horizontal principal directions were statically coupled, analysis for excitations parallel to a model's two horizontal principal axes, has been accomplished by

a. The response spectra method of analysis (used for the design of structures modeled in system analyses), which involves

1. Analyzing the model for x-excitation

2. Analyzing the model for y-excitation

3. Combining the results of Steps 1 and 2 by the following equation:

$$\sigma_d = \sqrt{\sigma_{cx}^2 + \sigma_{cy}^2} \qquad \text{square root of the sum of squares} \qquad (3.7\text{-}2)$$

where

σ_d = design seismic stress

σ_{cx} = stress component from x-direction seismic excitation

σ_{cy} = stress component from y-direction seismic excitation

b. The time-history method of analysis is used to generate response spectra for subsystem analyses by

1. Analyzing the model for x-excitation

2. Computing the average of the four x-excitations

3. Analyzing the model for y-excitation

4. Computing the average of the four y-excitation

5. Plotting the maximum of the average x-spectra and average y-spectra.

Site-specific internal building spectra were developed using a single synthesized time history for analysis. In this work, the spectra were thus generated directly and no averaging was necessary.

The horizontal dynamic analysis was performed using a shear structure system, a frame structure system, and a combined shear-frame structure system. A description of these analysis systems are as follows:

a. Shear structure system - The plant building structures are complex systems, asymmetric in plan, with heavy concrete slabs at the various floor elevations. These slabs are interconnected with numerous concrete shear walls and/or heavy cross-braced steel members. The overall height dimensions are smaller than the plan dimensions. This low height-to-plan ratio indicates that under lateral loads the predominant deformations of the long shear walls are shear deformations. Consequently, the relative rotations of the slabs about horizontal axes do not cause significant deformations; but, due to asymmetrical mass-stiffness distribution, rotation of the slabs about a vertical axis does occur when this type of structure is subjected to lateral loads. Since the predominant deformation of this type of structure under horizontal seismic loading is a horizontal shear deformation of the walls, it has been referred to as a shear structure system

Figure 3.7-10 shows a simplified shear structure system and the x-y-z axis system where the z-axis is vertical and the x- and y-axes are parallel to the principal axes of the structures. The significant deformations of the structure under horizontal seismic excitation are described with three coordinates, X, Y, and θ_z. These three degrees of freedom describe the motion of the concrete slab. Neglect of the θ_x, θ_y, and Z degrees of freedom implies that the slab mass moves in a horizontal plane

In describing the shear structure system model, the words "model slab" are substituted for the words "lumped-mass," because the mass of the actual structure was simulated in the model with virtually infinite rigid slabs located at the elevations of the major floor slabs and roof of the structure

The mass of the walls between two floors was lumped to the floors that they connect. The mass of equipment supported on slabs in the actual structure is included in the calculated mass of the virtually infinite rigid slabs. The actual slabs are considered to be infinitely rigid in their own planes. The rigid body motions of the model slabs consist of three degrees of freedom: horizontal translation in two perpendicular directions and rotation about a vertical axis. The model slabs are interconnected by weightless elastic springs that possess stiffness in the x- or y-direction and simulate the shear walls and vertical bracing in the structure. These springs are distributed horizontally on the model slabs so that the torsional stiffness interconnecting two slabs is approximated

Since the ends of the springs are considered to be horizontally distributed on the spatial extent of the model slabs, the model slabs are not point masses. Rather, they may be thought of as rigid bodies with horizontal dimensions only, because the mass of the actual structure has been considered to be lumped in the planes of the model slabs. This is the advantage of the slabspring model over the lumped-mass frame model

Three coordinates are required to describe the motion of each model slab. Therefore, three mass parameters are determined for each model slab. These mass parameters for the ith slab of the model are

1. M_{xi}, associated with x-translation
2. M_{yi}, associated with y-translation
3. $I_{\theta i}$, associated with the rotation about a vertical axis.

The mass parameters associated with x-translation and y-translation are the same and are equal to the mass of the slab. The mass polar moment of inertia, θ_z, is about a vertical axis through the centroid of the slab

To evaluate the stiffness of the structural components that interconnect slabs, the following assumptions are made.

1. All floor and roof slabs are considered rigid in their own planes; no point can displace another point relative to it on the same slab

2. Walls interconnecting slabs offer resistance only to relative displacement of slabs parallel to their line of action

3. The stiffness of small reinforced-concrete columns or walls and steel framing other than the braced bents is neglected, because their stiffness is small compared to the stiffness of shear walls.

When resisting lateral loads applied parallel to the long dimension, most walls act as short, deep beams; therefore, the contribution of shear to the deflection is considered in calculating the stiffness of a wall

The stiffness of steel framing which acts as springs was evaluated with conventional elastic frame or truss analysis computer programs such as EASE (Section 3.13)

Dynamic analysis of the shear structure systems was accomplished with the computer program DSASS. The input to DSASS is compiled by using the code, Spring Slab Analysis (SSANA). The centroid, total weight, and the weight moment of inertia about the vertical centroidal axis of the slabs; the spring constants; and the location of springs with respect to the slab centroid were calculated by SSANA. The description and analytical details of programs SSANA and DSASS are in Section 3.13.

b. <u>Frame structure system</u> - In the shear structure system, the motion of the structure's mass is restricted to a horizontal plane. For many structural systems under dynamic loading, motions are not restricted to a horizontal plane, and all six possible degrees of freedom of the discrete masses are required to describe the dynamic behavior of the structure. Dynamic analysis of this type of structure was accomplished by the program MASS-IV. This is a general frame program that can be used to analyze a plane frame, truss, grid, space truss, and space frame

c. <u>Combined shear-frame structure system</u> - The shear-type structures with three degrees of freedom for each slab mass and the frame-type structures with six degrees of freedom for each mass could both be present in a building system. The analysis of a coupled shear-frame structure was performed by DYNAS, which combines the features of DSASS and MASS-IV. Rigid or flexible frame members are used to connect the joints of the frame members to the slab centroids where interconnections exist.

<u>Vertical Analysis</u>

The dynamic behavior of a building in the vertical direction is a function of the wall axial stiffness, the floor system flexural stiffness, and the mass distribution. An examination of the vertical mass distribution of a building structure shows that there are mass concentrations at the floor elevations. A plane-frame model was developed to simulate the behavior of the building in the vertical direction.

Figure 3.7-11 shows an example of a plane frame, typical of that used to simulate a building's dynamic response in the vertical direction. The horizontal members in the model simulate the flexural stiffness of the floor systems. The lumped masses shown on the schematic simulate the mass of the building structure and the mass of equipment supported by the structure. Although only two wall systems are shown in Figure 3.7-11, any number of wall systems can be incorporated in an analysis. The number of wall systems depends upon the layout of the structure to be analyzed. The mass distribution in the model consisting of the actual structure's mass concentrated at floor slab elevation is distributed between the walls and the horizontal members. This mass distribution is used because part of the actual structure's mass moves with the walls, whereas part of the mass motion is amplified because of slab flexibility. The flexural stiffness of the horizontal members is adjusted to represent the stiffness of the actual floor systems. Since a floor system consists of slabs of various thicknesses, beams, and openings, and since it is supported by interior and exterior walls, many periods of vibration occur in the floor system at a single elevation when a building structure is subjected to vertical seismic loading. Therefore, the periods of vibration of a floor system cannot be simulated by a single horizontal member in a frame model. For this reason, a multimember-mass system has been used to simulate a complex floor system (see upper level on Figure 3.7-11). Each member-mass system is adjusted to have frequency characteristics matching one of the calculated frequencies of the actual slab system. The analysis of the vertical model is performed by the MASS-IV program.

Response spectra are generated at each mass of the system used to represent a slab. These spectra are plotted on a single plot and enveloped with a smooth curve. The floor slabs were designed by using seismic coefficients obtained from the rigid end (frequency response greater than 33 Hz) of the resulting spectra. Vertical seismic stresses in the building walls were obtained from the vertical members of the vertical models. Equipment supported on a slab was designed using the resulting spectra as the vertical seismic load. Equipment located near walls was designed using response spectra generated on masses located on the vertical members.

3.7.2.1.2.2 Description of Mathematical Models

Horizontal Seismic Analysis

The massive stiff floor slab-shear wall configurations of the reactor/auxiliary building (Figures 3.7-12 through 3.7-14) and the RHR complex are modeled as a slab-spring system. The slabs, treated as infinitely rigid in their own planes, are interconnected by weightless linear elastic springs used to simulate the stiffness of shear walls within the structural system, as described in Subsection 3.7.2.1.2.1.

Rotations about the horizontal axes could be significant in the reactor containment portion of the reactor/auxiliary building. Since these degrees of freedom, θ_x and θ_y, cannot be modeled with the slab model, a conventional three-dimensional frame analytical model is used to model the containment shield, the containment vessel, the RPV and internals, the reactor support pedestal, and the biological shield. The lumped masses in this portion of the model are allowed X, Y, θ_x, θ_y, and θ_z degrees of freedom, and are interconnected with frame members. The slab model and the frame model are connected by axial springs at various elevations to represent the behavior of the actual structure more accurately. The configuration of this model is shown in Figure 3.7-15 except for the model of the RPV and its internals, which is shown in Figure 3.7-16. The RPV is supported by the reactor pedestal at Mass 29 and laterally supported at Masses 26 and 32 by the refueling bellows and stabilizer, respectively. The seismic methods and analysis procedures for the RPV and its internals are described in Subsection 3.7.3.15.

The reactor building crane bridge and associated steel structures (between the fifth floor and the roof) have been simulated in the horizontal dynamic model as shown in Figure 3.7-17. The model is based on the assumption that the crane would be parked at the end bay during a seismic event. The vertical lines represent steel columns connected by rigid members at the bottom and top ends to the mass centroids of Slabs 5 and 6, respectively. (NOTE: Subsequent to the original analysis, an analysis (Reference 22) was performed which qualifies the crane girder steel superstructure interior support columns for the crane deadload plus rated load combined with either wind or seismic loads. The additional analysis assumes that the overhead crane is located anywhere along the crane's travel path to maximize the member stresses.)

The mass parameters of the reactor/auxiliary building slabs in the dynamic model are presented in Tables 3.7-3 and 3.7-4. These mass properties are calculated by considering the mass of the actual structure concentrated at the slab elevations, and distributed laterally on virtual infinitely rigid slabs in accordance with the lateral mass distribution in the structure. Therefore, each model slab represents the concrete of, and equipment on, actual slabs and the tributary mass of equipment structure between slabs. Both the translational and rotational inertia of the actual structure are taken into consideration.

The lumped masses in the frame part of the reactor/auxiliary building model are calculated from the physical properties of the containment and reactor support system, and are also presented in Table 3.7-4. However, the properties of the masses for the RPV are not included in this table.

The stiffness elements that interconnect the lumped masses of the dynamic models are shown schematically in Figure 3.7-15 for the reactor/auxiliary building and Figure 3.7-18 for the RHR complex. The solid vertical lines interconnecting slabs represent groups of linear elastic springs that simulate the stiffness of the walls in the structural complex. The walls in the building complex that are considered to act as springs are shown in Figures 3.7-19 through 3.7-24 for the reactor/auxiliary building, and Figures 3.7-25 through 3.7-27 for the RHR complex with walls parallel to the X-axis treated as X-springs and walls parallel to the Y-axis treated as Y-springs.

Each wall or group of walls considered to act as a spring in this analysis is assigned a six-digit identification number which is shown on the figures. For any identification number that does not have six digits, leading zeros are implied. The digits of the identification number convey the following information:

a. <u>First two digits</u> - slab number that the lower end of the spring is connected to

b. <u>Second two digits</u> - slab number that the upper end of the spring is connected to

c. <u>Third two digits</u> - ith spring with its lower end connected to the slab given by the lst two digits (if the 3rd two digits form an even number, the wall is a Y-spring and if these two digits form an odd number, the wall is an X-spring).

Frame members in the reactor containment portion of the model are represented on Figure 3.7-15 with dashed lines. The properties of these members are calculated from the physical properties of the primary containment, the reactor support pedestal, and the biological shield. Table 3.7-5 presents the properties and the topography of the frame members of the reactor/auxiliary building model, except for the members of the RPV part of the frame model. To eliminate assigning artificial horizontal distances between the centroids of masses in the containment and pedestal-shield cantilevers, the stiffness of the connections represented by horizontal dotted lines in Figure 3.7-15 is given in Table 3.7-6 as stiffness coefficients.

To evaluate the stiffness of the structural components that interconnect the masses of the shear models shown in Figures 3.7-15 and 3.7-18, the following assumptions have been made:

a. All points on the same slab translate in the horizontal plane passing through the mass-center of the slab and the slab rotates only about the vertical axis

b. The walls offer resistance to relative displacements between slabs only in their longitudinal direction.

When resisting lateral loads applied parallel to the long dimension, most walls act as short, deep beams; therefore, the contributions of both flexure and shear to the deflection must be considered in calculating the stiffness of a wall. The stiffness of an individual wall was calculated by the following formula:

$$K = \frac{1}{\Delta} \tag{3.7-3}$$

$$\Delta = \frac{1.2h}{GA} + \frac{h^3}{12EI} \tag{3.7-4}$$

where

h	=	height of wall
I	=	moment of inertia of wall for bending about centroidal axis perpendicular to length of wall
A	=	cross-sectional area of wall
E	=	elastic modulus of concrete
G	=	shear modulus of concrete
K	=	stiffness
Δ	=	deflection of wall due to a unit force

Vertical Seismic Analyses

No attempt was made to set up a three-dimensional model on account of the excessive number of degrees of freedom. The vertical dynamic model of the building was developed on the basis that the amplification in the vertical direction is a function of the axial stiffness of the walls and bending stiffness of the beam-slab system.

The vertical stiffness is due mainly to two structural systems in each model. They are

a. Reactor/auxiliary building model

   1. The reactor containment shield (right side of Figure 3.7-28)

   2. Reactor/auxiliary building walls (left side of Figure 3.7-28).

b. RHR complex model

1. The cooling tower walls (right side of Figure 3.7-29)
2. The RHR building wall (left side of Figure 3.7-29).

The two wall systems are connected by the reactor building floor slab at all the floor elevations for the reactor building model and at Elevation 617 ft for the RHR complex model. The auxiliary building floor slab is represented by a single-degree-of-freedom system connected to the joints of the reactor/auxiliary building wall system at each elevation.

In the dynamic model formulated for these analyses, the masses can displace, relative to one another, with one degree of freedom in the vertical direction. The mass parameters are calculated in the following manner:

a. The masses are concentrated at joints (as shown in Figures 3.7-28 and 3.7-29) and interconnected by weightless linear springs that simulate the stiffness of the slabs or walls
b. In general, the wall masses are lumped equally to the nearest joints
c. For the slabs, it has been assumed that one-third of the total slab mass is effective; the remaining mass of the slab was lumped with the wall mass at that elevation
d. The mass of the reactor containment shield includes only the mass of concrete and contributory slab mass.

The determination of the spring stiffness and the modification of the original model, to simulate higher mode contribution of slabs, is described as follows:

a. <u>Wall springs</u> - For the wall system, the effective area is the sum of the areas of all the individual walls at a particular level. The walls that are connected monolithically with the top and bottom slab only, provide vertical stiffness. For the reactor containment shield, the effective area is that of a circular ring. In cases where the radius changes between two mass points, the average area is used
b. <u>Slab springs</u>
   1. <u>Slab natural frequency</u> - The stiffness of a member representing a slab in the vertical model simulates the lowest natural frequency of the slab. As a grid model is analyzed to determine the lowest natural frequency of a typical slab, the frequencies of other floors are determined based on the grid analysis and standard formulae
   2. <u>Modification of the model</u> - To determine the response spectrum of the slab at a particular level, the model is modified at that level to include the multi-degree behavior of the slab system. The stiffness and mass properties of slabs at other levels are not changed and correspond to the lowest fundamental frequency of the slab at that level. The modified vertical model for determining slab response spectrum at Elevation 684 ft 6 in. of the reactor /auxiliary building is shown in Figure 3.7-30. The slab system at this level consists of six masses and the springs on each side are connected to the same wall joint. The total effective slab mass is

divided by the number of masses and is assigned to each individual mass. In this case, Mass l simulates the stiffness of the lowest natural frequency of the slab as calculated before, and the rest of the masses were assigned frequencies higher than the calculated natural frequency at regular intervals. The highest frequency assigned, 30 Hz (Reference 25), has negligible amplification. Similarly, the stiffness parameters of the auxiliary building slab system are determined. The model for Elevation 6l3 ft 6 in. of the reactor/ auxiliary building is shown in Figure 3.7-31. The model for the RHR complex is shown in Figure 3.7-29.

3.7.2.1.2.3 Analysis of Mathematical Models for Structures

To determine the free vibrational characteristics of the dynamic models, the model equation for a multi-degree lumped-mass system may be written as

$$[\mathrm{M}]\{\ddot{\mathrm{x}}\} + [\mathrm{K}]\{\mathrm{x}\} = 0 \qquad (3.7\text{-}5)$$

where

[M]	=	mass matrix
[K]	=	stiffness matrix
$\{x\}$, $\{\ddot{x}\}$	=	displacement, acceleration vectors

where the mode shapes and frequencies are solved in accordance with

$$[\mathrm{K} - \omega_n^2 \mathrm{M}]\{\phi_n\} = 0 \qquad (3.7\text{-}6)$$

This set of equations has as eigenvalues the squares of the circular natural frequencies, ω_n. Associated with each frequency is a mode shape ϕ_n which may be arranged as one of the columns of the matrix $[\phi]$.

The modal participation factors are given by

$$[\Gamma]\ \mathrm{n_i} = \frac{[\phi]^{\mathrm{T}}[\mathrm{M}]\ [\mathrm{D}]_{\mathrm{i}}}{[\phi]^{\mathrm{T}}\ [\mathrm{M}]\ [\phi]} \qquad (3.7\text{-}7)$$

where

$[\Gamma]n_i$	=	participation factor
$[\phi]^T$	=	transpose of mode shape vector for nth mode
$[D]_i$	=	earthquake direction vector referring to direction i

The response of the system in one mode, A_i, is given by

$$A_{\mathrm{i}} = \begin{Bmatrix} \mathrm{a_i^1} \\ \mathrm{a_i^2} \\ \vdots \\ \mathrm{a_i^n} \end{Bmatrix} = \mathrm{T_i}\ \{\phi_{\mathrm{i}}\}\mathrm{R_i} \qquad (3.7\text{-}8)$$

where

$\{\phi_i\}$ = one column of the matrix $[\phi]_n$ corresponding to the mode

T_i = corresponding element in column matrix of $[T_i]$

R_i = response of a single-degree-of-freedom system of period T_i and damping ratio B_i from specified ground response spectrum for the site

At any mass coordinate in the system, the total response, $\frac{k}{a}$, is given by

$$\frac{k}{a} = \sqrt{\sum_{i=1}^{n}\left(a_i^k\right)^2} \qquad (3.7\text{-}9)$$

where

a_i^k = response at coordinate k in ith mode

n = number of modes

Floor slab-shear wall type structures are modeled as a slab spring system in which the mass of the structure is lumped at floor slab elevations. The weight of each shear wall is lumped equally between the floor slab above and the floor slab below. The containment vessel, the concrete shield wall, the sacrificial shield, and the reactor support pedestal were modeled with a sufficient number of lumped masses so that all the modes up to 33 Hz can be extracted. The number of lumped masses for these elements was at least three more than the number of modes below 33 Hz as determined from closed form solutions.

Dynamic analysis has been carried out to include all the significant response modes.

The applicable stress/deformation criteria are described in Subsection 3.8.4.

3.7.2.1.2.4 Basis for Computing Combined Responses

In the original design performed in 1971, horizontal and vertical seismic effects were not combined in the structural design. In subsequent analyses, the effects of two statistically independent time histories were added algebraically and then combined with the vertical component effect by the SRSS rules.

3.7.2.1.3 Buried Electrical Ducts

3.7.2.1.3.1 General

There are two sets of Category I ductbanks between the RHR complex and the Reactor/Auxiliary building, with a Division I and Division II ductbank in each set. The first set of ductbanks was installed during plant construction. The analysis of these Category I buried electrical ducts is described in the following paragraphs.

The forces in the duct due to wave propagation in soil and rock are determined (Reference 7). The duct design is required to take into account the relative seismic displacements at its anchor points with the building, in addition to the strains induced due to wave propagation in the surrounding soil. The anchorage of the duct with the building and manhole is designed to be flexible such that 1 in. maximum displacement in any direction is allowed for analytical purposes. Thus, if the relative displacement of the buildings and duct at the anchorage is less than the maximum allowable displacement of 1 in., the flexural strains are only due to wave propagation.

The analytical procedure used to evaluate the seismic influence on buried electrical ducts considers the soil condition at the plant site. The method of analysis follows the method of Reference 8.

The second set of Category I 4160-V electrical ductbanks run between the RHR cable vaults and the Reactor/Auxiliary building cable vaults. These ductbanks (including the cable vaults and manholes) are designed as Seismic Category I components. The buried portion of the ductbank is designed for seismic response effects utilizing the approach identified in ASCE 4-98, as endorsed by NUREG-0800 Standard Review Plan, section 3.7.3 Revision 3 (March 2007). This approach is an extension of the Fermi 2 methodology used for the first set of Category I ductbanks. This extended methodology provides an accurate analytical means for the prediction of the seismic responses of buried structural components, specifically at bends and other geometric discontinuities, precluding the need for physical measures (such as loosely compacted sand) at these discontinuities. The ductbanks connecting to rigid structural components, such as the manholes and the transition vaults at the RHR and Auxiliary buildings, are provided with one inch physical gaps, similar to that for the first set of Category I ductbanks, to preclude locked in stresses due to potential differential displacements during and after postulated seismic events.

3.7.2.1.3.2 Analysis

The design of the ducts ascertains that the stresses caused by the strains do not exceed the acceptable safe limits in the event of an SSE.

The maximum axial strain in the straight portion of a duct has an upper bound equal to the maximum strain in the surrounding soil in the direction of the duct. If the wave length is much larger than the straight portion of the duct, the maximum strain in the duct is assumed to be uniform along the duct run. However, in cases where the duct is very long, the duct displaces relative to the surrounding soil because of strain incompatibility between the soil and the duct. The relative displacement between the soil and the end of the duct is determined by deducting frictional restraint to the movement of the duct from the upper-bound soil displacement in the direction of the duct.

The effect of axial displacement of a straight portion of duct relative to the soil, at bends and at juncture points, is evaluated by the "beam on elastic foundation" concept. To obtain forces in the bend, each bend is subjected to the relative displacement as obtained previously. A fill of well-graded, loosely compacted sand is provided on either side of the bend to avoid concentration of forces around the bend due to stiff subgrade, and to distribute the subgrade stresses uniformly.

The design of the new Category I 4160-V electrical ductbanks that run between the RHR cable vaults and the Reactor/Auxiliary building cable vaults uses a more conservative approach at bends and elbows. In the analysis, the elbow is treated as an inflexible structure, whereas longitudinal and traverse legs are treated as flexible structures, as outlined in the ASCE Report “Seismic Response of Buried Pipes and Structural Components” (1983) (Referenced in NUREG-0800, Standard Review Plan 3.5.3). Therefore, loosely compacted sand fill is not required on either side of the ductbanks bends.

The concrete structures of the new Category I 4160-V electrical ductbanks were analyzed using the guidance in accordance with ACI 349-01 “Code Requirements for Nuclear Safety

Related Concrete Structures" and Regulatory Guide 1.142 "Safety-Related Concrete Structures for Nuclear Power Plants (Other Than Reactor Vessels and Containments)".

For both the new and existing ductbanks, effects of flexural strains were evaluated at points of maximum possible curvature between the duct attachment points. As commonly observed, the strains associated with such effects were found to be negligibly small from the practical design standpoint.

The corresponding effects of flexural strains were similarly evaluated by means of calculation from the maximum possible curvature between the duct attachment points. As commonly observed, the strains associated with such effects were found to be negligibly small from the practical design standpoint.

3.7.2.1.4 Seismic Design of Category I Buried Piping

The seismic analysis of buried piping located between the RHR complex and the reactor/auxiliary building is performed in exactly the same way as the seismic analysis of buried electrical ducts described in Subsection 3.7.2.1.3. The stresses/strains do not exceed the acceptable safe limits in the event of an SSE.

During the course of safety evaluation review, at the request of the NRC, additional information on this was submitted. Included was Reference 9, which discussed lateral pressure and the analysis of buried piping, and which forwarded a February 3, 1970, D&M report, Reference 10. Also included were References 11 and 12, which added to the information provided by References 9 and 10.

The Category I structures and buried pipes and conduits have been structurally reassessed for the effect of the SSE.

In reference to LOCA stresses, the pertinent information on original load combinations and respective stress components, including those resulting from a LOCA, have been presented in Chapter 4 and in appendixes of the reassessment report.

The three components of the earthquake have been considered in the reassessment report. Two horizontal components have been considered to be acting simultaneously, and the vertical component has been added as an absolute sum or square root of the sum of the squares as appropriate.

A damping value of 7 percent has been used in accordance with Regulatory Guide 1.61, since the Category I structures are of reinforced-concrete construction, and the structural elements are highly stressed for the site-specific earthquake loading.

3.7.2.2 Natural Frequencies and Response Loads

The analysis of the models developed in Subsection 3.7.2.1 yields the natural frequencies, mode shapes, and modal responses of the overall system. These results are presented for both the horizontal and vertical analysis.

3.7.2.2.1 Reactor/Auxiliary Building

3.7.2.2.1.1 Horizontal Analysis

a. Frequencies and mode shapes - The periods, mode shapes, and dynamic response of the lumped-mass system are computed with the use of DYNAS. Table 3.7-7 presents the summary of the first 20 modal periods, the modal participation factors for X-direction base excitation, and the modal participation factors for Y-direction base excitation

b. Response spectrum - The program DYNAS was used to perform the time-history analysis of the dynamic model, damped with 2 percent and 5 percent of critical damping for the OBE and SSE, respectively, and to generate response spectra at selected mass centroids for E-W and N-S base excitations. Newmark's β-method of numerical integration for a linear system with time-dependent input base motion, combined with modal superposition, was used to obtain the motions of the lumped masses. The time-histories of the mass motions were not printed out of computer storage because of the large quantity of data, but rather response spectra generating subroutine used the stored slab motions to generate response spectra for specified masses

   Separate spectra curves are not plotted for the N-S excitation and the E-W excitation; rather, at each spectra period for a given spectra damping, the average response from the four N-S excitations from Subsection 3.7.1, and the average response from the four E-W excitations from Section 3.7.1 were calculated, and the maximum of the averages was plotted. The plotted spectra curves, with their valleys and peaks, were smoothed by enveloping the peaks with the envelope at a peak extending ten percent, on the period scale, to either side of the peak. The resulting smooth curves are presented in Figures 3.7-32 through 3.7-55 for OBE and Figure 3.7-56 through 3.7-79 for SSE

c. Displacement response - Table 3.7-8 summarizes the probable displacements obtained from this analysis.

3.7.2.2.1.2 Vertical Analysis

a. Frequencies and mode shapes - The vertical model shown in Figures 3.7-28, 3.7-30, and 3.7-31 has been analyzed by the MASS-IV program. Table 3.7-9 lists the periods and participation factors for 24 modes for the model shown in Figure 3.7-30. The variation of main structural period in models shown in Figures 3.7-28, 3.7-30, and 3.7-31 is negligible

   The vertical analysis was used to generate response spectra for the design of Category I equipment located at different floor levels. The forces in the structure are also determined by the response spectra method.

   The slabs and shear walls of the reactor building and the reactor containment are designed to withstand these forces due to vertical excitation

b. Response spectrum - A computer program, MASS-IV, was used to analyze the vertical models and generate vertical response spectra.

Response spectra were generated at two elevations (Elevation 613 ft 6 in. and 684 ft 6 in.) at the reactor containment shield, reactor/auxiliary building wall, reactor building slab, and auxiliary building slab for OBE (2 percent structural damping) and SSE (5 percent structural damping). The spectra at other elevations were not generated, but were classified in one of the two levels. At each period considered in the spectra generation process, the average response from the four earthquakes was calculated. These averages were plotted. The rough curves were smoothed by enveloping the peaks and extending 20 percent to either side of a peak. The vertical response spectra are presented in Figures 3.7-80 through 3.7-88 for OBE and in Figures 3.7-89 through 3.7-97 for SSE.

3.7.2.2.2 Residual Heat Removal Complex

3.7.2.2.2.1 Horizontal Analysis

a. Frequencies and mode shapes - The periods and mode shapes and dynamic responses of the lumped-mass system are computed by the use of DYNAS. A summary of the model periods and modal participation factors for the x and y excitations is presented in Reference 13

b. Response spectrum - The program DYNAS was used to perform the time-history analysis of the dynamic model, damped with 2 percent of critical damping, and generate response spectra at selected mass centroids for E-W and N-S base excitations. Newmark's β-method of numerical integration for a linear system with time-dependent input base motion, combined with modal superposition, was used to obtain the motions of the lumped masses. The time-histories of the mass motions were not printed out of computer storage because of the large quantity of data, but rather response spectra generating subroutine used the stored slab motions to generate response spectra for specified masses

   Separate spectra curves were plotted for the N-S excitation and the E-W excitation; at each spectra period for a given spectra damping, the average response from the four N-S excitations and the average response from the four E-W excitations were calculated

   The plotted spectra curves, with their valleys and peaks, were smoothed by enveloping the peaks with the envelope at a peak extending 10 percent, on the period scale, to either side of the peak's period

   The representative resulting smooth curves are presented in Figures 3.7-98 through 3.7-101 for OBE and in Figures 3.7-102 through 3.7-105 for SSE.

3.7.2.2.2.2 Vertical Analysis

a. Frequencies and mode shape - The periods, mode shapes, and dynamic response of the lumped-mass system are computed by the use of MASS-IV. A summary of the modal periods and modal participation factors for the x and y excitations is presented in Reference 13

b. Response spectrum - MASS-IV was used to analyze the vertical models and to generate vertical response

Response spectra were generated at two elevations (Elevation 590 ft, 0 in. and Elevation 617 ft, 0 in.) at the building walls and the building slabs for OBE (2 percent structural damping) and SSE (5 percent structural damping)

At each period considered in the spectra generation process, the average response from the four earthquakes was calculated. These averages were plotted. The rough curves were smoothed by enveloping the peaks with a smooth curve, which, as the period scale, extends 20 percent to either side of a peak. The representative vertical response spectra are presented in Figures 3.7-106 through 3.7-110 for OBE and in Figures 3.7-111 through 3.7-115 for SSE.

3.7.2.3 Procedures Used To Lump Masses

For dynamic analysis, Category I equipment was represented by lumped-mass systems that consist of discrete masses connected by weightless springs. The criteria used to lump masses were

a. Because the number of modes of a dynamic system is controlled by the number of masses used, the number of masses was chosen so that all significant modes are included

b. Mass was lumped at any point where a significant concentrated weight is located. Examples are the motor in the analysis of pump motor stand, and the propeller in the analysis of pump shaft

c. If the equipment has a free end overhang span whose flexibility is significant compared to the center span, a mass was lumped at the overhang span

d. When a mass was lumped between two supports, it was located at a point where the maximum displacement was expected to occur. This tends to conservatively lower the natural frequencies of the equipment. Similarly, in the case of live loads (mobile) and a variable support stiffness, the location of the load and the magnitude of support stiffness were chosen so as to yield the lowest frequency content for the system. This is to ensure conservative dynamic loads since equipment frequencies are such that the floor spectra peak is in the lower frequency range.

Slab masses were lumped in accordance with the procedures described in Subsection 3.7.2.1.2.1.

3.7.2.4 Rocking and Translational Response Summary

The site response spectra developed for Fermi 2 are the bedrock spectra. Since the Fermi 2 Category I structures are founded directly on bedrock, the rocking and translational effect due to soil structure interaction is not applicable to this location. See Subsection 3.7.1.6 for a description of the studies that document that the Fermi 2 site behaves as a rigid foundation.

3.7.2.5 Method Used To Couple Soil With Seismic System Structures

Fermi 2 Category I structures are all founded on bedrock and do not require an evaluation of soil structure interaction (Subsection 3.7.1.6).

3.7.2.6 Development of Floor Response Spectra

3.7.2.6.1 Introduction

If a structure is subjected to an earthquake, the base of a subsystem (or equipment) mounted on a floor slab or wall experiences the motion of the slab or wall. This motion may be significantly different from the input motion at the base of the structure. Therefore, the response spectra used in the analysis of the structure are not directly applicable to the analysis of subsystems mounted in the structure unless the subsystem element is modeled in the dynamic model of the structure. Also, unless the subsystem element is a rigid mass, rigidly connected to the slab or wall, the motion of the subsystem is different from the motion of the slab or wall, because the subsystem element is a flexible elastic system that responds dynamically to the motion of the slab. For these reasons, the motion experienced by a subsystem is the structure's base excitation modified as a function of the structure's characteristics, the subsystem's characteristics, and the mode of attachment to the structure.

To establish explicit slab or wall motions, applicable to development of subsystem design criteria, time-history forcing functions were used to excite the building models used in the system analysis. Resulting time-history slab or wall motions were used to generate response spectra for the analysis of subsystems supported in the building.

3.7.2.6.2 Horizontal Response Spectra

The seismic models used to generate the response spectra at various building elevations are described in Subsection 3.7.2.1.2. The base input forcing functions are described in Subsection 3.7.1.2 and shown in Figure 3.7-2 for OBE, and 3.7-3 for SSE. Site-specific analyses were completed using statistically independent synthesized time histories in orthogonal directions. The response spectrum evaluations for the reactor/auxiliary building and the RHR complex are described in Sutbsection 3.7.2.2.2. Representative reactor/auxiliary building horizontal response spectra for selected building elevations are shown in Figures 3.7-32 through 3.7-55 for OBE and Figures 3.7-56 through 3.7-79 for SSE. Representative RHR complex response spectra are shown in Figures 3.7-98 through 3.7-101, and 3.7-102 through 3.7-105 for OBE and SSE, respectively. The spectra ensemble defining the facility aseismic design bases is described in Subsection 3.7.2.2.1.1.

3.7.2.6.3 Vertical Response Spectra

The scaled time-history forcing functions for the vertical direction (Subsection 3.7.1.2) were used to perform time-history analyses of the vertical seismic models described in Subsection 3.7.2.l.2.2. A single synthesized time history was used for the site-specific evaluation.

The procedure for determining subsystem response spectra in the vertical direction is the same as for the horizontal direction, as described in Subsections 3.7.2.2.1.2 and 3.7.2.2.2.2.

In this case, response spectra were generated for uncoupled time-history motion in the vertical or z direction.

The resulting reactor/auxiliary building vertical response spectra for selected building elevations are shown in Figures 3.7-80 through 3.7-88 for OBE and in Figures 3.7-89 through 3.7-97 for SSE. The RHR complex response spectra are shown in Figures 3.7-106 through 3.7-110 and 3.7-111 through 3.7-115 for OBE and SSE, respectively.

3.7.2.7 Differential Seismic Movement of Interconnected Components

The effects of differential movements of interconnected components due to seismic disturbance were considered in the seismic analysis of the piping systems and components where they contribute significantly to the overall response (Subsection 3.7.3.6).

All means and mechanisms of interconnection are designed to limit the applicable stress and deformation to within the ASME Section III Code Allowable Limits.

3.7.2.8 Effects of Variations on Floor Response Spectra

The increase in peak width, to account for variations in structural properties and damping, is described in Subsection 3.7.2.2. Variations in material properties are described in Subsections 3.7.2.15.2 and 3.7.2.15.3.

3.7.2.9 Use of Constant Load Factors

Vertical seismic system multi-mass dynamic models were used to obtain vertical response loads for the seismic design of Category I structures, systems, and components (Subsection 3.7.2.1). A constant load factor was used only when it was established that the structure, system, and/or component under consideration was rigid.

3.7.2.10 Method Used To Account for Torsional Effects

Category I structures may have natural torsional modes of vibration due to eccentricities between the centers of rigidity and centers of mass of the structural elements. As described in Subsection 3.7.2.1.2.2, the torsional response was accounted for by interconnecting the slab with weightless resisting elements, parallel to the x and y axes, distributed on the slabs as the shear walls are distributed in the structure.

3.7.2.11 Comparison of Responses

The forces obtained from the response spectrum method of analysis were used in the design of structural components of the building. The floor response spectra were generated by time-history analyses (Figures 3.7-32 through 3.7-115). Comparisons of accelerations were made at various elevations in the building to ensure that the floor response spectrum was obtained from a seismic load equivalent to or greater than the seismic load specified by the site response spectra.

3.7.2.12 Methods for Seismic Analysis of Earth Structures

The design of Fermi 2 does not include Category I earth structures except the shore barrier which was designed to meet Category I requirements. The shore barrier was analyzed using the computer code ICES-SLOPE. Details on slope stability analysis of the shore barrier were provided to the NRC staff during their safety evaluation review (see Subsection 3.4.4.5 and References 14 through 17).

3.7.2.13 Methods To Determine Category I Structures/Overturning Moments

The overturning moments induced by seismic excitation were computed by applying the inertia forces determined in Subsection 3.7.2.1, with vertical inertia forces taken upward, reducing the structure's effective weight. The inertia force on each mass was determined by computing the square-root-of-sum-of-squares of the modal acceleration contributions for that mass. Tensile base reactions were not allowed.

3.7.2.14 Analysis Procedure for Damping

Structural damping is energy loss due to internal friction within the structural material and at connections. The damping force is a function of the intensity of motion and the stress levels induced in the system. Damping is also highly dependent on the makeup of the structural system and the energy absorption mechanisms within the system. Considerable energy is also absorbed at cracked surfaces when the elements on each side of the crack can move relative to one another. In the linear dynamic analysis, the procedure used to account properly for the previous damping in different elements of a coupled system model was as follows:

a. The structural damping of the various elements of the model was first specified. These values are referred to as the damping ratios (Bi) of the various components making up the complete systems

b. A modal analysis of the linear system model was performed. This results in a modal column matrix (ψ) normalized such that $\psi T\ M\psi = I$; where M is the mass matrix, I is the identity matrix, and ψT is the transpose of ψ

c. Using the kinetic energy of the individual components as a weighting function, the following equation was used to obtain a suitable damping ratio (Bi) for the ith mode.

$$B_i = \psi^T \left[B_j\right] M\psi \qquad (3.7\text{-}10)$$

The diagonal terms of this matrix product are the modal damping ratios (B_i) of the coupled system. The damping ratios (B_j) of the individual substructures making up the complete system under investigation were used as input to [B_j] in order to calculate B_i.

3.7.2.15 Miscellaneous Considerations

3.7.2.15.1 Parametric Study

To evaluate the effects of the variation in mass-stiffness parameters on the seismic response of the building systems analyzed, several cases were studied by varying the original stiffness properties, or original mass properties, or both.

3.7.2.15.2 Structural Material Parameter

The modulus of elasticity, e_c, for concrete is taken as

$$e_c = (W^{1.5})33\sqrt{f_c'} \qquad (3.7\text{-}11)$$

where

W = density of concrete, lb/ft^3

f_c' = specified compressive strength of concrete, $lb/in.^2$

The modulus of elasticity of nonprestressed steel reinforcement and steel structures is taken as $29 \times 10^6\ lb/in^2$.

3.7.2.15.3 Interconnecting Category I and Other Structures

No Category I and nonseismic structures are integrally connected. The nonseismic structure is provided with sufficient seismic rattlespace or a flexible boundary layer to ensure that there is no effect on the adjacent Category I structure.

3.7.3 Seismic Subsystem Analysis

3.7.3.1 Determination of Number of Earthquake Cycles

Seismic loading cycles were considered for those Category I systems requiring fatigue analysis by applicable codes. The number of seismic cycles at maximum load per seismic event used on the various Category I systems and components varies from 5 to 250 cycles, depending on the component's natural frequency. In addition, the magnitude of the cyclic load varies with each component. The stated number of loading cycles was determined by actually performing a time-history analysis of reactor systems subjected to the full durations of the El Centro, Taft, and Olympia earthquakes. The number of cycles selected was always conservative with respect to the usage factor; an example of these cycles is presented as follows.

a. For components - ASME Section III NB-3650 requires that a number of earthquake cycles used in the analysis of ASME III Code components be specified as part of the design mechanical loads. The following criteria were used for all equipment within the jurisdiction of this code:

   1. A total of two OBEs and one SSE was assumed during the lifetime of the plant

   2. For conservative component design, structures were assumed to cycle (full sign reversal) 20 times per earthquake

3. Systems and components classified as relatively rigid with respect to local structural response will "ride" with the structure and are thus assigned 20 stress cycles per earthquake

4. If the system and/or component is relatively flexible (fundamental frequency equal to or less than 50 percent of structural fundamental frequency), a 20-cycle criterion governs.

b. For piping systems - The dynamic analysis using the floor response spectra as input motion performs an actual cycle count of the first mode vibration. The duration of the earthquake is taken as 10 sec and the result is adjusted to consider reduced stress range cycles. The number of effective cycles determined varies around 200. For valves and many other mechanical items, a conservative number of 250 is used.

For the GE-supplied equipment, the reactor/auxiliary building dynamic model was excited by the same time-histories as previously specified. The modal response was truncated such that the response of three different frequency bandwidths could be studied: 0-10 Hz, 10-20 Hz, and 20-50 Hz. This was done to give a good approximation to the cyclic behavior expected from structures with different frequency content. Using the results from the three earthquakes and averaging the results from several different points on the dynamic model, the cyclic behavior was formed (Table 3.7-10).

Independent of earthquake or component frequency, 99.5 percent of the stress reversals occur below 75 percent of the maximum stress level, and 95 percent of the reversals lie below 50 percent of the maximum stress level. This relationship is shown in Figure 3.7-116.

In summary, the cyclic behavior number of fatigue cycles of a component during an earthquake was found in the following manner:

a. The fundamental frequency and peak seismic loads were found by a standard seismic analysis

b. The number of cycles which the component experiences were found from Table 3.7-10 according to the frequency range within which the fundamental frequency lies

c. For fatigue evaluation, 1/2 percent (0.005) of these cycles are conservatively assumed to be at the peak load, and 4.5 percent (0.045) at three-quarter peak. The remainder of the cycles will have negligible contribution to fatigue usage, as their resultant stresses are well below the fatigue limits set forth in the ASME B&PV Code Section III.

The SSE has the highest level of response. However, the encounter probability of the SSE is so small that it was not necessary to postulate the possibility of more than one SSE during the life of a plant. Fatigue evaluation due to the SSE was not necessary since it is an emergency condition and thus not required by ASME B&PV Code Section III.

The OBE is an upset condition and therefore, must be included in fatigue evaluations according to ASME B&PV Code Section III. Investigation of seismic histories in the PSARs of many plants show that during a 40-year life it is probable that five earthquakes with intensities one-tenth of their individual prescribed SSE intensity, and one earthquake approximately 20 percent of their individual prescribed SSE intensity, will occur. Therefore, the probability of even an OBE is extremely low. To cover the combined effects of these earthquakes and the cumulative effects of even lesser earthquakes, one OBE intensity earthquake was postulated for fatigue evaluation. Table 3.7-11 shows the calculated number of fatigue cycles and the number of fatigue cycles used in design.

3.7.3.2 Basis for Selection of Forcing Frequencies

Amplified response spectra (floor) developed for horizontal (two directions) and vertical direction earthquakes was the basic source of seismic design accelerations. As noted in Subsections 3.7.1.2 and 3.7.3.6, seismic accelerations are selected from the amplified response spectra based on natural frequency calculations for the component or system. All frequencies in the range of 0.25 to 33 Hz were considered in the analysis and testing of structures, systems, and components.

3.7.3.3 Root-Mean-Square Basis

The term "root-mean-square basis" is not to be used in the procedure for combining modal responses. The SRSS is used to describe the method of combining modal responses when used herein and is described as follows:

$$R = \sqrt{\sum_{i=1}^{n}(R_i)^2} \qquad (3.7\text{-}12)$$

where

R = combined response

R_i = response in the ith mode

n = number of modes considered in the analysis

3.7.3.4 Procedure for Combining Modal Responses

When a response spectrum method of analysis is used to analyze a system or subsystem, the maximum response (displacements, accelerations, shears, and moments) in each mode is calculated independently of time; whereas, actual modal responses are nearly independent functions of time, and maximum responses in different modes do not necessarily occur simultaneously. The maximum possible response is given by the sum of the maximum modal responses without regard to sign. It has been shown that the probable maximum response is equal to the square root of the sum of the squares of the modal maxima. This square-root criterion is used in combining the modal responses in the response-spectrum method of analysis, except in combining closely spaced in-phase modes of vibration.

These closely spaced coupled modes of vibration are detected by computing the model's modal responses and then using both the square-root criterion and the absolute-sum criterion in combining modes. In many locations in a complex model, both criteria give nearly equal results, indicating that a single mode is contributing to the response. If the two criteria give results that differ by a large amount, then more than one mode is contributing to the response. The modes that contribute are examined; if they are closely spaced coupled modes, they are combined using the absolute-sum criterion and are treated as a single mode when combined with the rest of the modes using the square-root criterion.

When the time-history method of seismic analysis is used, the physical displacements, accelerations, shears, and moments due to each mode are added algebraically at each instant of time. Hence, no criterion concerning the method of combining loads from the individual modes needs to be set.

3.7.3.5 Significant Dynamic Response Modes

All significant modes were included in modal dynamic analysis. Generally, the number of significant modes varied between 10 and 30 modes.

A static analysis was used in seismic design if the component, structure, or equipment was essentially rigid or could be properly represented by a single-degree-of-freedom system. If it was rigid, the static load was based on the zero-period acceleration.

If it could be properly represented by a single-degree-of-freedom system, the static load was based on the acceleration corresponding to the natural period of the system. Using the peak of the floor spectrum curve was a conservative approach.

When a static analysis based on the peak floor spectrum curve was used in the seismic design of a component, structure, or piece of equipment that could not be represented by a single-degree-of-freedom system, an amplification factor was used to bound anticipated multi-mode phenomena, or it was ensured that the fundamental natural period of the system was far enough from the period corresponding to the peak value. Therefore, the participation of the expected following modes would not cause the resultant acceleration to exceed the peak value used in the static analysis.

3.7.3.6 Design Criteria and Analytical Procedures for Piping

3.7.3.6.1 Introduction

All Category I piping was seismically analyzed by either a simplified analysis or a multi-degree dynamic analysis, depending on its quality group and nominal size, as shown in Table 3.7-12. The loading combinations correspond to various stress criteria; this is also shown in Table 3.7-12.

3.7.3.6.2 Design Spectra and Anchor Movement

Two orthogonal horizontal earthquake motions and one vertical earthquake motion were considered. The two horizontal earthquake spectra were distinctly applied in north-south and east-west directions along with a vertical response spectra. These spatial results were combined for each point in the piping model by the method of the SRSS.

Modal responses in seismic response analysis were combined using the methods described in NRC Regulatory Guide 1.92, Revision 1. All modes with frequencies of 33 Hz or less were considered.

In cases where more than one response spectrum was applied to a subsystem (i.e., if the system is supported from locations in the structure having different response spectra), an envelope of all applicable response spectra was applied to the subsystem. When GE piping systems are anchored and supported at points with different excitations, the multiple response spectra method was used.

Secondary stresses of piping systems due to seismic anchor movements were computed by using the maximum relative displacements in two horizontal and vertical directions as the boundary conditions at support (anchor) points. The computed secondary stresses were added absolutely to other stresses in accordance with the procedures specified in ANSI B-31.7, Nuclear Piping and ASME B&PV Code Section III-1971.

For the GE-supplied piping, the maximum value of the modal displacement was used in the static calculation of the stresses due to relative displacements in the response-spectrum method. Therefore, the mathematical model of the equipment was subjected to a maximum displacement at its supporting points obtained from the modal displacements. This procedure was repeated for the significant modes of the structure (modes contributing most to the total displacement response at the supporting point). The total stresses due to relative displacement were obtained by combining the modal results using the SRSS method. Since the maximum displacement for different modes does not occur at the same time, the SRSS method is a realistic and practical method.

3.7.3.6.3 Simplified Analysis

When simplified seismic analysis was used for piping, the system is restrained such that the combined seismic stress of the system (SRSS of all three excitations) is less than 7000 psi for the OBE. The methods used and their limitations are presented in Subsection 3.9.2.7. For equipment and piping supplied or analyzed by GE, a simplified dynamic analysis was not used.

3.7.3.6.4 Dynamic Analysis

The general procedure for the modal analysis response-spectrum method for piping systems is described in Subsection 3.7.3.16. Each pipeline is idealized as a mathematical model consisting of lumped masses connected by elastic members. Appendages having significant dynamic effects on the piping system, such as motors attached to motor-operated valves, are included in the model. Using the elastic properties of the pipe, the stiffness matrix for the piping system is determined. The flexibility matrix of each beam element includes axial, bending, shear, and torsional flexibilities. The size of the stiffness matrix for each piping structural element is 12 by 12, since six forces and moments and six deflections and rotations are considered by the piping flexibility program in each of the two nodes of an element.

The unrestrained general stiffness matrix [K] of a dynamic structural model is condensed to a square reduced-stiffness matrix [k]. The purpose of this procedure is to exclude rigid constraints and to condense rotational stiffness coordinates into dependent coordinates of the translational displacement stiffness matrix.

After development of stiffness and mass matrices, natural frequencies and their associated modal shapes are determined by solution of the following equation:

$$\{[\mathrm{k}] - \omega_i^2 \, [\mathrm{m}]\} \, [\mathrm{Q_i}] = 0 \qquad (3.7\text{-}13)$$

where

$[k]$ = square reduced-stiffness matrix

$[\omega_i]$ = natural frequencies of system (i = 1,2,...n)

$[m]$ = mass matrix

$[Q_i]$ = mode shape vector associated with ith mode

The ω values and $[Q_i]$ matrix for each of the n modes are computed (i = 1, 2,...n, where n equals degrees of freedom of the piping system dynamic structural model). For the acceleration response spectrum method of analysis, the maximum displacements in global coordinates are shown as:

$$\{y_{max_n}\} = [Q]\,\{q_{max}\} \qquad (3.7\text{-}14)$$

where

$[Q]$ = square matrix containing eigenvectors for each mode

$\{qmax\}$ = $[\omega_n^2]^{-1}\,[S_a]\,[M_n]^{-1}\,[Q]^T\,[m]D$

$[M_n]$ = generalized mass = $[Q]^T[m][Q]$

$\{D\}$ = direction vector

$[S_a]$ = matrix of special acceleration values

The maximum displacement equation can be rewritten as:

$$\{y_{max}\} = [Q][\omega_n^2]^{-1}[S_a]\{\Gamma\}_n \qquad (3.7\text{-}15)$$

where

$\{\Gamma\}_n$ = participation factor of system

$\{\Gamma\}_n$ = $[M_n]^{-1}[Q]^T[m]\{D\}$

Inertia forces for each mass point are then calculated from

$$\{F_{max}\}_n = [m]_n[Q][\omega_n^2]_d\{q_{max}\}_n \qquad (3.7\text{-}16)$$

(nxn)(nxd)(dxd) (dx1)

where

d = number of modes considered

The computation of internal moments at each mass node represents maximum seismic inertial responses due to excitations of vertical amplified response spectrum and horizontal amplified response spectrum applicable to the piping system. The stresses due to the inertia forces were determined using the SRSS of the horizontal responses and the vertical response.

The relative displacement between anchors was determined from the dynamic analysis of the structures. The results of the relative anchor point displacements were used for a static analysis to determine the additional stresses due to relative anchor point displacements as described in Subsection 3.7.3.6.2.

All of the calculations outlined in this subsection, except for those of the GE scope of supply, were performed by using the computer program AutoPIPE, PIPSYS, or NUPIPE, for the analysis of a three-dimensional piping system (Section 3.13).

3.7.3.6.5 Allowable Stress

Allowable stresses in the piping caused by an earthquake are in accordance with the ASME Code Section III. Internal moments and forces, computed in Subsection 3.7.3.6.4 as the seismic responses of the piping system, were then combined with deadweight, pressure, thermal, and other mechanical loads to complete the stress analysis of all Category I and some nonseismic piping.

For ASME Code Class 1 piping larger than 1-in. nominal pipe size, stress intensities and cumulative usage factors of the piping system were computed based on formulations specified in ASME Code Section III-1971, NB-3653. For ASME Code Class 1 piping, 1-in. nominal pipe size and smaller, the stress intensities were computed based on formulations specified in the ASME Code Section III-1971, NC-3650.

General seismic design and analysis criteria for ASME Code Classes 1, 2, and 3 are defined in Table 3.7-13. For additional information, see Section 3.9.

Allowable stresses in the earthquake restraint components such as shock suppressors are in accordance with stress limits established by American Institute of Steel Construction (AISC)-1969 for original plant design, subsequent design codes are as described in subsection 3.9.2.2.5.2.

3.7.3.7 Basis for Computing Combined Responses

The two horizontal components and one vertical component of ground motion are accounted for in the following manner:

a. Components - The procedure described in Subsection 3.7.3.16 for Category I component analysis in combining the dynamic responses from horizontal and vertical amplified response loading was based on

   1. Static analysis - The sum of the horizontal plus the vertical responses

   2. Dynamic analysis - The SRSS of the two horizontal modal responses and vertical modal responses.

b. Piping systems - The procedure described in Subsection 3.7.3.6 for Category I piping analysis in combining the dynamic responses from horizontal and vertical amplified response loading was based on the SRSS of the two horizontal spatial responses and the vertical spatial response.

Alternatively, for subsystems or components under the GE scope of supply, the two horizontal components and one vertical component of ground motion can be accounted for in the following manner: Two sets of seismic results are obtained.

First, the maximum value of the horizontal component of the earthquake is assumed to act in one horizontal direction simultaneous with the vertical component, and the loads are computed for this combination. Next, the maximum value of the horizontal component of the earthquake is assumed to act perpendicular to the direction previously assumed and simultaneous with the vertical component, and loads are computed for this combination. The larger of these two loads at each point in the system is used for design.

This method of analysis is based on the fact that the seismologist specified the maximum resultant value of the horizontal component of the earthquake when specifying the horizontal component of the SSE. Using this method, it is conservatively assumed that the horizontal and vertical components of the earthquake response occur simultaneously.

3.7.3.8 Amplified Seismic Responses

Constant load factors were not used for vertical floor response in the seismic design of Category I components. As described in Subsection 3.7.1.2, amplified response spectra (floor) were developed for horizontal (two directions) and vertical seismic excitation. Components and systems were designed for the combination of operating loads acting simultaneously with horizontal and vertical seismic loads based on these response spectra. As noted in Subsection 3.7.2.1, three directions of earthquake motion were considered.

In the simplified dynamic analysis described in Subsection 3.7.3.9 for Category I piping, constant load factors based on applicable amplified response spectra were used as the vertical and horizontal amplified floor response loading.

3.7.3.9 Use of Simplified Dynamic Analysis

Simplified dynamic analysis methods for piping are discussed in Subsection 3.9.2.7.

3.7.3.10 Modal Period Variation

The modal period variation was considered in the derivation of floor response spectra curves by widening the peaks of those curves (Subsection 3.7.2.6).

3.7.3.11 Torsional Effects of Eccentric Masses

If the torsional effect of the valve operator was likely to have a significant effect on the results of an analysis, the operator's mass and moment arm were included in the mathematical model. However, if the pipe stress due to the torsional effect was expected to be less than 500 lb/in^2, the offset moment due to the operator was neglected.

3.7.3.12 Piping Outside Containment Structure

Category I piping located outside the containment, but not buried, was analyzed so that allowable piping and structural stresses were not exceeded due to differential movement at support points, at containment penetrations, and at entry points into other structures, as specified in Subsection 3.7.3.6.

3.7.3.13 Interaction of Other Piping With Category I Piping

For systems that are partially Category I, the seismically qualified portion of the system extends to the first seismic constraint (anchor) beyond the isolation valves that separate the safety-related from the nonseismic portions of the system. The isolation valve(s) that defines the operational boundary location between seismic and nonseismic portions of the system is identified on the respective piping and instrumentation diagram(s). The specific constraint beyond the isolation valve that is included in the seismic analysis of the piping system would be identified on the "dash-2 version" of the system-piping isometric drawing(s). These isometric drawings are commonly referred to as the system hanger drawings. The hanger drawings and required seismic analyses are retained as permanent plant records.

3.7.3.14 Field Location of Supports and Restraints

The field location of seismic supports and restraints for piping and piping systems was so selected as to keep the seismic stresses and deflections below the allowable limits. The following procedure was used to ensure that the seismic constraints were actually applied consistent with the assumptions used in the seismic analysis of the piping:

a. The seismic analyst recommended approximate locations for seismic restraints

b. The piping designer and/or the field engineer found an exact location for each restraint (including the methods of attachment) and notified the seismic analyst of these locations by generating as-built field sketches

c. The final seismic analysis was performed using the agreed-upon locations to arrive at piping loads

d. The piping stress analysis was performed to ensure that applicable code limits are not exceeded.

The field location of seismic supports and restraints for GE Category I piping and piping system components was selected to satisfy the following two conditions:

a. The location selected must furnish the required response to control stresses and deflections to allowable limits

b. Adequate building strength for attachment of components must be available.

The final location of seismic supports and restraints for Category I piping, piping system components, and equipment, including the placement of snubbers, was checked against the drawings and instructions issued by the engineer. An additional examination of these supports and restraining devices by an engineer competent in the design of Category I systems and components was made to ensure that the location and characteristics of these supports and restraining devices were consistent with the dynamic and static analyses of the systems.

3.7.3.15 Seismic Analysis for the Reactor Pressure Vessel, Fuel Elements, Control Rod Assemblies, and Control Rod Drives

The seismic loads on the RPV and internals were based on a dynamic analysis of the reactor/auxiliary building, with the appropriate forcing function supplied at ground level. The seismic model of the RPV and internals is given in Figure 3.7-16.

This mathematical model consists of lumped masses connected by elastic (linear) members. Using the elastic properties of the structural components, the stiffness properties of the model were determined. This included the effects of both bending and shear. To facilitate hydrodynamic mass calculations, several mass points (fuel, shroud, vessel) were selected at the same elevation. The various lengths of control rod drive (CRD) housings were grouped into the two representative lengths shown. These lengths represent the longest and shortest housings in order to adequately represent the full range of frequency response of the housings.

The high fundamental natural frequencies of the CRD housings result in very small seismic loads. Furthermore, the small frequency differences between the housings due to the various lengths result in negligible differences in dynamic response. Hence, the modeling of intermediate length members becomes unnecessary. Not included in the mathematical model are light components such as jet pumps, in-core guide tubes and housings, sparger, and their supply headers. This reduces the complexity of the dynamic model.

The presence of fluid and other structural components (e.g., fuel within the RPV) introduces a dynamic coupling effect. Dynamic effects of water enclosed by the RPV were accounted for by introduction of a hydrodynamic mass matrix. This matrix served to link the equations of motion acceleration terms of points at the same elevation in concentric cylinders with a fluid entrapped in the annulus. The seismic model of the RPV and internals had two horizontal coordinates for each mass point considered in the analysis. The remaining translational coordinate (vertical) was excluded because the vertical frequencies of RPV and internals were well above the significant horizontal frequencies. Furthermore, all support structures, buildings, and containment walls have a common centerline, making the coupling effects negligible.

The vertical seismic loads acting on the structures within the RPV are based on a separate vertical dynamic analysis.

The multi-node mathematical model used represents the RPV, RPV internals, pedestal, and the shield wall by lumped masses and a set of springs idealizing both the inertial and stiffness properties of the system. Between mass points, the structural properties are reduced to uniform beam segments of crosssectional area, effective shear area, and moment of inertia. The two rotational coordinates about each node point were excluded because of the momentary contribution of rotary inertia from surrounding nodes. Since all deflections were assumed to be within the elastic range, the rigidity of some components was accounted for by equivalent linear springs.

The shroud support plate was loaded in its own plane during a seismic event, and hence was extremely stiff. Therefore, it was modeled as a rigid link in the translational direction. The shroud support gussets and the local flexibilities of the vessel and shroud contribute to the rotational flexibilities, and were thus modeled as an equivalent torsional spring. The foundation mat was considered to be fixed. The effect of the water inside the RPV was included in the vertical model by adding concentrated mass to the node points in the mathematical model.

The seismic analysis was performed by a modal super-position time-history analysis. Design calculations were made using one of the following: peak loads or accelerations from the response time histories; amplified response spectra appropriately broadened; or peak displacements created by each natural mode of the structure. Table 3.7-14 lists several of the seismic loads on the RPV and RPV internals.

3.7.3.16 Seismic Analysis of Components

3.7.3.16.1 General

All Category I equipment has been documented for seismic adequacy. Depending on equipment location, the basic source of seismic design data is either the ground response spectrum or the amplified response spectrum, derived through a dynamic analysis of the relevant structure.

The uncertainties in the calculated values of fundamental structural frequencies due to reasonable variations in the structural properties are taken into account in the use of amplified response spectra. The peak resonant period value(s) in the amplified response spectra was developed as described in Subsection 3.7.2.6.

Three principal methods of documenting adequacy for Category I components are

a. Analysis

b. Analysis and testing

c. Testing.

Static Analysis

Static analysis was used for equipment that could be characterized as a relatively simple structure. This type of analysis involves the multiplication of the equipment or component weight times the applicable acceleration value (direction-dependent loading) to produce forces that have been applied at the center of gravity in the horizontal and vertical directions. A stress analysis of equipment components, such as feet, hold-down bolts, and other structural members, has been performed to determine their adequacy.

In the specification of equipment for static analysis, two or more sets of acceleration data were provided, the choice of which set to use being dependent on the equipment's fundamental natural frequency. The relevant response curves were reviewed to determine a "cutoff frequency" which bounds the rigid range from the resonance range of the response curves. Components having fundamental natural frequencies above the cutoff frequency were analyzed to rigid range response accelerations.

For components having a fundamental natural frequency below the cutoff frequency, analysis was based on response accelerations that were not less than those indicated by the amplified response curves over the full frequency range of the component. If the fundamental mode of the component fell within any of the resonant response peaks, and if the component cannot be characterized as a single degree-of-freedom system, the resonant peak response acceleration was used.

Each of the three defined directions of earthquake input (two horizontal and one vertical taken orthogonally) was evaluated separately. The calculated results of the analyses were superimposed on an SRSS of the maximum horizontal with the vertical basis. The particular response values to be combined are optional (i.e., acceleration, force, stress) but must remain consistent throughout.

Dynamic Analysis

A detailed dynamic analysis was performed when component complexity or dynamic interaction precluded static analysis, or when static analysis had been too conservative.

To fully describe the behavior of a component subjected to dynamic loads, infinite numbers of coordinates are required. Since calculation at every point of a complex model is impractical, the analysis is simplified by a selection of a limited number of mass points. The lumped-mass approach is used in the dynamic analysis. In the lumped-mass idealizations, the main structure is divided into substructures, and the masses of these substructures are concentrated at a number of discrete points. The nature of these substructures and the stiffness properties of the corresponding modeling elements determine the minimum spacing of the mass points and the degrees of freedom to associate with each point. In accordance with the minimum spacing requirements, the analyst could then choose, for the model, particular mass points reflecting predominant masses of the components that give significant contribution to the total response.

In cases for which some dynamic degrees of freedom do not contribute to the total response, static or kinematic condensation was used in the analysis.

The normal mode approach was used for dynamic seismic analysis of components. Natural frequencies, eigenvectors, participation factors, and modal member-end forces and moments of the undamped structure were calculated. The system of equations that describe the free vibrations of an n-degree-of-freedom undamped structure is:

$$[\mathrm{M}]\left\{\ddot{\mathrm{X}}\right\}+[\mathrm{K}]\{\mathrm{X}\}=0 \tag{3.7-17}$$

where

$[\mathrm{M}]$	=	mass matrix
$[\mathrm{K}]$	=	stiffness matrix
$\{\mathrm{X}\},\left\{\ddot{\mathrm{X}}\right\}$	=	displacement, acceleration vectors

The mode shapes and frequencies were solved in accordance with:

$$[\mathrm{K}-\omega_{\mathrm{n}}^{2}\mathrm{M}]\{\phi\}_{\mathrm{n}}=0 \tag{3.7-18}$$

where

ω_{n}^{2}	=	frequency of nth mode
$\{\phi\}_{\mathrm{n}}$	=	mode shape vector for nth mode

Eigenvector-eigenvalue extraction routines, such as Householder-QR, Jacobi reduction, and inverse iteration, are used, depending upon the total number of dynamic degrees of freedom and the number of modes desired.

For each mode, the participation factor for the specific direction "i" is defined by:

$$\Gamma_{\mathrm{n_i}}=\frac{[\phi]^{\mathrm{T}}[\mathrm{M}][\mathrm{D}]_{\mathrm{i}}}{[\phi]^{\mathrm{T}}[\mathrm{M}][\phi]} \tag{3.7-19}$$

where

$\Gamma_{\mathrm{n_i}}$	=	participation factor shape vector for nth mode in ith direction
$[\phi]^{\mathrm{T}}$	=	transpose of mode
$[\mathrm{D}]_{\mathrm{i}}$	=	earthquake direction i

The modal member-end forces and moments were determined by:

$$[F_m]_n = [K_m]\,[\phi]_n \tag{3.7-20}$$

where

K_m = member stiffness matrix

For each modal frequency, the corresponding response acceleration was determined for a given level of equipment damping from the applicable response curve. Modes within the broadened response peak were assigned the peak resonant response value.

The maximum response for each mode was found by computing

$$\begin{aligned}
[\ddot{X}] &= \Gamma_{n_i} R_{n_i} [\phi]_n \\
[\dot{X}] &= \frac{1}{\omega_n}[\ddot{X}]_n \\
[X] &= \frac{1}{\omega_{n^2}}[\ddot{X}]_n \\
[F]_n &= \frac{\Gamma_n R_{n_i}}{\omega_n^2}[F_m]_n
\end{aligned} \tag{3.7-21}$$

where

$[\ddot{X}]_n$ = modal acceleration for nth mode

$[\dot{X}]_n$ = modal velocity for nth mode

$[X]_n$ = modal displacement for nth mode

$[F]_n$ = moment vectors for nth mode

R_{n_i} = spectral acceleration for nth mode in ith direction

The basis for combination of modal responses is described in Subsection 3.7.3.4.

Each of the three defined directions of earthquake input (two horizontal and one vertical taken orthogonally) were evaluated separately. The calculated results of the maximum horizontal and vertical directions were combined on an SRSS basis. The particular response values to be combined are optional (i.e., acceleration, force, stress) but must remain consistent throughout.

Testing

For tested equipment that has an operability function, the Fermi 2 requirements supplement other applicable industry standards (such as IEEE-344-1971, Section 3.10) or provide guidance for testing where no such codes are available. Equipment packages or components were shown to be adequate either by being tested individually, as part of a simulated structural section, or as part of an assembled module or unit. In any case, the minimum acceptance criteria were

a. No loss of function, or ability to function, during and/or after the proposed test, as required

b. No structural/electrical failure (i.e., connections and anchorages) that would compromise component integrity

c. No adverse or maloperation during and after the proposed test that could result in an improper safety action.

Equipment vendors and suppliers were required to formulate programs for qualifying the equipment in accordance with the conditions specified in the earthquake design requirements.

Sinusoidal, sine beat, and random input tests were accepted as methods of seismic qualification based on the particular component location, structure, and floor response characteristics. Structures, particularly at lower elevations, exhibit a broad frequency range response similar to the ground motion during an earthquake. This broad range frequency motion is filtered at higher structural elevations, and response becomes more sinusoidal in nature. Knowledge of the floor response characteristics of the structure generally dictates the requirements for testing. Periodic testing is applicable where periodic floor motion is indicated and, conversely, random input testing is most applicable for broad frequency range input to components. Periodic testing can be used to develop multiple peak floor responses, as well as single peak, providing sufficiently high force is used.

Conservative periodic (sine wave) inputs to the tested component have been specified regardless of floor input characteristics since the test requires a sine sweep throughout the full frequency range at "zero period" response levels associated with relevant floor and building locations, as well as the generally required resonance dwells at discovered equipment resonance requencies. Other less conservative but generally acceptable testing techniques (periodic) have been reviewed to ensure conservatism of test results.

Either single or multiaxis test results are considered acceptable. While multiaxis tests, with some definition of "most conservative phasing" are ideal, the availability of testing machines and techniques capable of attaining this ideal is severely limited.

General testing guidance criteria specified for components include the following:

a. Sinusoidal testing

   1. A frequency scan (2 octaves per minute maximum) at a constant acceleration level is performed for as much of the range between 1 and 35 Hz as practicable or justified. The objective of this test is to determine the natural frequencies and amplification factors of the tested equipment and its critical components or appurtenances and to ensure general seismic adequacy over the full frequency range of interest. The acceleration inputs used are the maximum rigid range accelerations indicated by the relevant response spectrum curves

   2. A dwell test of the equipment at its fundamental natural frequency is included at the acceleration values specified previously in Item 1. Additionally, other frequencies are selected if amplification factors of 2.0 or more are indicated. A minimum 15-sec duration is considered acceptable for each dwell.

b. Sine beat testing

A sine beat test is performed in conjunction with a sine scan and is an alternative to the dwell portion of the program outlined previously in Item 2. The sine beat test is performed at natural frequencies and bands of large amplification identified during the sine scan. The duration and peak amplitude of the beat for each particular test frequency are chosen to most nearly produce a magnitude of equipment response equivalent to that produced by the particular floor response spectrum at justifiable damping levels

Current practice indicates that a minimum of 10 cycles per beat should be used unless it can be shown that a lower number of cycles is sufficient to duplicate or exceed the response spectra for the equipment at the appropriate location. Five sine beats with a time delay between beats are commonly used

c. Random motion testing

Random excitation may be used for components. The excitation is controlled to provide a test response spectrum that is required to envelope the required response spectrum

Additionally, as stated in Subsection 3.10.1.1, components purchased after the issuance of IEEE-344-1975 are specified to be qualified to the requirements of that standard.

3.7.3.16.2 Category I Equipment

In the analysis of the building systems, the Category I equipment was lumped with the building floor on which the equipment is supported. The equipment was analyzed as a secondary system, and the model simulating the equipment was excited by the floor response spectra obtained from the time-history analysis of the building. However, the equipment model was included in the building model if the mass of the equipment was large enough to cause significant change in the building response.

Equipment was idealized as a mathematical model consisting of lumped masses connected by elastic members or springs. Results for some selected large generic nuclear steam supply system (NSSS) Category I equipment are given in Table 3.7-15. Seismic loadings due to two orthogonal horizontal directions and the vertical direction were combined as detailed in Subsection 3.7.3.7.

When the equipment was supported at more than two points located at different elevations in the building, the response spectrum at the elevation near the center of gravity of the equipment was chosen as the design spectrum for the GE equipment. An envelope of each applicable spectrum was developed for the equipment.

The relative displacement between supports was determined from the dynamic analysis of the structure. The relative support point displacements were used for a static analysis to determine the additional stresses due to support displacements. Further details are given in Subsection 3.7.3.6.2.

The seismic design criteria for Category I equipment and components are described in Section 3.9.

3.7.3.17 Cable Tray Support Systems

3.7.3.17.1 Introduction

A cable tray and its attachment to a building comprise a structural system used to support electrical cables in a power plant. This subsection describes some of the aspects that are considered in designing cable tray supports to meet seismic criteria. A cable tray system's response characteristics, its modal periods of vibration, its relation to the seismic load, and its floor response spectra determine how the system is analyzed to ensure that it meets the seismic criteria.

3.7.3.17.2 Analysis and Design

The cable trays and cable tray support system were evaluated to withstand forces caused due to dead load, live load, and seismic conditions.

The following combinations of dead load, live load, and earthquake were investigated and checked to determine the most severe condition:

a. Dead load of various components with allowable stresses according to AISC specifications. The dead load on cable trays consists of cables, trays, and attachments. In the case of hangers, it includes the dead weight of hangers also. The original cable tray design loading was 40lb/ft^2 generally, except in the relay room area, where it was 50 lb/ft^2. An on-going program was later established to monitor the actual weight of cables in the trays and to account for fire wrap, conduit and air drop loads. Cable tray design load is adjusted to reflect these actual loads. See Subsection 8.3.1.4.3 for additional information

b. Dead load plus a concentrated live load of 200 lb at the mid-span was specified for all trays with the exception of those in the drywell. For drywell trays, a dead load plus a concentrated live load of 250 lb was specified

c. Dead load plus earthquake.

The cable trays and the support system were modeled as a multidegree-of-freedom system with the mass of the cables plus tray lumped at the levels at which they are supported.

For vertical excitation, the fundamental period of vibration was computed by using a simplified model of a continuous beam with hinged ends. This approximation was found to be consistent with the numerous models studied for this purpose.

The response spectrum obtained from the analysis of the building was used in determining the response of the cable tray support.

The horizontal and vertical seismic excitations were assumed to be acting simultaneously along the principal axis on the cable tray system. The seismic response was computed by taking the SRSS of the individual responses.

It was observed that contribution due to nonfundamental modes was negligible, and hence the effect of closely spaced modes was negligible also.

The design was based on the 1968 edition of the "Specifications for the Design of Cold-Formed Steel Structural Members."

In the design specification for cable trays, deadweight loading did not include the weight of fire wrapping material or any other attachments, such as the top hat cover, which were subsequently added. Accordingly, hanger modifications were made where necessary, and the structural adequacy of the cable trays was verified.

3.7.3.18 Safeguard Against Derailing the Reactor/Auxiliary Building Crane

The crane is safeguarded against derailing in the three principal directions of seismic movement.

The crane was subjected to a detailed analysis (results reported in Reference 18). Seismic responses of the crane to an SSE based on the crane's fundamental frequency in the vertical and two horizontal directions (perpendicular and parallel to girder) in the loaded and unloaded conditions were determined on the basis of the reactor building seismic response spectra. Vertical accelerations did not exceed 0.431g and horizontal accelerations did not exceed 0.65g for the loaded and unloaded crane in all positions. Thus, no uplift is encountered.

In the horizontal direction parallel to the runway, the crane is regarded as a suspended mass in space. Maximum seismic acceleration is limited by the friction forces of the crane's wheels. In the parked position, the crane is locked to the runway by means of electrically operated locking bars on both sides of the crane. These bars are designed to secure the crane in a stationary position in the event of a tornado strike or horizontal seismic forces (Figure 3.8-32).

In the horizontal direction perpendicular to the runway, the crane bridge wheels have sufficient play on their axles to accommodate thermal movement and seismic deflection of the crane supporting structure. In the event that seismic deflections exceed axle play, the insides of the girders are provided with seismic end stops impacting on the runway structure.

The trolley is equipped with seismic end stops to prevent excessive movement perpendicular to its runway. The trolley is not restrained of movement parallel to its runway. The movement is expected to be minimal as only wheel friction forces are transmitted and also due to the stabilizing effect of the cable and hook assembly, which acts as a pendulum.

3.7.3.19 Other Subsystems

This subsection refers to the structural subsystems such as cranes, racks, ventilation ducts, and tanks. If the subsystem is idealized as a single-degree-of-freedom system, the forces in each direction are determined by applying, through the center of gravity, a static force equal to the weight of the subsystem multiplied by a frequency-dependent multiplier obtained from the floor response spectrum curve. In all other cases, the subsystem is modeled as a multidegree system with an adequate number of lumped masses that predict the true dynamic response of the subsystem. For tanks, the dynamic effect of fluid oscillations is considered in both the horizontal and vertical directions.

The Control Center (CC) HVAC System and Standby Gas Treatment System (SGTS) duct and duct supports were revalidated to demonstrate their structural adequacy under the combined effects of dead load, internal duct pressure (normal operating and maximum credible), and three-directional seismic (OBE and SSE) loads in accordance with the requirements and acceptance criteria contained in Reference 20.

The horizontal and vertical seismic excitations used for the revalidation of the CCHVAC and SGTS duct and duct supports were based on Figures 3.7-36 through 3.7-41, 3.7-83, 3.7-85, 3.7-86 and 3.7-87 for OBE, and on Figures 3.7-60 through 3.7-65, 3.7-92, 3.7-94, 3.7-95 and 3.7-96 for SSE. For revalidation of the duct systems under OBE effects, damping values of 4% and 2% were used for rectangular and round duct, respectively. For SSE effects, damping values of 7% and 4% were used for rectangular and round duct respectively.

Structural acceptance criteria for CCHVAC and SGTS duct and duct supports were based on the minimum published yield and ultimate strengths of the duct and duct support materials. Straight duct segment maximum stresses were limited to 0.9 Fy of the duct material for SSE effects (0.6 Fy for OBE effects) in accordance with ANSI/ASME-N509-1980 (Reference 21). Duct support allowable member stresses were governed by Table 3.8-19 for structural steel. Duct support anchorages (base plates and anchors) were also evaluated for adequacy. References 22 and 23 were used for the expansion anchor acceptance criteria. To conform to these acceptance criteria, duct system structural modifications were made where necessary, and the structural adequacy of the systems was verified.

3.7.4 Seismic Instrumentation Program

3.7.4.1 Comparison With Regulatory Guide 1.12

A seismic instrumentation program has been implemented to monitor and record the input motion and behavior of Fermi 2 in the event of an earthquake. The instrumentation program described below meets the intent of Regulatory Guide 1.12, Revision 1. (See Subsection A.1.12 for regulatory guide compliance statement.)

The seismic event recording system conceived and designed for Fermi 2 was documented in January 1972, prior to the issuance of Regulatory Guide 1.12. The project reviewed the Fermi 2 earthquake recording system for compliance with the requirements of Regulatory Guide 1.12, Revision 1, and concluded that the intent of Regulatory Guide 1.12 was satisfied. The seismic monitoring system is classified as Seismic Category II/I; however, it is designed, tested, mounted and maintained in a manner that gives a high degree of confidence that it will function during and after a seismic event of the Fermi 2 SSE. Seismic Category II/I is consistent with Regulatory Guide 1.29.

3.7.4.2 Location and Description of Instrumentation

Strong motion triaxial accelerographs are installed in two different reactor/auxiliary building locations. One of the accelerographs measures the response of the free field at the building foundation. The other device establishes the anticipated excitation to the reactor building containment structure and major internal equipment.

Strong motion triaxial response spectrum recorders are additionally installed at six seismically interesting plant locations. Three of these passive devices are contained in the reactor/auxiliary building, one at the free field/foundation location, adjacent to the active accelerograph, one in the relay room on the second floor, and one at the top of the reactor/

auxiliary building on the fifth floor. The other three response spectra recording devices are installed in the RHR complex. One of the devices is installed to measure the excitation to the diesel generators and the RHR pumps, a second device is installed to measure the excitation to the items at higher RHR complex elevations, and the third device is installed at a location in the RHR complex to measure the excitation experienced at the mechanical draft cooling towers.

3.7.4.2.1 Active Sensors

Active earthquake-recording instrumentation has been provided to measure and record the basic ground motion time-history acceleration, as well as the seismic excitation of the reactor/auxiliary building complex foundation and the primary containment structural elements including major internal equipment items. The complete system consists of an active seismic recording system and an active seismic playback system. The active seismic recording system consists of two triaxial accelerometers and a digital recorder. Both triaxial accelerometers are installed with the same geometrical orientation. The active seismic playback system consists of a computer and printer.

A seismic trigger activates the seismic recording system and indicates to control room personnel that a seismic event has occurred. The trigger is initiated from the High Pressure Coolant Injection (HPCI) room accelerometer, where free field and building foundation excitations are established. The seismic trigger senses any acceleration above a preset limit, 0.01g, and activates the recording system.

3.7.4.2.1.1 Active Instrumentation Locations

Triaxial accelerographs responding to acceleration excitation in three mutually perpendicular axes have been installed at two locations, as shown in Figure 3.7-117. The recording axes directions coincide with each other. A vertical axis is used, as well as two horizontal axes corresponding to the mutually orthogonal primary directions of the reactor/auxiliary building structure. The specific instrument locations are identified as follows:

a. Reactor/auxiliary building subbasement in the HPCI room (Figure 3.7-117, Location 1). This record is used for direct comparison with the ground motion and reactor building earthquake design excitation. This single triaxial earthquake accelerogram is used to establish not only the ground motion, but also the building foundation excitation, since it has been established that soil-structure interaction effects are negligible at Fermi 2

b. At the bottom of the RPV pedestal, adjacent to the floor at the base of the drywell (Figure 3.7-117, Location 2). This record is used to establish the primary containment element excitation, anticipated RPV motions, and the environment for major containment structure equipment items.

3.7.4.2.1.2 Active Instrumentation Specifications

Over the frequency range of interest (0.1 to 40 cps), the output of the seismic transducer is a voltage proportional to acceleration. This voltage is filtered and conditioned such that the overall sensitivity of the channel is approximately 2.5 V/g.

The seismic trigger is activated at the .01g level. This trigger not only initiates recording by the accelerometers, but also activates an operator indication and on-line monitor of the free field, subbasement time-history excitation. All data is stored in a unique file in memory, which is subsequently analyzed and available for evaluation.

3.7.4.2.2 Passive Sensors

Passive earthquake recording instrumentation has been provided throughout the complex to measure various ground motion and in-structure response spectra. These directly measured triaxial spectra may be used for comparison with basic facility design spectra without the need for intermediate data reduction. The passive instrumentation serves as a backup for the active sensors, and provides basic definitions of reactor/auxiliary building and RHR complex input motion and response phenomena. In addition, this instrumentation provides a direct definition of internal equipment environments in the Category I structures, as well as basic information defining the Category I structure and internal equipment response.

The complete system comprises 18 response-spectrum recorders (six triaxial spectrum recorders) that are identical in configuration and orientation and differ only in their installation location.

3.7.4.2.2.1 Passive Instrumentation Locations

Triaxial response spectrum recorders, which respond to accelerations in three mutually perpendicular axes, have been installed at six locations, as illustrated in Figures 3.7-117 and 3.7-119. These devices have been installed so that the directions of the recording axes coincide. One recording axis is vertical, and two are horizontal, corresponding to the mutually orthogonal directions of both the reactor/auxiliary building and RHR complex. The specific passive instrumentation locations are described as follows:

a. At the reactor/auxiliary building subbasement adjacent to the active accelerograph in the HPCI room (Figure 3.7-117, Location 1). Spectra generated at this location will be used to evaluate the recorded seismic spectra relative to the corresponding facility operating bases response spectra. These data will assist in the determination of the need to shut down the facility after an earthquake and will also be used for possible subsequent comparison with ground motion spectra generated from the active accelerometer records

b. At the reactor/auxiliary building second floor relay room (Figure 3.7-117, Location 4). These spectra will define the in-structure equipment environment at an intermediate height for investigation of critical Category I equipment

c. At the reactor/auxiliary building fifth floor (Figure 3.7-117, Location 5). This device will define the in-structure equipment environment spectra at an upper level for investigation of Category I elements at this structural elevation

d. At a critical location in the RHR complex (Figure 3.7-119, Location 6). This instrument will define the environment for investigation of the structural and equipment response for this Category I structure at the emergency diesel generator and RHR system pump location

e. At a critical location in the RHR complex (Figure 3.7-119, Location 7). This instrument will define the environment for the investigation of the structural and equipment response of this Category I structure at an elevated equipment location

f. At a third critical location in the RHR complex (Figure 3.7-119, Location 8). This instrument will define the environment for the investigation of the structural and equipment response of this Category I structure at an upper elevation corresponding to the sensitive region for mechanical draft cooling tower equipment apparatus.

3.7.4.2.2.2 Passive Instrumentation Specifications

There are 12 sensing elements included in each single response spectrum recorder. These elements provide a resolution of 1 percent of full scale at damping between 1 and 3 percent of critical, and are accurate in a temperature range of -50°C to +85°C. A tabular summary of representative reed frequencies and nominal full-scale acceleration limits follows:

Reed Number	Nominal Frequency (cps)	Nominal Full Scale Acceleration Limit (g)
1	2.0	±1.6
2	2.5	±2.5
3	3.2	±4
4	4.0	±6
5	5.0	±10
6	6.4	±16
7	8.0	±24
8	10.1	±34
9	12.7	±42
10	16.0	±64
11	20.2	±81
12	25.4	±90

3.7.4.3 Operator Seismic Event Notification and Recording System

The active seismic recording system is equipped with an earthquake event indicator which has been placed in the facility control room (Figure 3.7-117, Location 3). This event indicator notifies the control room operator that an excitation has occurred at the facility foundation level in excess of the 0.01g trigger setpoint.

Concurrent with this operator notification, the seismic trigger automatically activates the recording system and on-line monitor in the facility relay room (Figure 3.7-117, Location 4).

An earthquake is considered to have occurred if the trigger mechanism and companion event indicator are actuated. Post-earthquake data evaluation and reduction activities ensue in accordance with established project procedures.

The minimum system recording time is limited only by memory and will provide a minimum of 25 minutes of continuous recording. The lengths of pre-event and post-event memory are user selectable and recorded for ease of analysis. Continuous system actuation capability is ensured by an internal battery, which remains “trickle” charged from an ac power line. Minimum system accuracy is ± 8%.

The seismic recording system has playback capability enabling the facility operators to immediately obtain the representative acceleration time-history.

3.7.4.4 Post-Earthquake Evaluation Activities

An earthquake is considered to have occurred if the trigger mechanism is activated (.01g or larger) with attendant control room indication. Essential post-earthquake evaluation activities are summarized by the flow chart included in Figure 3.7-120.

In accordance with the requirements of Appendix A to 10 CFR 100, if the earthquake excitation exceeds that described by the facility OBE spectra, the reactor must be shut down to cease operation in as timely a manner as possible. The sequence of events by which this shutdown decision is made is described in Subsection 3.7.4.4.1. Subsequent earthquake data reduction and analysis activities are described in Subsections 3.7.4.4.2 and 3.7.4.4.3.

3.7.4.4.1 Immediate Operational Decision

Immediately upon signal indication of earthquake occurrences, the control room operator verifies that there are no abnormal changes in critical plant parameters as indicated by operational instrumentation. If any malfunctions are indicated by the instruments, shutdown is initiated as dictated by the severity of the malfunction.

In the absence of instrumentation-indicated malfunctions, plant personnel go to the relay room to examine the active earthquake system records, and to the HPCI subbasement location to extract the ground motion spectra from the passive measurement device.

In examining the active information, the earthquake ground motion response time-history from the subbasement location which is played on-line may immediately be evaluated as to whether or not the observed peak acceleration exceeds the OBE (.08g horizontal, .05g vertical). If the observed peak acceleration is greater than the OBE value, controlled shutdown activities are initiated.

Three directional response spectra are extracted from the passive earthquake recording device in the HPCI room subbasement location by recording the observed acceleration record associated with each of the tuned reeds at their various response frequencies. The spectra obtained from the passive recording device are compared with the facility OBE spectra, and if the response observed at any measured frequency exceeds that corresponding OBE level, facility shutdown is initiated. If not, the remaining passive data are extracted from all the passive instrumentation, the passive gages are reset, and the facility continues to operate with no further earthquake data investigation required.

If it is determined during the data operational evaluation process that the facility is to be shut down, data reduction and analysis activities ensue as described in the following subsections.

3.7.4.4.2 Earthquake Data Reduction

If the active or passive earthquake recording instrumentation indicates that the OBE design level was exceeded, data-reduction activities commence. In this regard, concurrent passive and active data reduction is accompanied by physical facility structural and component inspection.

All active data are reduced by generation of detailed acceleration time-histories from each active instrument. These time-histories are subsequently used to generate response spectra for all active instrument locations.

Passive spectral instrumentation exists at six varied facility locations. The 18 resulting passive measured response spectra are plotted after extraction of the necessary raw information from the recording devices.

Detailed inspection activities are documented for all Category I items, and any malfunctions or permanent distortions in the apparatus are recorded.

A document is prepared summarizing and presenting the reduced data for further evaluation purposes. Detailed earthquake data analysis activities are described in the following subsection.

3.7.4.4.3 Earthquake Data Analysis

Data reduction activities result in assembly of facility response spectra for representative locations and elevations at the Fermi 2 site in the Category I structures. These spectra are compared with the established facility SSE spectra for initial evaluation purposes. If the recorded event spectra do not exceed the facility established SSE spectra, no further investigation is necessary, and facility operations may resume. Certain essential structures and components were reassessed to a site-specific earthquake spectrum (larger than the SSE spectrum). Such items can be screened out of the investigation in a similar manner.

If there are spectra that exceed the SSE facility spectra at some facility locations, all Category I items in this proximity are noted and specifically evaluated with respect to the observed excitations. For each of these items identified, actual fragility level capability will be documented and compared with the excitation environment recorded. Items assessed to be satisfactory in this evaluation may be considered acceptable for continuing plant use.

If an item fragility level is equal to or less than the earthquake event excitation level recorded, a detailed dynamic analysis and/or system test combined with comprehensive item inspection will be required to establish whether or not the particular item is satisfactory for continuing facility service. If in this investigation it is established that tolerable permanent deformation or damage was sustained, the item will be considered satisfactory for continuing use. If not, the item shall be fully refurbished or a new item must be procured and installed for continuing plant operation.

3.7.5 Seismic Design Control

3.7.5.1 Introduction

Category I systems and components are designed to perform their intended function during and after the specified earthquakes. Category I items, at various locations in the reactor/auxiliary building and the RHR complex, are capable of withstanding the seismic excitation specified in the specifications (Subsection 3.7.5.2). Rational analyses or test results as described in this specification validating the seismic performance of all Category I items were submitted to Edison. Furthermore, independent documented reviews are performed to validate the adequacy of the seismic designs performed and to ensure the compatibility of such designs. The seismic design control procedure is outlined in Table 3.7-16.

All Category I structures, systems, and components were reviewed on an item-by-item basis. Nonseismic structures, systems, and components were examined to ensure that they do not adversely interact with close-proximity Category I items. General Electric-supplied items are subjected to a rigorous independent design review. The independent reviewer assists in an audit of GE seismic design documentation only, since independent design review is performed by GE.

Items that have significant mass and size relative to the building in which they are located were analyzed coupled to the structure itself to appropriately consider interaction effects. The RPV, primary containment, and crane are so considered in Subsection 3.7.2.1.2.2.

Items that are small enough relative to the building in which they are located so as not to influence the dynamic response of the building itself are considered uncoupled from the building. These items are validated to be capable of withstanding the earthquake excitation defined by the response of the building at the location where they are attached.

3.7.5.2 Seismic Performance Specification

To ensure that the various Fermi 2 vendors provide seismically adequate systems and components, a seismic performance specification was prepared.

It was specified in the seismic performance portion of the component specification that items mounted directly to a building are validated as capable of withstanding the excitation from the building at the location where they are attached. Design requirements are delineated in the specification. There are also other components that are attached to systems attached to the building rather than to the building itself. These components cannot be validated to the building excitation since it is necessary to consider the influence of the response of the system to which the component is attached.

In many cases, the component was procured as a part of the total system. A total system validation was required in this situation and the component validation was undertaken to the levels indicated as appropriate from the system analysis.

When a rigid component must be procured apart from the system to which it belongs, it is validated by the vendor to the mounting amplified acceleration or to the maximum acceleration on the response spectrum applicable for the parent system. This is conservative since essentially the assumption is made that the system is in resonance with the building. Nonrigid components are examined by the seismic design reviewer on an item-by-item basis.

A procurement specification is prepared for each item required for Fermi 2. Seismic provisions are accounted for by reference to the seismic performance portion of the specification. Generally, the location of the item being purchased is delineated so that the appropriate validation spectra are selected from the performance specification, unless plant-wide use qualification is required.

In addition, the potential vendors are informed that they must submit a description of their proposed validation with their basic bid package. A vendor is not selected until his seismic design approach is reviewed and found acceptable.

The seismic environment for items mounted directly to the structures is defined as a function of the item location in terms of vertical and horizontal response spectra. The vertical and horizontal excitations are assumed to act simultaneously. Figures 3.7-32 through 3.7-115 define the response spectra for both the reactor/auxiliary building and the RHR complex. Enveloping spectra have also been generated for plant-wide use qualification.

The seismic environment for rigid components not mounted directly to the structure, but rather mounted to a system that is connected to the structure, are validated to the peak acceleration indicated on the appropriate response spectrum. If the component is considered part of the system connected to the floor, then it is validated to the system acceleration obtained directly.

3.7.5.3 Seismic Acceptance Criteria

3.7.5.3.1 Validation Procedures

The seismic capability of vendor-supplied items is validated by either a rational dynamic response analysis or a suitable dynamic system test, or some combination of both as hereinafter specified.

3.7.5.3.2 Dynamic Response Analysis

The rational dynamic response analysis conforms to standard techniques of engineering mechanics. Stress and deformation of all elements of the vendor-supplied items are examined in accordance with the design criteria as shown in Sections 3.8 and 3.9. The vendor seismic dynamic response analysis is submitted to Edison for approval before acceptance of the items. The analysis submitted to Edison includes the following:

a. Description of the mathematical model used in the analysis

b. Description of the determination of properties such as the model mass distribution, damping, and stiffness characteristics

c. Development of the dynamic response analysis equations of motion

d. Discussion of experimental investigation supporting the given model and equations of motion

e. Description of the way the seismic input is applied in the analysis

f. Description of the solution techniques for the equations of motion

g. Evaluation of the seismic capability of the equipment including calculations of stress and deformation levels.

3.7.5.3.3 Dynamic System Test

Where dynamic system tests are made to verify the acceptability of the vendor-supplied items in accordance with the design criteria as shown in Sections 3.8 and 3.9, the tests impose upon the equipment a dynamic test environment equal to or greater than that specified in the earthquake criteria at all frequencies. Acceptable test environments are achieved by use of a controlled shaker table or a shock machine. Other test techniques are acceptable if the input is suitably defined. Before the testing is undertaken, a test procedure document is submitted to Edison for approval. This document contains a complete description of the testing to be done including descriptions of the following:

a. Method of measurement of the test environment including descriptions of active and passive instrumentation and techniques used in generating response spectra

b. Method of measurement of the response of the equipment including descriptions of active and passive instrumentation and operational testing

c. Method of deciding the adequacy of the equipment.

After the dynamic system tests are performed and before the acceptance of the equipment, a report summarizing the results of the testing is submitted to Edison for approval. The report includes pertinent test data as well as an analysis of the test data.

3.7.5.4 Independent Review

An independent review of the seismic design approach proposed by the various vendors is performed. In review of a proposed analytical validation, the approach is accepted or modifications are recommended. It is possible that for some items no analytical validation could be acceptable. In this case, it is recommended that the vendor be required to provide a test validation.

During the independent review of a proposed test validation, the approach is accepted or modifications are recommended.

The vendor then updates and modifies his seismic design package until it is accepted without any recommended modifications. The complete results of the seismic analysis either by testing or by calculations are documented in a clear and concise format and submitted.

The documentation submitted generally includes the following:

a. The abstract describes the purpose of the test or calculations and gives a brief description of the problem

b. The conclusions summarize the results obtained from the test or calculations. A concise statement is made regarding the conclusion reached, which is related to the purpose of the test or calculations

c. Both data and assumptions are listed. In the case of testing, the documentation includes the type of test machine used, the loads considered, and the efforts made to idealize the actual case in preparing the test. In the case of calculations, the documentation includes the loads considered, the weights used, the damping values chosen, and the assumptions used to convert the design criteria to actual loads, stresses, or displacements

d. A description of the test or the method of analysis is included. In the case of testing, the type of test, the input motion, and the generated response spectrum from this motion are presented. In the case of calculations, the analytical method, all analytical equations and their derivation from basic principles, any assumptions made to idealize boundary to initial conditions, the limitations of the applicability of the analysis (if any), and documentation to establish the validity of any computer program used are stated

e. The documentation outlines the results of the test or analytical calculations. In the case of testing, the measurements obtained, their interpretations, and numerical or graphical form of the test results are shown. In the case of calculations, design calculations as well as figures and sketches for the mathematical model showing loads, resultant forces, and displacements (if possible) are presented

f. Design drawings of the component and its support, including all necessary dimensions, are provided.

3.7.6 Testing of General Electric-Supplied Equipment

For GE-supplied essential mechanical equipment, two types of tests were used in the dynamic testing of equipment: free vibration and forced vibration tests. Dynamic analysis was also used for qualification of components. A description of the qualification methods is given below.

3.7.6.1 Free Vibration Test

This test was performed on equipment whose response is dominated by the fundamental mode. The critical damping ratio and fundamental frequency were determined from this test and were used to verify or supplement calculated values used in dynamic analysis of this equipment. This test was not used alone to demonstrate dynamic capability.

In this test an initial displacement or initial velocity was imparted to the equipment. The initial displacement was introduced by forcibly displacing the equipment and then suddenly releasing the force. The initial velocity was obtained by applying an impulse. Accelerometers or strain gages were mounted on the equipment. After first ensuring that the equipment was vibrating in its primary mode, the critical damping ratio was calculated from the logarithmic decrement.

3.7.6.2 Forced Vibration Test

The equipment was mounted on a shake table or driven by an eccentric shaker. The critical damping ratios, resonant frequencies, and the equipment's functional capability were determined.

The critical damping ratio of the equipment was determined by applying a sinusoidal acceleration and measuring the forced response curve (amplitude versus forcing frequency). The critical damping ratio was then calculated by using the half-power method, fitting a theoretical forced response curve through the data points, or direct reading of the resonant amplification. The vibratory motion used was such that the vibratory loads equaled or exceeded seismic loads represented by the applicable floor spectra. When testing was the only method used to demonstrate functional capability of equipment, the mounting conditions were simulated and the equipment was operating during and after the tests.

When the seismic testing is supplemented by analysis, the seismic stresses are added to those from normal and accident conditions in the appropriate loading combinations in order to ensure that the equipment will perform its required safety functions. Each type of equipment is examined individually to provide this assurance.

As an example of the approach required for extremely complicated geometrical configurations, the tests performed on the HPCI turbine are summarized below.

The major structures of the HPCI and reactor core isolation cooling (RCIC) turbines were qualified by dynamic analysis. The turbine-control-unit components were qualified by dynamic testing on a shake table with electrical and hydraulic systems functional. The actual mounting brackets were simulated in the test mounting. Vibration in all three perpendicular axes (two horizontal and one vertical) was accomplished by orienting the equipment in three directions on a horizontal shake table. A resonant search was made from 1 to 200 Hz, and the components with substantial resonances below 33 Hz were modified before the functional qualification test was performed. These modifications were applied to the standard design. This equipment was then tested with a sinusoidal input of 1.6g and then 3.0g for at least 30 sec at each of the arbitrary frequencies of 10, 15, and 23 Hz in each of the three perpendicular directions, with all systems operational. Since there were no functional failures, the equipment was deemed qualified for up to 3.0g horizontal or vertical maximum floor acceleration for all frequencies 33 Hz and below.

When required, all tests conducted will use methods and procedures comparable to those in the foregoing example. Furthermore, the amplitudes supplied at the support brackets will be equal to or greater than the levels predicted by system dynamic analysis.

3.7 SEISMIC DESIGN

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TABLE 3.7-1 MODIFIED MERCALLI INTENSITY (DAMAGE) SCALE OF 1931 (Abridged)

I. Not felt except by a very few under especially favorable circumstances (I Rossi-Forel Scale).

II. Felt only by a few persons at rest, especially on upper floors of buildings. Delicately suspended objects may swing (I to II Rossi-Forel Scale).

III. Felt quite noticeably indoors, especially on upper floors of buildings, but many people do not recognize it as an earthquake. Standing motorcars may rock slightly. Vibration like passing of truck. Duration estimated (III Rossi-Forel Scale).

IV. During the day felt indoors by many, outdoors by few. At night some awakened. Dishes, windows, doors disturbed; walls make creaking sound. Sensation like heavy truck striking building. Standing motorcars rocked noticeably (IV to V Rossi-Forel Scale).

V. Felt by nearly everyone, many awakened. Some dishes, windows, etc., broken: a few instances of cracked plaster; unstable objects overturned. Disturbance of trees, poles, and other tall objects sometimes noticed. Pendulum clocks may stop (V to VI Rossi-Forel Scale).

VI. Felt by all, many frightened and run outdoors. Some heavy furniture moved; a few instances of fallen plaster or damaged chimneys. Damage slight (VI to VII Rossi-Forel Scale).

VII. Everybody runs outdoors. Damage negligible in buildings of good design and construction; slight to moderate in well-built ordinary structures; considerable in poorly built or badly designed structures; some chimneys broken. Noticed by persons driving motorcars (VIII Rossi-Forel Scale).

VIII. Damage slight in specially designed structures; considerable in ordinary substantial buildings with partial collapse; great in poorly built structures. Panel walls thrown out of frame structures. Fall of chimneys, factory stacks, columns, monuments, walls. Heavy furniture overturned. Sand and mud ejected in small amounts. Changes in well-water. Persons driving motorcars disturbed (VIII + to IX Rossi-Forel Scale).

IX. Damage considerable in specially designed structures; well-designed frame structures thrown out of plumb; great in substantial buildings, with partial collapse. Buildings shifted off foundations. Ground cracked conspicuously. Underground pipes broken (IX+ Rossi-Forel Scale).

X. Some well-built wooden structures destroyed; most masonry and frame structures destroyed with foundations; ground badly cracked. Rails bent. Landslides considerable from riverbanks and steep slopes. Shifted sand and mud. Water splashed (slopped) over banks (X Rossi-Forel Scale).

XI. Few, if any (masonry) structures remain standing. Bridges destroyed. Broad fissures in ground. Underground pipelines completely out of service. Earth slumps and land slips in soft ground. Rails bent greatly.

XII. Damage total. Waves seen on ground surfaces. Lines of sight and level distorted. Objects thrown upward into the air.

TABLE 3.7-2 DAMPING VALUES

Item	Percent of Critical: Operating-Basis Earthquake	Percent of Critical: Safe-Shutdown Earthquake
General		
Equipment and large-diameter piping	0.5	1.0
Small-diameter piping	0.5	1.0
Welded and H.S. bolted steel framed structures	2.0	5.0
Bolted and riveted steel framed structures	5.0	10.0
Welded structural Assemblies (equipment and supports)	2.0	4.0
Reinforced-concrete structures	2.0	5.0
Specific		
Reactor pressure vessel	2.0	2.0
CRD housing	3.5	3.5
Fuel	7.0	7.0
Drywell-building (coupled)	2.0	5.0
CCHVAC and SGTS Rectangular Ducts and Duct Supports	4.0	7.0
CCHVAC and SGTS Round Ducts and Duct Supports	2.0	4.0

TABLE 3.7-3 THE REACTOR/AUXILIARY BUILDING COORDINATES OF MASS CENTROIDS

Mass		Coordinates of Centroid X	Y	Z
1	Slab model	13.93	1.42	43.50
2		-0.15	11.79	73.50
3		-0.08	10.45	107.50
4		+3.85	-1.18	119.50
5		+14.08	4.83	144.50
6		-42.56	+0.23	195.50
7		-91.44	-105.27	43.50
8		-91.44	-105.27	68.00
9		62.25	32.79	157.50
10	Frame model	-99.69	0.23	195.50
11		-99.69	0.23	144.50
12		-23.69	0.00	32.08
13		-23.69	0.00	43.16
14		-23.69	0.00	73.50
15		-23.69	0.00	90.16
16		-23.69	0.00	107.50
17		-23.69	0.00	119.50
18		-23.69	0.00	144.50
19		-23.69	0.00	39.92
20		-23.69	0.00	57.00
21		-23.69	0.00	74.33
22		-23.69	0.00	85.00
23		-23.69	0.00	96.00
24		-23.69	0.00	107.50
25		-23.69	0.00	118.66
26		-23.69	0.00	122.50
27		-23.69	0.00	135.90
28		-23.69	0.00	44.33
29		-23.69	0.00	57.90
30		-23.69	0.00	66.00
31		-23.69	0.00	87.90
32		-23.69	0.00	107.50

TABLE 3.7-4 THE REACTOR/AUXILIARY BUILDING MASS PROPERTIES

Mass Number	Description	Elevation	X	Kips Y	Z	Kip – ft^2 θ_x	θ_y	θ_z
1	Reactor building 1st floor	583 ft 6 in.	30,162	30,162	-			271,238,976
2	Reactor building 2nd floor	613 ft 6 in.	24,024	24,024	-			151,530,000
3	Reactor building 3rd floor	641 ft 6 in.	20,224	20,224	-			124,675,856
4	Reactor building 4th floor	659 ft 6 in.	17,993	17,993	-			113,462,096
5	Reactor building 5th floor	684 ft 6 in.	20,628	20,628	-			122,659,328
6	Reactor building roof	735 ft 6 in.	684	684	-			2,310,000
7	Equip. access building floor	583 ft 6 in.	809	809	-			217,400
8	Equip. access building roof	608 ft 0 in.	458	458	-			122,000
9	Auxiliary bay roof	669 ft 6 in.	9,076	9,076	-			20,475,808
10	Upper crane support	735 ft 6 in.	0	0	-			0
11	Lower crane support	684 ft 6 in.	0	0	-			0
12	Reactor support pedestal	572 ft 1 in.	6,776	6,776	-	3,196,640	3,197,640	5,408,625
13	Containment shield	583 ft 6 in.	2,772	2,772	-	1,923,671	1,923,671	3,552,663
14	Containment shield	613 ft 6 in.	2,951	2,951	-	1,903,922	1,903,922	3,463,821
15	Containment shield	630 ft 3 in.	1,222	1,222	-	373,070	373,070	539,254
16	Containment shield	647 ft 6 in.	892	892	-	168,779	168,779	303,694
17	Containment shield	659 ft 6 in.	3,953	3,953	-	238,502	239,502	389,470
18	Containment shield	684 ft 6 in.	3,598	3,598	-	169,475	169,475	259,431
19	Containment vessel	579 ft 10 in.	137	137	-	42,568	42,568	81,232
20	Containment vessel	597 ft 0 in.	200	200	-	42,785	42,785	81,324

TABLE 3.7-4 THE REACTOR/AUXILIARY BUILDING MASS PROPERTIES

Mass Number	Description	Elevation	X	Kips Y	Z	Kip – ft^2 θ_x	θ_y	θ_z
21	Containment vessel	614 ft 4 in.	61	61	-	26,240	26,240	49,924
22	Containment vessel	625 ft 0 in.	91	91	-	12,231	12,231	24,177
23	Containment vessel	636 ft 0 in.	35	35	-	7,412	7,412	13,304
24	Containment vessel	647 ft 6 in.	30	30	-	6,008	6,008	11,351
25	Containment vessel	658 ft 8 in.	43	43	-	5,209	5,209	9,946
26	Containment vessel	662 ft 6 in.	32	32	-	3,008	3,008	6,001
27	Containment vessel	675 ft 11 in.	66	66	-	3,319	3,319	6,638
28	Reactor support pedestal	584 ft 4 in.	465	465	-	49,966	49,966	68,198
29	Reactor support pedestal	597 ft 11 in.	297	297	-	28,165	28,165	45,541
30	Biological shield	606 ft 0 in.	191	191	-	23,595	23,595	35,894
31	Biological shield	662 ft 11 in.	262	262	-	33,613	33,613	49,074
32	Biological shield	664 ft 6 in.	123	123	-	15,242	15,242	23,047

TABLE 3.7-5 THE REACTOR/AUXILIARY BUILDING MEMBER PROPERTIES

Member	From	To	Area (ft^2)	Moment of Inertia (ft^4) I_x and I_y	I_z	Elastic Modulus K. S. F.	Poisson's Ratio	Shear Factor
1	94	12	4,656.0	1,725,569	3,451,138	552,000	0.17	2.0
2	12	13	2,475.0	1,397,911	2,795,822	552,000	0.17	2.0
3	13	14	1,699.0	1,112,287	2,224,574	552,000	0.17	2.0
4	14	15	1,329.0	493,748	987,496	552,000	0.17	2.0
5	15	16	814.0	138,363	276,727	552,000	0.17	2.0
6	16	17	814.0	138,363	276,727	552,000	0.17	2.0
7	17	18	814.0	138,363	276,727	552,000	0.17	2.0
8	12	19	24.2	8,381	16,762	4,175,000	0.27	2.0
9	19	20	21.2	10,901	21,803	4,175,000	0.27	2.0
10	20	21	15.6	8,193	16,386	4,175,000	0.27	2.0
11	21	22	33.2	8,039	17,078	4,175,000	0.27	2.0
12	22	23	19.9	3,833	7,663	4,175,000	0.27	2.0
13	23	24	10.8	2,050	4,100	4,175,000	0.27	2.0
14	24	25	14.5	2,537	5,075	4,175,000	0.27	2.0
15	25	26	13.0	1,771	3,542	4,175,000	0.27	2.0
16	26	27	13.0	1,771	3,542	4,175,000	0.27	2.0
17	12	28	315.0	25,421	50,841	552,000	0.17	2.0
18	28	29	364.0	27,741	55,482	552,000	0.17	2.0
19	29	30	8.2	766	1,532	4,175,000	0.27	2.0
20	30	31	8.2	766	1,532	4,175,000	0.27	2.0
21	31	32	8.2	766	1,532	4,175,000	0.27	2.0

TABLE 3.7-6 THE REACTOR/AUXILIARY BUILDING STIFFNESS COEFFICIENTS

Stiffness Element	Stiffness Coefficients					
	K/ft			K-ft/rad		
	x	y	z	θ_x	θ_y	θ_z
$K_{1,13}$	∞	∞	-	0.	0.	∞
$K_{2,14}$	∞	∞	-	0.	0.	∞
$K_{3,16}$	∞	∞	-	0.	0.	∞
$K_{4,17}$	∞	∞	-	0.	0.	∞
$K_{5,18}$	∞	∞	-	0.	0.	∞
$K_{16,24}$	∞	∞	-	0.	0.	∞
$K_{24,32}$	2.33×10^5	2.33×10^5	-	0.	0.	2.36×10^8
$K_{26, REACTOR}$	3.20×10^4	3.20×10^4	-	0.	0.	0.30×10^8
$K_{32, REACTOR}$	4.80×10^4	4.80×10^4	-	0.	0.	0.10×10^8

TABLE 3.7-7 REACTOR/AUXILIARY BUILDING SUMMARY OF THE FIRST 20 MODAL PERIODS AND PARTICIPATION FACTORS (HORIZONTAL MODEL)

Mode	Period, sec	Participation Factors, X-Excitation	Y-Excitation
1	0.6583	-0.00054	0.00153
2	0.3686	-0.00029	0.00082
3	0.3479	0.00113	-0.00315
4	0.3116	-0.00132	0.00363
5	0.2832	7.35972	-3.01693
6	0.2829	3.07018	6.70456
7	0.2221	3.58447	-14.67056
8	0.2219	-12.66471	-3.11176
9	0.2011	17.41747	-46.04075
10	0.1994	-26.94208	-20.12656
11	0.1877	-14.71599	27.16832
12	0.1845	-49.52908	-13.47238
13	0.1674	0.19769	-0.78225
14	0.1673	2.78885	0.47093
15	0.1597	0.12897	-1.17272
16	0.1597	-0.01402	0.00499
17	0.1548	-0.41594	15.01317
18	0.1527	0.00384	0.03227
19	0.1223	-0.54652	1.35398
20	0.1177	3.22427	0.85541

TABLE 3.7-8 REACTOR/AUXILIARY BUILDING PROBABLE MAXIMUM DISPLACEMENTS

Horizontal Displacement (ft)[a]

	OBE		SSE	
Mass No.	X-Excit. X-Displ. (ft)	Y-Excit. Y-Displ. (ft)	X-Excit. X-Displ. (ft)	Y-Excit. Y-Displ. (ft)
1	0.00110	0.00095	0.00157	0.00136
2	0.00257	0.00245	0.00366	0.00349
3	0.00376	0.00260	0.00535	0.00469
4	0.00430	0.00376	0.00611	0.00534
5	0.00483	0.00340	0.00686	0.00594
6	0.03502	0.03240	0.05082	0.04623
7	0.00149	0.00117	0.00209	0.00164
8	0.00330	0.00143	0.00465	0.00201
9	0.00491	0.00500	0.00692	0.00705
10	0.03500	0.02780	0.05080	0.04040
11	0.00490	0.00310	0.00689	0.00465
12	0.00070	0.00040	0.00094	0.00060
13	0.00110	0.00070	0.00157	0.00102
14	0.00250	0.00160	0.00357	0.00252
15	0.00310	0.00210	0.00436	0.00322
16	0.00380	0.00270	0.00536	0.00419
17	0.00430	0.00320	0.00610	0.00485
18	0.00480	0.00390	0.00689	0.00600
19	0.00090	0.00060	0.00126	0.00086
20	0.00150	0.00100	0.00208	0.00152
21	0.00220	0.00160	0.00314	0.00238
22	0.00260	0.00190	0.00371	0.00284
23	0.00310	0.00220	0.00441	0.00341
24	0.00380	0.00270	0.00536	0.00419
25	0.00420	0.00300	0.00602	0.00466
26	0.00440	0.00320	0.00625	0.00483
27	0.00490	0.00350	0.00698	0.00539
28	0.00100	0.00060	0.00140	0.00097

TABLE 3.7-8 REACTOR/AUXILIARY BUILDING PROBABLE MAXIMUM DISPLACEMENTS

Horizontal Displacement (ft)[a]

	OBE		SSE	
Mass No.	X-Excit. X-Displ. (ft)	Y-Excit. Y-Displ. (ft)	X-Excit. X-Displ. (ft)	Y-Excit. Y-Displ. (ft)
29	0.00140	0.00090	0.00212	0.00164
30	0.00180	0.00120	0.00263	0.00200
31	0.00290	0.00190	0.00409	0.00306
32	0.00380	0.00270	0.00540	0.00415

Vertical Displacement[a]

Floor Elevation	OBE	SSE
583 ft 6 in. (1st floor)	0.00013	0.00020
613 ft 6 in. (2nd floor)	0.00026	0.00039
641 ft 6 in. (3rd floor)	0.00035	0.00052
659 ft 6 in. (4th floor)	0.00039	0.00057
684 ft 6 in. (5th floor)	0.00044	0.00064

[a] Displacements are relative to the base of the structure.

TABLE 3.7-9 THE REACTOR/AUXILIARY BUILDING SUMMARY OF PERIODS AND PARTICIPATION FACTORS (VERTICAL MODEL)

Mode	Period	Participation Factors
1	0.08136	53.79
2	0.06564	13.71
3	0.06304	-9.36
4	0.06219	-3.69
5	0.05874	27.35
6	0.05554	0.16
7	0.05520	-8.99
8	0.05368	6.22
9	0.05019	3.98
10	0.04999	-2.60
11	0.04985	-4.52
12	0.04925	-1.12
13	0.04575	7.67
14	0.04552	0.22
15	0.04533	-0.48
16	0.04426	7.71
17	0.04162	0.20
18	0.04156	-4.41
19	0.03947	-2.99
20	0.03846	-1.39
21	0.03826	-5.00
22	0.03572	0.79
23	0.03564	-4.34
24	0.03331	2.47

TABLE 3.7-10 NUMBER OF DYNAMIC RESPONSE CYCLES EXPECTED DURING A SEISMIC EVENT

Frequency band (Hz)	0 to 10	10 to 20	20 to 50
Number of seismic cycles	168	359	643

TABLE 3.7-11 FATIGUE EVALUATION DUE TO SEISMIC LOAD

Component	Calculated No. of Cycles at Peak Stress	Design No. of OBE Cycles at Peak Stress
1. Reactor pressure vessel		
Vessel	< 3	10
Shroud support	< 3	10
Skirt	< 3	10
2. Category I piping		
Recirculation lines	< 3	60
Steam lines	< 3	60

TABLE 3.7-12 PIPING SYSTEM SEISMIC CRITERIA FOR PIPING LOCATED INSIDE BUILDING STRUCTURES

Group Classification	Type of Earthquake	Type of Seismic Analysis	Combined Stress Calculations	Stress Criteria
A (Size 1-1/4 in. NPS and larger)	OBE[a]	Dynamic response spectra	ASME Section III NB-3650	Normal and upset condition
	SSE[b]	Dynamic response spectra	ASME Section III NB-3650	Emergency and faulted condition
A (Size 1 in. NPS and smaller)	OBE	Response spectra	ASME Section III NC-3650	Normal and upset condition
	SSE	Response spectra	ASME Section III NC-3650	Emergency and faulted condition
B and C (Size 4 in. NPS and smaller)	OBE	Simplified dynamic analysis or dynamic response spectra	ASME B&PV Code - 1971 Section III, Sub-section NC-3650	Upset condition
	SSE	Simplified dynamic analysis or dynamic spectra response	ASME B&PV Code - 1971 Section III, Sub-section NC-3650	Emergency or faulted condition
D+	Unclassified but seismic Group B and C seismic criteria are used.			
D	None	None	ANSI-B-31.1.0	
B and C (Size 5 in. NPS and larger)	OBE	Dynamic Response Spectra	ASME B&PV Code - 1971 Section III, Sub-section NC-3650	Upset Condition
	SSE	Dynamic Response Spectra	ASME B&PV Code - 1971 Section III, Sub-section NC-3650	Emergency or faulted condition

[a] OBE = operating-basis earthquake.

[b] SSE = safe-shutdown earthquake.

TABLE 3.7-13 SEISMIC DESIGN LIMITS FOR CATEGORY I EQUIPMENT

Type of Earthquake	ASME Code Equipment	Loading Combination[a]	ASME Code Operating Category and Design Limits	Deflection Criteria[b]	Seismic Test Criteria[c]
OBE	Active	0.5 SSEL + OCL	Upset	For active equipment	For active equipment
OBE	Passive	0.5 SSEL + OCL	Upset	For passive equipment	For passive equipment
SSE	Active	SSEL + OCL + DSL	Upset or Emergency or Faulted	For active equipment	For active equipment
SSE	Passive	SSEL + OCL + DSL	Emergency or Faulted	For passive equipment	For passive equipment

[a] OCL stands for operating conditions loads, the loads acting on the equipment in each condition to which the equipment is subjected in accordance with "Normal Conditions" as defined by the ASME B&PV Code Section III, 1971.

SSEL stands for safe-shutdown earthquake loads, the seismic loads to which the equipment is subjected during the SSE.

DSL stands for other dynamic loads, such as relief valve blowdown loads. Earthquake loads are combined with otl dynamic loads as described in section 3.9.1.6.3.

[b] Deflection Criteria for Active Equipment: The deflection of any point on the equipment due to all applicable loads shall not impair the function of the equipment or any other Category I active equipment.

Deflection Criteria for Passive Equipment: The deflection of any point on the equipment due to all applicable loads shall not impair the function of any Category I active equipment.

[c] Test Criteria for Active Equipment: The equipment shall perform its intended function during and after the seismic test. Monitoring devices shall be installed during the test to verify that the equipment satisfies the above criteria. In cases where this is not possible, the equipment shall be tested for operation after the seismic test, and realistic engineering evidences which show that the equipment will function during the seismic test shall be presented.

Test Criteria for Passive Equipment: The equipment shall be inspected and checked after the seismic test to ensure that the pressure boundary integrity has been maintained.

TABLE 3.7-14 COMPARISON OF THE DESIGN AND COMPUTED HORIZONTAL SEISMIC LOADS OF REACTOR PRESSURE VESSEL AND INTERNALS

(Some Representative Values)

Location	Seismic Loads X-Excitation	Seismic Loads Y-Excitation	Allowable Loads
Top guide shear	74	116	687
Core plate shear	66	113	687
Stabilizer force (Total)	205	186	2,400
Max. fuel moment: Total	2,410	6,040	32,200
Per bundle	3.15	7.91	
Max. shroud moment	179,000	120,000	207,000
Max. shroud shear	732	537	1,184
Max. vessel skirt moment	101,000	106,000	1,152,000
Vessel skirt shear	286	280	2,600

Units: Moment - in-kip; Force - kip; Shear - kip

COMPARISON OF THE MAXIMUM SSE LOAD ON REACTOR VESSEL AND INTERNALS DUE TO VERTICAL EARTHQUAKE

Component	Seismic Load (kips)	Allowable Load (kips)
Shroud Support-Axial	183	>183[a]
Vessel Skirt-Axial	594	>594[a]

[a] That is, calculated loads result in stresses that are lower than allowable stress.

TABLE 3.7-15 COMPARISON OF CALCULATED SEISMIC LOADS TO DESIGN SEISMIC LOADS OF CATEGORY I EQUIPMENT, SSE CONDITION

(Some Generic NSSS Large Category I Items)

		Calculated Results		
	Equipment	Natural Frequency (Hz)	Seismic Loads	Design Seismic Load
1.	HPCI pump and turbine	>33	0.43g	1.5g
2.	RCIC pump and turbine	>33	0.43g	1.5g
3.	SLC tank	>33	0.8g	1.5g
4.	Spent-fuel racks	≈ 9[a]	0.46g	1.5g
5.				
6.	New-fuel racks	18.75[a]	0.22g	1.5g
7.	Refueling platform[b]	1.3	20,600 psi	36,000 psi
8.	Control room panels	Seismic adequacy determined by test		
9.	Fuel prep machine	>.79	0.1g	1.5g
			Fermi 2 only	
10.	RHR heat exchanger	>15	0.6g	1.5g
11.	Hydraulic control unit	>10.4	0.6g	4.9g

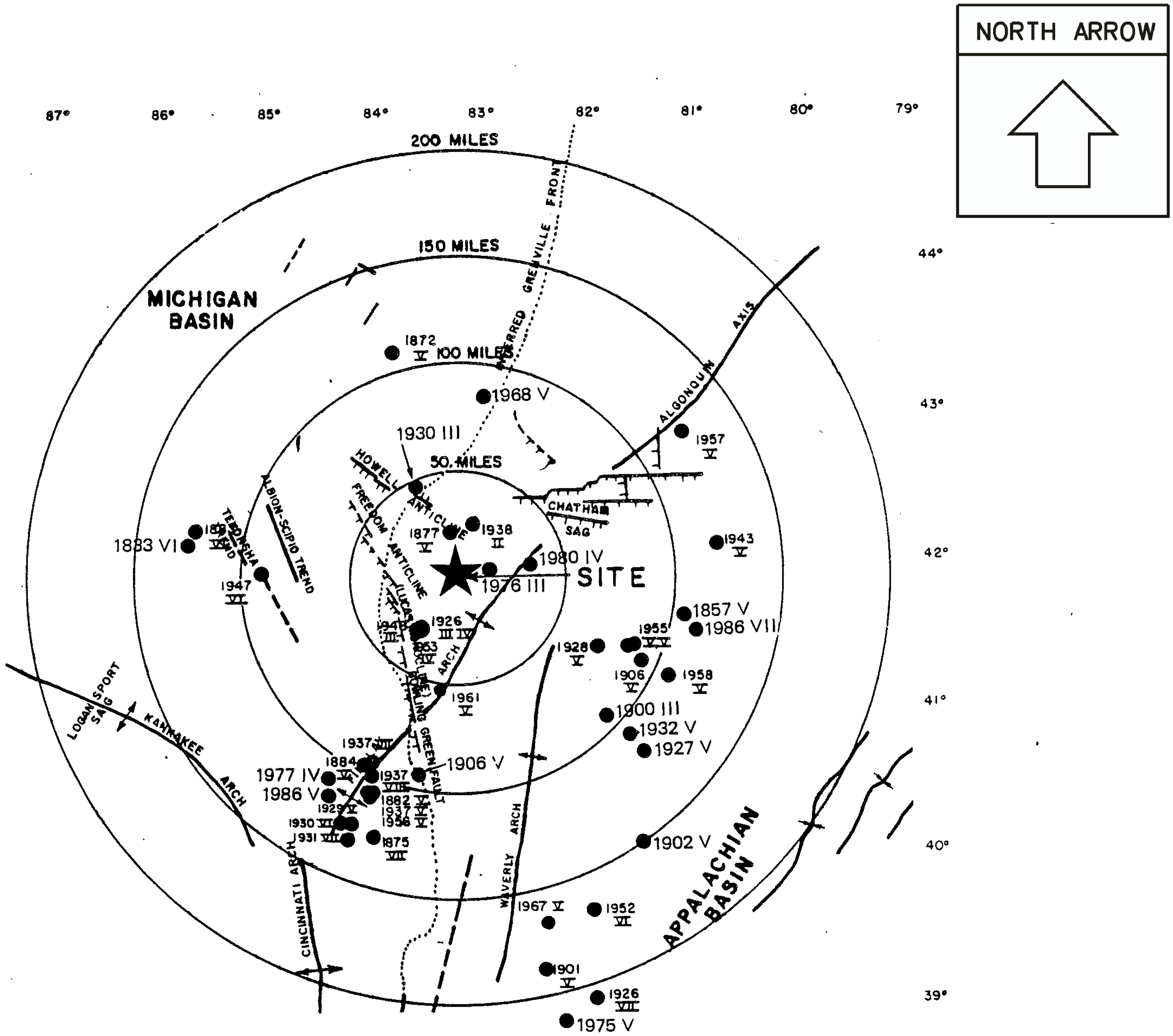
[a] Two percent Damping Calculated Lowest Natural Frequency.

[b] The refueling platform has been reclassified as Seismic Category II/I.

TABLE 3.7-16 SEISMIC DESIGN CONTROL ACTION ITEMS

(General Block Diagram)

Item	Responsibility	Description of Action			
1	Edison engineer (EE)	Prepare specification of vendor equipment			
2	EE	Transmit specification to the independent reviewer (IR) for aseismic performance review			
3	Independent reviewer (IR)	Review aseismic performance specification			
4	EE	Submit equipment specification to vendor (including the IR's review comments)			
5	Vendor	Select method of validation			
		Analytical		Testing	
		(or combination of both)			
6	Vendor	Perform analysis		Develop test procedures	
7	EE	Transmit report to the IR		Transmit test procedures to IR	
8	IR	Review report		Review test procedures	
9	EE			Action on test procedures:	
				Approved	Disapproved
				OK for testing	Modify and resubmit
10	Vendor			Perform test and submit report to Edison	
11	EE			Submit vendor test report to IR	
12	IR			Review report	
13	IR	Transmit documented review of report to Edison			
14	EE	Action on Analysis Report:		Action on Test Report:	
		Approved	Disapproved	Approved	Disapproved
15	Vendor		Revise analysis and resubmit		Perform revised test and resubmit
16	EE	File approved vendor validation package and IR report			
17	Vendor	File Edison's aseismic design approval			



NOTE: ALL REPORTED EARTHQUAKES WITHIN 50 MILES OF THE SITE ARE SHOWN. ONLY EARTHQUAKES OF INTENSITY V AND GREATER ARE SHOWN WITHIN 50 TO 200 MILES OF THE SITE.

LEGEND:

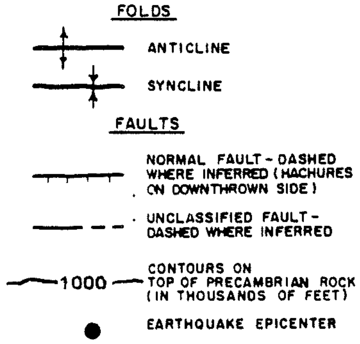


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FIGURE 3.7-1

EPICENTER MAP

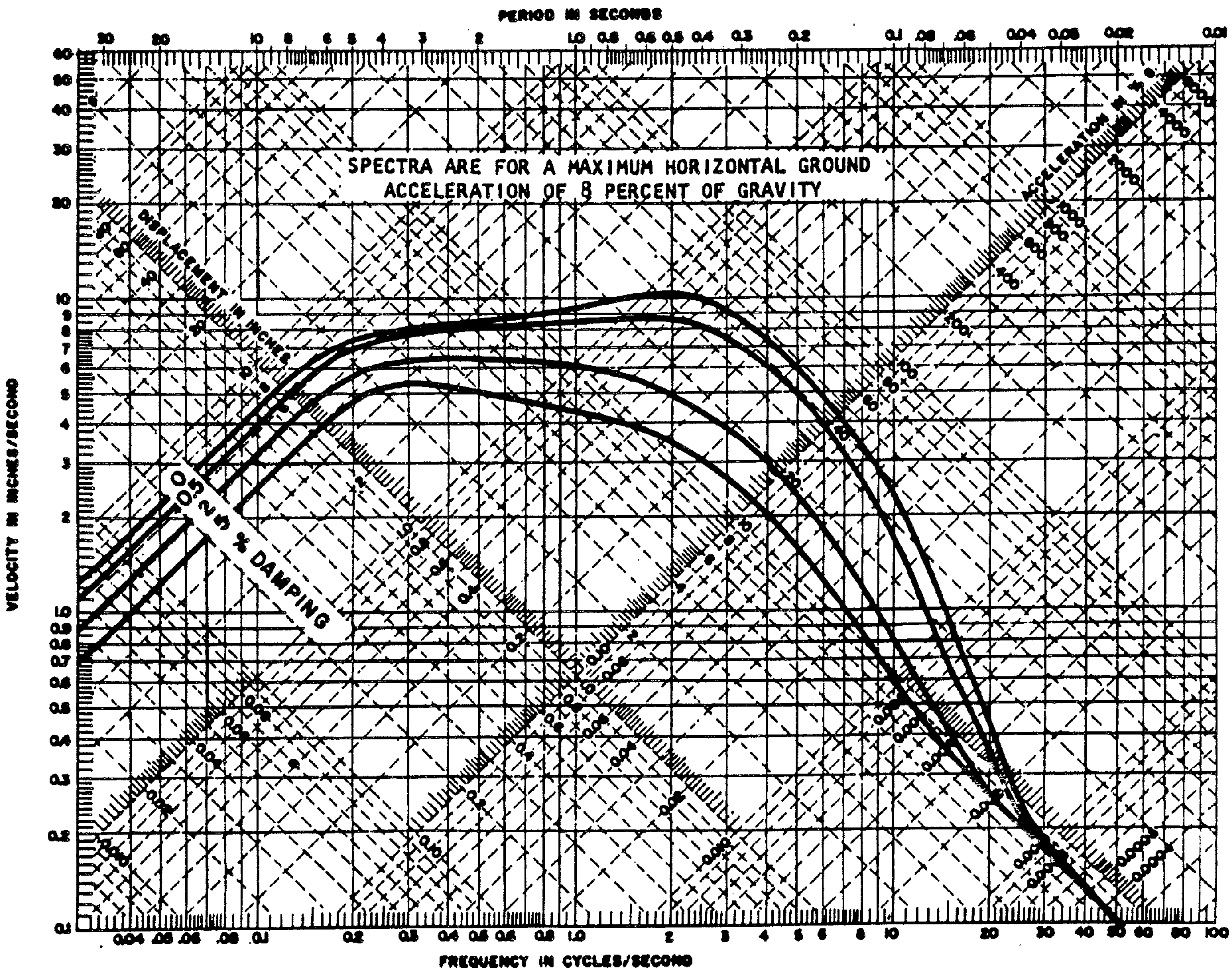

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FIGURE 3.7-2

HORIZONTAL RESPONSE SPECTRA
OPERATING-BASIS EARTHQUAKE
GROUND LEVEL

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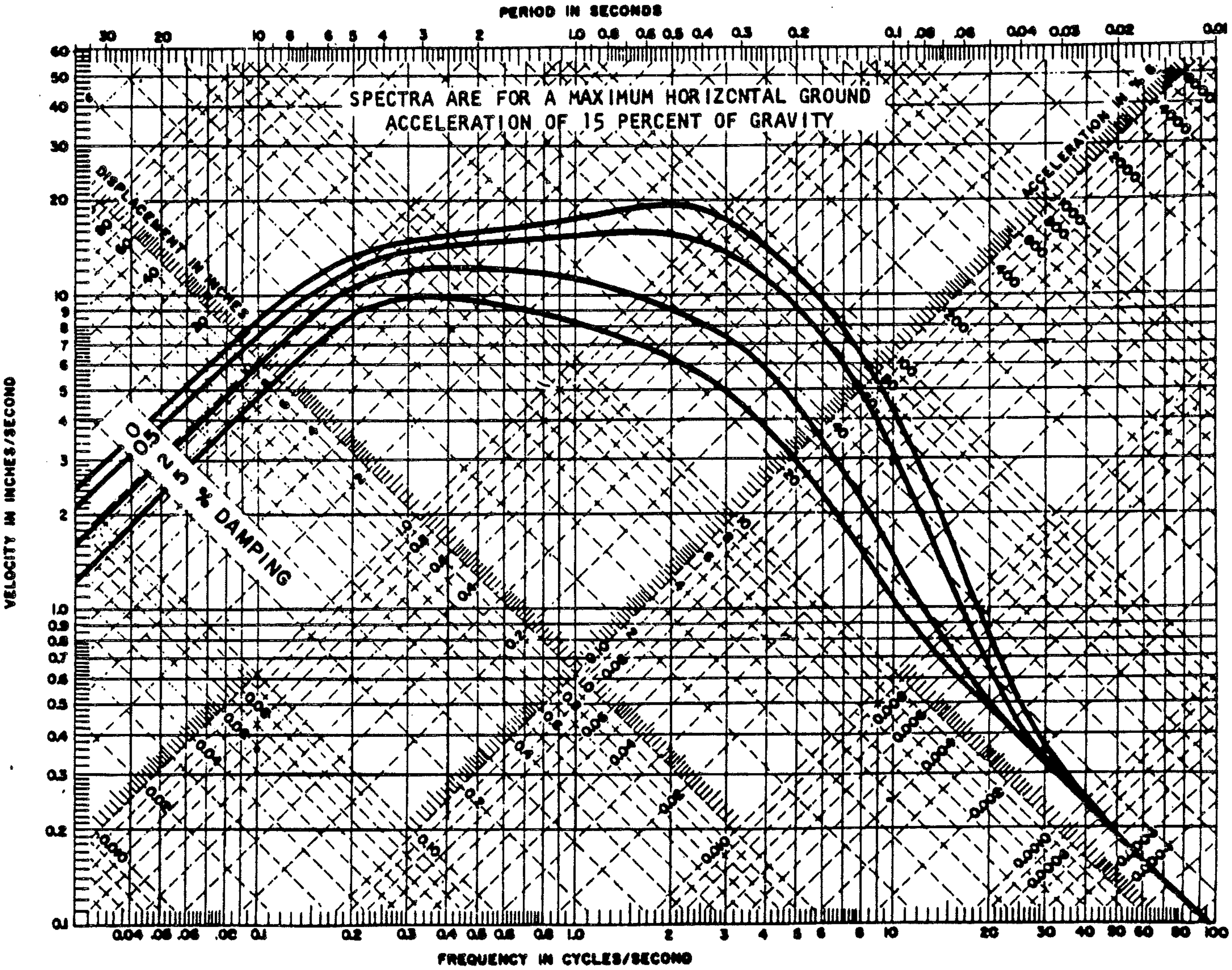

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FIGURE 3.7-3

HORIZONTAL RESPONSE SPECTRA
SAFE-SHUTDOWN EARTHQUAKE
GROUND LEVEL

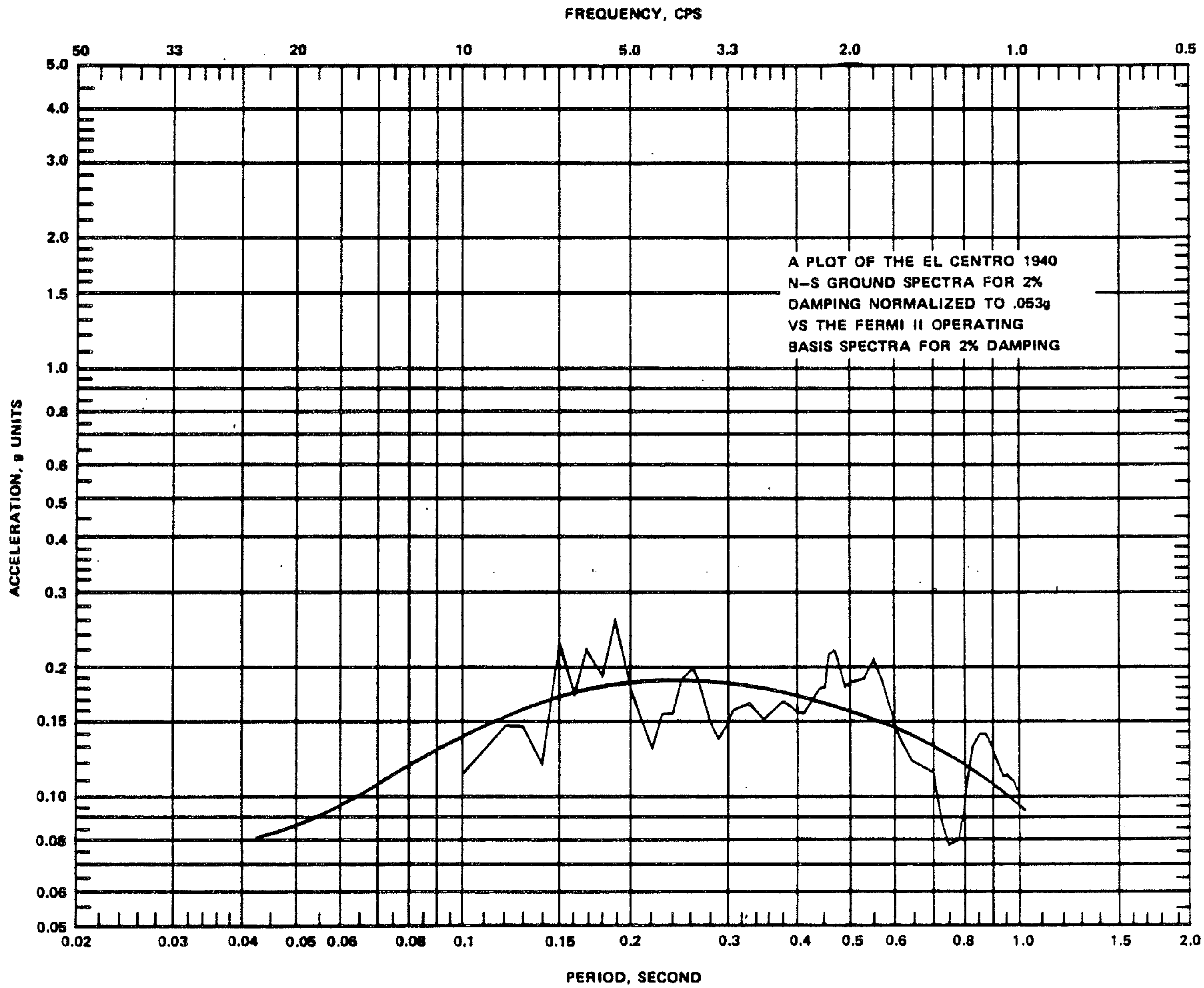

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FIGURE 3.7-4

EL CENTRO 1940 – N-S GROUND SPECTRA

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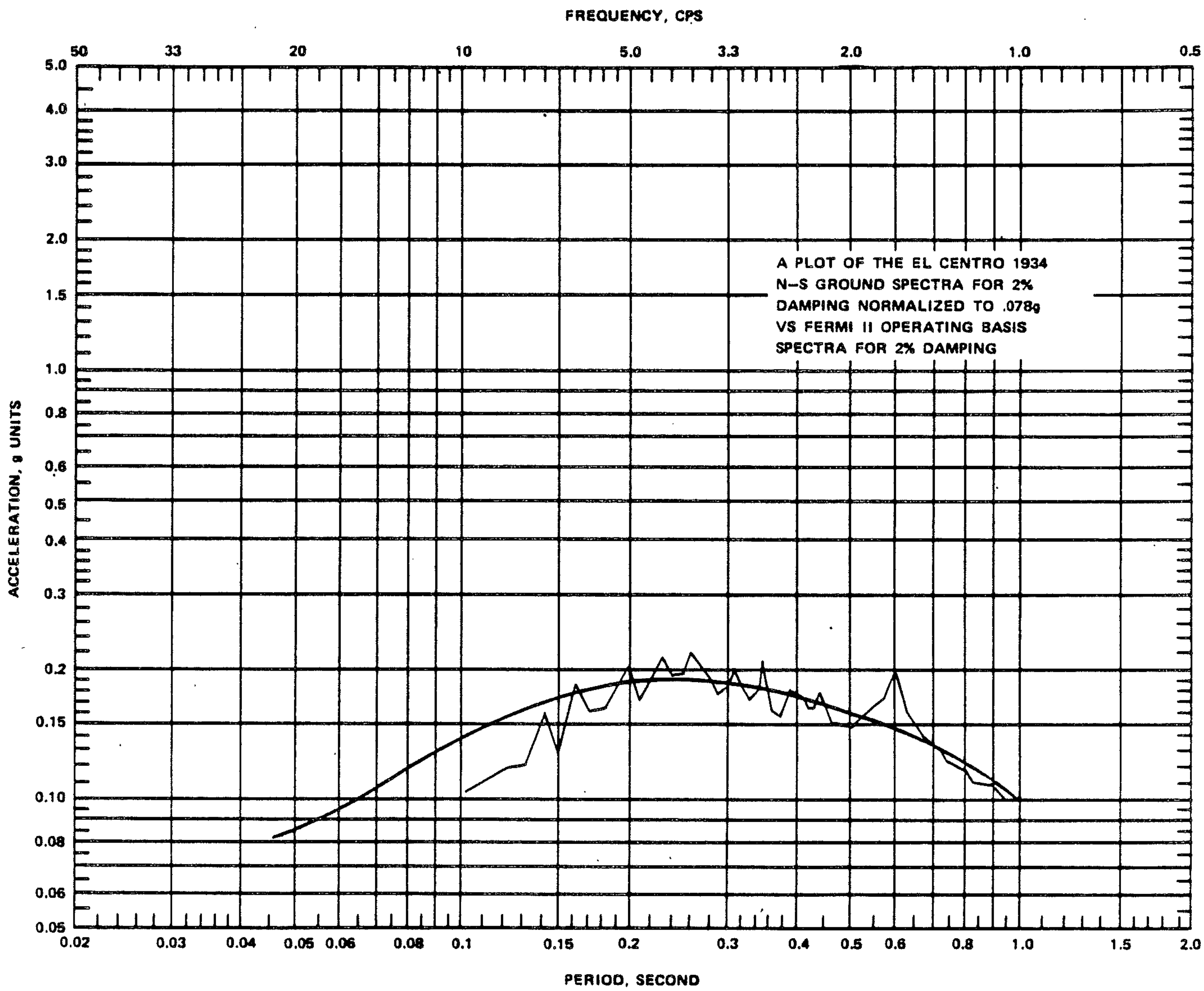

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FIGURE 3.7-5

EL CENTRO 1934 – N-S GROUND SPECTRA

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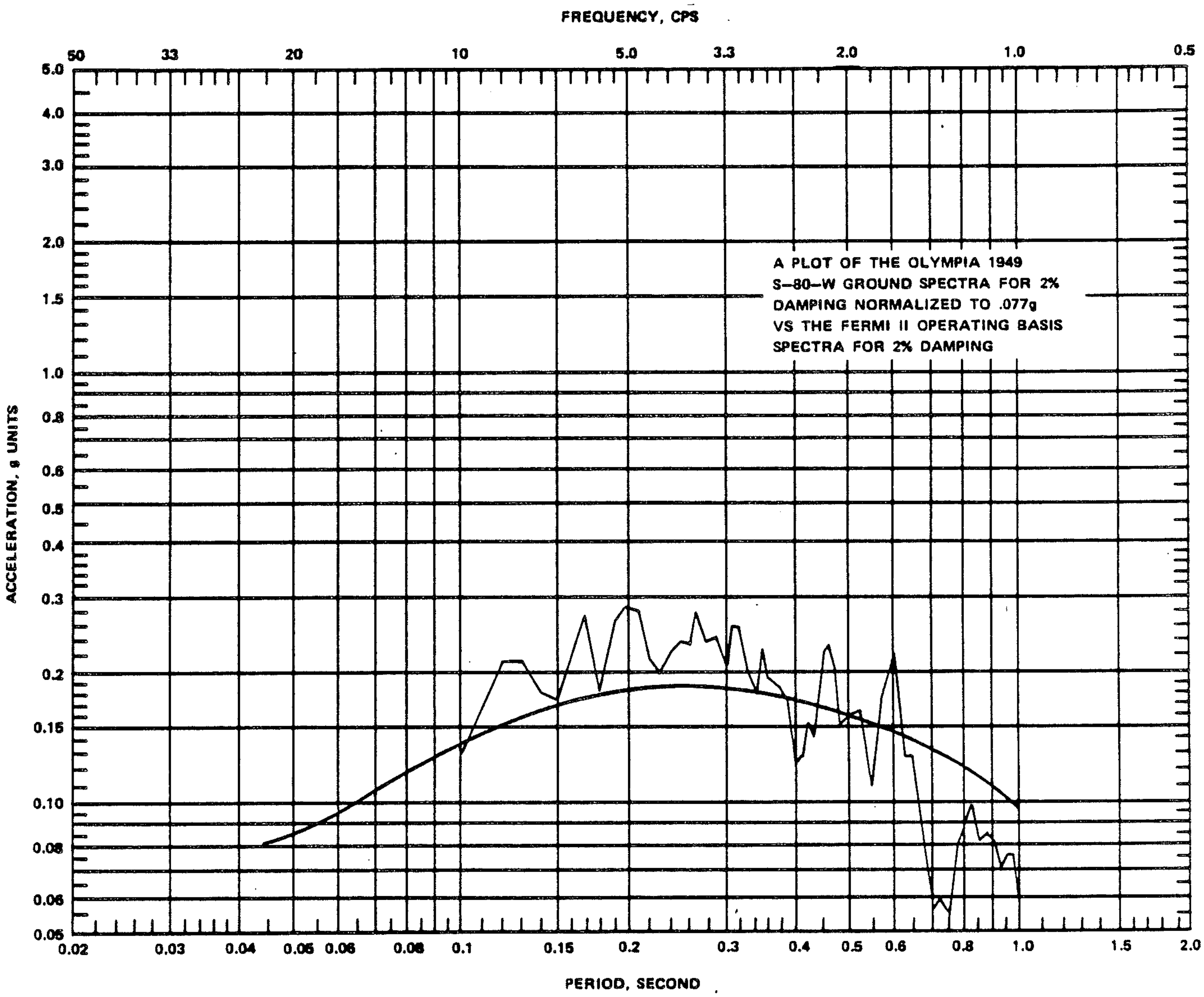

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FIGURE 3.7-6

OLYMPIA 1949 – S-80-W GROUND SPECTRA

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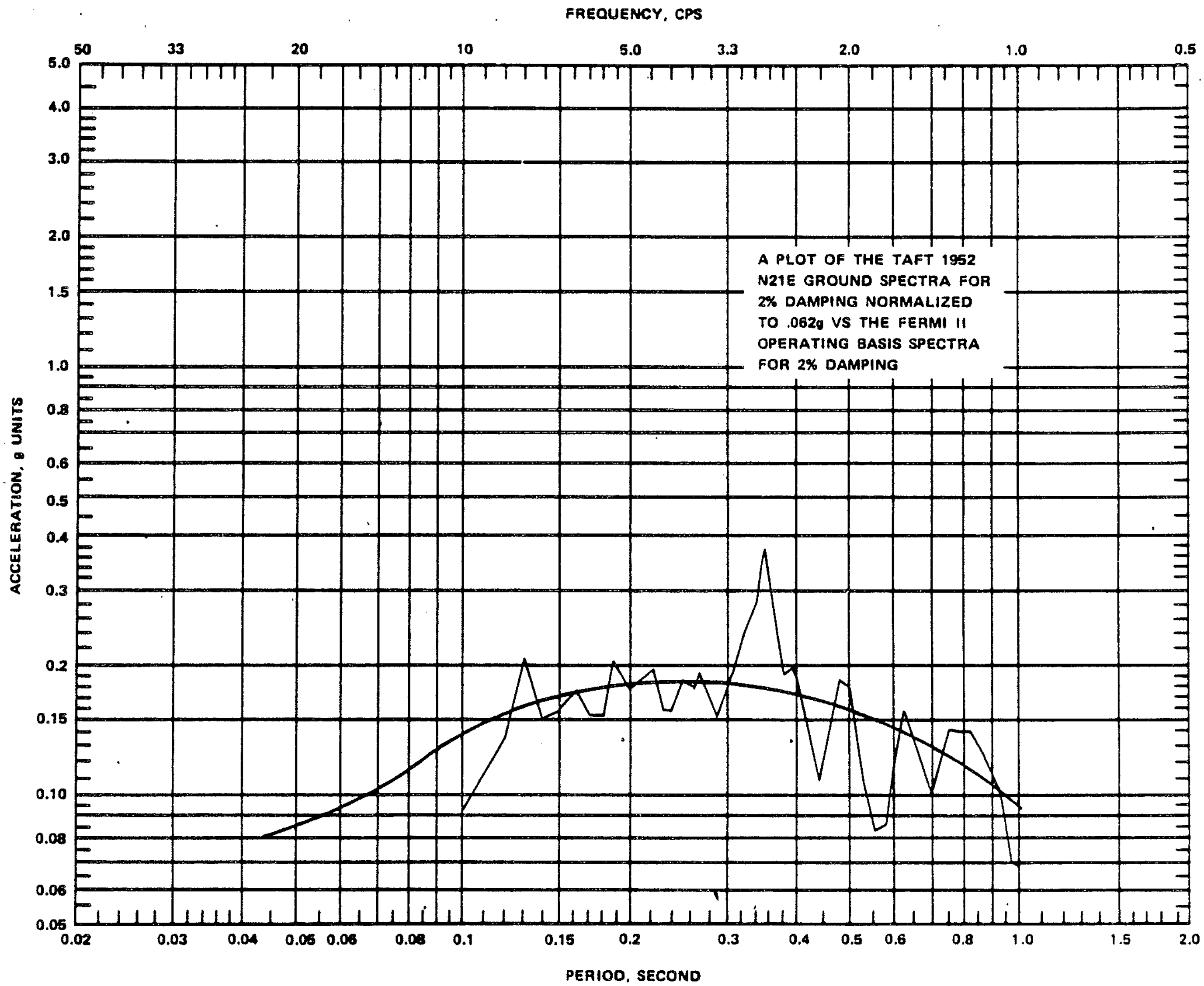

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FIGURE 3.7-7

TAFT 1952 – N-21-E GROUND SPECTRA

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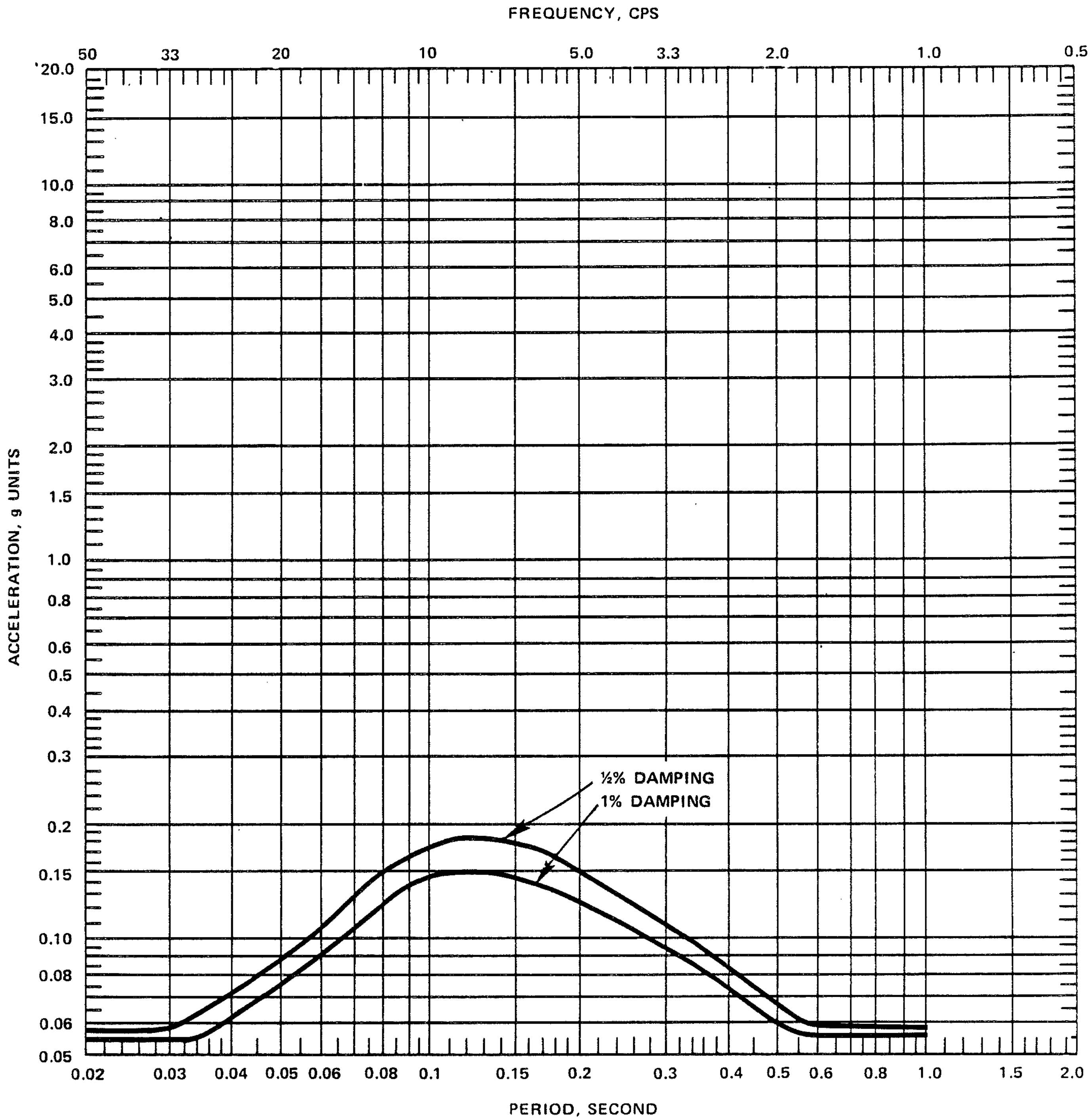

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FIGURE 3.7-8

VERTICAL RESPONSE SPECTRA
OPERATING-BASIS EARTHQUAKE
GROUND LEVEL

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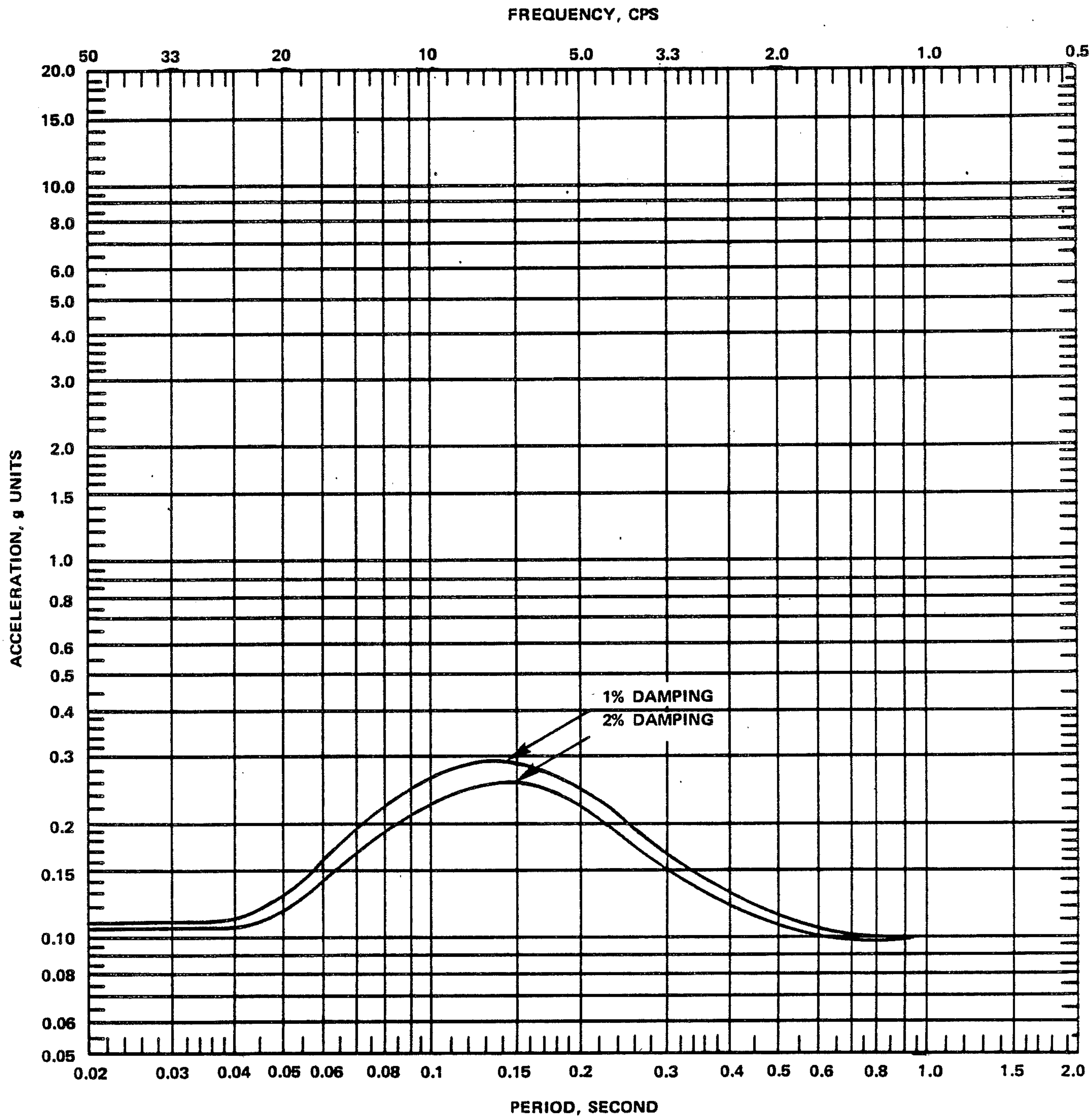

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FIGURE 3.7-9

VERTICAL RESPONSE SPECTRA
SAFE-SHUTDOWN EARTHQUAKE
GROUND LEVEL

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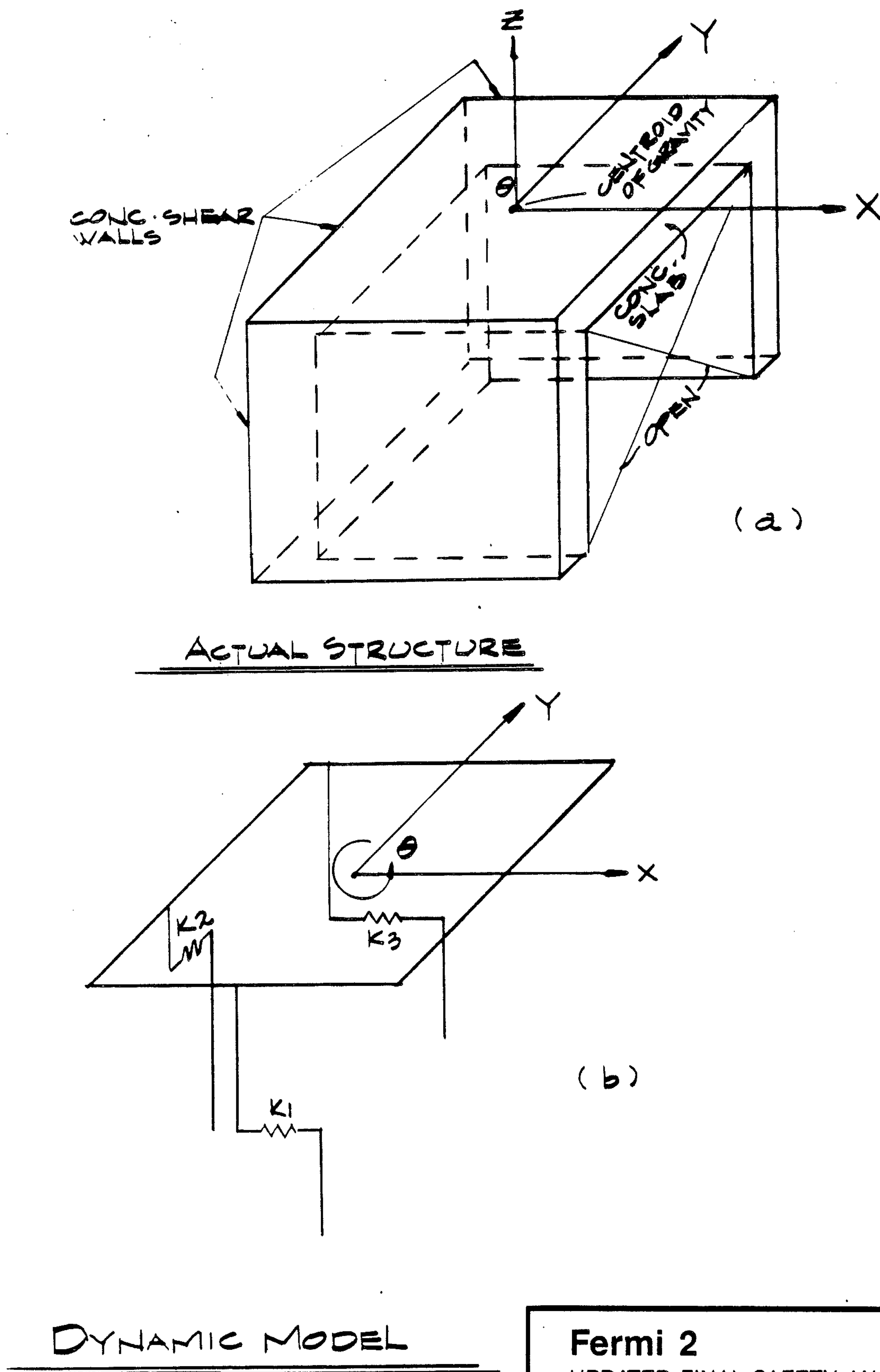

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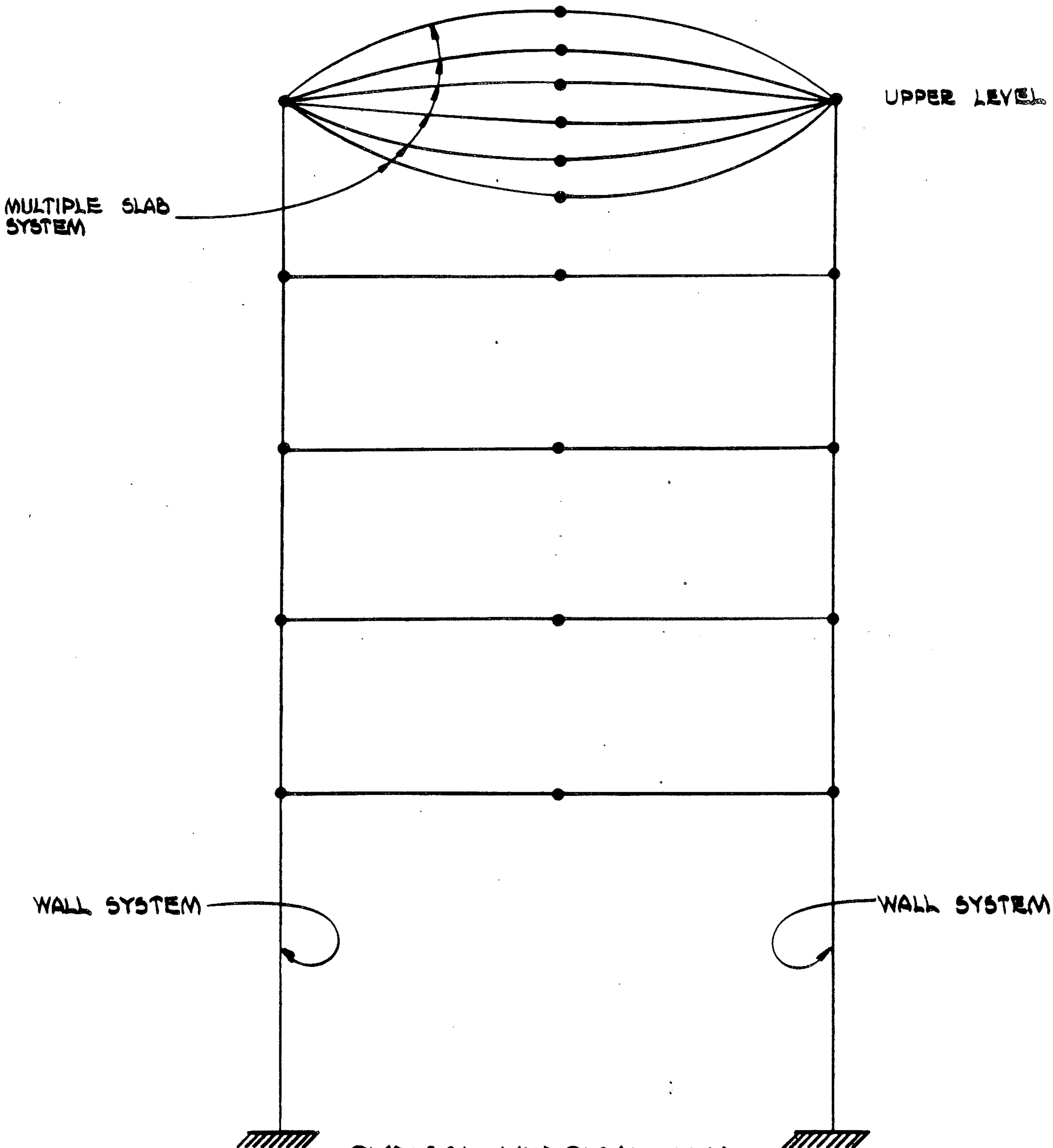
FIGURE 3.7-10

TYPICAL SLAB SPRING DYNAMIC MODEL



TYPICAL VERTICAL MODEL

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FIGURE 3.7-11

TYPICAL VERTICAL MODEL

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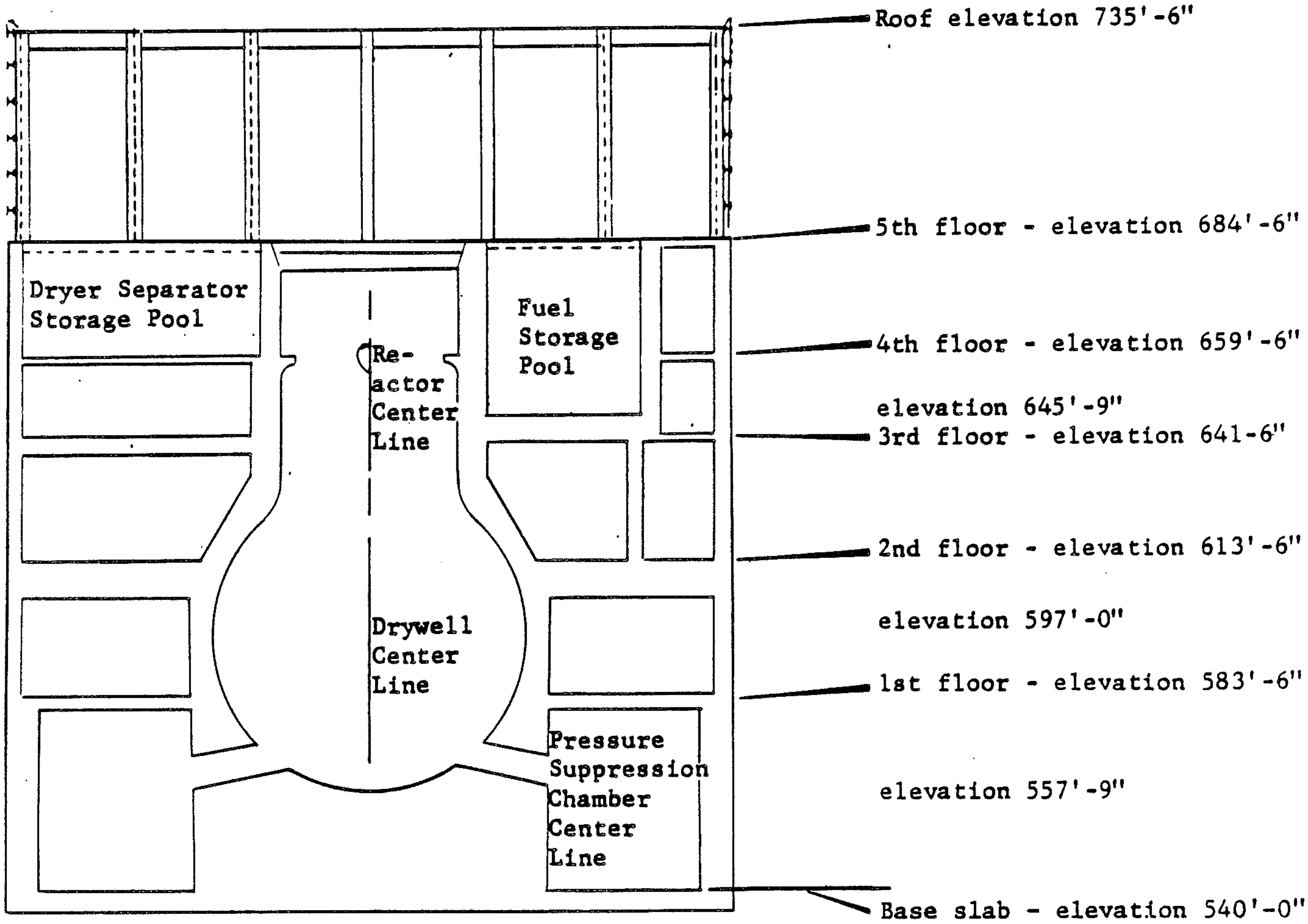

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FIGURE 3.7-12

REACTOR/AUXILIARY BUILDING – NORTH-SOUTH SECTION THROUGH REACTOR CENTERLINE LOOKING WEST

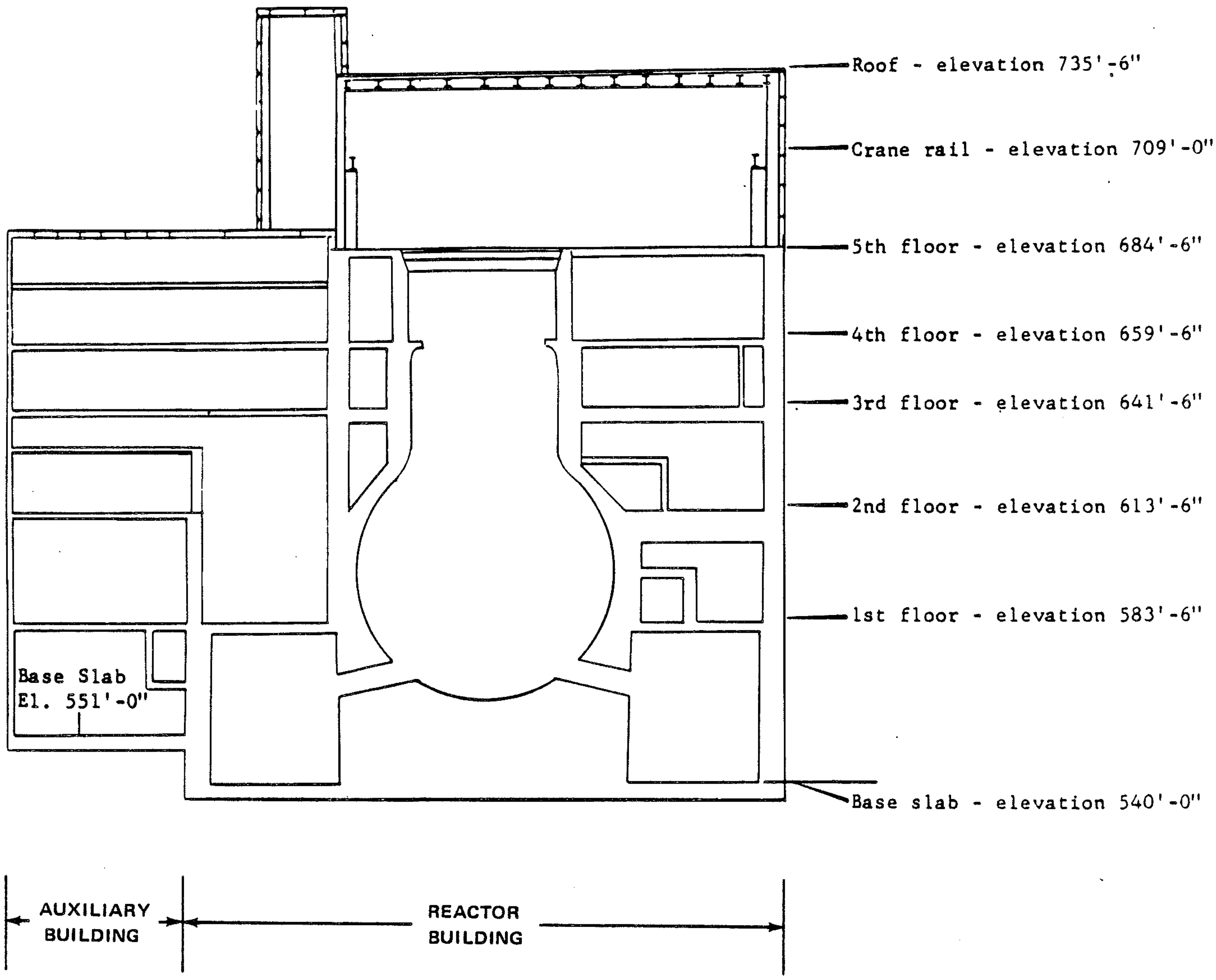

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FIGURE 3.7-13

REACTOR/AUXILIARY BUILDING – EAST-WEST SECTION THROUGH REACTOR CENTERLINE LOOKING SOUTH

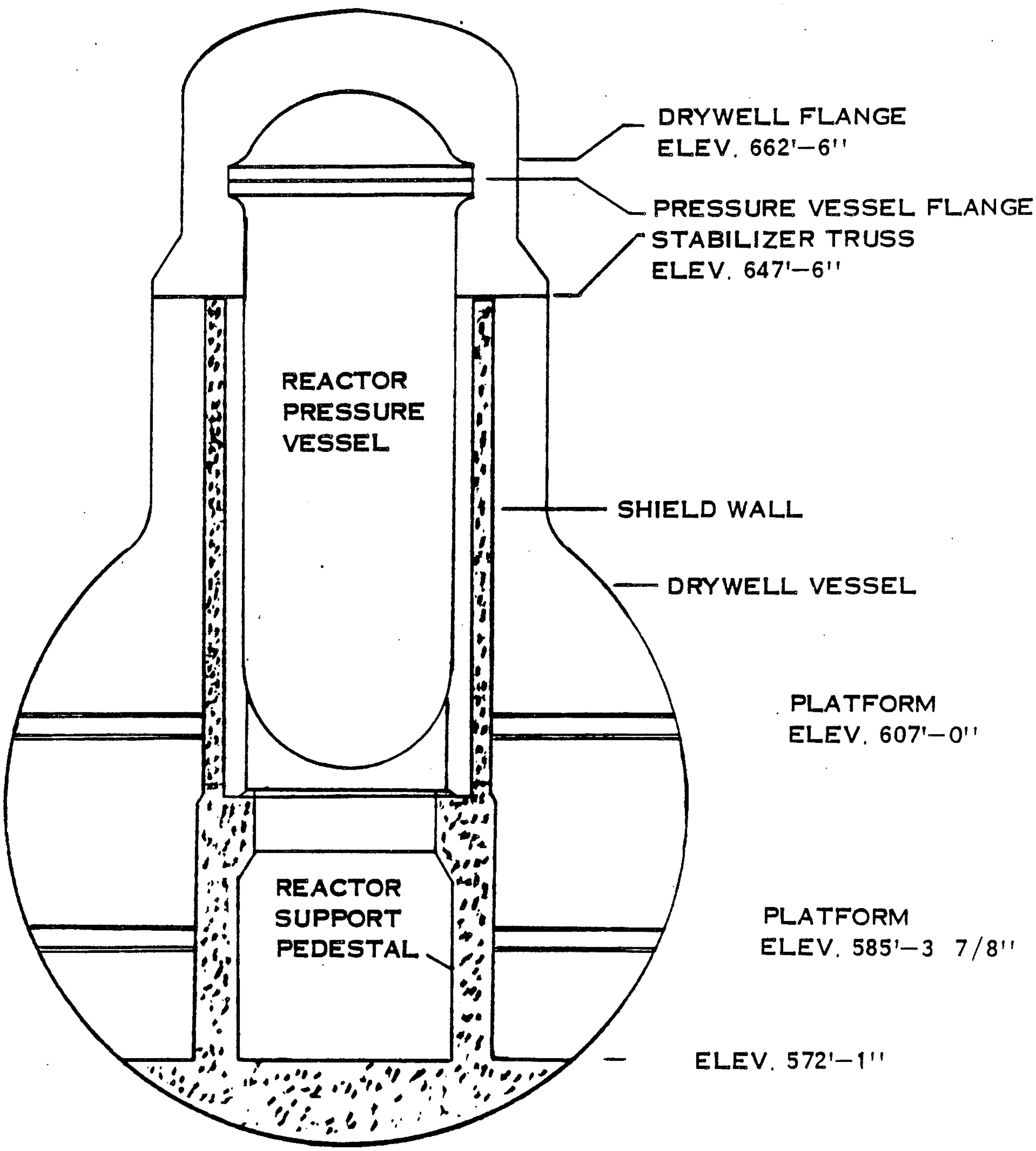

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FIGURE 3.7-14

SECTION THROUGH CENTERLINE OF DRYWELL

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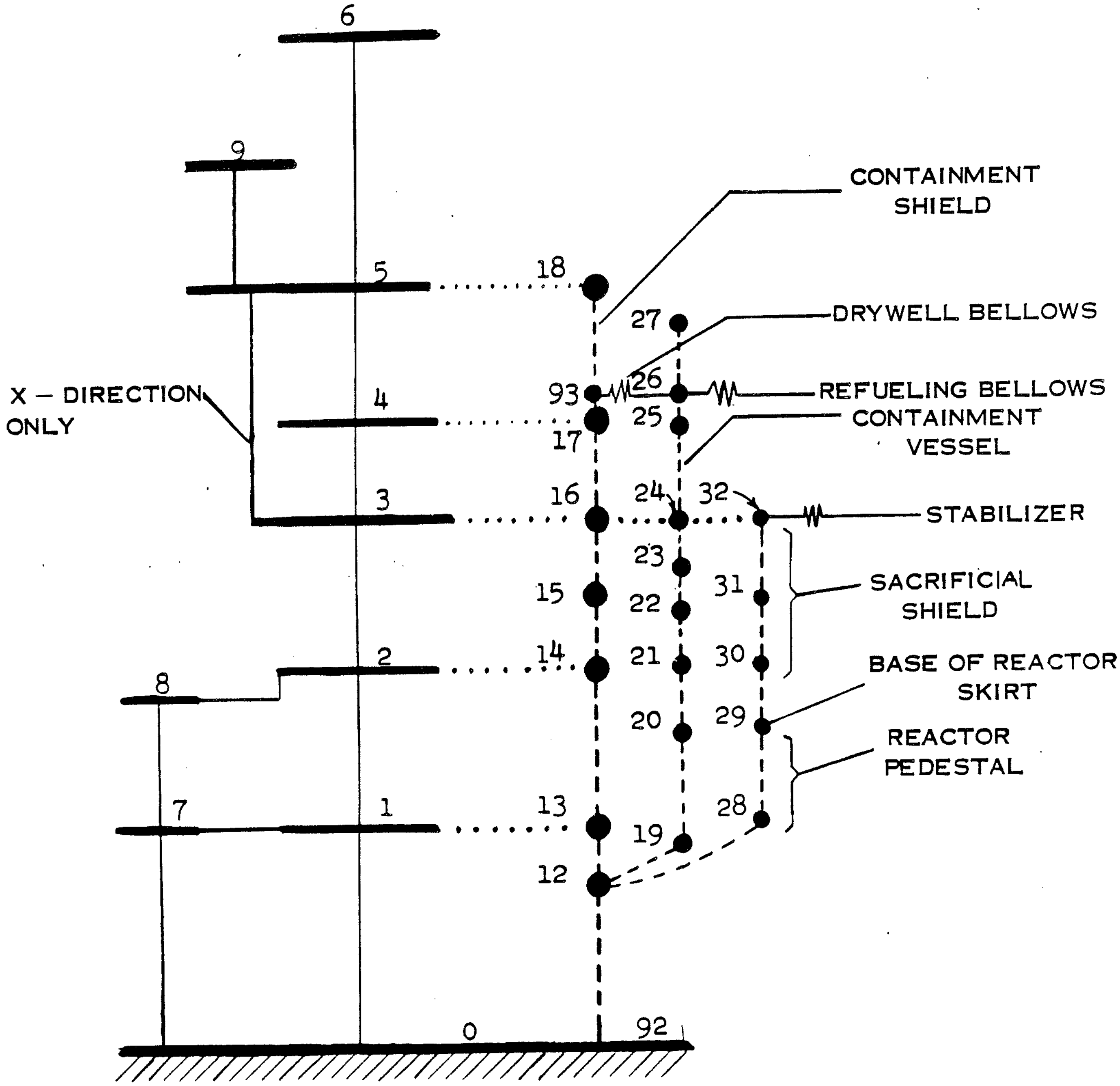

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FIGURE 3.7-15

REACTOR/AUXILIARY BUILDING – HORIZONTAL DYNAMIC MODEL

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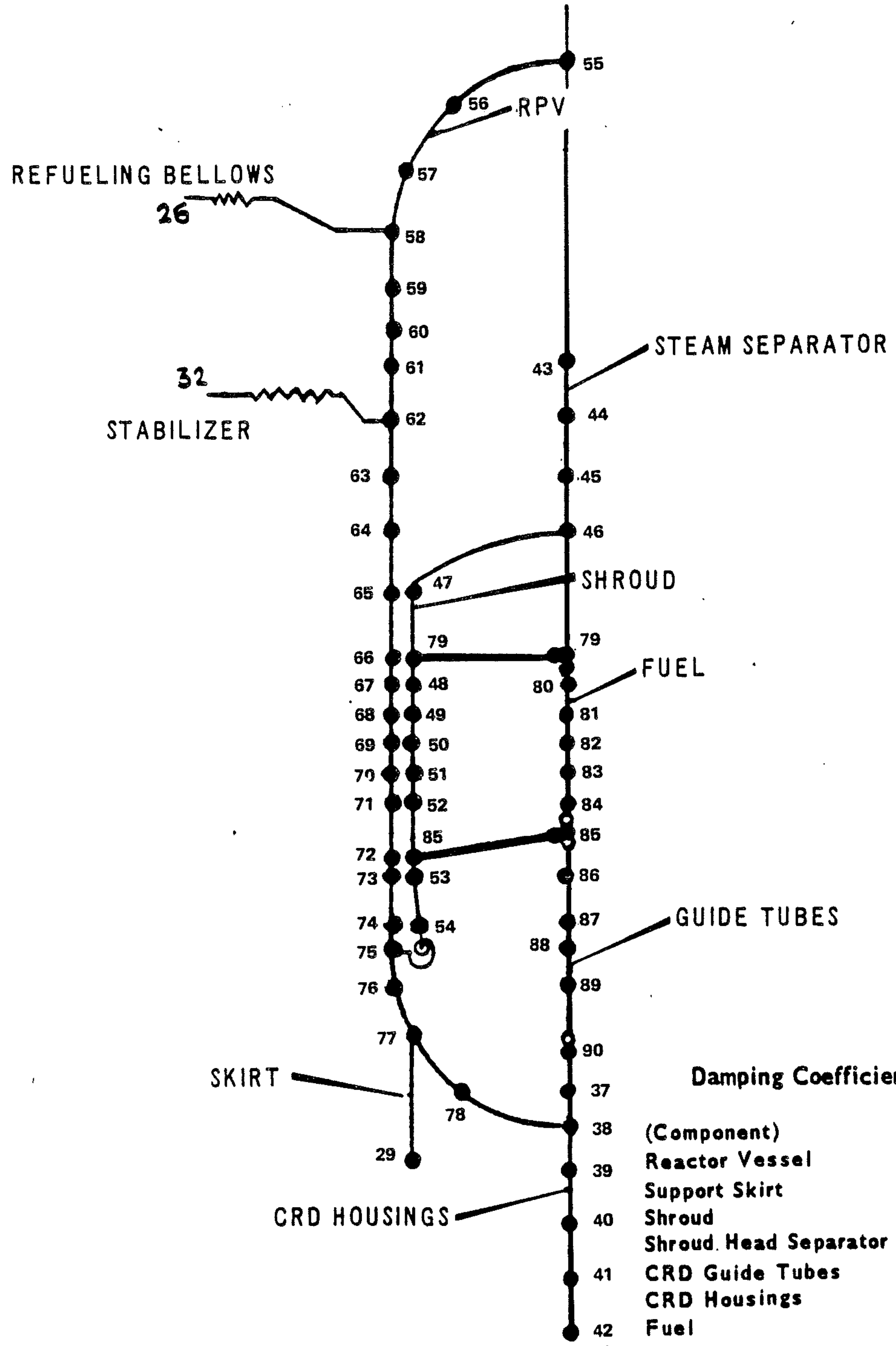

Damping Coefficients for OBE & DBE

(Component)	(% Critical Damping)
Reactor Vessel	2.0
Support Skirt	2.0
Shroud	2.0
Shroud Head Separator	2.0
CRD Guide Tubes	2.0
CRD Housings	3.5
Fuel	7.0

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FIGURE 3.7-16

MATHEMATICAL MODEL – REACTOR PRESSURE VESSEL AND INTERNALS

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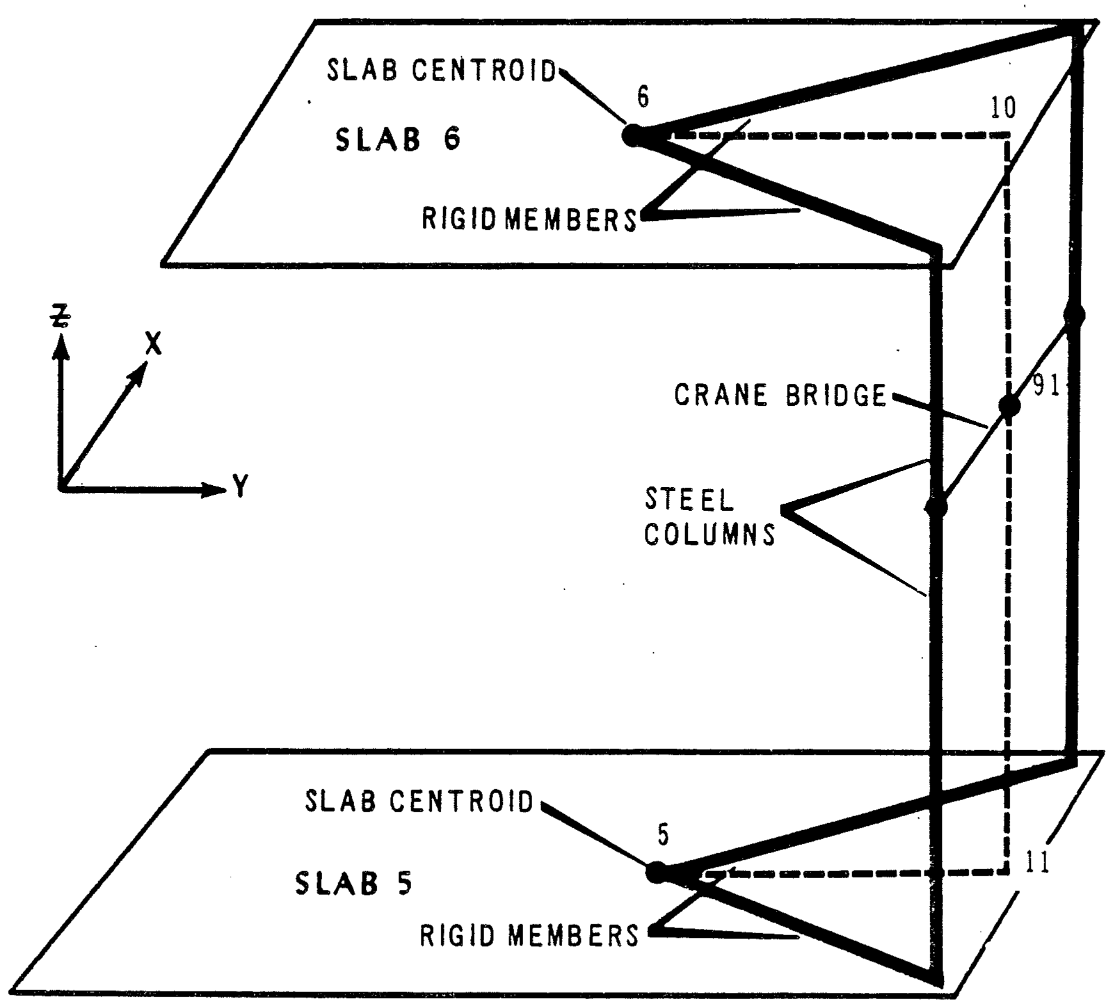

NOTE:

▬▬▬▬ SIMPLIFIED SEISMIC MODEL OF CRANE

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FIGURE 3.7-17

REACTOR/AUXILIARY BUILDING CRANE MODEL

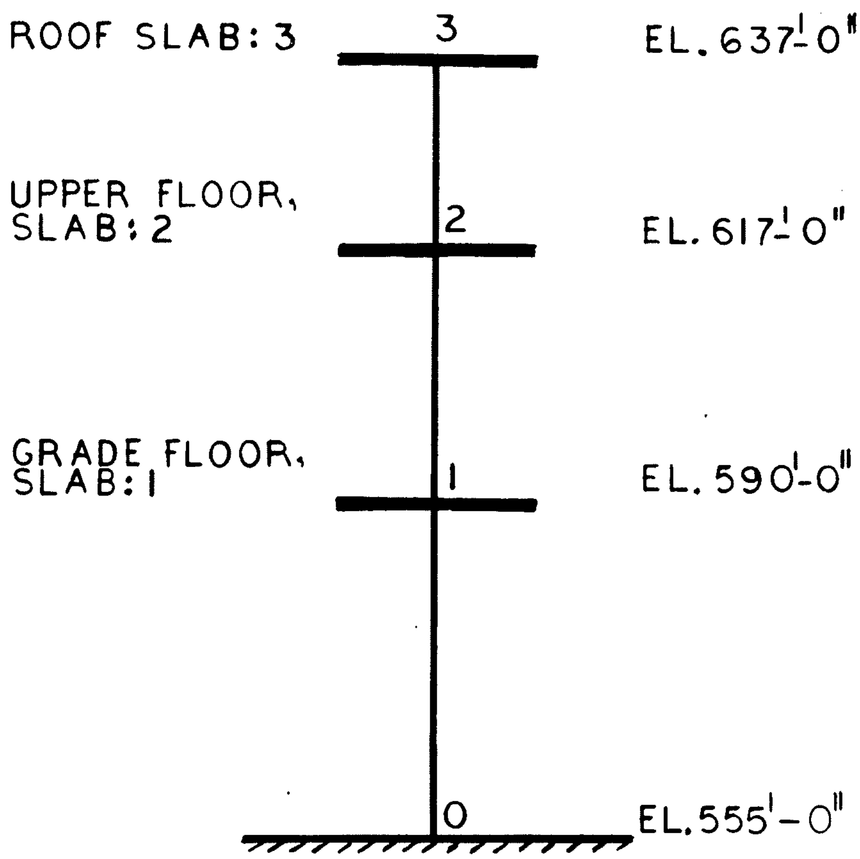

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FIGURE 3.7-18

RESIDUAL HEAT REMOVAL COMPLEX DYNAMIC MODEL FOR HORIZONTAL EXCITATION

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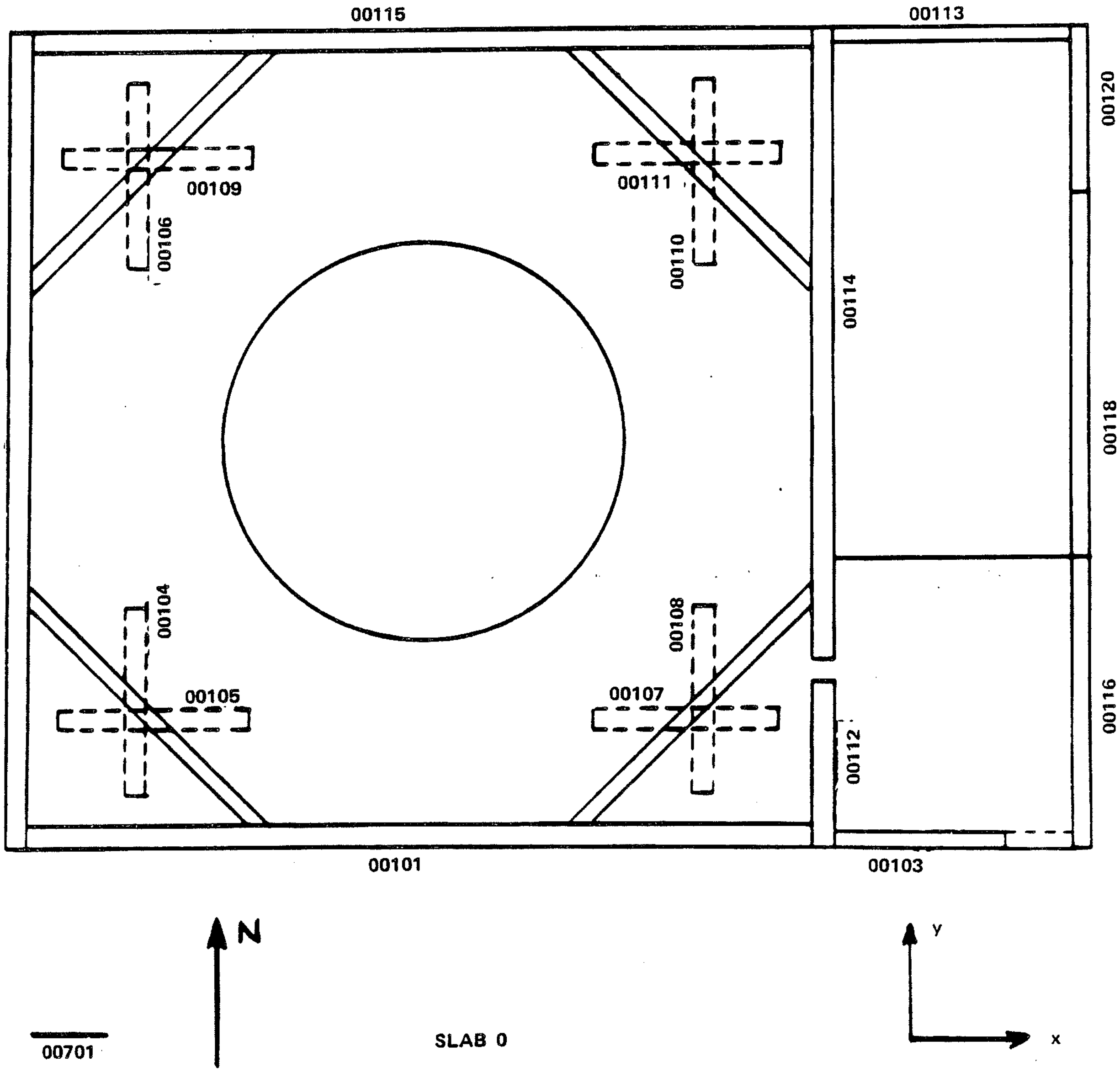

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FIGURE 3.7-19

SEISMIC ANALYSIS – REACTOR/AUXILIARY BUILDING BASE SLAB – ELEVATION 540.0 FT

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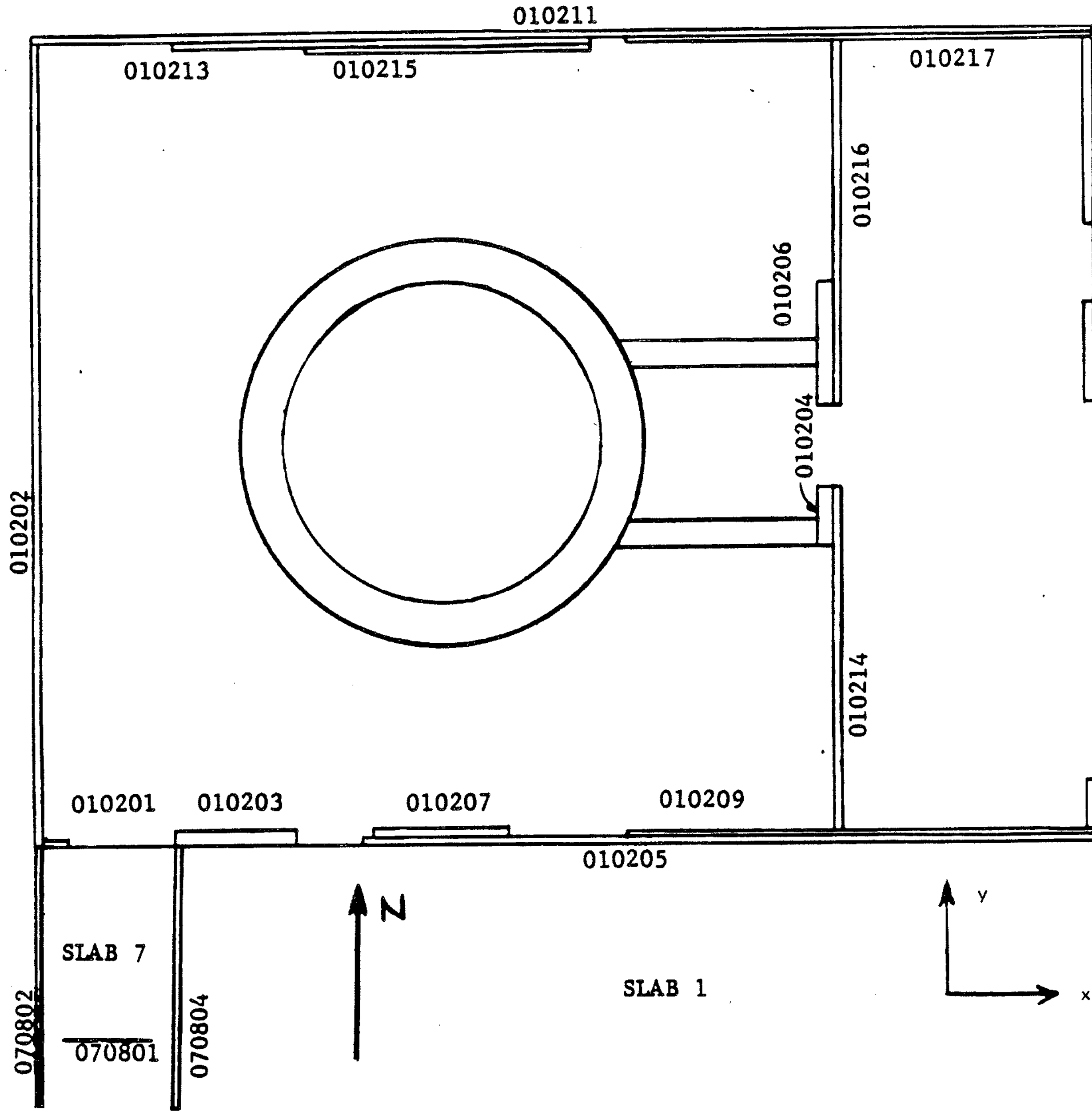

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FIGURE 3.7-20

SEISMIC ANALYSIS – REACTOR/AUXILIARY BUILDING FIRST FLOOR – ELEVATION 583.5 FT

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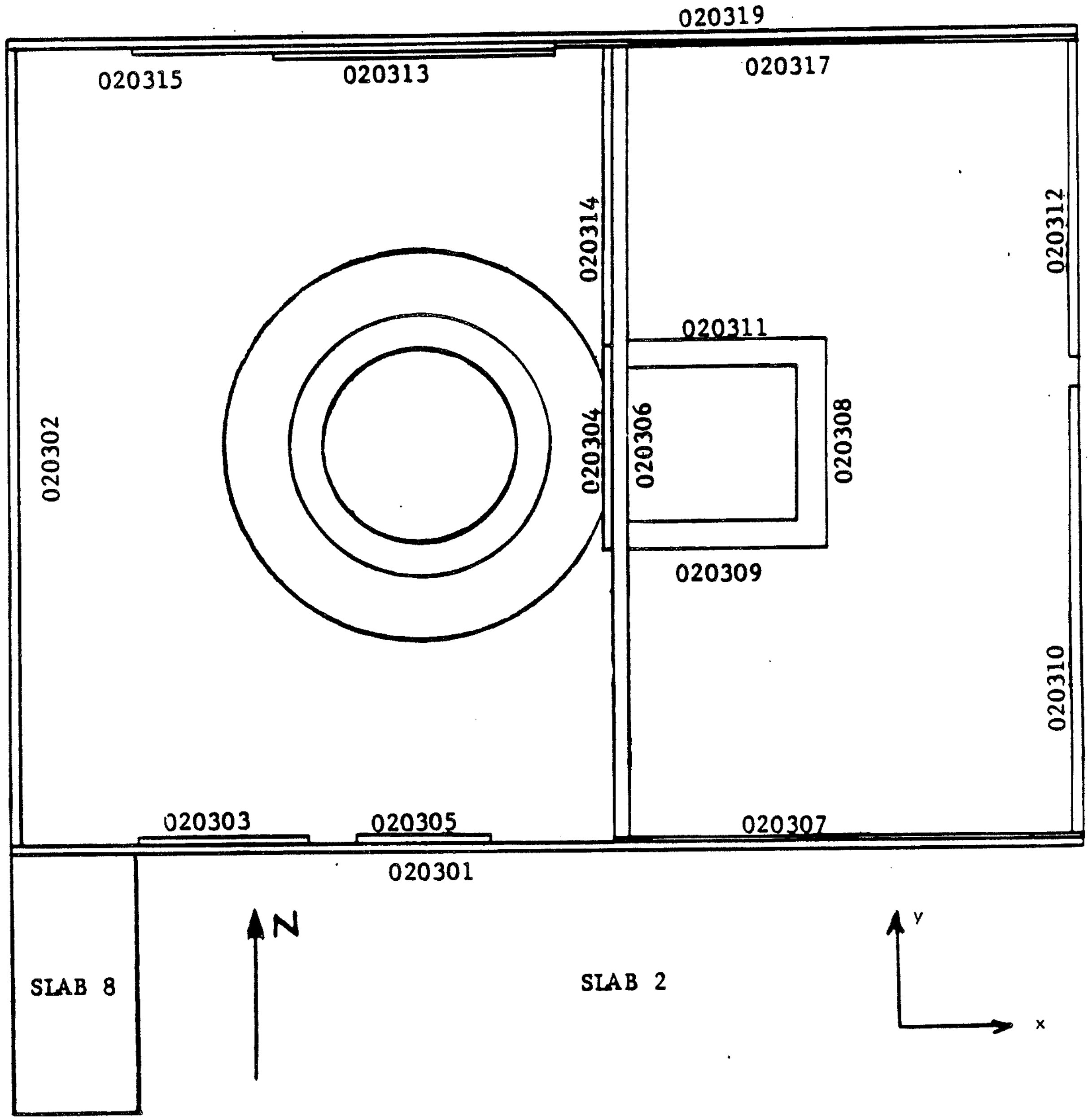

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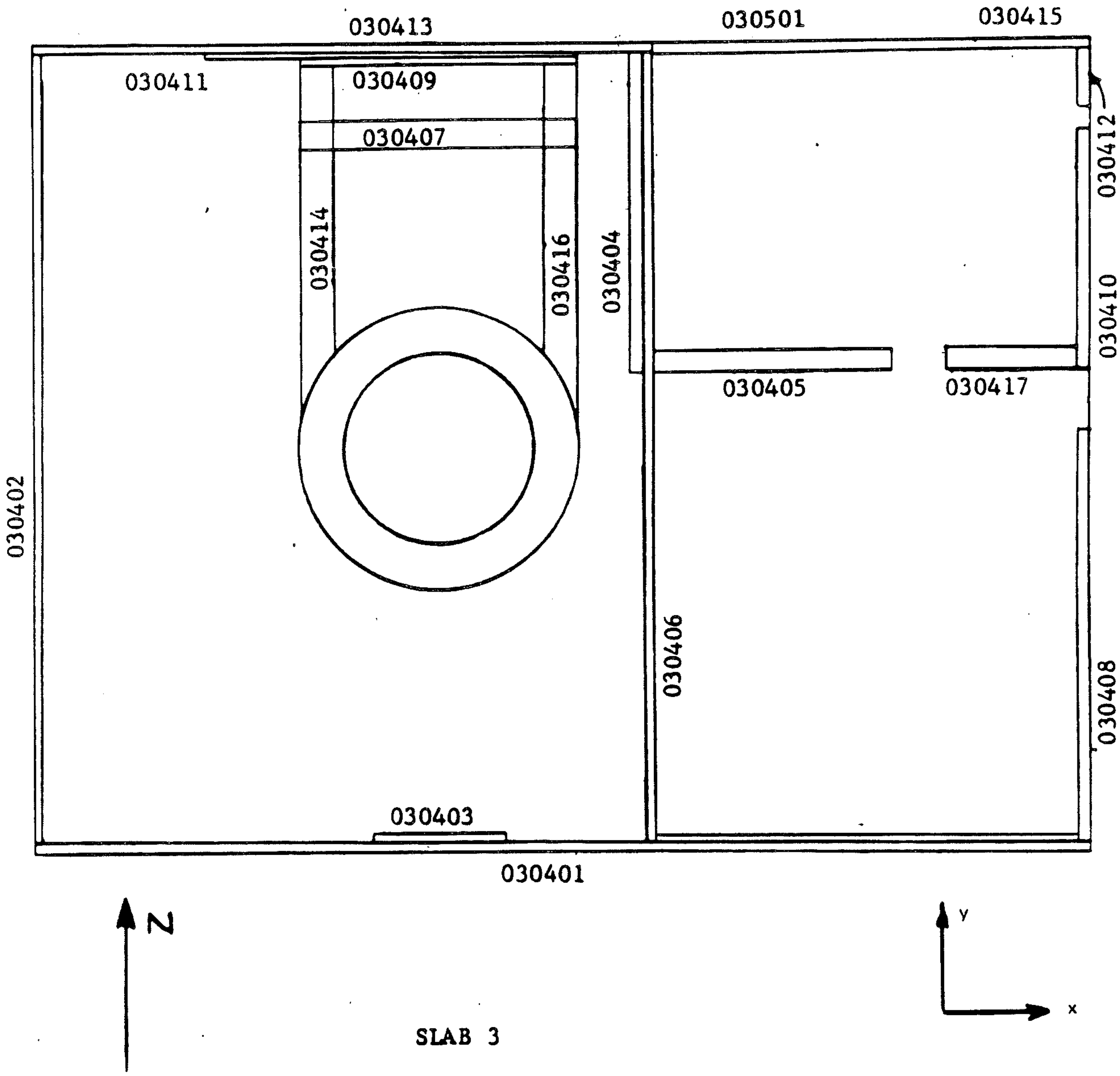
FIGURE 3.7-21

SEISMIC ANALYSIS – REACTOR/AUXILIARY BUILDING SECOND FLOOR – ELEVATION 613.5 FT

SARGENT & LUNDY REPORT NO. SL-2682



SLAB 3

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FIGURE 3.7-22

SEISMIC ANALYSIS – REACTOR/AUXILIARY BUILDING THIRD FLOOR – ELEVATION 641.5 FT

SARGENT & LUNDY REPORT NO. SL-2682

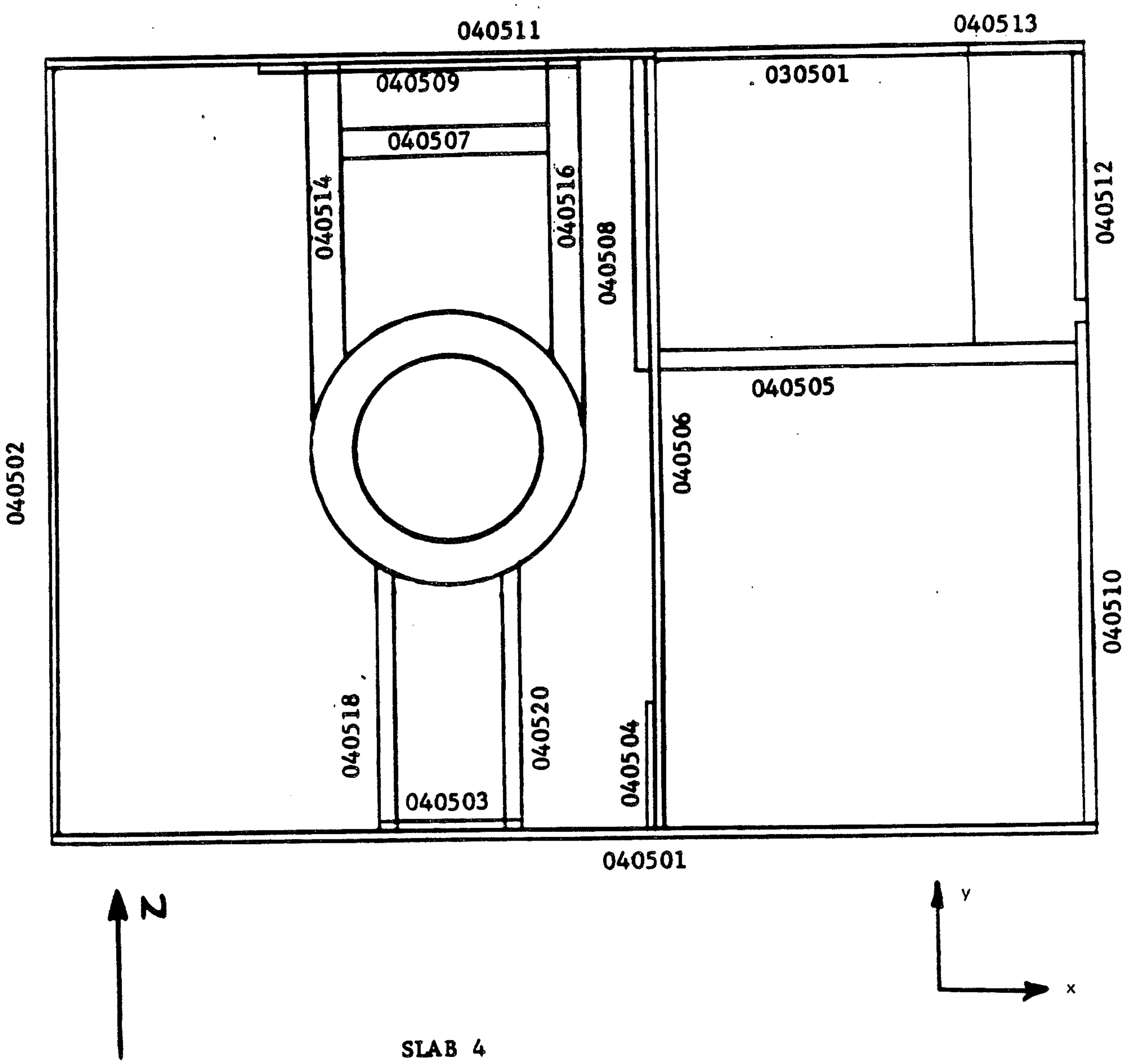

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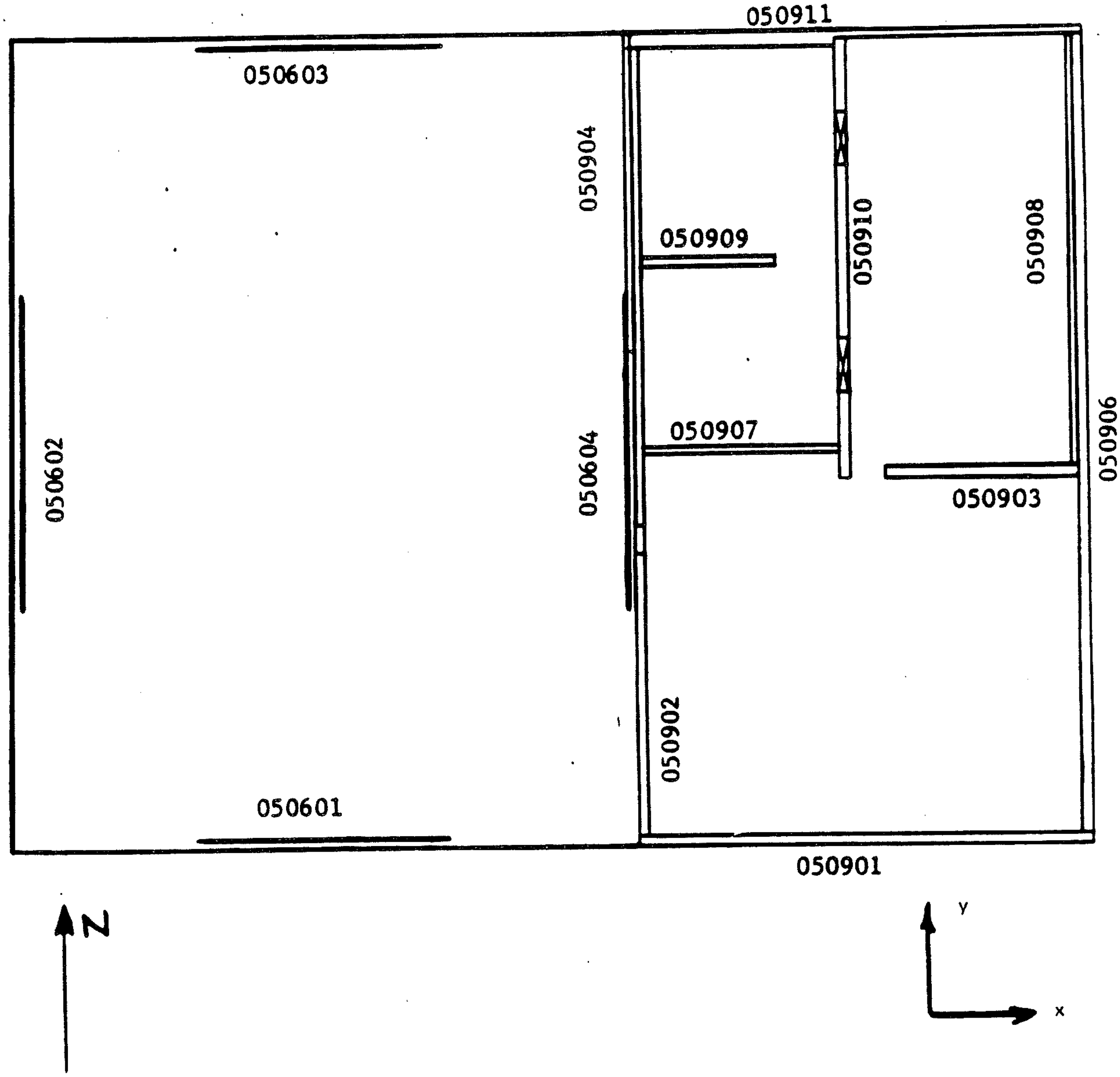
FIGURE 3.7-23

SEISMIC ANALYSIS – REACTOR/AUXILIARY BUILDING FOURTH FLOOR – ELEVATION 659.5 FT

SARGENT & LUNDY REPORT NO. SL-2682



SLAB 5

SARGENT & LUNDY REPORT NO. SL-2682

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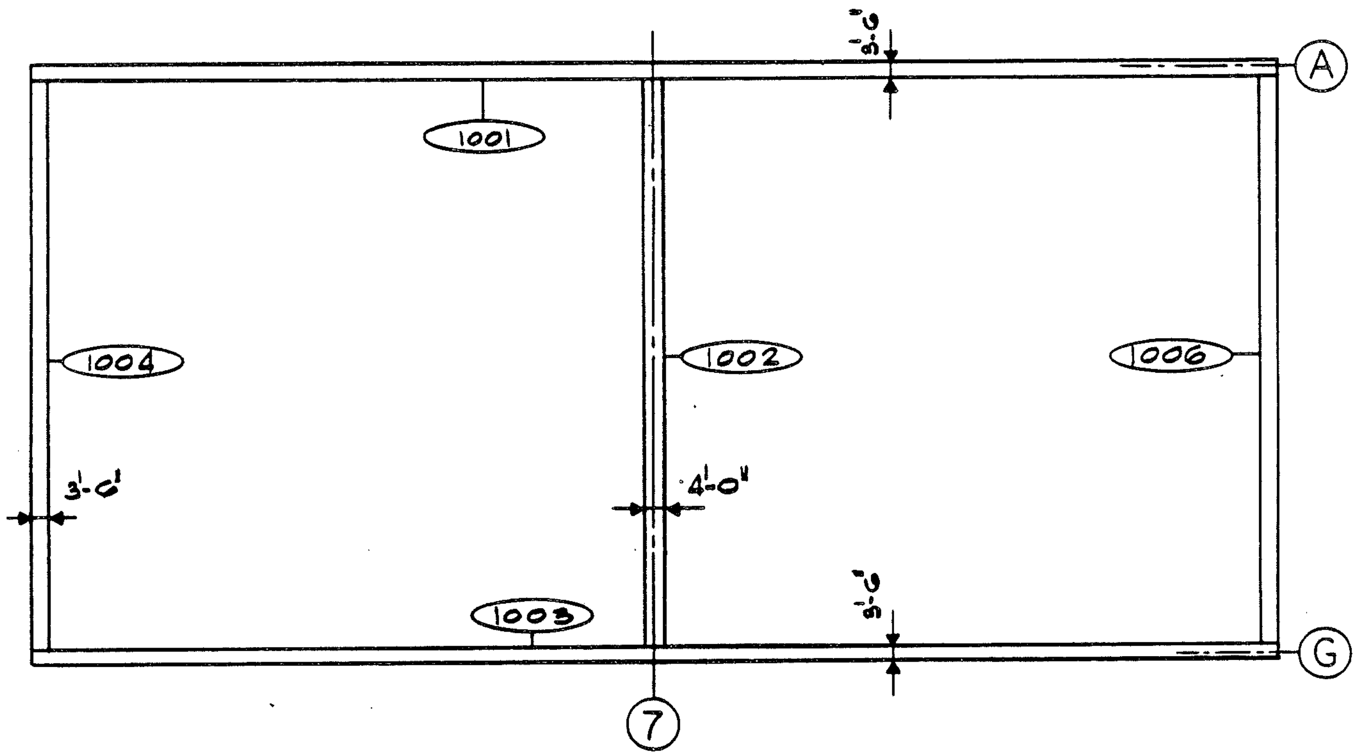
FIGURE 3.7-24

SEISMIC ANALYSIS – REACTOR/AUXILIARY BUILDING FIFTH FLOOR – ELEVATION 684.5 FT



BASEMENT FLOOR
SLAB-0 ELEV. 555'-0"

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FIGURE 3.7-25

RESIDUAL HEAT REMOVAL COMPLEX BASEMENT FLOOR – SLAB 0 – ELEVATION 555.0 FT

SARGENT & LUNDY REPORT NO. SL-3147

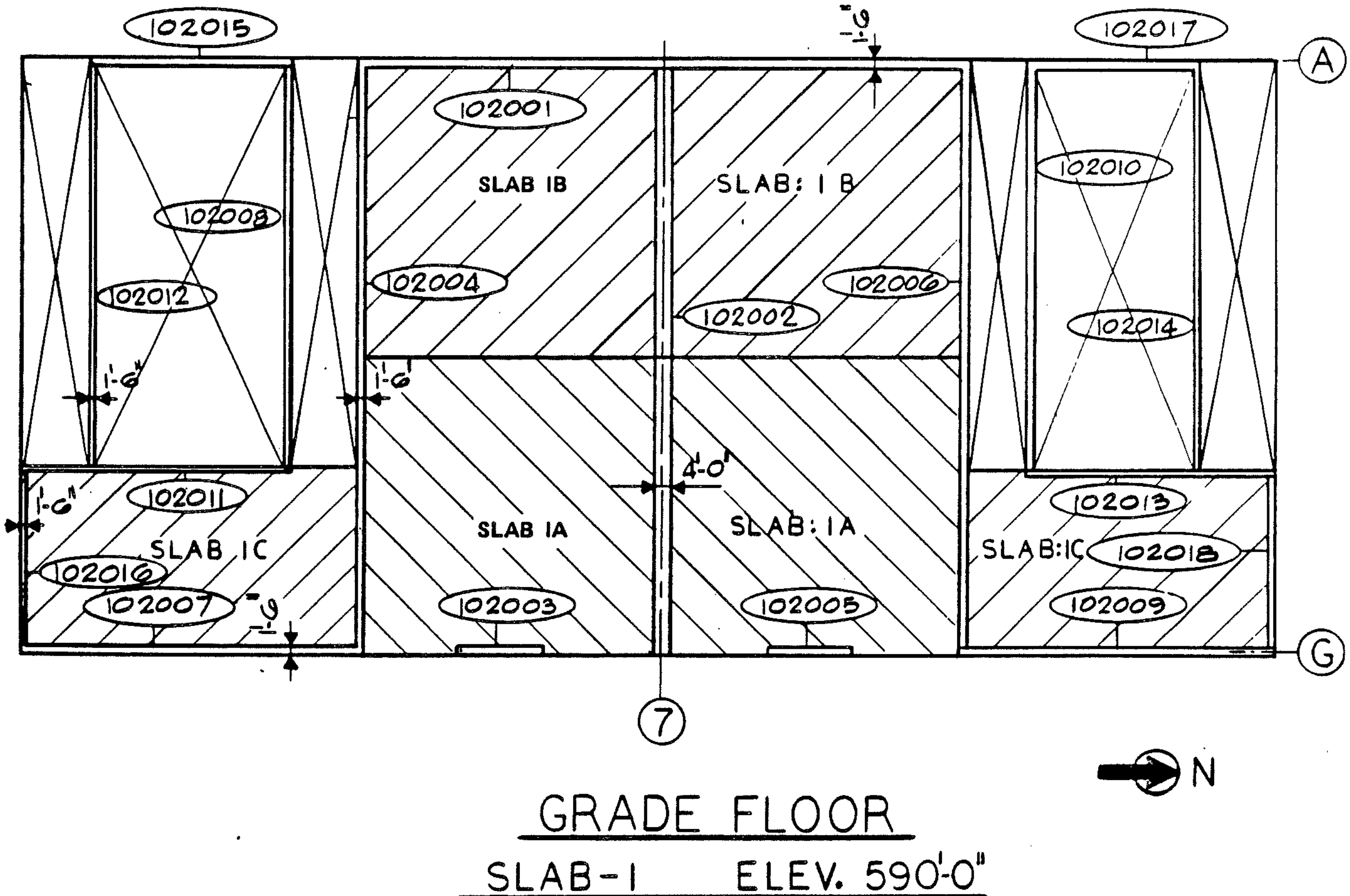

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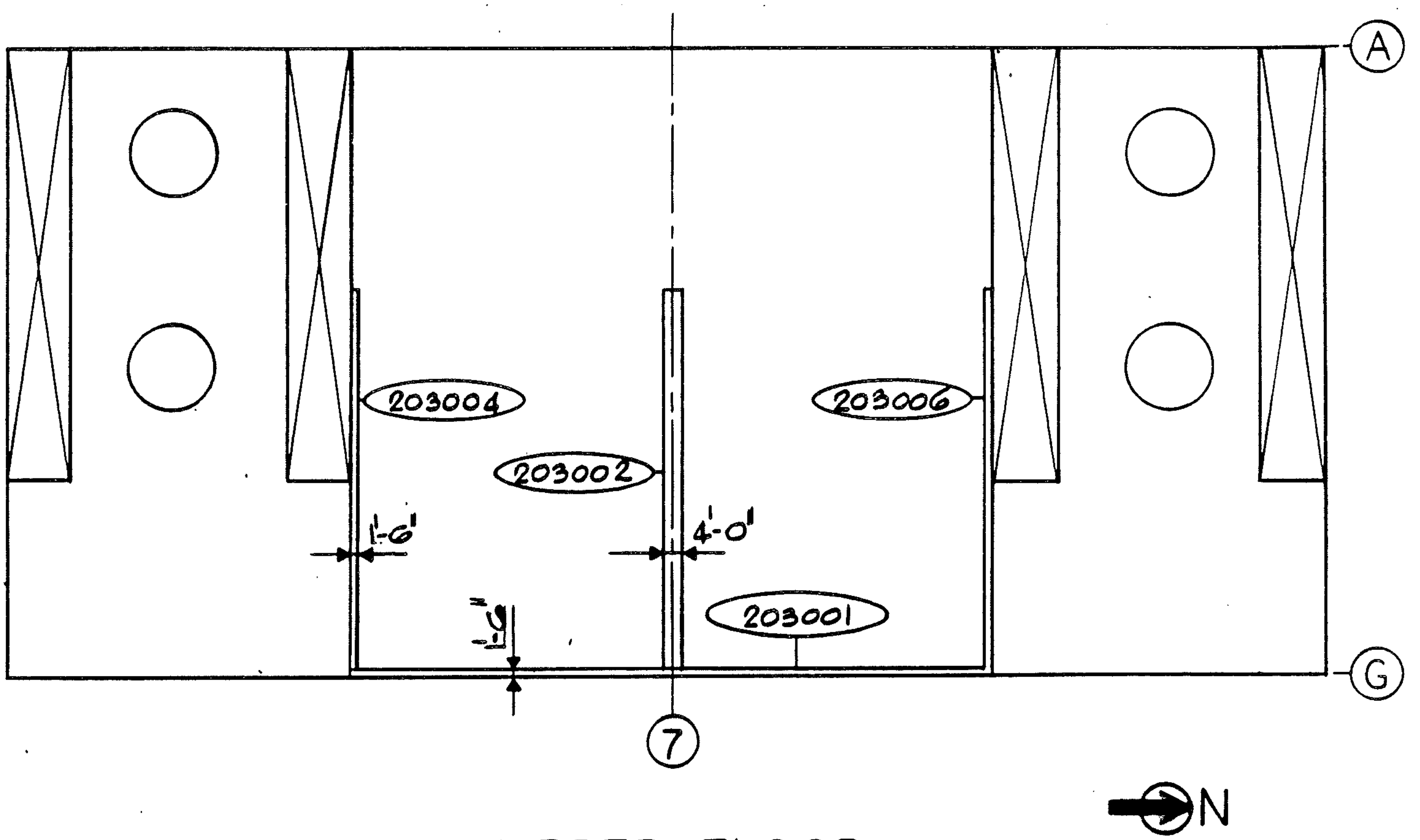
FIGURE 3.7-26

RESIDUAL HEAT REMOVAL COMPLEX GRADE FLOOR – SLAB 1 – ELEVATION 590.0 FT

SARGENT & LUNDY REPORT NO. SL-3147



UPPER FLOOR

SLAB 2 ELEV. 617'-0"

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FIGURE 3.7-27

RESIDUAL HEAT REMOVAL COMPLEX UPPER FLOOR – SLAB 2 – ELEVATION 617.0 FT

SARGENT & LUNDY REPORT NO. SL-3147

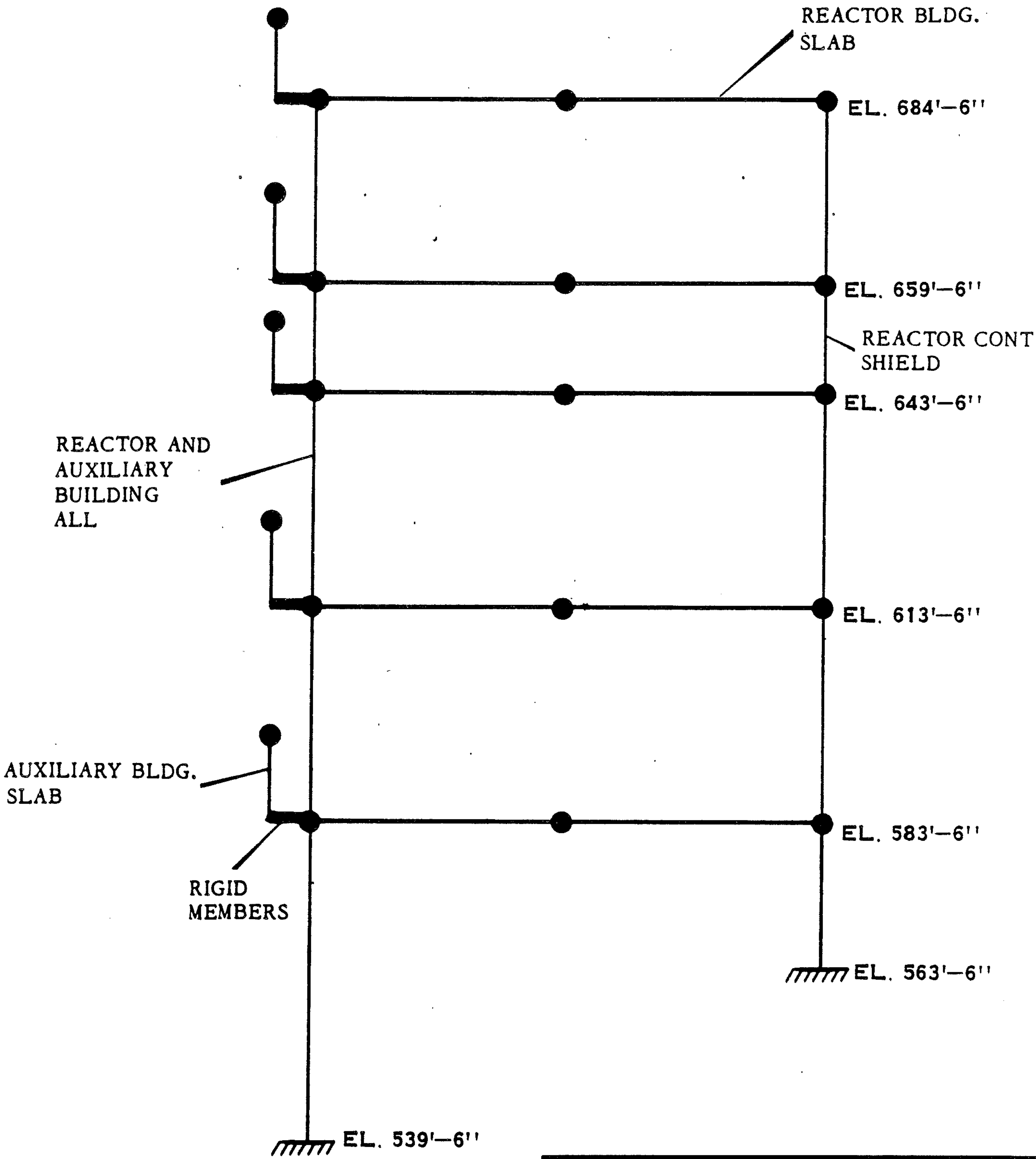

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FIGURE 3.7-28

REACTOR/AUXILIARY BUILDING VERTICAL MODEL GENERAL

SARGENT & LUNDY REPORT NO. SL-2682

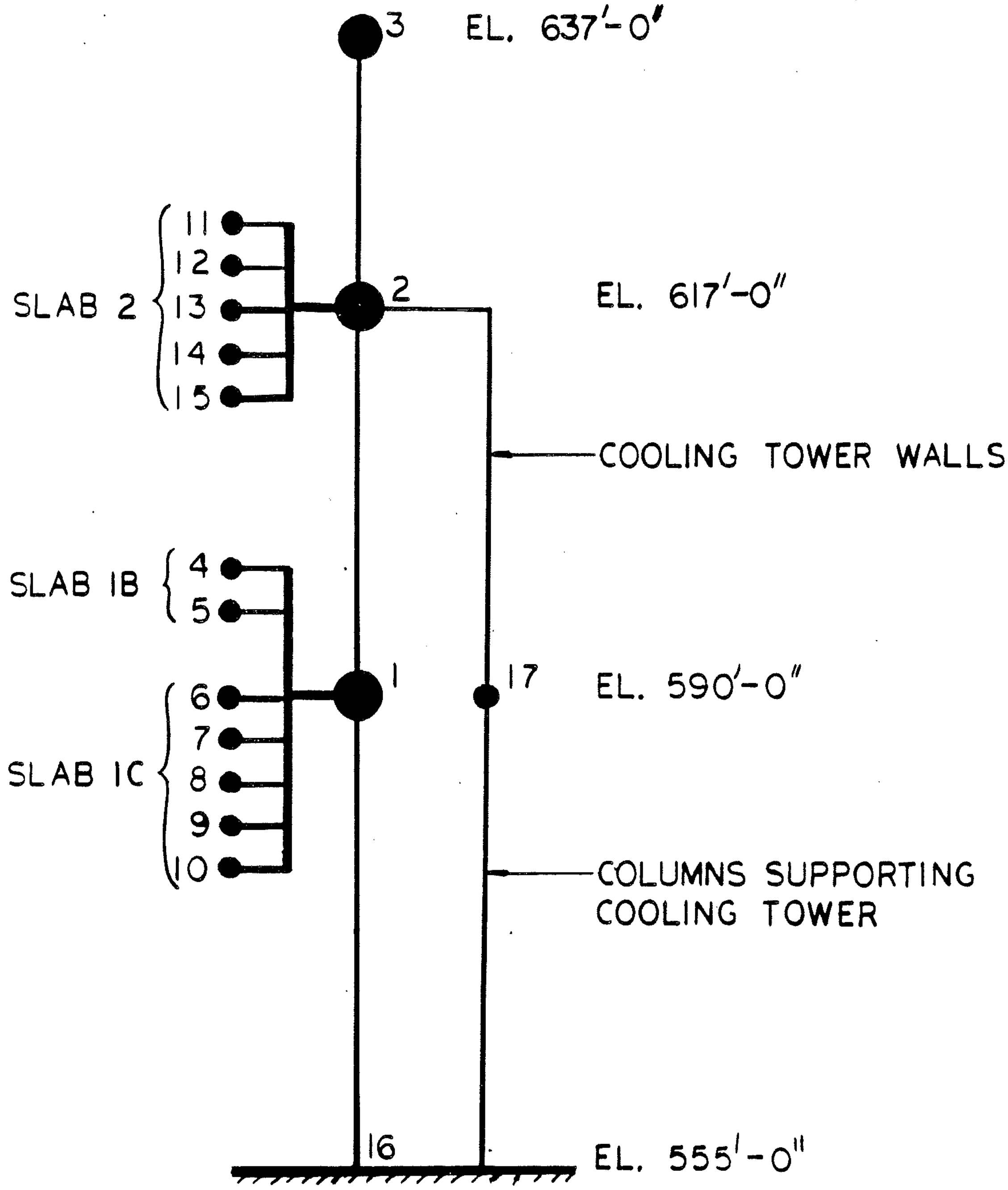

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FIGURE 3.7-29

RESIDUAL HEAT REMOVAL COMPLEX DYNAMIC MODEL FOR VERTICAL EXCITATION

SARGENT & LUNDY REPORT NO. SL-3147

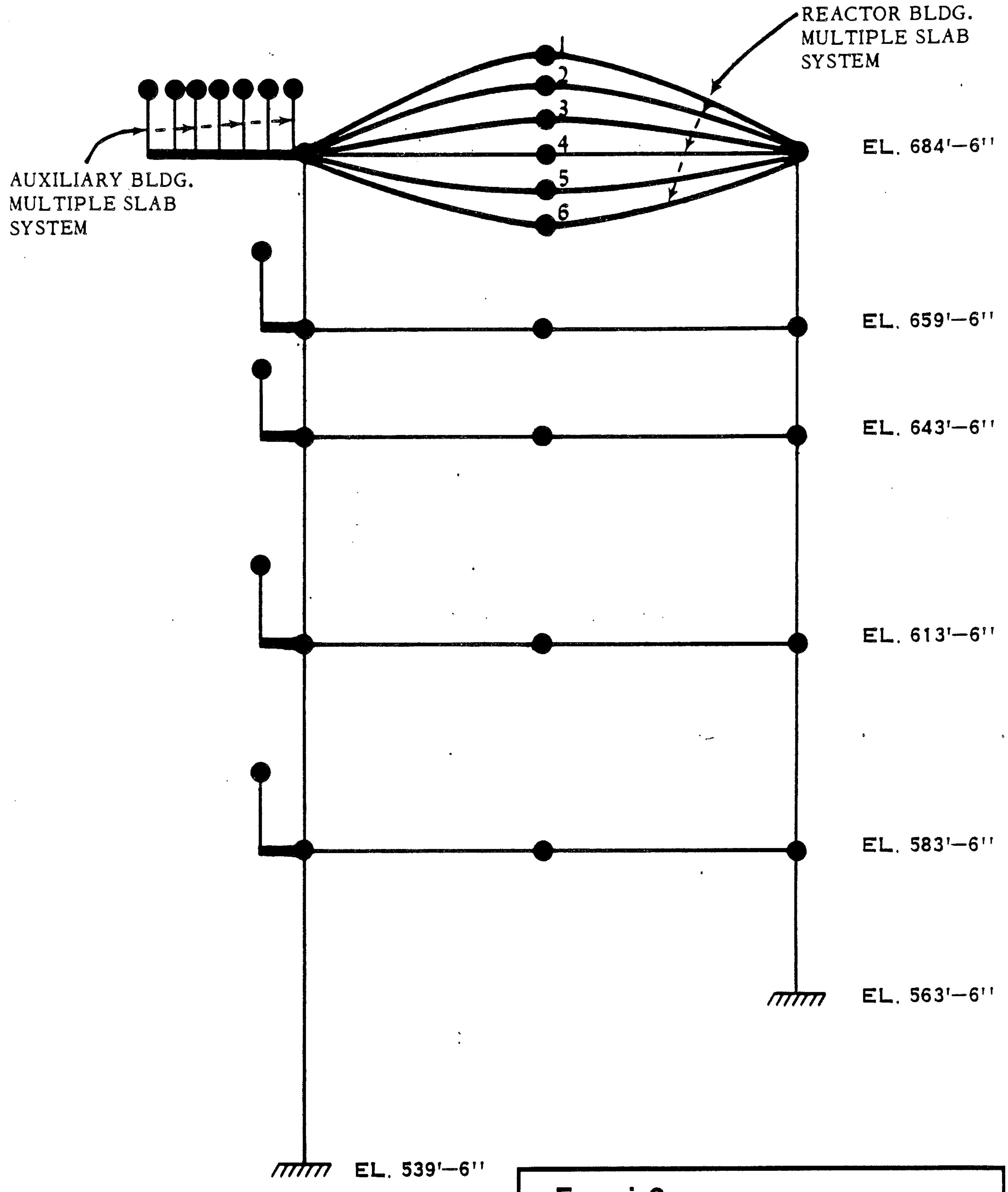

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FIGURE 3.7-30

REACTOR/AUXILIARY BUILDING VERTICAL MODEL FOR GENERATING SPECTRUM AT ELEVATION 684.5 FT

SARGENT & LUNDY REPORT NO. SL-2682

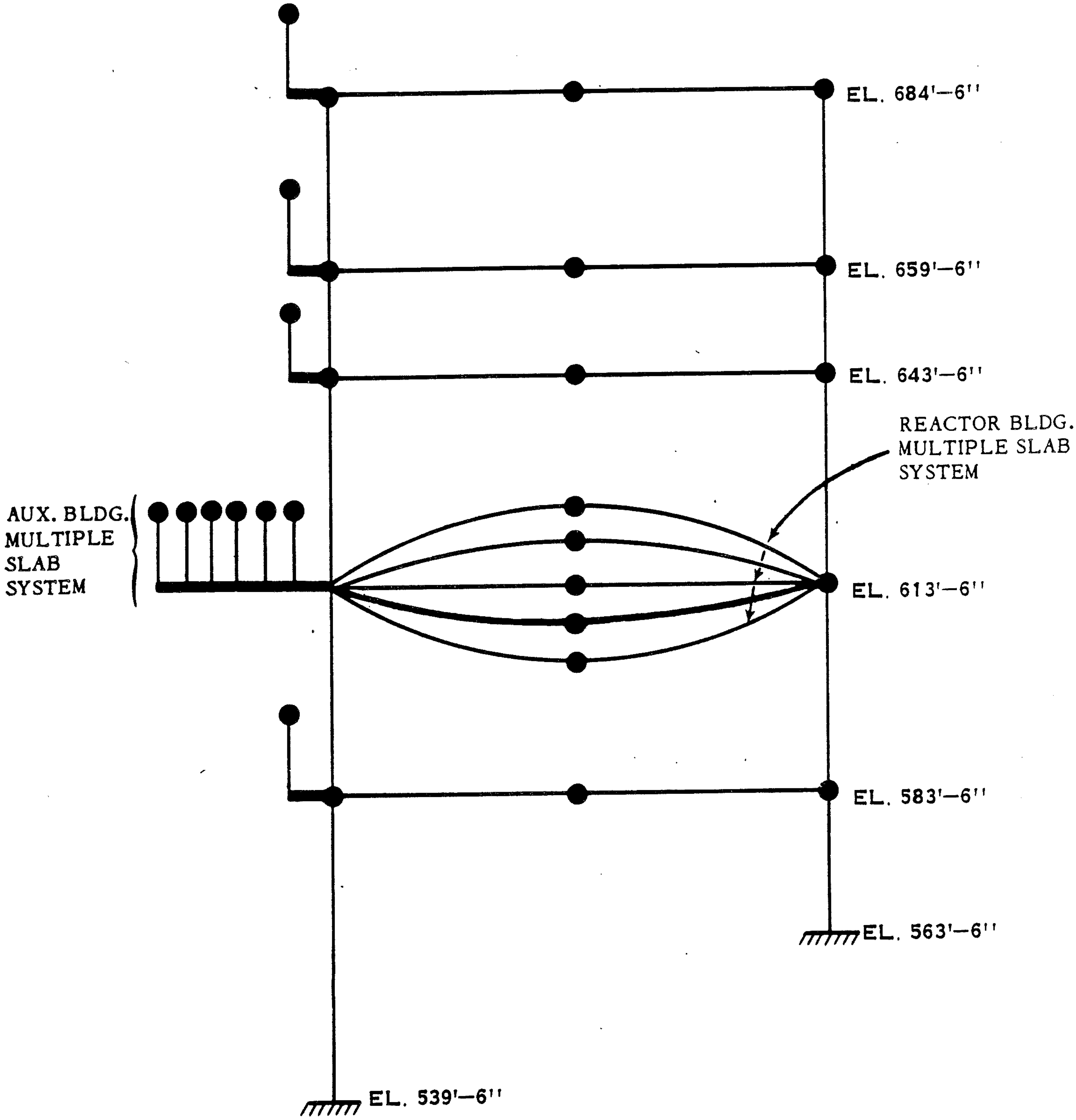

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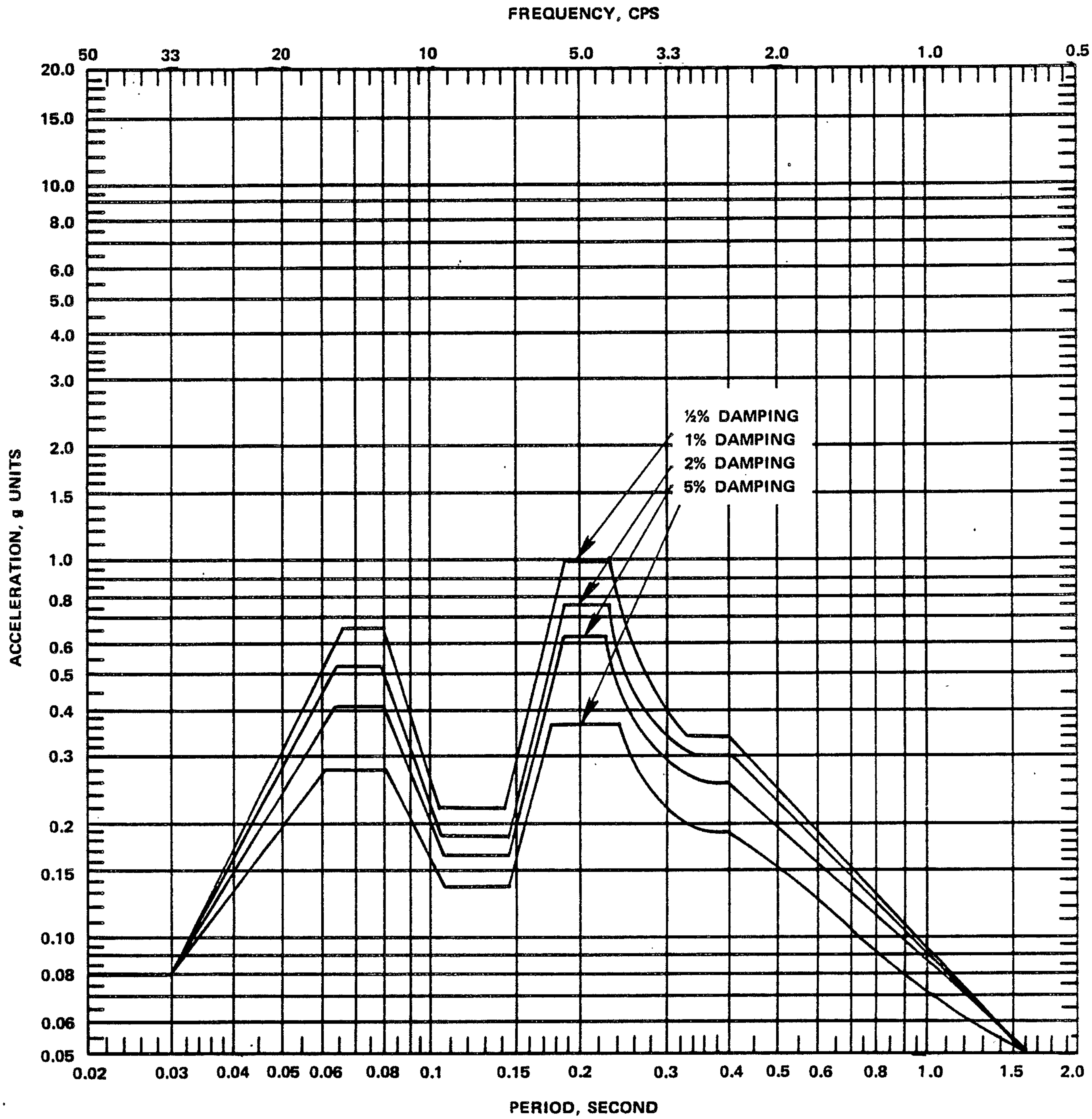
FIGURE 3.7-31

REACTOR/AUXILIARY BUILDING VERTICAL MODEL FOR GENERATING SPECTRUM AT ELEVATION 613.5 FT

SARGENT & LUNDY REPORT NO. SL-2682



SARGENT & LUNDY REPORT NO. SL-2682

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FIGURE 3.7-32

HORIZONTAL FLOOR RESPONSE SPECTRA
OPERATING-BASIS EARTHQUAKE
ELEVATION 583.5 FT – SLAB 1
REACTOR/AUXILIARY BUILDING NORTH-SOUTH COMPONENT

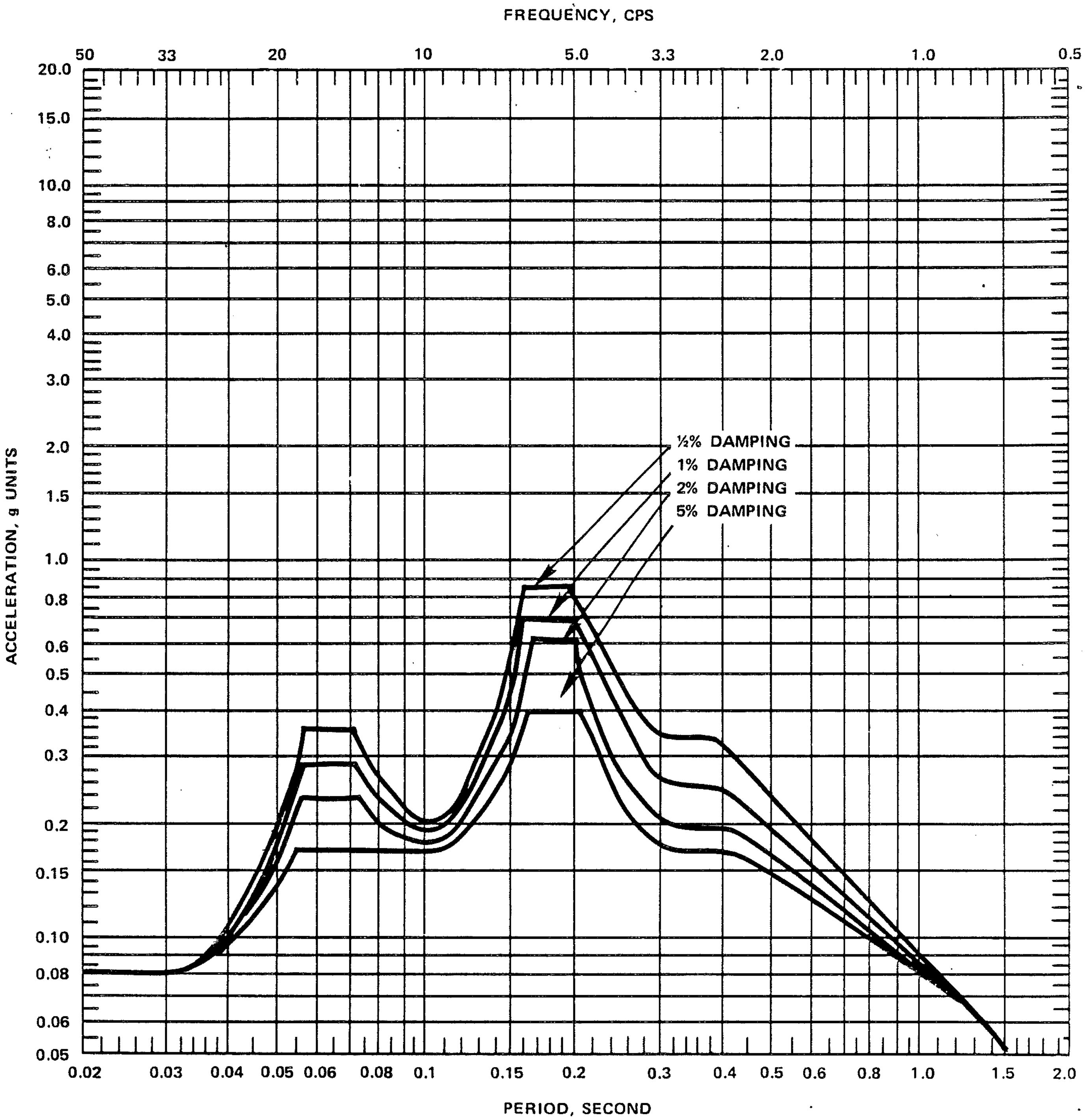

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FIGURE 3.7-33 HORIZONTAL FLOOR RESPONSE SPECTRA OPERATING-BASIS EARTHQUAKE ELEVATION 583.5 FT – SLAB 1 REACTOR/AUXILIARY BUILDING EAST-WEST COMPONENT

SARGENT & LUNDY REPORT NO. SL-2682

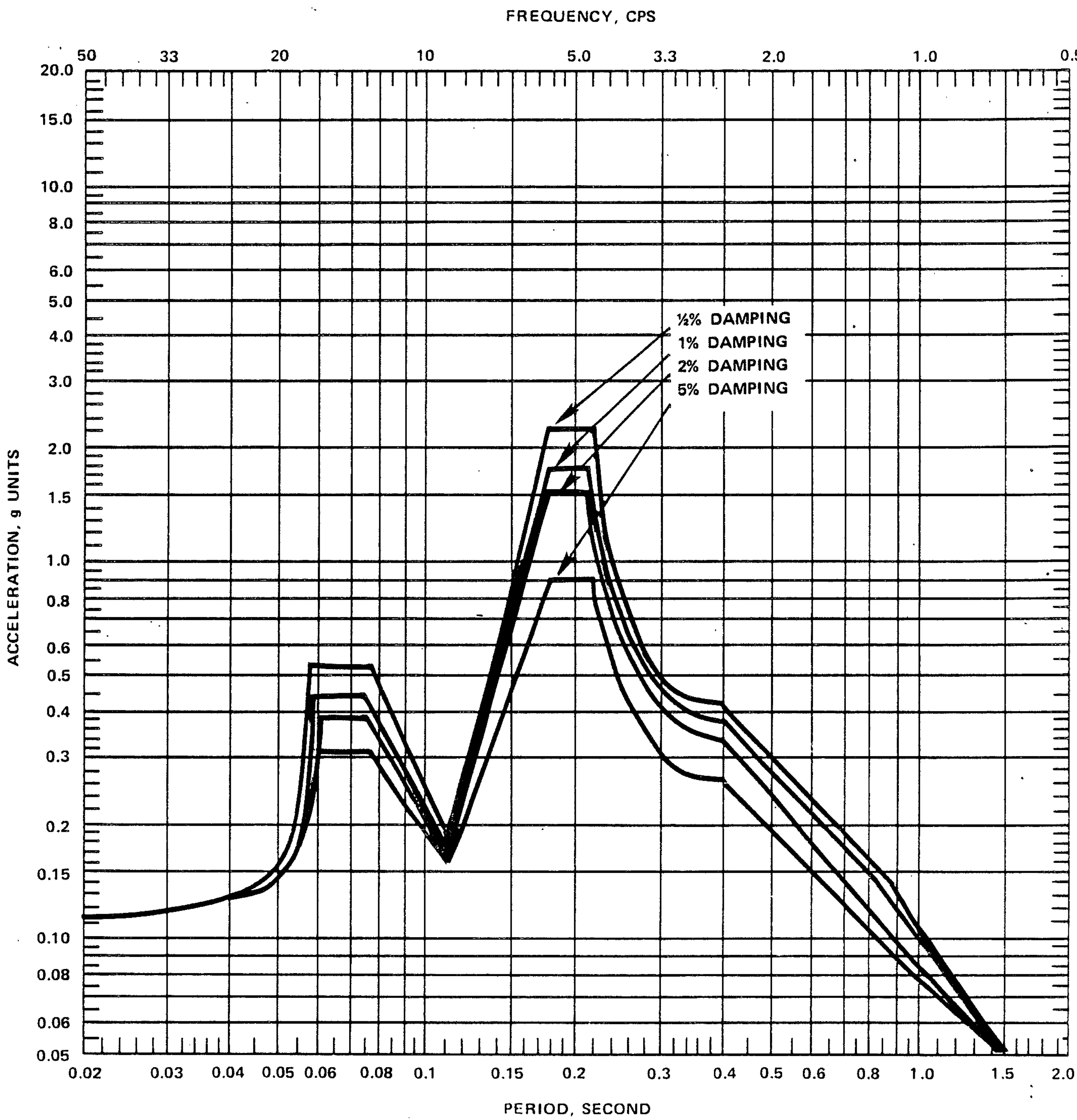

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FIGURE 3.7-34

HORIZONTAL FLOOR RESPONSE SPECTRA
OPERATING-BASIS EARTHQUAKE
ELEVATION 613.5 FT – SLAB 2
REACTOR/AUXILIARY BUILDING NORTH-SOUTH COMPONENT

SARGENT & LUNDY REPORT NO. SL-2682

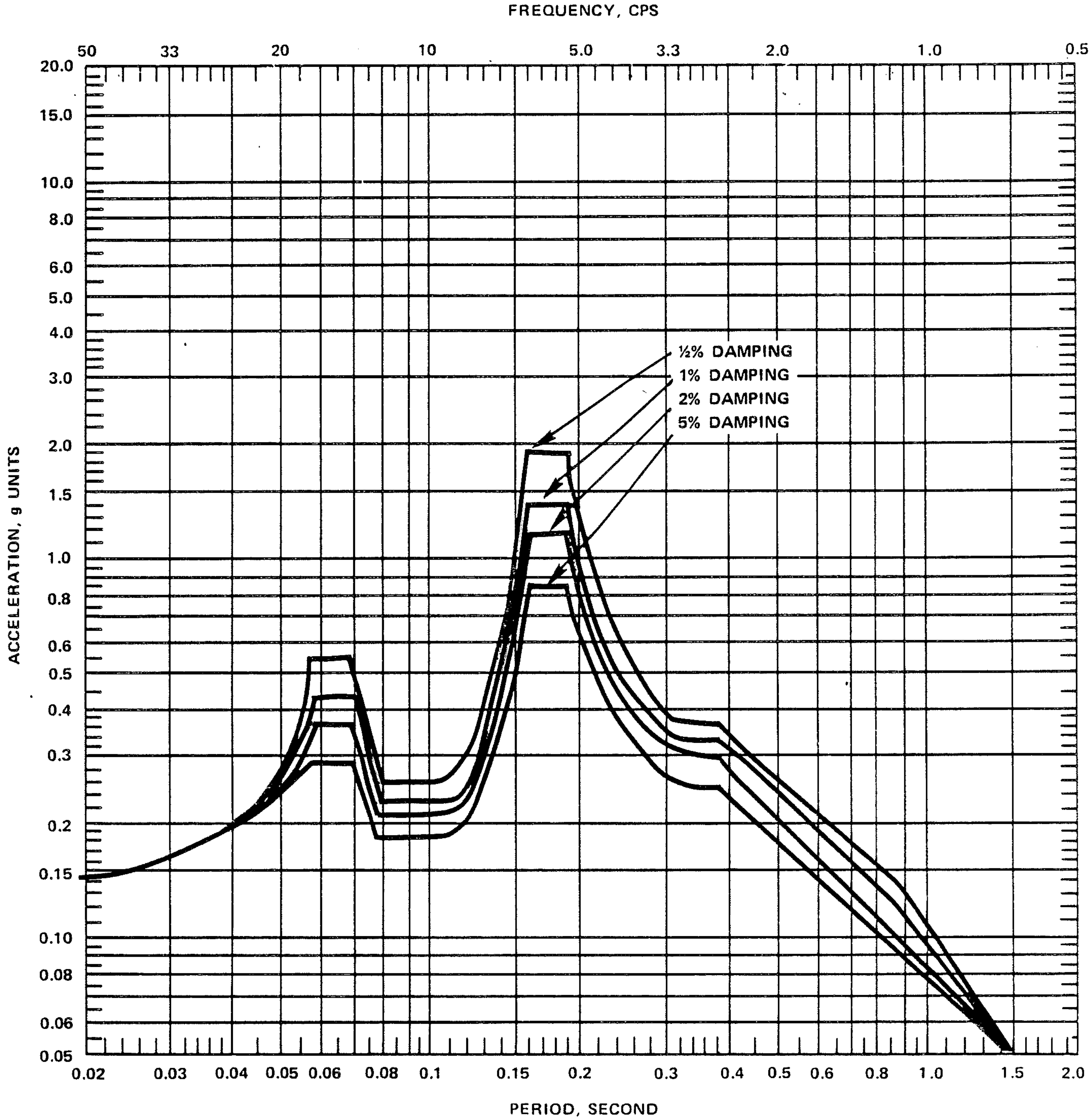

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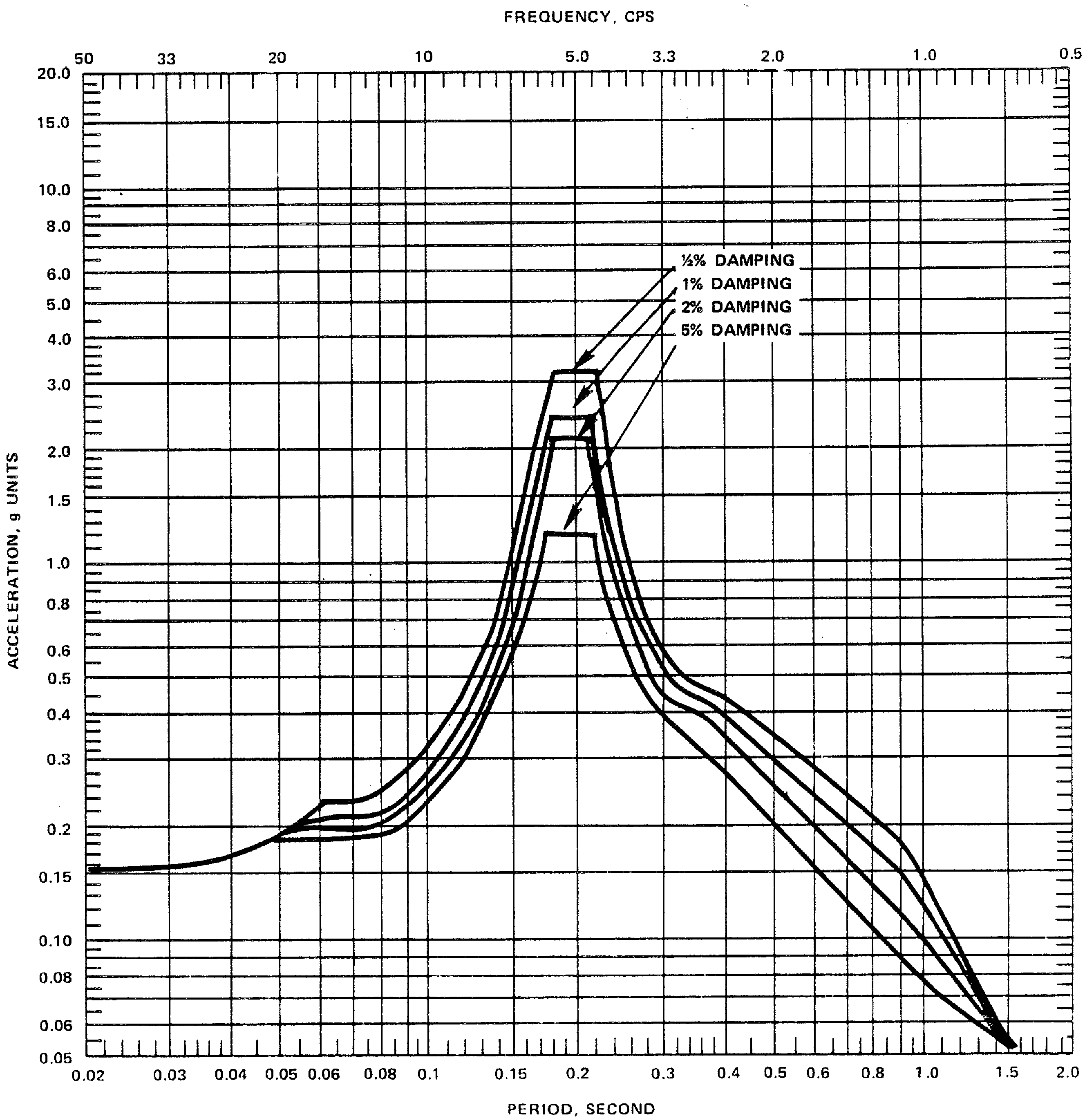
FIGURE 3.7-35

HORIZONTAL FLOOR RESPONSE SPECTRA
OPERATING-BASIS EARTHQUAKE
ELEVATION 613.5 FT – SLAB 2
REACTOR/AUXILIARY BUILDING EAST-WEST
COMPONENT

SARGENT & LUNDY REPORT NO. SL-2682



SARGENT & LUNDY REPORT NO. SL-2682

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FIGURE 3.7-36

HORIZONTAL FLOOR RESPONSE SPECTRA
OPERATING-BASIS EARTHQUAKE
ELEVATION 641.5 FT – SLAB 3
REACTOR/AUXILIARY BUILDING NORTH-SOUTH COMPONENT

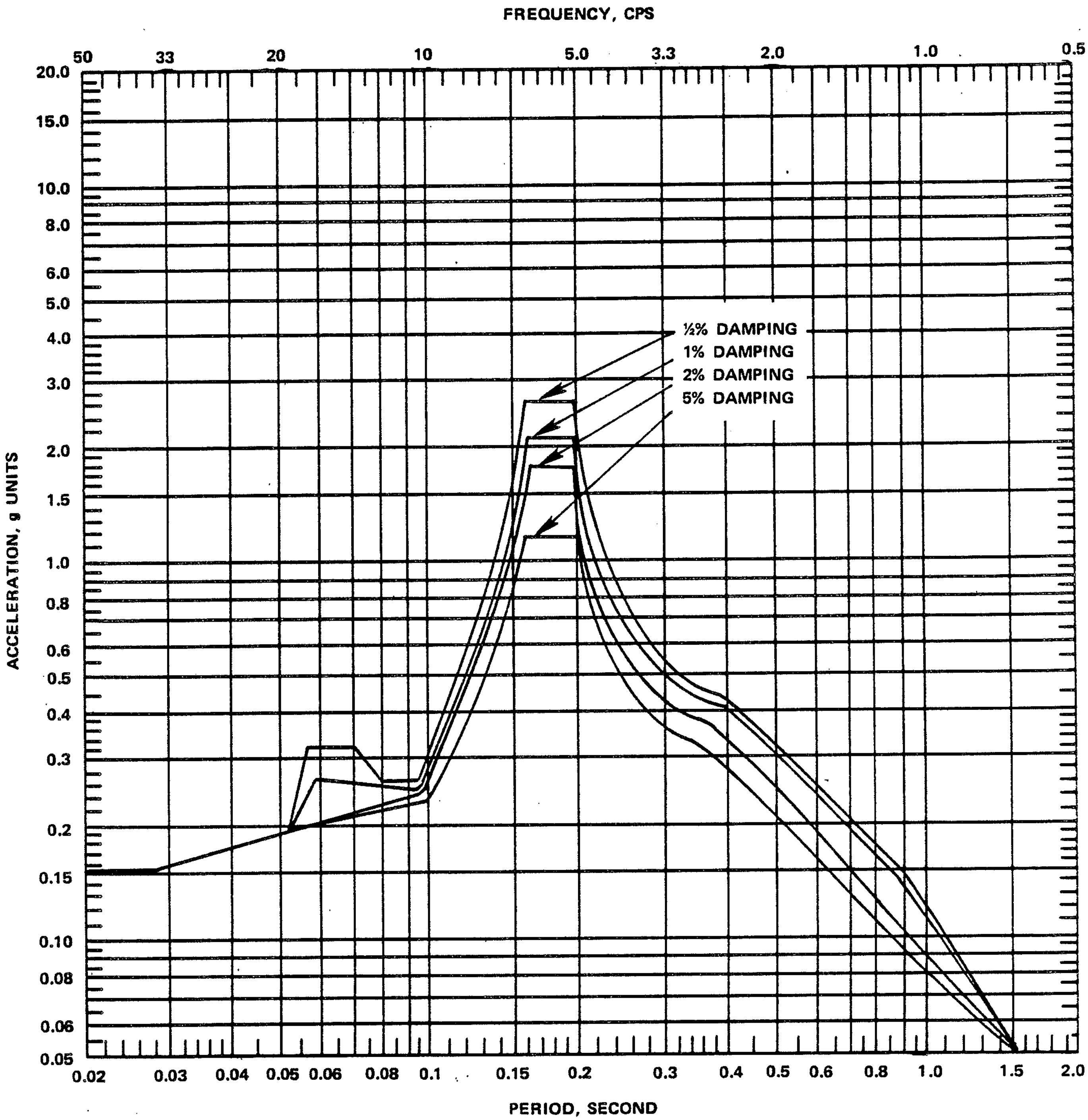

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FIGURE 3.7-37

HORIZONTAL FLOOR RESPONSE SPECTRA
OPERATING-BASIS EARTHQUAKE
ELEVATION 641.5 FT – SLAB 3
REACTOR/AUXILIARY BUILDING EAST-WEST
COMPONENT

SARGENT & LUNDY REPORT NO. SL-2682

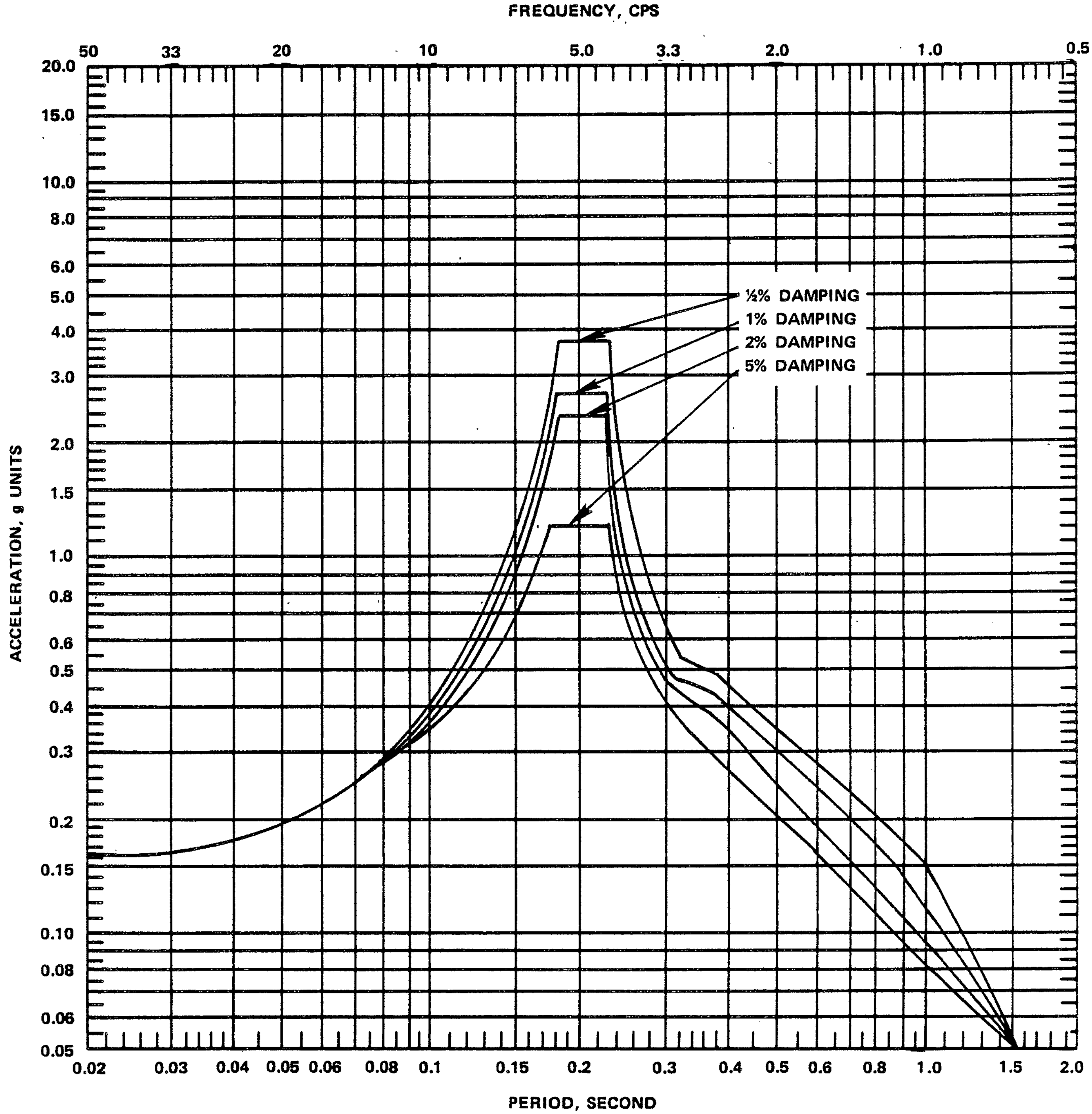

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FIGURE 3.7-38

HORIZONTAL FLOOR RESPONSE SPECTRA
OPERATING-BASIS EARTHQUAKE
ELEVATION 659.0 FT – SLAB 4
REACTOR/AUXILIARY BUILDING NORTH-SOUTH
COMPONENT

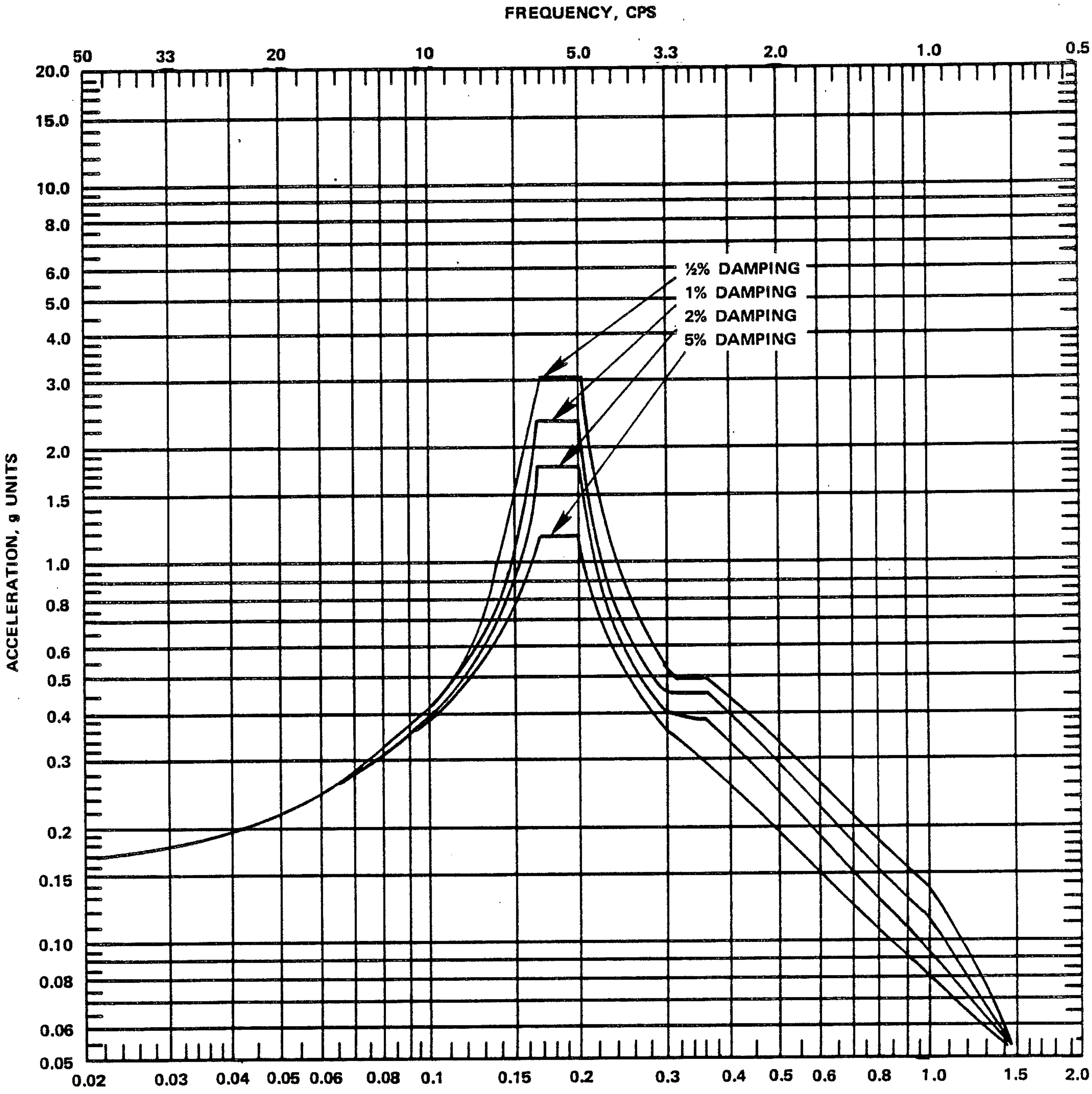

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FIGURE 3.7-39

HORIZONTAL FLOOR RESPONSE SPECTRA
OPERATING-BASIS EARTHQUAKE
ELEVATION 659.0 FT – SLAB 4
REACTOR/AUXILIARY BUILDING EAST-WEST
COMPONENT

SARGENT & LUNDY REPORT NO. SL-2682

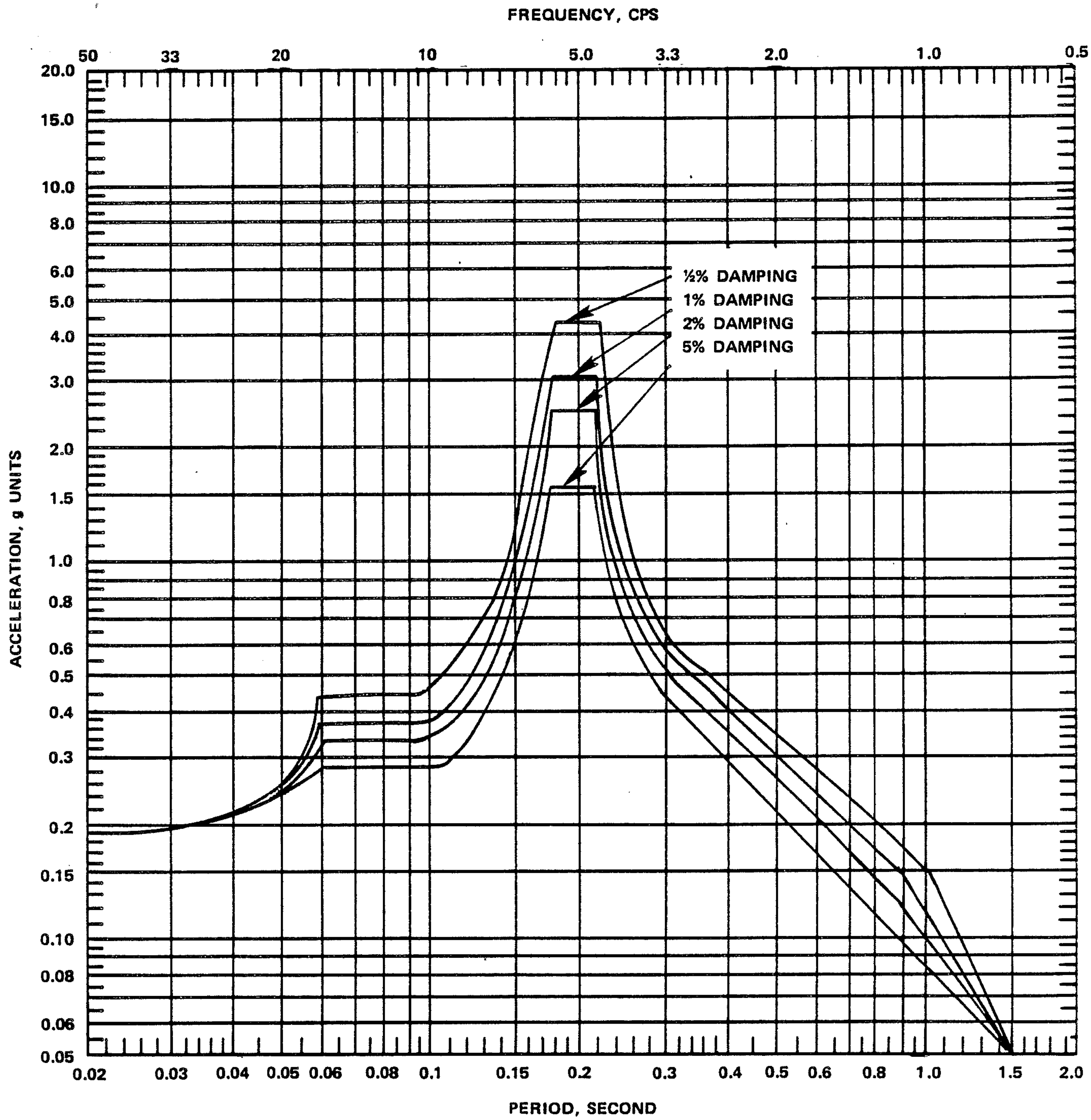

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FIGURE 3.7-40

HORIZONTAL FLOOR RESPONSE SPECTRA
OPERATING-BASIS EARTHQUAKE
ELEVATION 684.5 FT – SLAB 5
REACTOR/AUXILIARY BUILDING NORTH-SOUTH
COMPONENT

SARGENT & LUNDY REPORT NO. SL-2682

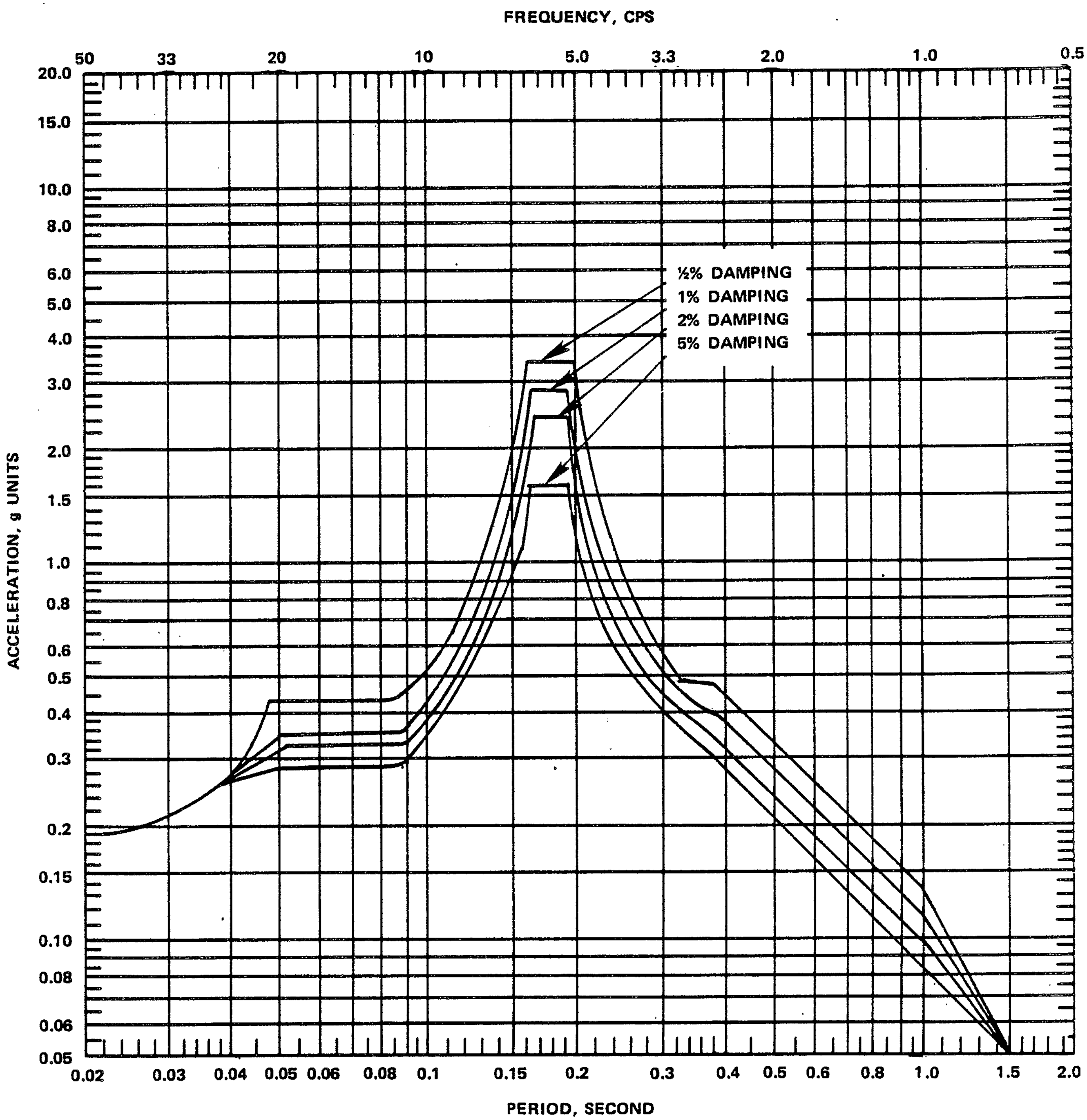

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FIGURE 3.7–41

HORIZONTAL FLOOR RESPONSE SPECTRA
OPERATING-BASIS EARTHQUAKE
ELEVATION 684.5 FT – SLAB 5
REACTOR/AUXILIARY BUILDING EAST-WEST
COMPONENT

SARGENT & LUNDY REPORT NO. SL-2682

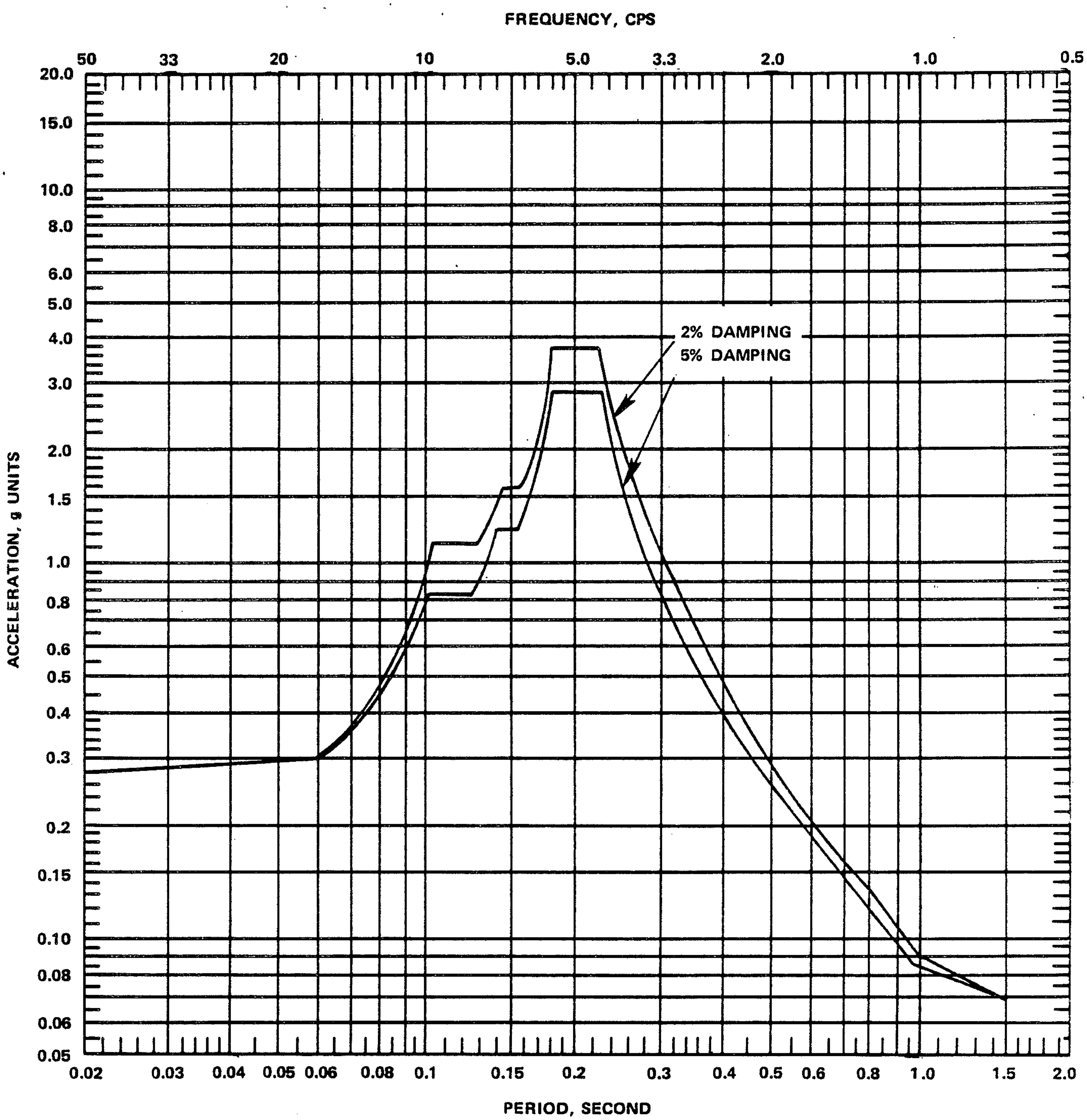

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FIGURE 3.7-42

REACTOR/AUXILIARY BUILDING HORIZONTAL RESPONSE SPECTRA – OPERATING-BASIS EARTHQUAKE AT CRANE RAIL – CRANE ADJACENT TO COLUMN ROW 17 – NORTH-SOUTH COMPONENT

SARGENT & LUNDY REPORT NO. SL-2682

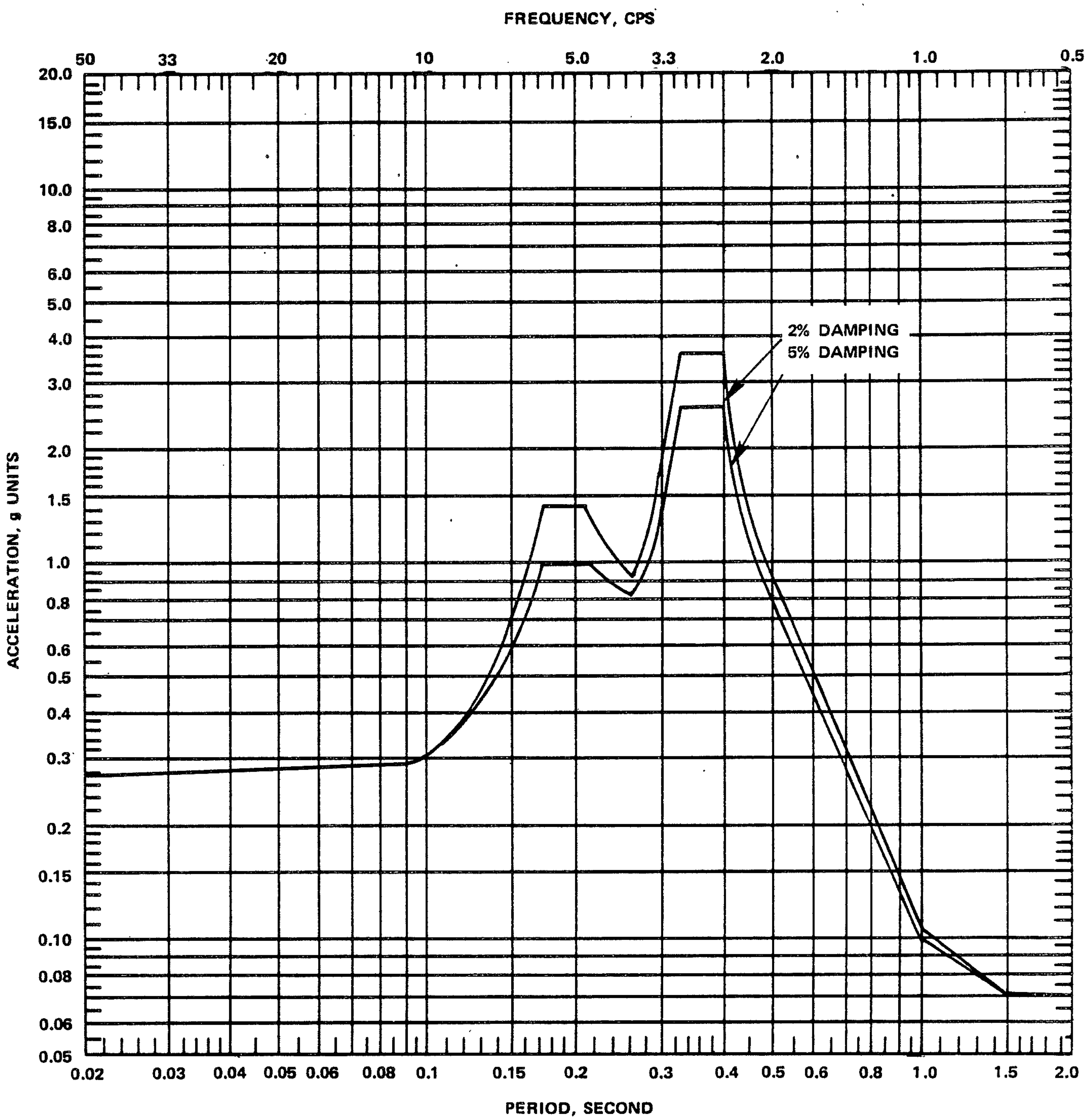

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FIGURE 3.7-43

REACTOR/AUXILIARY BUILDING HORIZONTAL RESPONSE SPECTRA – OPERATING-BASIS EARTHQUAKE AT CRANE RAIL – CRANE ADJACENT TO COLUMN ROW 17 – EAST-WEST COMPONENT

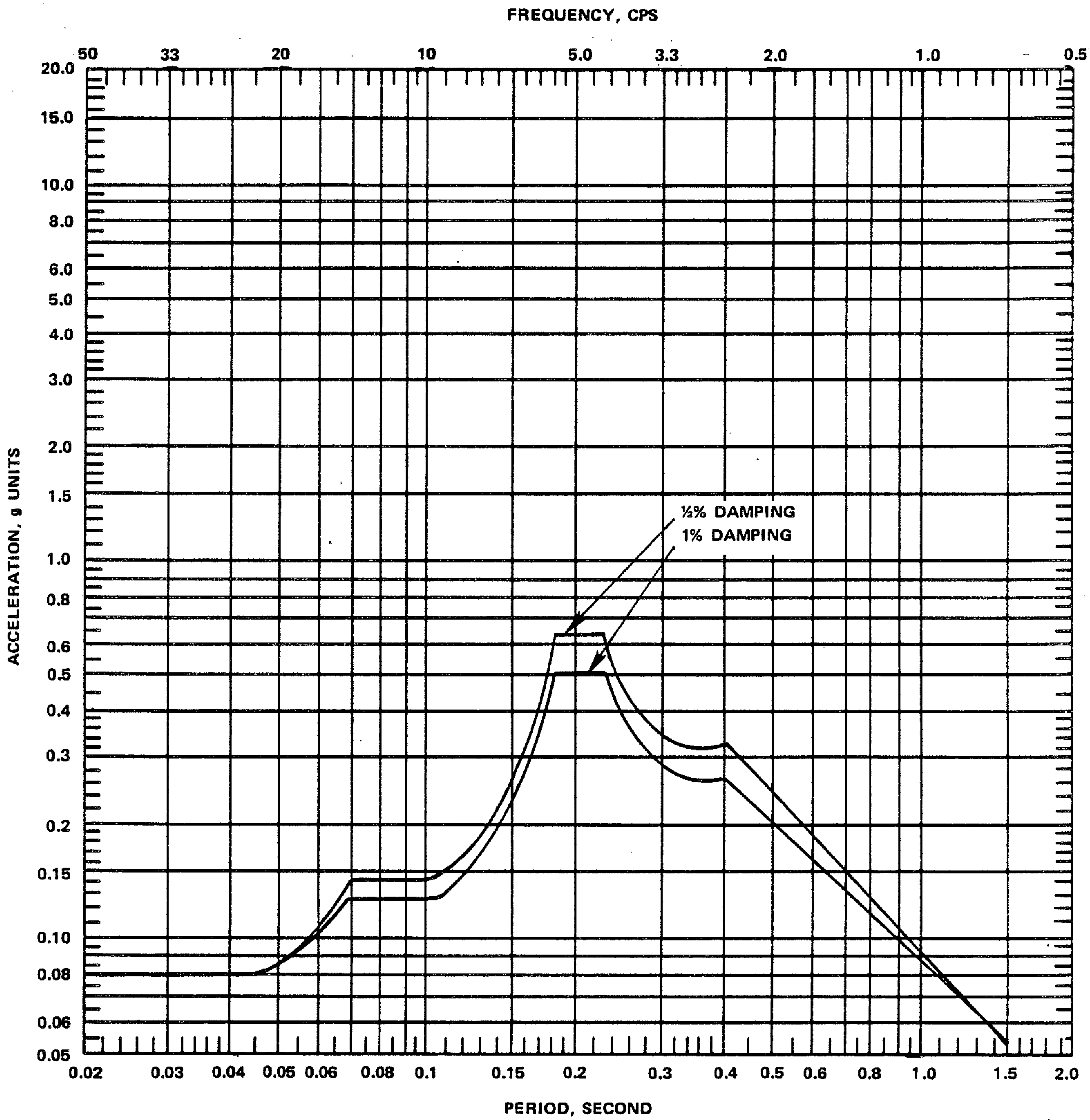

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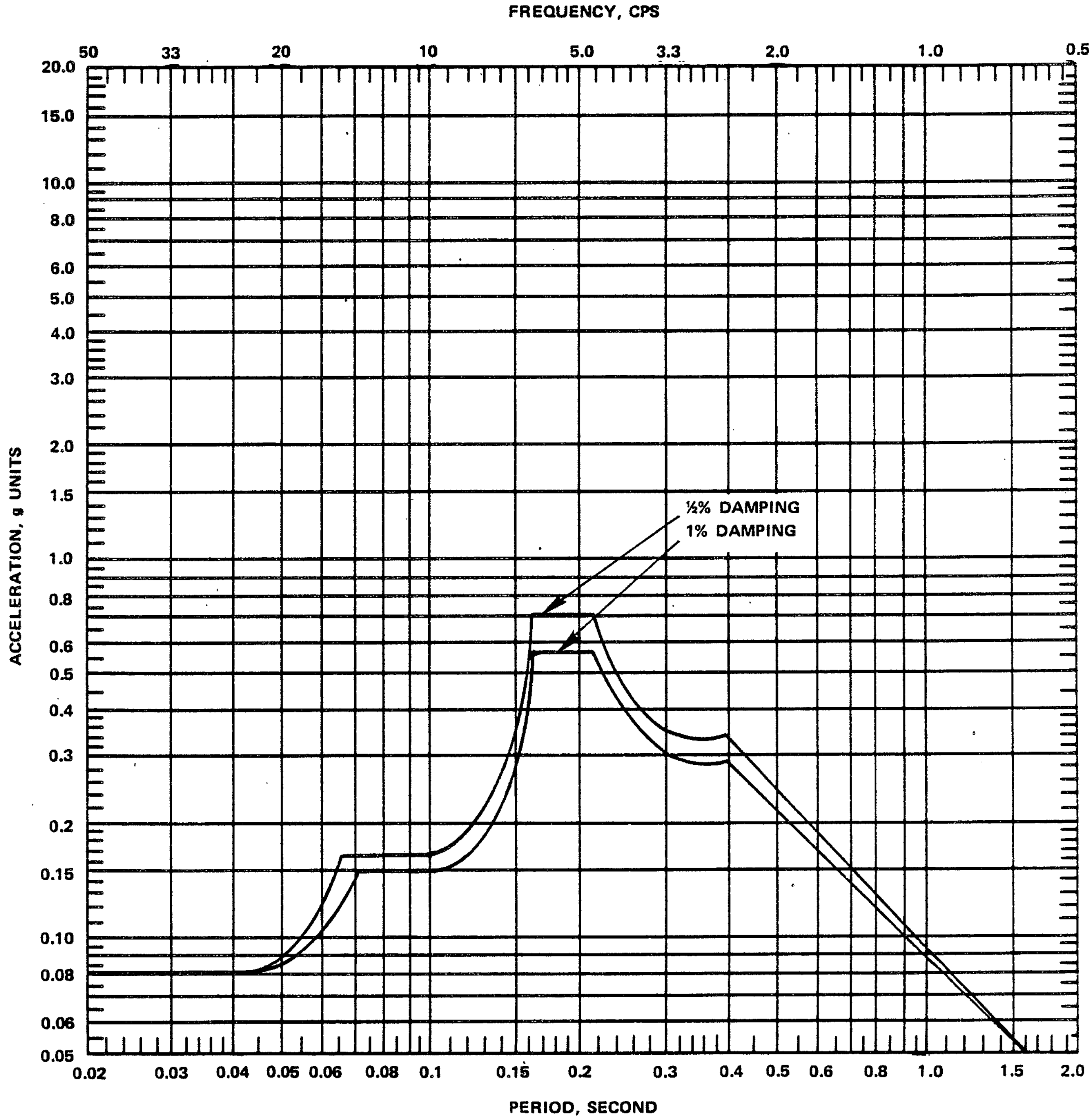
FIGURE 3.7-44

HORIZONTAL RESPONSE SPECTRA – OPERATING-BASIS EARTHQUAKE – DRYWELL CONTAINMENT 18.0 FT BELOW REACTOR PRESSURE VESSEL INVERT NORTH-SOUTH COMPONENT

SARGENT & LUNDY REPORT NO. SL-2682



Fermi 2

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FIGURE 3.7-45

HORIZONTAL RESPONSE SPECTRA – OPERATING-BASIS EARTHQUAKE – DRYWELL CONTAINMENT 18.0 FT BELOW REACTOR PRESSURE VESSEL INVERT EAST-WEST COMPONENT

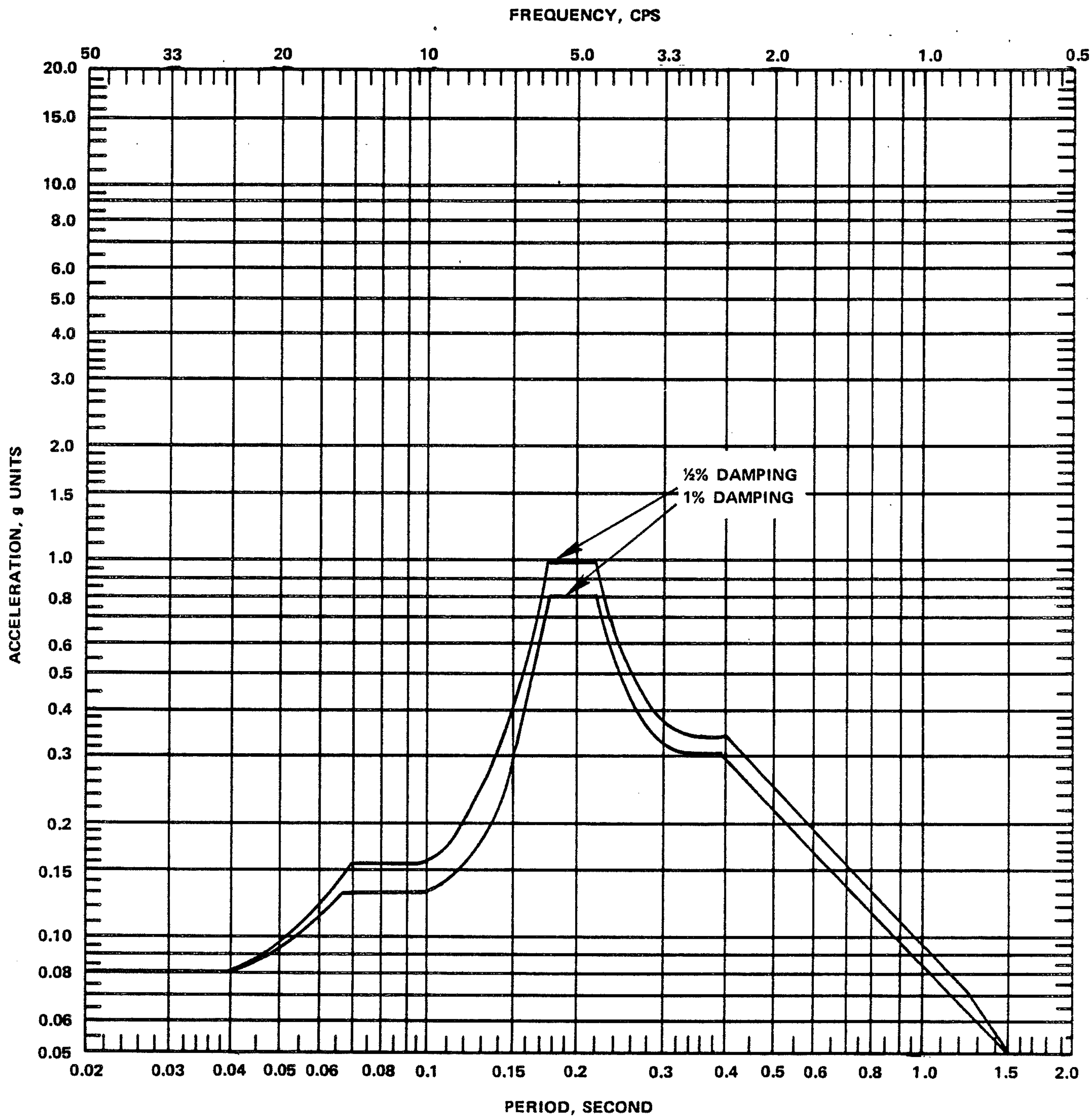

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FIGURE 3.7-46

HORIZONTAL RESPONSE SPECTRA – OPERATING-BASIS EARTHQUAKE – DRYWELL CONTAINMENT 6.0 FT BELOW REACTOR PRESSURE VESSEL INVERT NORTH-SOUTH COMPONENT

SARGENT & LUNDY REPORT NO. SL-2682

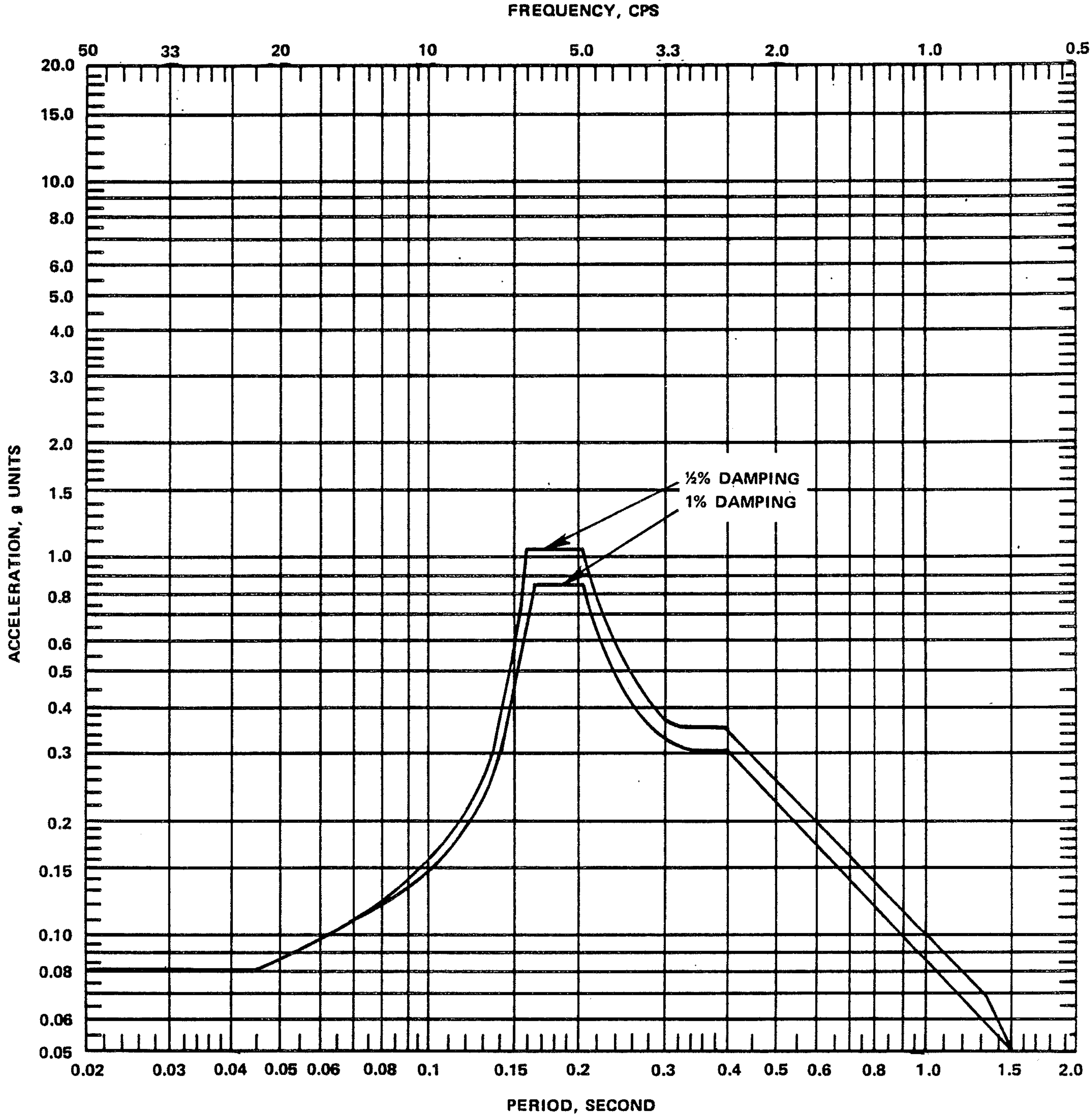

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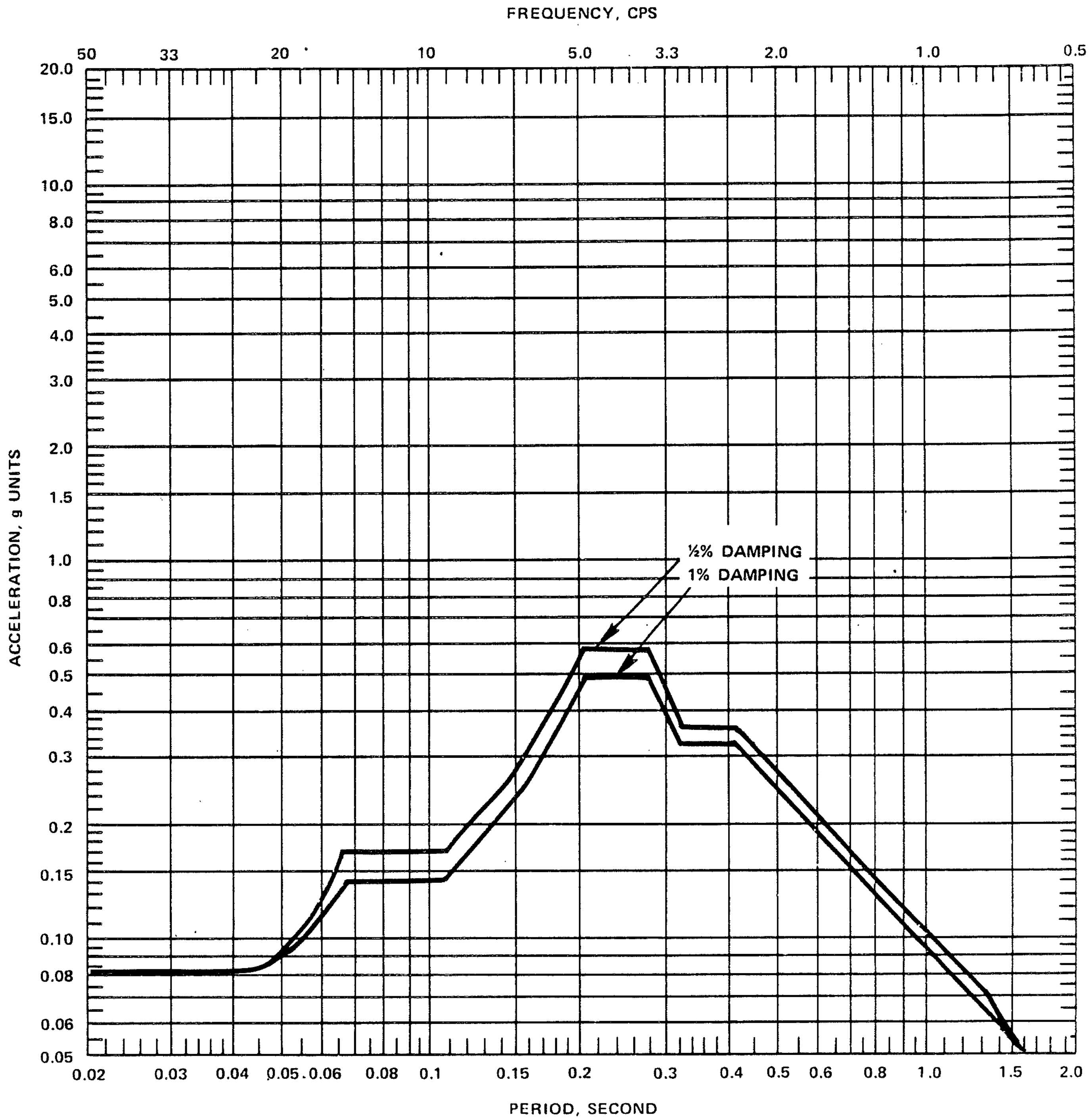
FIGURE 3.7-47

HORIZONTAL RESPONSE SPECTRA – OPERATING-BASIS EARTHQUAKE – DRYWELL CONTAINMENT 6.0 FT BELOW REACTOR PRESSURE VESSEL INVERT EAST-WEST COMPONENT

SARGENT & LUNDY REPORT NO. SL-2682



SARGENT & LUNDY REPORT NO. SL-2682

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FIGURE 3.7-48

HORIZONTAL RESPONSE SPECTRA – OPERATING-BASIS EARTHQUAKE – REACTOR PEDESTAL 18.0 FT BELOW REACTOR PRESSURE VESSEL INVERT NORTH-SOUTH COMPONENT

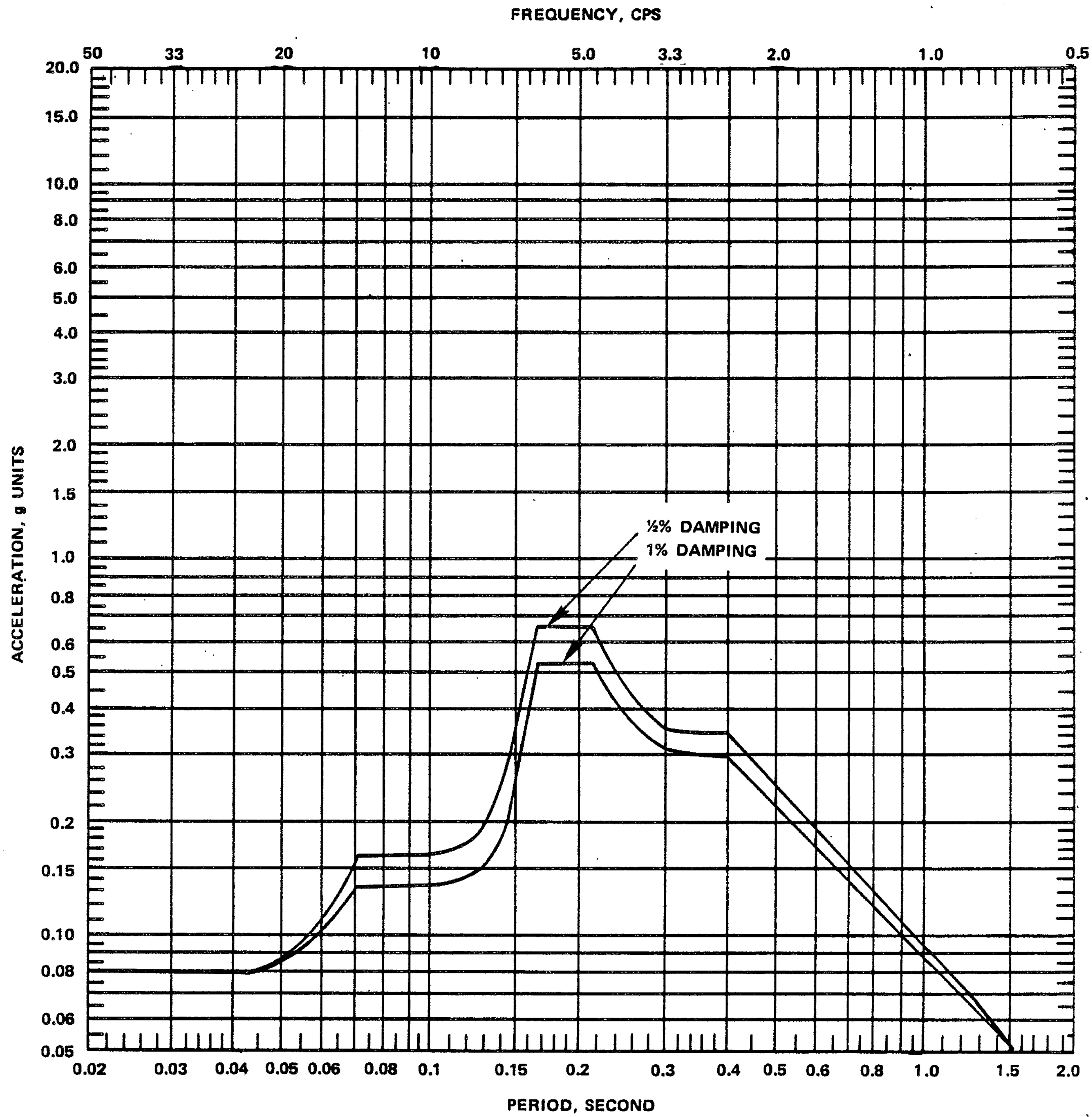

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FIGURE 3.7-49

HORIZONTAL RESPONSE SPECTRA – OPERATING-BASIS EARTHQUAKE – REACTOR PEDESTAL 18.0 FT BELOW REACTOR PRESSURE VESSEL INVERT EAST-WEST COMPONENT

SARGENT & LUNDY REPORT NO. SL-2682

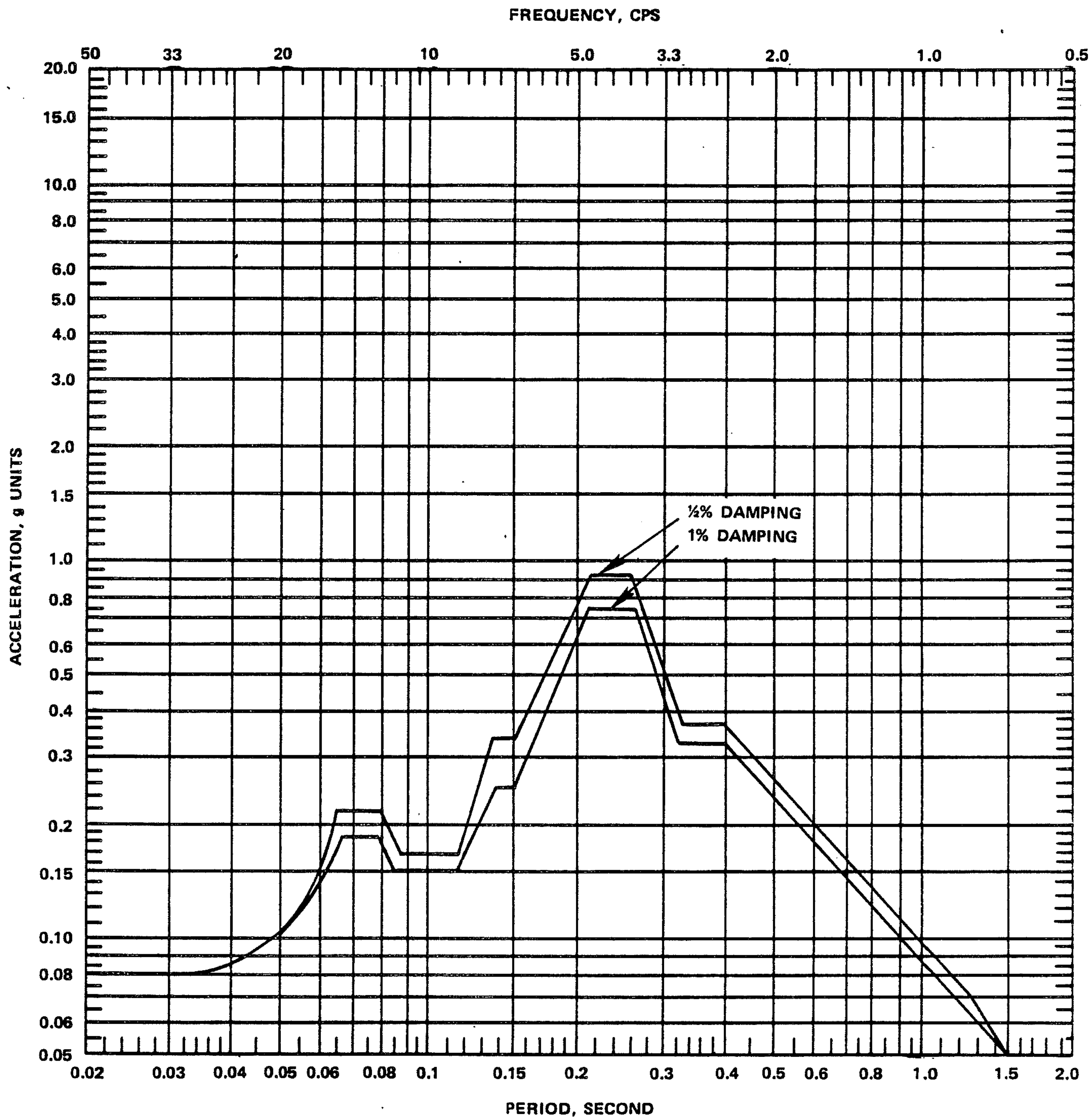

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FIGURE 3.7-50

HORIZONTAL RESPONSE SPECTRA
OPERATING-BASIS EARTHQUAKE – TOP OF
REACTOR PEDESTAL – NORTH-SOUTH COMPONENT

SARGENT & LUNDY REPORT NO. SL-2682

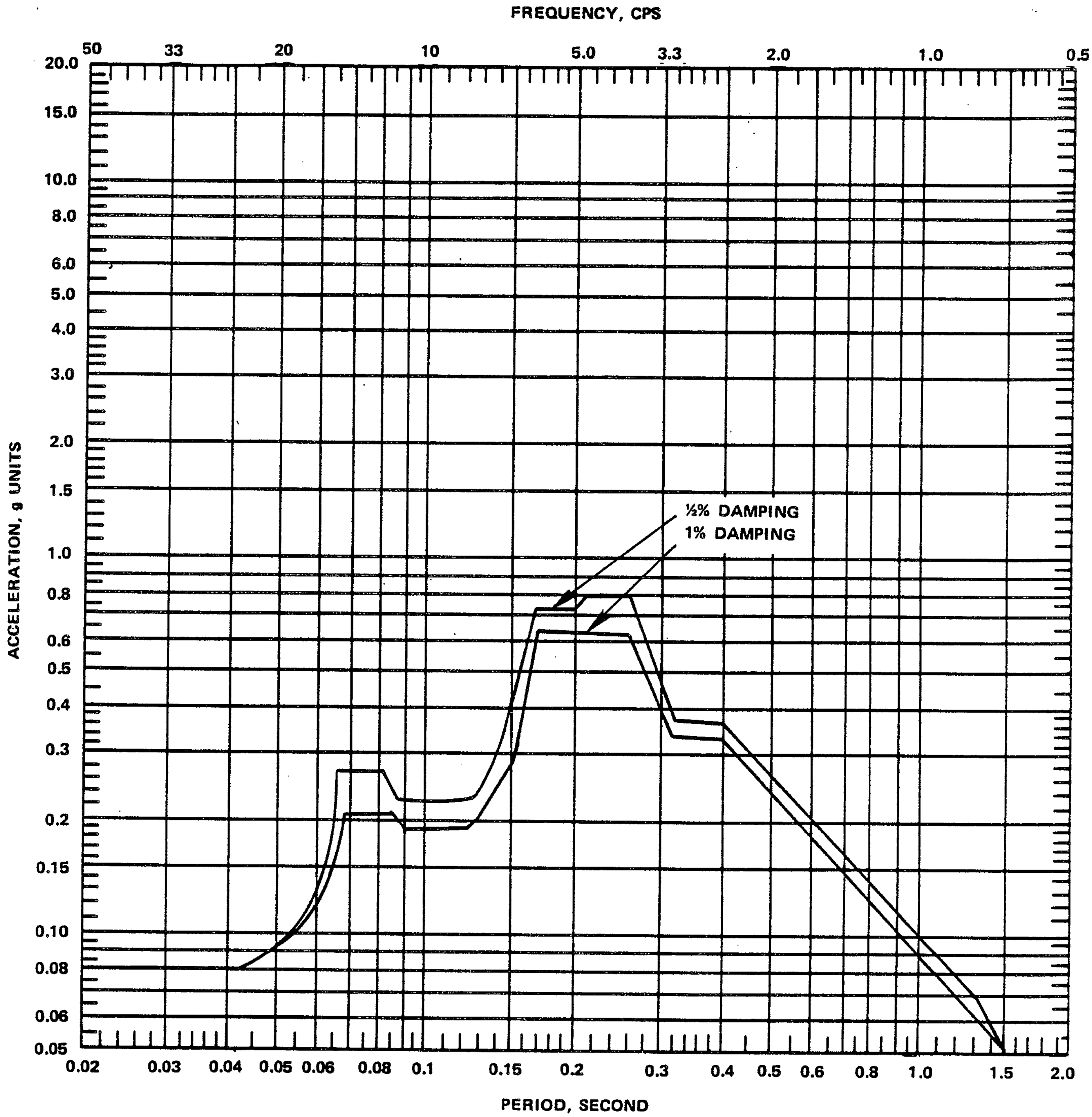

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FIGURE 3.7-51

HORIZONTAL RESPONSE SPECTRA
OPERATING-BASIS EARTHQUAKE – TOP OF
REACTOR PEDESTAL – EAST-WEST COMPONENT

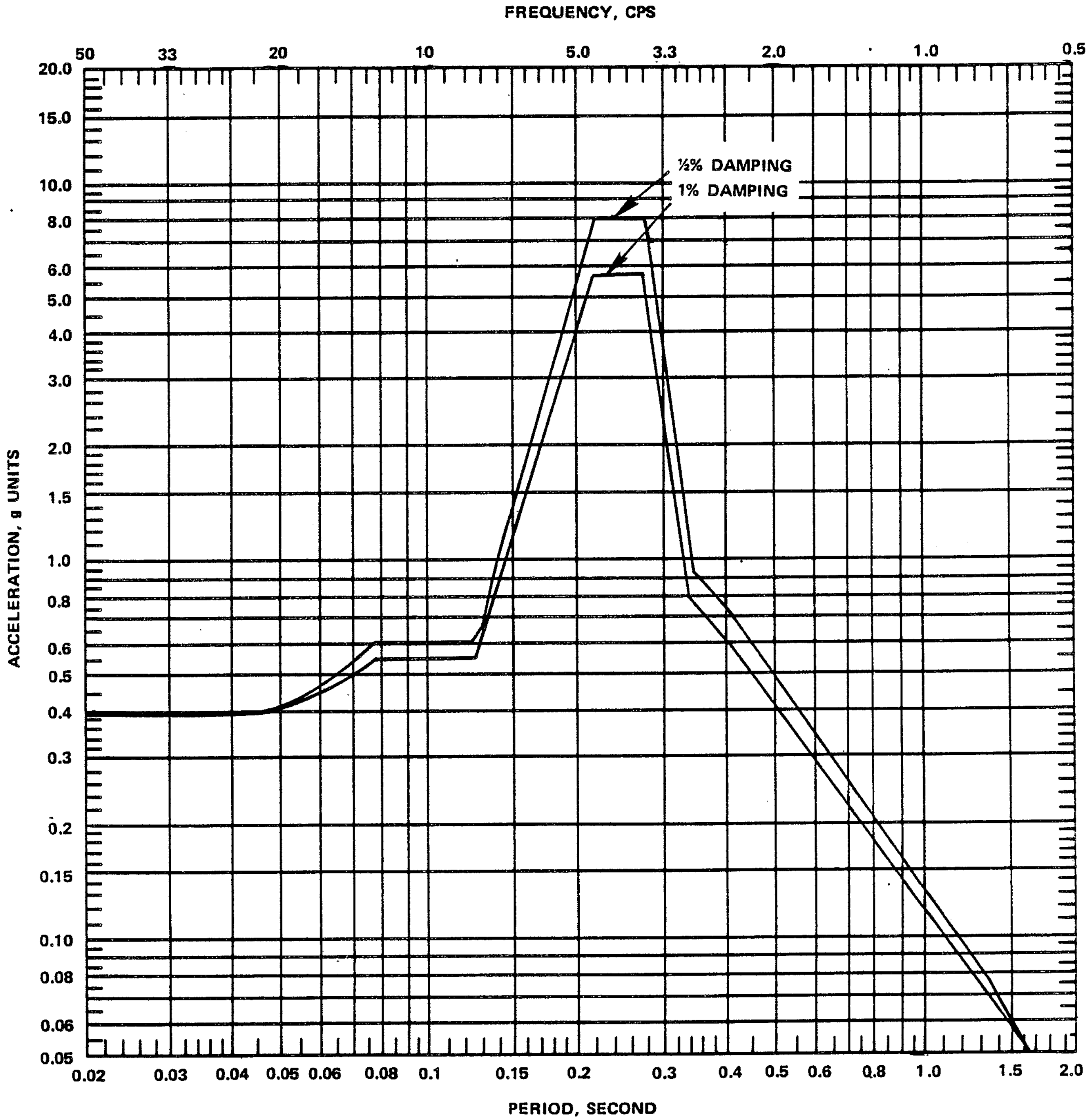

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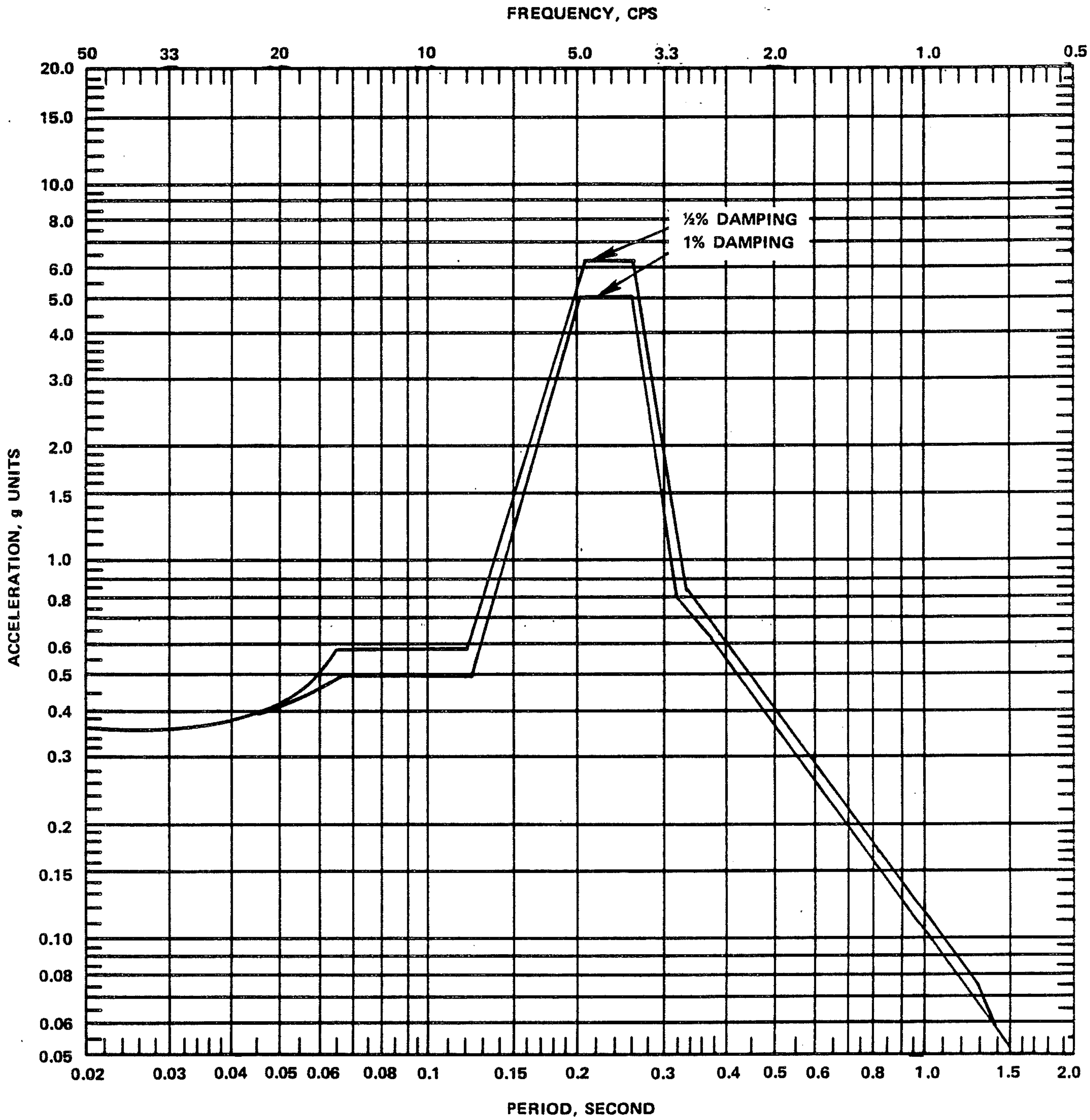
FIGURE 3.7-52

HORIZONTAL RESPONSE SPECTRA – OPERATING-BASIS EARTHQUAKE – REACTOR PRESSURE VESSEL 14.0 FT ABOVE REACTOR PRESSURE VESSEL INVERT NORTH-SOUTH COMPONENT

SARGENT & LUNDY REPORT NO. SL-2682



Fermi 2

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FIGURE 3.7-53

HORIZONTAL RESPONSE SPECTRA – OPERATING-BASIS EARTHQUAKE – REACTOR PRESSURE VESSEL 14.0 FT ABOVE REACTOR PRESSURE VESSEL INVERT EAST-WEST COMPONENT

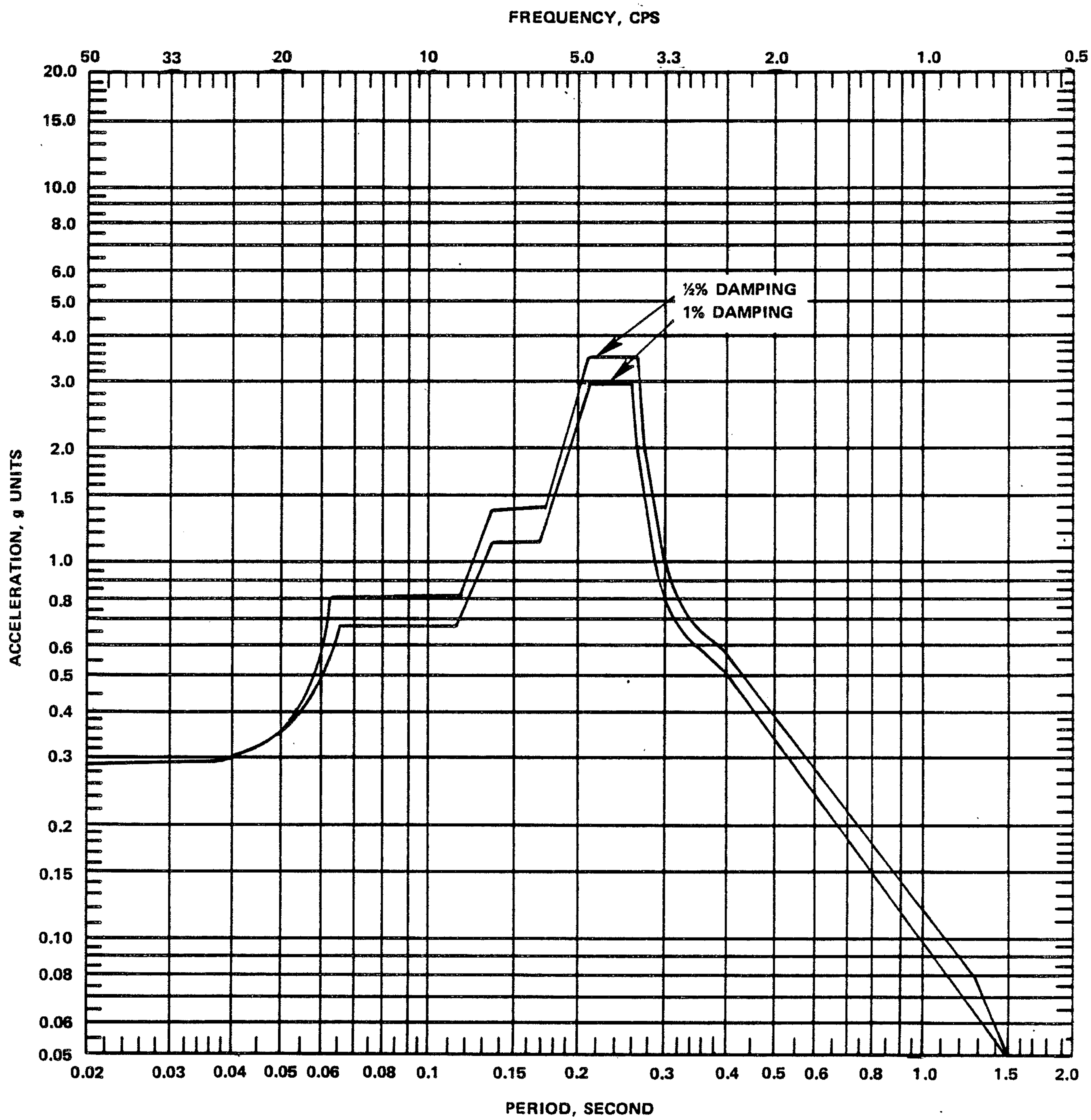

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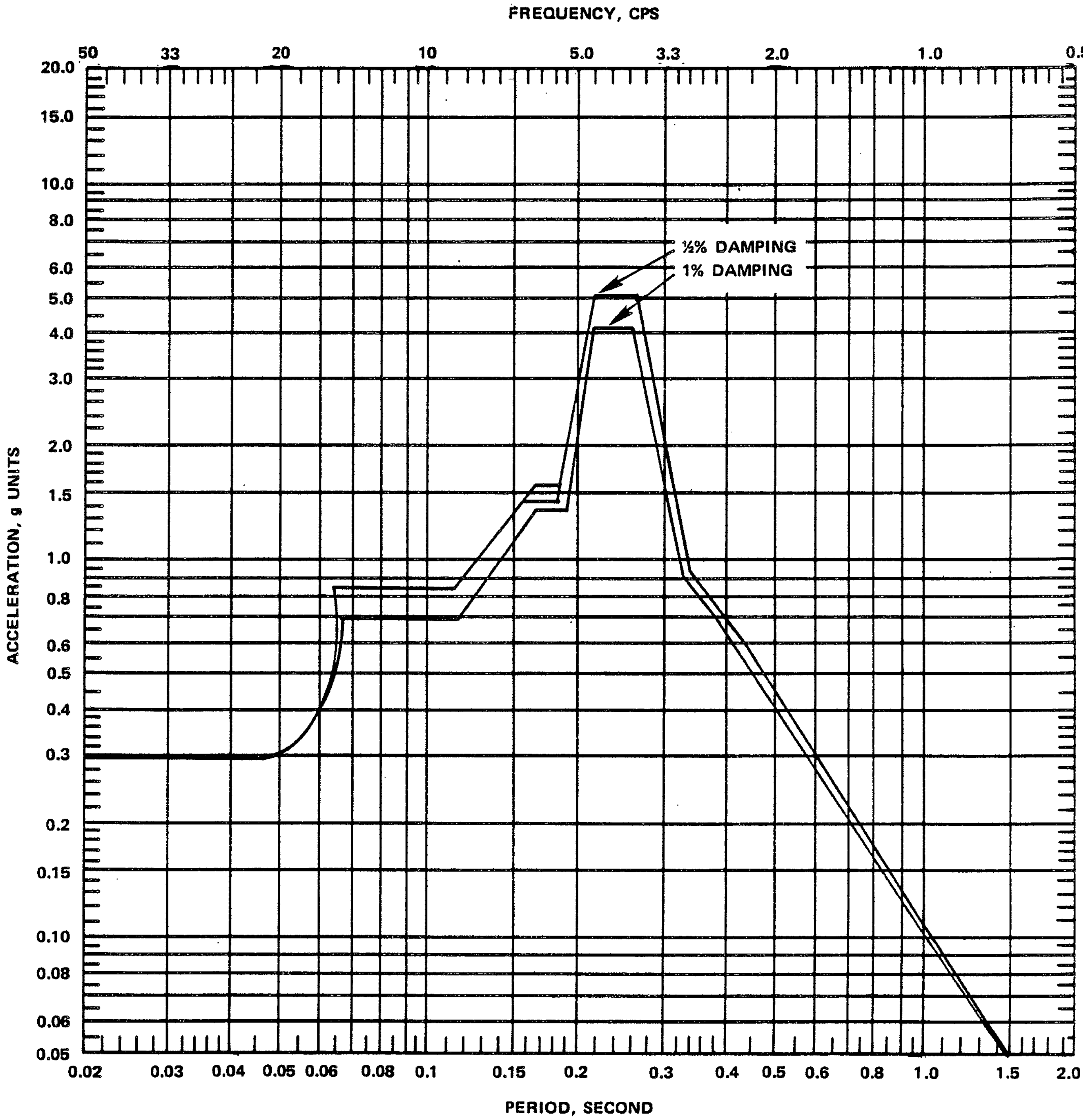
FIGURE 3.7-54

HORIZONTAL RESPONSE SPECTRA – OPERATING-BASIS EARTHQUAKE – REACTOR PRESSURE VESSEL 54.0 FT ABOVE REACTOR PRESSURE VESSEL INVERT NORTH-SOUTH COMPONENT

SARGENT & LUNDY REPORT NO. SL-2682



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UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 3.7-55

HORIZONTAL RESPONSE SPECTRA – OPERATING-BASIS EARTHQUAKE – REACTOR PRESSURE VESSEL 54.0 FT ABOVE REACTOR PRESSURE VESSEL INVERT EAST-WEST COMPONENT

SARGENT & LUNDY REPORT NO. SL-2682

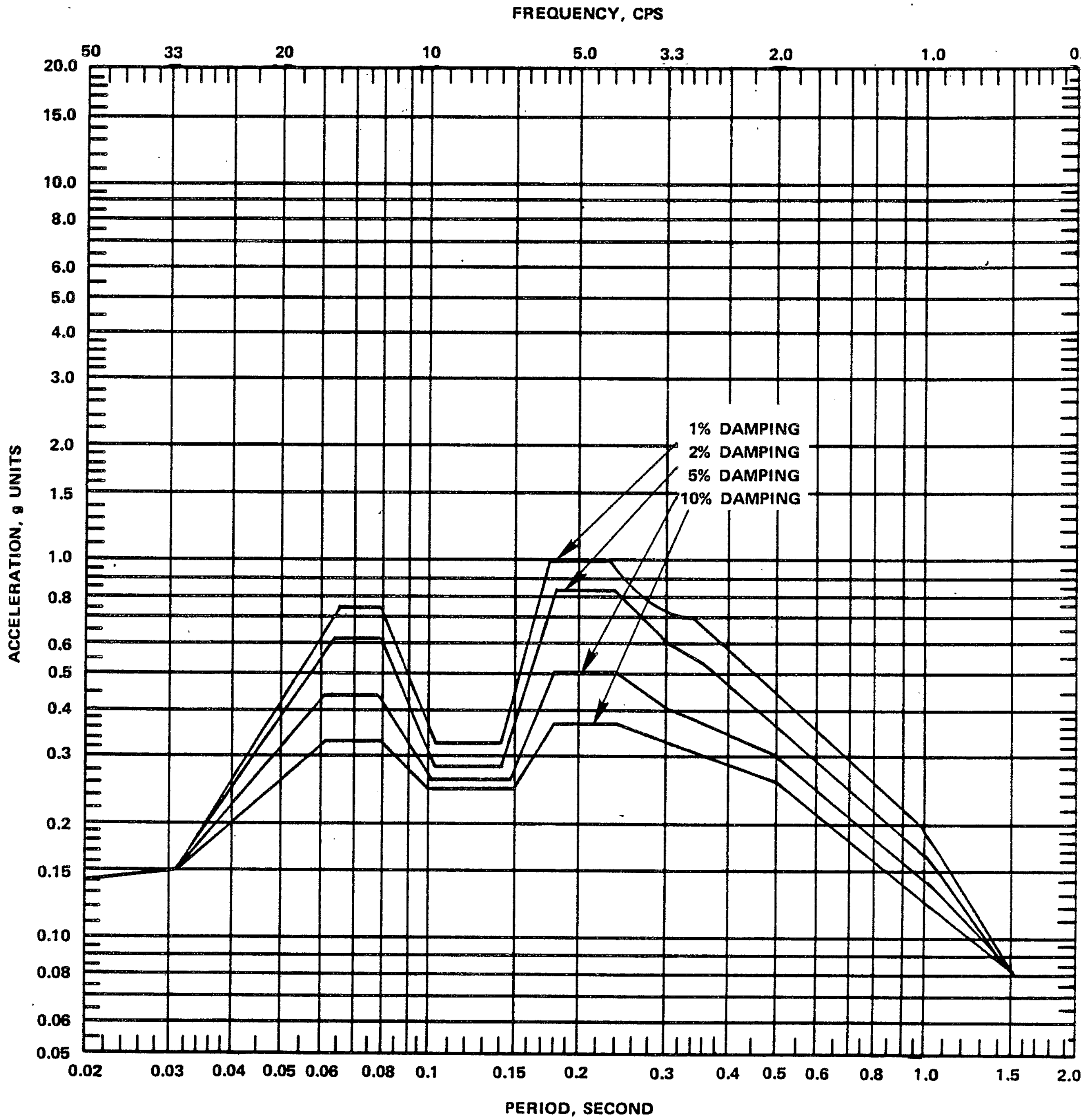

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FIGURE 3.7-56

HORIZONTAL FLOOR RESPONSE SPECTRA
SAFE-SHUTDOWN EARTHQUAKE
ELEVATION 583.5 FT – SLAB 1
REACTOR/AUXILIARY BUILDING NORTH-SOUTH COMPONENT

SARGENT & LUNDY REPORT NO. SL-2682

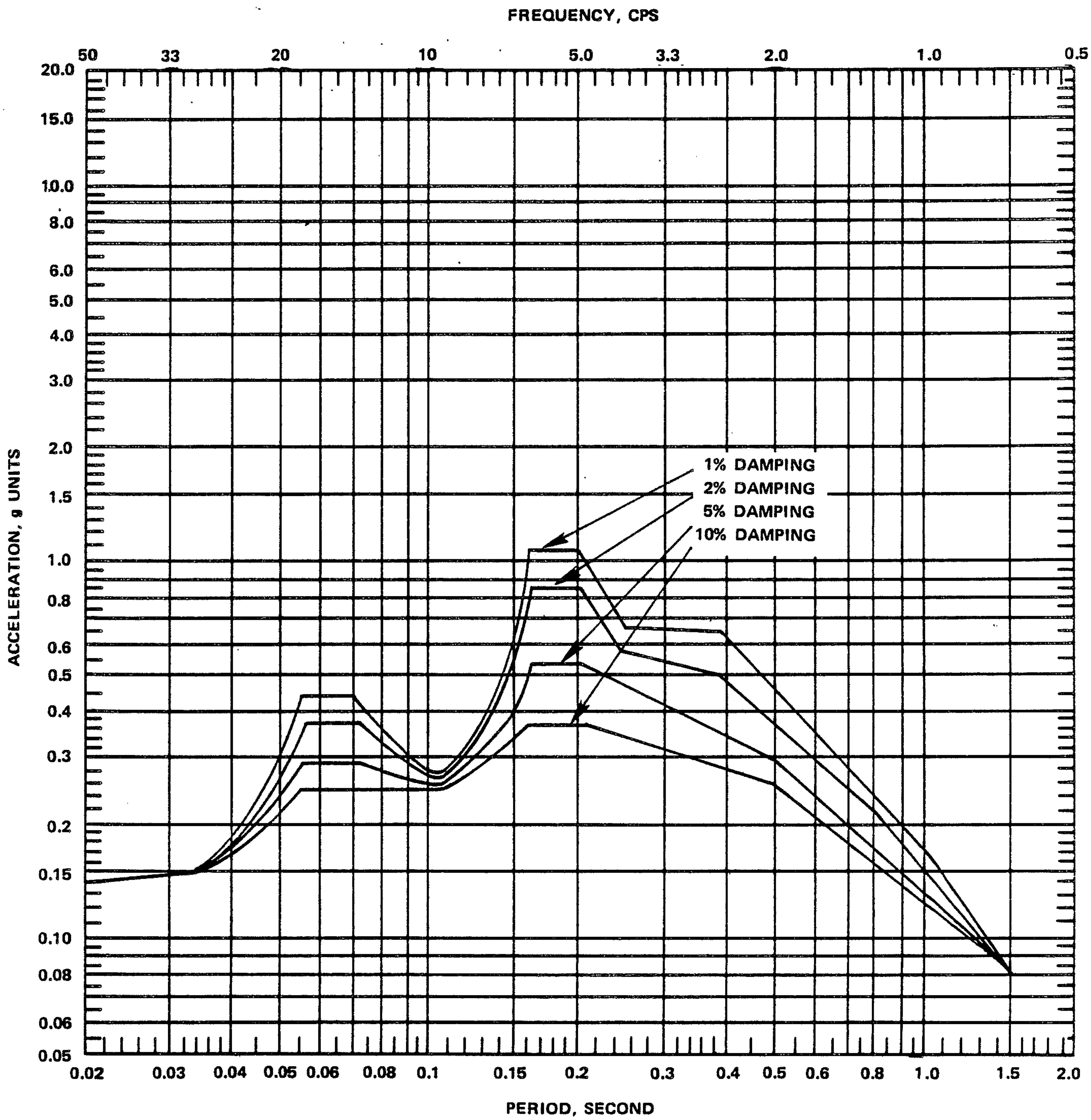

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FIGURE 3.7-57

HORIZONTAL FLOOR RESPONSE SPECTRA
SAFE-SHUTDOWN EARTHQUAKE
ELEVATION 583.5 FT – SLAB 1
REACTOR/AUXILIARY BUILDING EAST-WEST
COMPONENT

SARGENT & LUNDY REPORT NO. SL-2682

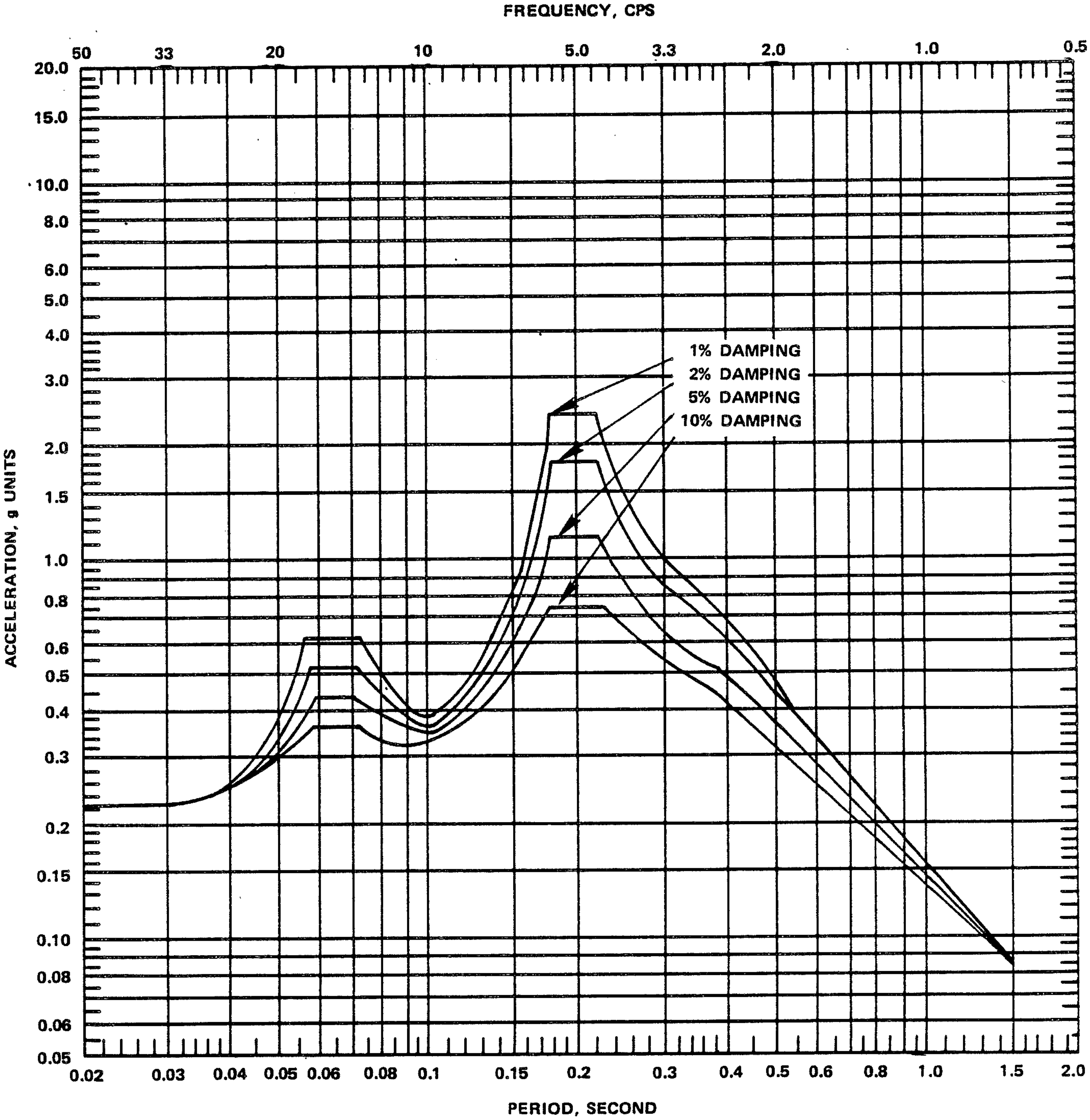

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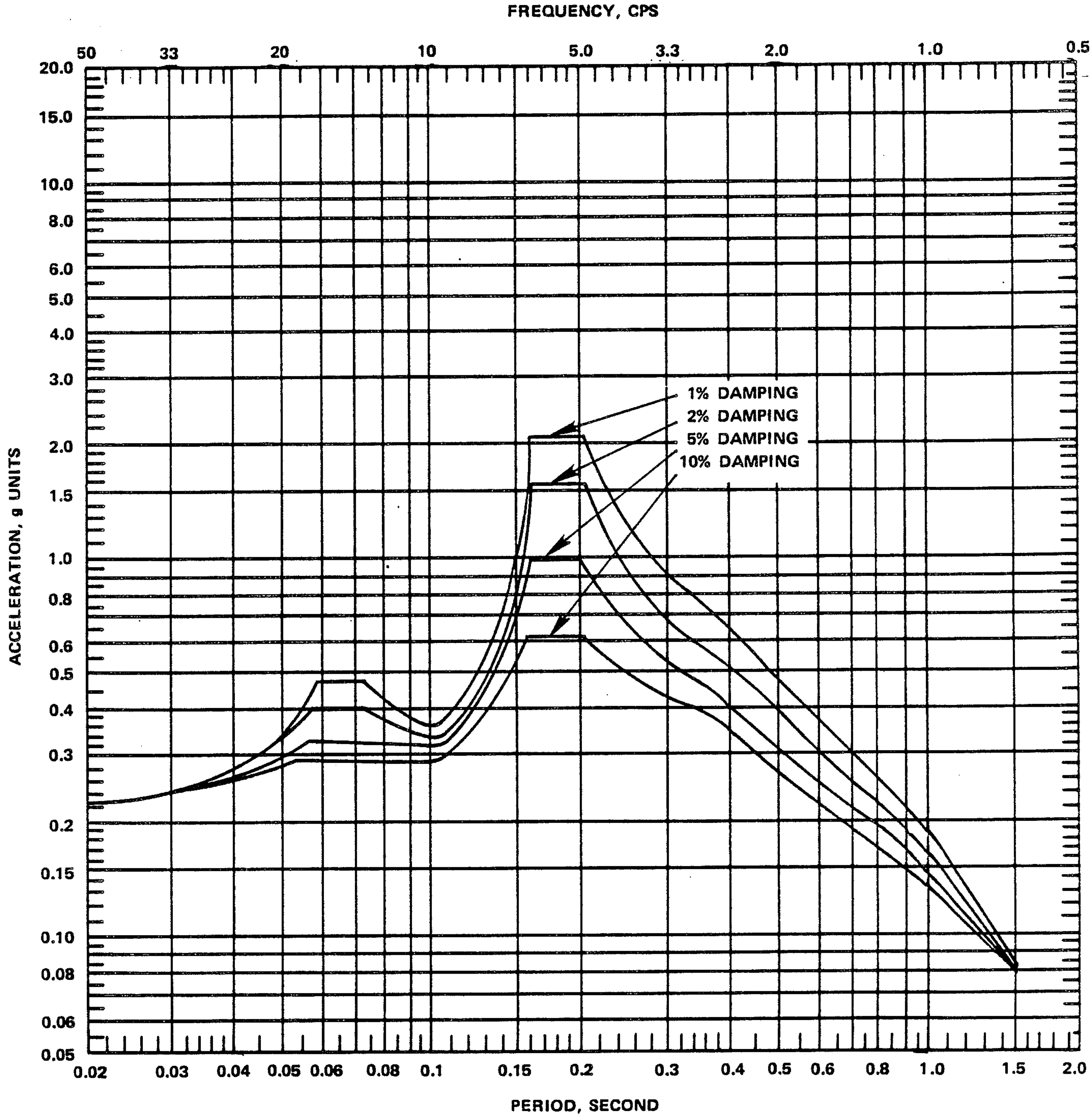
FIGURE 3.7-58

HORIZONTAL FLOOR RESPONSE SPECTRA
SAFE-SHUTDOWN EARTHQUAKE
ELEVATION 613.5 FT – SLAB 2
REACTOR/AUXILIARY BUILDING NORTH-SOUTH
COMPONENT

SARGENT & LUNDY REPORT NO. SL-2682



SARGENT & LUNDY REPORT NO. SL-2682

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FIGURE 3.7-59

HORIZONTAL FLOOR RESPONSE SPECTRA
SAFE-SHUTDOWN EARTHQUAKE
ELEVATION 613.5 FT – SLAB 2
REACTOR/AUXILIARY BUILDING EAST-WEST
COMPONENT

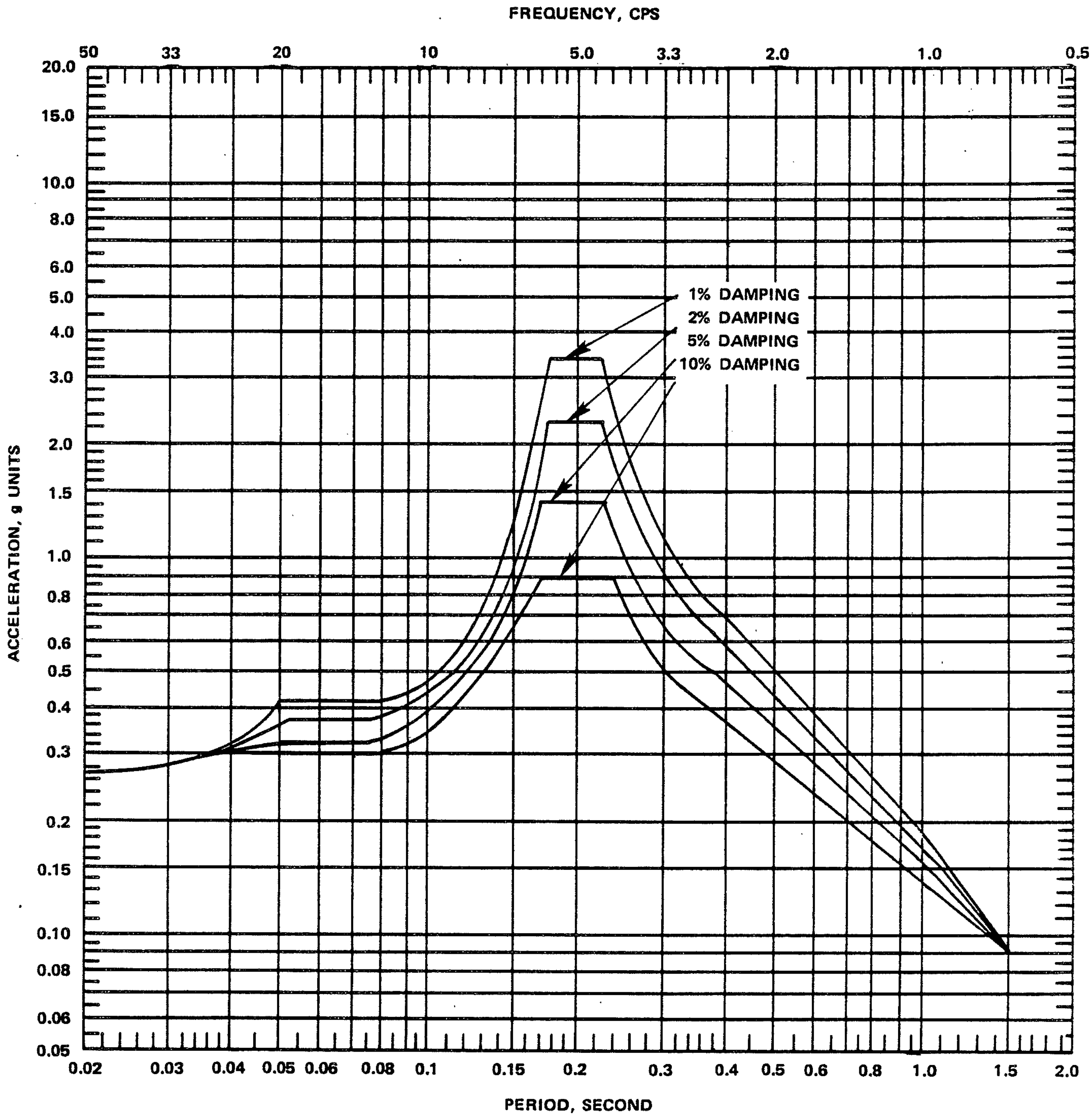

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FIGURE 3.7-60

HORIZONTAL FLOOR RESPONSE SPECTRA
SAFE-SHUTDOWN EARTHQUAKE
ELEVATION 641.5 FT – SLAB 3
REACTOR/AUXILIARY BUILDING NORTH-SOUTH
COMPONENT

SARGENT & LUNDY REPORT NO. SL-2682

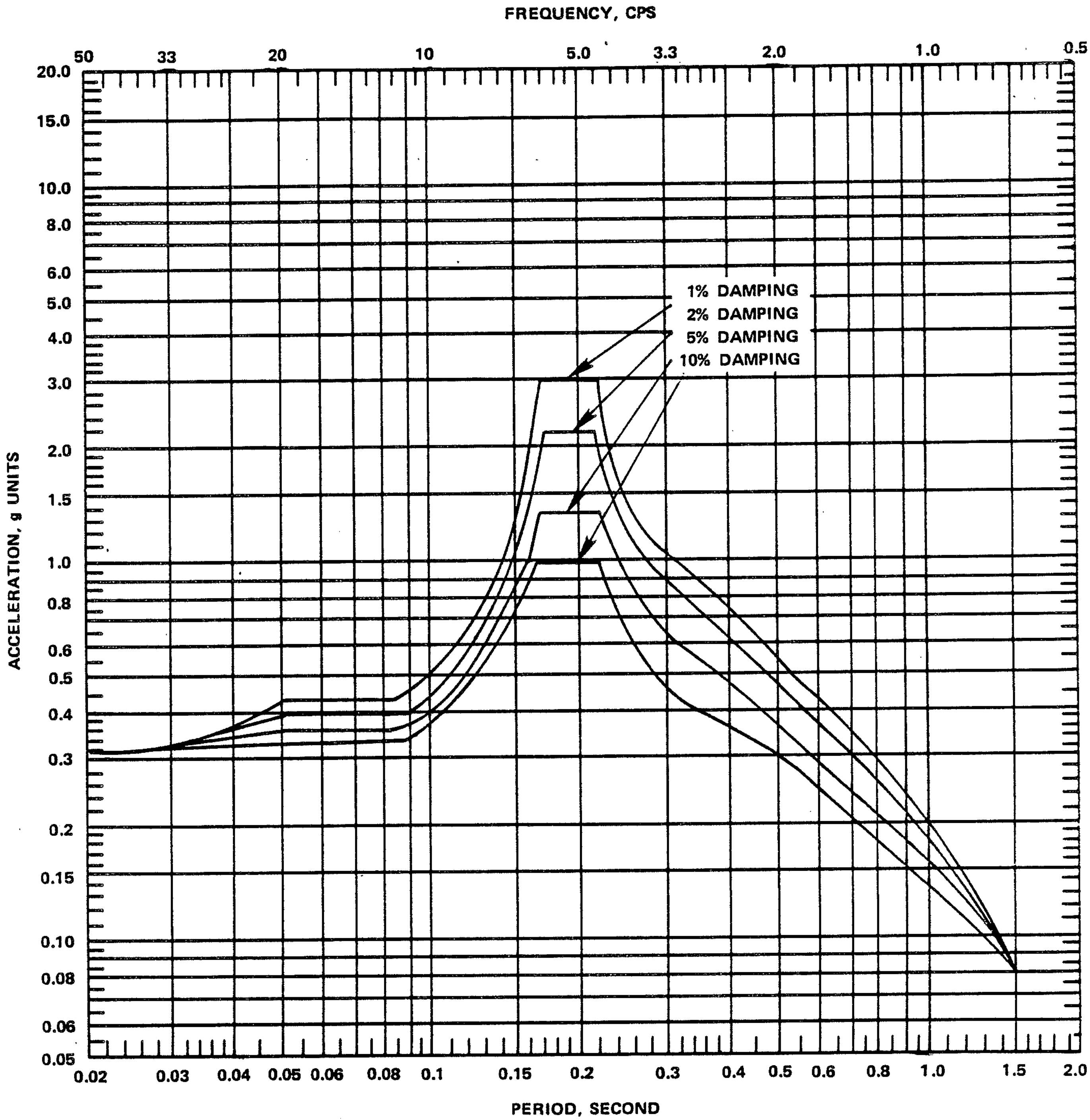

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FIGURE 3.7-61

HORIZONTAL FLOOR RESPONSE SPECTRA
SAFE-SHUTDOWN EARTHQUAKE
ELEVATION 641.5 FT – SLAB 3
REACTOR/AUXILIARY BUILDING EAST-WEST
COMPONENT

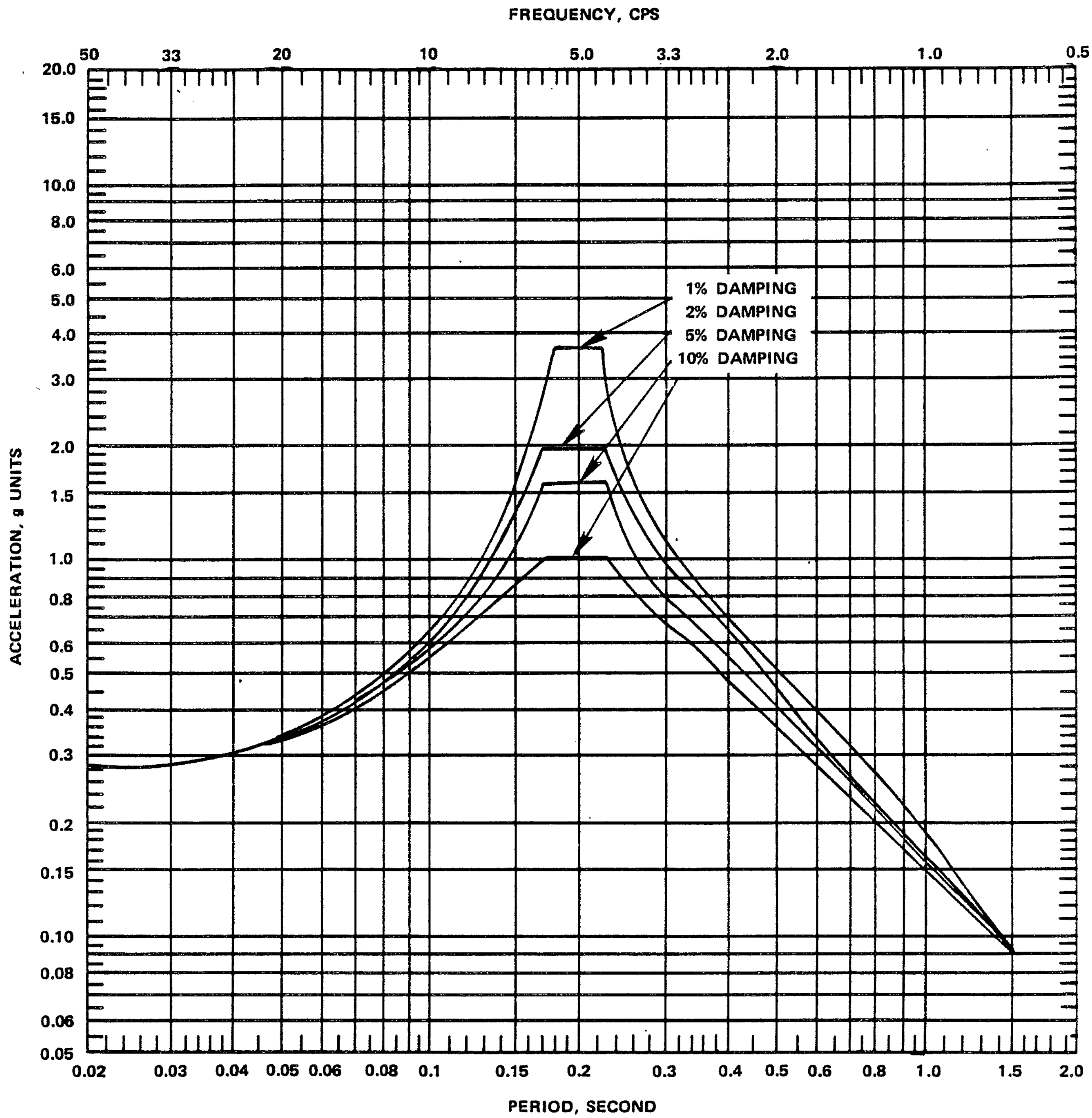

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FIGURE 3.7-62

HORIZONTAL FLOOR RESPONSE SPECTRA
SAFE-SHUTDOWN EARTHQUAKE
ELEVATION 659.0 FT – SLAB 4
REACTOR/AUXILIARY BUILDING NORTH-SOUTH
COMPONENT

SARGENT & LUNDY REPORT NO. SL-2682

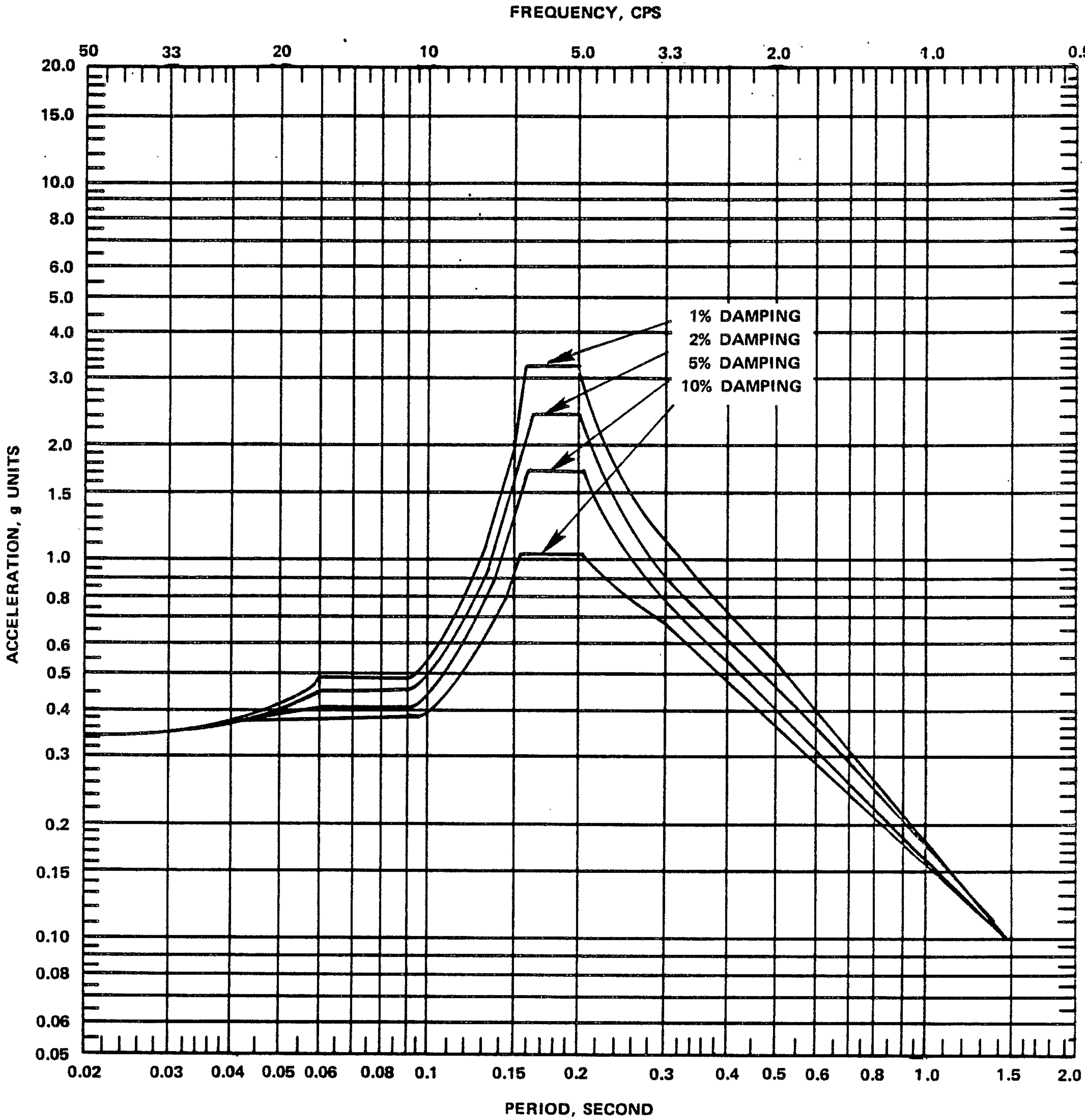

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FIGURE 3.7-63

HORIZONTAL FLOOR RESPONSE SPECTRA
SAFE-SHUTDOWN EARTHQUAKE
ELEVATION 659.0 FT – SLAB 4
REACTOR/AUXILIARY BUILDING EAST-WEST
COMPONENT

SARGENT & LUNDY REPORT NO. SL-2682

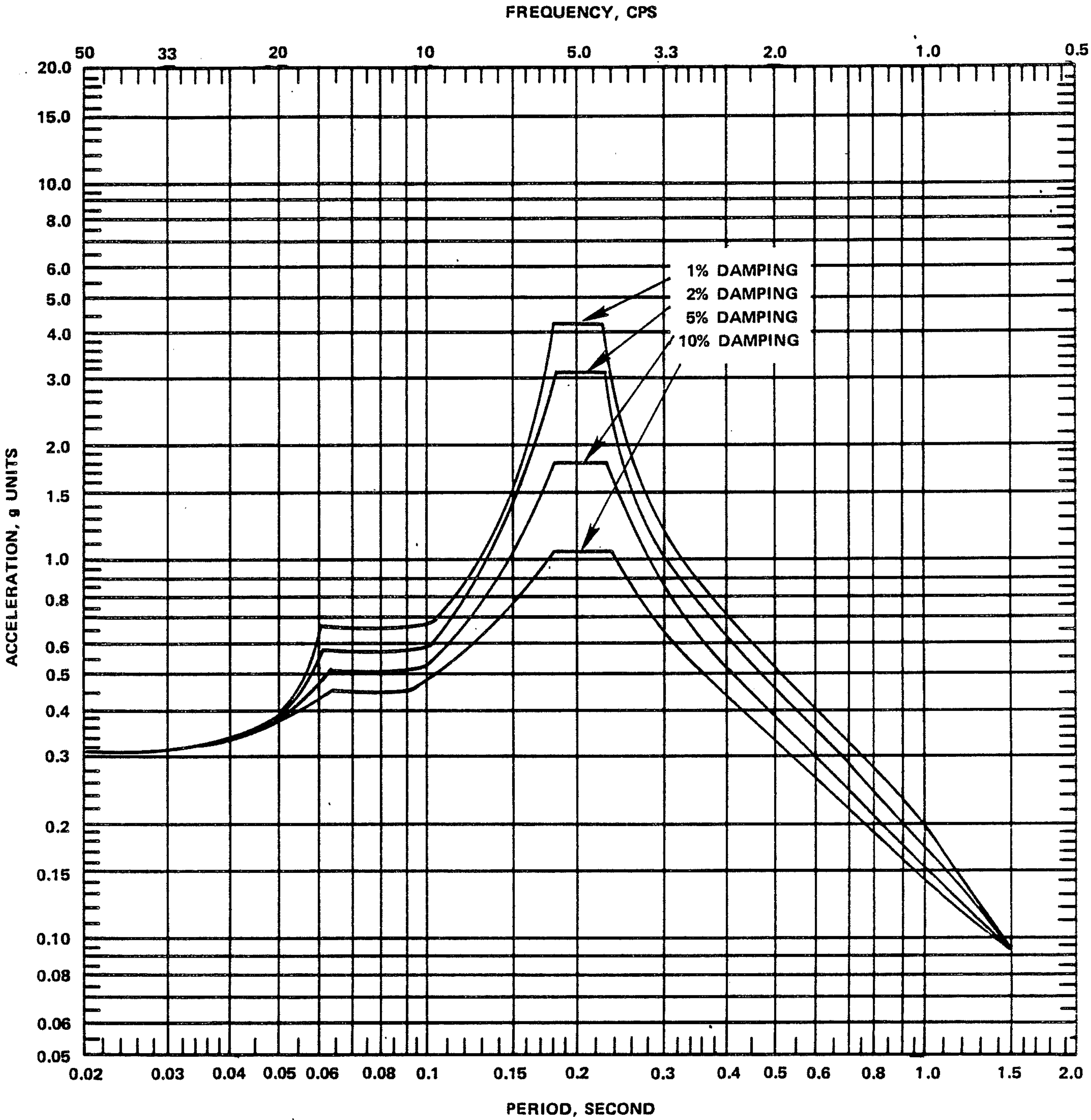

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FIGURE 3.7-64

HORIZONTAL FLOOR RESPONSE SPECTRA
SAFE-SHUTDOWN EARTHQUAKE
ELEVATION 684.5 FT – SLAB 5
REACTOR/AUXILIARY BUILDING NORTH-SOUTH COMPONENT

SARGENT & LUNDY REPORT NO. SL-2682

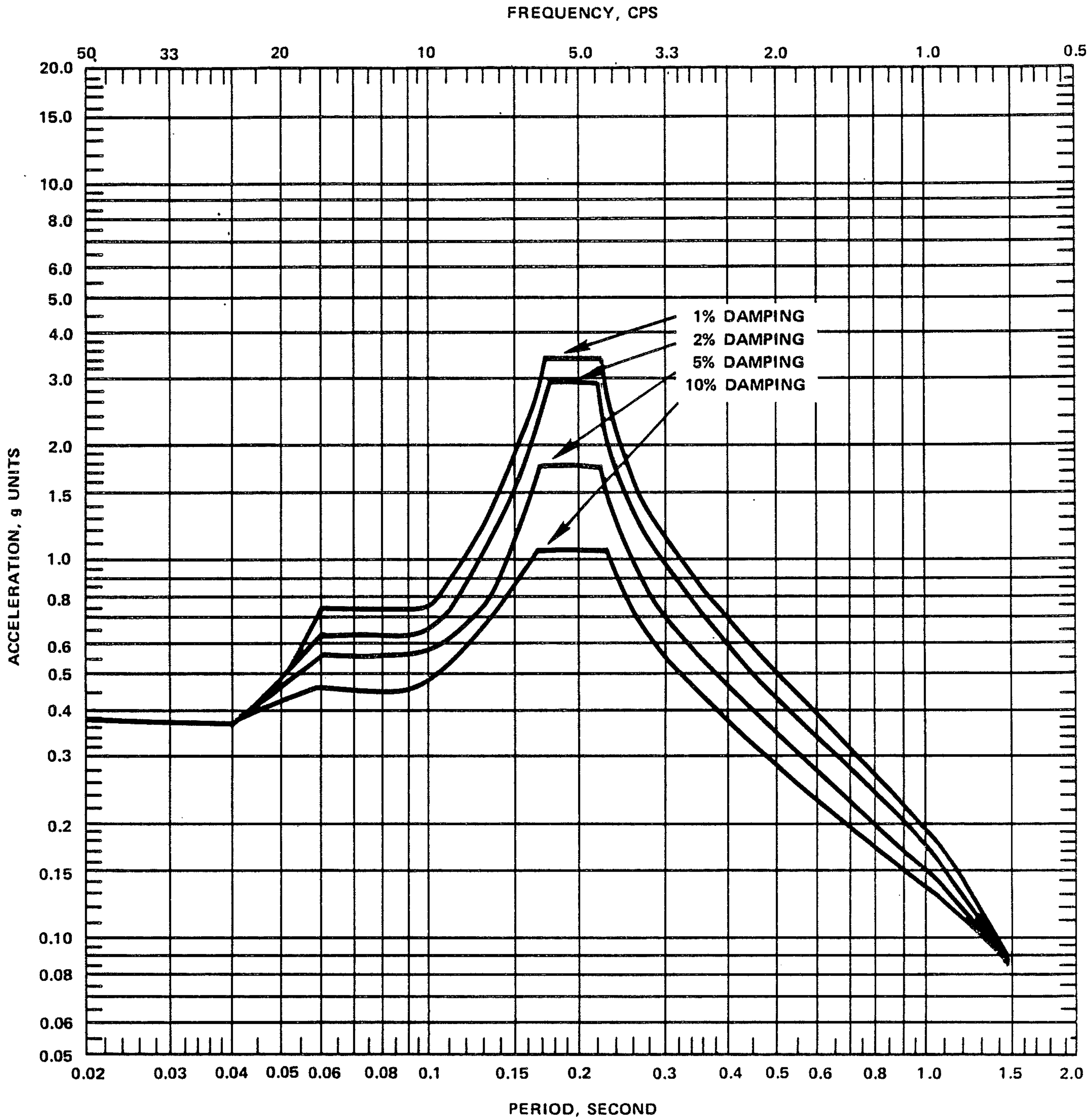

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FIGURE 3.7-65

HORIZONTAL FLOOR RESPONSE SPECTRA
SAFE-SHUTDOWN EARTHQUAKE
ELEVATION 684.5 FT – SLAB 5
REACTOR/AUXILIARY BUILDING EAST-WEST
COMPONENT

SARGENT & LUNDY REPORT NO. SL-2682

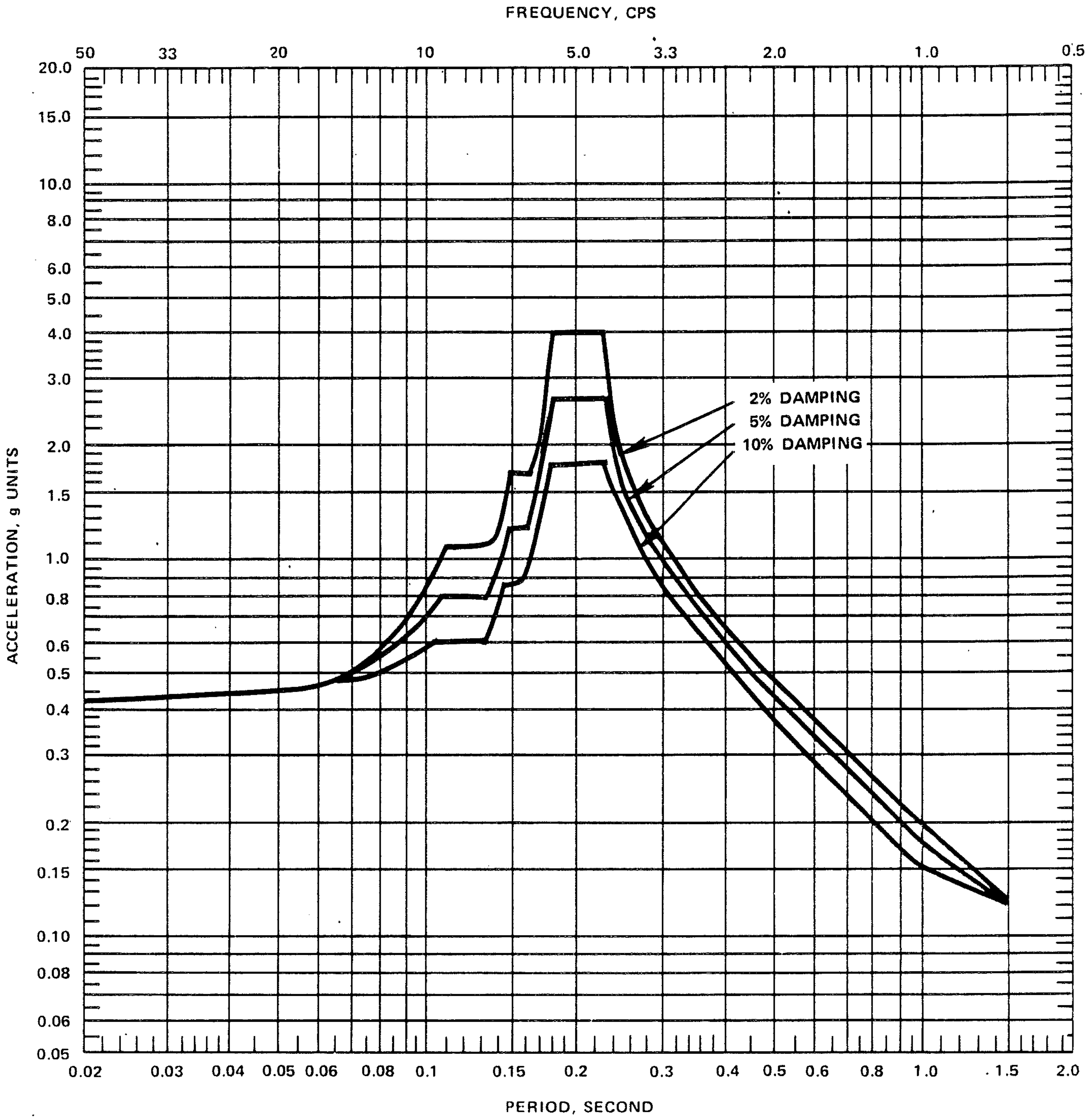

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FIGURE 3.7-66

HORIZONTAL RESPONSE SPECTRA REACTOR BUILDING CRANE – SAFE-SHUTDOWN EARTHQUAKE – CRANE ADJACENT TO COLUMN ROW 17 – NORTH-SOUTH COMPONENT

SARGENT & LUNDY REPORT NO. SL-2682

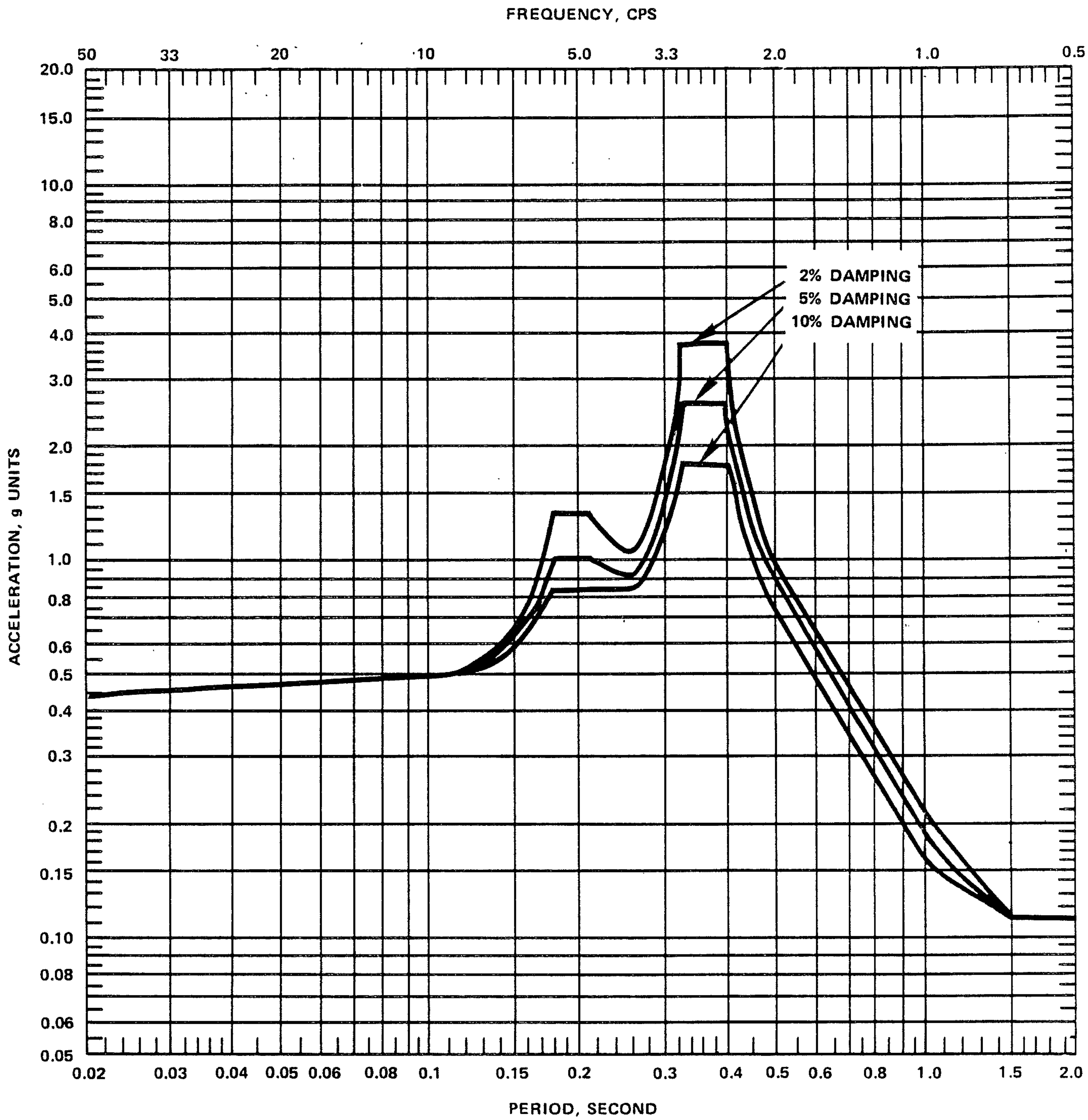

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FIGURE 3.7-67

HORIZONTAL RESPONSE SPECTRA REACTOR BUILDING CRANE – SAFE-SHUTDOWN EARTHQUAKE – CRANE ADJACENT TO COLUMN ROW 17 – EAST-WEST COMPONENT

SARGENT & LUNDY REPORT NO. SL-2682

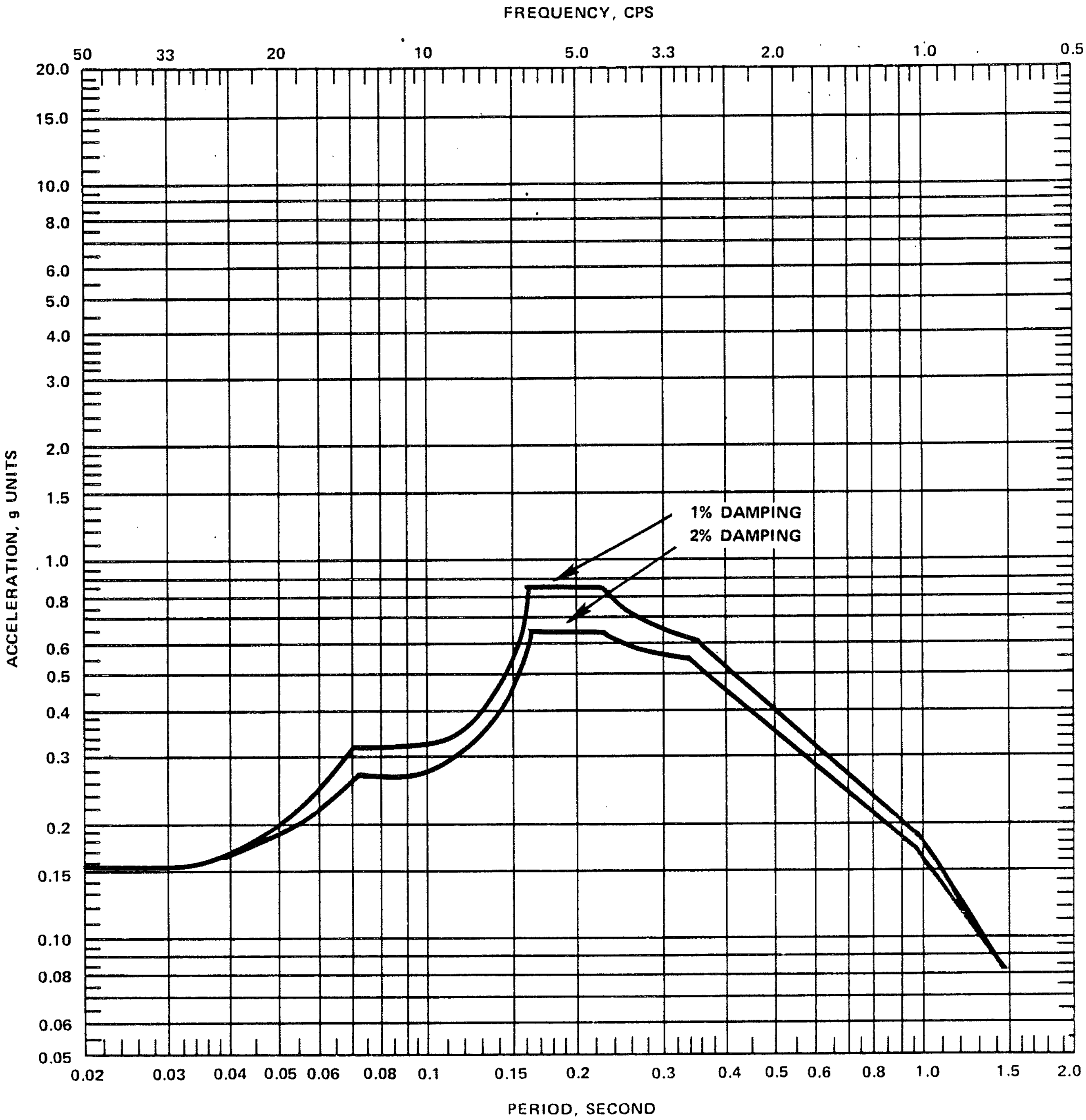

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FIGURE 3.7-68

HORIZONTAL RESPONSE SPECTRA
SAFE-SHUTDOWN EARTHQUAKE – DRYWELL
CONTAINMENT 18.0 FT BELOW REACTOR PRESSURE
VESSEL INVERT – NORTH-SOUTH COMPONENT

SARGENT & LUNDY REPORT NO. SL-2682

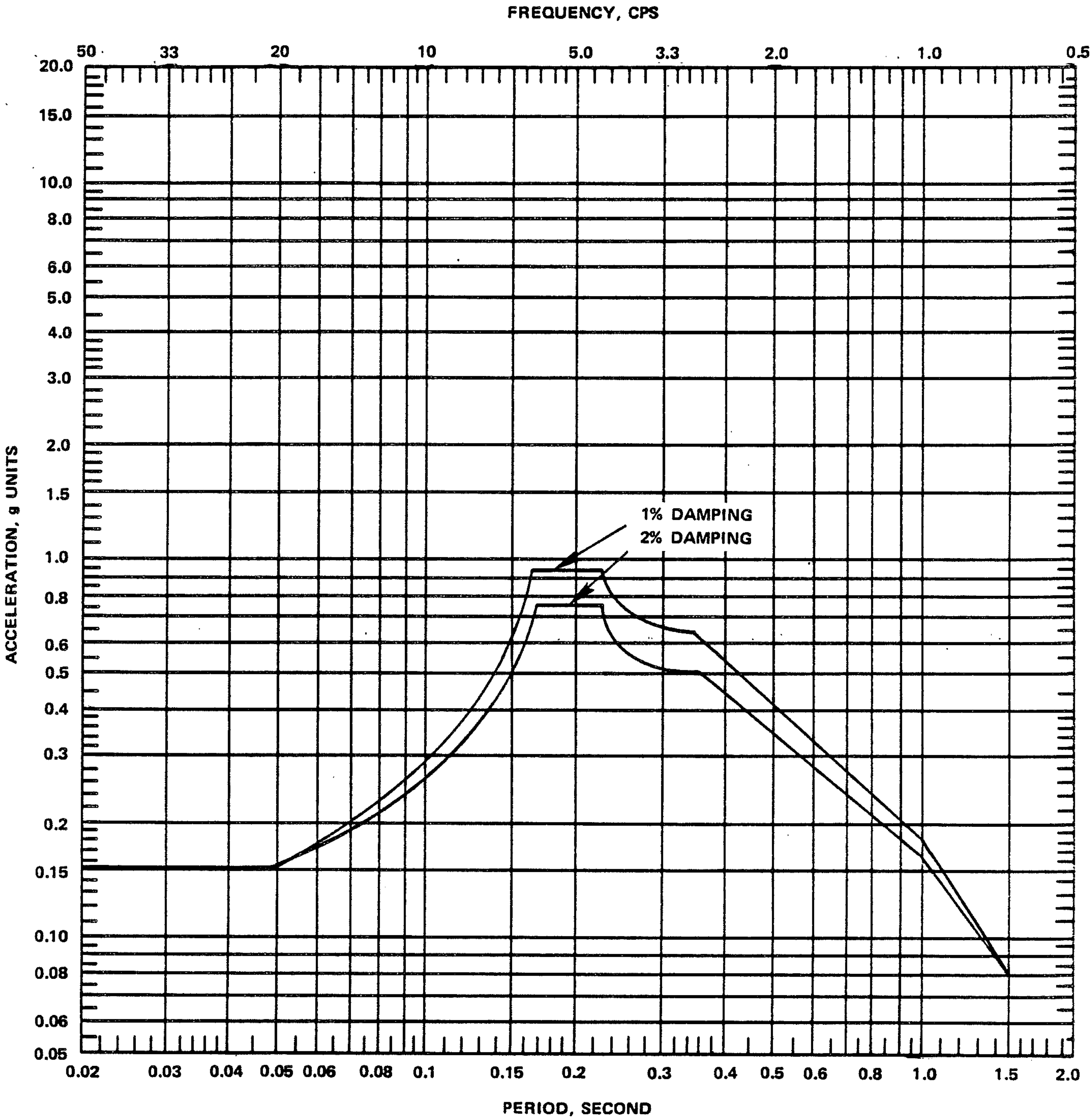

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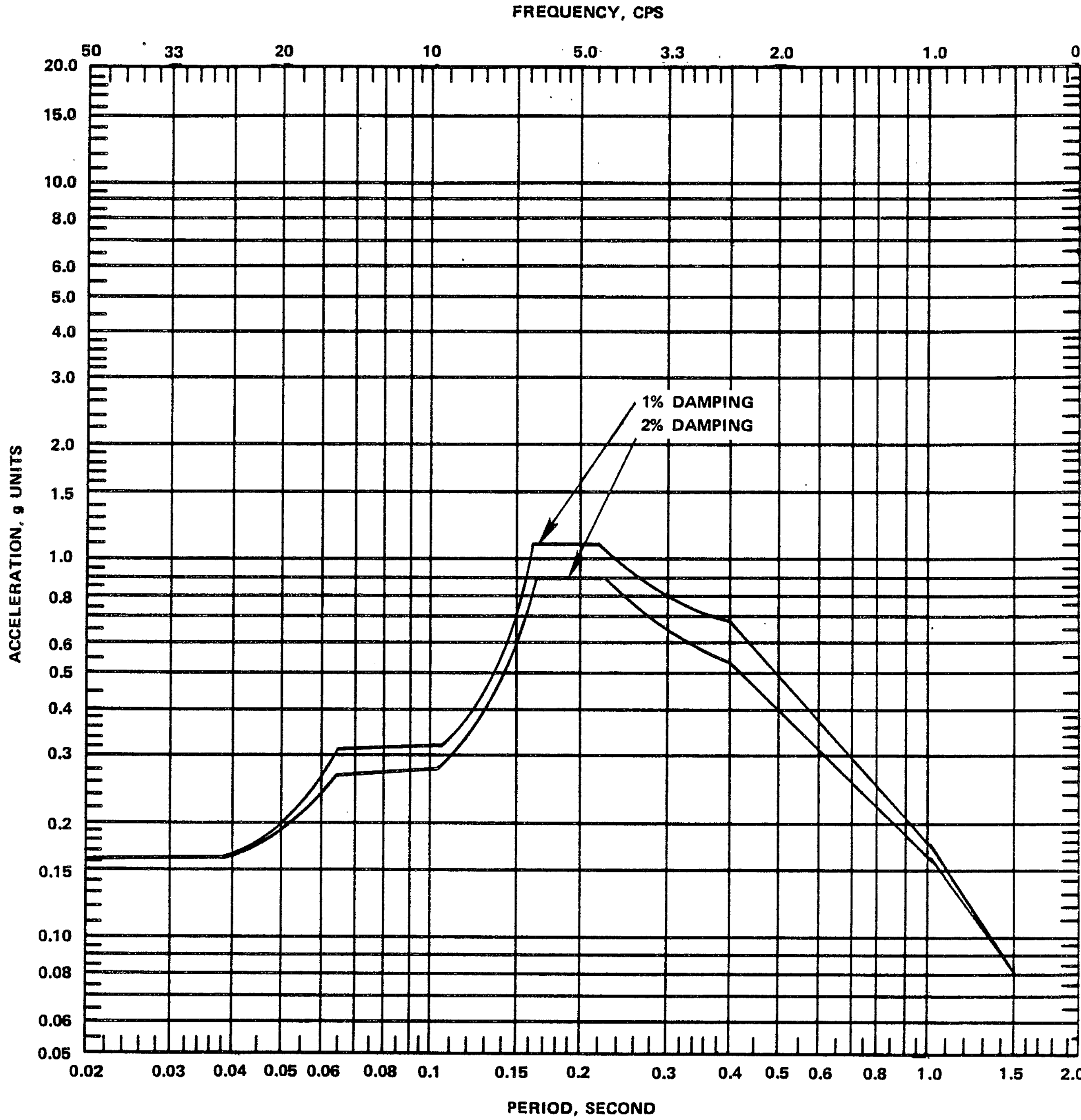
FIGURE 3.7-69

HORIZONTAL RESPONSE SPECTRA
SAFE-SHUTDOWN EARTHQUAKE – DRYWELL
CONTAINMENT 18.0 FT BELOW REACTOR PRESSURE
INVERT – EAST-WEST COMPONENT

SARGENT & LUNDY REPORT NO. SL-2682



SARGENT & LUNDY REPORT NO. SL-2682

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FIGURE 3.7-70

HORIZONTAL RESPONSE SPECTRA
SAFE-SHUTDOWN EARTHQUAKE – DRYWELL
CONTAINMENT 6.0 FT BELOW REACTOR PRESSURE
VESSEL INVERT – NORTH-SOUTH COMPONENT

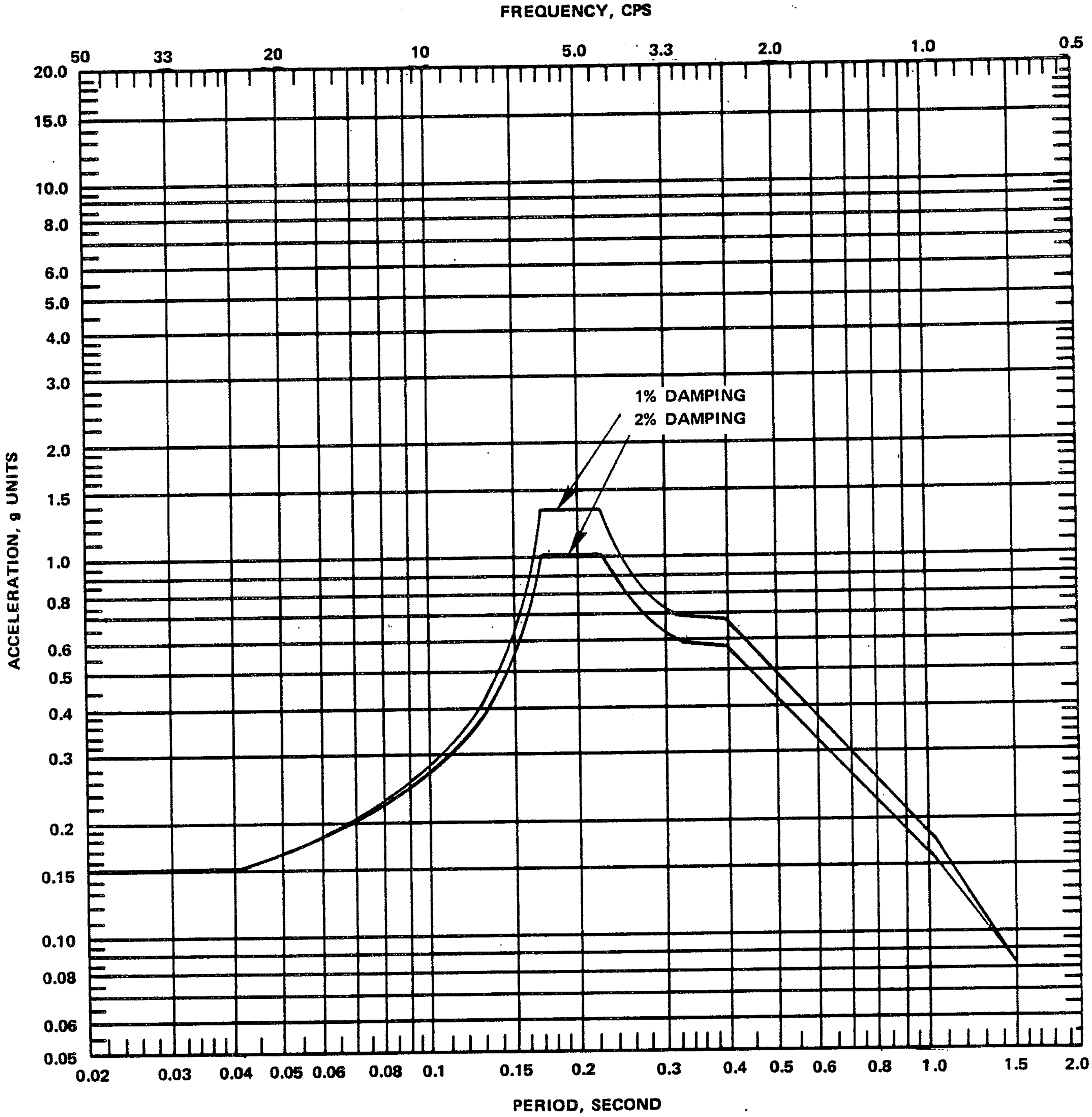

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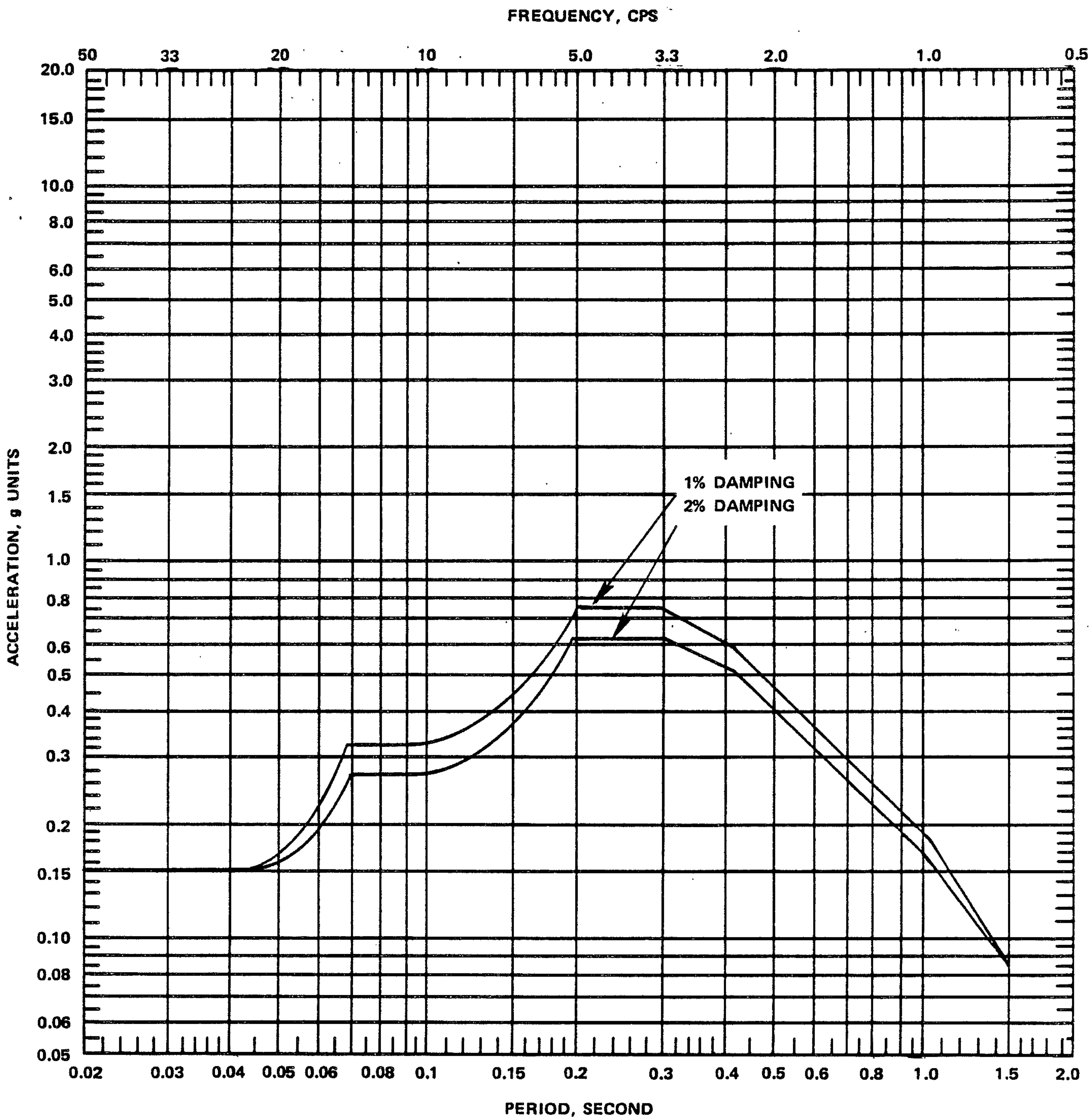
FIGURE 3.7-71

HORIZONTAL RESPONSE SPECTRA
SAFE-SHUTDOWN EARTHQUAKE – DRYWELL
CONTAINMENT 6.0 FT BELOW REACTOR PRESSURE
VESSEL INVERT – EAST-WEST COMPONENT

SARGENT & LUNDY REPORT NO. SL-2682



SARGENT & LUNDY REPORT NO. SL-2682

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FIGURE 3.7-72

HORIZONTAL RESPONSE SPECTRA
SAFE-SHUTDOWN EARTHQUAKE – REACTOR
PEDESTAL 18.0 FT BELOW REACTOR PRESSURE
VESSEL INVERT – NORTH-SOUTH COMPONENT

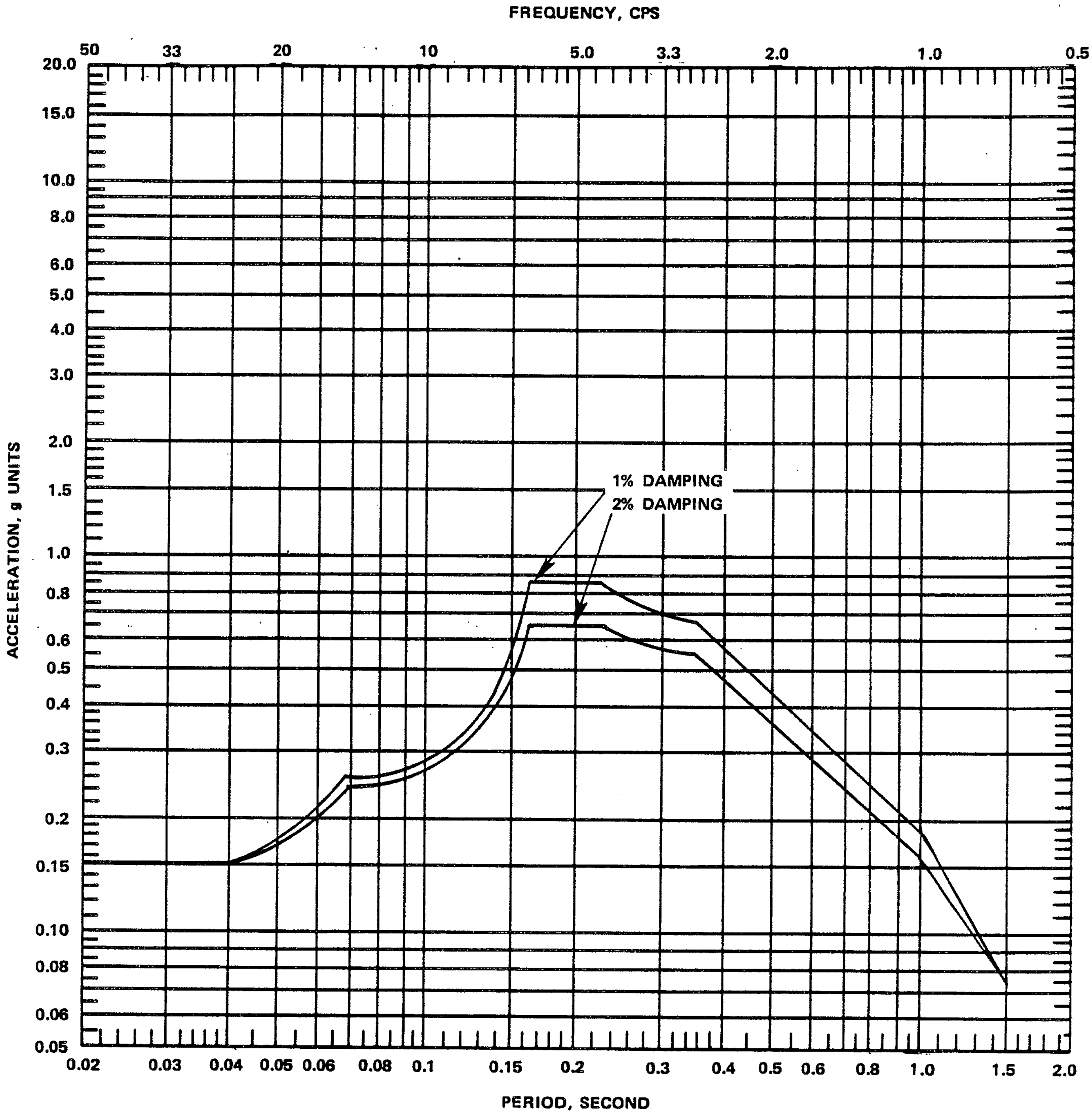

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FIGURE 3.7-73

HORIZONTAL RESPONSE SPECTRA
SAFE-SHUTDOWN EARTHQUAKE – REACTOR
PEDESTAL 18.0 FT BELOW REACTOR PRESSURE
VESSEL INVERT – EAST-WEST COMPONENT

SARGENT & LUNDY REPORT NO. SL-2682

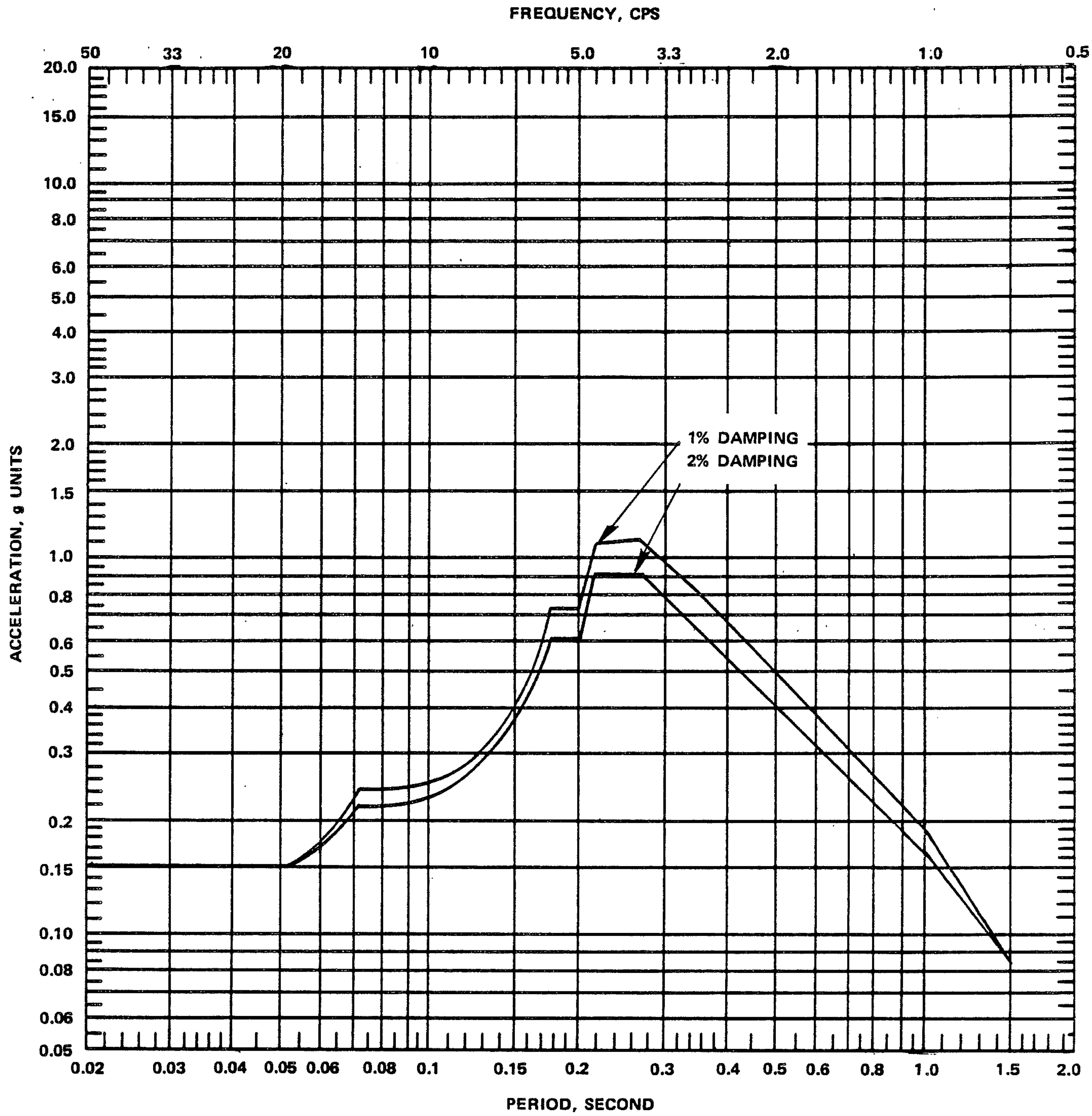

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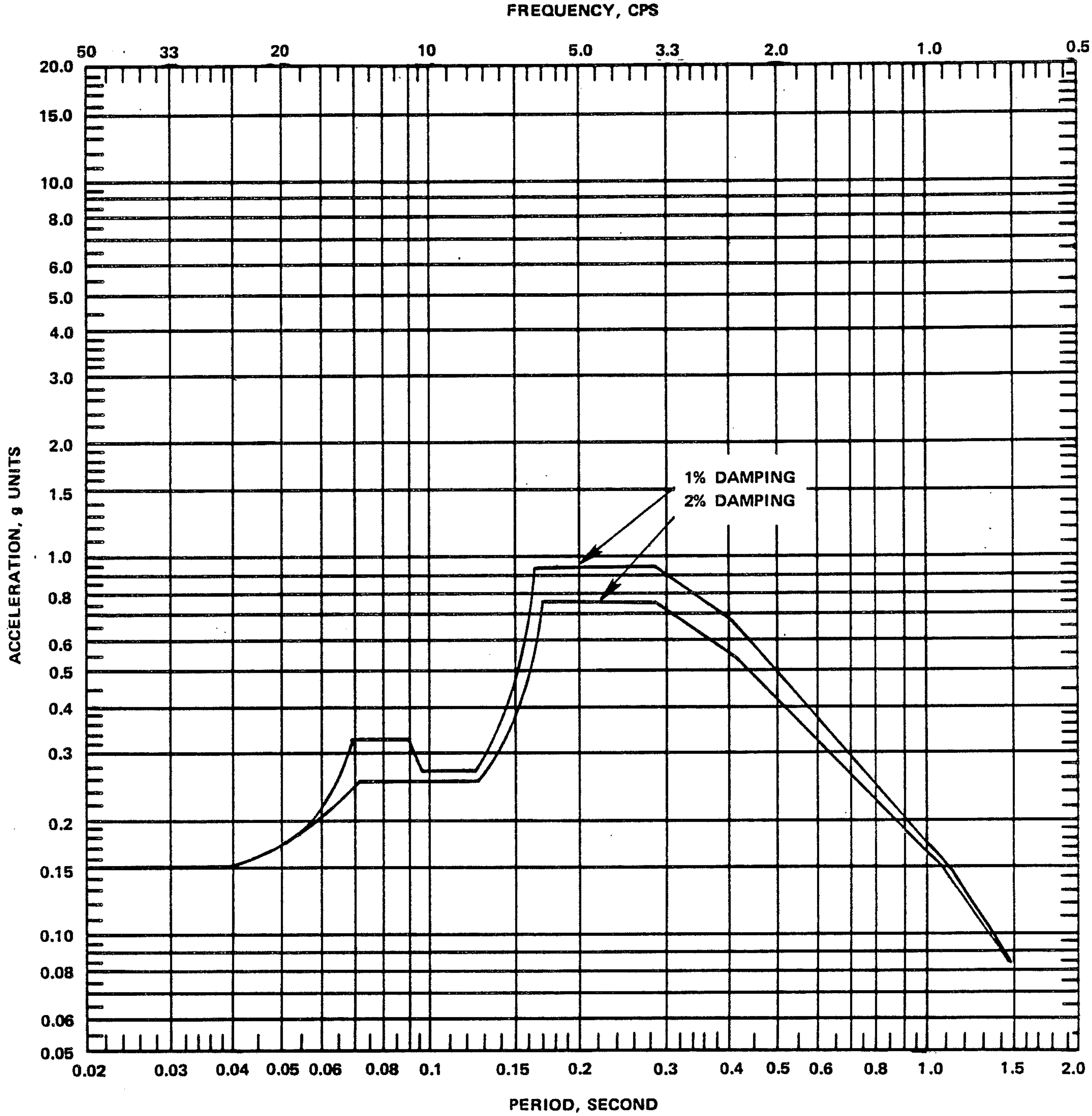
FIGURE 3.7-74

HORIZONTAL RESPONSE SPECTRA
SAFE-SHUTDOWN EARTHQUAKE
TOP OF REACTOR PEDESTAL
NORTH-SOUTH COMPONENT

SARGENT & LUNDY REPORT NO. SL-2682



SARGENT & LUNDY REPORT NO. SL-2682

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FIGURE 3.7-75

HORIZONTAL RESPONSE SPECTRA
SAFE-SHUTDOWN EARTHQUAKE
TOP OF REACTOR PEDESTAL
EAST-WEST COMPONENT

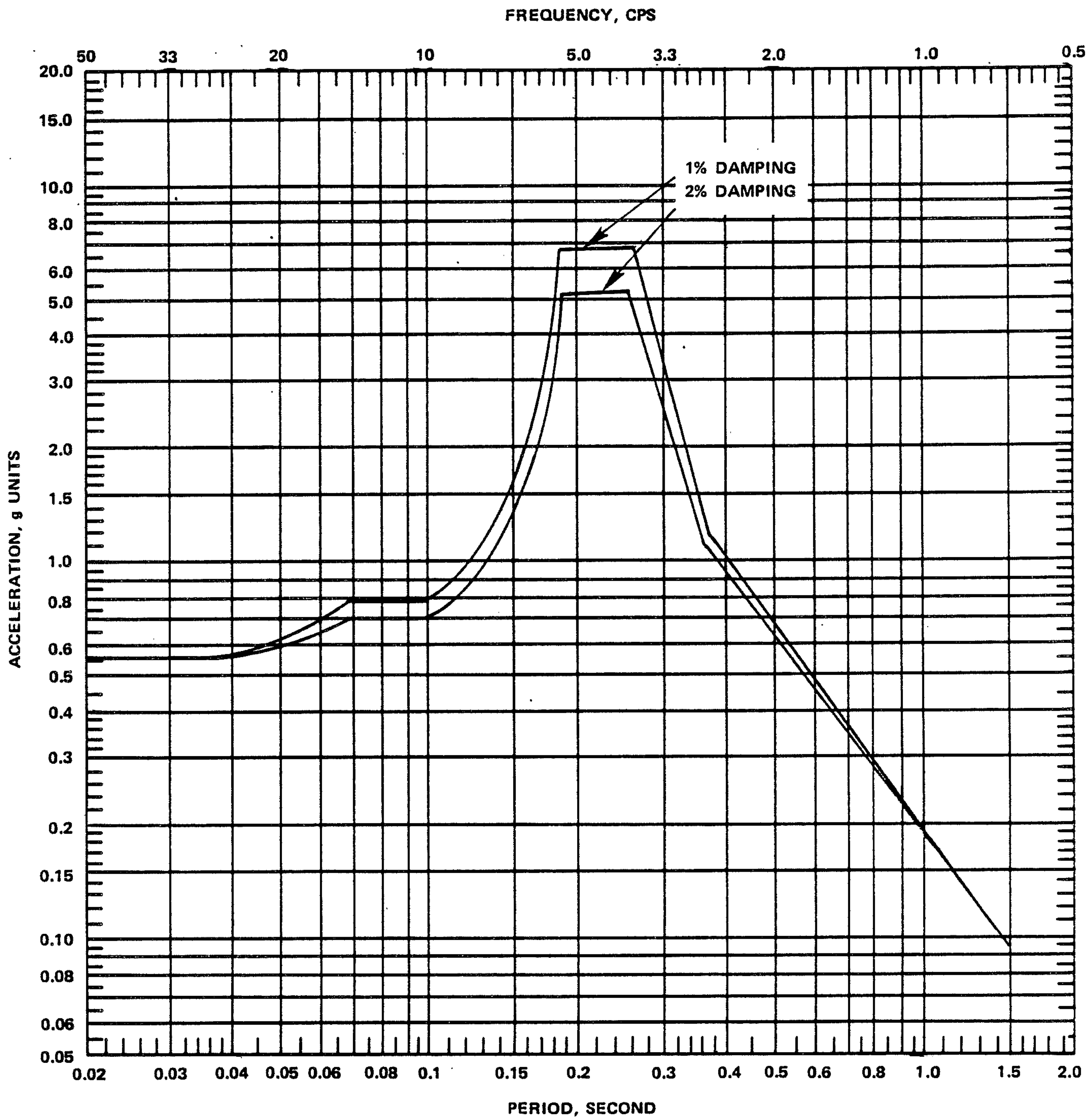

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FIGURE 3.7-76

HORIZONTAL RESPONSE SPECTRA
SAFE-SHUTDOWN EARTHQUAKE – REACTOR
PRESSURE VESSEL 14.0 FT ABOVE REACTOR
PRESSURE VESSEL INVERT – NORTH-SOUTH
COMPONENT

SARGENT & LUNDY REPORT NO. SL-2682

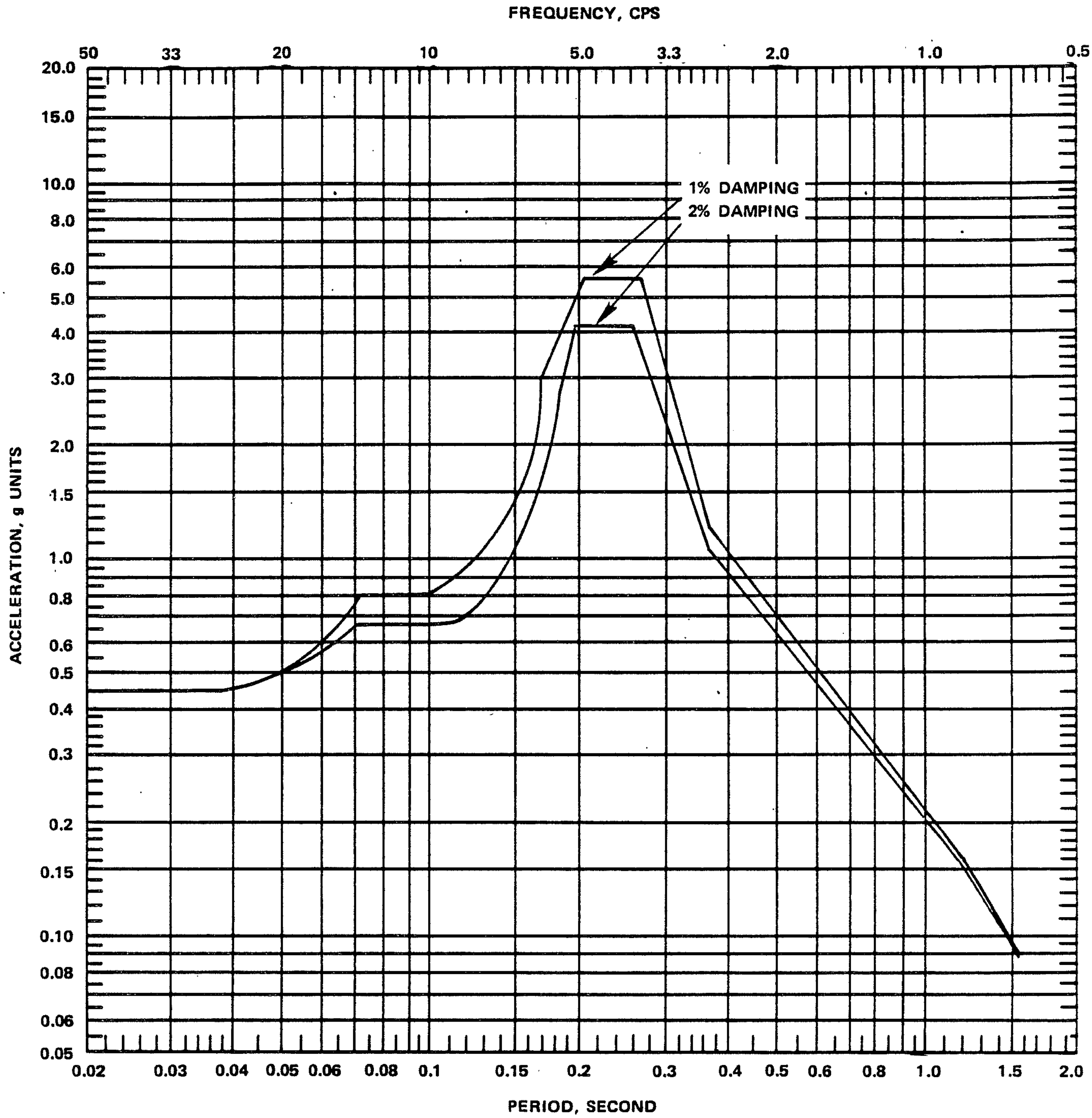

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FIGURE 3.7-77

HORIZONTAL RESPONSE SPECTRA
SAFE-SHUTDOWN EARTHQUAKE – REACTOR
PRESSURE VESSEL 14.0 FT ABOVE REACTOR
PRESSURE VESSEL INVERT – EAST-WEST
COMPONENT

SARGENT & LUNDY REPORT NO. SL-2682

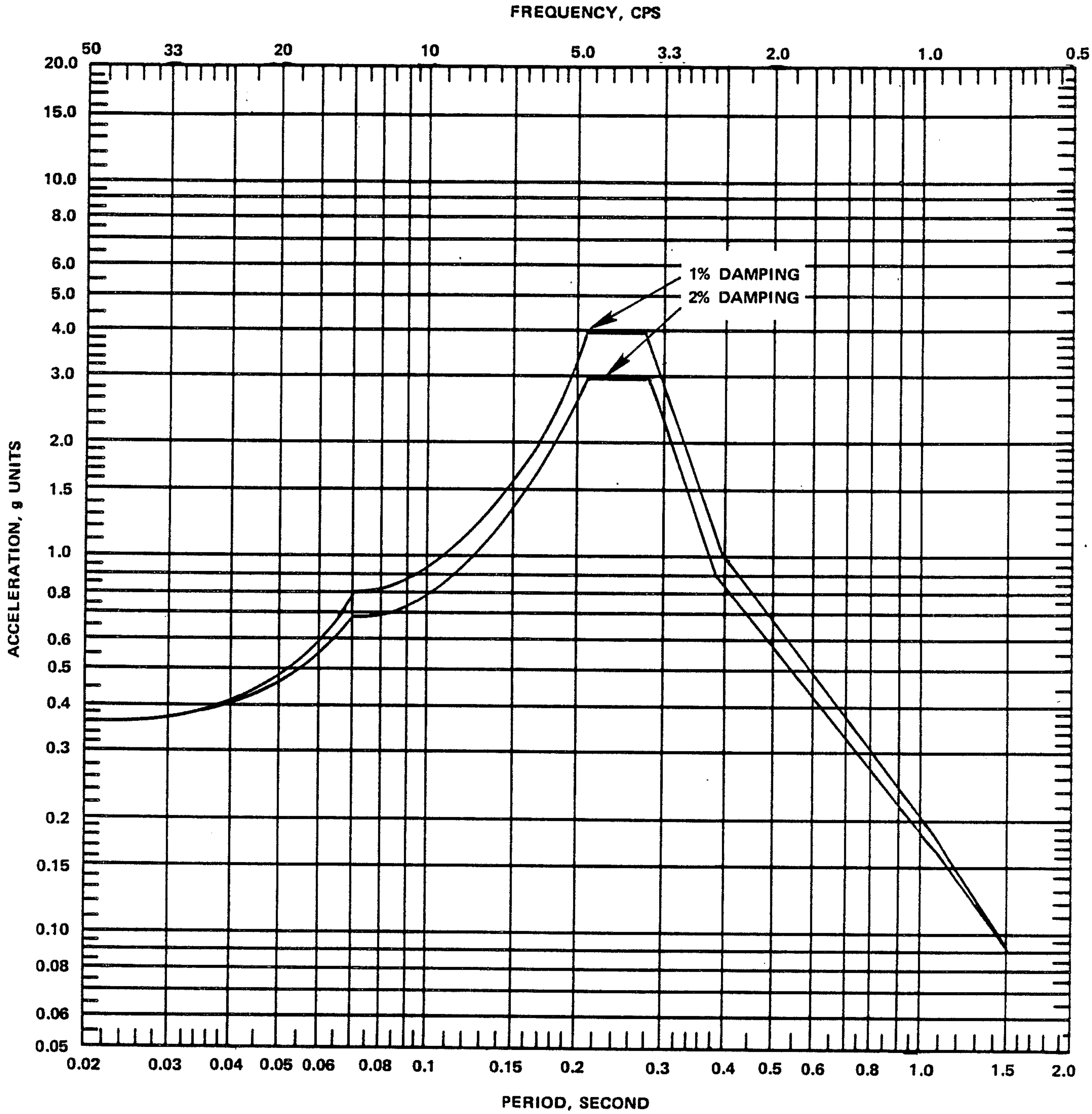

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FIGURE 3.7-78

HORIZONTAL RESPONSE SPECTRA
SAFE-SHUTDOWN EARTHQUAKE – REACTOR
PRESSURE VESSEL 54.0 FT ABOVE REACTOR
PRESSURE VESSEL INVERT – NORTH-SOUTH
COMPONENT

SARGENT & LUNDY REPORT NO. SL-2682

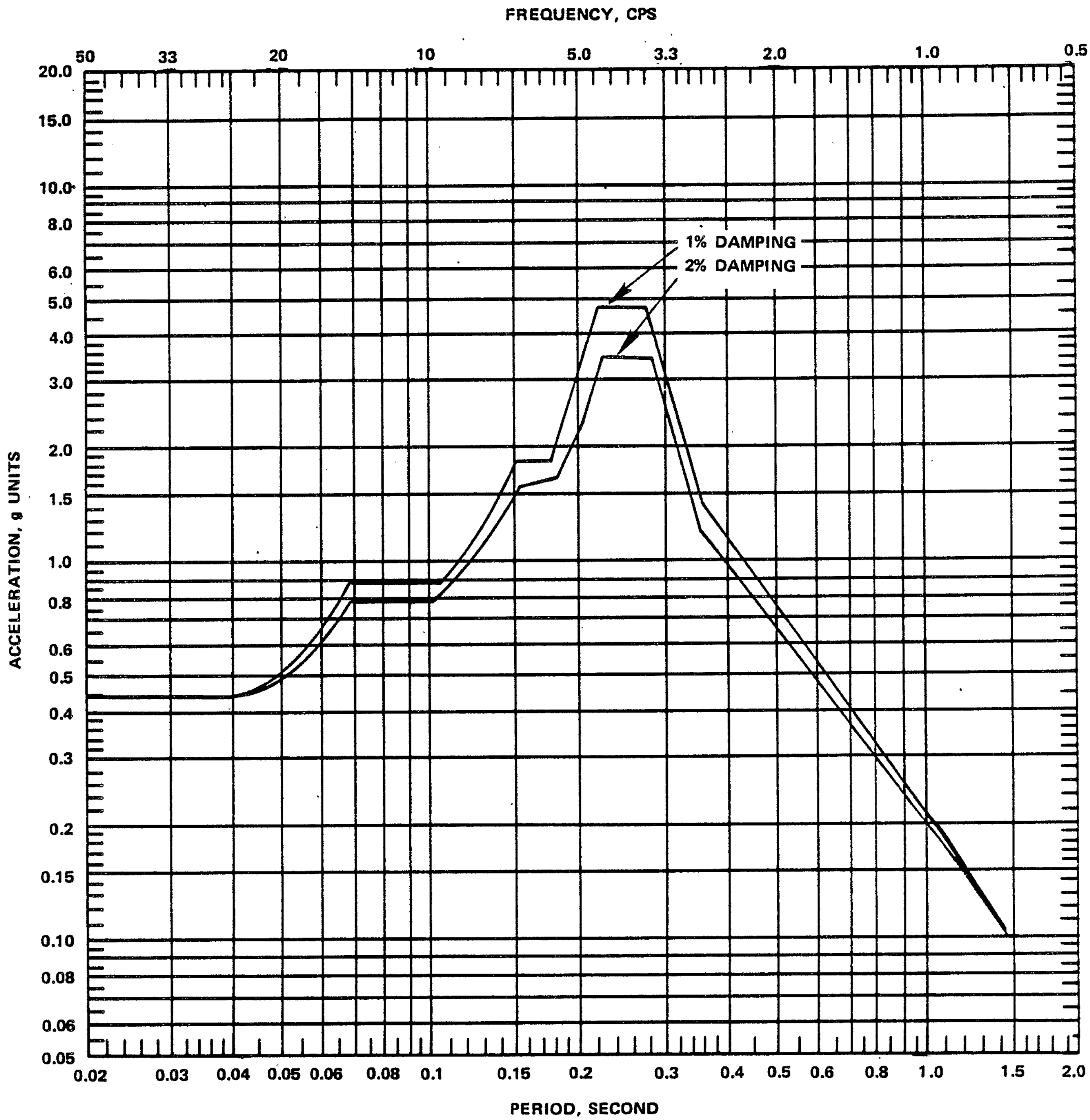

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FIGURE 3.7-79

HORIZONTAL RESPONSE SPECTRA SAFE-SHUTDOWN EARTHQUAKE – REACTOR PRESSURE VESSEL 54.0 FT ABOVE REACTOR PRESSURE VESSEL INVERT – EAST-WEST COMPONENT

SARGENT & LUNDY REPORT NO. SL-2682

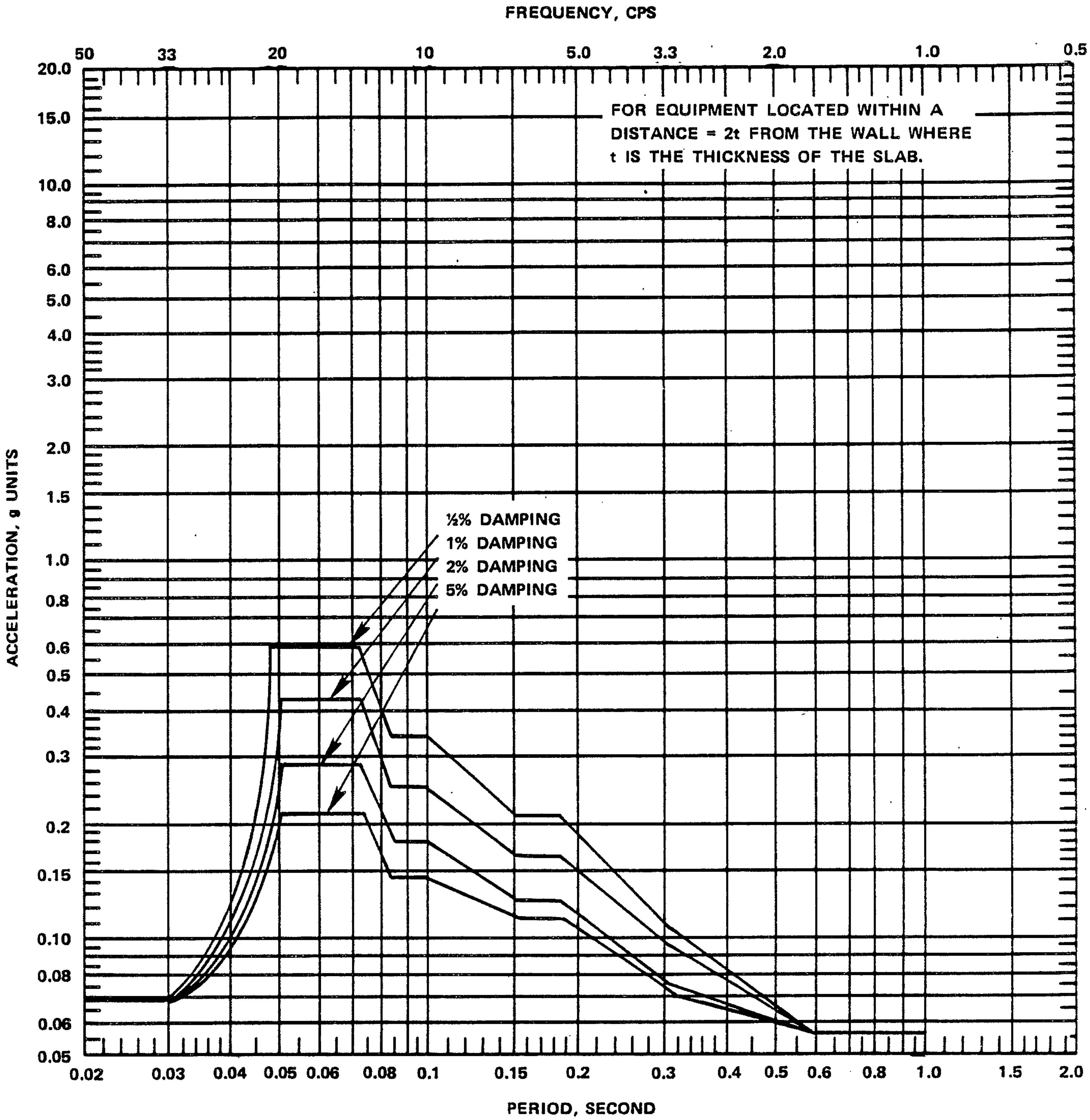

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FIGURE 3.7-80

VERTICAL RESPONSE SPECTRA
OPERATING-BASIS EARTHQUAKE
REACTOR CONTAINMENT SHIELD
ELEVATIONS 583.5 FT AND 613.5 FT

SARGENT & LUNDY REPORT NO. SL-2682

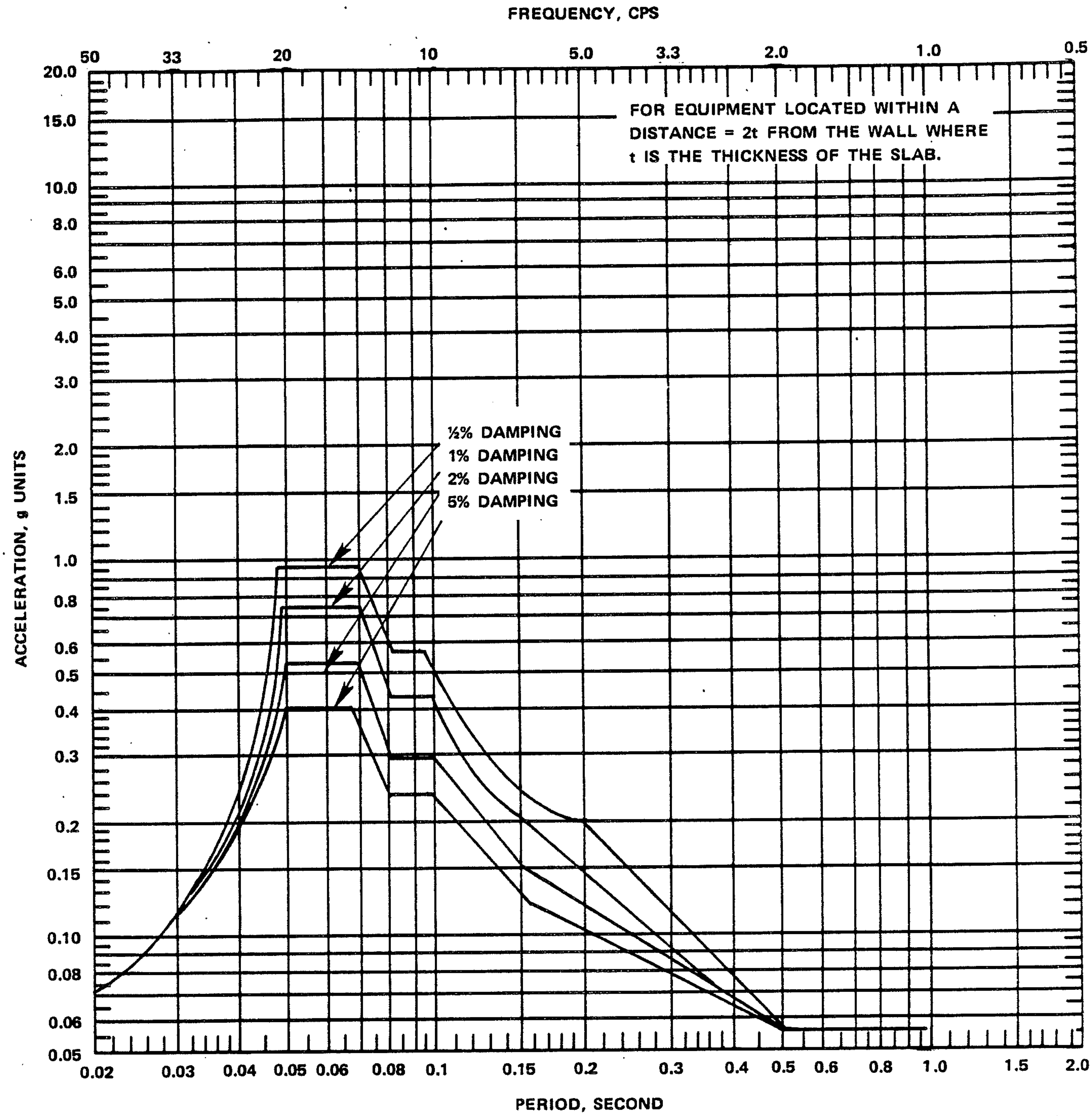

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FIGURE 3.7-81

VERTICAL RESPONSE SPECTRA
OPERATING-BASIS EARTHQUAKE
REACTOR CONTAINMENT SHIELD
ELEVATIONS 643.5 FT, 659.5 FT, AND 684.5 FT

SARGENT & LUNDY REPORT NO. SL-2682

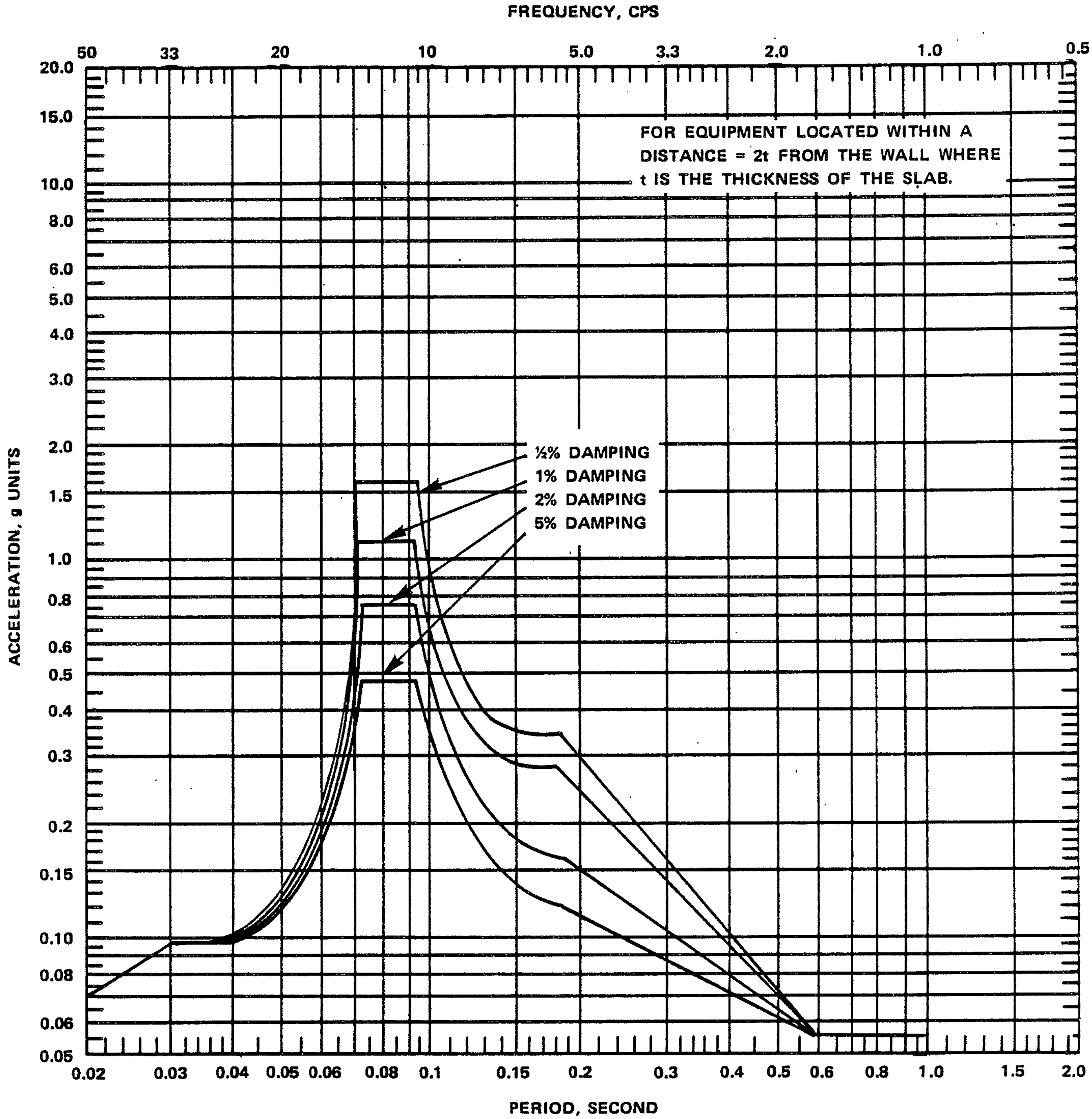

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FIGURE 3.7-82

VERTICAL RESPONSE SPECTRA
OPERATING-BASIS EARTHQUAKE
REACTOR/AUXILIARY BUILDING WALL
ELEVATIONS 583.5 FT AND 613.5 FT

SARGENT & LUNDY REPORT NO. SL-2682

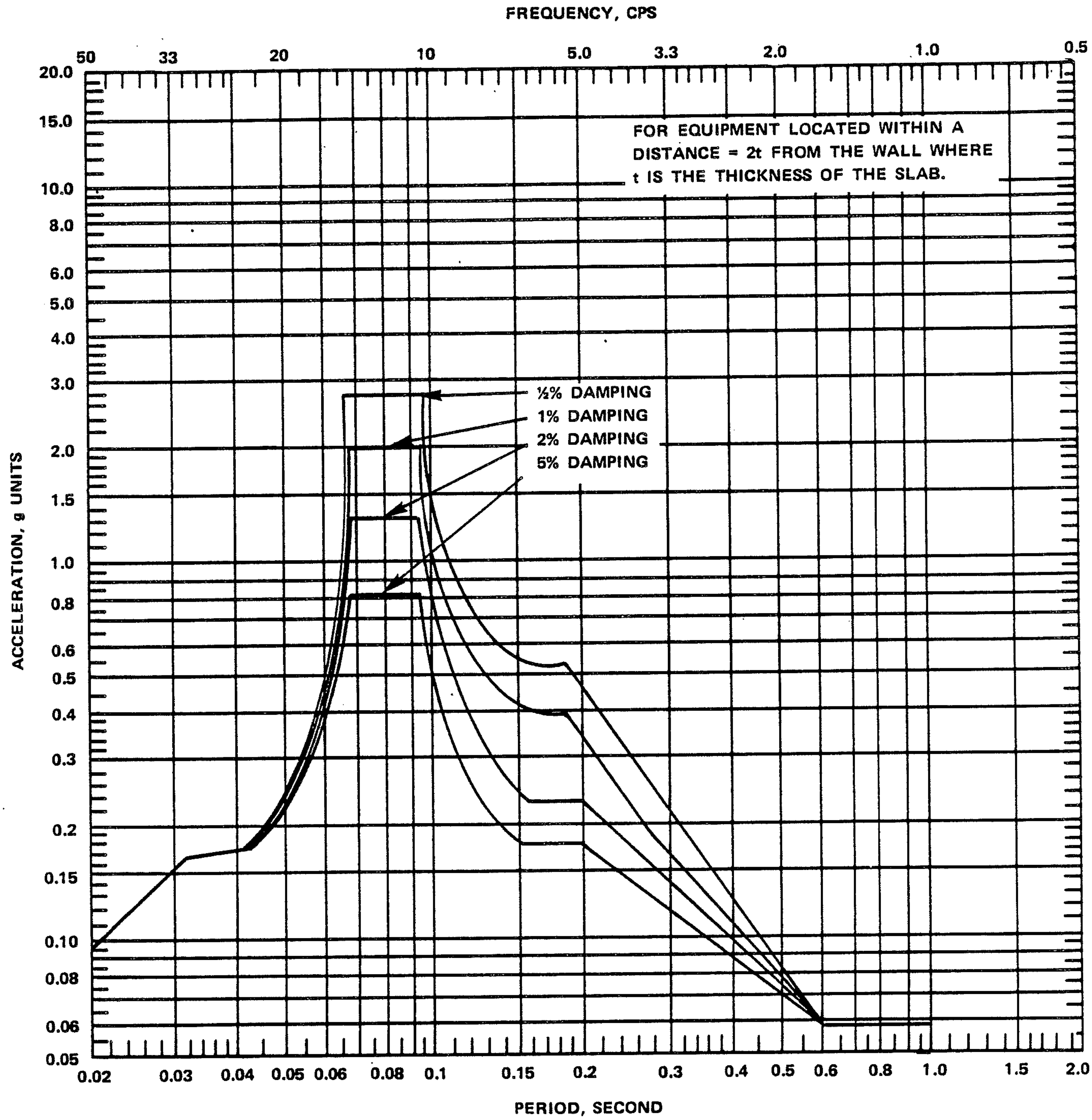

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FIGURE 3.7-83

VERTICAL RESPONSE SPECTRA
OPERATING-BASIS EARTHQUAKE
REACTOR/AUXILIARY BUILDING WALL
ELEVATIONS 641.5 FT, 659.5 FT, AND 684.5 FT

SARGENT & LUNDY REPORT NO. SL-2682

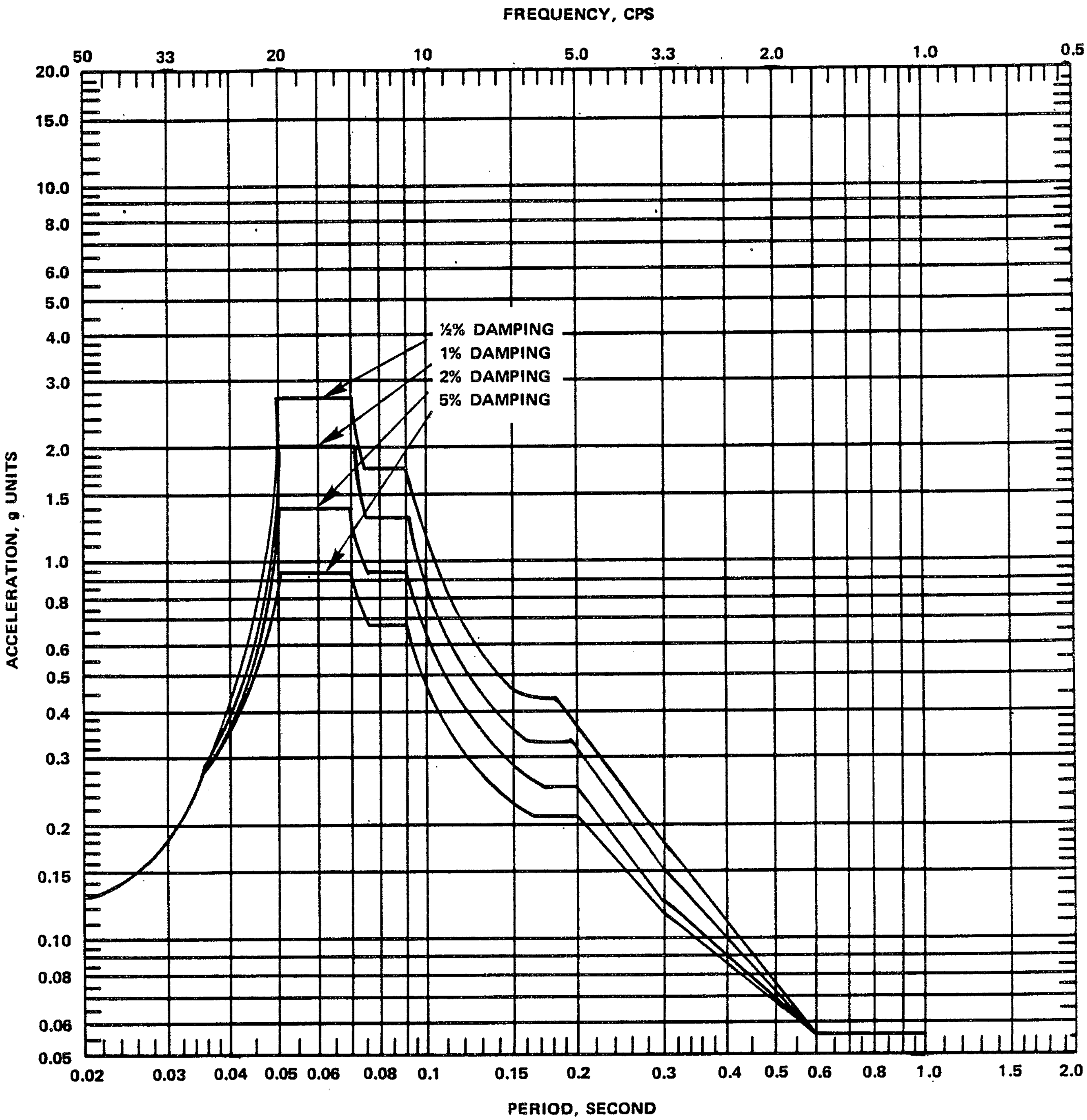

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FIGURE 3.7-84

VERTICAL RESPONSE SPECTRA
OPERATING-BASIS EARTHQUAKE
REACTOR BUILDING SLAB
ELEVATIONS 583.5 FT AND 613.5 FT

SARGENT & LUNDY REPORT NO. SL-2682

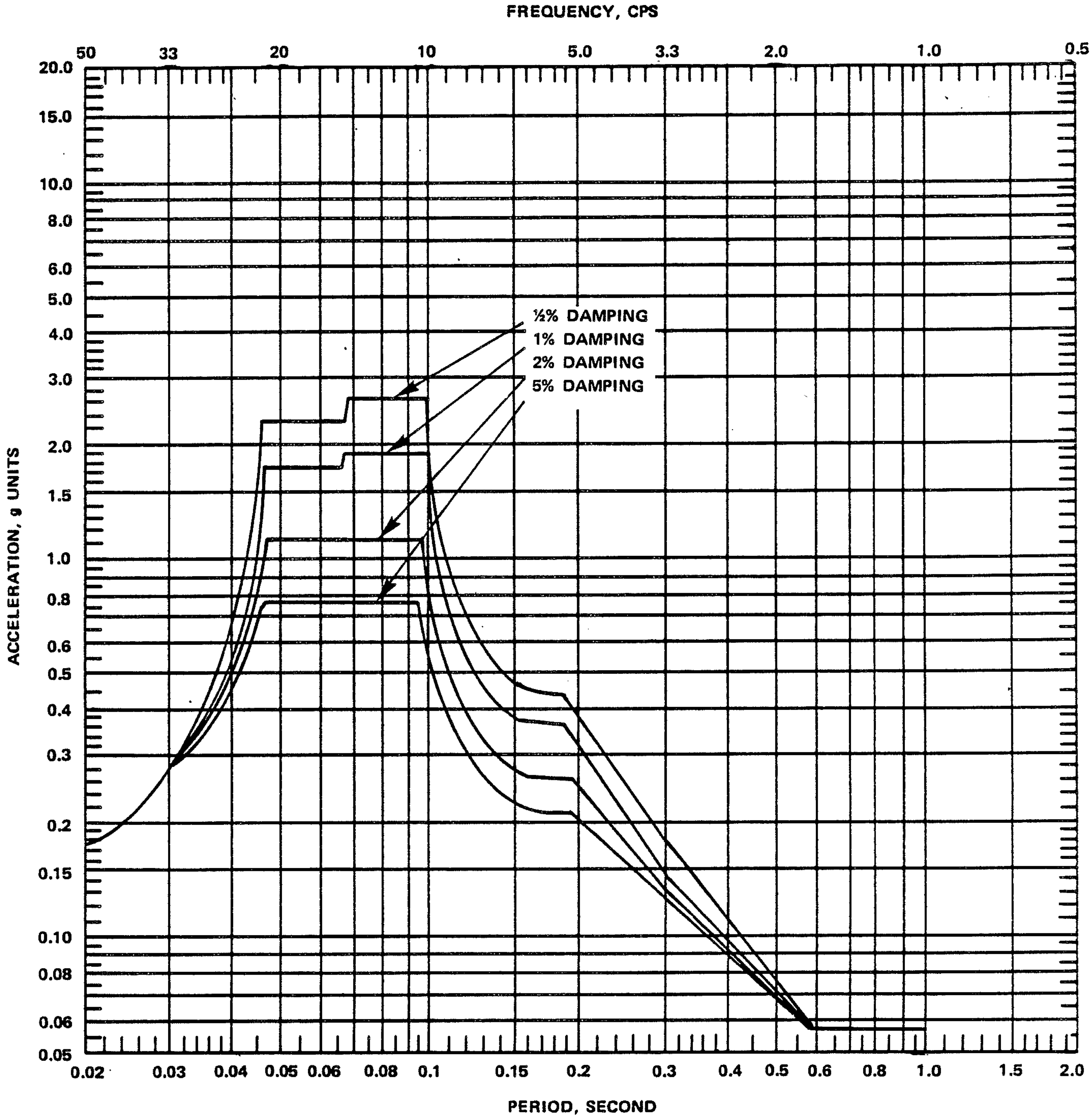

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FIGURE 3.7-85

VERTICAL RESPONSE SPECTRA
OPERATING-BASIS EARTHQUAKE
REACTOR BUILDING SLAB
ELEVATIONS 641.5 FT, 659.5 FT, AND 684.5 FT

SARGENT & LUNDY REPORT NO. SL-2682

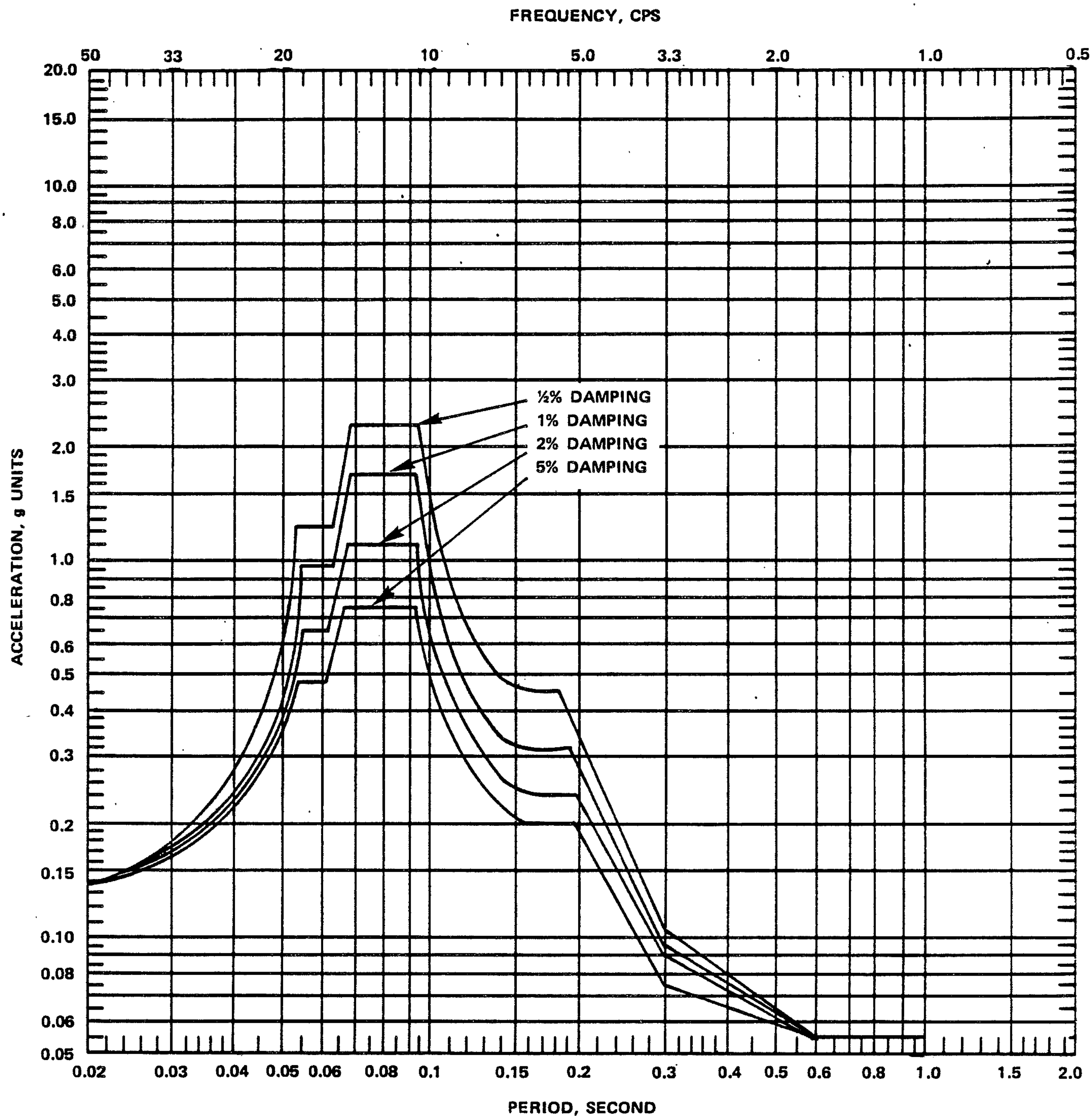

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FIGURE 3.7-86

VERTICAL RESPONSE SPECTRA
OPERATING-BASIS EARTHQUAKE
AUXILIARY BUILDING SLAB
ELEVATIONS 583.5 FT, 613.5 FT, AND 659.5 FT

SARGENT & LUNDY REPORT NO. SL-2682

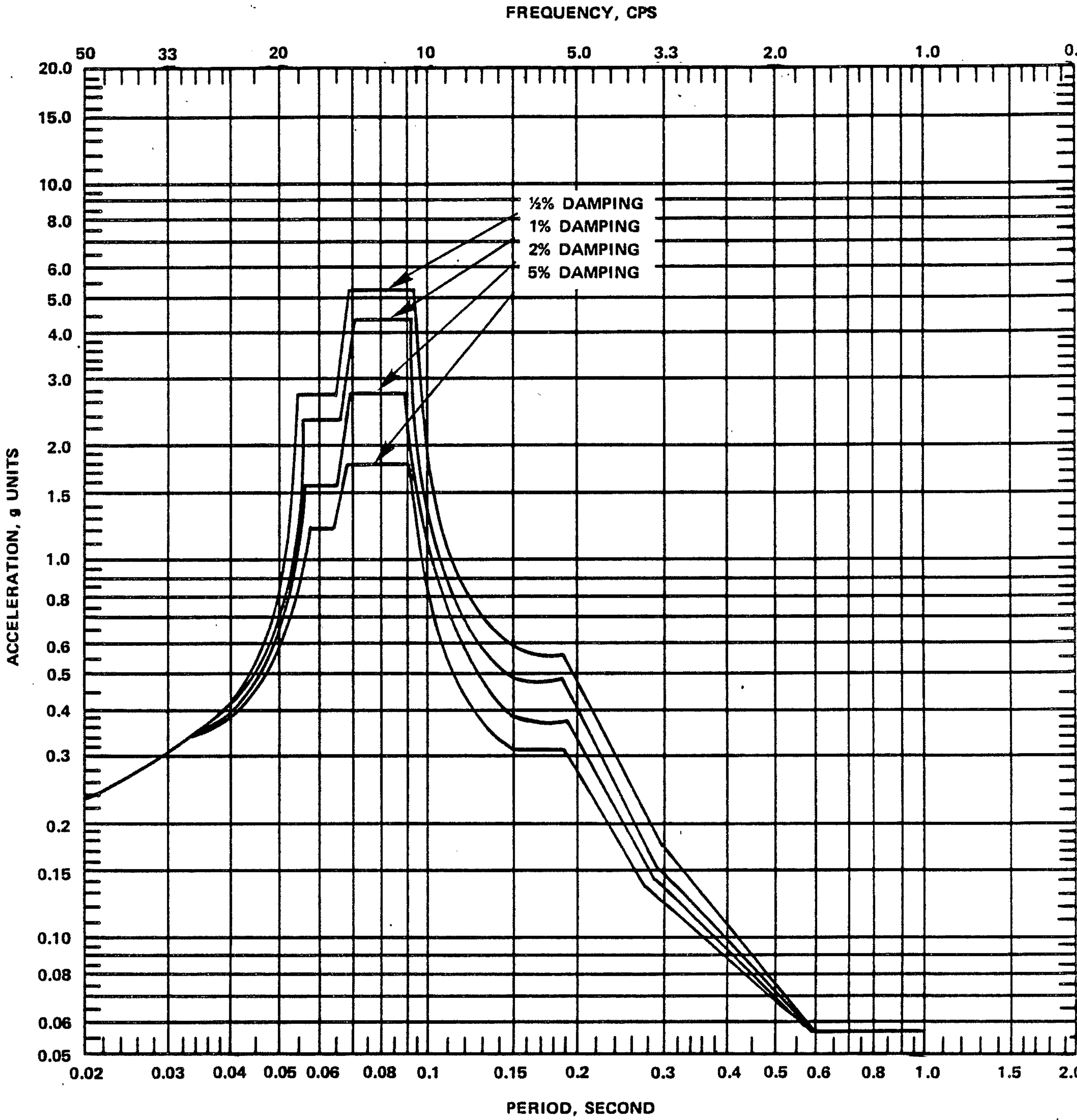

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FIGURE 3.7–87

VERTICAL RESPONSE SPECTRA
OPERATING-BASIS EARTHQUAKE
AUXILIARY BUILDING SLAB
ELEVATIONS 643.5 FT AND 677.5 FT

SARGENT & LUNDY REPORT NO. SL–2682

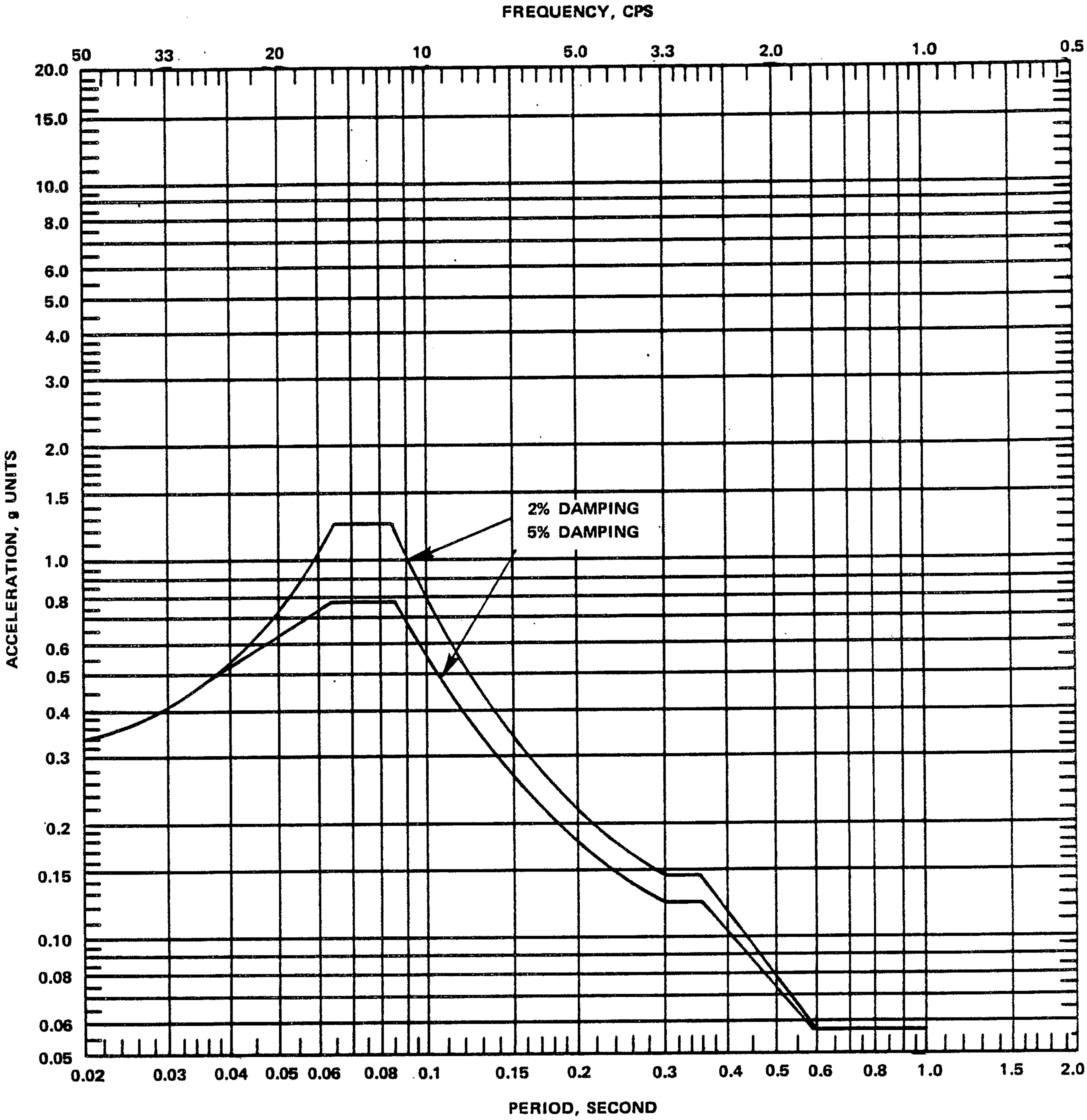

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FIGURE 3.7-88

VERTICAL RESPONSE SPECTRA
OPERATING-BASIS EARTHQUAKE
REACTOR/AUXILIARY BUILDING
CRANE RAIL ELEVATION

SARGENT & LUNDY REPORT NO. SL-2682

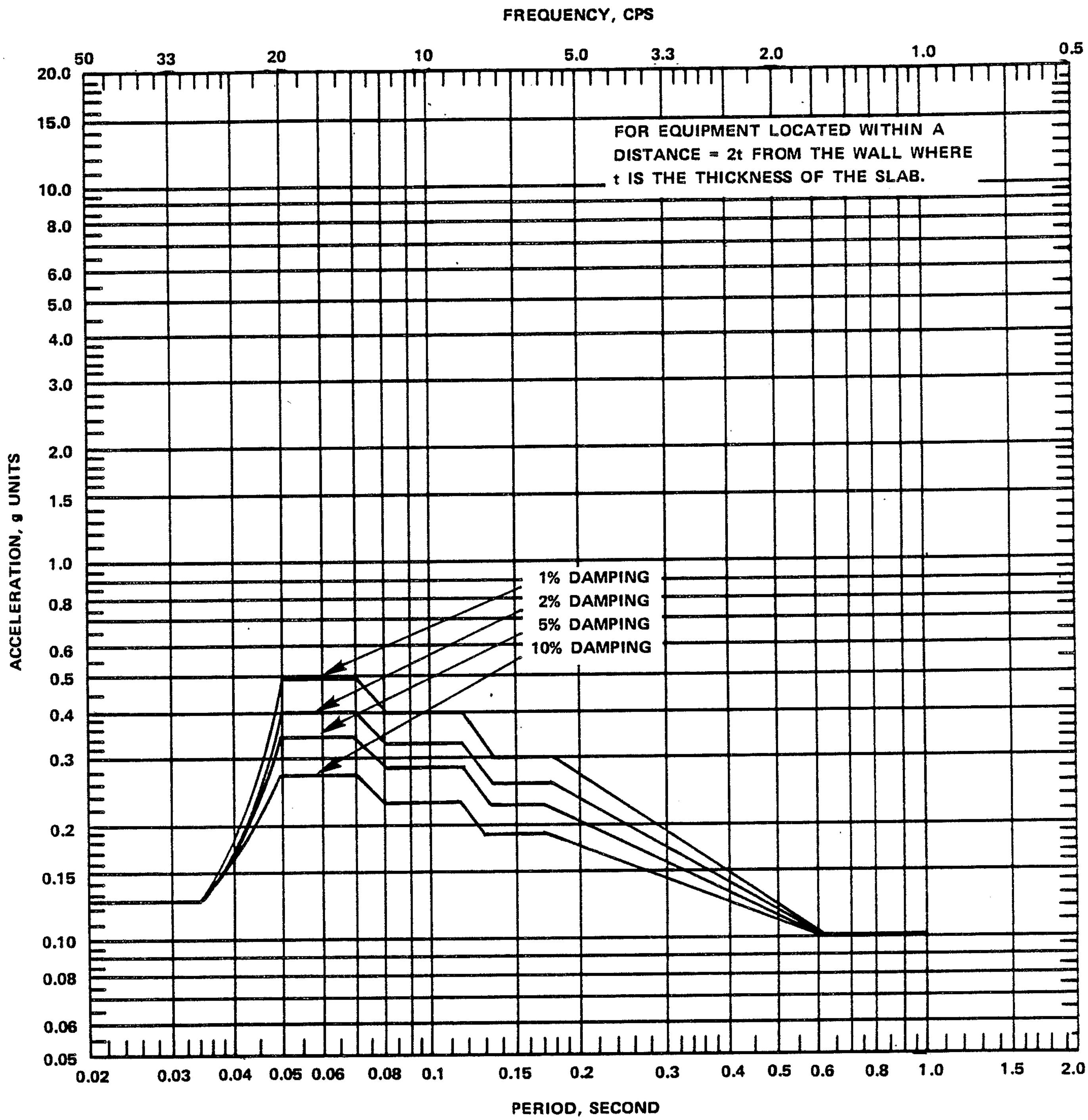

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FIGURE 3.7-89

VERTICAL RESPONSE SPECTRA
SAFE-SHUTDOWN EARTHQUAKE
REACTOR CONTAINMENT SHIELD
ELEVATIONS 583.5 FT AND 613.5 FT

SARGENT & LUNDY REPORT NO. SL-2682

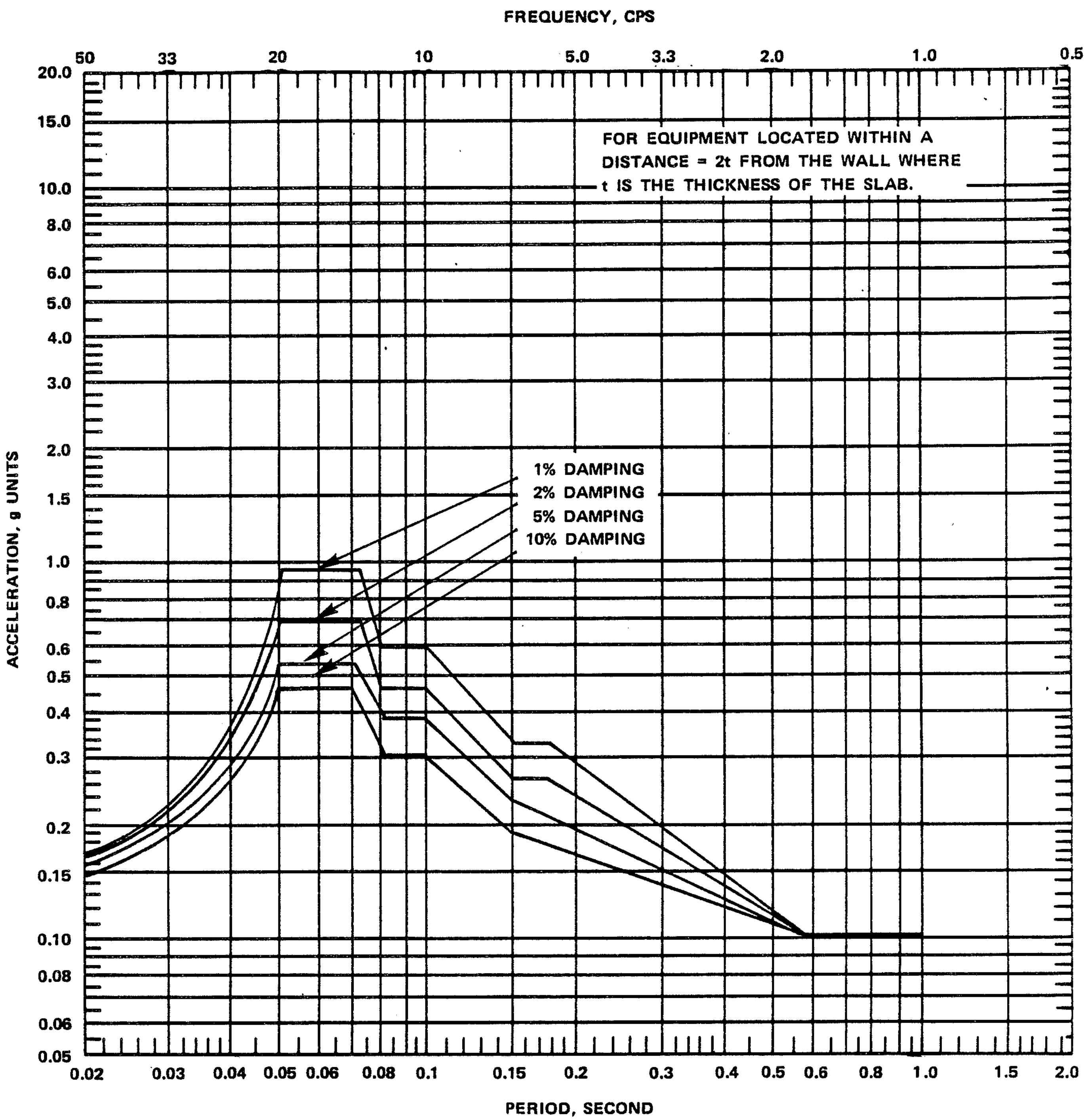

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FIGURE 3.7-90

VERTICAL RESPONSE SPECTRA
SAFE-SHUTDOWN EARTHQUAKE
REACTOR CONTAINMENT SHIELD
ELEVATIONS 643.5 FT, 659.5 FT, AND 684.5 FT

SARGENT & LUNDY REPORT NO. SL-2682

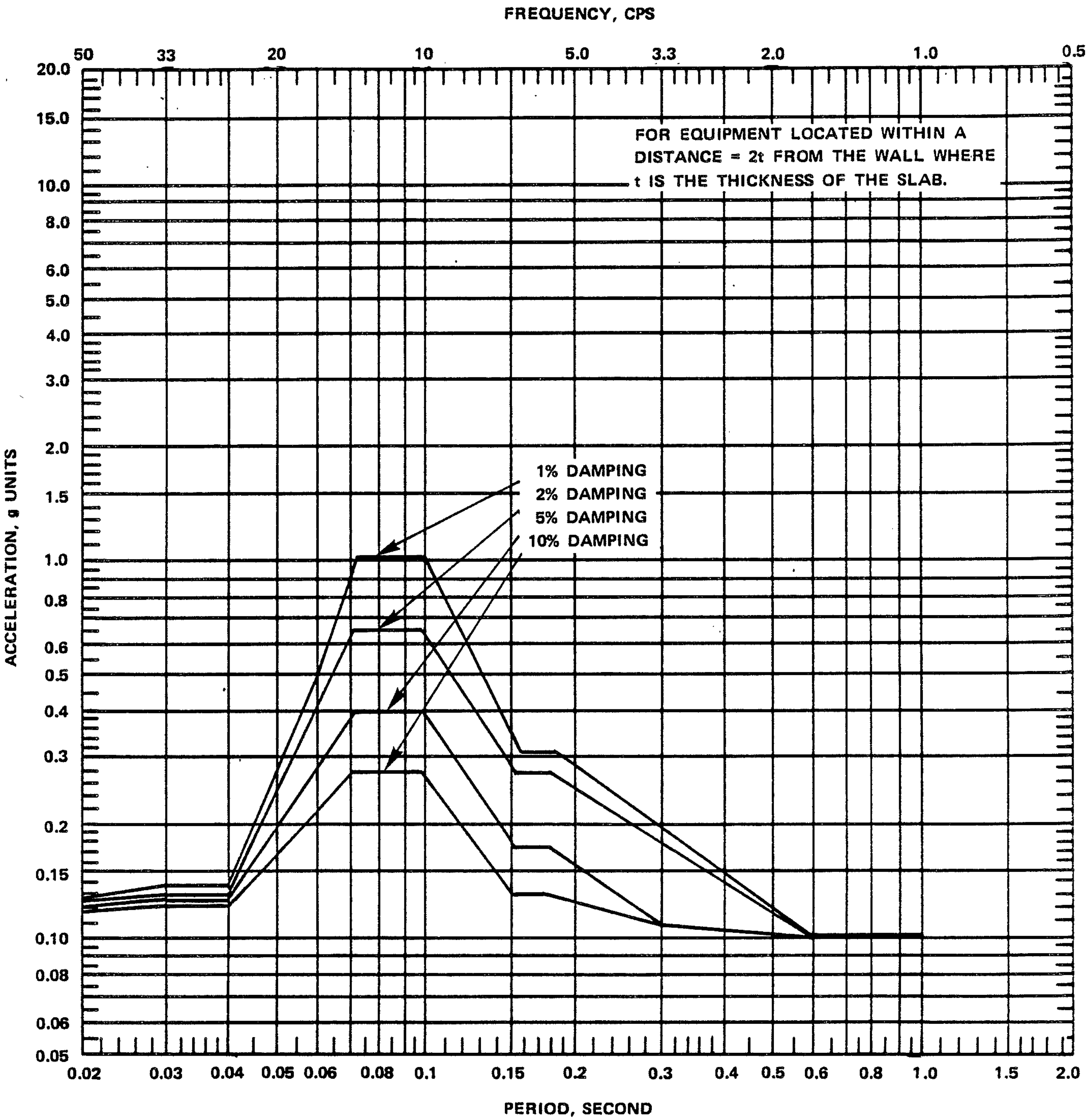

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FIGURE 3.7-91

VERTICAL RESPONSE SPECTRA
SAFE-SHUTDOWN EARTHQUAKE
REACTOR/AUXILIARY BUILDING WALL
ELEVATIONS 583.5 FT AND 613.5 FT

SARGENT & LUNDY REPORT NO. SL-2682

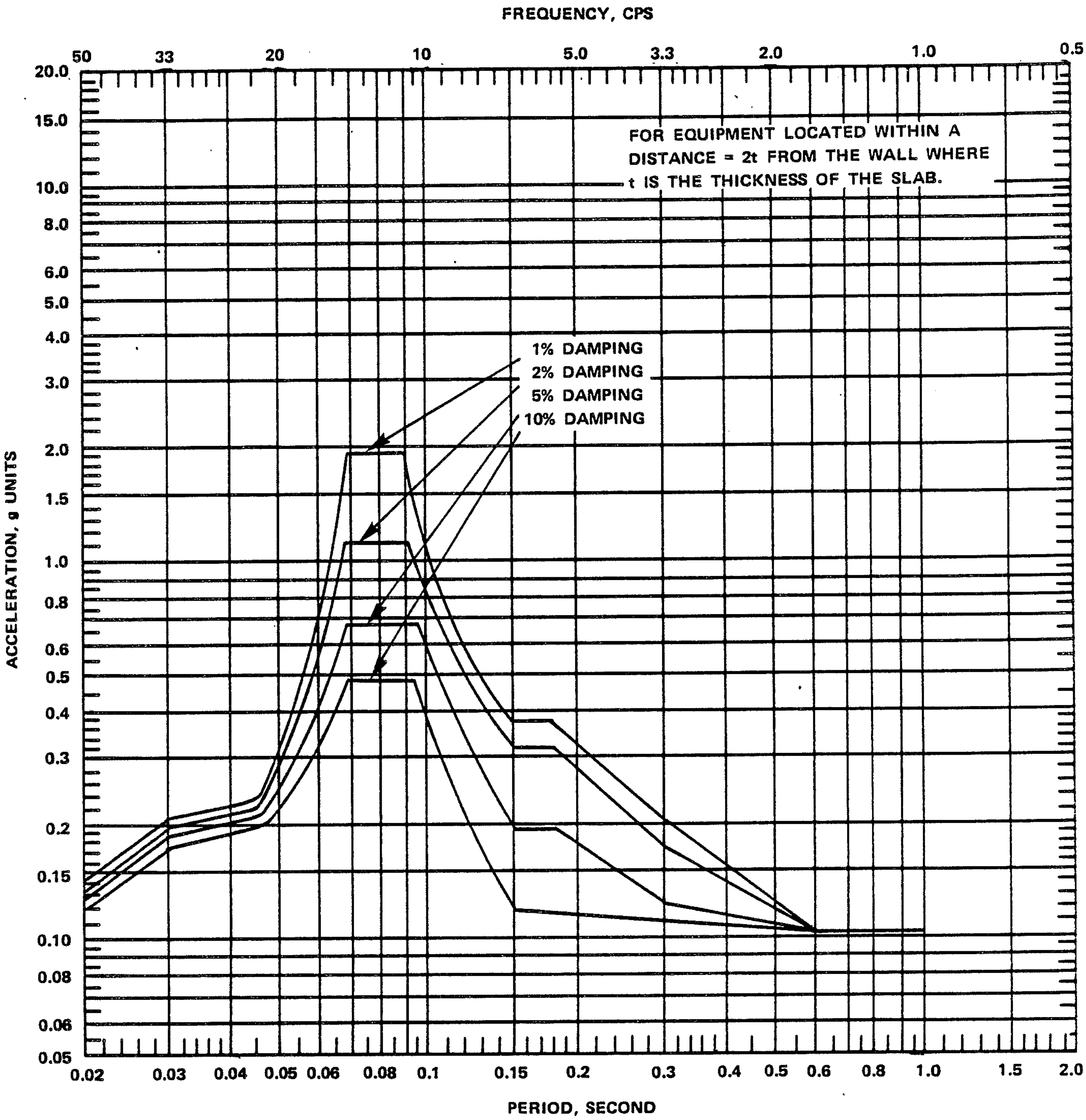

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FIGURE 3.7-92

VERTICAL RESPONSE SPECTRA
SAFE-SHUTDOWN EARTHQUAKE
REACTOR/AUXILIARY BUILDING WALL
ELEVATIONS 641.5 FT, 659.5 FT, AND 684.5 FT

SARGENT & LUNDY REPORT NO. SL-2682

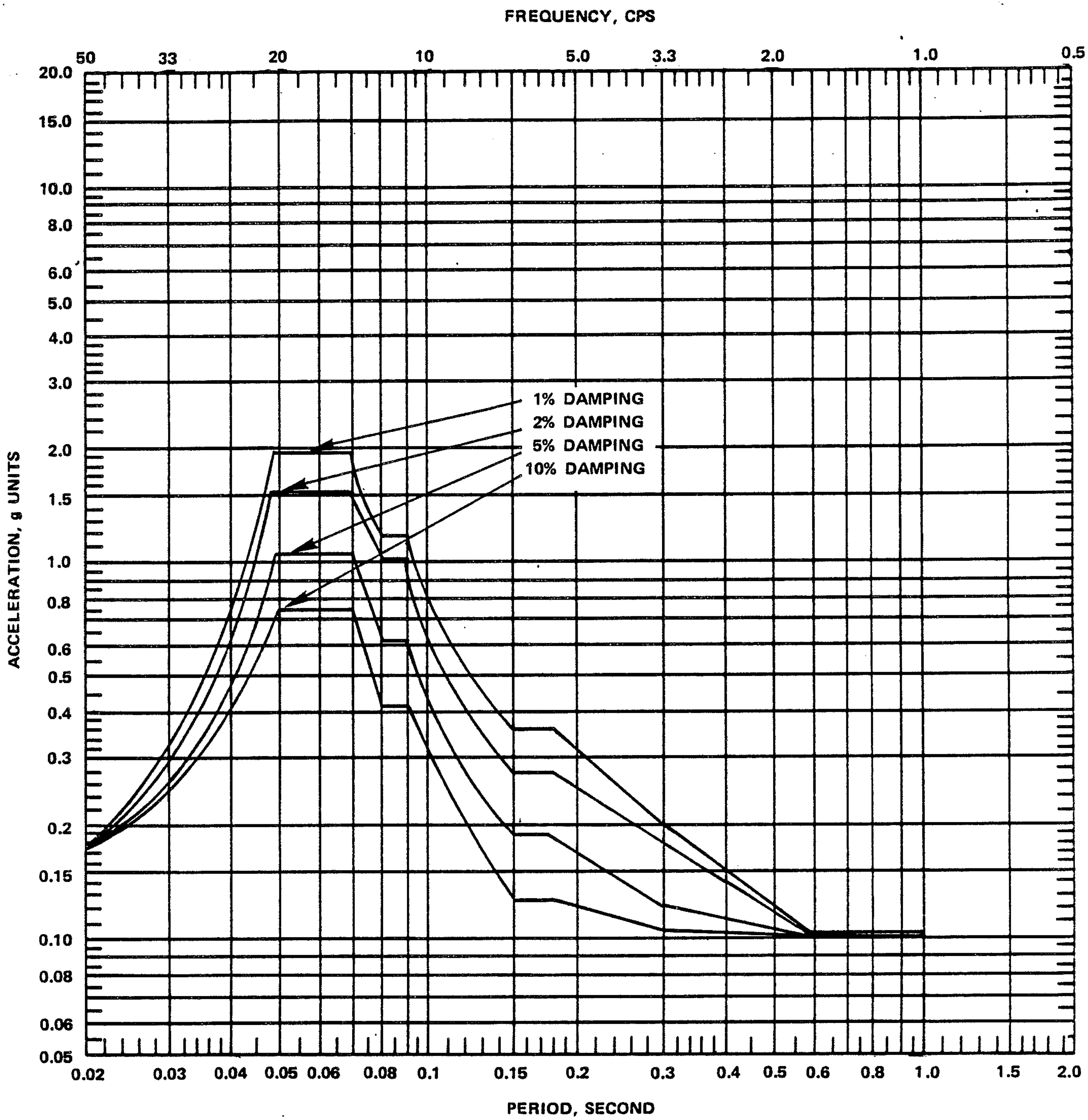

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FIGURE 3.7-93

VERTICAL RESPONSE SPECTRA
SAFE-SHUTDOWN EARTHQUAKE
REACTOR BUILDING SLAB
ELEVATIONS 583.5 FT AND 613.5 FT

SARGENT & LUNDY REPORT NO. SL-2682

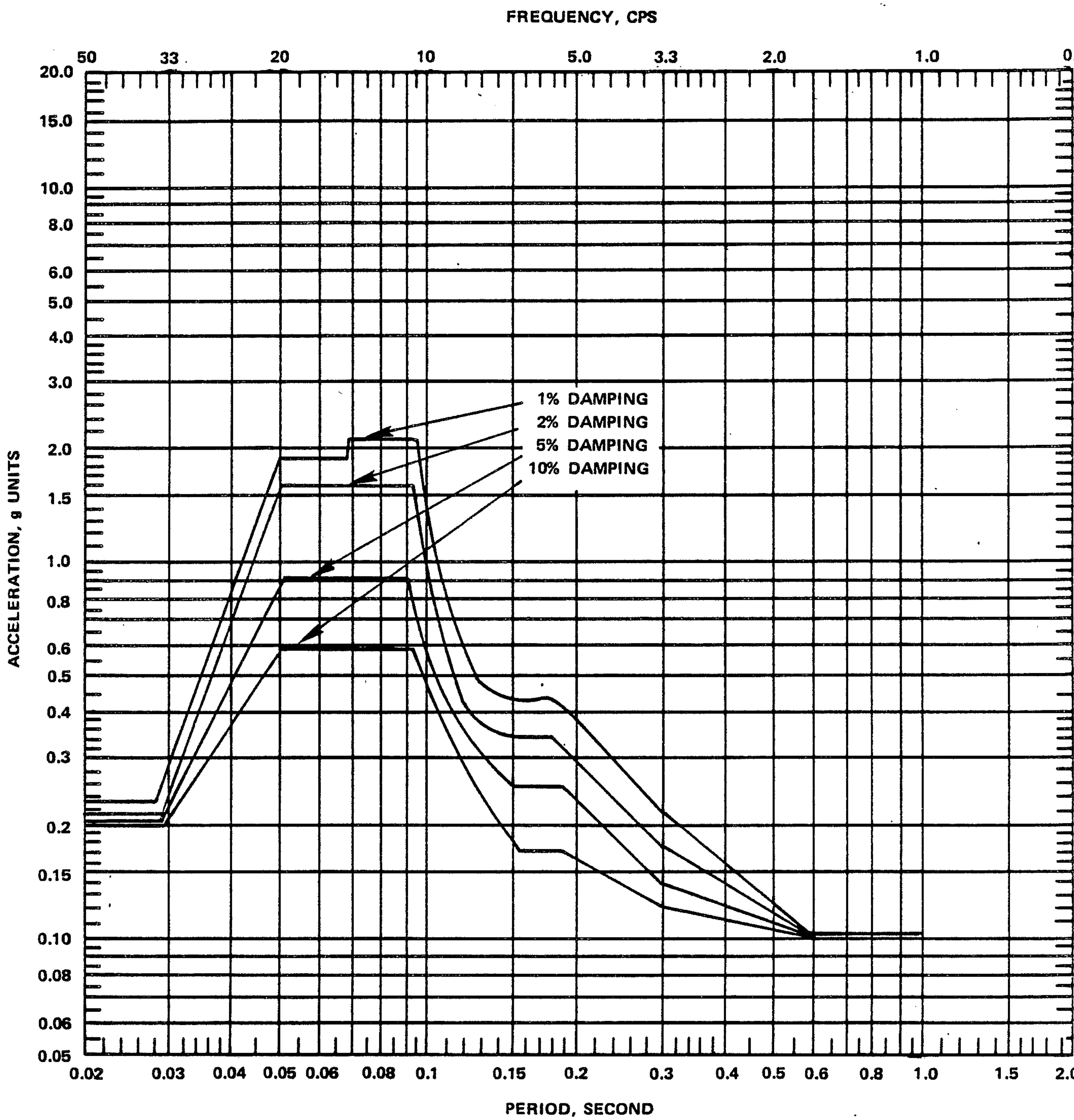

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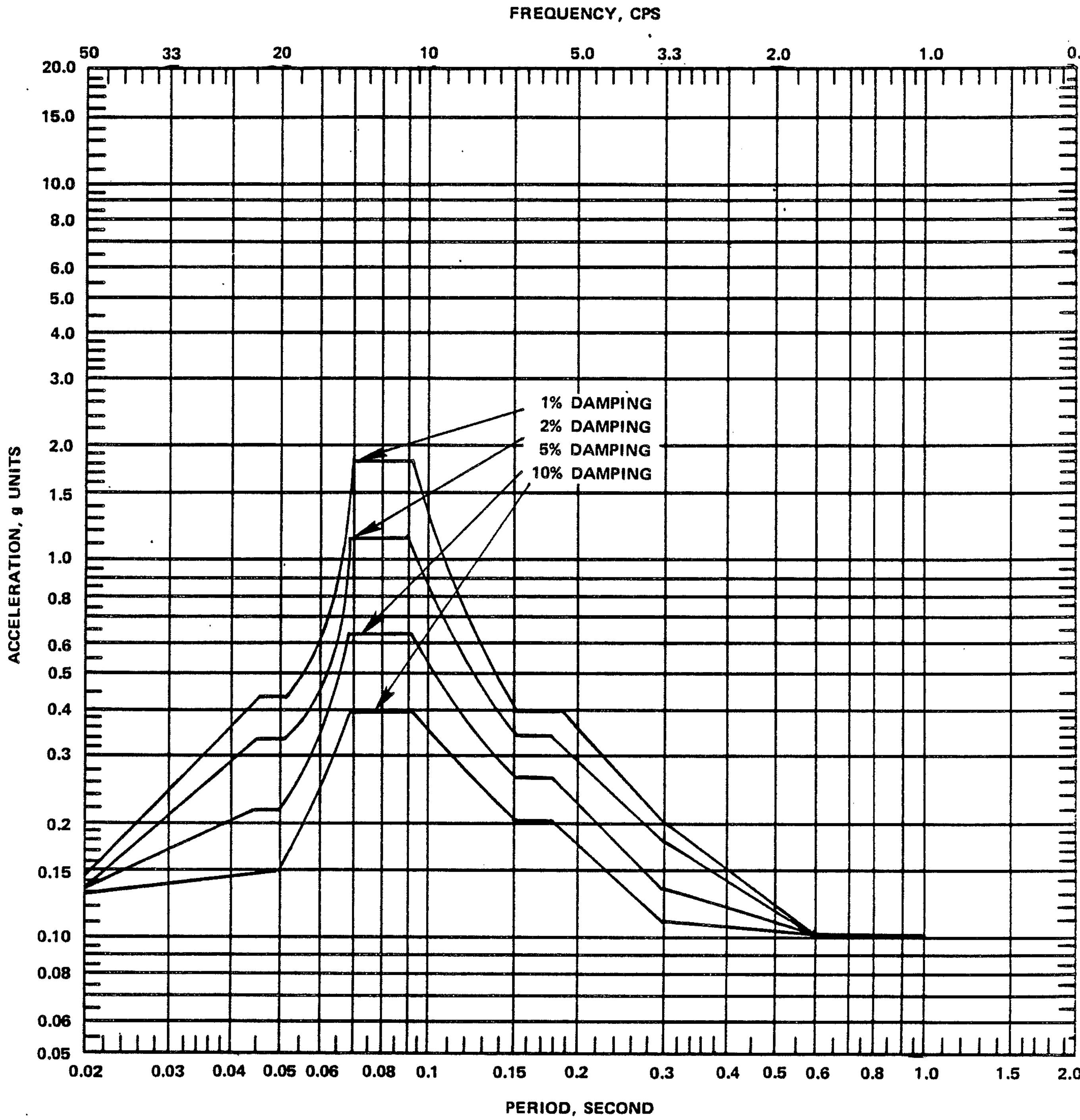
FIGURE 3.7-94

VERTICAL RESPONSE SPECTRA
SAFE-SHUTDOWN EARTHQUAKE
REACTOR BUILDING SLAB
ELEVATIONS 641.5 FT, 659.5 FT, AND 684.5 FT

SARGENT & LUNDY REPORT NO. SL-2682



SARGENT & LUNDY REPORT NO. SL-2682

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FIGURE 3.7-95

VERTICAL RESPONSE SPECTRA
SAFE-SHUTDOWN EARTHQUAKE
AUXILIARY BUILDING SLAB
ELEVATIONS 583.5 FT, 613.5 FT, AND 659.5 FT

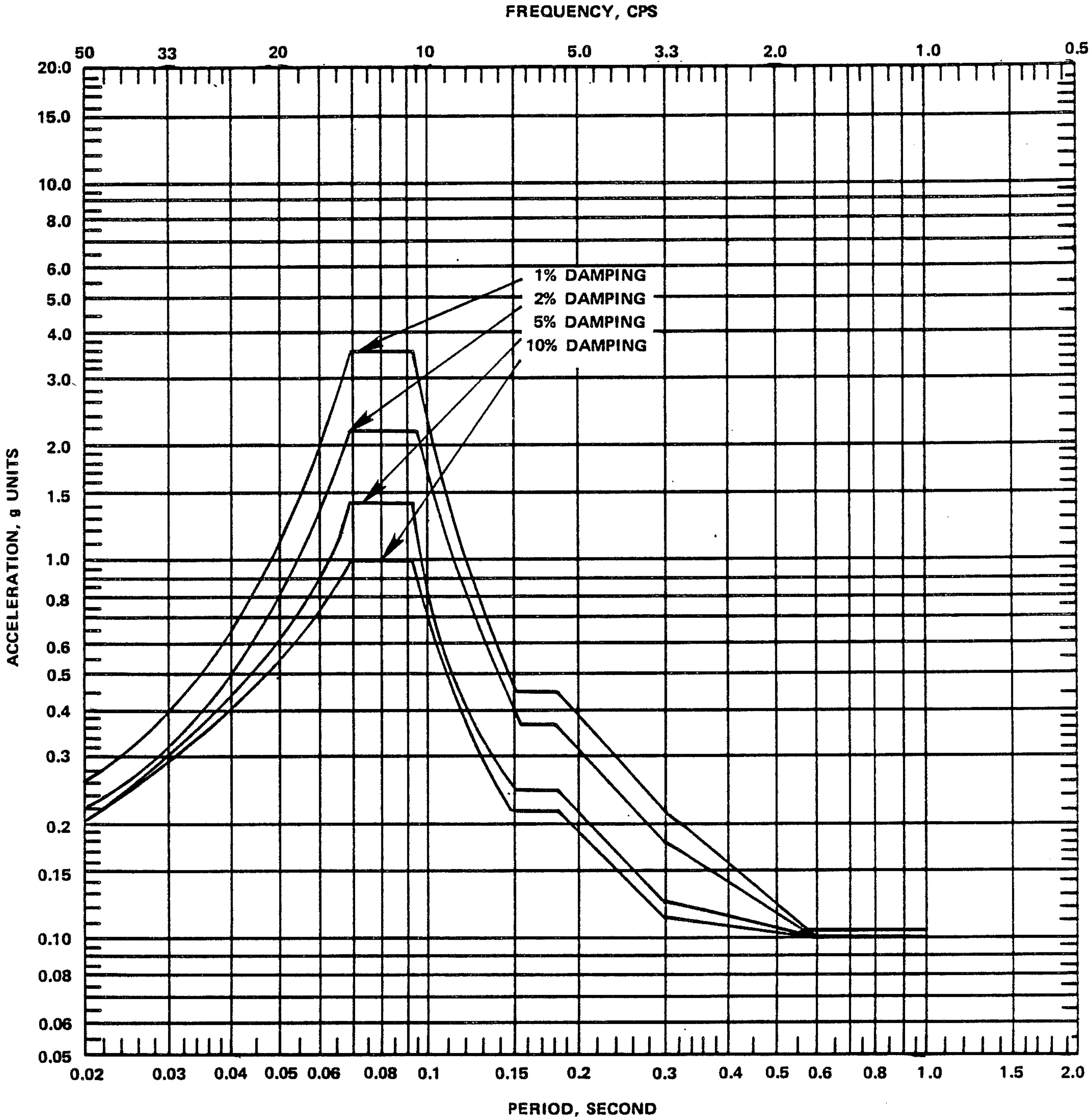

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FIGURE 3.7-96

VERTICAL RESPONSE SPECTRA
SAFE-SHUTDOWN EARTHQUAKE
AUXILIARY BUILDING SLAB
ELEVATIONS 643.5 FT AND 677.5 FT

SARGENT & LUNDY REPORT NO. SL-2682

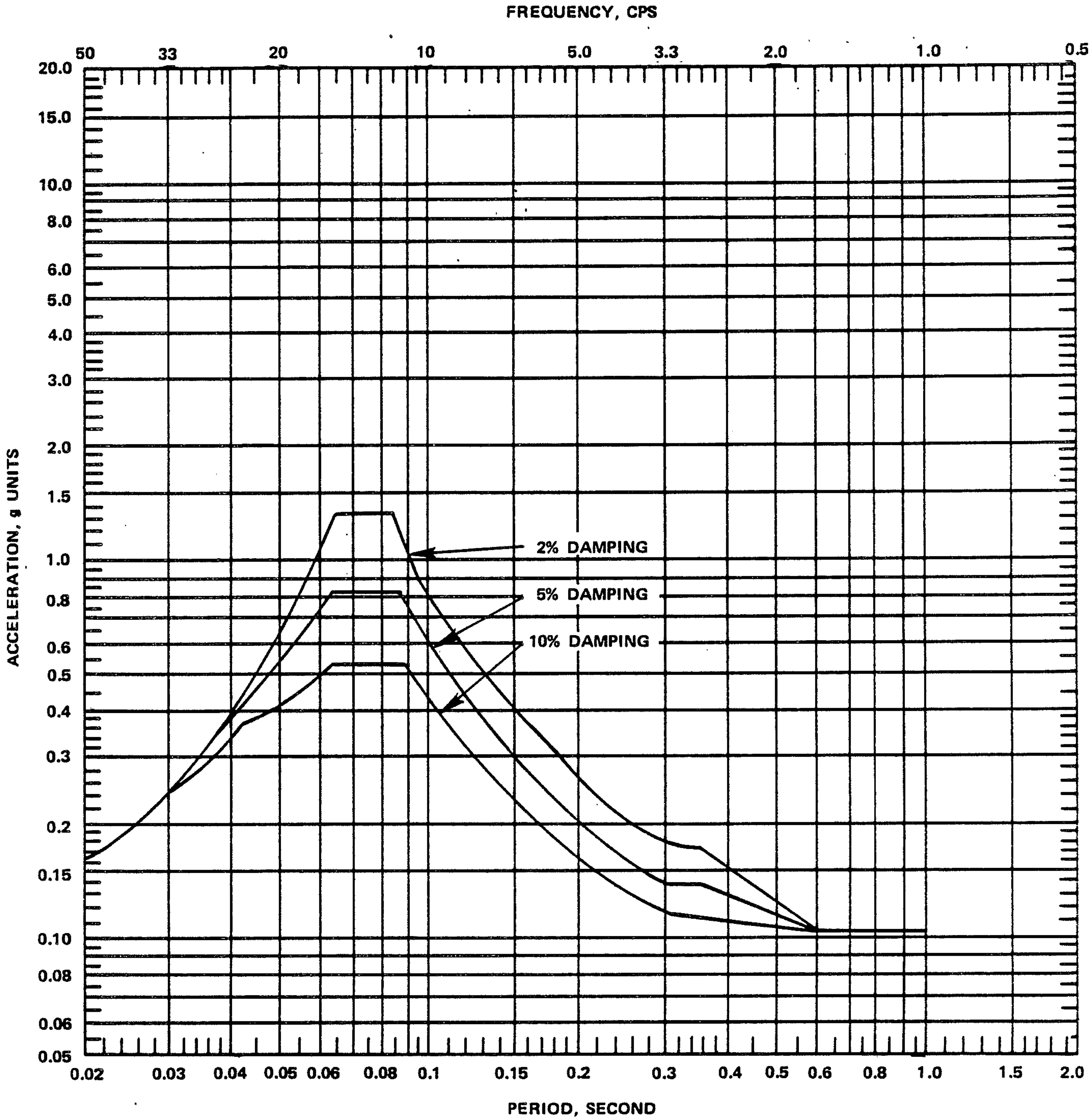

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FIGURE 3.7-97

VERTICAL RESPONSE SPECTRA
SAFE-SHUTDOWN EARTHQUAKE
REACTOR/AUXILIARY BUILDING
CRANE RAIL ELEVATION

SARGENT & LUNDY REPORT NO. SL-2682

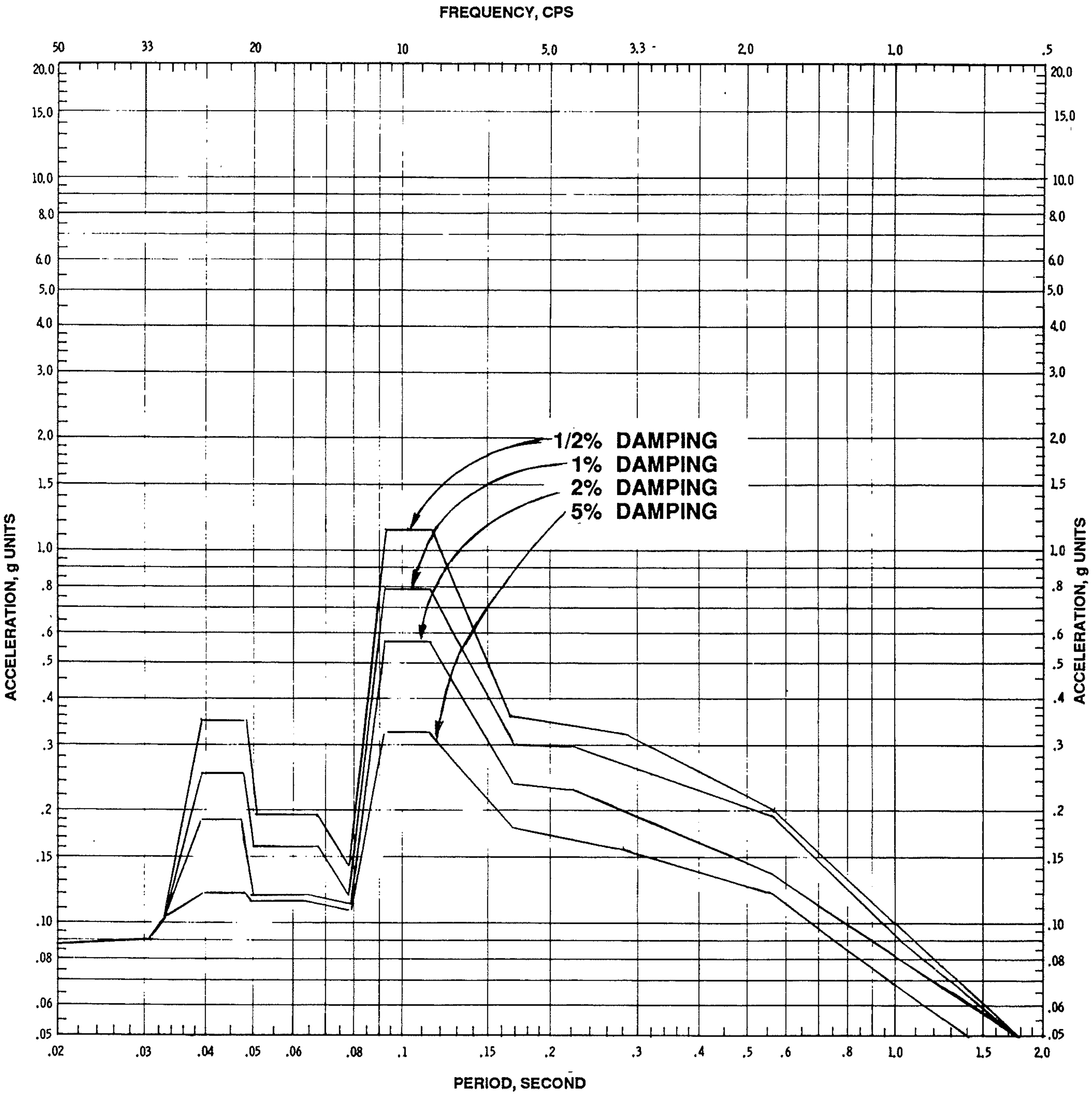

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FIGURE 3.7-98

HORIZONTAL FLOOR RESPONSE SPECTRA
OPERATING-BASIS EARTHQUAKE – RESIDUAL
HEAT REMOVAL COMPLEX – NORTH-SOUTH
COMPONENT – SLAB 1 – ELEVATION 590.0 FT

SARGENT & LUNDY REPORT NO. SL-3147

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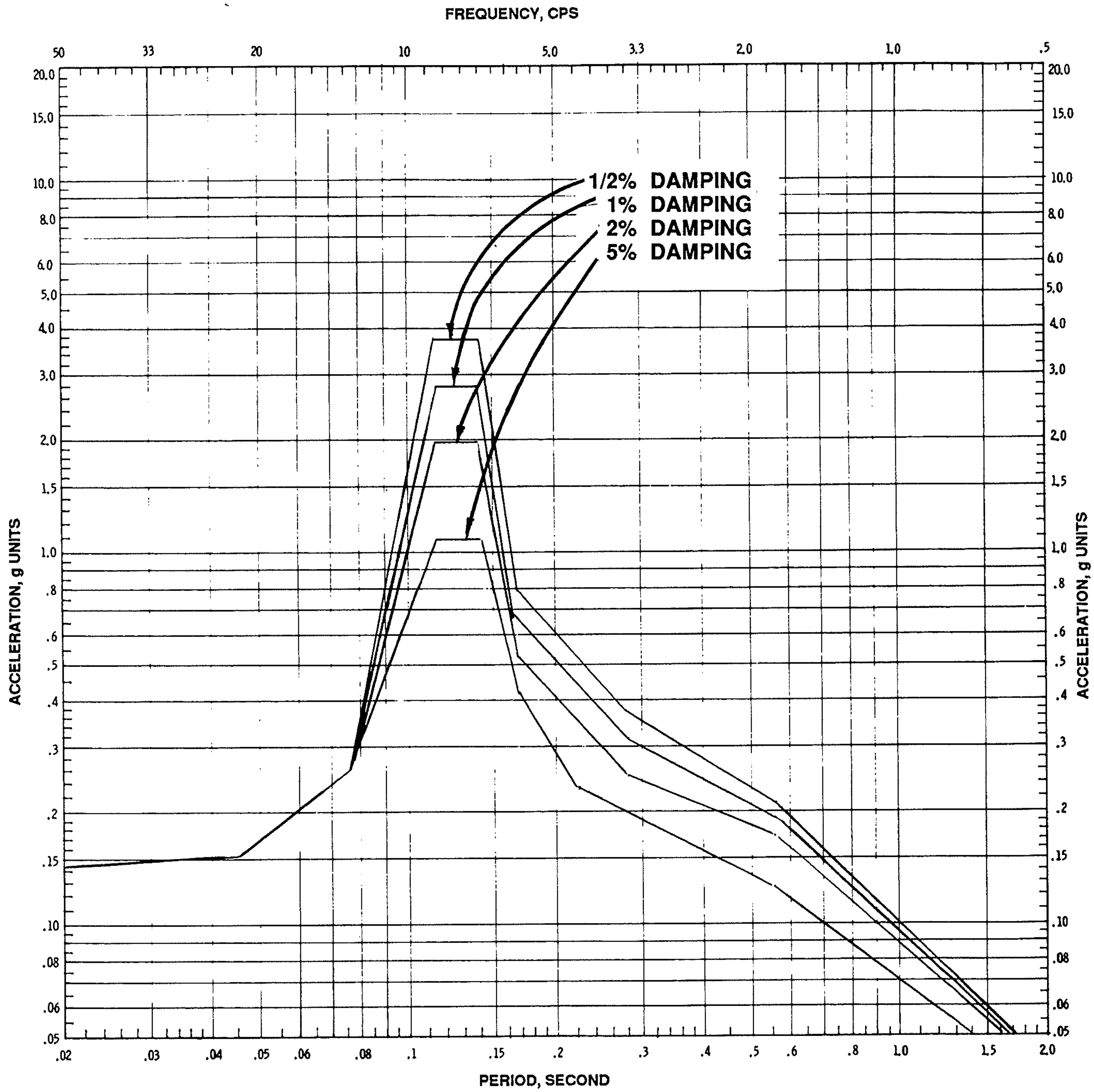

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UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 3.7-99

HORIZONTAL FLOOR RESPONSE SPECTRA OPERATING-BASIS EARTHQUAKE – RESIDUAL HEAT REMOVAL COMPLEX – EAST-WEST COMPONENT – SLAB 1 – ELEVATION 590.0 FT

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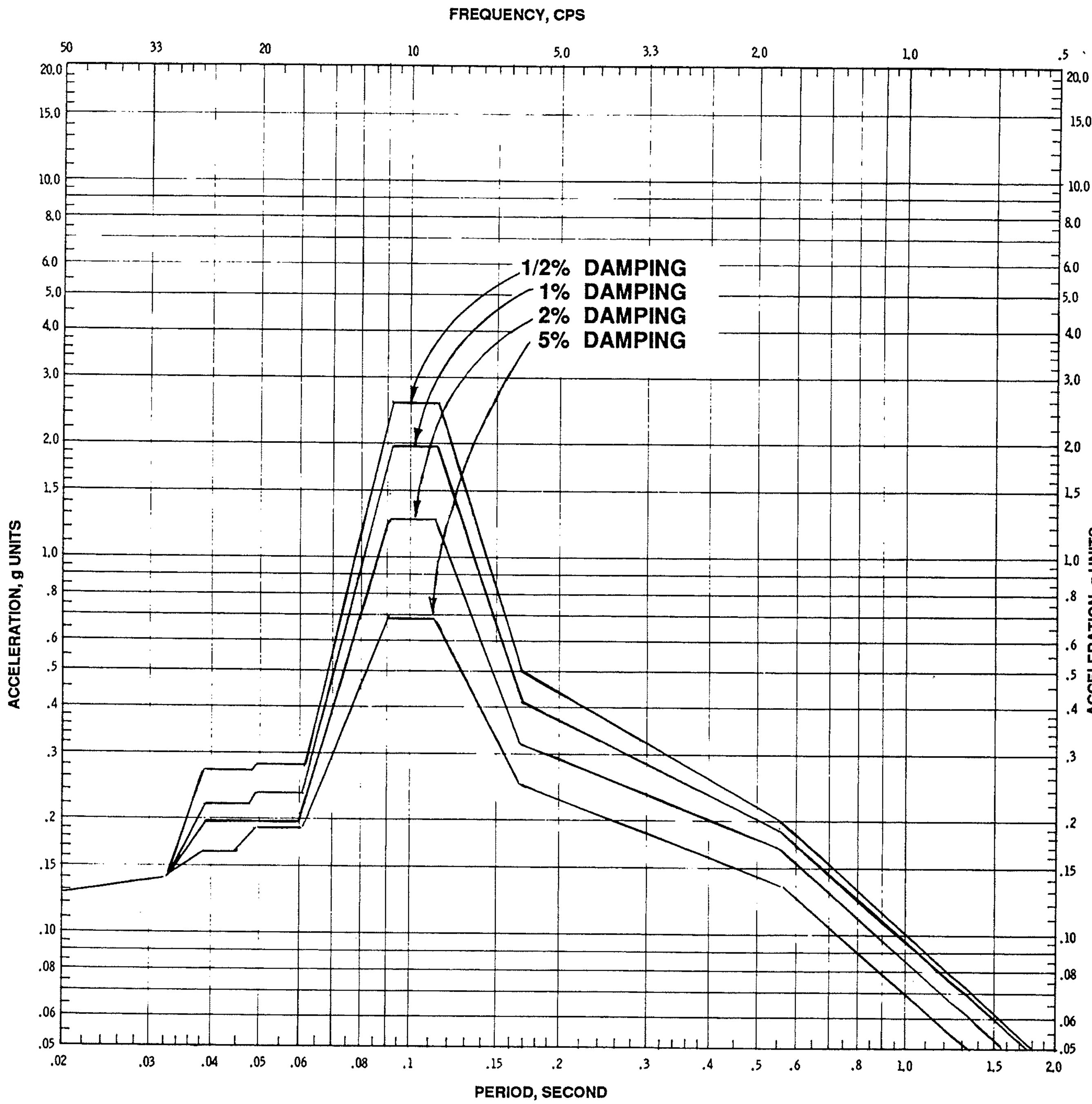

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FIGURE 3.7-100

HORIZONTAL FLOOR RESPONSE SPECTRA OPERATING-BASIS EARTHQUAKE – RESIDUAL HEAT REMOVAL COMPLEX – NORTH-SOUTH COMPONENT – SLAB 2 – ELEVATION 617.0 FT

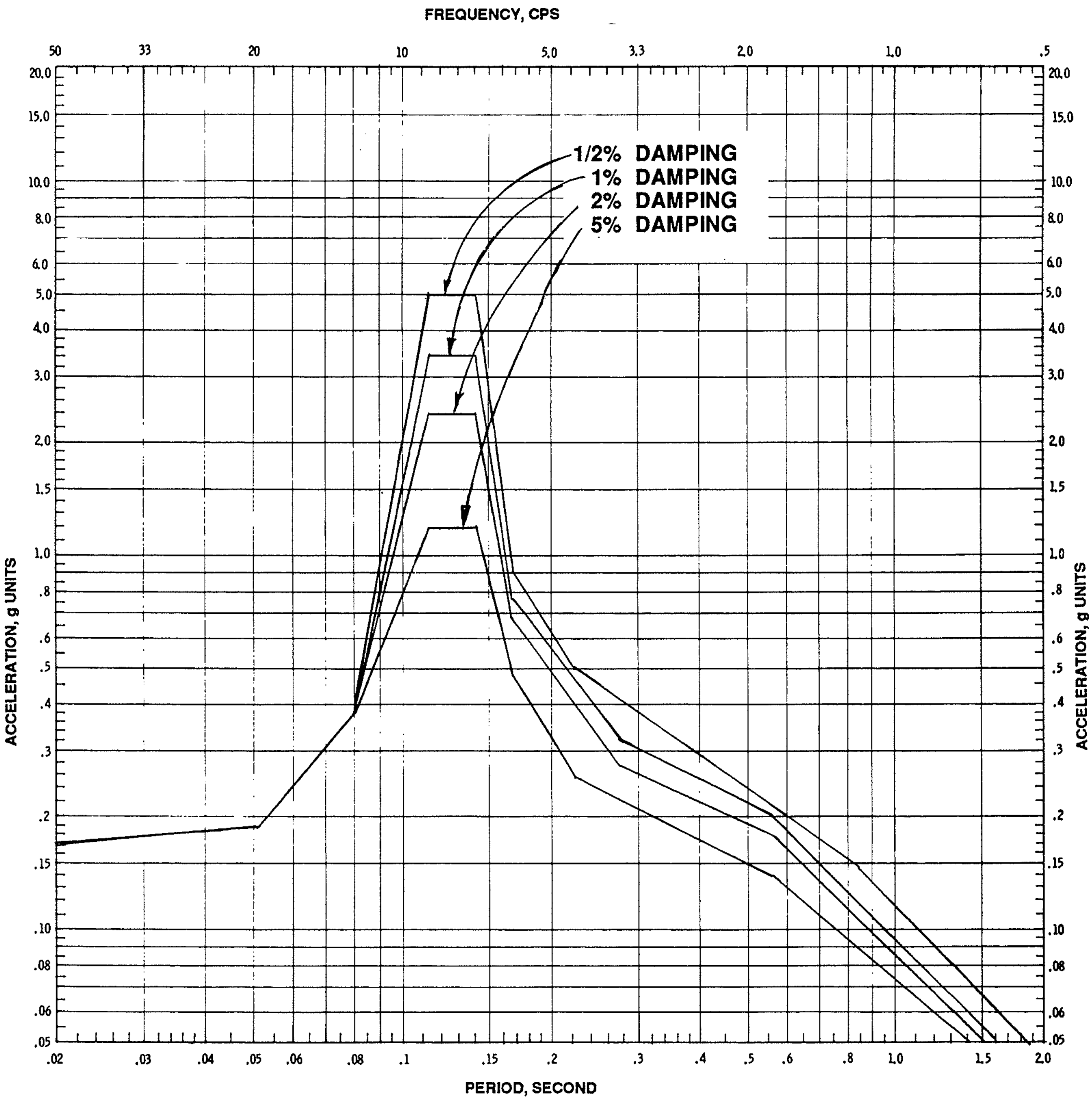

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FIGURE 3.7-101

HORIZONTAL FLOOR RESPONSE SPECTRA OPERATING-BASIS EARTHQUAKE – RESIDUAL HEAT REMOVAL COMPLEX – EAST-WEST COMPONENT – SLAB 2 – ELEVATION 617.0 FT

SARGENT & LUNDY REPORT NO. SL-3147

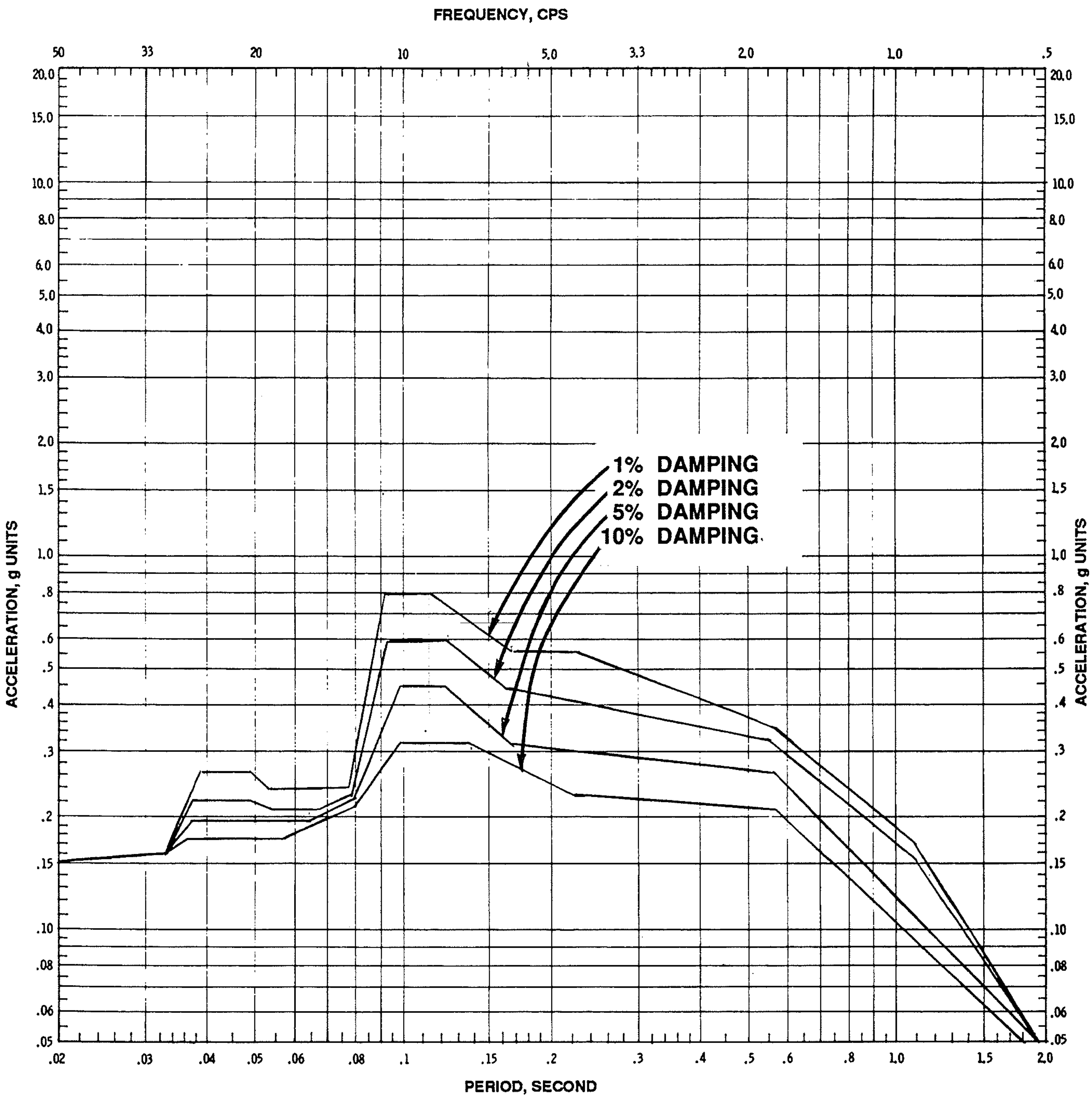

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FIGURE 3.7-102

HORIZONTAL FLOOR RESPONSE SPECTRA SAFE-SHUTDOWN EARTHQUAKE – RESIDUAL HEAT REMOVAL COMPLEX – NORTH-SOUTH COMPONENT – SLAB 1 – ELEVATION 590.0 FT

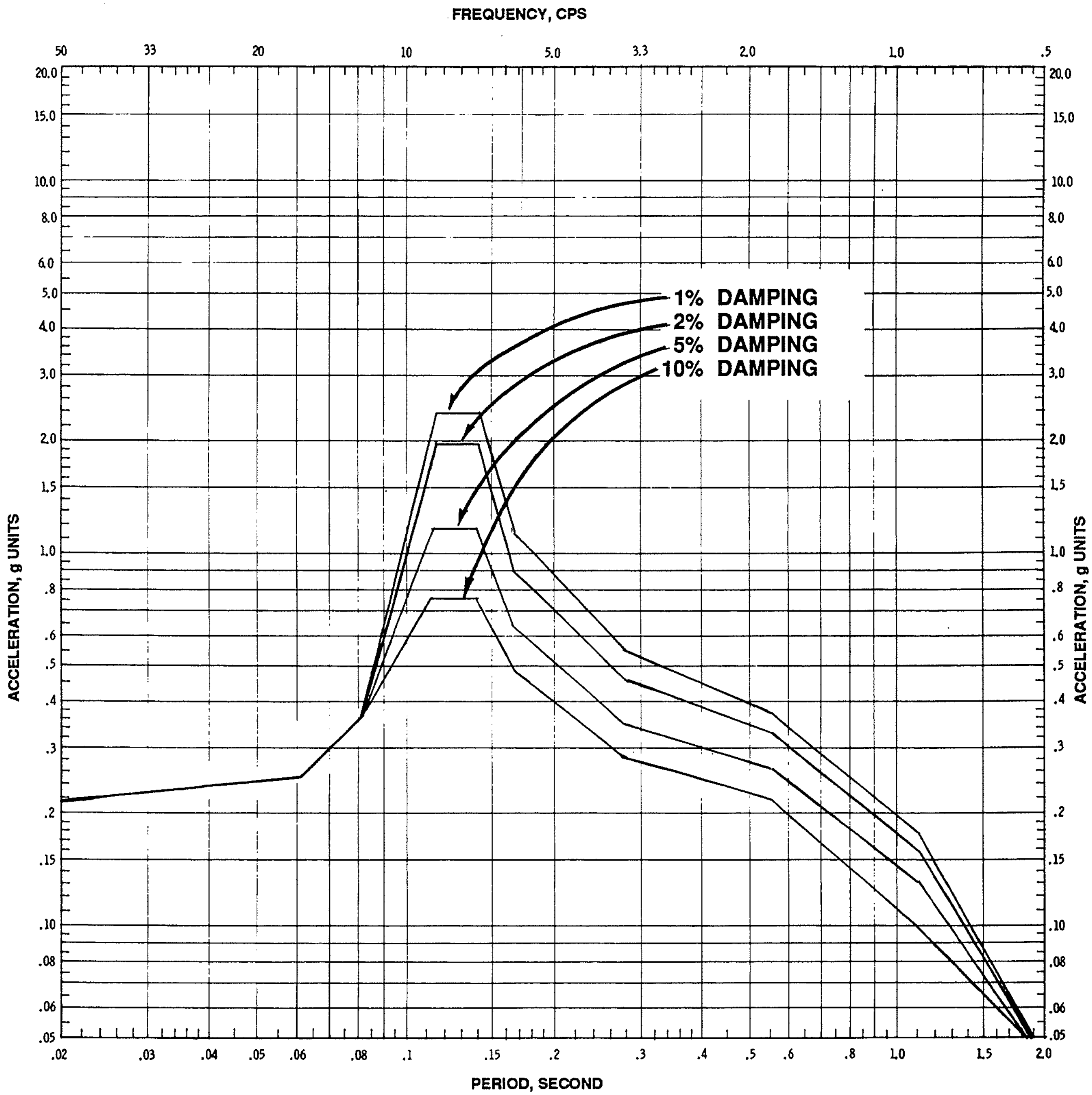

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FIGURE 3.7-103

HORIZONTAL FLOOR RESPONSE SPECTRA
SAFE-SHUTDOWN EARTHQUAKE – RESIDUAL
HEAT REMOVAL COMPLEX – EAST-WEST
COMPONENT – SLAB 1 – ELEVATION 590.0 FT

SARGENT & LUNDY REPORT NO. SL-3147

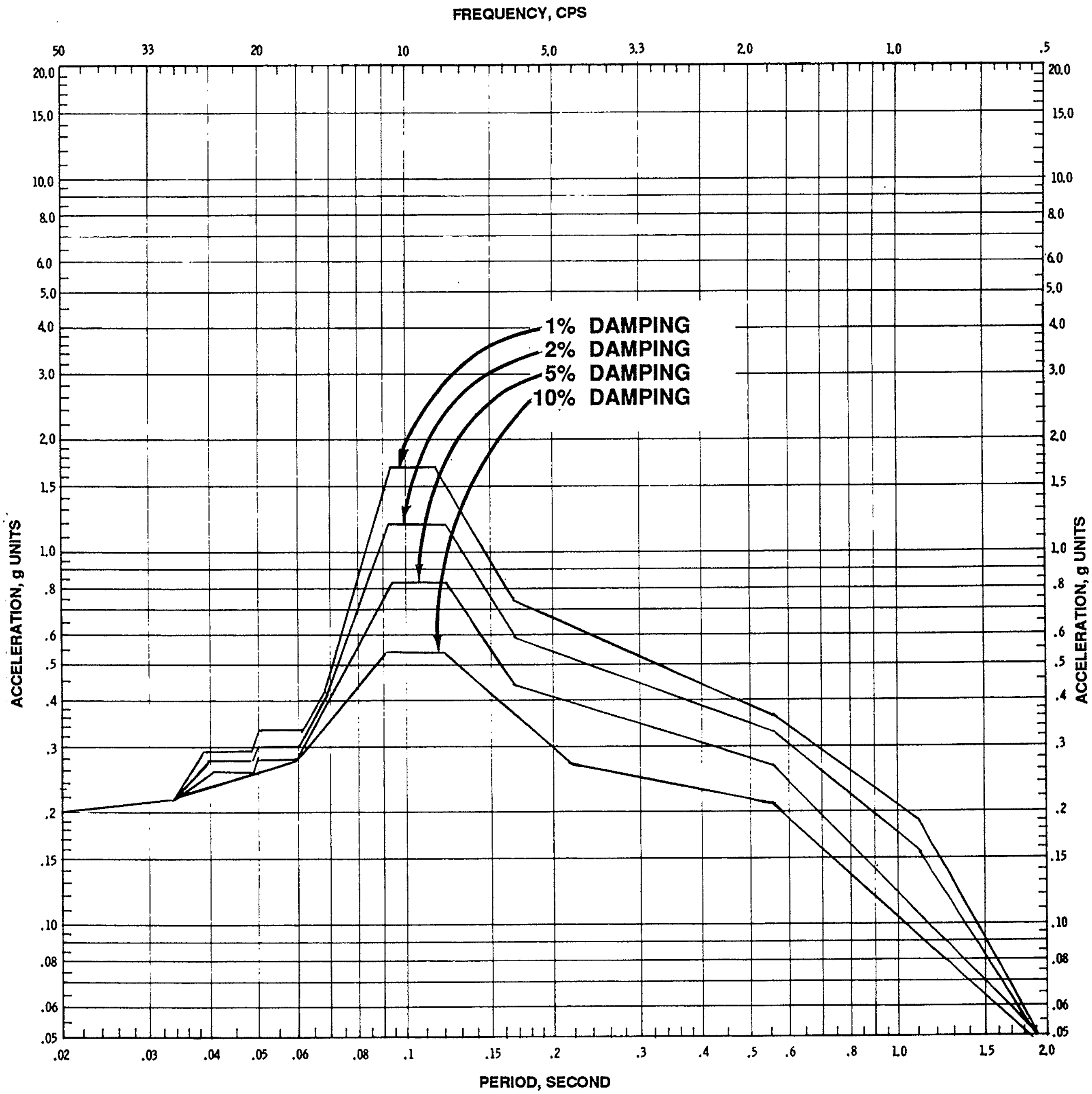

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FIGURE 3.7-104

HORIZONTAL FLOOR RESPONSE SPECTRA SAFE-SHUTDOWN EARTHQUAKE – RESIDUAL HEAT REMOVAL COMPLEX – NORTH-SOUTH COMPONENT – SLAB 2 – ELEVATION 617.0 FT

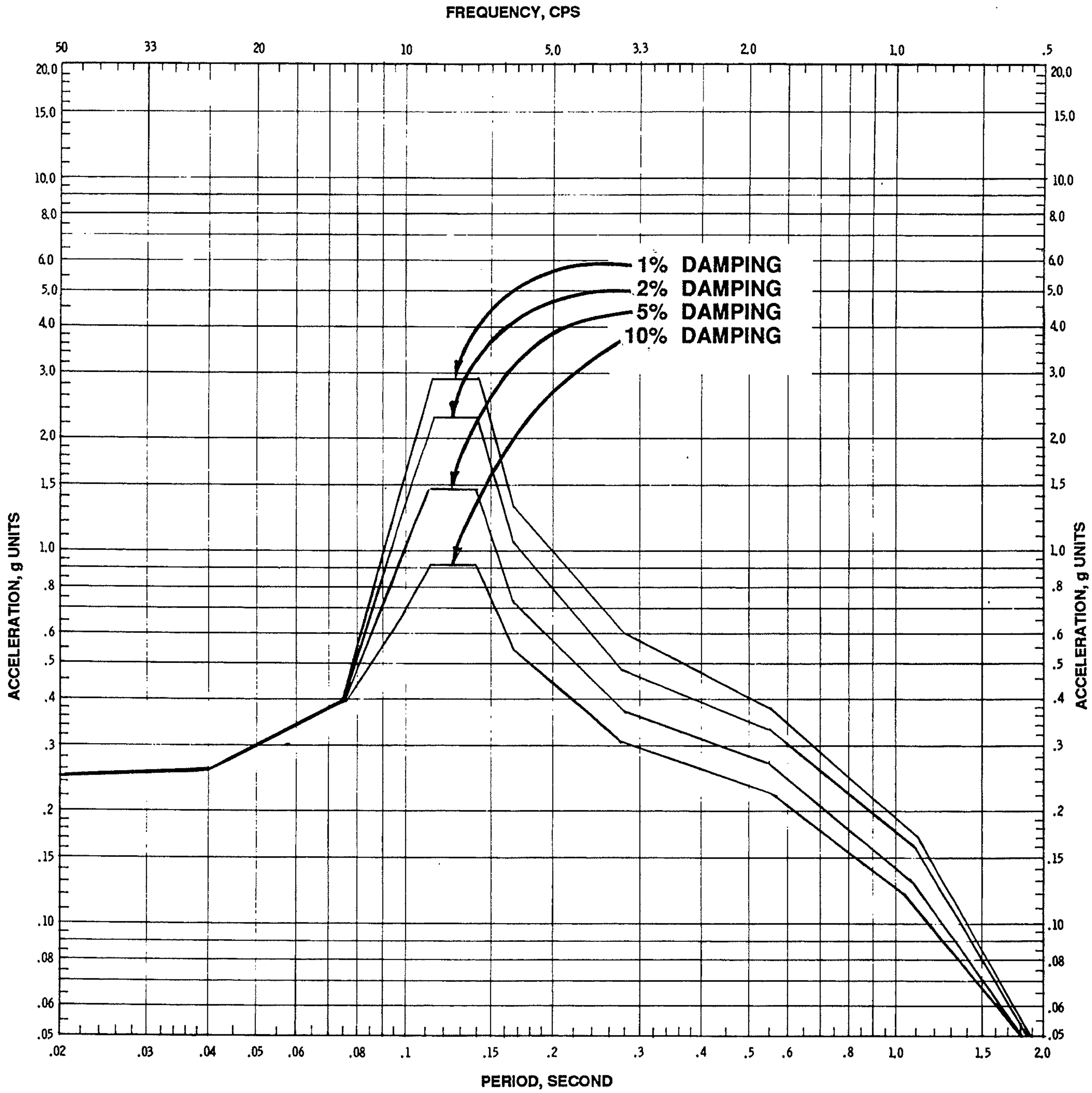

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FIGURE 3.7-105

HORIZONTAL FLOOR RESPONSE SPECTRA SAFE-SHUTDOWN EARTHQUAKE – RESIDUAL HEAT REMOVAL COMPLEX – EAST-WEST COMPONENT – SLAB 2 – ELEVATION 617.0 FT

SARGENT & LUNDY REPORT NO. SL-3147

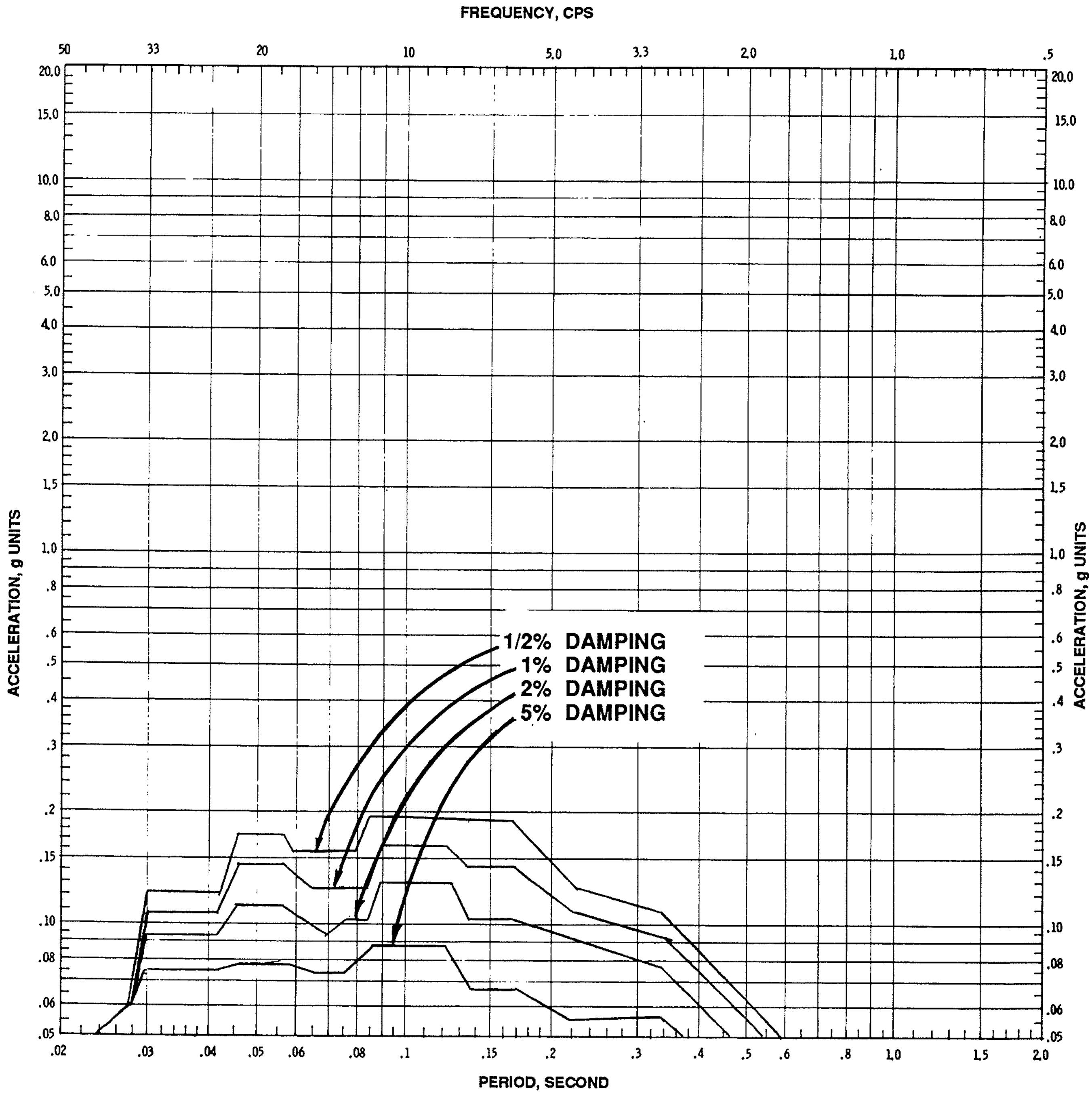

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FIGURE 3.7-106

VERTICAL RESPONSE SPECTRA OPERATING-BASIS EARTHQUAKE – RESIDUAL HEAT REMOVAL COMPLEX WALLS AND SLAB 1A ELEVATION 590.0 FT

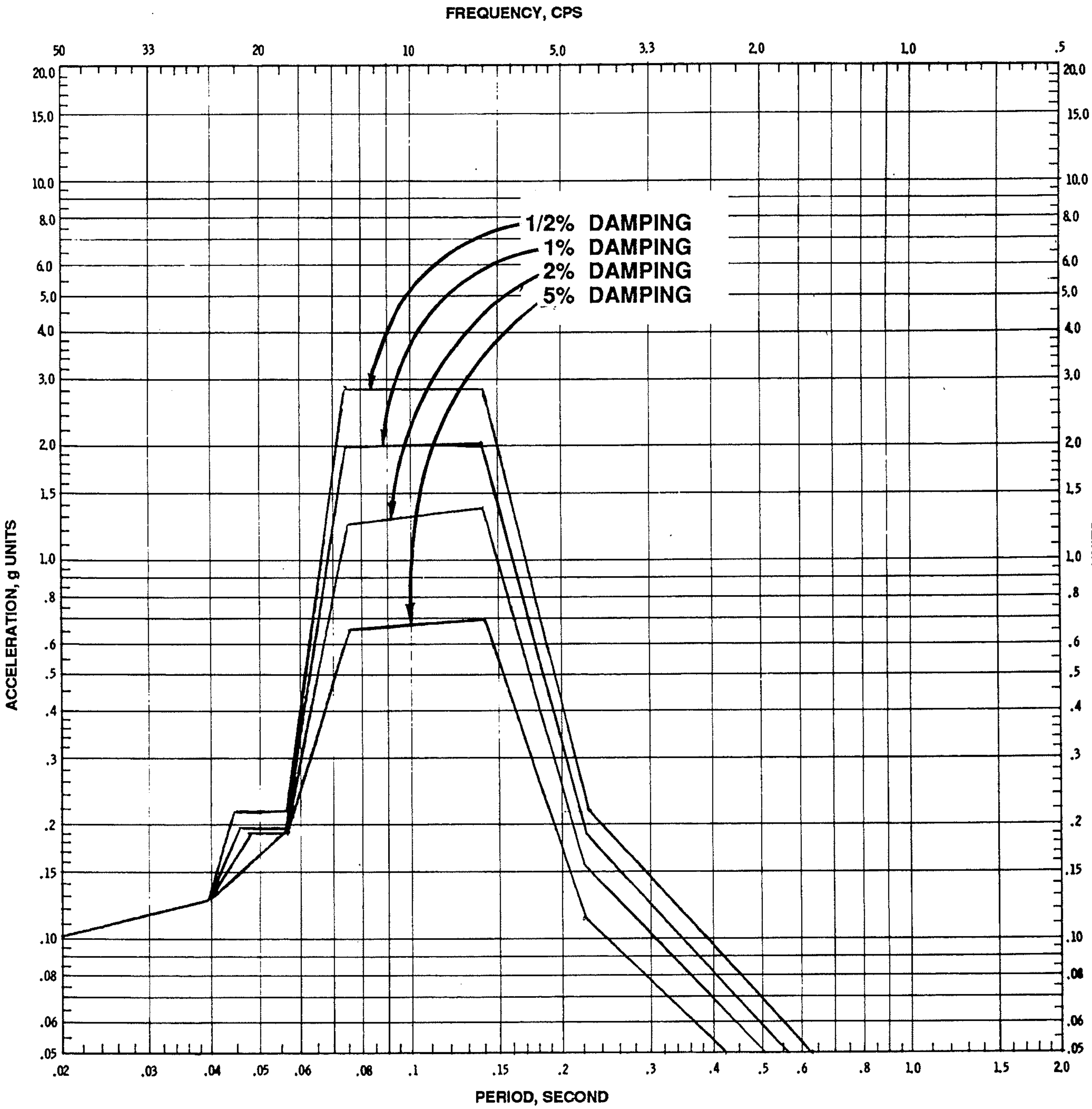

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FIGURE 3.7-107

VERTICAL RESPONSE SPECTRA
OPERATING-BASIS EARTHQUAKE – RESIDUAL
HEAT REMOVAL COMPLEX – SLAB 1B
ELEVATION 590.0 FT

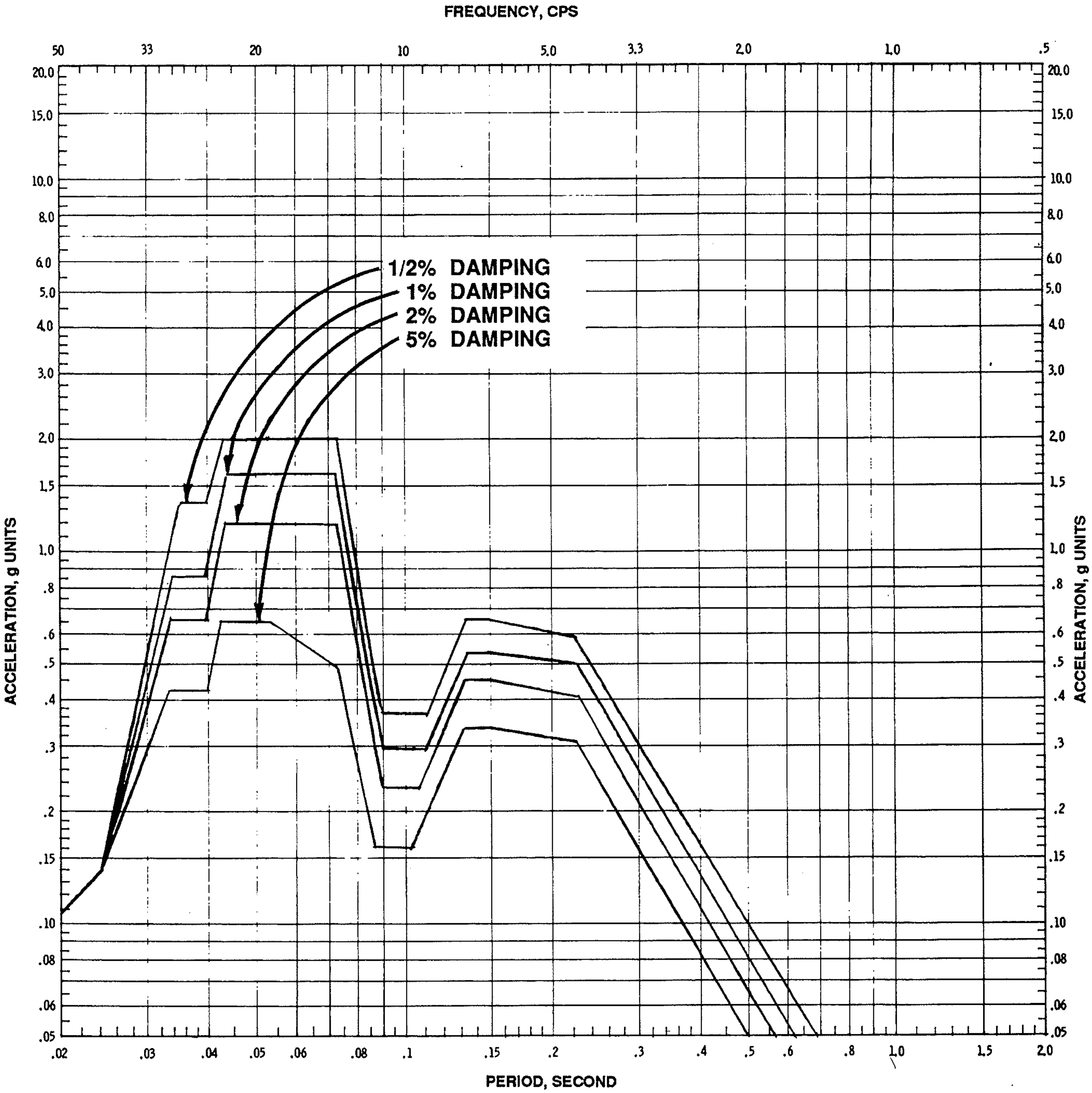

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FIGURE 3.7-108

VERTICAL RESPONSE SPECTRA OPERATING-BASIS EARTHQUAKE – RESIDUAL HEAT REMOVAL COMPLEX – SLAB 1C ELEVATION 590.0 FT

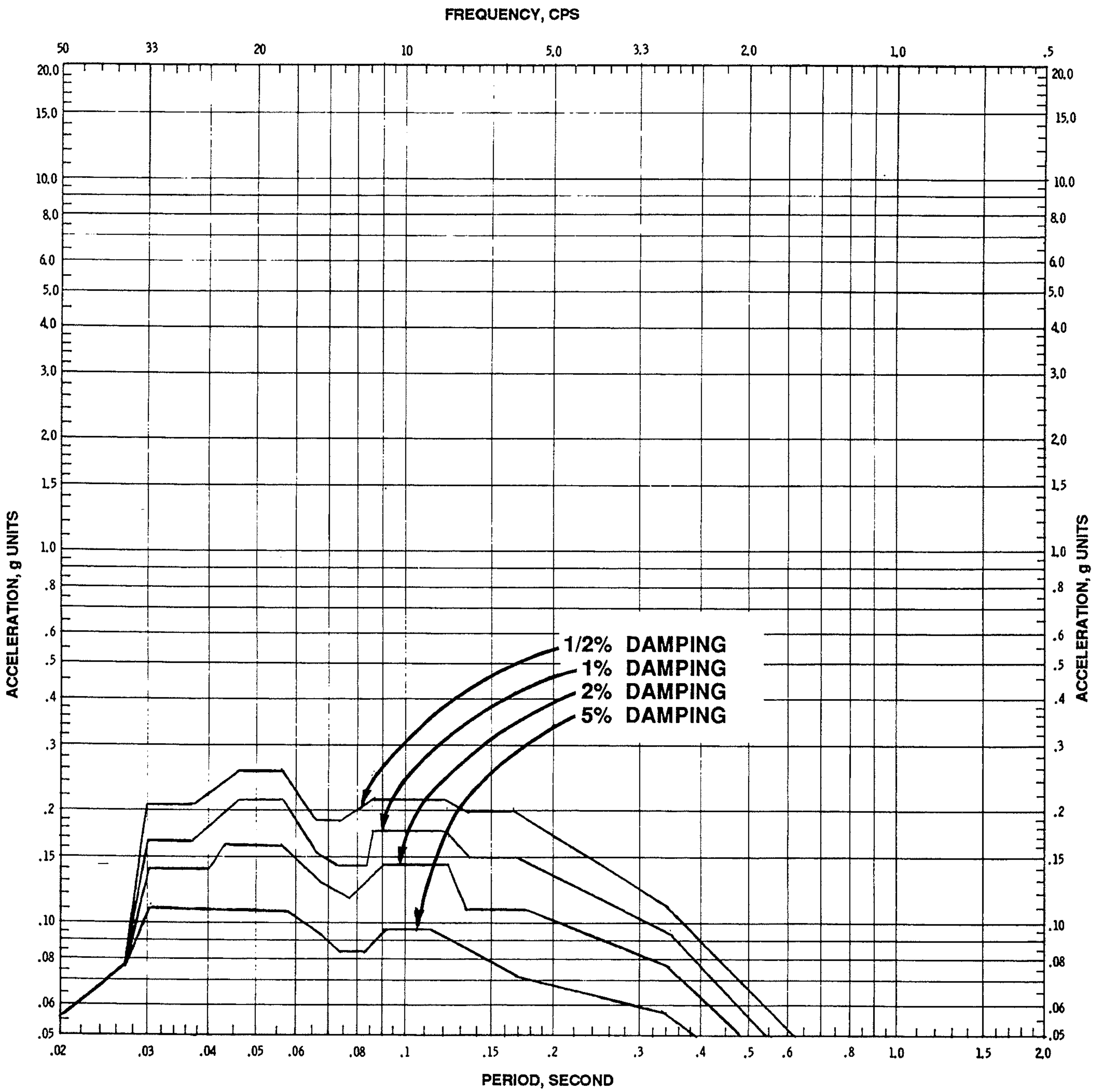

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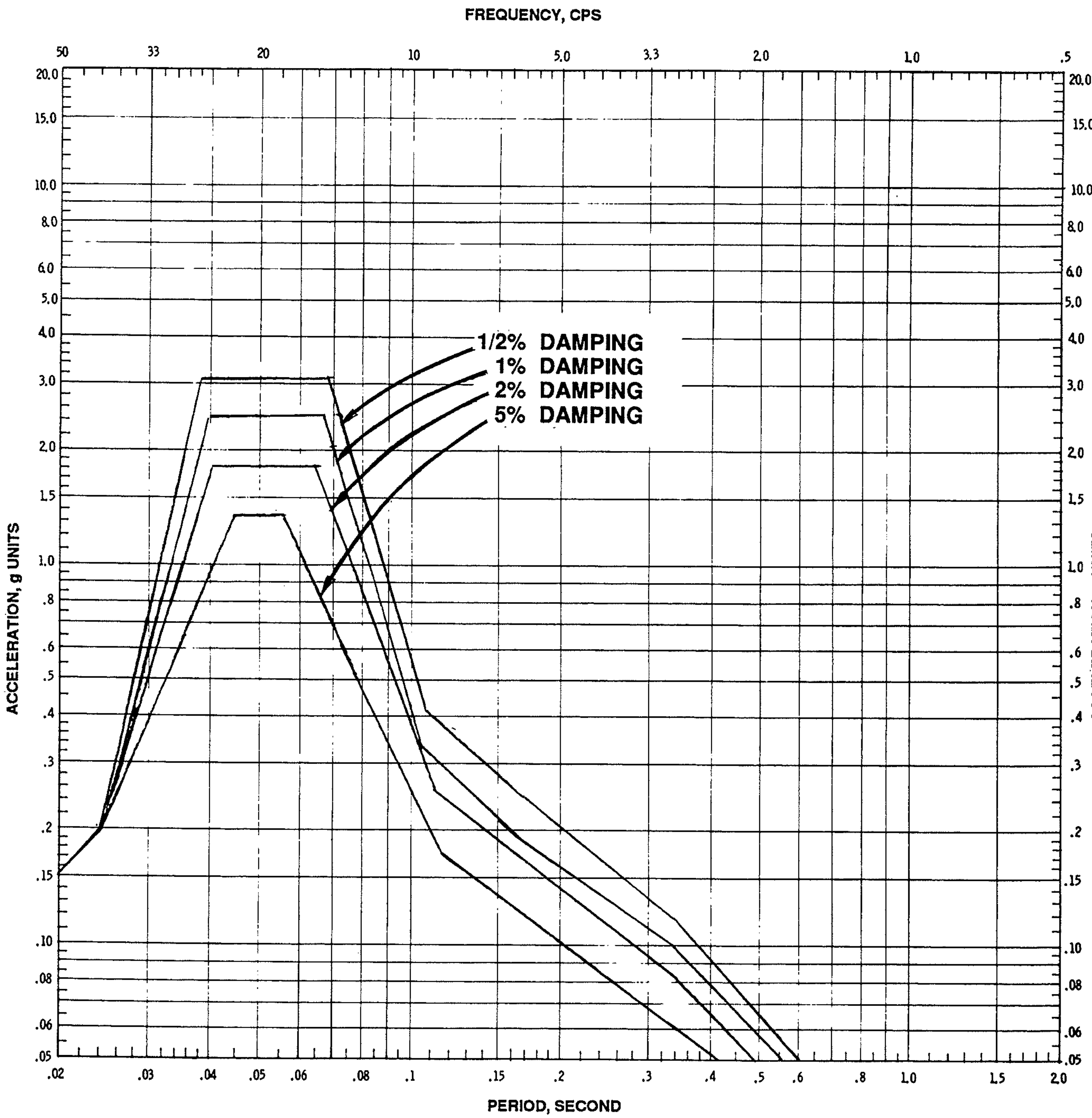
FIGURE 3.7-109

VERTICAL RESPONSE SPECTRA OPERATING-BASIS EARTHQUAKE – RESIDUAL HEAT REMOVAL COMPLEX – WALLS ELEVATION 617.0 FT

SARGENT & LUNDY REPORT NO. SL-3147



SARGENT & LUNDY REPORT NO. SL-3147

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FIGURE 3.7-110

VERTICAL RESPONSE SPECTRA
OPERATING-BASIS EARTHQUAKE – RESIDUAL
HEAT REMOVAL COMPLEX – SLAB 2
ELEVATION 617.0 FT

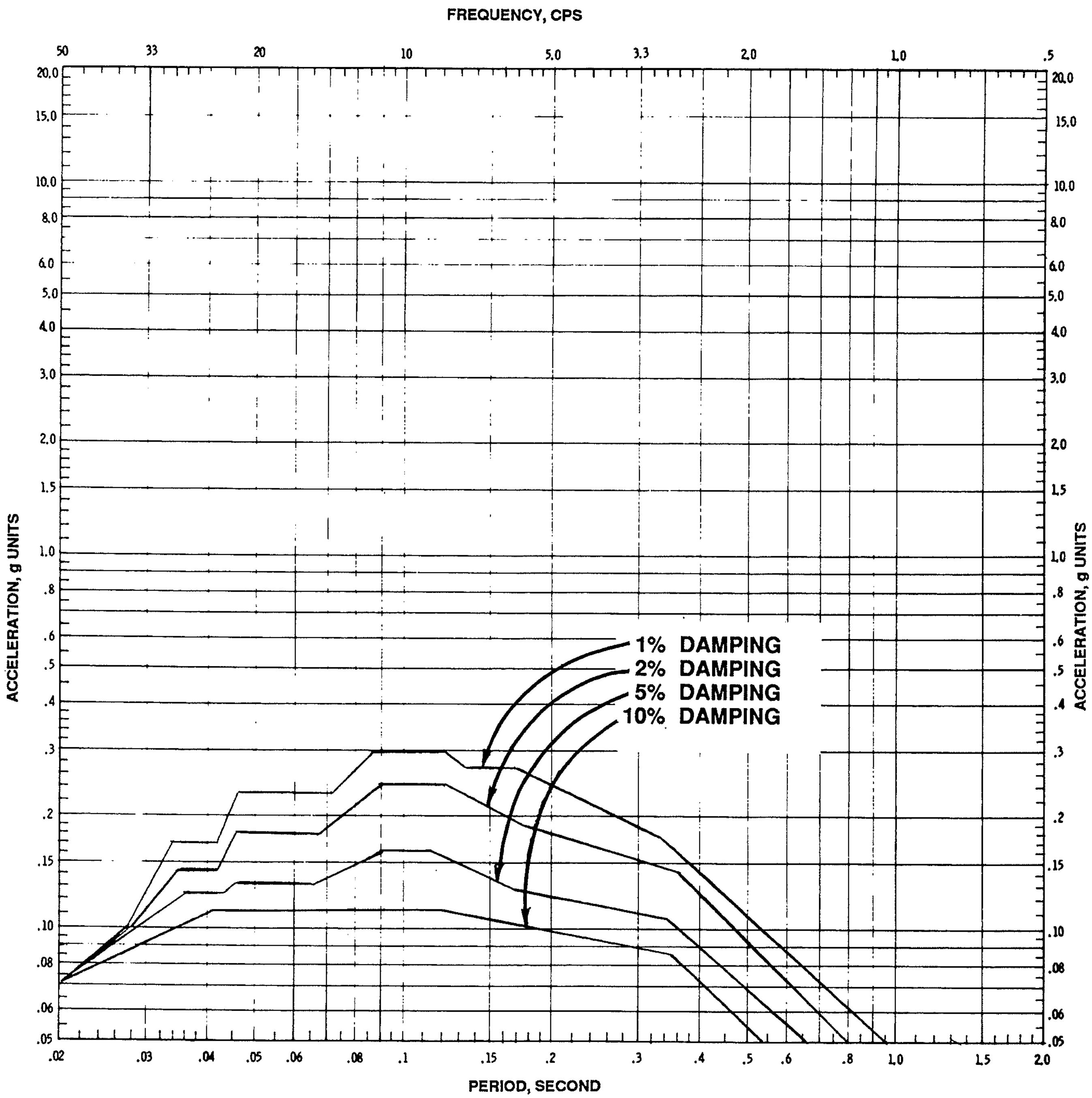

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FIGURE 3.7-111

VERTICAL RESPONSE SPECTRA
SAFE-SHUTDOWN EARTHQUAKE – RESIDUAL
HEAT REMOVAL COMPLEX – WALLS AND SLAB 1A
ELEVATION 590.0 FT

SARGENT & LUNDY REPORT NO. SL-3147

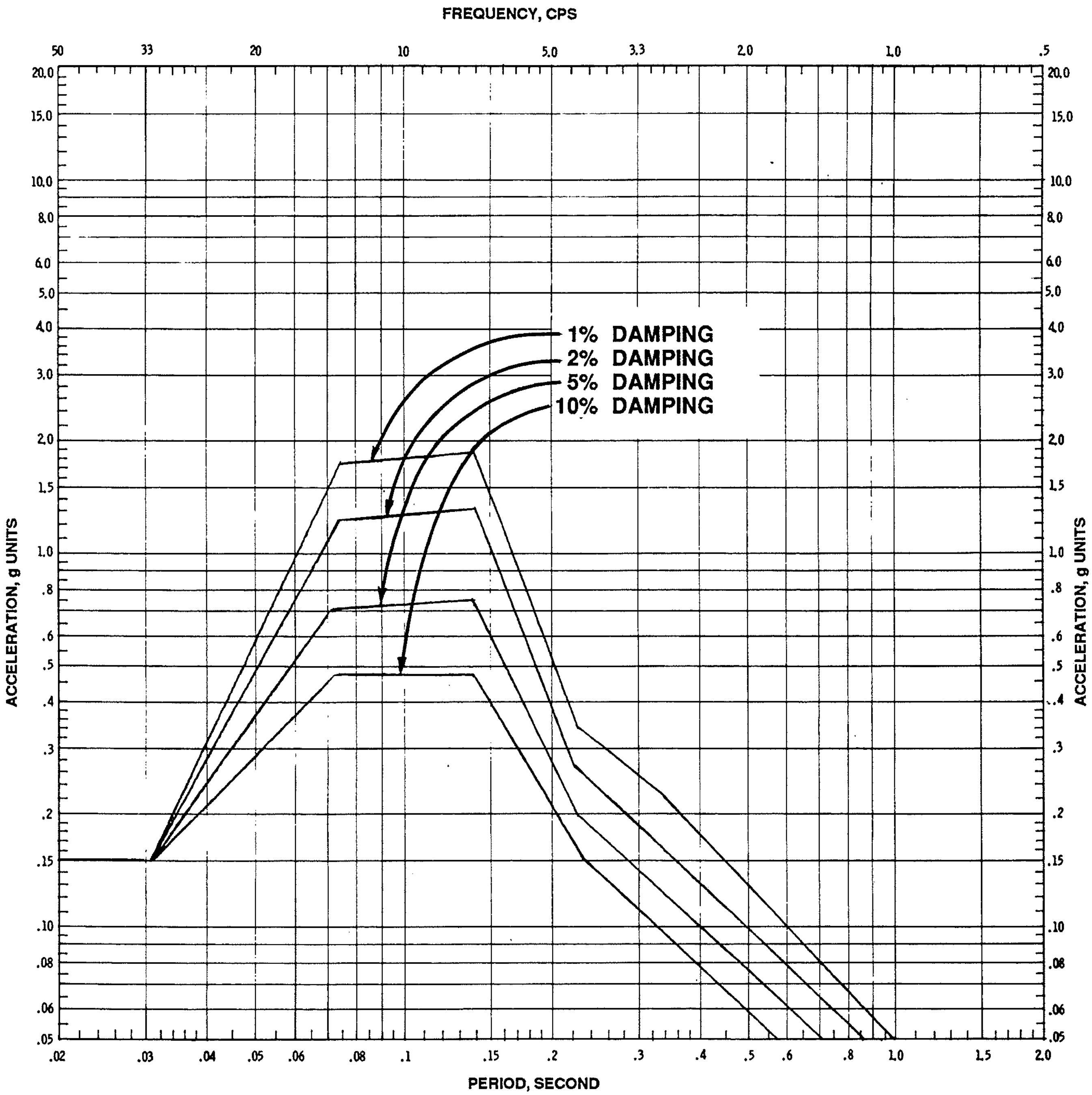

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FIGURE 3.7-112

VERTICAL RESPONSE SPECTRA
SAFE-SHUTDOWN EARTHQUAKE – RESIDUAL
HEAT REMOVAL COMPLEX – SLAB 1B
ELEVATION 590.0 FT

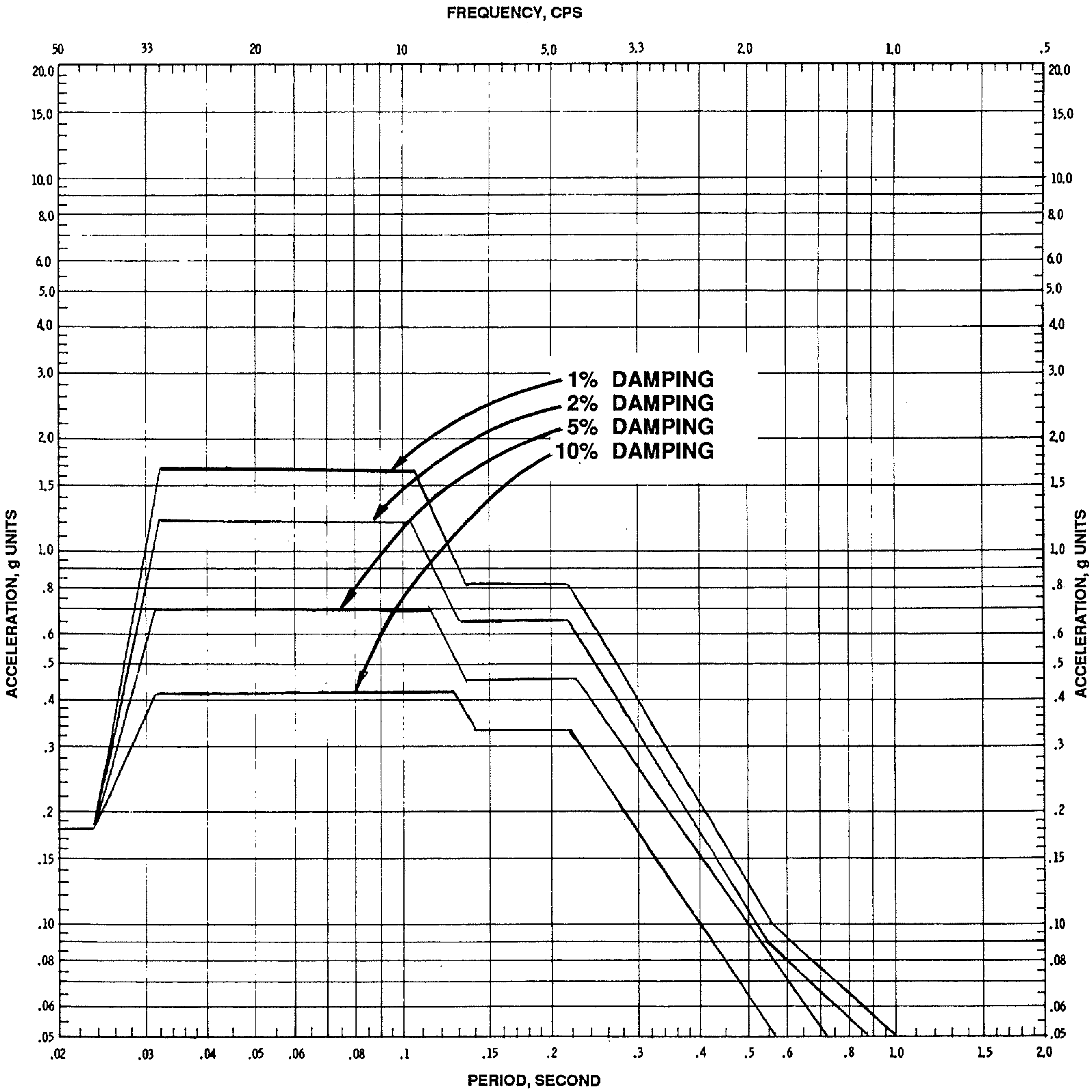

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FIGURE 3.7-113

VERTICAL RESPONSE SPECTRA
SAFE-SHUTDOWN EARTHQUAKE – RESIDUAL HEAT REMOVAL COMPLEX – SLAB 1C
ELEVATION 590.0 FT

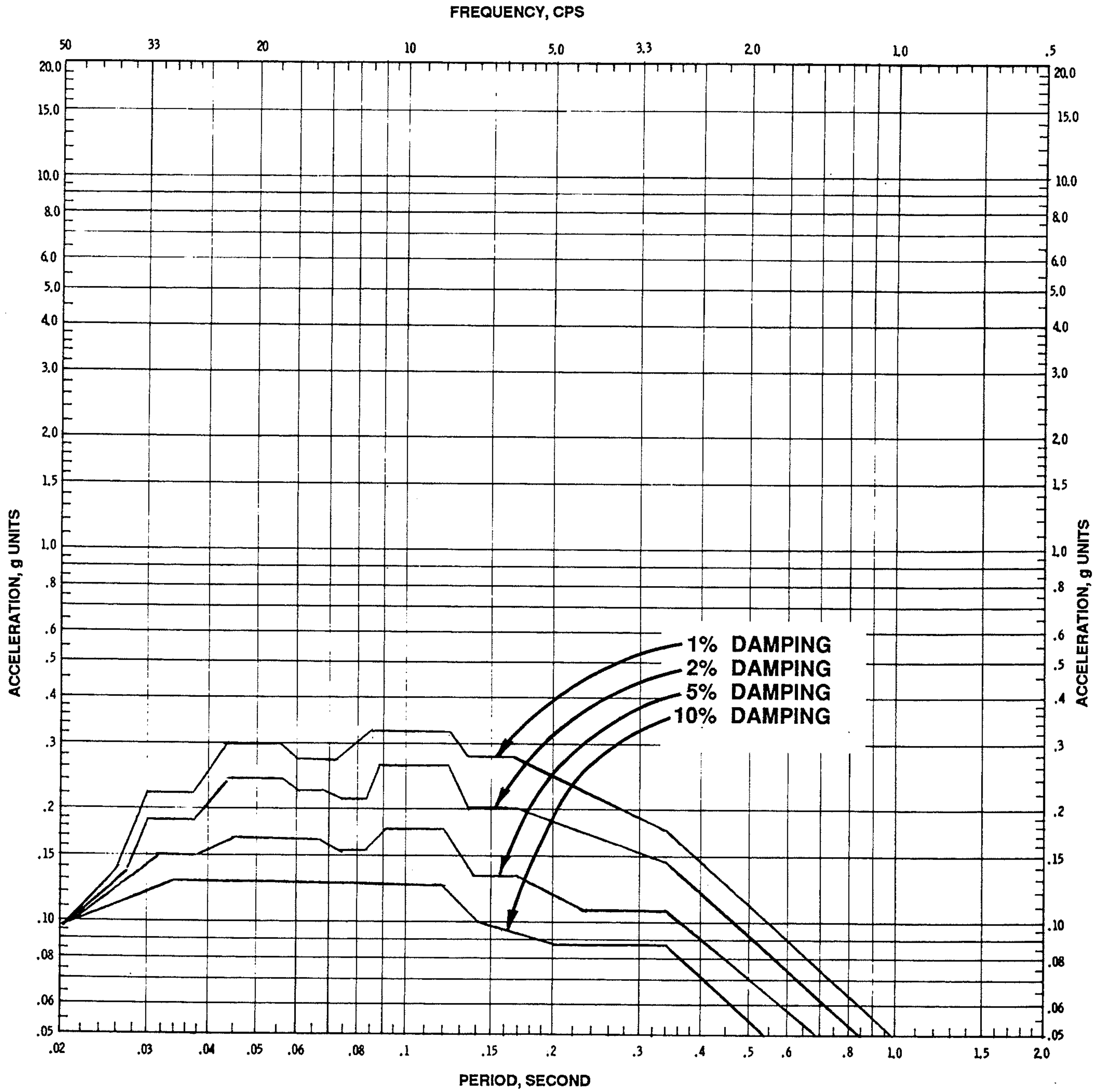

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FIGURE 3.7-114

VERTICAL RESPONSE SPECTRA SAFE-SHUTDOWN EARTHQUAKE – RESIDUAL HEAT REMOVAL COMPLEX – WALLS ELEVATION 617.0 FT

SARGENT & LUNDY REPORT NO. SL-3147

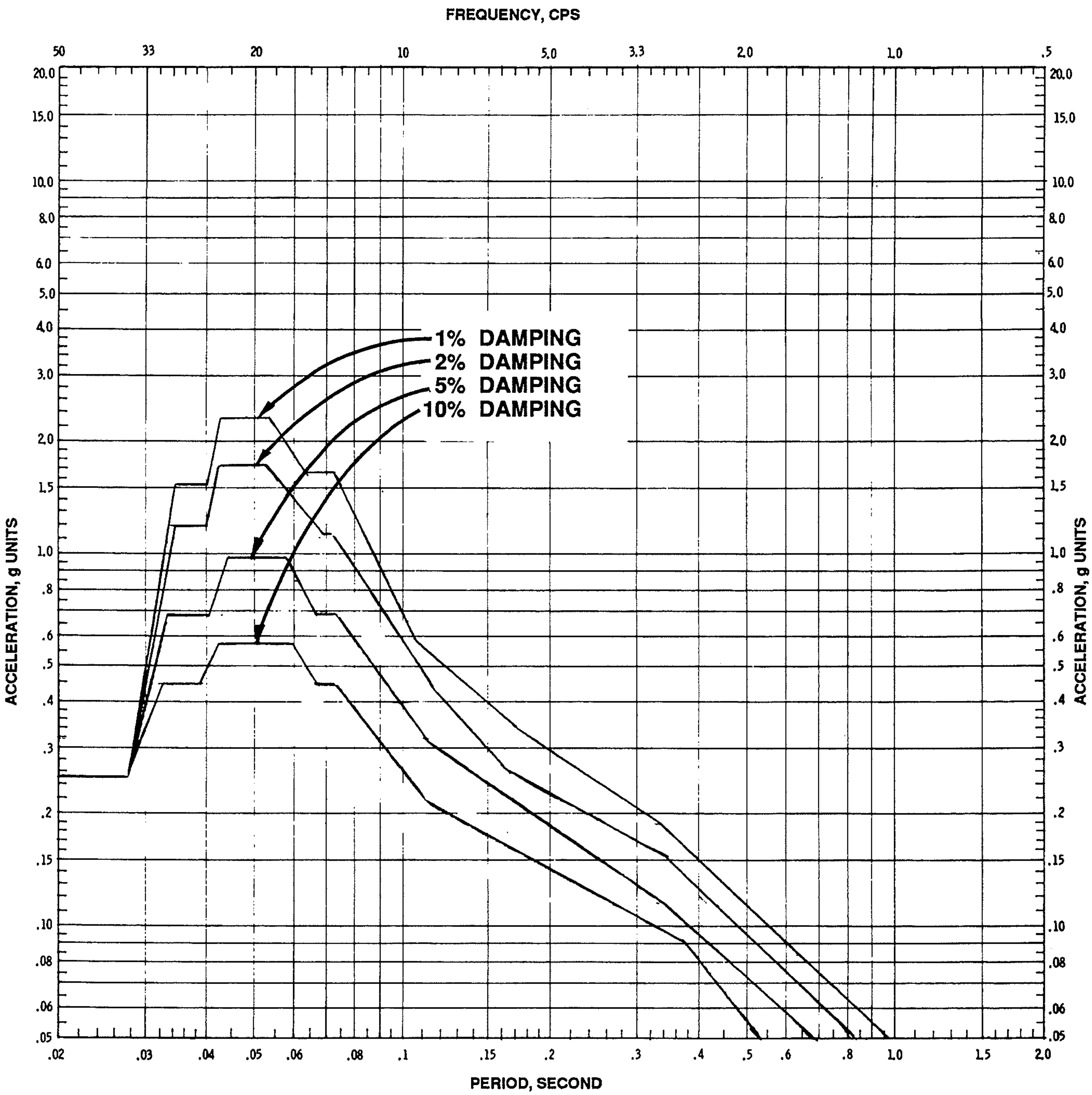

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FIGURE 3.7-115

VERTICAL RESPONSE SPECTRA
SAFE-SHUTDOWN EARTHQUAKE – RESIDUAL
HEAT REMOVAL COMPLEX – SLAB 2
ELEVATION 617.0 FT

SARGENT & LUNDY REPORT NO. SL-3147

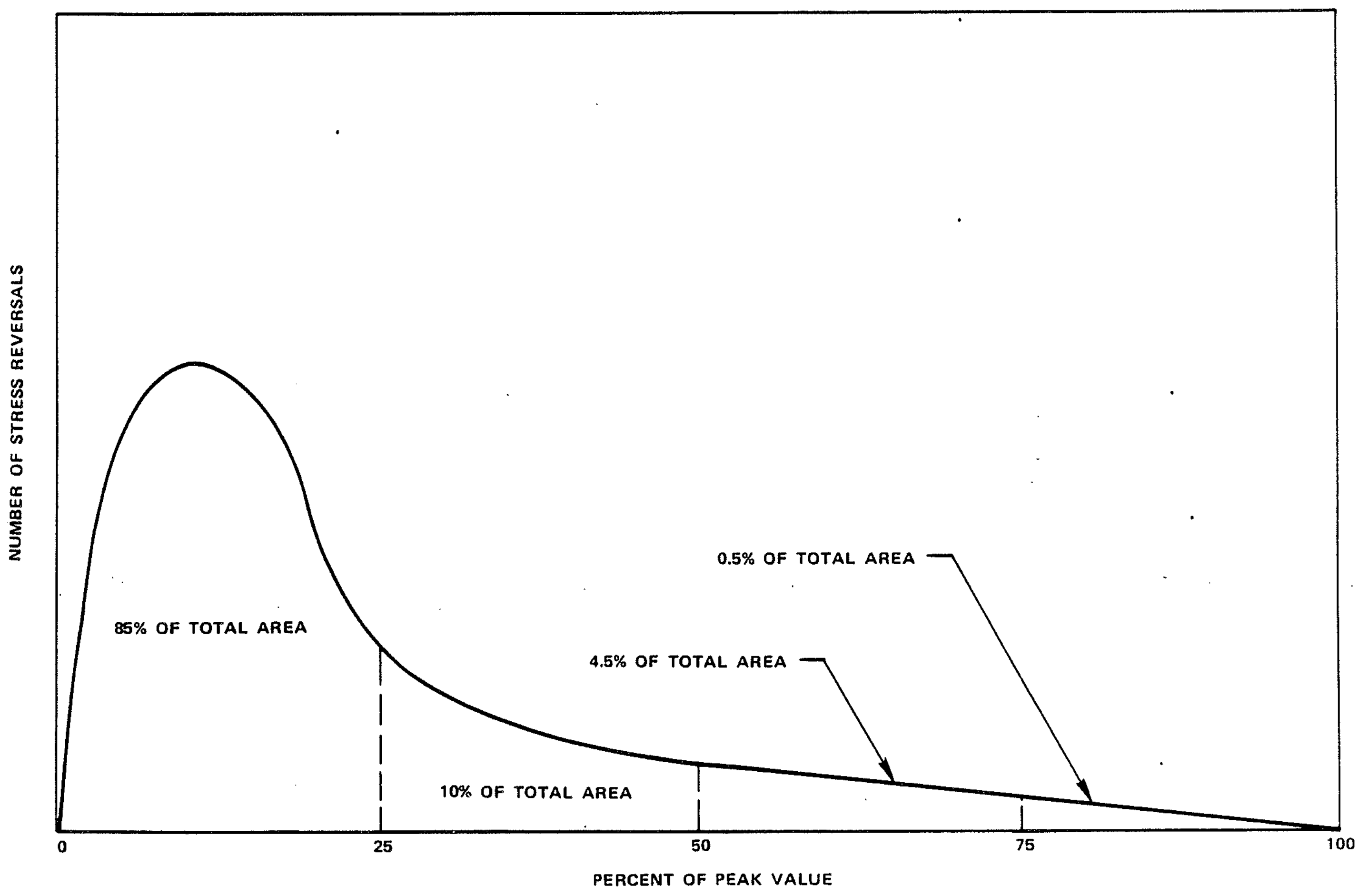

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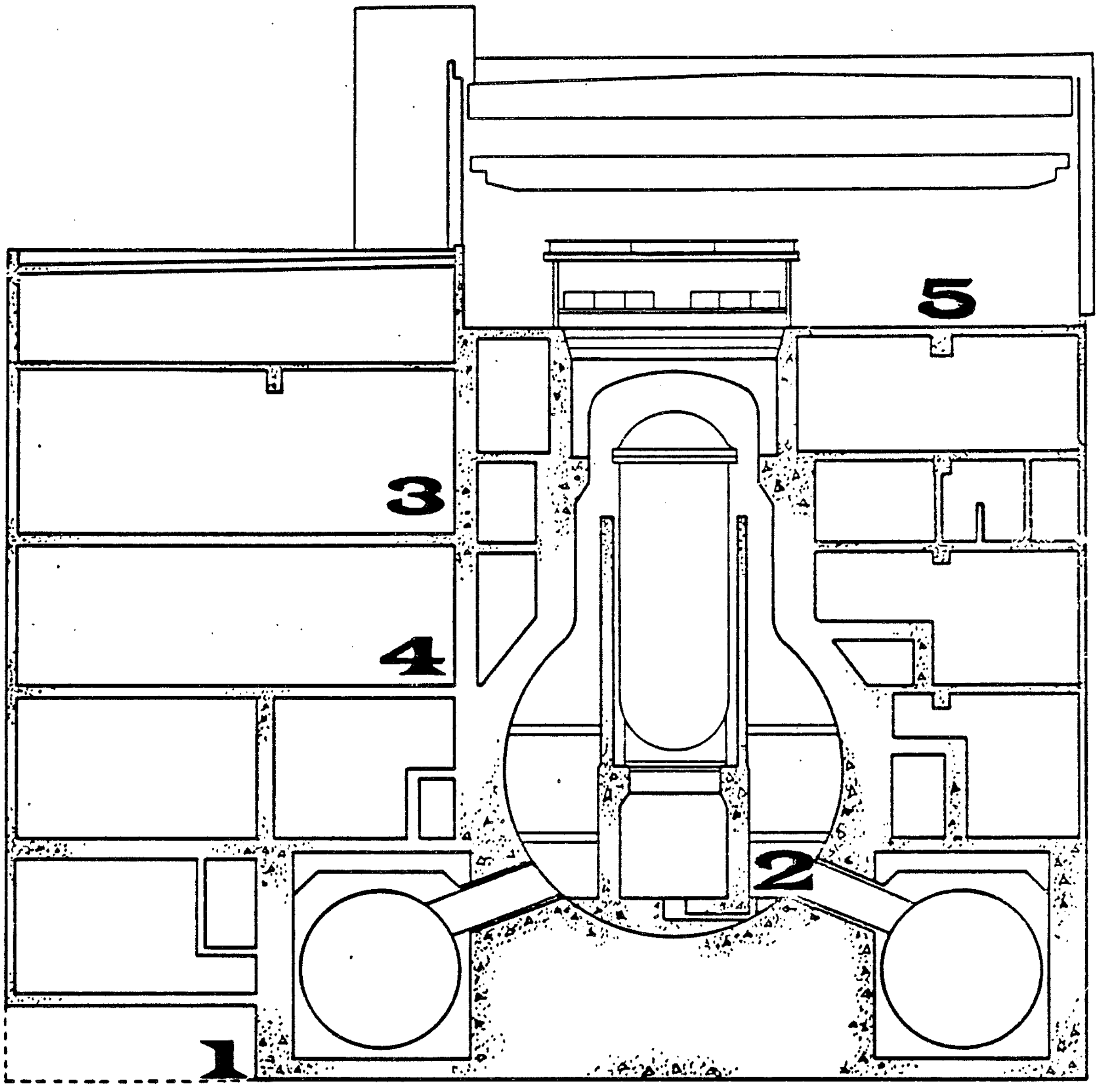
FIGURE 3.7-116

DENSITY OF STRESS REVERSALS



SECTION

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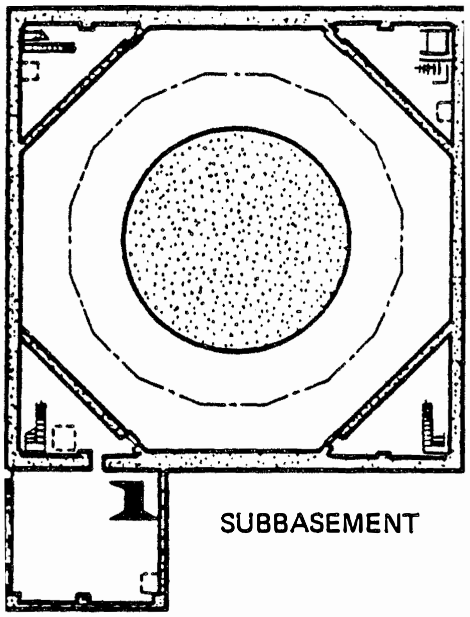
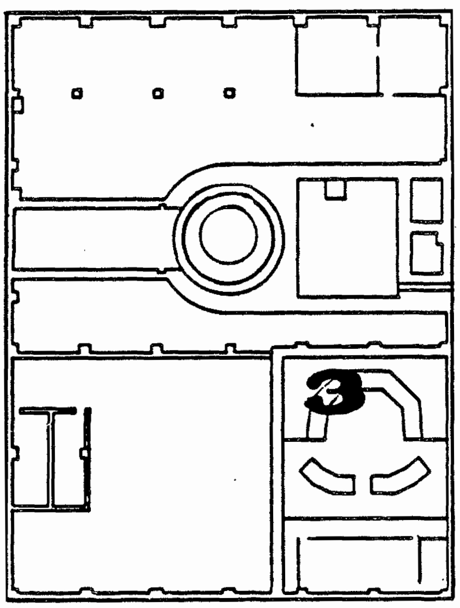
FIGURE 3.7-117, SHEET 1

REACTOR/AUXILIARY BUILDING SENSOR LOCATIONS

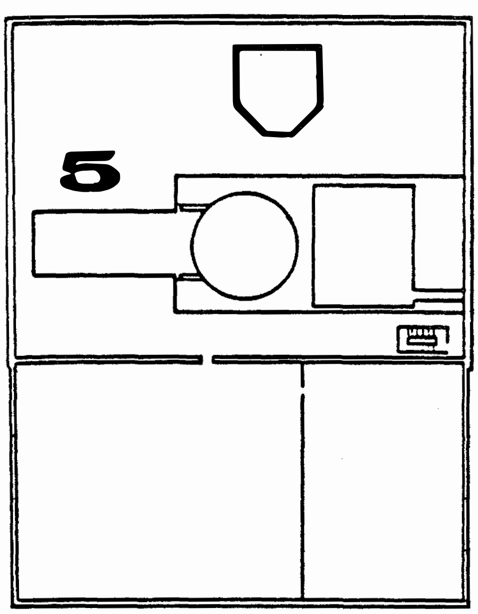
RALPH M. PARSONS COMPANY DRAWING



SUBBASEMENT

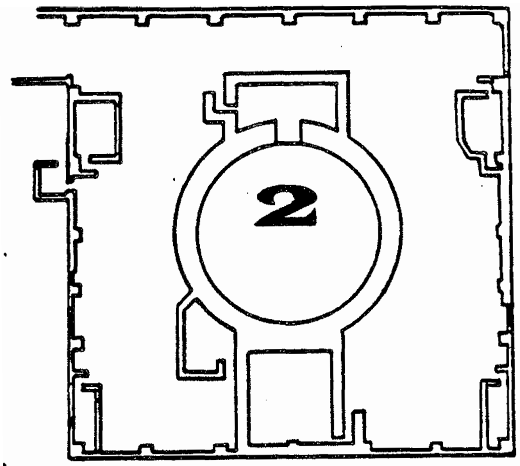


THIRD FLOOR

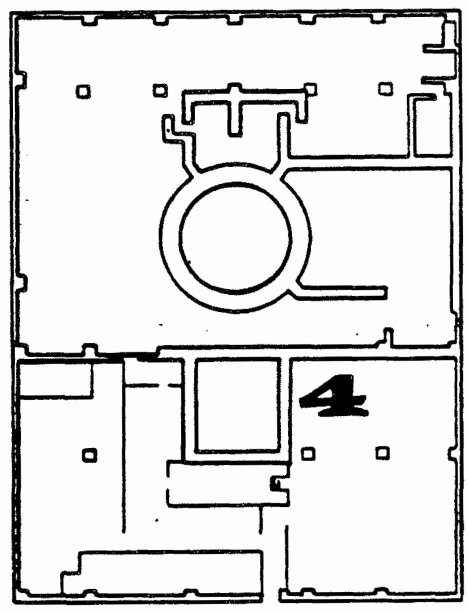


FIFTH FLOOR

RALPH M. PARSONS COMPANY DRAWING



BOTTOM OF PEDESTAL



SECOND FLOOR

1. SUBBASEMENT, HPCI ROOM
2 BOTTOM OF PEDESTAL
3. CONTROL ROOM
4. SECOND FLOOR RELAY ROOM
5. FIFTH FLOOR

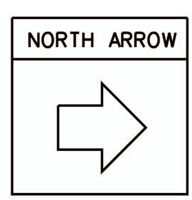


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FIGURE 3.7-117, SHEET 2

REACTOR/AUXILIARY BUILDING SENSOR LOCATIONS

FIGURE 3.7-118, SHEETS 1 AND 2 HAVE BEEN DELETED

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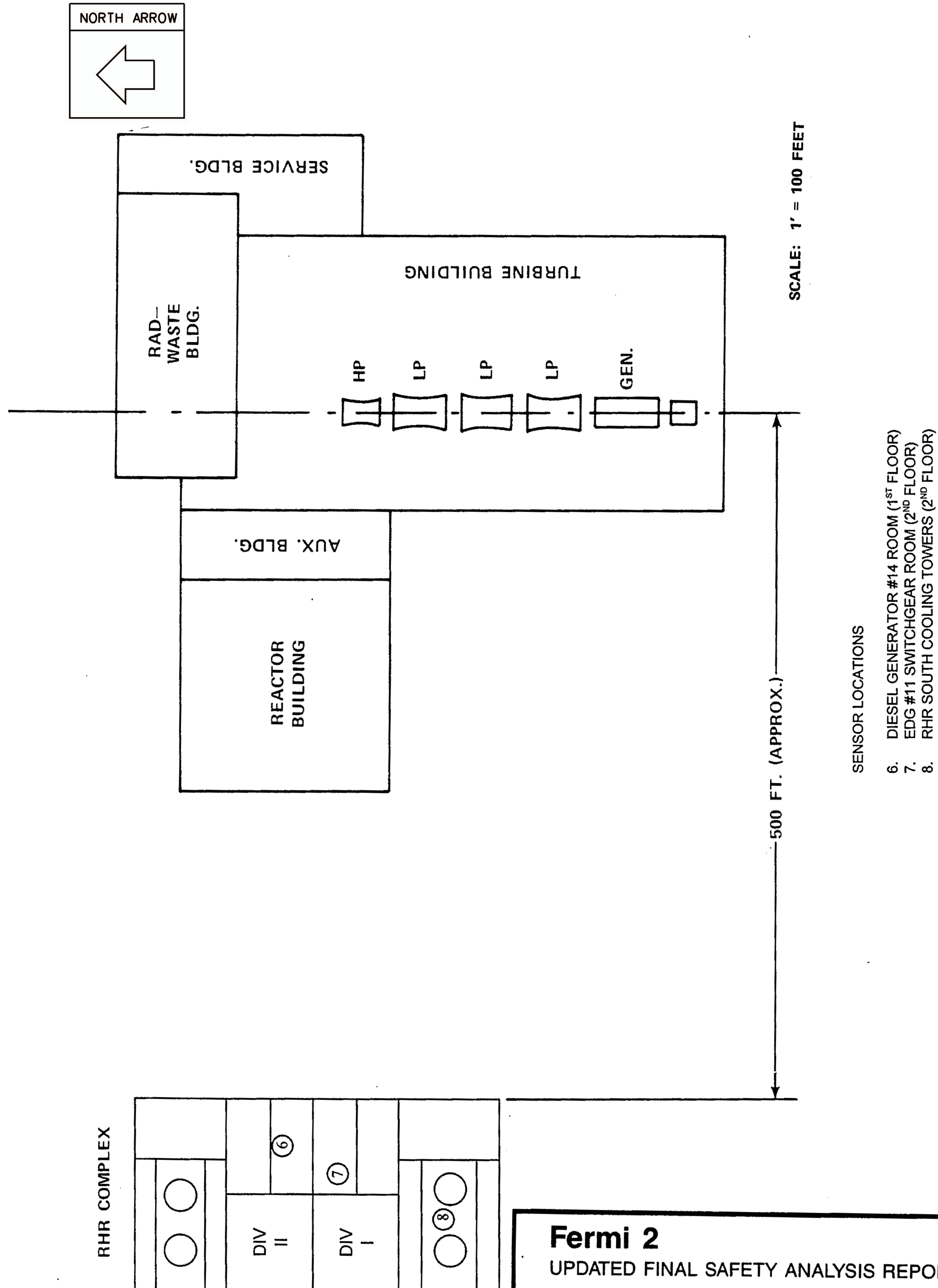

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FIGURE 3.7-119

GENERAL ARRANGEMENT PLAN MAJOR STRUCTURES

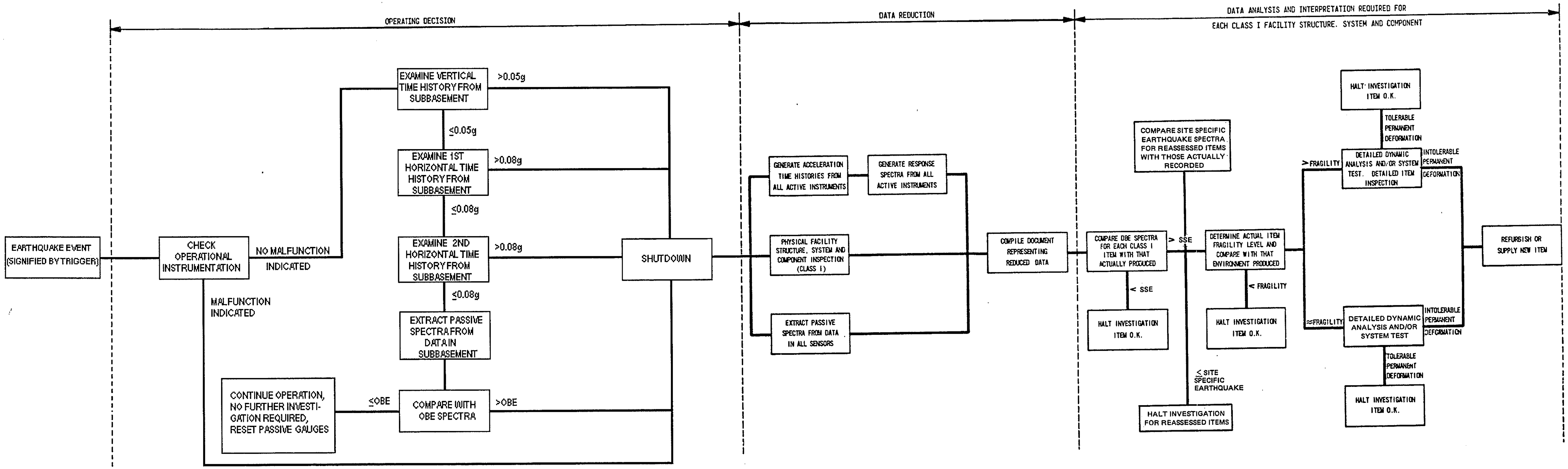

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FIGURE 3.7-120

DATA REDUCTION/ANALYSIS FLOW CHART

3.8 DESIGN OF CATEGORY I STRUCTURES

3.8.1 Concrete Containment

Fermi 2 uses a steel primary containment. Subsection 3.8.2 and Reference 1 discuss the steel containment, and Subsection 3.8.4.1.1 discusses the concrete reactor building surrounding the primary steel containment and used as a secondary containment. Information about the foundation supporting these structures can be found in Subsection 3.8.5.

3.8.2 Steel Containment System (ASME Class B Components)

3.8.2.1 Description of the Containment

3.8.2.1.1 Introduction

The primary containment (known as the Mark I containment) is a leaktight steel-plate containment vessel consisting of a light- bulb-shaped drywell and a torus-shaped suppression chamber. The primary containment was designed, erected, and pressure-tested by the Chicago Bridge & Iron Company.

The basic objective of the primary containment system is to provide the capability, in the event of the postulated design- basis accident (DBA), that is, LOCA, to limit the release of fission products to the plant site environs so that offsite doses do not exceed the values specified in 10 CFR 50.67 or 10 CFR 100. The reactor building, in conjunction with the steel containment, is designed as a secondary containment. A standby gas treatment system (SGTS) is installed to exhaust (automatically or manually) the reactor building atmosphere by way of its filter system to a vent on the auxiliary building roof, thereby causing the reactor building internal pressure to be lower than the external pressure, so that leakage is into the reactor building.

To meet the basic safety objective, the following subsidiary objectives are achieved by the system or one or more of its components:

a. The primary containment system is capable of withstanding the conditions that could result from any of the postulated accidents for which the primary containment system is assumed to be functional, including the largest amount of energy release and mass flow associated with the DBA. The criteria set forth in the NRC's Safety Evaluation Report on the Mark I containment program, NUREG-0661 (Reference 2), have been applied as the basis for acceptance of the analysis methods and the primary containment system design

b. The primary containment system has a design margin for metal/water reactions and other chemical reactions subsequent to any postulated DBA for which the primary containment system is assumed to be functional, consistent with the performance objectives of the nuclear safety systems and engineered safety feature (ESF) systems

c. The primary containment system has the capability to maintain its functional integrity during any postulated design event, including protection against missiles from internal or external sources, excessive motion of pipes, and jet forces associated with the flow from the postulated rupture of any pipe within the containment

d. The primary containment system is capable of being filled with water as an accident recovery method for any postulated DBA in which a breach of the nuclear system primary barrier cannot be sealed

e. The primary containment system, in conjunction with other nuclear safety systems and ESF systems, is capable of limiting leakage during any of the postulated DBAs for which it is assumed to be functional such that offsite doses do not exceed guideline values

f. The primary containment system has the means of rapidly condensing the steam portion of the flow from the postulated design-basis rupture of a recirculation line

g. The primary containment system has the means to

    1. Conduct the flow from postulated pipe ruptures to the suppression chamber

    2. Distribute such flow uniformly throughout the pool

    3. Limit pressure differentials between the drywell and the suppression chamber during the various postaccident cooling modes

    4. Effectively quench the steam flow from safety/relief valve (SRV) discharges.

h. The primary containment system has the capability to rapidly close or isolate all pipes or ducts that penetrate the primary containment, thereby maintaining leakage within permissible limits

i. The primary containment system is capable of being periodically leak tested to confirm the integrity of the containment at pressure

j. The primary containment system is capable of storing sufficient water to supply the emergency core cooling system (ECCS) requirements.

3.8.2.1.2 General Description

The steel primary containment consists of a drywell, vent pipes, and suppression chamber, and houses the reactor pressure vessel (RPV), recirculation system, and other primary components.

The primary containment is a steel structure composed of a series of vertical cylinders and truncated cones which form a drywell. This drywell is attached to a suppression chamber through a series of vents. The suppression chamber is a steel pressure vessel in the shape of a torus. The drywell total free air volume and torus minimum air and water volumes are referenced in Table 6.2-1.

In the event of a process system piping failure within the drywell, reactor water and steam are released into the drywell air space. The resulting increased drywell pressure then forces a mixture of air, steam, and water through the vents into a pool of water stored in the suppression chamber. The steam condenses rapidly and completely in the suppression chamber, resulting in a rapid pressure reduction in the drywell. Air that is transferred to the suppression chamber pressurizes the chamber and subsequently is vented to the drywell to equalize the pressure between the two vessels. The specific suppression chamber hydrodynamic events that result from a process system piping failure are detailed in Reference 1. A containment cooling spray system is provided to remove heat from the drywell and suppression chamber. Appropriate isolation valves are actuated during this period to ensure containment of radioactive materials that might otherwise be released from the primary containment during the course of an accident.

The primary containment system free volume is capable of being inerted with a nitrogen atmosphere during normal operation. The containment atmosphere control system is capable of reducing and maintaining the oxygen content of the atmosphere below 3.9 percent during normal operation to eliminate the possibility of a hydrogen/oxygen reaction.

3.8.2.1.2.1 Description of the Drywell

The drywell is a steel pressure vessel with a spherical lower portion 68 ft in diameter and a cylindrical upper portion 38 ft 10 in. in diameter. The overall height is approximately 114 ft 8 in. The design, fabrication, inspection, and testing of the drywell comply with the requirements of Section III, Sub-section B, of the ASME Boiler and Pressure Vessel (B&PV) Code, 1968 edition. The thickness of the cylindrical portion of the drywell and the lower spherical portion has been determined by the rules defined in Section UG-27 of ASME Section VIII. The drywell is enclosed in a reinforced-concrete biological shield (Subsection 3.8.4) and is supported by the drywell pedestal, as shown in Figure 3.8-1. The biological shield provides resistance to deformation and buckling in areas where it backs up the steel shell. Below the transition zone located at elevation 659.5 ft (New York Mean Tide, 1935), the drywell is separated from the shield by a gap of approximately 2 in.; this gap is filled with a compressible polyurethane material to allow for movement between the drywell and concrete. The polyurethane sheets are coated on both sides with an epoxy resin binder to prevent water leakage into the foam. The bottom portion of the shell (below elevation 572 ft 6 in.) is totally embedded in concrete and therefore is not subject to significant thermal stresses. The lower portion of the transition zone is backed by compacted sand to aid in condensation drainage. There are four 1-1/2-in. drain lines that can be used to remove moisture from the sand cushion in case of leakage into the gap between the drywell and shield. Shielding over the top of the drywell is provided by a removable, segmented, reinforced-concrete shield plug. See Figure 3.8-2 for a developed view of the drywell and the drywell penetration schedule.

In addition to the drywell head, one double-door air lock and two bolted equipment hatches are provided for access to the drywell (Subsection 3.8.2.1.3.4 and Figures 3.8-3 and 3.8-4). The locking mechanism on each air-lock door is designed to maintain a tight seal when the doors are subject to either external or internal pressure. The doors are mechanically interlocked so that neither door can be operated unless the other door is closed and locked. The drywell head and hatch cover are bolted in place and sealed with gaskets. Provisions have been made to permit leakage testing of the door and hatch cover seals.

The drywell will be entered during low power operation; however, access is nonroutine, infrequent, and rigidly controlled.

The exposed interior surfaces of the drywell pressure boundary are coated as described in Subsection 6.2.1.6 to protect steel surfaces from galvanic corrosion and to facilitate decontamination.

Drywell and equipment sumps are provided at the bottom of the drywell to collect and drain waste liquids. All waste liquids are then routed from the drywell sumps to the radwaste building with the aid of sump pumps.

The supporting structure for the drywell and biological shield is described in Subsection 3.8.5.

3.8.2.1.2.2 Description of the Suppression Chamber and Vent System

The suppression vent system, which connects the drywell and the suppression chamber, conducts flow from the drywell to the suppression chamber without excessive resistance and distributes this flow effectively and uniformly in the pool following a postulated DBA, intermediate-break accident (IBA), or small-break accident (SBA) in the drywell. The suppression chamber receives this flow, the steam portion is condensed, and the noncondensible gases are released to the suppression chamber air space. The suppression chamber and vent system response due to a postulated design-basis pipe rupture or main steam relief valve operation is further discussed in Reference 1. The suppression-chamber-to- drywell vacuum breakers limit the pressure differential between the drywell and the suppression chamber during postaccident primary containment system cooling.

A total of eight circular vent pipes, 6 ft in diameter, form the connection between the drywell and the suppression chamber. Jet deflectors (Figure 3.8-5) are provided in the drywell at the inlet end of each vent pipe to prevent possible damage to the vent pipes from jet forces accompanying a pipe break in the drywell. The pipes are enclosed in sleeves and provided with expansion joints to accommodate differential motion between the drywell and the suppression chamber.

The suppression chamber is a torus-shaped, continuous, leaktight steel pressure vessel with a major diameter of 112 ft 6 in. situated below and encircling the drywell. The inside diameter of the mitered cylinders that make up the suppression chamber is 30 ft 6 in. The suppression chamber shell thickness is typically 0.587 in. above the horizontal centerline and 0.658 in. below the horizontal centerline, except at penetration locations where it is locally thicker.

The suppression chamber shell is reinforced at each mitered joint location by a T-shaped ring beam. The ring beam is braced laterally with stiffeners connecting the ring beam web to the suppression chamber shell.

The suppression chamber is supported vertically at each mitered joint location by inside and outside columns and by a saddle support that spans the inside and outside columns (Figure 3.8-6). The columns, associated column connection plates, and saddle support are located parallel to the mitered joint in the plane of the ring beam web. Space has been provided outside the chamber for inspection and maintenance.

The anchorage of the suppression chamber to the basemat is achieved by a system of base plates, stiffeners, and anchor bolts located at each column and at two locations on each saddle support.

The design, fabrication, inspection, and testing of the suppression chamber comply with the requirements of ASME B&PV Code Section III, Class B. The thickness of the torus-shaped pressure vessel has been determined by means of the rules defined in Sections UG-27 and UG-28 of ASME Section VIII.

The suppression chamber shell, supports, internals, and attachments have also been reevaluated (References 1, 3, and 4) to include the hydrodynamic loading events and analysis methods defined by Topical Report NEDO-21888, Mark I Containment Program Load Definition Report (Reference 5), and NUREG-0661 (Reference 2). The appropriate service limits and edition of Section III of the ASME Code, specified in NUREG-0661, have been applied to the reevaluation.

The chamber has a total volume of approximately 251,980 ft^3. The center of the torus lies slightly below the bottom of the drywell (see Figure 3.8-7 for a plan view of the suppression chamber).

The drywell vents are connected to a torus-shaped ring header, 4 ft 3 in. in diameter, placed within the air space of the suppression chamber. Eighty 24-in.-diameter downcomer pipes project from the ring header and terminate below the water surface in the chamber pool. The pool water level is maintained to ensure a 3.00- to 3.33-ft submergence of the downcomer pipes.

A vent from the primary containment system is provided and is normally closed, but permits the vent discharge to be routed to the plant SGTS to control the release of gases from the primary containment.

The physical parameters of the primary containment are summarized in Table 3.8-1.

The total water and steam volume of the reactor vessel and recirculation system are referenced in Table 3.8-1.

3.8.2.1.3 Primary Containment Penetrations

Penetrations carry piping, mechanical systems, and electrical wiring through the biological shield and primary containment vessel. These penetrations can be classified as follows:

a. Piping penetrations (sleeved and unsleeved)

b. Electrical service penetrations

c. Mechanical system penetrations (traversing in-core probe penetrations)

d. Access openings.

To maintain design containment integrity, containment penetrations have the following design characteristics:

a. Capability to withstand peak transient pressures

b. Capability to withstand without failure the forces caused by impingement of the fluid from the rupture of the largest local pipe or connection

c. Capability to accommodate without failure the thermal and mechanical stresses that may be encountered during all modes of operation.

The number and sizes of the drywell penetrations are shown in Table 3.8-2. The corresponding details of these penetrations are shown in Figure 3.8-8. Penetrations for the suppression chamber are listed in Table 3.8-3.

3.8.2.1.3.1 Pipe Penetrations

The two general types of pipe penetrations provided are (1) those that must accommodate thermal movement (sleeved), shown in Figure 3.8-9, and (2) those that experience relatively little thermal stress (unsleeved), as shown in Figures 3.8-10 and 3.8-11.

Sleeved Penetrations

Relative or thermal movement is accommodated wherever required by using bellows-type expansion joints. For this type of joint, the penetration sleeve passes through concrete and is welded to the primary containment vessel reinforcement plate. The process line that passes through the penetration is free to move axially, and a bellows expansion joint accommodates the movement. A guard pipe surrounds the process line and is designed to protect the bellows and maintain the penetration. Insulation and air gaps reduce thermal stresses and limit the radial heat flow resulting from convection and radiation from the pipe penetration, and keep the temperature of the concrete adjacent to the sleeve below 150°F. Also, penetrations accommodating hot pipes feature cooling coils on the guard pipe.

Where necessary, the penetration lines are anchored outside the containment to limit the movement of the lines relative to the containment. The bellows accommodates the relative movement between the pipe and the containment shell. This design ensures the integrity of the flexing penetration during plant operation. The configuration of the sleeved penetrations is shown in Figure 3.8-9.

Figure 3.8-12 shows a main steam line penetration assembly, its associated inboard and outboard isolation valves, the penetration flued head anchor structure, outboard pipe whip restraint structure, and the inboard pipe whip restraint/seismic guide. The configuration is typical of those cases where high-energy line penetrations are required to resist pipe whip or jet impingement loads due to postulated pipe breaks. Design details and criteria of the various components that make up the containment penetration system shown in Figure 3.8-12 are discussed below.

Penetration Assembly

The penetration assembly consists of the process pipe, guard pipe, penetration sleeve bellows, and flued head. The process pipe is mounted concentrically within the penetration. It is connected at the outboard side to the penetration flued head, and is considered part of the piping inside containment. The process pipe is constructed of ASME Type SA-l06, Grade B, or SA-333, Grade 6 material, and is designed in accordance with ASME III, Class 1 requirements.

For all normal and upset conditions specified, design criteria limits are provided in Subsection 3.6.2.1.2.2. It should be noted that for Fermi 2 the upset condition includes the operating-basis earthquake (OBE).

The guard pipe is designed to protect the containment penetration sleeve and the containment sleeve bellows from damage due to pressurization or jet impingement loads in the event of a break in the process pipe within the penetration assembly. A jet deflector ring mounted on the inboard end of the guard pipe protects the containment sleeve from damage due to jet impingements emanating from other sources inside the containment. The guard pipe connection is hinged to the flued head to prevent excessive bending loads from being transferred from the guard pipe to the flued head, in the event of a break in the process pipe. The hinged connection is provided with a bellows to ensure the pressure integrity of the guard pipe. The guard pipe is constructed from American Society for Testing and Materials (ASTM) A-106 Grade B, or A-155 Grade KCF 70 material. Design criteria limit the stress in the guard pipe and hinge bellows to 0.90 of the yield strength, when the guard pipe is subjected to the design pressure and temperature of the process pipe.

The flued head serves as an extension of the process pipe and the process pipe anchorage point, and as a part of the primary containment pressure boundary. The flued head is constructed from a one-piece forging of ASTM A-l05 Grade II, or ASTM A-182 type-304 or 316 material, as required for compatibility with the process piping. Design of the flued head is in accordance with ASME III Class 1 requirements. The flued head forging is ultrasonically examined and radiographed in accordance with ASME III requirements. Attachment of the flued head to the anchor structure is by mechanical means; there is no welding involved.

The containment sleeve bellows allows relative movement between the containment sleeve attached to the primary containment shell and the flued head anchored to the biological shield wall. The bellows is constructed of ASTM A-240 material. Design calculations are made per Expansion Joint Manufacturers Association (EJMA) standards. Design pressure and temperature for the bellows under the various operating modes (normal, upset, emergency, and faulted) are identical with those of the primary containment.

<u>Flued Head Anchor Structure</u>

The flued-head anchor structure is provided as a structural support between the primary containment penetration flued head and the biological shield wall. The structure is designed to accept normal and upset condition loads as well as piping system reactions as a result of emergency (safe-shutdown earthquake [SSE]) and faulted condition loads (pipe whip and/or jet thrust). The structure is fabricated from a series of built-up structural tubes made from ASTM A-588 material. Design criteria under the various loading conditions limit allowable stresses to the following:

a. Normal and upset (OBE) conditions - American Institute of Steel Construction (AISC) allowable stresses

b. Emergency conditions - 0.9 x yield strength

c. Faulted conditions - 0.9 x ultimate strength.

For anchor structures that support more than one flued head, only one pipe line is assumed to be in the faulted condition at a given time.

<u>Piping Between the Containment Penetration and the Outboard Isolation Valve</u>

Piping between the primary containment flued head and the outboard isolation valve is designed to ASME III Class 1 requirements. Maximum stresses, considering all normal and upset conditions, may not exceed the limits provided in Subsection 3.6.2.1.2.2.

Outboard Pipe Whip Restraint Structure

A pipe whip restraint structure is provided at the outboard side of the outboard isolation valve. The structure is designed to limit the bending and downward thrust loads associated with pipe whips resulting from postulated breaks downstream of the isolation valve. Torsional loads on the valve are controlled by a U-bolt-type restraint system on the riser at the top of the main steam tunnel. A complete description of the outboard restraint structures, including the relevant design criteria, is given in Subsection 3.6.2.2.1.2.

Inboard Pipe Whip Restraint and Seismic Guide

The inboard pipe whip restraint and seismic guide is a dual purpose structure. During seismic events, the guide serves to support the piping system and limit its deflections to acceptable limits. During pipe-break events, a series of crushable stainless-steel tubes in the annular space between the pipe and guide intercept the pipe and absorb its kinetic energy. A more complete description of the inboard pipe-whip restraint/seismic guide is given in Subsection 3.6.1.5.1.5 and in Reference 1 to Section 3.6.

Unsleeved Penetrations

Low-temperature pipelines that contain fluids whose temperature is 150°F or less, and that do not require anchorage to the biological shield, are routed through unsleeved penetration assemblies of the type shown in Figure 3.8-11. Design criteria and analyses for those unsleeved penetrations serving ASME III Class 1 piping systems are the same as those previously described for the sleeved penetrations.

Piping penetrations serving ASME III Class 2 and 3 piping systems are classified ASME III Class 2.

The primary containment piping penetration arrangement for Class 2 systems is typically made up of three major components. They are the piping from the inboard isolation valve to the flued head, the flued head proper, and the piping from the flued head to the outboard isolation valve.

The inboard and outboard process piping between the isolation valves is designed to meet the criteria defined in Subsection 3.6.2.1.2.2.

The fabrication and materials used for the construction of the unsleeved flued heads are similar to those described previously for the sleeved flued heads. Analyses are performed in accordance with the requirements of ASME III, Subsection NC-3000.

Penetration LOCA Thermal Overpressure

NRC Generic Letter 96-06, “Assurance of Equipment Operability and Containment Integrity During Design Basis Accident Conditions”, raises the concern that during a postulated LOCA, piping inside containment will be heated beyond its normal operating temperature. The temperature increase would cause water trapped in piping (isolated by closed valves) to expand and the resulting pressurization could challenge piping integrity. Nonessential penetrations with piping susceptible to LOCA thermal overpressure have been evaluated in accordance with the criteria of the ASME Boiler and Pressure Vessel Code, Section III, Appendix F. Alternatively, some susceptible penetrations will relieve the overpressure condition before the limits of Appendix F are exceeded.

3.8.2.1.3.2 Electrical Penetrations

Figure 3.8-13 shows an electrical penetration and associated radiation shields of the general type that is used for power, control, and instrumentation circuits. Electrical conductors penetrating the biological shield and primary containment pass through the penetrations that are mounted in steel pipe sleeves. The sleeves are welded to the primary containment vessel.

Electrical termination cabinets are mounted on each end of the penetration canisters, which are attached by bolted flange connections and with O-ring seals. Each primary containment electrical penetration has provisions for continual testing for leaktightness with a pressure gage.

3.8.2.1.3.3 Traversing In-Core Probe Penetration

A total of seven traversing in-core probe (TIP) penetrations (five for guide tubes, and two spares) pass from the reactor building through the primary containment. (See Figure 3.8-14.) Penetrations of the insertion guide tubes through the primary containment are sealed by brazing and meet the requirements of ASME Section VIII. These seals also meet the intent of ASME Section III, even though the ASME Code has no provisions for qualifying the procedures or performance.

3.8.2.1.3.4 Personnel and Equipment Access Lock

One personnel access lock is provided for access to the drywell (see Figure 3.8-4). The lock has two gasketed doors in series and is designed to withstand the drywell design pressure. The doors are mechanically interlocked to ensure that at least one door is locked at all times. The locking mechanisms are designed so that a tight seal is maintained when the doors are subjected to either internal or external pressure. The seals on this access opening are capable of being tested for leakage. Both doors are furnished with a pressure-equalizing connection.

Two equipment access hatches and a control rod drive (CRD) removal hatch are provided and welded in the spherical portion, thus permitting extensive maintenance of the drive mechanism. These hatches have double testable seals and are bolted in place. (Figures 3.8-3 and 3.8-4 show hatch details.) The double seals are provided with a leakage test tap with which the space enclosed between the seals is pressurized to containment design pressure to test for leakage through the seal when the cover or door is locked in place.

3.8.2.1.3.5 Access To the Suppression Chamber

Access from the reactor building to the suppression chamber is provided at two locations. Each is a 4-ft-diameter manhole entrance with a double-gasketed bolted cover connected to the chamber by a 4-ft-diameter steel pipe. These access ports are bolted closed when the primary containment is required, and are opened only when the primary system temperature falls below 212°F and the pressure suppression system is not required to be operational.

The double seals are provided with a leakage test tap by which the enclosed space between the seals is pressurized to containment design pressure to test for leakage through the seal when the cover is bolted in place.

Externally, access to the suppression chamber is provided by maintenance platforms and walkways.

3.8.2.1.3.6 Access for Refueling Operations

The drywell head is removed during refueling operations. This head is held in place by bolts and is sealed with a double seal. It is bolted closed when the primary containment is required and is opened only when the primary coolant temperature falls below 212°F and the pressure suppression system is not required to be operational.

The double seals are provided with a leakage test tap by which the enclosed space between the seals is pressurized to containment design pressure to test for leakage through the seal when the cover is bolted in place.

3.8.2.2 Applicable Codes, Standards, and Specifications

Table 3.8-4 contains a comprehensive listing of all applicable codes, standards, and specifications for Fermi 2.

3.8.2.2.1 Primary Containment Vessel and Suppression Chamber

a. ASME Codes - The ASME B&PV Code, 1968 edition up to and including summer l969 Addenda, including the following sections:

    1. Section II, "Material Specifications," Part A, "Ferrous" - All steel material used in the primary containment and the suppression chamber conforms to the requirements of this section

    2. Section III, Class B, including Code Cases 1330-2, 1177-6, 1431, and 1443 - This section is used for the design, fabrication, examination, testing, inspection, and material specification for the primary containment vessel (Subsection 3.8.2.1.2.1) and the suppression chamber and vent system (Subsection 3.8.2.1.2.2)

    3. Section VIII.

b. AISC Steel Construction Manual - The "Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings," Sixth Edition, 1963, of the AISC is used in the design of non-pressure-retaining components

c. Code of Federal Regulations - The primary containment system leakage rate test is performed in accordance with the requirements of Appendix J, 10 CFR 50, "Reactor Containment Leakage Testing for Water-Cooled Power Reactors." The details of the type of testing performed are addressed in Subsection 6.2.4

d. ACI Specification ACI 318-63 - This American Concrete Institute (ACI) specification, titled "Building Code Requirements for Reinforced Concrete" and dated June 1963, is used in the design of the primary containment system

e. Steiger Occupation Safety and Health Act of l970

f. NUREG-0661 - "Safety Evaluation Report, Mark I Containment Long-Term Program," July 1980 (Reference 2), which establishes requirements affecting the design and operation of the primary containment system.

3.8.2.2.2 Penetrations

a. ASME Codes - The ASME B&PV Code, 1971 edition, including the following sections:

   1. Section II, "Material Specifications," Part A, "Ferrous" - All steel material used in the penetration conforms to the requirements of this section

   2. Section III, Class 1 and 2

   3. Section XI, for inservice inspection and baseline data accumulation, is used for examination and inspection

   4. The bellows used for the piping penetrations are designed in accordance with ASME Code Case 1177-6 (Subsection 3.8.2.3.2.2)

   5. Section VIII

   6. Section III, Subsection NE, is used for the design, fabrication, and testing of primary electrical penetrations (penetrations are class MC)

   7. Section IX is used for welding.

b. EJMA Specification - The design of all expansion joints conforms to the specifications of the EJMA

c. AISC Steel Construction Manual - The "Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings," Sixth Edition, 1963, of the AISC is used in the design of non-pressure-retaining components

d. Code of Federal Regulations - The penetration leak- detection and leakage rate test is performed in accordance with the requirements of Appendix J, 10 CFR 50, "Reactor Containment Leakage Testing for Water-Cooled Power Reactors." The details of the type of testing performed are addressed in Subsection 6.2.4

e. IEEE Standard 317-1972 - This standard of the Institute of Electrical and Electronics Engineers (IEEE), titled "IEEE Standard for Electric Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations," is used as a guide for the design, construction, testing, and installation of electrical penetrations

f. Steiger Occupation Safety and Health Act of 1970

g. NUREG-0661 - "Safety Evaluation Report, Mark I Containment Long-Term Program," July 1980, (Reference 2) which establishes requirements affecting the design and operation of the attachments to the suppression chamber.

3.8.2.2.3 Access Opening

a. ASME Codes - The ASME B&PV Code, l968 edition up to and including summer l969 addenda, including the following sections:

   1. Section II, "Material Specifications," Part A, "Ferrous" - All steel material used in the access opening conforms to the requirements of this section

   2. Section III, Class B, including Code Cases 1330-2, 1177-6, 1431, and 1443 - This section is used for the design, fabrication, examination, testing, inspection, and material specification for all access openings described in Subsections 3.8.2.1.3.4 through 3.8.2.1.3.6

   3. Section VIII.

b. AISC Steel Construction Manual - The "Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings," Sixth Edition, 1963, of the AISC is used in the design of non-pressure-retaining components

c. Code of Federal Regulations - The access openings leak detection and leakage rate test is performed in accordance with the requirements of Appendix J, 10 CFR 50, "Reactor Containment Leakage Testing for Water-Cooled Power Reactors." The details of the type of testing performed are addressed in Subsection 6.2.4

d. Steiger Occupation Safety and Health Act of 1970.

3.8.2.2.4 Special Precautions

Special precautions in addition to those required by codes are taken in the fabrication of the drywell shell. The steel plate is preheated to a minimum temperature of 200°F before welding whenever seam thickness exceeds 1 in., regardless of the surrounding air temperature. Furthermore, the plate is preheated to a minimum temperature of l00°F before the welding of all seams 1 in. or less in thickness if the ambient temperature falls below 40°F.

3.8.2.3 Loads and Loading Combinations

3.8.2.3.1 General Description

The loads and loading combinations given in Tables 3.8-5 through 3.8-17 were applied in the design of the primary containment.

The suppression chamber, vent system, and piping penetrations have also been analyzed for load combinations, including seismic and hydrodynamic loads resulting from LOCA-related and safety/relief valve discharge events. These loads and load combinations are described in Fermi 2 Mark I containment long-term program plant unique analysis reports (References 1 and 3).

Following is a general description of the loads that are normally associated with containment vessel design:

a. Seismic load - Horizontal and vertical accelerations for both the OBE and the SSE are considered. The following maximum accelerations are used to determine the seismic loads on the structure

1. OBE

Horizontal	0.08g
Vertical	0.053g

2. SSE

Horizontal	0.15g
Vertical	0.10g

b. Pipe break loads

c. Bellows loads

d. Gallery floor loads

e. Hydrostatic load - The containment may be flooded to the operating floor level during fuel-retrieving operations after an accident

f. Construction loads

g. Jet impingement loads

h. Dead load

i. Selected design temperatures and pressures

1. Suppression chamber

Internal design pressure	56 psig
External design pressure minus internal pressure	2 psid
Maximum external pressure	2 psig
Internal design temperature	281°F

2. Drywell

Internal design pressure	56 psig
External design pressure minus internal pressure	2 psid
Maximum external pressure	2 psig

	Internal design temperature	340°F
3.	Vent pipes and vent header	
	Internal design pressure	56 psig
	External design pressure minus internal pressure	2 psid
	Internal design temperature	281°F

3.8.2.3.2 Loading Combinations

3.8.2.3.2.1 Drywell

a. Cylindrical and spherical portion (general shell loads) -These parts of the drywell are designed for the loads and loading combinations described in Table 3.8-5. Their design is in accordance with ASME Section III for Class B Vessels and the AISC Specification for non-pressure-retaining parts. The drywell is protected from pipe rupture jet and reaction forces as described in Subsection 3.6.1. The drywell is also protected from concentrated missile loads as described in Section 3.5. Flooding of the drywell to an elevation of 684 ft 6 in. may be necessary for postaccident recovery and is considered in Table 3.8-5. The allowable stress consideration for these loading combinations is presented in Figure 3.8-15

b. Drywell vent penetrations (accident loads) - The pressure-retaining parts of the drywell vent penetrations are designed for the loads and loading combinations described in Table 3.8-7. These parts are designed in accordance with ASME Section III for Class B Vessels

c. Spherical embedment (accident loads) - The spherical embedment section of the drywell is designed for the loads and loading combinations described in Table 3.8-8. It is designed in accordance with ASME Section III for Class B Vessels

d. Drywell knuckle region (accident loads) - The knuckle region of the drywell is designed for the loads and loading combinations described in Table 3.8-9. These parts are designed in accordance with ASME Section III for Class B Vessels

e. Drywell cone and top head (accident loads) - The cone and top head region of the drywell is designed for the loads and loading combinations described in Table 3.8-10. These parts are designed in accordance with ASME Section III for Class B Vessels

f. Drywell top flange - The drywell top flange is designed for the loads and loading combinations described in Table 3.8-11. Since the flanges are attached to, and are considered part of, the pressure boundary, their design is in accordance with ASME Section III for Class B Vessels. The water seal is designed in accordance with the AISC Specification

g. Equipment hatches - The equipment hatch doors and other pressure-retaining parts are designed for the loads and loading combinations listed in Table 3.8-12. The design of these parts is in accordance with ASME Section III for Class B Vessels

   Those parts that do not form part of the pressure boundary (i.e., support bracket, pin, etc.) are designed for the loads and loading combinations listed in Table 3.8-12. The design of these parts is in accordance with the AISC Specification

h. Personnel lock - The loads and loading combinations for the personnel locks are the same as those given for the equipment hatch in Table 3.8-12

   In addition, the personnel lock attachment to the drywell shell is designed for the seismic loading condition of the SSE applied at the lock center of gravity. The design of the attachment to the drywell is in accordance with ASME Section III for Class B Vessels, as shown in Table 3.8-12

i. Beam seats - These parts of the drywell are designed for the loads and loading combinations described in Table 3.8-13

   Since they are not pressure-retaining parts, their design is in accordance with the AISC Specification. The part of the drywell to which the supports are attached is a pressure-retaining part and is designed for the loads and loading combinations listed in Table 3.8-13, in accordance with ASME Section III for Class B Vessels

j. Spray header - These parts of the drywell are designed for the loads and loading combinations described in Table 3.8-14

   Since they are not pressure-retaining parts, their design is in accordance with the AISC Specification. The part of the drywell to which the supports are attached is a pressure-retaining part and is designed for the loads and loading combinations listed in Table 3.8-14, in accordance with ASME Section III for Class B Vessels

k. Vent jet deflectors - These parts of the drywell are designed for the loads and loading combinations described in Table 3.8-14

   Since they are not pressure-retaining parts, their design is in accordance with the AISC Specification. The part of the drywell to which the supports are attached is a pressure-retaining part and is designed for the loads and loading combinations listed in Table 3.8-14, in accordance with ASME Section III for Class B Vessels

l. Stabilizer connection - The stabilizer connection is designed for the loads and loading combinations described in Table 3.8-15

   Since these parts are not pressure-retaining parts, their design is in accordance with the AISC Specification. The part of the drywell to which the stabilizer plates are attached is a pressure-retaining part and is designed using the allowable limit specified in ASME Section III for Class B Vessels

m. Skirt - The skirt is designed for the loads and loading combinations described in Table 3.8-16

Since these parts are not pressure-retaining parts, their design is in accordance with the AISC Specification. The part of the drywell to which the skirt is attached is a pressure-retaining part and is designed using the allowable limit specified in ASME Section III for Class B vessels

n. Penetrations - All penetrations are designed in accordance with ASME Section III for Class B Vessels. Pressure area replacement has been completed on each penetration in addition to the design for piping loads completed on those having significant loading. The loads and loading combinations for those penetrations having significant piping reactions are described in Table 3.8-17.

3.8.2.3.2.2 Suppression Chamber

a. Cylindrical torus - These parts of the suppression chamber are designed for the loads and loading combinations described in Table 3.8-6 and Reference 1. Their design is in accordance with ASME Section III for Class B vessels and the AISC Specification for non-pressure- retaining parts. Flooding of the suppression chamber during accident recovery is considered in Table 3.8-6. The allowable stress considerations for the loading conditions applied in the original design are presented in Figure 3.8-15. The allowable stresses for the load and load combinations resulting from the subsequently identified LOCA-related and safety/relief valve discharge events are addressed in References 1 and 3.

b. Torus support system - These parts of the suppression chamber are designed for the loads and loading combinations described in Table 3.8-6 (conditions 5 through l0) and Reference 1. The allowable stress limitations are presented in Reference 1

c. Penetrations

1. Bellows/vent - The vent penetrations in the suppression chamber have been provided with a bellows expansion joint to limit stresses in the suppression chamber below those allowed by ASME Section III for Class B Vessels. The design of the bellows is in accordance with Code Case 1177-6 for the design movement specified below:

Axial (compression)	0.875 in.
Axial (tension)	0.375 in.
Lateral (positive or negative)	0.625 in.

2. General - All penetrations are designed in accordance with ASME Section III for Class B Vessels. Pressure area replacement has been completed on each penetration. The loads and loading combinations for the penetrations are presented in Reference 3.

3.8.2.4 Design and Analysis Procedures

The primary containment vessel was designed and has been analyzed in accordance with the ASME B&PV Code, 1968 edition including the summer 1969 addenda, Section III for Class B Vessels. The suppression chamber shell, supports, internals, and attachments have also been reevaluated (References 1 and 3) to include the hydrodynamic loading events and analysis methods defined by Topical Report NEDO-21888, "Mark I Containment Program Load Definition Report" (Reference 5), and NUREG-0661 (Reference 2). The appropriate service limits and editions of Section III of the ASME Code, specified in NUREG-0661, have been applied in the reevaluation. The NRC reviewed the Fermi 2 Plant Unique Analysis Report (PUAR) for the Mark I containment long-term program and concluded that the PUAR analysis verified that the completed containment modifications had restored the original design safety margin to the Fermi 2 Mark I containment (Reference 6).

3.8.2.4.1 Drywell

In general, the drywell has been analyzed and designed as an axisymmetrically loaded thin shell of revolution. The drywell has complete freedom of movement, except at its base, where it is rigidly attached to the drywell pedestal, and at its top, where it is restrained tangentially by the earthquake-stabilizer truss system (see Subsection 3.8.3 for a description of the earthquake-stabilizer truss system).

The primary shell membrane stresses have been computed for each of the load combinations specified in Subsection 3.8.2.3.2 by using the general equations for an axisymmetrically loaded shell of revolution. The derivation of these equations can be found in Chapter 14 of Reference 7. A CBI computer program, No. 7-78 (Section 3.13), which uses these equations to solve for the membrane forces, deflections, stresses, and strains, was used. The membrane stresses obtained from this analysis have been compared with the ASME allowables, and the compressive membrane stresses have been compared with the critical buckling stresses.

Shear and moment diagrams for both OBE and SSE accelerations have been calculated as outlined in Section 3.7 and are shown in Figures 3.8-16 through 3.8-21. These shears and moments are applied as static loads to determine the stresses in the drywell shell.

Included in the analysis of the drywell are the effects of dead and live loads, internal and external pressures, temperatures, earthquake loads, and the hydrostatic load of water in the drywell during an accident or refueling. The effects from penetrations, access openings, and beam seats are local in nature and are not considered to affect the overall analysis. These localized effects are analyzed individually as described in the following paragraphs. The drywell is reinforced around penetrations and access openings to minimize the effects from localized loads. The effects of significant nonaxisymmetric and transient loads are considered in all analyses.

During pressurization of the drywell, the vent pipes exert radial and vertical thrusts on the drywell shell. Because the vent pipes are equally spaced around the drywell circumference, the radial thrusts cancel each other. The upward lift of the vent pipes is conservatively neglected in the drywell analysis, because it opposes the shell weight. However, local membrane and secondary bending stresses are found at the local shell region of the vent penetration for the various vent thrusts specified in Subsection 3.8.2.3.2. This local shell analysis was completed by the method outlined in Welding Research Council Bulletin No. l07 (Reference 8), with the resulting stresses being compared with those allowed in ASME Section III for Class B Vessels. These penetrations have also been evaluated for the stress conditions resulting from the LOCA-related and safety/relief valve discharge events defined in NUREG-0661. The analytical-model and stress results are presented in Reference 1.

During erection and pressure testing, the drywell was supported by a temporary construction skirt anchored to the drywell pedestal. Openings in the skirt permit proper placing of concrete fill between the structural concrete pedestal and the drywell bottom.

The skirt is designed to provide for forces due to vent pipe thrust during the pressure test, wind load, and the dead load of the drywell vessel. On completion of the pressure tests, the skirt was embedded into the concrete slab. The local discontinuity region of the spherical shell to concrete embedment was analyzed by using the KALSHEL computer code developed by A. Kalnins of Yale University (see Section 3.13). This program performs the analysis of shells of revolution that are subject to symmetrical and nonsymmetrical loadings.

Included in the model loading are the restraining effects of the concrete surrounding the steel plates that make up the concrete transition section, as well as the effects of dead and live loads, internal and external pressures, temperatures, earthquake loads, and the hydrostatic load of water in the suppression pool (see Subsection 3.8.2.3.2). The boundary conditions for the transition section were taken as being fixed at the concrete junction. The stresses in those parts of the skirt that are not pressure-retaining were analyzed considering acting forces and moments, and were compared with the allowable limit of the AISC Specification. Refer to Subsection 3.8.3 for a discussion of the anchorage for the drywell floor to the drywell support pedestal.

The drywell shell was analyzed in the region of the knuckle for the accident condition to determine its discontinuity stresses. The knuckle was subjected to pressure loads acting normal to the shell, and to vertical loads resulting from dead, live, and seismic loads applied by the cylindrical shell to the knuckle.

The analysis was performed using the KALSHEL program. The boundary conditions were taken from the general shell analysis performed by CBI Program 7-78. Maximum primary stresses were calculated and compared with those allowed in ASME Section III for Class B Vessels.

The drywell shell was analyzed in the regions of the cone section and top head for the accident condition to determine the discontinuity stresses. The shell was subjected to an internal pressure of 56 psig. The boundary conditions were taken from general equilibrium equations.

The drywell head region is separated from the rest of the drywell by the bulkhead plate (Subsection 5.4.6.3.6.). During normal operation, atmospheres in the two regions communicate via eight 12-in. holes in the bulkhead plate. A study has been made on the head region pressure transient caused by the rupture in the head spray line.

The calculation was in two parts:

a. Mass flow out of the break

b. Pressure differential across the bulkhead plate for that mass flow rate.

Equations and physical parameters were obtained from standard engineering references and handbooks. Mass flow out of the break is based on choke flow in the 3-in. inside diameter pipe in the nozzle. Empirical equations for mass flow rate of steam under choke-flow conditions give a mass flow of 10^5 lb/sec.

Given this mass flow, the pressure drop across the bulkhead plate was calculated. The equation used was for flow rate through an orifice for cases other than choke flow. The equation includes the parameters of gas constant, R, ratio of specific heats, k, and discharge factor for the orifice, c. The values used for the parameters were selected to be representative of saturated steam, i.e., 65 lbf ft/lbm °R, 1.3 and 0.6 respectively.

The study showed the pressure in the head region would be 2 lb/in^2 greater than the drywell when all eight holes are open, and 8 lb/in^2 if half of the holes are blocked. These pressure differentials are far below design criteria on the drywell head and the bulkhead plate.

The design is in accordance with the allowable stress limits of ASME Section III for pressure-retaining parts and the AISC Specification for non-pressure-retaining elements. The loadings specified in Subsection 3.8.2.3.2 were used in the design calculations.

The drywell equipment hatches were analyzed using standard hand formulas taken from References 9, 10, and 11.

Their design is in accordance with the allowable stress limits of ASME Section III for pressure-retaining parts and the AISC Specification for non-pressure-retaining elements. The loadings specified in Subsection 3.8.2.3.2 were used in the design calculations and consist of jet forces, bolt loads, pressure (plus or minus), and earthquake forces. The local area between the equipment hatch and the drywell shell is designed to meet the area reinforcement requirement shown in Paragraph N-454 of ASME Section III.

The design evaluation of the personnel lock was completed by the same methods and loading conditions as those described for the equipment hatch, with the following exceptions:

a. A finite element study has been completed for the effect of jet forces on the rectangular door

b. Additional calculations were made for the overhang of the personnel lock with relation to local drywell shell stresses. Local stresses in the drywell were calculated by the methods outlined in Reference 8 for the loading conditions of dead weight and earthquake forces.

The beam seats, spray header, and jet deflectors were analyzed using standard hand formulas taken from References 7, 9, 10, 12, 13, and 14.

Their design is in accordance with the allowable stress limits of ASME Section III for pressure-retaining parts and the AISC Specification for non-pressure-retaining elements. The loadings specified in Subsection 3.8.2.3.2 were used in the design calculations and consist of dead and live loads, pressure, and jet forces. In addition, maximum compressive stresses were evaluated to the allowable limits specified in the buckling formulas prescribed in Welding Research Council (WRC) Standard 69.

The stabilizer mechanism is designed to transfer into the building the reaction due to seismic loads or seismic plus jet loads acting on the drywell, reactor, and shield. The stabilizer mechanism is composed of four components: (1) the connection between the reactor stabilizer and the drywell shell, (2) the male lug, (3) the female lug, and (4) the concrete shear connectors. The geometry of the stabilizer mechanism allows for radial and vertical movements due to pressure and temperature. Computed stresses in the stabilizer mechanism were found by standard elastic hand formulas taken from References 9 and 10.

The design of the stabilizer mechanism is in accordance with the allowable stress limits of ASME Section III for pressure- retaining parts and the AISC Specification for non-pressure-retaining elements. Anchorage to concrete structure was checked for allowable bearing and shear stresses in accordance with ACI 318-63. The loads and loading combinations are specified in Subsection 3.8.2.3.2.

All penetrations are designed for area replacement using the reinforcing requirements of ASME Section III. In addition, penetrations with significant nozzle loadings have been evaluated for those loadings by the methods presented in Reference 8. These loads and loading combinations are described in Subsection 3.8.2.3.2.

There are no pipe restraints attached to the drywell. However, in the event of a LOCA, pipes that penetrate the drywell may impart in-plane membrane forces to the shell.

In the areas where the drywell shell is not backed up by concrete (e.g., at the drywell head), primary stresses from all loads, including LOCA jet and piping reaction forces, are held within 0.90 times the yield strength of the material at the indicated temperature, as specified in Table N-424 of ASME Section III. The combined primary and secondary stresses are limited, in accordance with Paragraph N-414.4 of ASME Section III, to three times the allowable stress intensity values given in Table N-421 of ASME Section III.

In the areas where the drywell shell is backed by concrete, LOCA jet loadings and piping reaction forces were evaluated by conducting physical load-deflection tests. These tests were completed by CBI using a spherical shell segment of the same geometric configuration as that of the drywell sphere. Three tests were performed and consist of

a. The evaluation of the spherical shell deflection under the loading of a representative LOCA jet

b. The evaluation of the spherical shell deflection at an integrally reinforced penetration under the loading of a representative LOCA piping reaction

c. The evaluation of the spherical shell deflection at a pad reinforced penetration under the loading of a representative LOCA piping reaction.

In each test above, it has been shown that the steel shell can deflect up to 3 in. locally without failure. Considering the 2-in. gap between the drywell shell and the shielding concrete, this 3-in. deformation criterion ensures a conservative design. Permanent deformations are acceptable, providing that failure does not occur, as indicated by the above tests. The cylindrical drywell area was justified by a comparison of its rigidity to the sphere rigidity.

3.8.2.4.2 Suppression Chamber

The torus-shaped suppression chamber is designed as an axisymmetric shell of revolution. Analysis techniques similar to those used for the drywell were applied in the original design of the suppression chamber. The suppression chamber design has subsequently been reevaluated and modified for the effects of the LOCA-related loads and SRV discharge-related loads defined by NUREG-0661 (Reference 2) and the GE Report NEDO-21888, "Mark I Containment Program Load Definition Report" (Reference 5). The loads, load application methods, and structural analysis techniques applied in the suppression chamber reevaluation are described in References 1 and 3. The criteria set forth in NUREG-0661 and the original containment design specifications have been applied as a basis for acceptance of the analysis methods and the suppression chamber design.

3.8.2.5 Structural Acceptance Criteria

The structural acceptance criteria for stress and strain are specified in the codes. The following is a general listing of these criteria that for the suppression chamber have been supplemented or modified by the criteria set forth in NUREG-0661 (Reference 2):

a. The design of the primary containment is such that the stress intensities do not exceed the limits prescribed in Subarticle N-1320 of ASME Section III for Class B Vessels

b. The primary containment design details conform to the rules specified in Subarticle N-414 of ASME Section III

c. For configurations where compressive stresses occur, the critical buckling stresses were calculated, and the ratio of compressive stress to critical buckling stress was ascertained to be less than 1.0

d. Pneumatic testing is used for all pressure tests of the primary containment and is conducted in accordance with the requirements of Subarticle N-713 of ASME Section III

e. The ASME B&PV Code does not specifically address itself to deformation limits. However, the deformations have been limited by keeping the stresses within the elastic range of allowable stress requirements of ASME Section III. For local conditions, the biological shield, which is spaced 2 in. away from the primary containment, provides an ultimate limit for all local deformations

f. All non-pressure-retaining parts are designed such that no stresses exceed the limitation of the AISC Specification, Sixth Edition, 1963

g. All concrete bearing stresses are limited to the allowable stresses stated in ACI 318-63.

3.8.2.6 Design Loading Combination Stress Limits

The design loading combinations are categorized in Subsection 3.8.2.3.2. The design stress limits for these combinations are given in Subsection 3.8.2.5.

3.8.3 Concrete and Structural Steel Internal Structures of the Steel Containment

3.8.3.1 Description of the Internal Structures

The containment internal structures are Category I structures. They are mostly heavily reinforced-concrete walls and slabs, with the exception of structural steel flooring or truss systems. They are designed to support the principal nuclear steam supply equipment and the several floor levels within the containment. They are also designed for DBA condition and radiation shielding. The radiation will not adversely affect these structures. The containment internal structures include the following major components:

a. Sacrificial shield
b. Reactor pedestal
c. Drywell floor
d. Gallery floor levels
e. Earthquake-stabilizer truss system
f. Pipe-break-support truss system.

3.8.3.1.1 Sacrificial Shield

The sacrificial shield (Figure 3.8-22) is a composite structural steel and plain concrete open-ended cylindrical shell placed concentric to the reactor pressure vessel (RPV) vertical centerline (see Reference 15). It functions as a radiation and heat barrier between the RPV and the primary steel containment wall. Because of its proximity to the piping, it provides support for pipe whip restraints either directly or indirectly through a pipe-break- support truss system. The geometry of the shield is as follows.

a. Outside diameter: 29 ft 1 in.
b. Height: 48 ft 11-3/4 in.
c. Wall thickness: 1 ft 9-1/4 in.

The shield has 3/8-in.-minimum-thick steel plates on its exterior and interior surfaces and is stiffened meridionally by vertical steel columns. The steel plates are welded to the flanges of the columns, and the annular space between the plates is filled with grout.

Openings are provided in the shield for the passage of lines from the RPV to the drywell. Those openings which lie within an area 9 ft above and 16 ft below the centerline of the core are required to be shielded and are equipped with shielding doors. These doors are locked and will not open during a pipe break within the annulus. The openings above and below this band have no shielding requirements; they are covered with a light-weight rupture diaphragm designed to help relieve the annulus pressure should a break occur.

The exterior surfaces of the shield are sandblasted and coated as described in Subsection 6.2.1.6.

The shield is rigidly attached at the bottom to the reactor support pedestal; the top is free to displace in all directions, except tangential, which is restrained by an earthquake- stabilizer truss system.

3.8.3.1.2 Reactor Pedestal

The reactor pedestal concentric to the RPV vertical centerline (Figure 3.8-23) supports the RPV, sacrificial shield, and pipe whip restraints, which are attached to the pedestal, either directly or indirectly through a pipe-break-support truss system. The pedestal is a reinforced-concrete cylindrical shell with an outer radius of 14 ft 6-1/2 in. and a height of approximately 26 ft. The thickness of the shell varies from 4 ft at its base to 5 ft 6-1/2 in. at its top. The shell is reinforced on both faces by hoop and meridional steel and is integral with the drywell floor.

The RPV ring girder is bolted to a ring plate and then anchored to the top of the reactor pedestal with anchor bolts (Figure 3.8-24). Shear bars welded to the ring plate and embedded in the pedestal transfer tangential shear loads from the RPV to the pedestal; the anchor bolts resist vertical reactions and radial shear.

The inside and outside surfaces of the RPV support pedestal are coated with Nu-klad surfacer 110AA and one finish coat of Ameron polyamide epoxy No. 66.

This coating system protects the pedestal surfaces against attack by either demineralized (aggressive) water or radiation contamination and facilitates washdown.

3.8.3.1.3 Drywell Floor

The drywell floor is a reinforced-concrete pad poured on the bottom of the containment. It is connected to the basemat by special shear keys that transfer lateral forces to the mat (Figure 3.8-1). The shear lugs have anchors attached to them to transfer the uplift forces to the basemat. The main function of the drywell floor is to act as a foundation for the reactor support pedestal within the containment as well as to support the drywell vessel itself.

3.8.3.1.4 Gallery Floor Levels

There are two gallery floor levels within the containment; these serve as a means of access to the internals of the primary steel containment. The gallery levels consist of radial steel beams; the lower gallery is supported by the reactor pedestal, and the upper by the sacrificial shield.

3.8.3.1.5 Earthquake-Stabilizer Truss System

The earthquake-stabilizer truss system (Figure 3.8-25) is a structural steel truss constructed at the top elevation of the sacrificial shield. This system stabilizes the RPV and sacrificial shield under earthquake excitation by transferring the earthquake-induced forces to the concrete biological shield. The RPV is connected to the sacrificial shield, and the sacrificial shield, in turn, is connected to the primary steel containment by a steel truss arrangement. A special "shear lug" connection attaches the truss gusset plates to the containment wall. Similarly, a shear lug connection attaches the primary containment wall to the biological shield. Briefly, the shear lug connection permits radial movement and restrains tangential movement; this type of connection allows the primary steel containment to expand and contract freely under all service conditions.

3.8.3.1.6 Pipe-Break-Support Truss System

The primary steel containment is not designed to withstand loads imposed by pipe break restraints. Therefore, a structural steel pipe-break-support truss system is designed to carry those pipe restraints that cannot be carried by the steel containment (Reference 16 and

Section 3.6). The truss system is supported by the sacrificial shield, reactor pedestal, drywell floor, or any combination thereof (Figure 3.8-26).

3.8.3.2 Applicable Codes, Standards, and Specifications

This subsection lists the codes, specifications, standards of practice, regulatory guides, and other accepted industry guidelines that have been adopted to the extent applicable in the design and construction of the structures internal to the containment. To eliminate repetitious listing for each structure, the codes, standards, and specifications are listed and discussed in Table 3.8-4 and are given a specification reference number.

For each structure internal to the containment, the applicable specification reference numbers are as follows:

Structure	Specification Reference Numbers
Sacrificial shield	2 through 5, 8 through 11, 13 through 17, 20, 21, 23, 28, 34, 39, and 41
Reactor pedestal	1 through 9, 11, 13 through 17, 19, 20, 28, 34, 35, 38, 39, and 41
Drywell floor	Same as for the reactor pedestal
Gallery floor levels	20, 21, 23, 34, 39, and 41
Earthquake-stabilizer truss system	Same as for the gallery floor levels
Pipe-break-support truss system	Same as for the gallery floor levels

3.8.3.3 Loads and Loading Combinations

3.8.3.3.1 Sacrificial Shield

The sacrificial shield is designed for the following loads, in addition to its own dead and live loads (Reference 15):

a. Accident pressures caused by postulated pipe breaks at the nozzles of pipe lines, such as at the recirculation line

b. Thermal and pressure loads under normal operating and accident conditions

c. Pipe rupture loads transmitted by pipe whip restraints connected directly or indirectly through the pipe- break-support trusses to the sacrificial shield

d. Forces induced in either OBE or SSE.

The effects of shrinkage are minimized by designing the grout mix for minimal shrinkage (Subsection 3.8.4.6) and by prescribing construction techniques to minimize differential shrinkage. Where areas of critical shrinkage were defined in the design phase, appropriate shrinkage strains were input as loads in the analysis procedure.

The loading combinations and load factors shown in Tables 3.8-18 and 3.8-19 were applied in the design of the sacrificial shield. A project specification specifies the load combinations for which the sacrificial shield doors were designed.

3.8.3.3.2 Reactor Support Pedestal

The reactor support pedestal is designed to resist the following loads, in addition to its own dead load and live loads:

a. Dead and live loads from the RPV, sacrificial shield, gallery floor levels, and pipe-break-support trusses

b. Thermal and pressure loads under normal operating and accident conditions.

c. Pipe rupture loads transmitted by pipe whip restraints connected directly or indirectly through the pipe- break-support trusses to the reactor support pedestal

d. Forces induced in either OBE or SSE

e. Thermal, pressure, earthquake, and pipe rupture loads that act on the RPV and sacrificial shield and are transmitted to the reactor support pedestal via the support reactions.

The effects of shrinkage are minimized by designing the concrete mix for minimal shrinkage (Subsection 3.8.4.6) and by prescribing construction techniques to minimize differential shrinkage. Where areas of critical shrinkage were defined in the design phase, appropriate shrinkage strains were input as loads in the analysis procedure.

The loading combinations and load factors shown in Tables 3.8-19 and 3.8-20 were applied in the design of the reactor support pedestal.

3.8.3.3.3 Drywell Floor

The drywell floor is designed for the following loads in addition to its own dead and live loads:

a. The reactor pedestal support reactions (vertical, base shear, and overturning moment)

b. The reactions imposed by the pipe-break-support truss system

c. Thermal and pressure loads imposed during normal operating and accident conditions

d. Forces induced during an OBE or SSE.

The loading combinations and load factors shown in Tables 3.8-19 and 3.8-20 were applied in the design of the drywell floor.

3.8.3.3.4 Gallery Floor Levels

The gallery floor levels are designed for the following loads in addition to their own dead load:

a. A uniform platform load of 100 lb/ft^2

b. Miscellaneous loads from pipe hangers, ventilation ducts, and electrical cable trays

c. Forces induced during an OBE or SSE.

The loading combinations and load factors shown in Tables 3.8-l8 and 3.8-19 were applied in the design of the gallery floor levels.

3.8.3.3.5 Earthquake-Stabilizer Truss System

The earthquake-stabilizer truss system is designed for the following loads in addition to its own dead load (Reference 16):

a. Reactions imposed by the RPV overturning moment

b. Thermal and pressure loads imposed during normal operating and accident conditions

c. Forces induced during an OBE or SSE.

The loading combinations and load factors shown in Tables 3.8-18 and 3.8-19 were applied in the design of the earthquake- stabilizer truss system.

3.8.3.3.6 Pipe-Break-Support Truss System

The pipe-break-support truss system is designed for the following loads in addition to its own dead load:

a. Pipe whip restraint forces due to a rupture of the supported pipes (see Reference 16)

b. Miscellaneous loads from pipe hangers, ventilation ducts, and electrical cable trays as applicable

c. Temperature and pressure effects during normal operating and accident conditions.

The loading combinations and load factors shown in Tables 3.8-18 and 3.8-19 were applied in the design of the pipe-break-support truss system.

3.8.3.4 Design and Analysis Procedures

3.8.3.4.1 Sacrificial Shield

The sacrificial shield resists loads in the same manner as a meridionally stiffened cylindrical shell (Reference 15). The pipe whip restraints (Reference 16) are attached directly or through secondary members to column flanges, enabling the pipe whip forces to be rapidly distributed due to shell action. Buckling of the plates is prevented by welding studs to the plates and embedding the studs in the grout. The grout acts mainly as a radiation shield and is not reinforced to carry any direct or flexural stresses. However, because it is in an enclosed space, the grout has been designed to transfer shear forces between the exterior and interior plates.

The sacrificial shield is designed as an anisotropic, asymmetric, cylindrical shell. Asymmetry is due to the presence of openings in the shell. A Sargent & Lundy (S&L) three-dimensional finite element program, SLSAP, has been used to analyze the shield (Section 3.13).

The sacrificial shield columns have been modeled as beam elements; the plates and grout in between have been modeled as plane stress elements. The base of the shield was considered fixed in all directions against rotation and translation. The top of the shield was considered free to rotate and translate in all directions, except the tangential, which is fixed against translation by the earthquake-stabilizer truss system.

For both normal operating and accident conditions, the temperature gradients across the shield and their corresponding axial temperatures caused by radiation-generated heat were calculated by applying the principles of heat transfer. The temperature gradients and axial temperatures were input to the SLSAP model loading conditions (Subsection 3.8.3.3.1).

Loads were combined as appropriate, taking account of the postulated failure locations and types. It was concluded, because of the dynamic characteristics of the sacrificial shield, that peak restraint impact loads are local impulsive loads on the shield wall (Reference 15). These loads occur in the first milliseconds after rupture and are not combined with other loads. The shield wall is allowed to yield locally at regions of impact loads, provided

a. The overall capacity of the shield wall to resist elastically to the other forces listed is not affected

b. The local yielding does not produce effects that jeopardize the safety of other components.

The shield wall design is presently based on the maximum steady-state jet thrust of 1.25 p x A (where p is the pressure and A is the pipe area) at each postulated restraint location. This is conservative, since jet thrust loads decay, depending on break location proximity to feeding volumes.

For each loading condition, all the individual element stresses were output by SLSAP. A maximum stress envelope was then obtained for all the various load combinations specified in Subsection 3.8.3.3.1.

3.8.3.4.2 Reactor Support Pedestal

The reactor support pedestal is designed as a variable-thickness, axisymmetric cylindrical shell fixed at its base and free at its top. Two S&L shell structural analysis programs, SOR-III and KALSHEL (Section 3.13), were used to analyze the support. Geometry, thickness, boundary conditions, elastic properties, and loads are the inputs to both programs; stresses and force resultants at specified cross sections are the outputs. Thermal gradients and their corresponding axial temperatures caused by radiation-generated heat were calculated by applying the principles of heat transfer. The temperature gradients and axial temperatures were input as loads to SOR-III and KALSHEL.

The use of two independent analytical techniques, SOR-III and KALSHEL, provides a means of checking the analysis. Using the force-resultant outputs from SOR-III and KALSHEL, critical cross sections were chosen for detailed analysis by TEMCO-III (Section 3.13). The geometry of the concrete section and the force resultants acting on that section were inputs to TEMCO-III, and the reinforcing steel and concrete stresses are outputs. For sections that are critical in terms of allowable stresses, the capacity of a section under combined loads was verified by plotting an interaction diagram with the aid of the computer program INDIA (Section 3.13).

The top portion of the reactor support pedestal is designed to resist all seismic and pipe rupture forces transmitted through the RPV skirt and also the base of the shield wall. Pipe rupture forces and discontinuity forces at the base of the shield wall, resulting from pressurization of the annulus between the RPV and primary shield wall during a recirculation line break, were used to analyze and design the pedestal in combination with the seismic forces determined from the dynamic analysis of the reactor building.

In addition, the overturning moment and shear associated with a main steam line rupture in combination with seismic overturning moments and shears from the RPV and shield wall were used for the analysis and design of the pedestal.

The seismic and pipe rupture forces on the pedestal, discussed above, were used in combination with other loads as outlined in Subsection 3.8.3.3.2.

3.8.3.4.3 Drywell Floor

The drywell floor was analyzed using conventional elastic methods and designed in accordance with ACI 318-63 and/or ACI 318-71.

3.8.3.4.4 Gallery Floor Levels

The gallery floor levels were analyzed using conventional elastic methods and designed in accordance with the AISC Specification, 1969 Edition.

3.8.3.4.5 Earthquake-Stabilizer Truss System

The earthquake-stabilizer truss system was analyzed as a statically indeterminate truss by conventional elastic methods and designed in accordance with the AISC Specification, 1969 Edition. Applicable computer programs listed in Section 3.13 were used in part or totally for the structural analysis.

3.8.3.4.6 Pipe-Break-Support Truss System

The pipe-break-support truss system was analyzed by conventional elastic methods, as stated in the AISC Specification, 1969 Edition. Applicable computer programs listed in Section 3.13 were used in part or totally for the structural analysis.

3.8.3.5 Structural Acceptance Criteria

3.8.3.5.1 Sacrificial Shield

The stresses in the sacrificial shield steel plates are limited to those specified in the AISC Specification, 1969 Edition, Part I, when the steel plates were being designed for the loading combinations listed in Tables 3.8-18 and 3.8-19 (see Reference 15).

The appropriate factors of safety against yield used are those discussed in the Commentary to the 1969 AISC Specifications. The allowable steel stresses were increased to 1.6 times those specified above, subject to an upper limit of 0.95 f_y (yield stress), when designing for loading conditions 5, 10, and 11 in Table 3.8-18 and corresponding stresses in Table 3.8-19. In this situation a minimum design factor of safety of 1.0/0.95 = 1.05 against yield is ensured. In both cases, deformation of the steel plates is limited because the steel stresses are kept within the elastic range.

The stresses and strains in the plain concrete between the steel plates are limited to those specified by the Strength Design Method of ACI 318-71. The factors of safety against material strength are contained in the load factors listed in Tables 3.8-19 and 3.8-20, and the undercapacity factors (ϕ) are specified by ACI 318-71.

Earthquake-induced stresses and strains are limited to the aforementioned allowables; no increases are permitted.

3.8.3.5.2 Reactor Support Pedestal

The strain in the reinforcing steel and concrete is determined in accordance with ACI 318-63 and/or ACI 318-71.

The load combinations given in Tables 3.8-19 and 3.8-20 are designed for using the yield limit criteria. The yield limit strength of the structure was defined for this design as the upper limit of elastic behavior of the effective load-carrying material. The allowable stresses for this limit are in accordance with ACI 318, with the following limitations and clarifications:

a. Concrete

1. Compression

(a) Membrane stress = $0.6\ f_c'$

(b) Membrane plus flexural stress = $0.75\ f_c'$

(c) Local compression = $0.9\ f_c'$

2. Tangential shear

The principal stresses resulting from the tangential shear stresses and membrane stresses were computed for all load combinations. If principal tension greater than $3\sqrt{f_c'}$ developed in localized areas, the reinforcing steel was designed to carry the total tensile force.

b. Reinforcing Steel

1. Maximum tensile stress = $0.9\ f_y$

2. Maximum compressive stress = $0.9\ f_y$ (load carrying).

Deformations of the reactor support pedestal are limited by specifying a maximum allowable concrete strain of 0.002 in. per in. and by keeping the stresses in the reinforcing steel below yield. Redistribution of loads caused by plastic deformations is not permitted. The factors of safety against material strength are contained in the load factors listed in Table 3.8-20 and the under capacity factors (ϕ) specified in ACI 318. Serviceability checks in accordance with ACI 318 were made to ensure adequate crack control and to limit deformations.

As in the sacrificial shield, no increases in the allowable stresses or strains specified above were permitted when designing for earthquake-induced forces.

3.8.3.5.3 Drywell Floor

The stresses and strains in the reinforced-concrete floor are limited to those specified in ACI 318-63 and/or ACI 318-71. The factors of safety against material strength are contained in the load factors listed in Table 3.8-20 and in the under capacity factors (ϕ) of ACI 318. Serviceability checks are made in accordance with ACI 318 to limit cracking of the floor.

3.8.3.5.4 Gallery Floor Levels

The allowable steel stresses and strains for the gallery floor levels are as specified in Subsection 3.8.3.5.1. Steel member deflections were calculated and kept below the allowable AISC limits or below manufacturers' recommendations for equipment supported by the steel.

3.8.3.5.5 Earthquake-Stabilizer Truss System

The allowable steel stresses and strains in the earthquake-stabilizer truss system are specified in Subsection 3.8.3.5.1. No increases in the allowable stresses and strains were permitted when designing for the earthquake-induced forces.

3.8.3.5.6 Pipe-Break-Support Truss System

The allowable steel stresses and strains for the pipe-break-support truss system are specified in Subsection 3.8.3.5.l. Steel deflections were calculated and kept below allowable AISC limits or below manufacturers' recommendations for equipment supported by steel. For a discussion of the design criteria for the pipe break restraints, see Section 3.6.

3.8.3.6 Materials, Quality Control, and Special Construction Techniques

3.8.3.6.1 Sacrificial Shield

The construction materials and quality control (QC) procedures for the sacrificial shield conform to the standards set forth in Subsection 3.8.4.6.

Radiation damage to steel is caused by a neutron flux with neutrons of energy greater than l MeV. It has been ascertained that a neutron flux incident on the inside face of the sacrificial shield steel plate is 1.6 x 10^7 neutrons per square centimeter per second. This will result in a neutron fluence of 2.0 x 10^{16} n/cm^2 in the 40-year operating life of the plant.

The first indication of neutron damage to steel is a decrease in the brittle fracture transition temperature. This occurs at a fluence of about 10^{19} n/cm^{2,} which is three orders of magnitude greater than the inside steel plates of the sacrificial shield will experience. Therefore, there is no danger of radiation damage to the sacrificial shield plates.

3.8.3.6.2 Reactor Support Pedestal, Drywell Floor, Gallery Floor Levels, Earthquake-Stabilizer Truss System, and Pipe- Break-Support Truss System

The construction materials and QC procedures for these structures conform to the standards set forth in Subsection 3.8.4.6. These structures are not located in a region of high-energy neutron flux; thus, radiation damage to these structures is not expected.

3.8.3.7 Testing and Surveillance Requirements

3.8.3.7.1 Testing and Surveillance Requirements During Plant Construction Phase

The structures specified in Subsection 3.8.3.1 are visually inspected as part of the Quality Control program. Structural steel members are examined for corrosion, excessive deformation, and warpage; their bolted or welded connections are examined for tightness and soundness. The structural integrity of reinforced concrete members is evaluated by mapping cracks in critical areas identifiable by design and by checking for spalling and excessive deformations. Anchor bolts are inspected for tightness.

Rigorous inspection is carried out during construction and in conjunction with the quality control (QC) assurance procedures for structural materials outlined in Subsection 3.8.4.6.

3.8.3.7.2 Testing and Inservice Surveillance Requirements

No inservice structural integrity and/or performance tests are conducted for containment internal structures.

3.8.4 Other Category I Structures

3.8.4.1 Description of the Structures

All structures that contain or support safety-related systems and/or equipment are designed to withstand both seismic and tornado loads, including tornado-generated missiles. Seismic loads are not considered to act simultaneously with tornado loads. Subsection 3.3.2 identifies the Category I equipment and structures that are protected against tornadoes.

No unique materials or new features are used in the design or construction of the structures described in this section.

No concrete block masonry walls have been used as load-bearing walls in Category I structures. Piping or equipment is not supported on masonry walls. The walls are basically non-load- bearing partitions. However, minor attachments of weight totaling less than about 2 percent of the weight of the wall, e.g., junction boxes or key card readers, are permitted. In cases where the weight of items attached to the wall is significant compared to the weight of the wall, the actual weight of the attachment is considered in the design.

Masonry walls, with exception of seismic Category 1 control center pressure boundary walls, are classified as seismic Category II/I structures, and are, therefore, required to maintain structural integrity during a safe shutdown earthquake (SSE). Control center boundary walls are classified as seismic Category I, since they are required to maintain pressure boundary integrity.

The walls are analyzed for dead load plus SSE Load. External supporting steel is installed, where required, to limit tension stresses in the mortar joints to allowable levels.

The block walls are modeled as plate elements with boundary conditions reflecting actual field installations. The provisions of IEEE Standard 344-1975 are used in the seismic analysis of the walls, i.e., a multi-frequency excitation and multi-mode response factor of 1.5, or any other justified factor, is used as a multiplier to the corresponding spectral acceleration. For those walls proved to be rigid by dynamic analysis, with no resonances in the response spectrum amplification range, a zero period acceleration (ZPA) is used in the seismic analysis.

Following are the remaining Category I structures not discussed above or in Subsections 3.8.1, 3.8.2, 3.8.3, or 3.8.5:

a. Reactor/auxiliary building

b. Residual heat removal (RHR) complex

c. Category I Ductbanks.

3.8.4.1.1 Reactor/Auxiliary Building

The reactor/auxiliary building is a single structure that houses both the reactor and auxiliary portions of the building. In the following subsections, the reactor portion of the reactor/ auxiliary building will be referred to as the reactor building, and the auxiliary portion will be referred to as the auxiliary building.

3.8.4.1.1.1 Reactor Building

The reactor building, in conjunction with the reactor building heating and ventilating system and the SGTS, constitutes the secondary containment. The primary purposes of the secondary containment are

a. To minimize ground-level release of airborne radioactive materials

b. To provide means for a controlled release of the building atmosphere.

See Section 1.2 for general arrangement drawings of the reactor building.

The reactor building completely encloses the drywell and the suppression chamber and is supported on the reactor building foundation mat. The structure provides secondary containment when the primary containment is closed and in service, and it provides primary containment during reactor refueling and maintenance operations when the primary containment is open. The reactor building houses the refueling and reactor servicing equipment, biological shield, new- and spent-fuel storage facilities, and other reactor auxiliary or service equipment, including the reactor core cooling (RCIC) system, reactor water cleanup isolation system (RWCUS), standby liquid control system (SLCS), equipment for the CRD system, the reactor core and containment cooling system, and components of the electrical equipment.

The approximate overall dimensions of the reactor building are 116 ft by 162 ft in plan and 200 ft in height measured from the subbasement floor to the top of the parapet. The substructures and exterior walls of the building up to the refueling floor consist of poured-in-place reinforced concrete. Above the level of the refueling floor, the building structure is steel-framed with insulated metal siding with sealed joints. The reactor building has a built-up roof over insulated metal deck. The reactor building has access openings from the auxiliary building and the outside for personnel and equipment. The access openings from the outside are provided with interlocked doors that have weather-strip-type seals. Interconnecting services between the reactor building (Category I) and other nonseismic structures have the flexibility to allow for all relative movement between the structures.

The reactor building has two ventilation exhaust systems. During normal power operation, shutdown, or refueling, the normal ventilation system provides outside filtered air to all levels and equipment rooms within the building. Air is exhausted through a vent extending above the reactor building roof level. During emergencies, the normal ventilation system shuts down, and the reactor building is ventilated through the SGTS. This system causes the building internal pressure to be lower than the external pressure to ensure inleakage rather than outleakage. For a complete discussion of the heating, ventilating, and air conditioning (HVAC) system, see Section 9.4.

The biological shield is a major structure enclosed by the reactor building. This shield is a reinforced-concrete structure with a thickness of 4 to 7 ft; it extends from the bottom of the drywell to the top of the refueling floor, completely encasing the drywell structure (Figure 3.8-27). The top of the shield consists of a removable, segmented reinforced-concrete plug.

The main function of the biological shield is to serve as a radiation shield around the drywell; however, it also functions as a major mechanical barrier for the protection of the containment and reactor system against missiles that may be generated external to the primary containment. The shield resists deformation and buckling of the drywell walls over areas where the shield is in contact with the drywell. Above the transition zone, the drywell is separated from the reinforced concrete by a gap of approximately 2 in.; this gap is filled with a compressible material.

In addition to the above functions, the biological shield supports the various reactor building floor elevations that frame into it, and it resists the earthquake-induced forces that act on the RPV and sacrificial shield transferred to it through the earthquake-stabilizer truss system.

The spent-fuel storage pool, dryer-separator pool, and reactor refueling pool are reinforced-concrete structures completely lined with seam-welded stainless steel plate. The stainless steel liners prevent leakage. There are no connections that would allow the fuel storage pool to be drained below the pool grade between the reactor well and the fuel storage pool. Channels are located in the concrete directly behind the welded seams of the pool liners, and these are monitored to detect leakage from the pools. (Figures 3.8-28 through 3.8-31.)

The reactor building crane runway and supporting structure are designed as an integral part of the building superstructure to withstand earthquake accelerations at the level of the crane runway. See Figure 3.8-32 and Subsection 9.1.4.2 for details of the crane seismic safety features.

3.8.4.1.1.2 Auxiliary Building

The auxiliary building is a reinforced-concrete structure supported on a reinforced-concrete mat foundation. The exterior walls provide tornado missile protection. The main steam tunnel passes through this building. Other piping and electrical cables pass through this building in separate tunnels and connect with adjacent buildings. The reinforced-concrete steam tunnel walls, floor, and roof protect the equipment outside the tunnel from the effects of a postulated steam line break within the tunnel.

The approximate dimensions of the auxiliary building are 88 ft by 160 ft in plan and 161 ft in height, measured from the subbasement floor to the top of the parapet. See Section 1.2 for general arrangement drawings of the auxiliary building.

The auxiliary building walls, floors, and roof are constructed mainly of cast-in-place reinforced concrete. A seismic category II/I steel frame penthouse, approximately 51 ft by 20 ft in plan and 48 ft in height, with steel siding walls, is constructed on the auxiliary building roof to house the exhaust stack for the ventilation equipment located in the auxiliary building. For a complete description of the HVAC equipment in the auxiliary building, refer to Section 9.4. The auxiliary building is integrally connected to the reactor building by the common east wall of the reactor building, but separated from the turbine building by a 4-in. seismic rattle space. Services interconnecting the auxiliary and turbine buildings have the flexibility to allow for all relative movement between the two structures.

The auxiliary building houses the following major plant and safety-related systems and components:

a. Main control room

b. High-pressure coolant injection (HPCI) pumps and turbines

c. CRD pumps

d. Emergency equipment cooling water (EECW) heat exchanger and pumps

e. Main battery room

f. SGTS rooms

g. Main ventilation room

h. Main power distribution center for the reactor building

i. Switchgear rooms

j. Relay room.

3.8.4.1.2 Residual Heat Removal Complex

The RHR complex is a reinforced-concrete structure designed to serve as the ultimate heat sink for the reactor during normal shutdowns and postulated accident conditions. The structure is approximately 280 by 127 ft in plan and is located west of the reactor/auxiliary building. The complex consists of two divisions: Division I and Division II. Each division is comprised of a water reservoir, a pump house, a two-cell mechanical draft cooling tower, and two emergency diesel generators. Division I is in the south side, and Division II is in the north side of the complex. With the two reservoirs cross-connected to permit access to the entire ultimate heat sink inventory, each division has the capacity to safely and orderly shut down the reactor during normal and/or accident conditions completely independent of the other. See Section 1.2 for general arrangement drawings of the RHR complex.

The RHR complex houses the RHR service water (RHRSW), emergency equipment service water (EESW), and the diesel generator service water (DGSW) systems. During normal and/or accident shutdown conditions, the function of the RHRSW and EESW systems is to remove decay heat from the RHR heat exchangers and the EECW heat exchangers, respectively. The function of the DGSW system is to remove the heat from the emergency diesel generator heat exchangers during operation of the generators.

Adequate protection from potential postulated missiles has been provided, as described in Section 3.5.

Penetrations are provided for the RHRSW and EESW systems. All penetrations below Elevation 590.0 ft are watertight, as described in Subsection 2.4.2.

3.8.4.1.3 Category I Electrical Ductbank Concrete Structures

There are two sets of Category I concrete ductbanks and manholes located between the RHR complex and the Reactor/Auxiliary Building, with a Division I and Division II ductbank in each set. The first set was designed and installed during plant construction. The essential I&C and Control cables will remain in these ductbanks and the 4160-V essential power circuits are abandoned and new cables routed in the second set.

The second set of Category I ductbanks and associated, manholes and above ground cable vaults were installed to house the 4160-V essential power cables that replaced the abandoned cables in the original ductbanks due to water intrusion issues. These ductbanks also have spare conduits should the need arise to replace other essential cables in the original ductbanks.

Both set of ductbanks are cast-in-place rectangular shaped reinforced concrete ducts with each 4160-V circuit separately house in its own conduit.

3.8.4.2 Applicable Codes, Standards, and Specifications

This section lists the codes, specifications, standards of practice, regulatory guides, and other industry-accepted guidelines that have been adopted to the extent applicable in the design and construction of all Category I structures. To eliminate repetitious listing for each structure, the codes, standards, and specifications are described and discussed in Table 3.8-4 and given a specification reference number. For each Category I structure, the applicable specification reference numbers are as follows:

Reactor/auxiliary building	1 through 9, 11 through 17, 19, 20, 21, 23, 25, 26, 28, 30, and 32 through 42
RHR Complex	1A, 2B through 9, 11 through 17, 19, 20, 21, 23, 29 through 36, and 38 through 42
Category I Ductbanks	
First Set	1A, 2B through 9, 11 through 17, 19, 20, 38, 39, 41
Second Set	43 through 46

During the construction period many of the industry codes, specifications, and standards have been revised. Project specifications have been revised to incorporate later editions, as considered appropriate, than those listed in Table 3.8-4.

3.8.4.3 Loads and Loading Combinations

3.8.4.3.1 Reactor/Auxiliary Building

The load factors and loading combinations given in Tables 3.8-l8 and 3.8-20 for structural steel members and for reinforced-concrete members, respectively, and the corresponding allowable stress values given in Tables 3.8-19 and 3.8-20 have been applied in the design of the reactor/auxiliary building floor slabs, walls, roof, reactor building crane, equipment foundations, biological shield, spent-fuel pool and dryer-separator storage pool, and all other structures integral with the reactor/ auxiliary building, as outlined in Subsection 3.8.4.1.1. Following is a general discussion of the loads for which the aforementioned structures are designed.

3.8.4.3.1.1 Reactor Building Crane

The reactor building crane rails and columns are designed to carry loads transmitted from the crane for the loading combinations listed in Tables 3.8-18 and 3.8-19. The lateral force on the crane runway is 20 percent of the sum of the weights for the lift load and of the crane trolley applied at the top of each rail, one-half on each side of the runway, acting in either direction normal to the runway. The longitudinal force is 10 percent of the maximum wheel loads of the crane. An induced impact of 25 percent of the wheel load was included in the design of the support structure.

3.8.4.3.1.2 Reactor/Auxiliary Building Roof

In addition to its dead load, the reactor/auxiliary building roof is designed for a normal live load of 30 lb/ft^2. The roof purlins and decking are designed to withstand a suction pressure of 33 lb/ft^2 induced by a 90-mph wind (Subsection 3.3.1) and to blow off before a suction pressure of 72 lb/ft^2 induced by a 200-mph wind is reached. The roof decking is assumed to blow away when the wind velocity exceeds 200 mph. The structural steel frames are designed to withstand the effects of the tornado specified in Subsection 3.3.2.

3.8.4.3.1.3 Reactor/Auxiliary Building Walls

The reactor/auxiliary building walls, in addition to their own dead load, are designed for external and internal missiles and transient thermal gradients caused by the temperature differential between the exterior and interior environs (see Table 3.8-21 for the specified temperature ranges). The walls are designed to carry all members, equipment, and floor elevations framing into them.

The concrete walls up to the refueling floor elevation are designed to withstand the effects of the tornado (Subsection 3.3.2 and Reference 17). However, the metal siding walls above that elevation are designed to withstand a 90-mph wind, but are designed to blow away before a wind velocity of 200 mph is reached. Where blowout panels are not provided in walls that form totally enclosed compartments, the walls are designed for a tornado-induced internal pressure of 3 psi, as specified in Section 3.3.

Walls below grade are designed for lateral soil pressure, hydrostatic pressure from ground water level at elevation 576 ft and a surcharge of 500 lb/ft^2 under normal condition. In addition, these walls are designed for lateral soil pressure and maximum flood level specified in Section 3.4 under extreme environmental condition (similar to tornado case).

The reactor/auxiliary building walls, interacting with the reactor/auxiliary building floor slabs, are designed to resist the reactor/auxiliary building seismically induced base shears.

3.8.4.3.1.4 Reactor/Auxiliary Building Equipment Supports

To account for the effects of impact, machinery support reactions have been increased by the following percentages:

a. For elevator supports - 100 percent

b. For supports of light machinery (shaft or motor driven) -20 percent

c. For supports of reciprocating machinery or power-driven units - 50 percent

3.8.4.3.1.5 Reactor/Auxiliary Building Floor Slabs

In addition to the slab and equipment dead loads, conservative live loads have been selected for each slab. Pattern live loads have been applied to determine the maximum shears and moments in the slab. In addition to floor live and dead loads, slabs are designed for internal missiles, temperature gradients, and pressure differentials caused by operating or accident conditions as applicable.

Additionally, the reactor building slabs are loaded during ISFSI campaigns to transfer nuclear fuel from the spent fuel pool to the outdoor long-term Independent Spent Fuel Storage Installation (ISFSI) location. A HI-TRAC transfer cask with a loaded multi-purpose canister (MPC) is moved from the spent fuel pool to the Dryer-Separator Storage Pool for processing prior to movement to a low profile transport on the first floor to be moved outside the Reactor Building. Horizontal seismic loads on the HI-TRAC are reduced by an engineered Teflon friction reducing pad that is placed between the HI-TRAC and the floor of the Dryer Separator Pool and low profile transport. Horizontal seismic loads were reduced, thus reducing moments that tend to overturn the HI-TRAC such that it will not tip and induce additional vertical loads on RB slabs.

3.8.4.3.1.6 Biological Shield

In addition to its own dead load, the biological shield is designed for the temperature gradients T_a and T_o (Table 3.8-21) between the containment and exterior face of the shield, seismic loads, pipe break loads, missile loads (Section 3.5), and the dead and live load reactions of the floor elevations that frame into it.

3.8.4.3.1.7 Spent-Fuel Pool and Dryer-Separator Storage Pool

The spent-fuel pool and dryer-separator storage pool are designed for the following loads:

a. Dead load

b. Water load (including the hydrodynamic forces associated with the water set in motion by seismic accelerations)

c. Mechanical equipment loads

d. Temperature gradient caused by a maximum water temperature of 150°F

e. Accident and operating temperature differential between the containment and exterior walls for both summer and winter extremes (Table 3.8-21).

f. ISFSI HI-TRAC with a fuel-loaded multi-purpose canister (MPC).

All of the reactor/auxiliary building Category I structures and structural components are designed for the vertical and horizontal accelerations of both OBE and SSE.

3.8.4.3.2 Residual Heat Removal Complex

The load factors and loading combinations given in Table 3.8-20 for reinforced-concrete members and in Table 3.8-18 for structural steel members and the corresponding allowable stress values given in Table 3.8-19 have been applied in the design of the floor slabs, walls, equipment foundations, roof, and other structures integral with the RHR complex, as outlined in Subsection 3.8.4.3.

The discussion on the design loads for the roof, floor slabs, walls, and equipment supports found in Subsection 3.8.4.3.1 applies to the RHR complex (Reference 18). The roof of the RHR complex is designed for a total live load of 70 lb/ft^2. In addition, the RHR complex reservoir walls are designed for the hydrodynamic forces of the water in the reservoir set in motion by seismic accelerations.

3.8.4.4 Design and Analysis Procedures

3.8.4.4.1 Reactor/Auxiliary Building

The reactor/auxiliary building floor slabs, roof, walls, and miscellaneous structures integral with the reactor/auxiliary building have been analyzed and designed using conventional elastic techniques. All significant openings and discontinuities in structural members were included in the structural model. The boundary conditions selected for all structural models were determined by evaluating the stiffness (flexural, torsional, and axial) of all the members connected at a boundary point, and those conditions represent, to the extent practicable, the actual restraint conditions.

The reactor/auxiliary building walls, interacting with the floor slabs, are proportioned to resist the combination of seismically induced overturning moments, vertical loads, and shears in accordance with the applicable provisions of ACI 318. Adequate provisions are made to transfer wall moments, vertical loads, and shears to the mat foundation.

The computer programs used in the analysis of walls, floor slabs, beams, roof, reactor building crane, and all other structures are listed in Section 3.13.

3.8.4.4.1.1 Biological Shield

The biological shield was originally analyzed by two methods. The first analysis was based on elastic shell theory using the KALSHEL computer program. The second analysis was based on finite element theory using the computer program DYNAX (Section 3.13). The biological shield was considered to be fixed at its base and restrained by the fuel pools at its top. The results of the two independent analyses were compared, and the more conservative of the two was used for design. To determine the local effects at larger penetrations, the areas around those penetrations were modeled by finite element programs such as PLFEM-II or SLSAP (Section 3.13). The element nodes lie along the centerline of the shield, thus modeling the curvature of the wall. The size of the model was chosen such that the boundary conditions are compatible with those obtained from KALSHEL. The final load verification calculation of the Biological Shield Wall addressing additional loads was performed using ANSYS.

3.8.4.4.1.2 Spent-Fuel Pool and Dryer-Separator Storage Pool

The pools were originally analyzed as a beam simply supported at both ends by the reactor building exterior walls and rigidly supported at the middle by the biological shield. Two independent structural models were used in the analysis. First, the structure was modeled as beam elements using the appropriate stiffness and the STRESS program (Section 3.13). The STRESS output consists of the moments and shears in the pool walls for all loading conditions. Second, a finite element model was made using the PLFEM-II program. PLFEM-II output gives localized moments in the pool walls caused by hydrostatic and temperature loads. The design of the pool walls is in accordance with ACI 318 and is based mainly on the PLFEM-II output with reference being made to STRESS. The temperature gradient loads were analyzed by hand to verify the results from PLFEM-II.

In the case of the Spent Fuel Pool the analysis has been updated to incorporate final loads. The new analysis uses ANSYS to analyze the design of the Spent Fuel Pool.

During an Independent Spent Fuel Storage Installation (ISFSI) campaign or storage cask unloading, a HI-TRAC with multi-purpose canister (MPC) containing spent fuel is temporarily placed in the Dryer-Separator Storage Pool for processing. The Dryer-Separator Storage Pool structures were analyzed using the STAAD.Pro program by an equivalent frame method similar to that of the original calculation. The potential tipping and sliding motion of the cask in the Dryer Separator Storage Pool has been analyzed for OBE and SSE vertical and horizontal accelerations.

3.8.4.4.2 Residual Heat Removal Complex

The RHR complex structure was designed and analyzed using conventional elastic techniques as described for the reactor building. The computer programs used in the design and analysis process for the RHR complex are listed in Section 3.13.

3.8.4.4.3 Second Set of Category I Ductbanks and Associated Manholes and Cable Vaults

The Category I underground ductbanks, manholes and above ground cable vaults at the RHR complex have been constructed and analyzed to meet all the requirements of Category I structures as provided in ACI 349-01 and RG 1.142 & RG 1.76.

The load factors and loading combinations given in Table 3.8-20 for reinforced concrete structures have been applied in the design of these Category I structures.

3.8.4.5 Structural Acceptance Criteria

3.8.4.5.1 Reactor/Auxiliary Building

The stresses and strains in the reinforced-concrete walls, floor slabs, beams, and equipment supports in the reactor/auxiliary building are limited to those specified in ACI 318-63 and/or ACI 318-71. Serviceability checks are made in accordance with ACI 318-63 and/or ACI 318-71 to ensure crack control and to keep deflections below the limits prescribed by the manufacturers' recommendations for equipment supported by reinforced concrete.

The basic criterion for strength design is expressed as required strength versus calculated strength.

All members and all sections of members are proportioned to meet this criterion. The required strength is expressed in terms of design loads or their related internal moments and forces. Design loads are defined as loads that are multiplied by their appropriate load factor (safety factors), as given in Tables 3.8-19 and 3.8-20.

Calculated strength is that computed by the provisions of ACI 318-63 and/or ACI 318-71.

Stresses and strains in the structural steel used for the reactor/auxiliary building are limited to those specified in the 1969 AISC Specifications, Part I, when the loading combinations listed in Tables 3.8-18 and 3.8-19 were being designed for. The appropriate factors of safety against yield are those discussed in the Commentary to the 1969 AISC Specifications. The allowable steel stresses have been increased to 1.6 times those specified above, subject to an upper limit of 0.95 f_y (yield stress), when loading combinations 10 and 11 of Table 3.8-18 were being designed for. In this situation, a minimum factor of safety of 1.05 against yield has been ensured. In either case, deformations of structural steel members are limited because the stresses are kept within the elastic range, and redistribution of loads due to plastic deformations is not permitted. In addition, the deflections of all critical steel members were calculated and kept below the limits prescribed by the 1969 AISC Specifications or manufacturers' recommendations for equipment supported by steel.

The biological shield was designed using the yield limit criteria defined for the reactor support pedestal in Subsection 3.8.3.5.2.

3.8.4.5.2 Residual Heat Removal Complex

The structural acceptance criteria for the RHR complex are in accordance with the 1969 AISC Specification and ACI 318-71 and are similar in method to those described in Subsection 3.8.4.5.1.

3.8.4.5.3 Category I Ductbanks

There are two sets of Category I concrete ductbanks and manholes between the RHR complex and the Reactor/Auxiliary building, with a Division I and Division II ductbank in each set. The structural acceptance criteria for the first set of concrete ductbanks and associated manholes are in accordance with the Specifications and ACI 318-71 and are consistent with criteria described in Subsection 3.8.4.5.1 for concrete structures.

The design and construction acceptance criteria for the second set of Category I 4160-V ductbanks and associated, manholes and cable vaults is in accordance with ACI 349-01 Code, Reg. Guide 1.142 and RG 1.76.

3.8.4.6 Materials, Quality Control, and Special Construction Techniques

Noncombustible and fire-resistant materials are used wherever necessary throughout the facilities, particularly in areas containing critical portions, such as the containment, main control room, and components of ESF systems.

The construction materials for the reactor/auxiliary building and RHR complex structure conform to the standards set forth in the following discussion.

3.8.4.6.1 Concrete

"Specifications for Structural Concrete for Buildings," ACI 301, together with ACI 347, "Recommended Practice for Concrete Formwork," and ACI 318, "Building Code Requirements for Reinforced Concrete," form the general basis for the concrete specifications.

The requirements of ACI 301 have been supplemented as necessary with mandatory requirements relating to types and strengths of concrete, proportioning of ingredients, reinforcing steel, joint treatments, and testing.

Admixtures, types of cement, bonding of joints, embedded items, concrete curing, additional test specimens, additional testing services, cement and reinforcing-steel mill test report requirements, and additional concrete test requirements are specified in detail.

Specifications ACI 349-01 “Code Requirements for Nuclear Safety Related Concrete Structures” and Regulatory Guide 1.142 “Safety-Related Concrete Structures for Nuclear Power Plants (Other Than Reactor Vessels and Containments)” provide the general basis for the design and construction of the second set of Category I 4160-V ductbanks, manholes and cable vaults.

3.8.4.6.1.1 Materials

All cement conforms to either ASTM C150, "Specification for Portland Cement Types I, II, and V," or Canadian Standards Association (CSA) Standard A5, "Portland Cements." The cement meets the requirements of the edition of the standard or specification that was current at the time the cement was manufactured.

Certified copies of mill tests, showing that the cement met or exceeded the ASTM requirements for portland cement, are furnished by the manufacturer.

Aggregates conform to the Michigan Department of State Highways Standard Specifications for Road and Bridge Construction, Article 8.02. Fine aggregates are of the natural sand designation 2NS. Coarse aggregates are of the designation 6AA; these requirements equal or exceed those of ASTM Specification C33. Where a larger size aggregate is specified for use in mass concrete portions of the work, it conforms in all respects, except size, to designation 6AA. Aggregates are free from any materials that would be deleteriously reactive in any amount sufficient to cause excessive expansion of mortar or concrete.

Mixing water is clean and free from injurious amounts of oils, acids, alkalies, salts, organic materials, or other substances deleterious to concrete or steel. Water used, as required, for concrete produced at the onsite batch plant is supplied from the Frenchtown Township Water Treatment Plant. This water is tested as processed and meets the Michigan Department of Public Health Drinking Water Standards.

An air-entraining agent is used in concrete subject to weathering. This agent conforms to the requirements of the Standard Specification for Air-Entraining Admixtures for Concrete, ASTM C260. The solution is batched by means of a mechanical dispenser capable of accurate measurement and in such a manner as to ensure uniform distribution of the agent throughout the batch during the specified mixing period. Air-entrained cement is not used.

Fly ash is obtained from the Trenton Channel Power Plant, which is also owned by the applicant, The Detroit Edison Company; it conforms to ASTM Specification C6l8. The quantity of fly ash used is determined by making laboratory tests on trial batches containing various amounts of fly ash. The mix selected is that with the maximum fly-ash-to-cement ratio that consistently yielded the specified concrete strength and provided workability.

Other admixtures to control the rate of set, reduce the water content, or improve the workability and cohesiveness of concrete are used in specific instances and conform to ASTM C494. Such admixtures are used only after tests have been made in combination with the cement and aggregates being used and specifically approved. Calcium chloride is not used under any circumstances.

3.8.4.6.1.2 Mixing

The concrete used is normal-weight concrete, with an average density of 145 lb/ft^3. Concrete or grout used for neutron shielding contains boron frits.

The proportioning of structural concrete conforms to ACI 301. In general, concrete mixes have a 28-day specified strength of 4000 psi.

Proportions of ingredients are determined and tests are conducted in accordance with the methods of ACI 301 for combinations of materials to be established by trial mixes.

Batching and mixing conform to ACI 301 and ASTM C94. Concrete ingredients are batched in an onsite central batch plant and transported to the point of placement in truck mixers, operating at agitating speed. In the event of a malfunction of the onsite plant, concrete may be batched at an offsite backup plant and truck mixed.

Concrete protection for reinforcement, preparation and cleaning of construction joints, concrete mixing, delivering, placing, and curing, with the following exceptions, is equal to or exceeds the requirements of ACI 301. The slump is varied as part of the mix design within a range of a maximum of 5 in. and a minimum of 1 in. to suit the portion of the work being placed. The minimum slump is waived on concrete used in ramps or other sloping construction. The samples for the slump tests are taken at the end of the last conveyor, chute, or pipeline before the concrete is placed in the forms.

3.8.4.6.1.3 Placement

Placing of concrete is by bottom dump buckets, chuting, concrete pump, or conveyor belt. The rate of placing concrete is controlled so that concrete is effectively placed and compacted by vibrating, with particular attention given around embedded items and near the forms.

Vertical drops greater than 6 ft are not permitted for any concrete, except where suitable equipment is provided to prevent segregation.

Cold and hot weather placing temperatures are as follows:

a. Cold weather - The ingredients are heated whenever necessary to produce concrete having a temperature of not less than 45°F. When the concrete ingredients are heated, the maximum temperature of the concrete is 80°F. Heated concrete is obtained by heating the water or aggregates, or both

b. Hot weather - Concrete deposited in hot weather has a placing temperature that does not cause difficulty from loss of slump, flash set, or cold joints. In addition, the following maximum temperatures are adhered to unless noted otherwise on the drawings:

   1. 75°F - Sections 6 ft or less but greater than 2 ft 6 in. in least dimension
   2. 65°F - Sections greater than 6 ft in least dimension.
   3. 85°F - Sections 2 ft 6 in. or less in least dimension and all electrical duct or pipe encasements.

3.8.4.6.1.4 Curing

Curing and protection of freshly deposited concrete conform to ACI 301, with the following supplementary provisions:

a. Concrete cured with water is kept wet by covering with an approved water-saturated material, by a system of perforated pipes or mechanical sprinklers, and by other approved methods that keep surfaces continuously wet. Water used for curing is clean and free from any elements that might cause objectionable effects. Curing compounds are also used

b. When curing compounds are used on surfaces on which additional concrete is to be bonded, the curing compound manufacturer provides documentary evidence that the curing compound will not prevent bond. In the event the manufacturer is unable to prove that the curing compound does not prevent bond, the curing compound is completely removed from the joint surface prior to bonding the next layer of concrete.

3.8.4.6.2 Concrete Testing

The concrete mix is designed in accordance with ACI 301-72, using method 1. Revisions of approved mix designs will be in accordance with method 2. The trial mixes are tested in accordance with the ASTM standards listed below:

Test	ASTM Designation
Making and curing of the test specimen	C192
Air content	C231
Slump	C143
Compressive	C39

Compressive strength tests are made at 7 and 28 days. A minimum of two cylinders are used for each test.

Concrete strength tests are evaluated in accordance with ACI 301 and ACI 214.

Strength of concrete is considered satisfactory if the averages of all sets of strength test results of the laboratory cured specimens at 28 days' age are equal to or greater than the specified compressive strength (f_c') of the concrete.

The Edison computer code Concrete Quality Assurance is used to evaluate the concrete compression strength tests. This program uses as input the 7- and/or 28-day test results, from individual or multiple concrete mixes, and plots the average strength as well as the moving averages to provide a means of forecasting the longterm trend of compression testing. Statistical means are used to find the concrete quality assurance variables, test averages, cumulated averages, moving averages, as the required average strength (RAS). The RAS value is calculated using the following formula:

$$\text{RAS} = \frac{\text{design strength}}{1-\text{(ACI constant) (coefficient of variation)}}$$

where the ACI constant depends on the allowable number of tests with results falling below the design strength specified in ACI 2l4.

The field tests for slump of portland cement concrete are in accordance with ASTM C43. Any batch not meeting specified requirements is rejected. Slump tests are made frequently during concrete placement and each time concrete test specimens are made.

If cylinders should fail to meet the concrete strength requirements at 28 days, strength development and design strength requirements are reviewed. Where necessary, nondestructive tests and core tests are conducted in accordance with ASTM C42, "Method of Obtaining and Testing Drilled Cores and Sawed Beams of Concrete."

3.8.4.6.3 Reinforcing Steel

All reinforcing conforms to Grade 60 of the Standard Specification for Deformed Billet-Steel Bars for Concrete Reinforcement, ASTM A6l5.

Mill test reports showing actual chemical and physical properties, including bend tests, are furnished for each heat of steel used in making all reinforcing steel furnished.

Placing of reinforcing steel conforms to the requirements of Chapter 5 of ACI 30l, "Structural Concrete for Buildings," and Chapter 7 of ACI 3l8, "Building Code Requirements for Reinforced Concrete."

Typical reinforcing steel details are shown in Figures 3.8-33 through 3.8-38.

In addition to ASTM A615, Grade 60, reinforcing steel for the second set of Category I 4160-V ductbanks, manholes and cable vaults conforms to the requirements of ACI 301, “Structural Concrete for Buildings”, ACI 349-01, “Code Requirements for Nuclear Safety Related Concrete Structures” and RG 1.142, “Safety-Related Concrete Structures for Nuclear Power Plants (Other Than Reactor Vessels and Containments)”.

3.8.4.6.4 Reinforcing-Steel Inspection and Testing

The testing of reinforcing bars was generally in accordance with Regulatory Guide 1.15, Testing of Reinforcing Bars for Concrete Structures, as modified below. (Regulatory Guide 1.15 was withdrawn by the NRC in July 1981.)

At least one full-diameter specimen of each bar size from every heat is control tested in accordance with ASTM A615.

Tests are performed in the field test laboratory under the jurisdiction of Edison under the direct supervision of qualified personnel.

Three test samples of each bar size and heat are obtained from the fabricator upon his receipt of an acceptable shipment from the mill. Tensile and bend tests are performed, and, if acceptable, the fabricator is authorized to proceed with fabrication.

Reinforcing concrete steel is fabricated from certified material that has been accepted by Edison. Bending conforms to ACI 318 or ACI 349-01.

3.8.4.6.5 Reinforcing-Steel Splices

Where required by space limitations or by design requirements, splices in reinforcing bars are made by cadwelding. Cadwelding is done according to written field procedures that conform to the intent of Regulatory Guide 1.10 (withdrawn in July 1981).

In order to qualify operators for making cadweld process joints, each operator is required to prepare two qualification splices for each of the splice positions to be used. The joints are tensile tested, simulating field conditions and using the same materials as those to be used in the structure.

The ends of the reinforcing-steel bars to be joined by the Cadweld process are saw cut or flame cut. The ends of the bars are thoroughly cleaned of all rust, scale, grease, oil, water, or other foreign matter before the joints are made.

3.8.4.6.6 Cadweld Testing and Inspection

Cadweld process splices are visually inspected in accordance with Regulatory Guide 1.10 (withdrawn in July 1981). Visual inspection includes random inspection of the ends of the bars for dryness and cleanliness prior to fitting the sleeve over the ends.

Completed splices are accepted or rejected according to the criteria described in the following:

Accept

a. Sound metal visible at both ends of the splice sleeve and at the tap hole in the center of the splice sleeve

b. Filler metal may be recessed 1/8 in. to as much as 1/2 in. from end of sleeve. Recessing is due to "bulging" of packing material

c. Presence of a single shrinkage bubble below riser

d. Radial pencil lines with "stars" or dendritic gas "pipes" when not combined with other indications

e. Splice sleeve not concentric and/or rebars not in axial alignment

f. Compression-only splices with solid metal in the tap hole may have voids to a maximum of 1 in. either as spot voids or complete circumferential low fill.

Reject

a. Presence of slag and the absence of solid metal in tap hole

b. Absence of filler at one end of horizontal splice

c. Absence of filler metal at top end of vertical splice

d. Porous metal in tap hole (general porosity).

Randomly selected cadweld splices based on position, size of rebar, and operator are removed from the structure and tensile tested, or a combination of production and companion splices is tested. Testing is in accordance with the following schedule if only production splices are tested:

a. One production splice of the first 10 splices

b. One production splice of the next 90 splices

c. Two production splices of the next and subsequent groups of 100 splices.

If combinations of production and companion splices are tested, the sample frequency is as follows:

a. One production splice of the first group of 10 production splices

b. One production and three companion for the next 90 production splices

c. Three splices, either production or companion splices, for the next and subsequent groups of l00 splices. At least one-fourth of the total number of splices tested are to be production splices.

When companion splice only is required, the following schedule

a. One companion splice of the first group of 10 splices (the companion splice is included in the group count)

b. Three companion splices of the next group of 90

c. Subsequent testing to be done at the rate of three companion splices included in each 100 splices made in accordance with the following schedule:

   1. One of the first group of 30 splices

   2. One of the last group of 30 splices

   3. One of the middle group of 40 splices.

The tensile strength of each sample tested equals or exceeds 125 percent of the specified minimum yield strength for the grade of reinforcing bar used. Failure of any splice to achieve 125 percent of the specified minimum yield strength is evaluated in accordance with Section 5 of the Procedure for Sub-Standard Tensile Test Results as given in Regulatory Guide l.l0, Mechanical (Cadweld) Splices in Reinforcing Bars of Concrete Containments.

3.8.4.6.7 Structural Steel

Structural steel material, erection, and fabrication tolerances are in accordance with the l969 AISC Specification. In general, steel used for structural framing conforms to ASTM A36.

Certified copies of mill test reports showing actual chemical and physical properties are furnished for each heat of steel in accordance with ASTM A6.

Welding of structural steel is in accordance with AWS Dl.0-69, AWS D1.1-72, and AWS D1.1 later issues as well.

The material installation and inspection of high-strength bolts, in general, conform to the requirements of the specification for structural joints using ASTM A325 or A490 bolts.

3.8.4.6.8 Summary of Quality Assurance for Construction and Construction Materials

The Quality Assurance Program, implemented with a full and complete field quality control system, has provided documented assurance that the structural work at the site, including all concrete, reinforcing steel, miscellaneous steel, structural steel, and all ingredients and special processes used in producing the aforementioned items, is in accordance with the project specification requirements and the applicable ACI, ASTM, and AISC standards.

The results of the continuous concrete and reinforcing bar testing program, carried out at the site laboratory, have confirmed the effectiveness of the controls. All reinforcing has met or exceeded the design tensile strength requirements, and the evaluation program for monitoring the concrete cylinder compression test results shows a continuous average strength well above the project specification requirements.

3.8.4.7 Testing and Inservice Surveillance Requirements

Secondary containment leak-rate testing is discussed in Subsections 6.2.1.4.2, 6.2.3.3.2, and 14.1.3.2.51.

Some cracking of the reactor building exterior walls may occur during an SSE, but large, predominantly open cracks are not expected. Therefore, the leakage rate from the reactor building will not change significantly subsequent to an SSE.

No other preliminary structural integrity or performance tests are conducted on the reactor/auxiliary building or RHR complex structures. However, rigorous inspection techniques and QC procedures are adopted throughout their construction, as indicated in Subsection 3.8.4.6.

3.8.5 Foundations and Concrete Supports

3.8.5.1 Description of Foundations and Supports

The reactor/auxiliary building is supported by a reinforced-concrete basemat (Figure 3.8-39), approximately 4 ft thick. A 77-ft-diameter by l9-ft-high reinforced-concrete pad, integral with the base and centered under the RPV, supports the biological shield, drywell, reactor support pedestal, and all other structures internal to the containment (Figures 3.8-40 and 3.8-41). The RHR complex is supported by a reinforced-concrete basemat approximately 4 ft thick.

The RHR complex and the reactor/auxiliary building foundation mats bear on bedrock at approximately Elevations 551.0 and 536.0 ft, respectively.

The dead weight of the RHR complex is designed to offset the remote and unlikely occurrence of building flotation. Therefore, anchoring of the reservoir bottom is not necessary.

Category I equipment is adequately anchored to and/or supported by concrete supports. The mass of the concrete supports is generally a minimum of 2-1/2 times the mass of the supported equipment. The concrete supports and anchorages for the following Category I machinery and equipment are discussed:

a. HPCI pump and turbine

b. RCIC pump turbine and barometric condenser

c. RHR pumps

d. Core spray pumps.

The HPCI pump and turbine foundation (Figure 3.8-42) is located in the subbasement of the auxiliary building at Elevation 540.0 ft. The pump and turbine foundations consist of reinforced-concrete pads poured monolithically with each other and connected integrally with dowels to the auxiliary building basemat. The HPCI turbine concrete pad is approximately 13 ft 1-1/8 in. by 6 ft 2-1/2 in. in plan and 2 ft 8 in. high; the HPCI pump concrete pad is approximately 16 ft 5 in. by 6 ft 2-1/2 in. in plan and 3 ft 11 in. high.

The RCIC pump and turbine and barometric condenser foundations (Figure 3.8-43) are located in the subbasement of the auxiliary building at Elevation 540.0 ft. The foundations consist of reinforced-concrete pads poured monolithically with each other and integrally connected with dowels to the auxiliary building basemat. The RCIC pump pad is approximately 5 ft 5 in. by 4 ft 8 in. in plan and 2 ft 1 in. high; the RCIC turbine pad is 7 ft 1 in. by 4 ft 8 in. in plan and 2 ft 11/l6 in. high; and the barometric condenser pad is 3 ft 4 in. by 4 ft 4 in. in plan and 6 in. high.

Foundations for four RHR pumps (Figure 3.8-44) are provided at the west end of the reactor building subbasement floor at Elevation 540.0 ft. Each pump is supported by a circular steel sole plate 2-1/2 in. thick and 7 ft 6 in. in diameter; this plate is directly anchored to the reactor building base mat by 24 anchor bolts (2 in. in diameter and 2 ft 3 in. long) equally spaced along a 7-ft-diameter bolt circle. The underside of the sole plate contains a rectangular grid pattern of grout grooves 1 in. wide and 3/8-in. deep. The sole plates rest on a 1-1/2-in. grout pad; the final elevation of the top of the sole plate is 540.0 ft. Leveling screws are provided in the plates to facilitate leveling before the plates are grouted in. The sole plates are drilled and tapped for 16 bolts, 1-3/4 in. in diameter, equally spaced along a bolt circle, about 2 ft 8 in. in diameter, to receive the RHR pumps.

Foundations for four core spray pumps (Figure 3.8-45) are provided in the auxiliary building subbasement floor at Elevation 540.0 ft. Each pump is supported by a steel sole plate that is 2 in. thick and 5 ft 5 in. in diameter; this plate is anchored directly to the auxiliary building basemat by 16 anchor bolts (1-3/4 in. in diameter and 2 ft long) equally spaced along a bolt circle that is 4 ft 10 in. in diameter. The undersides of the sole plates contain a rectangular grid pattern of grout grooves 1 in. wide by 3/8 in. deep. Leveling screws are provided in the sole plate to facilitate leveling prior to placing a 2-in. grout pad under the sole plates. The sole plates are drilled and tapped for 16 bolts, 1-5/8 in. in diameter, equally spaced along a bolt circle, 2 ft 8 in. in diameter, to receive the core spray pumps.

Figure 3.8-46 shows typical reinforcing patterns at the junction of reinforced-concrete walls and the foundation basemat. Typical anchor bolt details for Category I equipment are shown in Figure 3.8-47.

3.8.5.2 Applicable Codes, Standards, and Specifications

This section lists the codes, specifications, standards of practice, regulatory guides, and other accepted industry guidelines that have been adopted to the extent applicable in the design and construction of foundations and anchorages for Category I structures and equipment. To eliminate repetitious listing, the codes, standards, and specifications are described in Table 3.8-4 and given a specification reference number. The following are the specification reference numbers for the foundations:

a. 1 through 9 inclusive

b. 11 through 21 inclusive

c. 23 and 28

d. 33 through 35 inclusive

e. 38, 39, and 41.

3.8.5.3 Loads and Loading Combinations

The load combinations and load factors given in Tables 3.8-19 and 3.8-20 have been applied in the design of reinforced-concrete foundations and supports for Category I structures and equipment. The following is a brief description of the loads for which the RHR complex and reactor/auxiliary building basemats and foundation walls have been designed:

a. Dead load

b. Live load (the live load on the reactor building basemat is 350 lb/ft^2)

c. Equipment load

d. Wind load (Subsection 3.3.1)

e. Tornado load (Subsection 3.3.2)

f. Seismic load - Horizontal and vertical accelerations are applied for both OBE and SSE

g. Lateral pressure on subsurface walls - The lateral pressures due to soil and water under static and dynamic conditions are as shown in Figures 3.8-48 and 3.8-49

h. Hydrostatic loads - Foundation walls and basemats are designed for the following water levels:

   1. Design water levels at Elevation 576 ft

   2. Maximum design flood level at Elevation 588 ft (for wave forces, see Subsection 2.4.5).

i. Hydrodynamic loads - Foundation walls are designed for the hydrodynamic forces associated with ground water in motion under both OBE and SSE. For a complete discussion of this effect, refer to Section 3.7

   The RHR complex reservoir walls are designed for the hydrodynamic forces of water in the reservoir due to ground motions during both OBE and SSE

   The reactor building basemat has been designed for torus uplift loads that occur during earthquake, accident and safety/relief valve loading conditions (Reference 19)

j. Surcharge loads - The surcharge load of 500 lb/ft^2 was investigated

k. Thermal loads - The following thermal gradients were applied to the foundation walls:

   1. A 70°F ambient inside temperature under normal operating conditions and a 50°F ambient rock/soil temperature outside

   2. A 170°F ambient inside temperature under accident conditions and a 50°F ambient rock temperature outside. This applies to the reactor building subbasement.

All loads interior and exterior to the building are transferred to the basemat through elastic deformation of the slabs, supporting walls, and columns. Differential settlements of the mat foundations are not anticipated, because they are supported by rigid bedrock.

The foundation mats are properly sized and reinforced to accommodate the total overturning moments caused by winds and tornadoes without exceeding the allowable rock bearing stress at the toe of the mat while keeping the resultant upward soil reaction within the middle third of the mat area. Passive resistance of the soil acting against the foundation walls was neglected in computing the resisting overturning moments. Moreover, any uplift resistance that may be provided by bond of the concrete to the bedrock was neglected.

Horizontal translation of the mat foundations caused by wind loading is resisted by the frictional force between the concrete mat and the bedrock. Passive resistance of the soil acting against the subgrade walls was neglected. In computing the frictional resistance, the resultant uplift force caused by the hydrostatic pressure at the base of the mat was deducted from the building dead load.

The ability of the buildings to resist torsional rotation when engulfed by a tornado is provided by the adhesive forces between the building subgrade walls and soil, and the frictional resistance between the concrete basemats and bedrock.

In general, Category I concrete equipment supports and anchorages are designed for the following loads:

a. Dead load of the equipment

b. Seismic loads - Horizontal and vertical accelerations for both OBE and SSE

c. Operating live loads - This includes overturning moments and base shears caused by rotating or reciprocating type equipment, including short circuit or seizure moments and reactions from piping connected to the machinery

d. Impact loads - To account for the effects of impact and vibration, all centrifugal and rotating equipment support reactions were increased by 20 percent.

All equipment supports and anchorages are designed to behave elastically.

3.8.5.4 Design and Analysis Procedures

The design and analysis of the mat foundations and concrete supports for all Category I structures and equipment are in accordance with conventional elastic techniques. The mat foundations have been analyzed as a "mat on a rigid foundation." The boundary conditions selected for all structural models are determined by evaluating the stiffness (flexural, torsional, and axial) of all the members connected at a boundary point and represent (to the extent practicable) the actual restraint conditions. Loads are transferred from the foundation mats to the bedrock by direct bearing contact pressure. Because the rock provides a rigid support for the basemats, concentrated loads acting on the mats are not uniformly distributed over the area of the mat, and this effect is accounted for in the design of the mat. The analysis procedures for the reactor/auxiliary building and RHR complex mats neglect any uplift resistance (negative bearing pressure) that may be afforded by the bonding of the concrete to the bedrock.

To determine the seismic forces acting on the mat, the supported structure was analyzed by means of the computer programs DSASS and DYNAS (Section 3.13). To analyze the mat foundations for hydrostatic uplift pressures and thermal loads, the computer programs SOR-III and TEMCO-III, respectively, were used (Section 3.13).

The drywell pedestal (77 ft in diameter and 23 ft high, including the 4-ft-thick mat) for the support of the RPV, drywell, and biological shield was analyzed and designed in connection with the biological shield. The horizontal base shears and overturning moments from these structures induced by OBEs and SSEs and normal and operating accident conditions (including jet impingement forces from the complete and instantaneous severance of one of the largest connecting pipes) were applied at the top of the concrete pad. The critical section for the pad is at its base; the pad was designed taking special precautions to consider the net overturning moment at the base. Figure 3.8-41 shows the reinforcing plan at the top of the drywell pedestal.

3.8.5.5 Structural Acceptance Criteria

The allowable stresses and strains for the reinforced-concrete mat foundations and supports are in accordance with the provisions of ACI 318-71 for the RHR complex and ACI 318-63 and/or ACI 318-71 for the reactor/auxiliary building.

Serviceability checks are made in accordance with the above codes to ensure adequate crack control for the mat foundations and to limit deformations of the concrete supports within the limits prescribed by ACI 318-71 (for the RHR complex) and ACI 318-63 (for the reactor/auxiliary building) or the manufacturers' recommendations for equipment supported by the concrete supports.

A study by Dames & Moore (D&M) for the RHR complex foundation (see Reference 18) showed that the bedrock is permeable because of its fragmented nature and the presence of interconnected solution cavities (vugs). An evaluation of the rock quality based on measurements from core recovery indicated that the upper 15 to 20 ft is fractured. Based on results of compression tests on core samples and applying a reduction factor to account for the rock fractures, it was estimated that the ultimate bearing capacity of the rock is on the order of 300 ksf. In the design of the mat foundations, an allowable bearing capacity of 25 ksf was adopted, thereby providing a safety factor of 12 against bearing failure.

Furthermore, as specified in the Uniform Building Code, the minimum safety factor to be adopted against overturning is 1.5. In determining the safety factor (ratio of resisting moments to overturning moments), the resisting moment of the passive soil pressure against the subgrade walls was neglected. Also, the resultant of the base bearing pressure was kept within the middle third of the basemat.

The safety factor against base sliding (ratio of the resisting forces to driving forces) was taken as a minimum of 1.5. Moreover, the passive pressure of the soil against the subgrade walls was neglected in determining the resisting forces.

Differential settlements of the mat foundations are not expected, because they rest on essentially rigid bedrock. The load and load combinations, and the resulting factors of safety, are shown in Table 3.8-22.

3.8.5.6 Materials, Quality Control, and Special Construction Techniques

The construction materials used for the mat foundations, concrete supports, and machinery and equipment anchors conform to the standards set forth in Subsection 3.8.4.6, which contains a discussion of the QC procedures adopted (including the frequency and location of sampling and test requirements for the materials). Cadwelding is also described in detail.

A description of the construction procedures for the RHR complex mat is included here. A small amount of bedrock was removed prior to the placement of the structure's foundation. This rock was removed by a controlled and monitored program of blasting.

The blasting criteria and monitoring program ensured a minimal impact on the environment, including nearby residents. The excavation was dewatered by sump pumps, which included backup pumps in case of pump failure or other system malfunctions. Observation wells both on and off the site were used to monitor the ground-water level during construction to ensure that an unacceptable lowering of the adjacent ground-water level did not occur. Dewatering in the area of the RHR complex has been discontinued.

Pressure grouting of 15 to 20 ft of the upper rock layers was carried out to provide assurance that no zones of excessive fracturing or highly vugged material are horizontally continuous across the site. In consideration of the high sulfate content of the natural ground water, sulfate-resistant cement (Type V) is used for all cement grout and subsurface concrete that is in contact with the ground water. Grouting was accomplished in two stages, extending to depths of about 6 and 20 ft below the foundation level, respectively. Initial or primary holes within each zone were spaced 30 ft on centers, and final closure was achieved by grouting intermediate holes as required. The grout holes were drilled under qualified engineering supervision. The drilling methods permitted any zones of excessive fractures, vugs, or soil seams to be detected, and particular attention was given to these zones in subsequent grouting operations.

The foundations of the RHR complex are installed on the Bass Islands dolomite and are designed to limit the bearing pressures to values much less than the safe bearing capacity of 50,000 lb/ft^2.

As the foundations of the reservoirs are below the natural ground-water level, they are subject to uplift pressures when the reservoir is empty. The reservoir could be totally empty for possible maintenance. Flotation of the reservoirs has been prevented by using a 4-ft basemat.

Site fill is crusher-run rock material, predominantly dolomite 1-1/2 in. and smaller in diameter. It is placed in loose horizontal lifts approximately 12 in. deep. Each lift is compacted with a vibration roller similar to that used in the compaction test area. Dames & Moore conducted a seismic investigation of the compacted crushed rock (see Reference 20) and measured both compression and shear waves. These data were incorporated into the design of the Category I buildings. The RHR complex, being a Category I facility, was designed by applying the seismic design criteria used for the reactor/auxiliary building.

3.8.5.7 Testing and Inservice Surveillance Techniques

Preliminary field explorations were conducted to evaluate the soil and rock conditions at the Fermi 2 site. The field investigation consisted of the following:

a. Geologic test boring program - All geologic borings were logged in detail, and a general description of the soils and rocks encountered at the site was recorded (Subsection 2.5.1.2)

b. Water pressure tests - Pressure tests were performed during the drilling of representative borings to evaluate the bedrock (Subsection 2.5.1.2)

c. Piezometer observations - Piezometers were installed in several borings to study the seasonal fluctuations of the ground-water table; periodic ground-water level measurements were taken (Subsection 2.4.13.2)

d. Geologic reconnaissance - A geologic reconnaissance of the quarry that serves as a source of fill material for the site area was carried out to assist in the interpretation of subsurface conditions (Subsection 2.5.1.2).

In addition to the field explorations, the following laboratory tests were performed on undisturbed soil samples extracted from the borings to evaluate the physical properties of the soil and fill materials at the site (Subsection 2.5.1.2):

a. Unconfined compression tests - The purpose of this test was to determine the stress-strain characteristics of the soil. In addition, laboratory unconfined compression tests were performed on representative rock samples to determine the strength of the rock

b. Pulsating triaxial load tests - The pulsating triaxial load tests yield the dynamic moduli of elasticity and the shear moduli for the soils. The shear moduli of the bedrock were computed using the elastic relationships between the shear modulus, the modulus of elasticity, and Poisson's ratio. The moduli of subgrade reaction for the bedrock were computed by using the relationship between the subgrade modulus, the modulus of elasticity, Poisson's ratio, and the size of the loaded area used for the pulsating triaxial load specimen

c. Consolidation tests - The consolidation tests indicate the load-settlement properties of the soils

d. Moisture and density tests.

Routine observations are made of the mat foundations and concrete supports to determine the existence, if any, location, and extent of cracking. Representative equipment anchor bolts are tested periodically for tightness.

Rigorous inspection was carried out during construction in conjunction with the QC procedures outlined in Subsection 3.8.4.6 for the structural materials.

3.8 DESIGN OF CATEGORY I STRUCTURES

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19. "Enrico Fermi Atomic Power Plant Unit 2, Evaluation of Site-Specific Earthquake Base Mat Uplift Loads," DET-04-050, Nutech Engineers, May 1982.

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TABLE 3.8-1 SUMMARY OF THE PRIMARY CONTAINMENT PHYSICAL PARAMETERS

Primary system volume:

Volume water in vessel, ft^3	11,744
Volume steam in vessel, ft^3	9470
Volume water in recirc. loops	1168
Total, ft^3	22,382

Containment heat removal capacity per loop, using 90°F service water and 170°F pool temperature; one LPCI and two service water pumps, Btu/hr	66.5×10^6
Drywell free volume, including vent system, ft^3	163,730
Suppression chamber total volume, excluding vent System, ft^3	251,980
Submergence of vent pipe below suppression pool surface, ft, minimum	3.0
Submergence of vent pipe below suppression pool surface, ft, maximum	3.33

TABLE 3.8-2 DRYWELL PENETRATIONS

Type of Service	Penetration Number[a]	Type of Penetration[b]	Line Size (in.)	Sleeve Diameter (in.)	Number Provided
Equipment hatch	X-1A	-	-	156 I.D.	1
Equipment hatch	X-1B	-	-	144 I.D.	1
Personnel air lock	X-2	-	-	122 I.D.	1
Vent line	X-5A through X-5H	-	72	85 I.D.	8
CRD removal hatch	X-6	-	-	24 I.D.	1
Main steam	X-7A through X-7D	1	26	42	4
Steam drain	X-8	1	3	16	1
Reactor feedwater	X-9A, X-9B	1	24	40	2
Steam to RCIC turbine	X-10	1	4	18	1
Steam to HPCI turbine	X-11	1	10	28	1
RHR supply	X-12	1	20	36	1
RHR return	X-13A, X-13B	1	24	34	2
Spare	X-14	1	6	20	1
H2 control, Div. I	X-15	3	4	20	1
Core spray system	X-16A, X-16B	1	12	28	2
RHR RPV head spray[e]	X-17	1	6	20	1
DFDS[c] discharge	X-18	2	3	6	1
DEDS[d] discharge	X-19	2	3	6	1
Service water	X-20	2	6	8	1
Service air (Plugged)	X-21	2	1	3	1
Nitrogen supply	X-22	2	1	3	1
RBCCW supply	X-23	2	10	14	1
RBCCW return	X-24	2	10	14	1
Vent from drywell	X-25	3	24	24	1
Vent to drywell	X-26	3	24	24	1

TABLE 3.8-2 DRYWELL PENETRATIONS

Type of Service	Penetration Number[a]	Type of Penetration[b]	Line Size (in.)	Sleeve Diameter (in.)	Number Provided
Containment atmosphere sample and containment water level instrumentation	X-27	5	1	10	1
Jet pump instrumentation	X-28A, X-28C, X-28D	4	1	10	3
Spare	X-28B, X-28E, X-28F, X-28G	4	1	10	4
RPV instrumentation	X-29A, X-29B	4	1	10	2
Recirculating pump instrumentation	X-30A, X-30B	4	1	10	2
Spare	X-31A	4	1	10	1
Drywell on-line pressure control	X-31B	4	1	10	1
Recirculating flow to RPV	X-32A, X-32B	4	1	10	2
RPV instrumentation	X-33A, X-33B	4	1	10	2
EECW supply and return	X-34A, X-34B	2	10	14	2
TIP drive system	X-35B through X-35F	7	3/8	1 1/2	5
Spare	X-35A, X-35G	7	3/8	1 1/2	2
Nitrogen to drywell	X-36	2	4	10	1
Control rod drive insert	X-37A through X-37D	6	1	1	193
Control rod drive withdraw	X-38A through X-38D	6	3/4	1	193
Containment spray supply	X-39A, X-39B	3	12	12	2
RPV instrumentation	X-40A through X-40D	4	1	10	4
Spare	X-41	2	1	6	1
Standby liquid control	X-42	2	2	6	1
RWCU supply	X-43	1	6	30	1
H2 control, Div. II	X-44	3	4	26	1
Spare	X-45	1	20	34	1
Main steam flow	X-46A, X-46B	4	1	10	2

TABLE 3.8-2 DRYWELL PENETRATIONS

Type of Service	Penetration Number[a]	Type of Penetration[b]	Line Size (in.)	Sleeve Diameter (in.)	Number Provided
Reactor protection system	X-47	4	1	10	1
Containment atmosphere sample	X-48	4	1	10	1
Recirculating pump seal purge	X-49	4	1	10	1
Spare	X-50	4	1	10	1
Recirculating pump seal purge	X-51	4	1	10	1
Main steam flow	X-52	4	1	10	1
RPV instrumentation	X-53	4	1	10	1
Reactor level pressure	X-54A, X-54B	1	4	10	2
Reactor level pressure	X-55A, X-55B	1	4	10	2
Neutron monitor	X-100A, X-100G	8	-	12	2
Spare	X-100C, X-100E, X-100F	8	-	12	3
Low level signal vibration test	X-100D	8	-	12	1
Low voltage switching	X-100B	8	-	12	1
Recirculating pump power, 5 kV	X-101A through X-101F	8	-	12	6
Neutron monitor	X-102A	8	-	12	1
Low-voltage switching/RPS	X-102B	8	-	12	1
Thermocouples and misc. sign	X-103A	8	-	12	1
Neutron monitor	X-103B	8	-	12	1
CRD position indicators	X-104A through X-104F	8	-	12	6
Low voltage power (480 V)	X-105A	8	-	12	1
Low voltage switching/RPS	X-105B	8	-	12	1
Low voltage switching/RPS	X-105C	8	-	12	1

TABLE 3.8-2 DRYWELL PENETRATIONS

Type of Service	Penetration Number[a]	Type of Penetration[b]	Line Size (in.)	Sleeve Diameter (in.)	Number Provided
Low voltage power (480 V)	X-105D	8	-	12	1
Spare	X-106A	8	-	12	1
Low-level signal vibration test	X-106B	8	-	12	1
Spare	X-107A	8	-	12	1
Thermocouple	X-107B	8	-	12	1

[a] See Detroit Edison drawing 6C721-2304.

[b] See Figure 3.8-8.

[c] Drywell floor drain sump.

[d] Drywell equipment drain sump.

[e] RHR RPV head spray piping is no longer attached to RPV. Portion of head spray piping between RPV and bulkhead penetration is removed. The remaining head spray piping within the drywell is blind flanged.

TABLE 3.8-3 SUPPRESSION CHAMBER PENETRATIONS

Type of Service	Penetration Number[a]	Type of Penetration	Line Size (in.)	Sleeve Diameter (in.)	Number Provided
Access hatch	X-200A, X-200B	-	-	48 I.D.	2
Vent line	X-201A through X-201H	-	72	80-1/8 I.D.	8
Vacuum breaker	X-202A through X-202M	-	18	18	12
Vacuum breaker air	X-204A through X-204M	14	1	1	12
Purge penetrations	X-205A through X-205D	5	20	20	4
Liquid level indicator	X-206A through X-206D	6	1	1	4
Vent line drain	X-207A through X-207H	12	1	1	8
Electromatic relief valve discharge	X-208A through X-208P	-	12	12	15
Spares	X-209A, X-209C	8	1	1	2
Thermocouples	X-209B, X-209D	8	1	1	2
RHRS test line	X-210A, X-210B	6	18	18	2
RHRS to spray header	X-211A, X-211B	6	6	6	2
RCIC turbine exhaust	X-212	8	8	10	1
Torus water management discharge supply	X-213A, X-213B	-	8	8	2
RCIC and HPCI steam return vacuum Breaker	X-214	5	4	4	1
Post-LOCA H_2 continuous suction, Div. I	X-215	5	4	4	1
Spares	X-216A, X-216B	5	1/2	2	2
Grab sample	X-217	5	1/2	2	1
Post-LOCA H_2 continuous return, Div. I	X-218	5	4	10	1
Post-LOCA H_2 continuous suction, Div. II	X-219	5	10	10	1
HPCI turbine exhaust	X-220	8	24	24	1

TABLE 3.8-3 SUPPRESSION CHAMBER PENETRATIONS

Type of Service	Penetration Number[a]	Type of Penetration	Line Size (in.)	Sleeve Diameter (in.)	Number Provided
Condensate from HPCI turbine drain pot	X-221	8	2	2	1
RCIC vacuum pump discharge	X-222	8	2	2	1
Shutdown and RHRS pump suction	X-223A through X-223D	-	24	24	4
Core spray pump suction	X-224A, X-224B	-	20	20	2
HPCI pump suction	X-225	-	24	24	1
RCIC pump suction	X-226	-	8	8	1
Core spray test line	X-227A, X-227B	6	10	10	2
Vacuum breaker solenoids	X-228A through X-228D	6	-	10	4
Spare	X-229	15	1	1	1
PCMS suction, Div. I	X-230	15	1 1/2	1 1/2	1
PCMS suction, Div. II	X-231	15	1 1/2	1 1/2	1

[a] See Detroit Edison drawing 6C721-2305.

TABLE 3.8-4 LIST OF SPECIFICATIONS, CODES, AND STANDARDS FOR FERMI 2[a]

Specification Reference number	Specification or Standard Designation	Title	Edition
1A	ACI 318-71	Building Code Requirements for Reinforced Concrete[b]	Feb. 9, 1971
1B	ACI 318-63	Building Code Requirements for Reinforced Concrete[b]	June 1963
2A	ACI 301-72	Specifications for Structural Concrete for Buildings	1972
2B	ACI 301-66	Specifications for Structural Concrete for Buildings	1966
3	ACI 347-68	Recommended Practice for Concrete Formwork	1968
4	ACI 305-72	Recommended Practice for Hot Weather Concreting	1972
5A	ACI 211.1-74	Recommended Practice for Selecting Proportions for Normal Weight Concrete	1974
5B	ACI 211.1-70	Recommended Practice for Selecting Proportions for Normal Weight Concrete	1970
7	ACI 315-65	Manual of Standard Practice for Detailing Reinforced Concrete Structures	1965
8	ACI 306-66	Recommended Practice for Cold Weather Concreting	1966
9	ACI 309-72	Recommended Practice for Consolidation of Concrete	1972
10	ACI 322-72	Building Code Requirements for Structural Plain Concrete	1972
11	ACI 308-71	Recommended Practice for Curing Concrete	1971
12	ACI 212	Guide for Use of Admixtures in Concrete	ACI Journal, Sept. 1971

TABLE 3.8-4 LIST OF SPECIFICATIONS, CODES, AND STANDARDS FOR FERMI 2[a]

Specification Reference number	Specification or Standard Designation	Title	Edition
13	ACI 214-65	Recommended Practice for Evaluation of Compression Test Results in Field Concrete	1965
14	ACI 311-64	Recommended Practice for Concrete Inspection	1964
15	ACI SP-2	Manual of Concrete Inspection	1963
16	ACI 304-73	Recommended Practice for Measuring, Mixing, Transporting and Placing Concrete	1973
17	ACI Committee Report 304	Placing Concrete by Pumping Methods	ACI Journal, May 1971
18	ACI Committee Report 437 Subcommittee	Strength Evaluation of Existing Concrete Structure	Nov. 1967
19	CRSI	Manual of Standard Practice	19th Edition
20	UBC	Uniform Building Code[c]	1970
21A	AISC-69	Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings	Feb. 12, 1969
21B	AISC-63	Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings	1963
22	AISI	Specification for the Design of Light Gage Cold-Formed Steel Structural Members	1968
23A	AWS D1.1-72	Structural Welding Code	1972
23B	AWS D1.0-69	Structural Welding Code	1969
24	AWS D12.1-61	Recommended Practice for Welding Reinforcing Steel, Metal Inserts and Connections in Reinforced Concrete Construction	1961

TABLE 3.8-4 LIST OF SPECIFICATIONS, CODES, AND STANDARDS FOR FERMI 2[a]

Specification Reference number	Specification or Standard Designation	Title	Edition
25	ASME	1971 ASME Boiler and Pressure Vessel Code, Subsection NE of Section III	Summer of 1972 Addenda
26	ASME	ASME Boiler and Pressure Vessel Code Material Specifications, Part A - Ferrous	1972
27	ASME	ASME Boiler and Pressure Vessel Code, Section XI, "In Service Inspection of Nuclear Reactor Coolant Systems"	
28	ASTM	Annual Books of ASTM Standards	1972
29	ANSI B31.1.0	Standard Code for Pressure Piping, Power Piping	
30	API 620	Specifications for Welded Steel Storage Tanks	Feb. 1970
31	CTI	Standards for the Cooling Tower Institute	
32	NEC	National Electric Code	
33		U.S. Army Corps of Engineers - Regulations with Respect to Dredging and Construction	
34		Steiger Occupation Safety and Health Act	1970
35	Regulatory Guide. 1.10	Mechanical Cadweld Splices in Reinforcing Bars of Concrete Containments	Feb. 1, 1971 (withdrawn July 1981)
36	Regulatory Guide 1.12	Instrumentation for Earthquakes	Feb. 1, 1971
37	Regulatory Guide 1.13	Fuel Storage Facility Design Basis	Oct. 27, 1971
38	Regulatory Guide 1.15	Testing of Reinforcing Bars for Concrete Structures	Oct. 27, 1971 (withdrawn July 1981)

TABLE 3.8-4 LIST OF SPECIFICATIONS, CODES, AND STANDARDS FOR FERMI 2[a]

Specification Reference number	Specification or Standard Designation	Title	Edition
39	Regulatory Guide 1.26	Quality Group Classification and Standards	Mar. 23, 1972
40	Regulatory Guide 1.27	Ultimate Heat Sink	Mar. 23, 1972
41	Regulatory Guide 1.29	Seismic Design Classification	Rev. 3, September 1978
42	Regulatory Guide 1.31	Control of Stainless Steel Welding	Aug. 11, 1972
43	ACI 349-01	Code Requirements for Nuclear Safety Related Concrete Structures	2001
44	Regulatory Guide 1.142	Safety-Related Concrete Structures for Nuclear Power Plants (Other Than Reactor Vessels and Containments)	Rev. 2, Nov. 2001
45	ACI 318-05	Building Code Requirements for Reinforced Concrete	2005
46	ACI 318-77 Handbook	Handbook for Building Requirements for Reinforced Concrete	1977

[a] In design and operation, inspection, etc. of structures and other components for Fermi 2, it has been the practice to specify the use of code(s) and the related design guides applicable at the initiation of the design activity. In the course of design process, the use of later editions of the code and/or any supplements issued thereto has been allowed.

[b] Appendix A adopted for seismic design.

[c] Official building code of Frenchtown Township.

TABLE 3.8.5 DRYWELL LOADING

LOADS	Construction OBE	Construction SSE	Overload Test	Initial Leak Rate Test	Operating OBE	Operating SSE	Accident OBE	Accident SSE	Flooded OBE	Flooded SSE	Refueling OBE	Refueling SSE
Loading case no.	1	2	3	4	5	6	7	8	9	10	11	12
Dead load, vessel and attachment	x	x	x	x	x	x	x	x	x	x	x	x
Pressure, positive and negative		x	x	x	x	x	x	x				
Contained air			x	x								
Wind load	x	x	x	x								
Seismic	x	x			x	x	x	x	x	x	x	x
Vent thrusts			x	x	x	x	x	x				
Weld pads:												
Dead load	x	x	x	x	x	x	x	x	x	x	x	x
Live load					x	x					x	x
Jet forces							x	x				
Temporary pressure or unrelieved deflection due to concrete load					x	x	x	x				
Equipment support loads				x	x	x	x	x	x	x	x	x
Weight and/or restraint of compressible material					x	x	x	x	x	x	x	x
Personnel lock:												
Dead load	x	x	x	x	x	x	x	x	x	x	x	x
Live load					x	x					x	x
Equipment hatch:												
Dead load	x	x	x	x	x	x	x	x	x	x	x	x
Live load					x	x					x	x
Refueling seal loads					x	x					x	x
Water on refueling seals											x	x
Hydrostatic pressure due to flooding									x	x		

TABLE 3.8-6 SUPPRESSION CHAMBER LOADING

LOADS	Construction OBE	Construction SSE	Overload Test	Initial Leak Rate Test	Operating OBE	Operating SSE	Accident OBE	Accident SSE	Flooded OBE	Flooded SSE
Loading case no.	1	2	3	4	5	6	7	8	9	10
Dead load, vessel and attachments	x	x	x	x	x	x	x	x	x	x
Suppression pool water			x	x	x	x	x	x	x	x
Pressure:										
Positive										
Negative			x	x	x	x	x	x	x	x
Seismic	x	x			x	x	x	x	x	x
Vent thrusts			x	x			x	x		
Contained air			x	x						
Temporary concrete loads	x									
Suppression chamber spray header full of water	x	x	x	x	x	x	x	x		
Jet forces on downcomer pipes							x	x		
Live load on catwalks and platforms	x				x	x	x	x	x	x
Weld pads:										
Dead load	x	x	x	x	x	x	x	x	x	x
Live load					x	x				

Note: The operating and accident loads have been supplemented and/or modified according to References 1 and 3.

TABLE 3.8-7 LOADS AND LOADING COMBINATIONS FOR THE DRYWELL VENT PENETRATIONS

Design Category	Load Combination	Stress Comparison[a]
I	E_s	$P_m \leq S_m$ @ T_d
		$P_1 + P_b \leq 1.5\ S_m$ @ T_d
II	$R_p + R_t$	$P_m \leq S_m$ @ T_a
		$P_1 + P_b \leq 1.5\ S_m$ @ T_a
III	$R_p + P_t + E_s$ + Design	$P_1 \leq 1.1\ S_m$ @ T_a
		$P_1 + P_b \leq 1.5\ S_m$ @ T_a

E_s = Maximum seismic reaction due to SSE "g" loads on vent header

R_p = Piping reaction due to maximum accident pressure expansion between drywell and suppression pool.

R_t = Piping reaction due to maximum accident thermal expansion between drywell and suppression pool

Design = Maximum general stresses calculated at vent penetration in Table 3.8-5

T_d = Design temperature

T_a = Temperature associated with design accident

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[a] Stress nomenclature in accordance with the ASME B&PV Code Section III.

TABLE 3.8-8 LOADS AND LOADING COMBINATIONS FOR THE DRYWELL SPHERICAL EMBEDMENT

Design Category	Loading Combination	Stress Comparison[a]
I	Design + P_a + T_a	$P_1 \leq 1.5\ S_m$ @ T_a
		$P_1 + P_b + Q \leq 3.0\ S_m$ @ T_a

P_a = Pressure loading due to design accident

T_a = Temperature corresponding to design accident

Design = Maximum general shell stress due to loading in Table 3.8-5 for the specific location of the spherical embedment

[a] Stress nomenclature in accordance with the ASME B&PV Code Section III.

TABLE 3.8-9 LOADS AND LOADING COMBINATIONS FOR THE DRYWELL KNUCKLE REGION (ACCIDENT LOADS)

Design Category	Loading Combinations	Stress Comparison[a]
I	Design + P_a	$P_1 \leq S_m$ @ T_a
		$P_1 + P_b \leq 1.5\ S_m$ @ T_a

P_a = Operating pressure associated with design accident condition

Design = Maximum general shell stress in the knuckle region calculated from Table 3.8-5 for condition 8

T_a = Temperature associated with design accident

[a] Stress nomenclature in accordance with the ASME B&PV Code Section III.

TABLE 3.8-10 LOADS AND LOADING COMBINATIONS FOR THE DRYWELL CONE AND TOP HEAD

Design Category	Loading Combinations	Stress Comparison[a]
I	Design P_a	$P_1 \leq S_m$ @ T_a
		$P_1 + P_b \leq 1.5\ S_m$ @ T_a

P_a = Operating pressure associated with design accident condition

T_a = Temperature associated with design accident

[a] Stress nomenclature in accordance with the ASME B&PV Code Section III.

TABLE 3.8-11 LOADS AND LOADING COMBINATIONS FOR THE TOP DRYWELL FLANGE

Design Category	Loading Combination	Stress Comparison[a]
Operating		
I	$D_b + P_o + W_s$	$P_m \leq S_m$ @ T_d
II	$D_b + P_v + W_s$	$P_1 + P_b \leq 1.5\ S_m$ @ T_d
Refueling		
I	$D_b + W_s$	$P_m \leq S_m$ @ T_d
II	Ws	$P_1 + P_b \leq 1.5\ S_m$ @ T_d
Accident		
I	$D_b + P_a$	$P_m \leq S_m$ @ T_a
II	$D_b + P_v$	$P_1 + P_b \leq 1.5\ S_m$ @ T_a

D_b = Design bolting load calculated for gasket seating and for internal pressure

P_o = Design pressure during normal operation

P_v = Design vacuum pressure

P_a = Design accident pressure

W_s = Design loads due to the weight of the water seal, together with loads imposed by the expansion bellows

T_d = Design temperature

T_a = Temperature associated with design accident

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[a] Stress nomenclature in accordance with the ASME B&PV Code Section III.

TABLE 3.8-12 LOADS AND LOADING COMBINATIONS FOR THE EQUIPMENT HATCH

PRESSURE-RETAINING PARTS

Design Category	Loading Combination	Stress Comparison[a]
I	P_a	$P_m \leq S_m$ @ T_a
		$P_l + P_b \leq 1.5\ S_m$ @ T_a
II	$P_a + R_a$	$P_m \leq 0.9\ S_y$ @ T_{jet}

P_a = Accident pressure load

R_a = Jet force associated with pipe rupture

T_a = Temperature associated with design accident

T_{jet} = Temperature at the jet

STRUCTURAL PARTS

Design Category	Loading Combination	Stress Comparison[a]								
		Tension		Bending		Bearing		Shear		Weld
		P_L	Bolt	P_L	Bolt	P_L	Bolt	P_L	Bolt	
I	$D + L + P_a$	S_m	S_m	1 1/2 S_m	1 1/2 S_m	1.6 S_m	1.6 S_m	.4 F_y	.8 S_m	.8 S_m
		(17.5)	(25)	(26.25)	(37.5)	(28)	(40)	(14.5)	(16)	(14)
II	$D + L + P_a + R_j$	.9 F_y	.9 F_y	.9 F_y	[b]1.5 F_y	1.33 x .9 F_y	.9 F_y	.8 F_y	.8 F_y	.8 F_y
		(30.3)	(90)	(30.3)	(150)	(40.4)	(90)	(29)	(80)	(27)

D = Dead load

L = Live load

P_a = Accident pressure load

R_j = Reaction forces due to jet force R_a on cover

[a] Stress nomenclature in accordance with the ASME B&PV Code Section III.

[b] Maintain less than F_y in combination with shear.

TABLE 3.8-13 LOADS AND LOADING COMBINATIONS FOR THE DRYWELL BEAM SEATS

STRUCTURAL PARTS

Design Category	Loading Combination	Stress Comparison[a]
I	$D + L + E_o$	Per AISC Specification
II	$D + L + E_s$	1.33 Allowable Increase for Design II

PRESSURE–RETAINING PARTS

Design Category	Loading Combination	Stress Comparison[a] Shell	Weld
I	$D + L + E_o + P_a$	$P_1 \leq 1.5\ S_m$ @ T_a	
		$P_1 + P_b \leq 1.5\ S_m$ @ T_a	
II	$D + L + E_o + P_o$	Buckling Allowable per WRC 69[b]	$0.55\ S_m$ @ T_a
III	$D + L + E_s + P_a$	$P_1 \leq 1.5\ S_m$ @ T_a	
		$P_1 + P_b \leq 1.5\ S_m$ @ T_a	
IV	$D + L + E_s + P_o$	Buckling Allowable per WRC 69[b]	$0.55\ S_m$ @ T_a

D = Dead load

L = Live load

E_o = Operating–basis earthquake

E_s = Safe–shutdown earthquake

P_a = Operating pressure associated with design accident condition

P_o = Operating pressure associated with normal operating

T_a = Temperature associated with design accident

[a] Stress nomenclature in accordance with ASME B&PV Code Section III.

[b] Welding Research Council Standard 69.

TABLE 3.8-14 LOADS AND LOADING COMBINATIONS FOR THE SPRAY HEADER AND VENT JET DEFLECTOR

STRUCTURAL (NON-PRESSURE RETAINING) PARTS

Design Category	Load Combination	Stress Comparison[a]
I	R_a	Per AISC Specification with 1.33 Allowable Increase

PRESSURE–RETAINING PARTS

Design Category	Load Combination	Stress Comparison[a]
I	R_a	$P_1 \leq 1.1\ S_m$ @ T_a
		$P_1 + P_b \leq 1.5\ S_m$ @ T_a

R_a = Jet force associated with pipe rupture

T_a = Temperature associated with design accident

[a] Stress nomenclature in accordance with the ASME B&PV Code Section III.

TABLE 3.8-15 LOADS AND LOADING COMBINATIONS FOR THE DRYWELL STABILIZER CONNECTION

Design Category	Loading Combination	Stress Comparison[a] AISC (Membrane) Plate	AISC (Membrane) Weld	AISC (Bending) Plate	ASME (Membrane) Plate	ASME (Membrane) Weld	ACI
I	$D + L + E_o$	$P_m \le .5\ F_y$	$P_m \le 15800$	$P_1 + P_b \le .5\ F_y$	$P_m \le .5\ S_y$	13,600	Concrete Bearing Stresses in Accordance with ACI 318-71
II	$D + L + R_j + E_o$	$P_m \le F_y$	$P_m \le .8\ F_y$	$P_1 + P_b \le F_y$	$P_m \le S_y$	$.8\ S_y$	
III	$D + L + R_j + E_s$	$P_m \le F_y$	$P_m \le .8\ F_y$	$P_1 + P_b \le F_y$	$P_m \le S_y$	$.8\ S_y$	
IV	$D + L + R_f + E_s$	$P_m \le F_y$	$P_m \le .8\ F_y$	$P_1 + P_b \le F_y$	$P_m \le S_y$	$.8\ S_y$	

D = Dead load

L = Live load

E_o = Operating–basis earthquake

E_s = Safe–shutdown earthquake

R_j = Reaction force due to jet force R_a

R_f = Reaction force due to flooding

[a] Stress nomenclature in accordance with the ASME B&PV Code Section III.

TABLE 3.8-16 LOADS AND LOADING COMBINATIONS FOR THE DRYWELL SKIRT

Design Category	Loading Combinations	Stress Comparison
I	D + W	Per AISC Specification
II	D + E_s	Per AISC Specification
III	D + T	Per AISC Specification

D = Dead load

E_s = Safe–shutdown earthquake

T = Test condition

W = Design loads due to wind

TABLE 3.8-17 LOADS AND LOADING COMBINATIONS FOR PENETRATIONS

Design Category	Loading Combination	Stress Comparison[a]
I	$P_d + R_o$	$P_1 \leq 1.1\ S_m$ @ T_d
		$P_1 + P_b \leq 1.5\ S_m$ @ T_d

P_d = Pressure associated with design condition

R_o = Maximum piping reaction due to operating, accident, test, or flooding

T_d = Design temperature

[a] Stress nomenclature in accordance with the ASME B&PV Code Section III.

TABLE 3.8-18 LOADING COMBINATIONS FOR STEEL STRUCTURES, ELASTIC DESIGN[a]

Load Combination Category		Load Condition No.	Overall Loading Equation[b,c,d]
I	Construction	1	$F = 1.0(D + L + C + W + T_o)$
		2	$F = 1.0(D + L + S + C + T_o)$
II	Test	3	$F = 1.0(D + L + S + C + R_o + T_o)$
III	Normal	4	$F = 1.0(D + L + S + C + R_o + T_o)$
IV	Severe environmental	5	$F = 1.0(D + L + C + R_o + E_o + T_o)$
		6	Deleted
		7	$F = 1.0(D + L + C + R_o + W + T_o)$
V	Abnormal	8	$F = 1.0(D + L + S + C + R_a + T_a + P_a)$
		9	$F = 1.0(D + L + S + C + R_o + T_o + M)$
VI	Extreme environmental	10	$F = 1.0(D + L + C + R_o + E_s + T_o)$
		11	$F = 1.0(D + L + R_o + W_t + T_o)$
		12	$F = 1.0(D + L + C + R_o + T_o + H)$
VII	Abnormal/severe environmental	13	$F = 1.0(D + L + C + R_a + E_o + T_a + P_a + Y_r + Y_j + Y_m)$
VIII	Abnormal/extreme environmental	14	$F = 1.0(D + L + C + R_a + E_s + T_a + P_a + Y_r + Y_j + Y_m)$

[a] Loads not applicable to a particular system under consideration may be deleted. If for any load combination the effect of any load other than D reduces the load, it will be deleted from the combination. For both E_s and E_o, the resultant effects (resultant stresses) at both horizontal and vertical earthquake components shall be determined by combining the individual effects by the square root of the sum of the squares. This procedure also applies when combining the dynamic effects of W_t, M, R_a, and P_a.

[b] F = Working load.

[c] See Table 3.8-21 for definition of terms.

[d] For allowable stresses, see Table 3.8-19.

TABLE 3.8-19 ALLOWABLE DESIGN STRESSES

	Loading Condition	Structural Steel F_y = 36,000 psi: Tension (F_t) and Bending (F_b)	Structural Steel F_y = 36,000 psi: Compression (F_a)	Concrete* f'_c = 4000 psi, n = 8: Basic Design Stress	Concrete* f'_c = 4000 psi, n = 8: Compression Stress	Reinforcing Bars F_y = 60,000 psi: % F_y	Reinforcing Bars F_y = 60,000 psi: Tensile Stress F_s
A	Dead load (D.L.) + live load (L.L.)	F_t and F_b from Section 1.5, Appendix A, 1969 AISC Specification	F_a from Table 1-36 of 1969 AISC Specification	From ACI 318-63	$f_c = 0.45\ f'_c$	0.4 F_y	24,000 psi
B	D.L. + L.L. + OBE	F_t and F_b from Section 1.5, Appendix A, 1969 AISC Specification	F_a from Table 1-36 of 1969 AISC Specification	From ACI 318-63	$f_c = 0.45\ f'_c$	0.4 F_y	24,000 psi
C	D.L. + 0.50 L.L. + OBE + forces due to thermal expansion and snubber loads	F_t and F_b from Section 1.5, Appendix A, 1969 AISC Specification	F_a from Table 1-36 of 1969 AISC Specification	From ACI 318-63	$f_c = 0.45\ f'_c$	0.4 F_y	24,000 psi
D	Case B, except SSE instead of OBE	$F_t = F_b = F_y$	1.67 x Case A	1.67 x Case A	$f_c = 0.85\ f'_c$ maximum	1.67 x Case A	0.9 F_y maximum = 54,000 psi
E	Case C, except SSE instead of OBE	$F_t = F_b = F_y$	1.67 x Case A	1.67 x Case A	$f_c = 0.85\ f'_c$	1.67 x Case A	0.9 F_y maximum = 54,000 psi
F	D.L. + L.L. + basic design wind	1.33 x Case A	1.33 x Case A	1.33 x Case A	$f_c = 0.60\ f'_c$	1.33 x Case A = 0.53 F_y	31,800 psi
G	D.L. + L.L. + tornado wind design or maximum	$F_t = F_b = F_y$	1.67 x Case A	1.67 x Case A	$f_c = 0.85\ f'_c$ maximum	1.67 x Case A	0.9 F_y maximum = 54,000 psi

D.L. = Dead load of structure and equipment plus any other permanent loads, such as soil or hydrostatic loads or operating pressure.

*Concrete with 4000 psi specified compressive strength (f'_c) is generally used in Fermi 2. The use of other grades of concrete or use of higher strength for the same grade of concrete based on the time-strength relationship has been noted in corresponding design document package.

TABLE 3.8-20 LOADING COMBINATIONS FOR REINFORCED CONCRETE STRUCTURES, ULTIMATE STRENGTH DESIGN[a]

Load Combination Category		Load Condition No.	Overall Loading Equation[b,c,d,e]
I	Construction	1	$u = 1.3(D + L + C + W + T_o)$
II	Normal	2	$u = 1.4(D + R_o) + 1.7(L + C) + 1.3T_o$
III	Test	3	$u = 1.1(D + R_o) + 1.3(L + C + T_o)$
IV	Severe environmental	4	$u = 1.4(D + R_o) + 1.7(L + C + W) + 1.3T_o$
		5	$u = 1.2(D + R_o) + 1.7W + 1.3T_o$
		6	$u = 1.4(D + R_o) + 1.7(L + C) + 1.9E_o + 1.3T_o$
		7	$u = 1.2(D + R_o) + 1.9E_o + 1.3T_o$
		8	Deleted
V	Abnormal	9	$u = 1.0(D + L + C + R_a + T_a) + 1.5P_a$
		10	$u = 1.0(D + L + C + R_o + T_o + M)$
VI	Extreme environmental	11	$u = 1.0(D + L + C + R_o + Es + T_o)$
		12	$u = 1.0(D + L + R_o + W_t + T_o)$
		13	$u = 1.0(D + L + C + R_o + T_o + H)$
VII	Abnormal/severe environmental	14	$u = 1.0(D + L + C + R_a + T_a + Y_r + Y_j + Y_m) + 1.25(E_o + P_a)$
VIII	Abnormal/extreme environmental	15	$u = 1.0(D + L + C + R_a + E_s + T_a + P_a + Y_r + Y_j + Y_m)$

[a] Loads not applicable to a particular system under consideration may be deleted. If for any load combination the effect of any load other than D reduces the load, it will be deleted from the combination. For both E_s and E_o, the resultant effects (resultant stresses) at both horizontal and vertical earthquake components shall be determined by combining the individual effects by the square root of the sum of the squares. This procedure also applies when combining the dynamic effects of W_t, M, R_a, and P_a.

[b] u = Ultimate load.

[c] See Table 3.8-21 for definition of terms.

[d] Allowable stresses shall be according to ACI 318-71.

[e] Allowable loads shall be according to ACI 349-01 & RG 1.142, Rev. 2 for the second set of Category I underground ductbanks, manholes and above ground cable vaults.

TABLE 3.8-21 NOTES FOR TABLE 3.8-18 AND TABLE 3.8-20

C = Crane-lifted load.

D = Dead load of the structure plus any other permanent load except prestressing forces, including vertical and lateral pressures of liquids, piping, cable pan, self weight of crane, and weight of permanent equipment and its normal contents under operating and test conditions.

E_o = Operating-basis earthquake (OBE) including dynamic lateral soil pressure and hydrodynamic ground-water pressure

Horizontal ground acceleration = 0.08g

Vertical ground acceleration = 66-2/3 percent of the horizontal acceleration where g = 32.2 ft/sec^2.

E_s = Safe-shutdown earthquake (SSE) including dynamic lateral soil pressure and hydrodynamic ground-water pressure

Horizontal ground acceleration = 0.15g

Vertical ground acceleration = 66-2/3 percent of the horizontal ground acceleration where g = 32.2 ft/sec^2.

H = Forces associated with the maximum probable flood or seiches (see Section 3.4).

L = Conventional floor and roof live loads, movable equipment loads, and other loads that vary in intensity, such as lateral soil pressure. Live load intensities may vary from zero to their maximum values to determine the most critical effect upon the structure for the load combination under consideration.

Note: Reduced intensities of live loads such as conventional floor loads may be associated with accident or extreme environmental conditions.

TABLE 3.8-21 NOTES FOR TABLE 3.8-18 AND TABLE 3.8-20

M = Loads associated with both internal and external missiles (see Section 3.5).

$P_a^{(a)}$ = Pressure load caused by a postulated pipe break accident. Containment design accident pressures based upon peak calculated pressure with appropriate margin provided for uncertainties are:

Internal pressure	56 psig
External pressure	2 psig

P_o = Design pressure during normal operating condition. Containment design normal pressures are:

Internal pressure	2 psig
External pressure	atmospheric

P_t = Containment test pressure:

Internal pressure	70 psig
External pressure	atmospheric

R_a = Pipe reactions due to postulated break accident including R_o.

R_o= Normal operating reactions of piping at supports or anchor points.

S = Stability load.

$T_a^{(a)}$ = Thermal loads generated by postulated break accident including T_o. Containment temperatures associated with a design accident are:

Internal temperature of the suppression chamber	281°F
Internal temperature of the drywell	340°F
Minimum external temperature	50°F

TABLE 3.8-21 NOTES FOR TABLE 3.8-18 AND TABLE 3.8-20

T_o= Thermal effects associated with normal, construction, and test conditions:

(a) Climatic temperature ranges:

Maximum outside temperature	102°F
Minimum outside temperature	-18°F

(b) Operating temperature ranges:

Ambient temperature inside the reactor/auxiliary building and RHR complex	70°F

u = Ultimate load capacity as defined by ACI 318-71 [b]

W = Design wind load (see Subsection 3.3.1)

W_t = Tornado load (see Subsection 3.3.2)

Y_j = Jet impingement equivalent static load.

Y_m = Missile impact equivalent static load.

Y_r = Equivalent static reaction load from high-energy line break

---

[a] Since these loads are time dependent, their effects will be superimposed accordingly.

[b] Use ACI 349-01 for the second set of Category I underground ductbanks, manholes and above ground cable vaults.

TABLE 3.8-22 FACTORS OF SAFETY FOR CATEGORY I FOUNDATIONS

Category I Structure	Load Combinations				
	D+H+E	D+H+W	D+H+E’	D+H+W_t	D+F'
Reactor and aux. bldg.	1.92	26.70	1.32	2.85	1.76
RHR complex	1.78	22.20	1.43	2.43	1.10*

*The factor of safety for flotation of the RHR complex is computed based on the reservoirs totally empty

where

D = dead loads or their related internal moments and forces, including any permanent equipment loads and hydrostatic loads

E = loads generated by the operating-basis earthquake

W = loads generated by the design wind specified for the plant

E’ = loads generated by the safe-shutdown earthquake

W_t = loads generated by the design tornado specified for the plant; tornado loads include loads due to the tornado wind pressure, the tornado-created differential pressure, and tornado-generated missiles

H = lateral earth pressure

F’ = buoyant force of the probable maximum flood (PMF)

Figure Intentionally Removed
Refer to Plant Drawing C-2407

FIGURE 3.8-1

TYPICAL DETAIL OF THE DRYWELL FLOOR CONNECTION TO THE DRYWELL SUPPORT PEDESTAL

Figure Intentionally Removed
Refer to Plant Drawing C-2304

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FIGURE 3.8-2
DEVELOPED VIEW OF THE DRYWELL

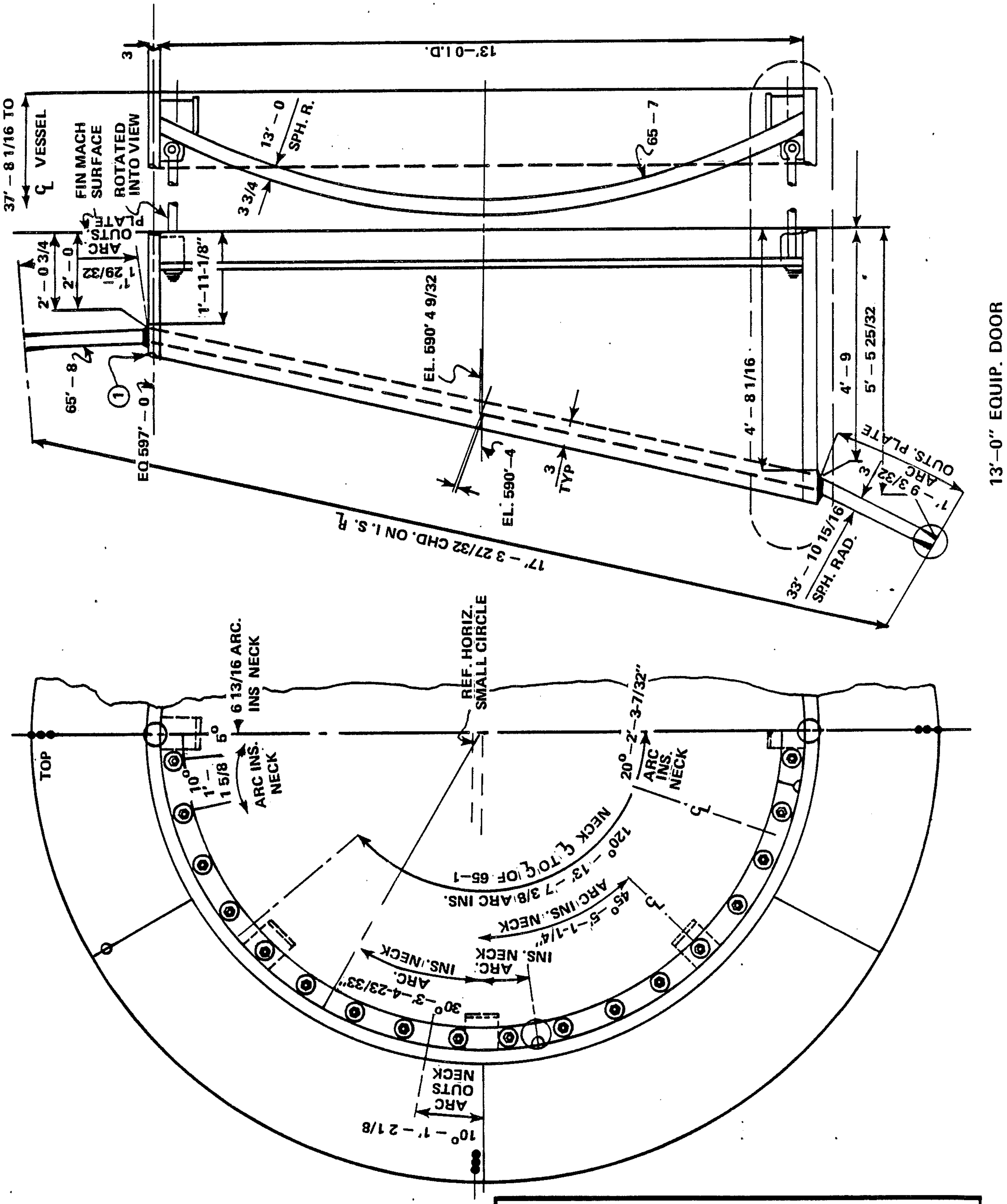

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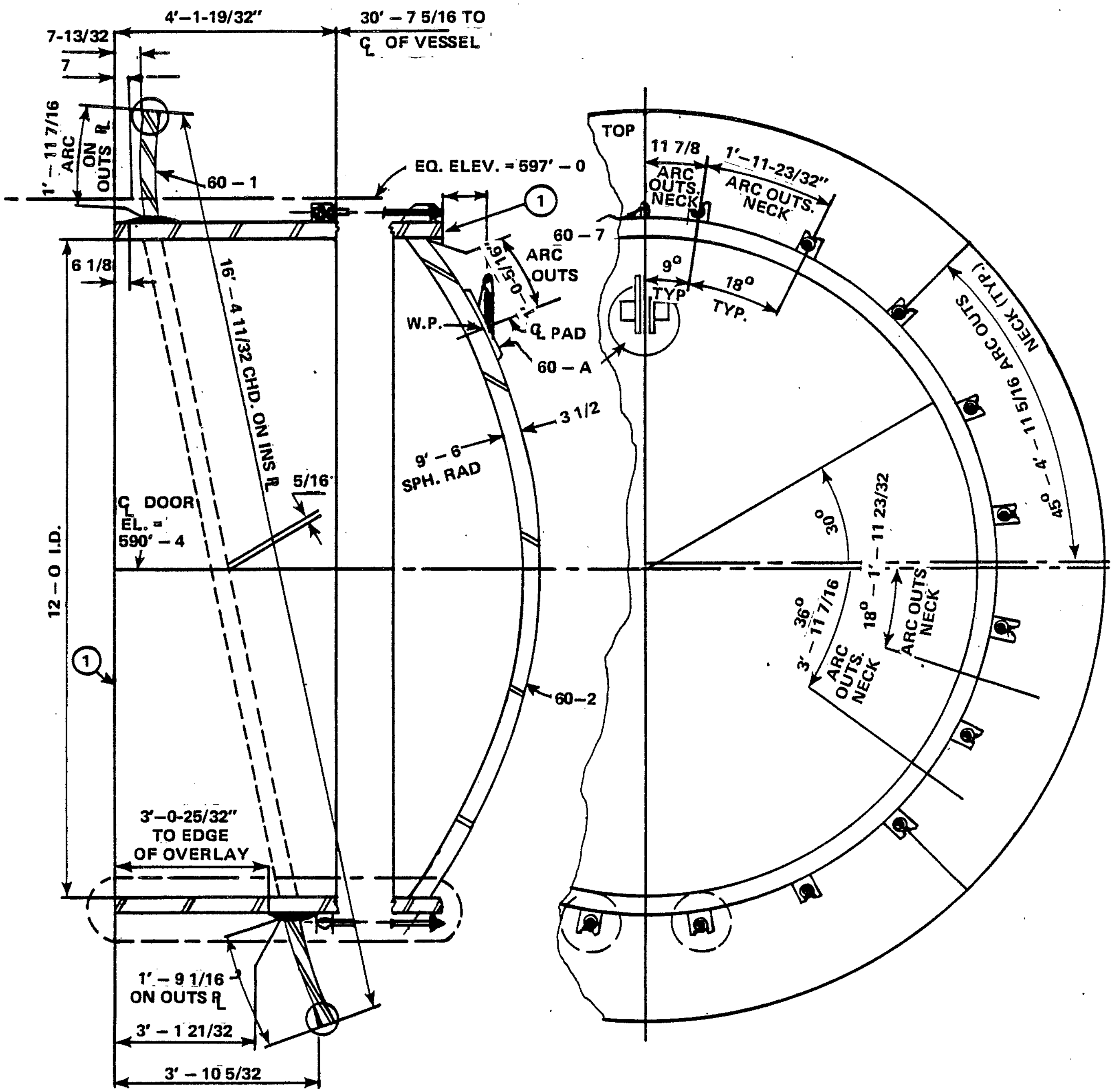
FIGURE 3.8-3, SHEET 1

PRIMARY CONTAINMENT EQUIPMENT HATCH

CHICAGO BRIDGE & IRON COMPANY
DRAWING NO. 64, REV. G



12'-0" EQUIP. DOOR

Fermi 2

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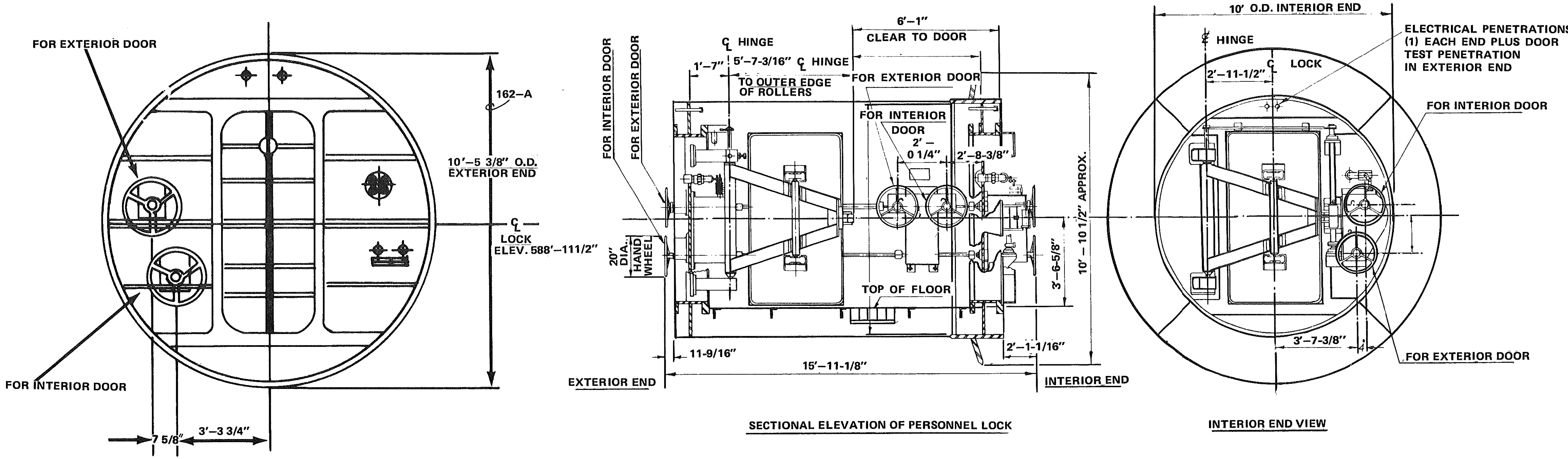
FIGURE 3.8-3, SHEET 2

PRIMARY CONTAINMENT EQUIPMENT HATCH

CHICAGO BRIDGE & IRON COMPANY
DRAWING NO. 59, REV. F



CHICAGO BRIDGE & IRON COMPANY DRAWING NO. 100, REV. B

Fermi 2

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FIGURE 3.8-4

PRIMARY CONTAINMENT PERSONNEL HATCH

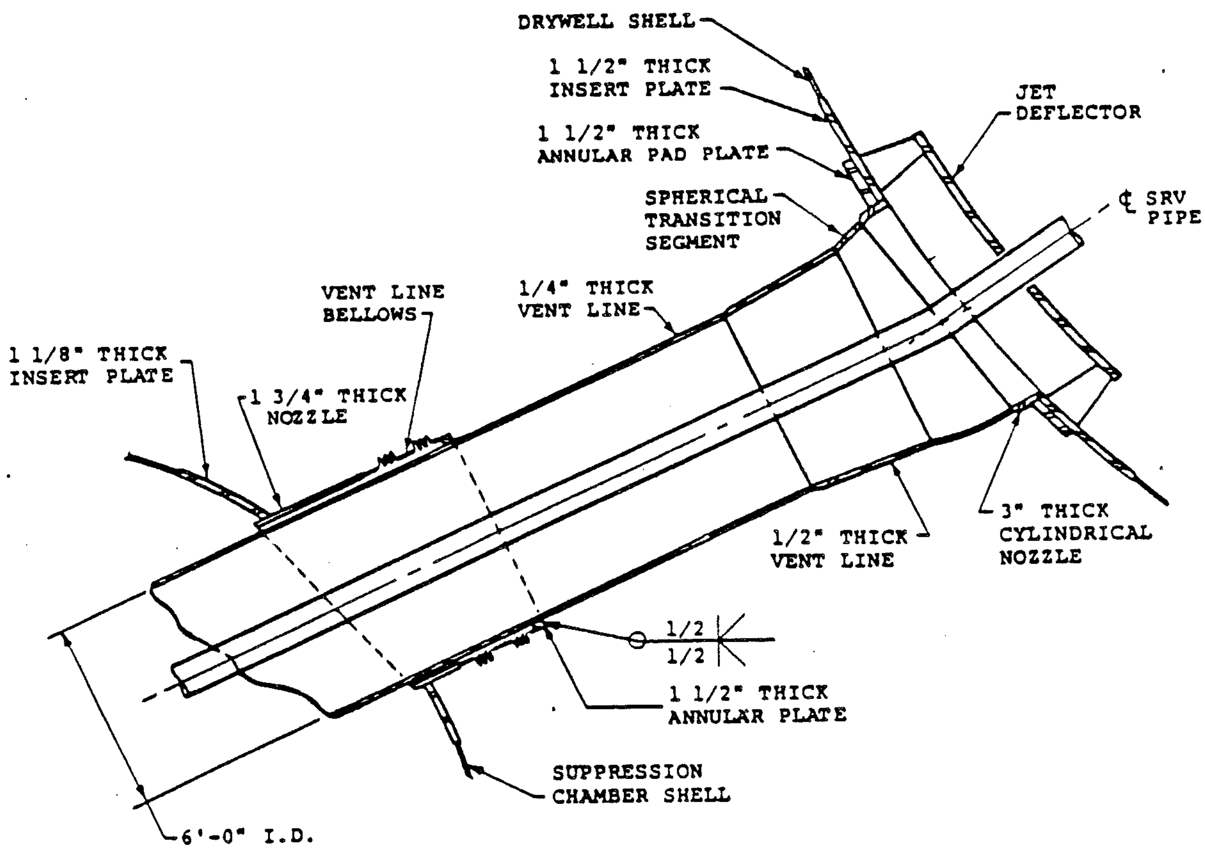

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FIGURE 3.8-5

VENT LINE DETAILS – UPPER END

NUTECH DRAWING NO. DET-04-028-3, REV. 0
PUAR FIGURE 3-2.1-7

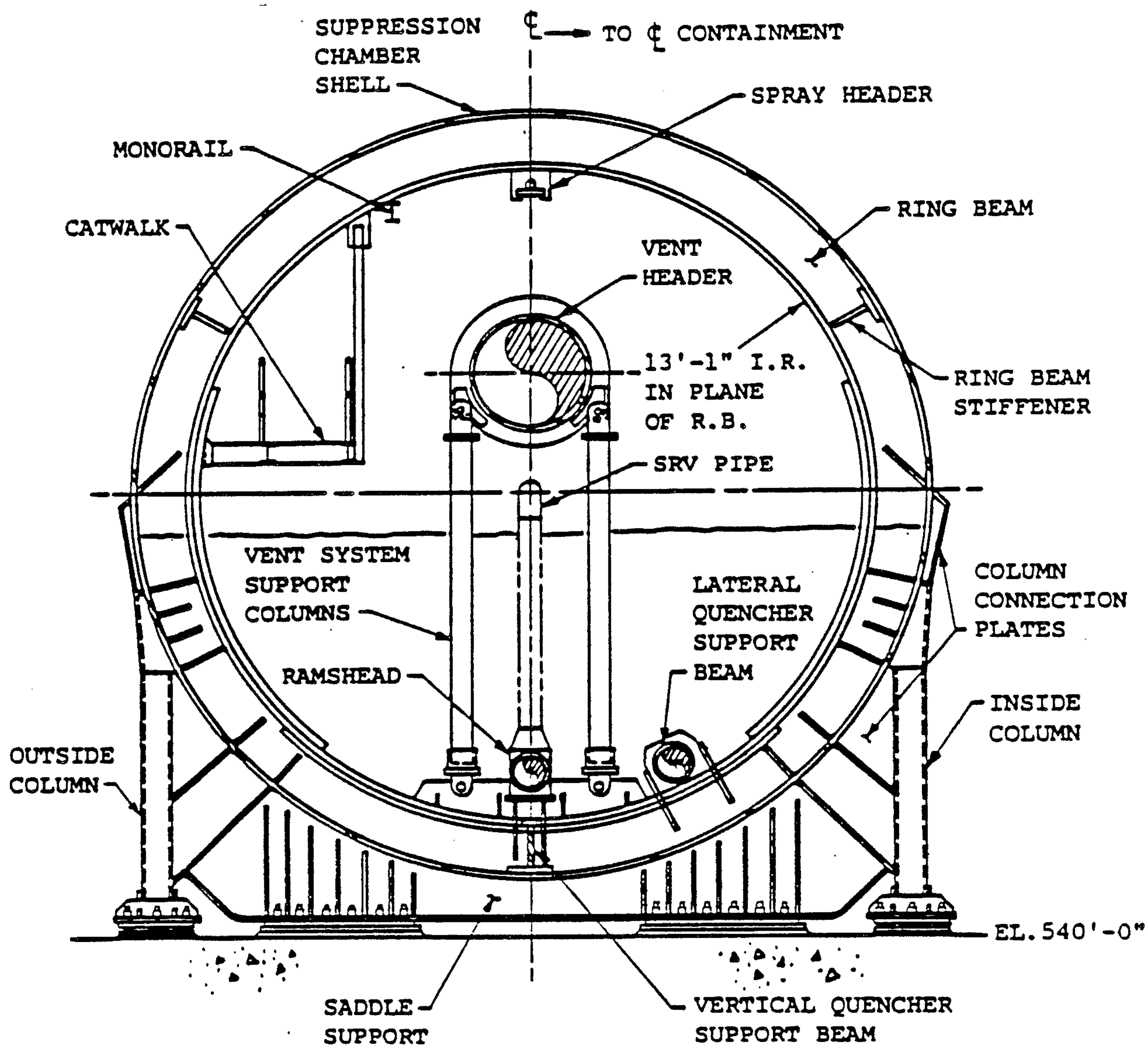

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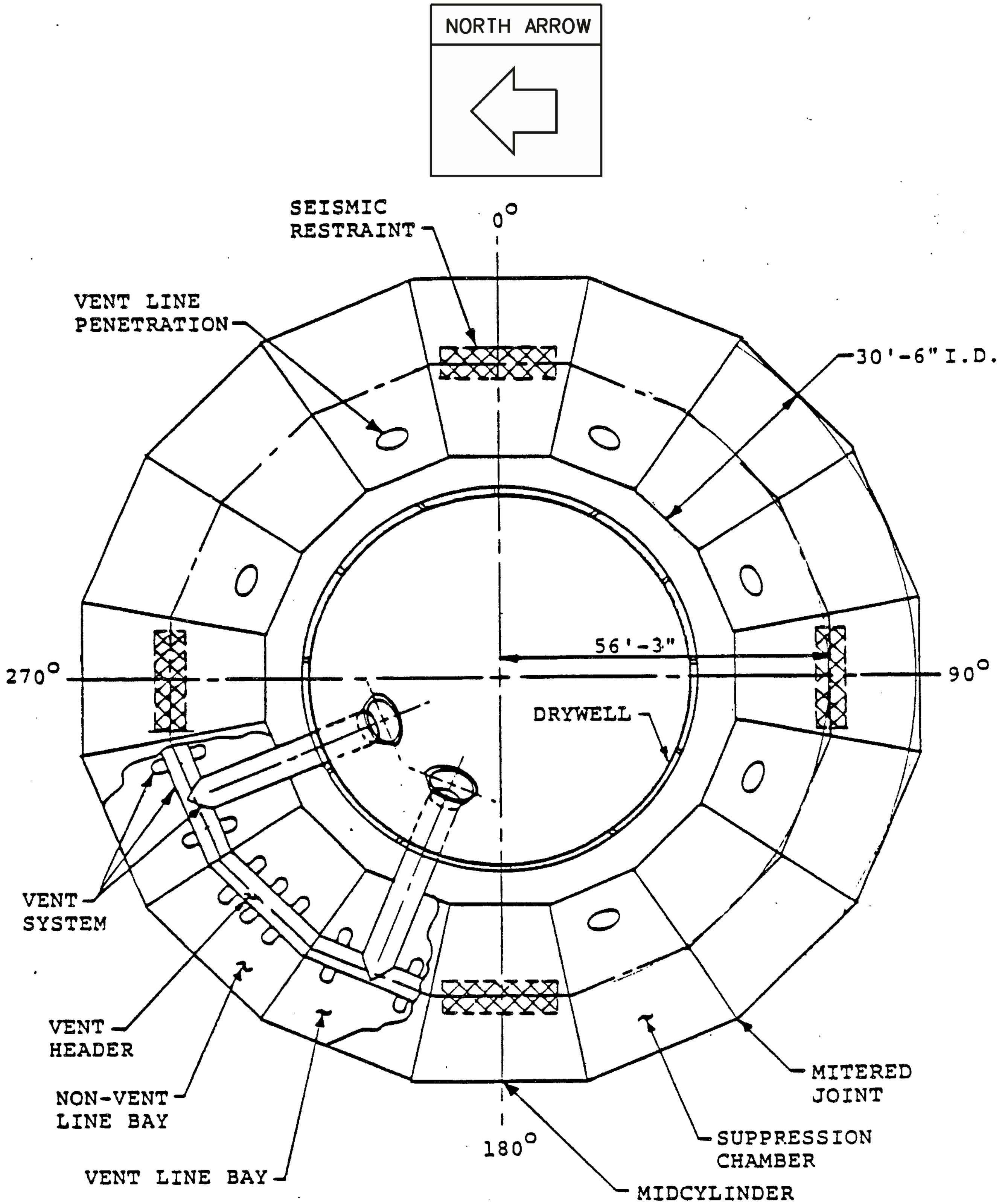
FIGURE 3.8-6

SUPPRESSION CHAMBER SUPPORT DETAILS

NUTECH DRAWING NO. DET-04-028-1, REV. 0
PUAR FIGURE 5-1-2.1-4



NUTECH DRAWING NO. DET-04-028-2, REV. 0
PUAR FIGURE 2-2.1-1

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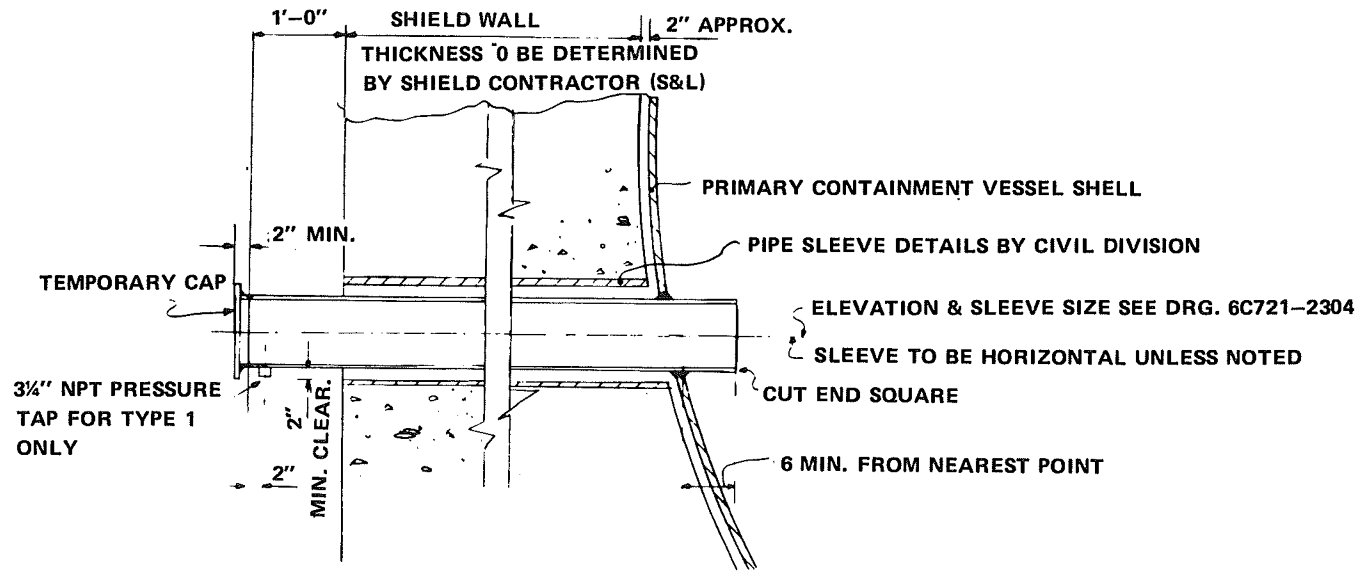
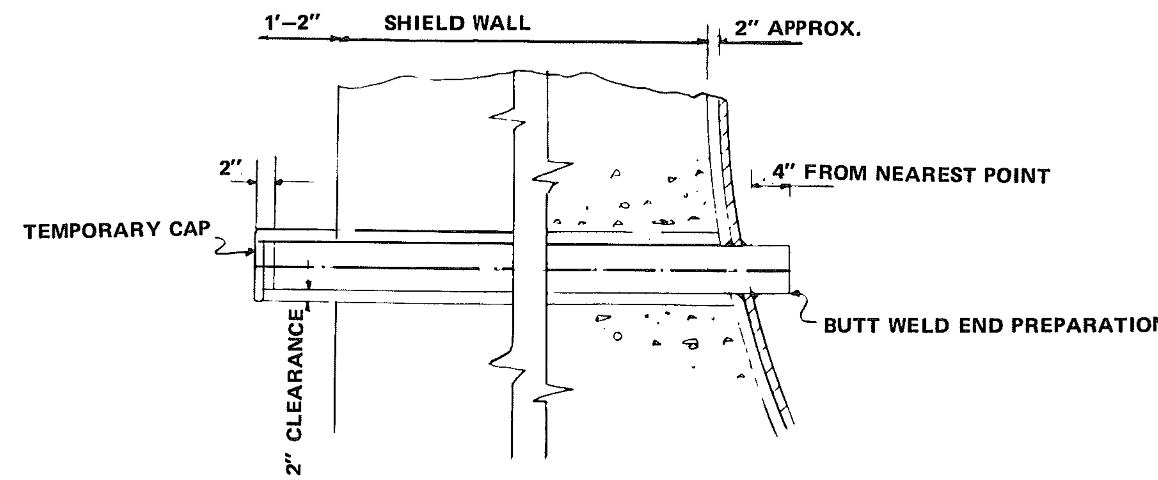
FIGURE 3.8-7

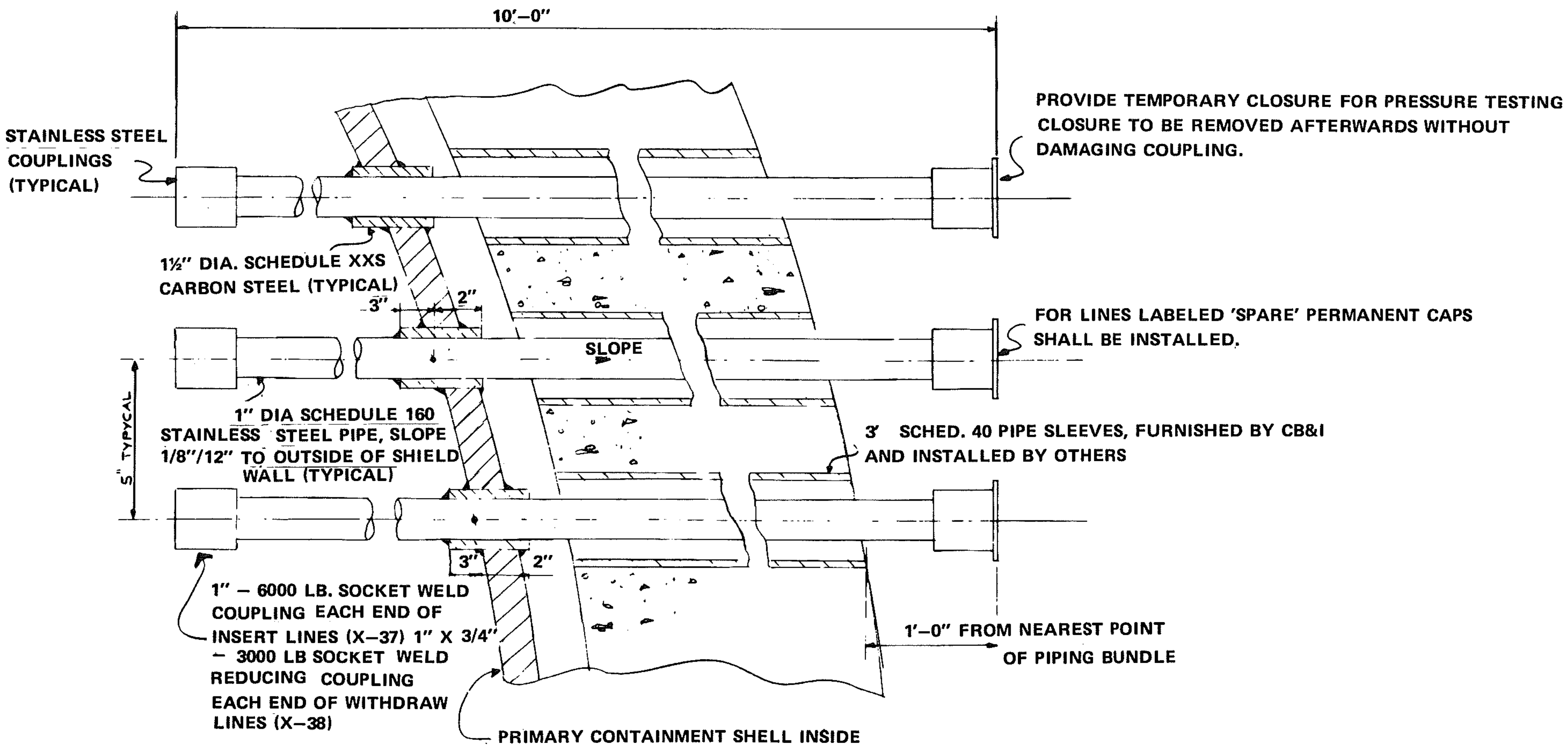
SUPPRESSION CHAMBER PLAN



PENETRATION NOZZLE DETAIL
TYPE 1 & 2



PENETRATION NOZZLE DETAIL
TYPE 3



PENETRATION NOZZLE DETAIL
TYPE 6

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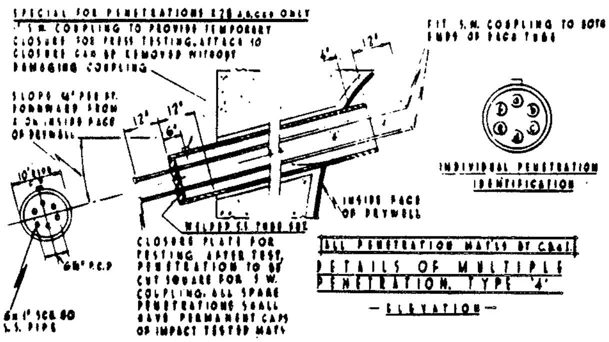
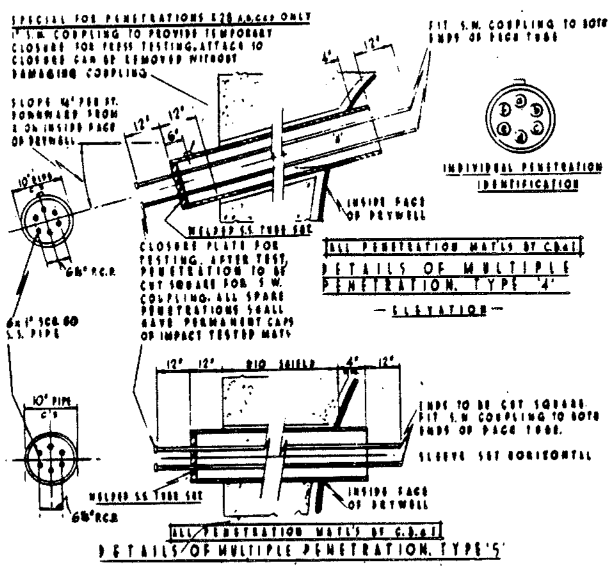
FIGURE 3.8-8, SHEET 1

DRYWELL PENETRATION TYPES

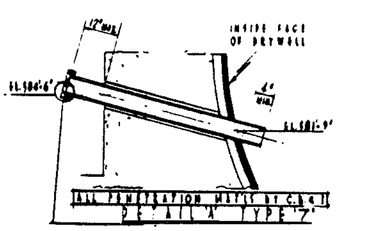


TYPE 4

NOTE: MATERIALS & WELD DETAILS SHALL MEET THE REQUIREMENTS OF ASME–3PVC SECTION II PARAGRAPH N–1333 OF LATEST ISSUE



TYPE 5



TYPE 7

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FIGURE 3.8–8, SHEET 2

DRYWELL PENETRATION TYPES

Figure Intentionally Removed
Refer to Plant Drawing M-2501

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FIGURE 3.8-9

PRIMARY CONTAINMENT SYSTEM PROCESS LINE SLEEVED PENETRATIONS

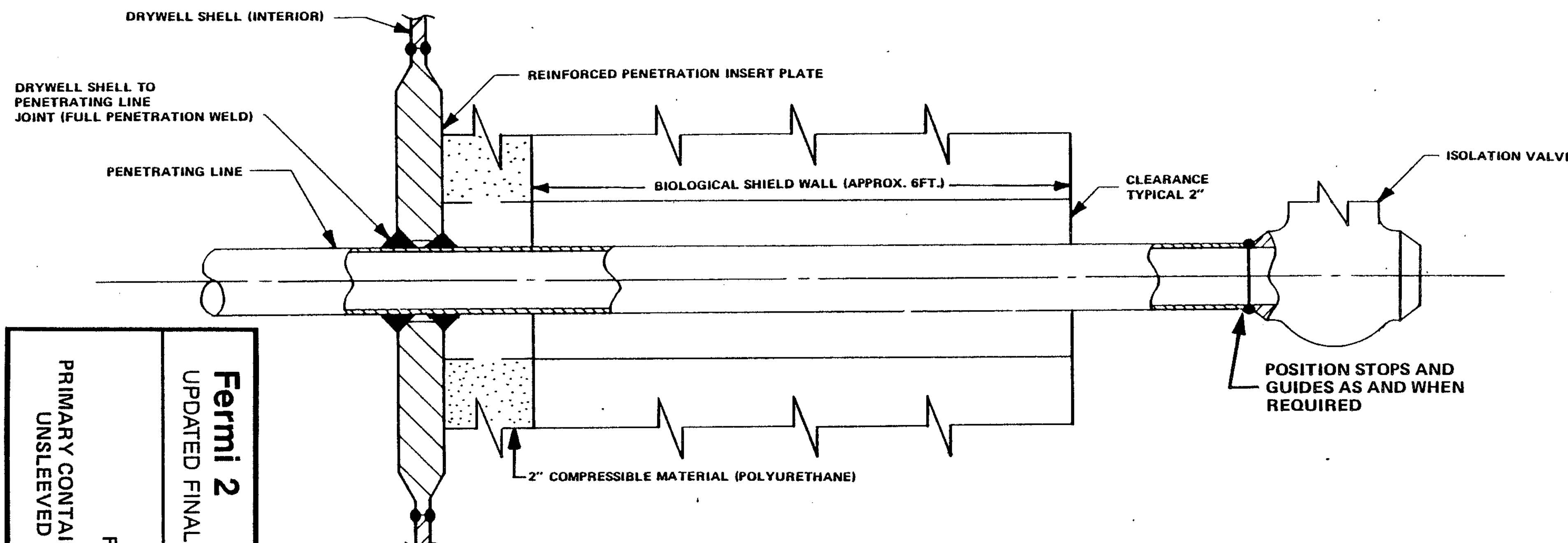

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FIGURE 3.8-10
PRIMARY CONTAINMENT SYSTEM PROCESS LINE
UNSLEEVED PENETRATION ASSEMBLY

Figure Intentionally Removed
Refer to Plant Drawing M-2502

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FIGURE 3.8-11

PRIMARY CONTAINMENT SYSTEM PROCESS LINE UNSLEEVED PENETRATIONS

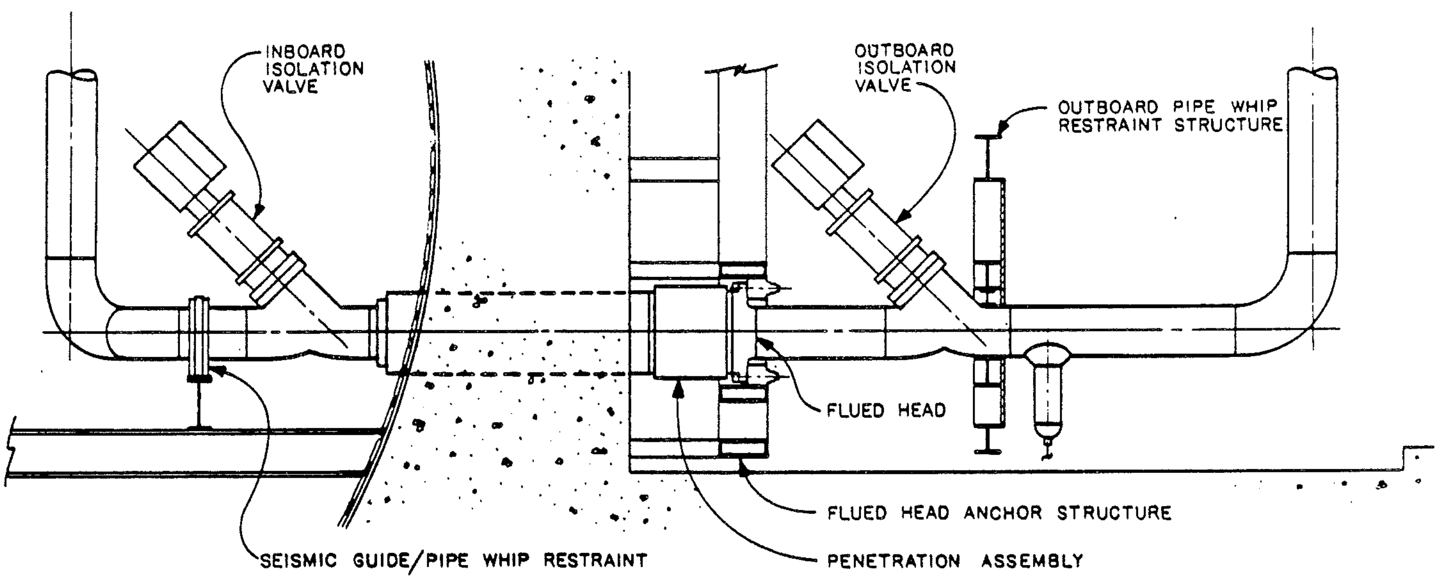

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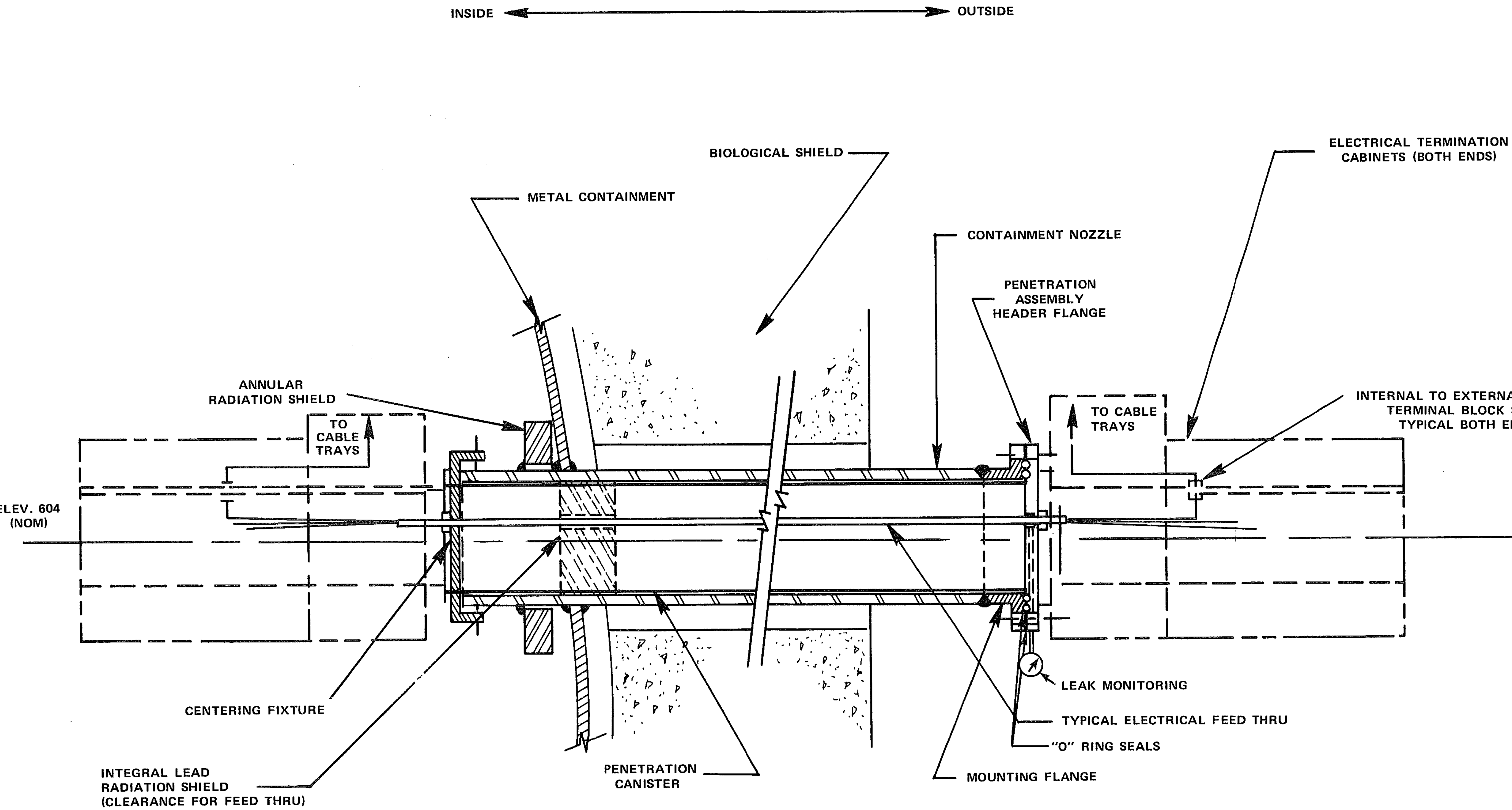
FIGURE 3.8-12

TYPICAL PRIMARY CONTAINMENT PENETRATION ARRANGEMENT



TYPE 8 PENETRATION

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FIGURE 3.8-13

PRIMARY CONTAINMENT SYSTEM ELECTRICAL PENETRATION

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Refer to Plant Drawing I-2146-02

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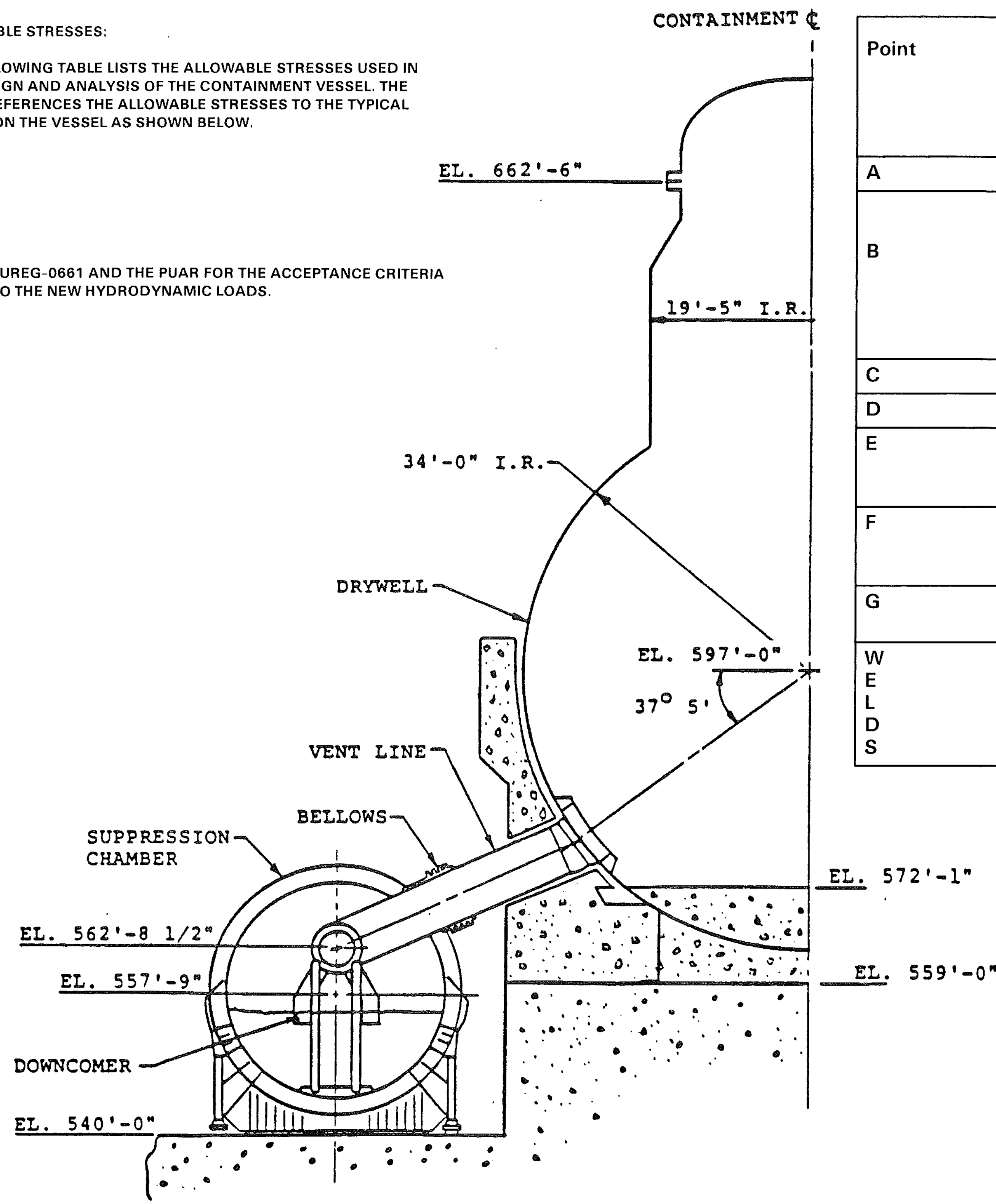
FIGURE 3.8-14

NUCLEAR INSTRUMENTATION SYSTEM POWER RANGE MONITORING SYSTEM TIP DRIVE SYSTEM

ALLOWABLE STRESSES:

THE FOLLOWING TABLE LISTS THE ALLOWABLE STRESSES USED IN THE DESIGN AND ANALYSIS OF THE CONTAINMENT VESSEL. THE TABLE REFERENCES THE ALLOWABLE STRESSES TO THE TYPICAL POINTS ON THE VESSEL AS SHOWN BELOW.

SEE NUREG-0661 AND THE PUAR FOR THE ACCEPTANCE CRITERIA DUE TO THE NEW HYDRODYNAMIC LOADS.



Point	Applicable Code	Type of Stress	Operating Condition		Accident Condition		Flooded Condition	
			Operating Basis Earthquake	Safe Shutdown Earthquake	Operating Basis Earthquake	Safe Shutdown Earthquake	Operating Basis Earthquake	Safe Shutdown Earthquake
A	ASME III-B	Membrane	S_m	S_y	S_m	S_y	S_y	S_y
B	AISC (Plate)	Bending	(.6 F_y)	F_y	(.6 F_y)	F_y	1.5 F_y	1.5 F_y
		Bearing	(.9 F_y)	1.33 (.9 F_y)	(.9 F_y)	1.33 (.9 F_y)	1.33 (.9 F_y)	1.33 (.9 F_y)
		Shear	(.4 F_y)	1.33 (.4 F_y)	(.4 F_y)	1.33 (.4 F_y)	.8 F_y	.8 F_y
		Compression	Code	1.33 Code	Code	1.33 Code	1.33 Code	1.33 Code
C	ASME III-B	Membrane	S_m	S_y	S_m	S_y	S_y	S_y
D	ASME III-B	Membrane	S_m	S_y	S_m	S_y	S_y	S_y
E	ASME III-B	Membrane	S_m	S_y	S_m	S_y	S_y	S_y
		Bending	(.9 F_y)	F_y	(.9 F_y)	1.33 F_y	1.5 F_y	1.5 F_y
F	AISC (Pin)	Bearing	(.9 F_y)	1.33 (.9 F_y)	(.9 F_y)	1.33 (.9 F_y)	1.33 (.9 F_y)	1.33 (.9 F_y)
		Shear	(.4 F_y)	1.33 (.4 F_y)	(.4 F_y)	1.33 (.4 F_y)	.8 F_y	.8 F_y
G	ACI	Bearing	.375 f'c .250 f'c	.626 f'c .418 f'c	.375 f'c .250 f'c	.626 f'c .418 f'c	.8 f'c	.8 f'c
W E L D S	AISC (Fillet & Groove)	Shear	15,800 psi	1.33 (.4 F_y)	15,800 psi	1.33 (.4 F_y)	.8 F_y	.8 F_y

NUTECH DRAWING NO. DET-04-028-1, REV. 0
PUAR FIGURE 1-2.1-1

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FIGURE 3.8-15

CONTAINMENT VESSEL STRESS LIMITS

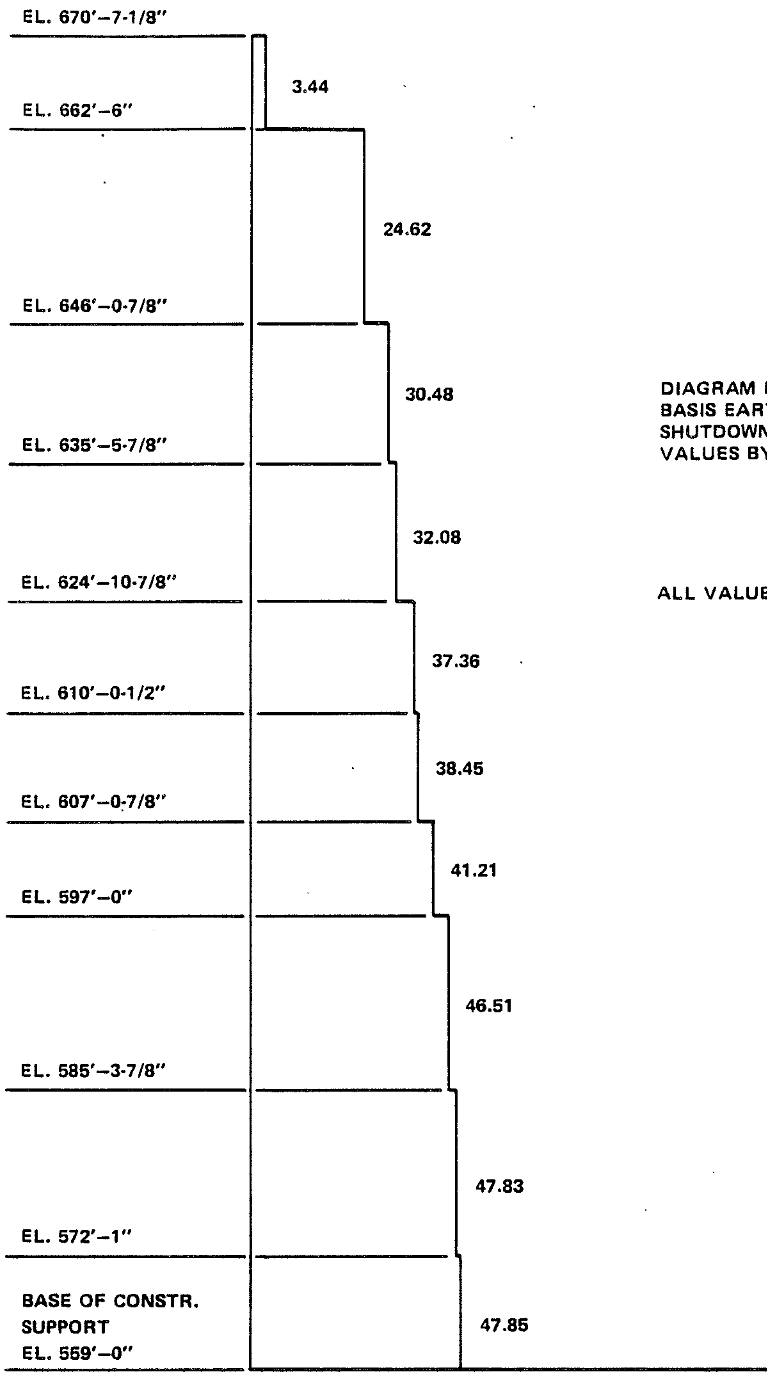

DIAGRAM BASED ON OPERATING BASIS EARTHQUAKE. FOR SAFE SHUTDOWN EARTHQUAKE INCREASE VALUES BY A FACTOR OF 1.875.

ALL VALUES SHOWN ARE IN KIPS.

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FIGURE 3.8-16

SHEAR DIAGRAM CONSTRUCTION MODEL DRYWELL

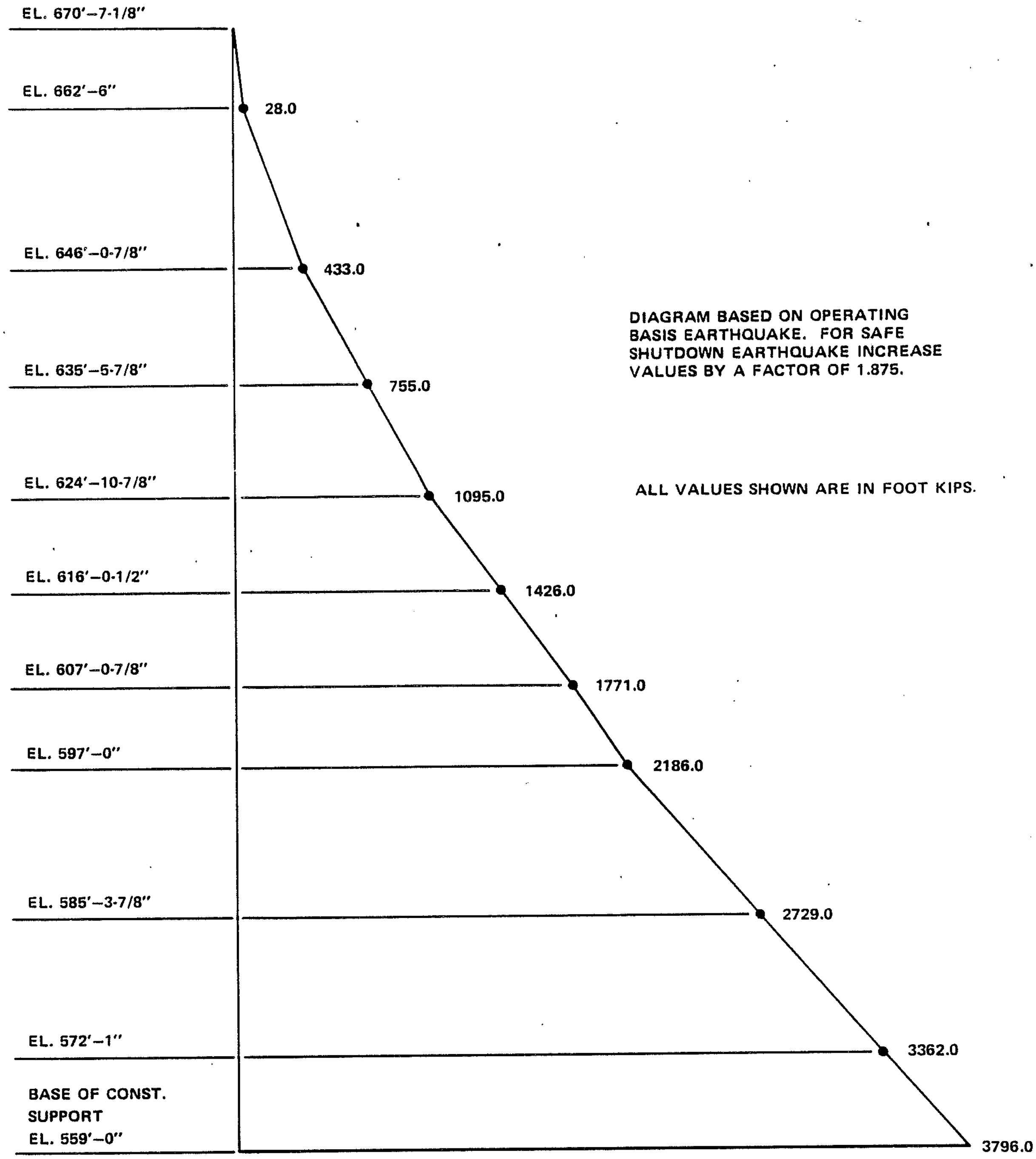

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FIGURE 3.8-17

MOMENT DIAGRAM CONSTRUCTION MODEL DRYWELL

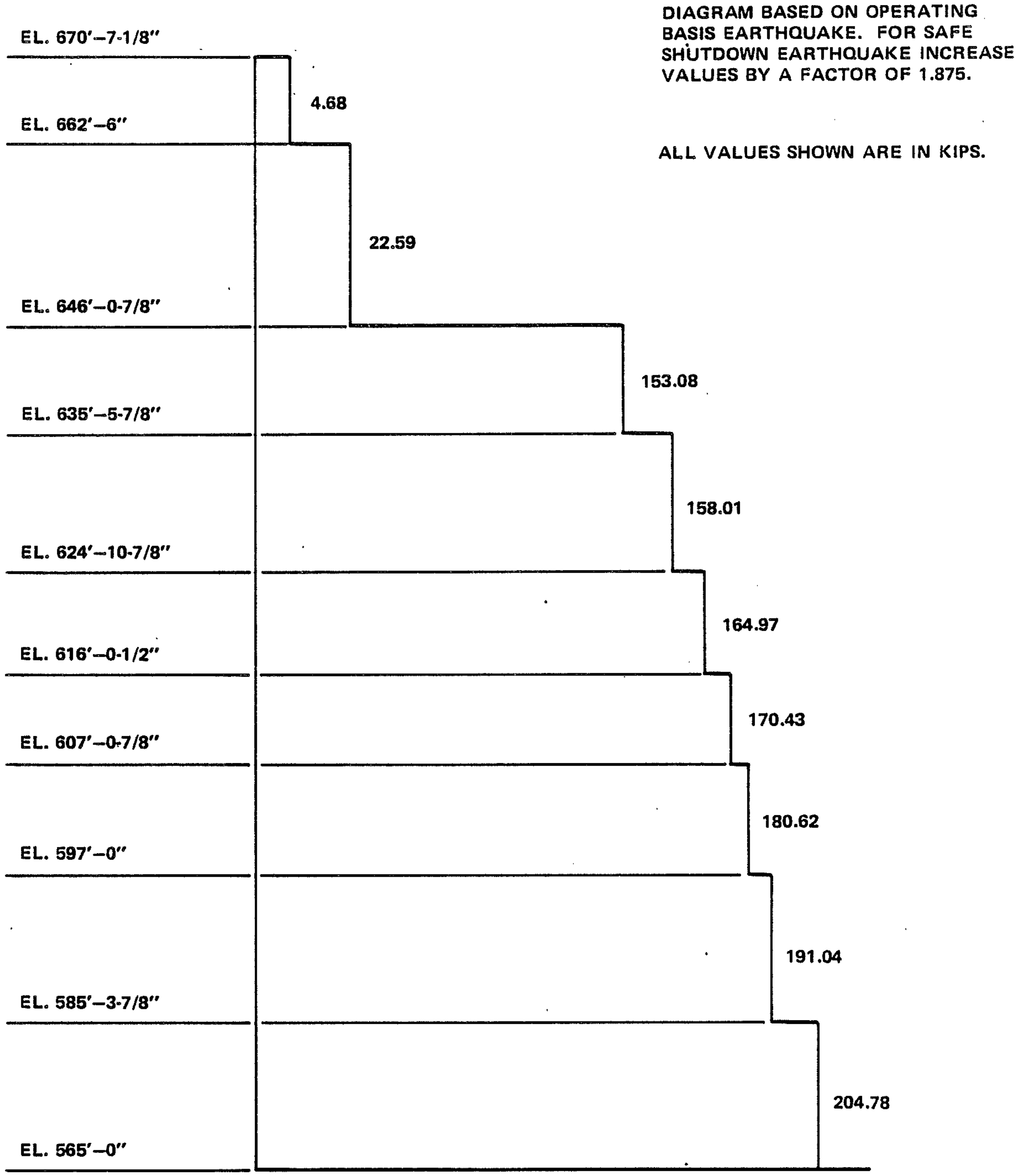

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FIGURE 3.8-18

SHEAR DIAGRAM – DRYWELL EMPTY

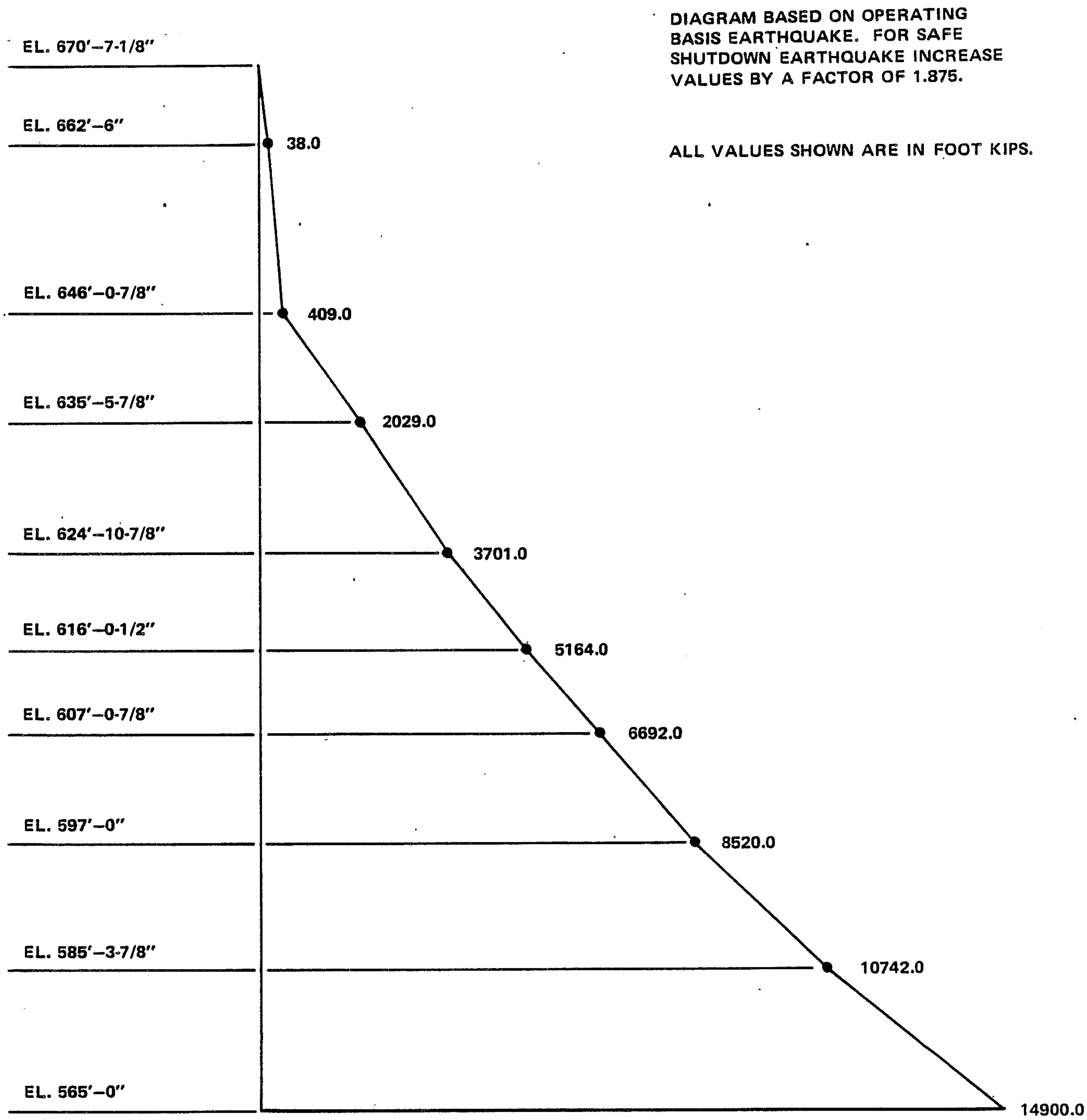

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FIGURE 3.8-19

MOMENT DIAGRAM – DRYWELL EMPTY

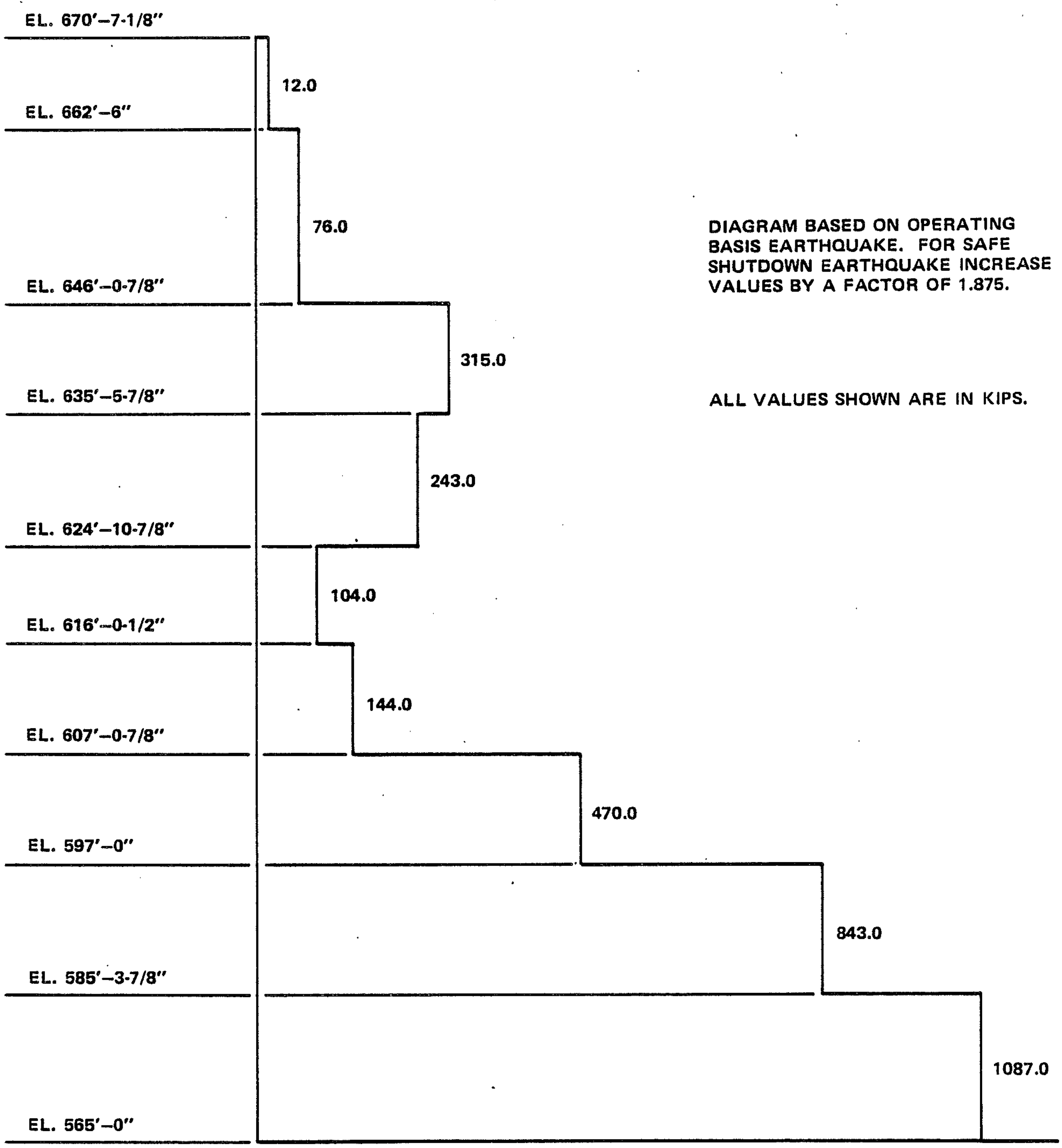

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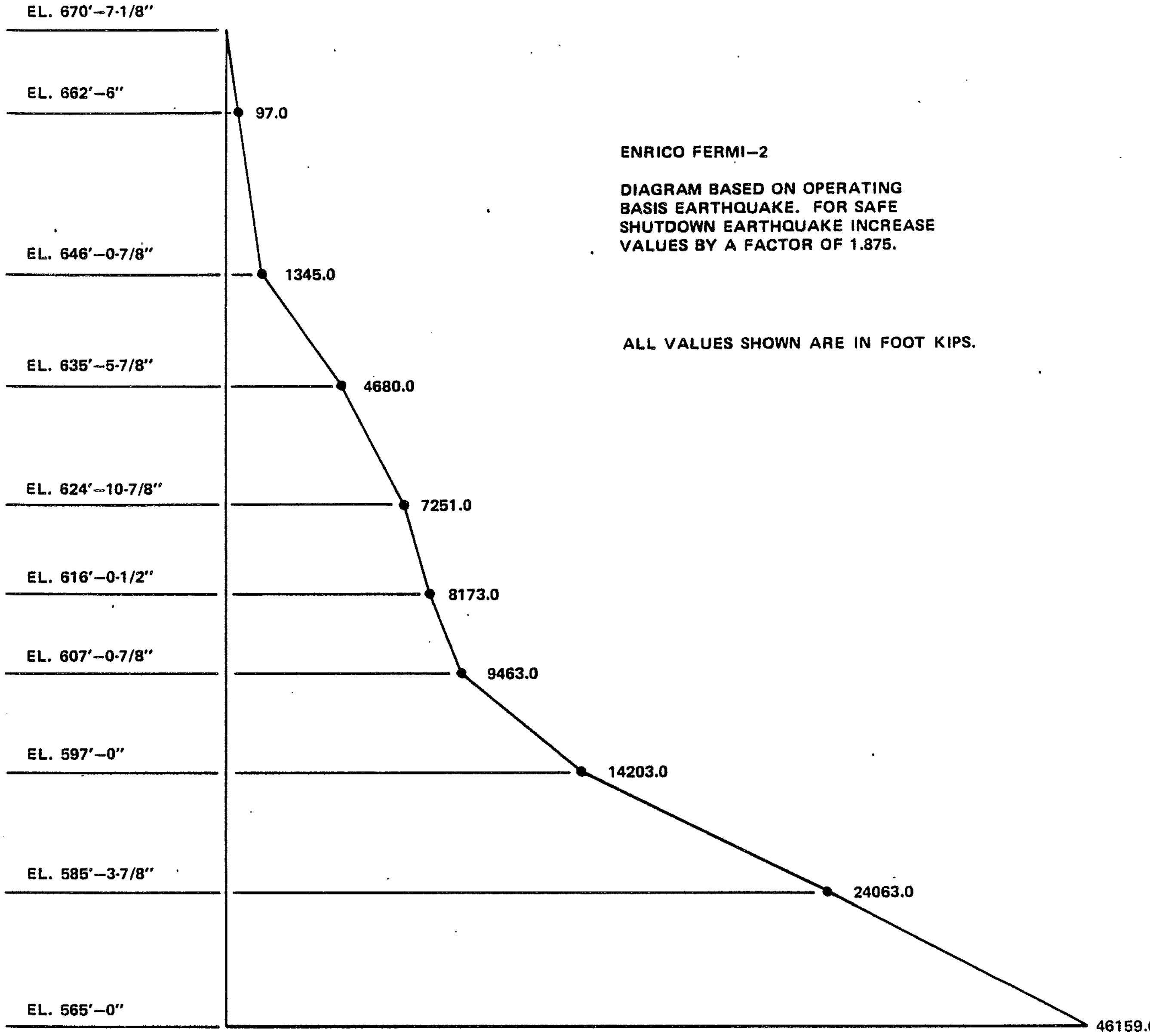
FIGURE 3.8-20

SHEAR DIAGRAM – DRYWELL FILLED WITH WATER



ENRICO FERMI–2

DIAGRAM BASED ON OPERATING BASIS EARTHQUAKE. FOR SAFE SHUTDOWN EARTHQUAKE INCREASE VALUES BY A FACTOR OF 1.875.

ALL VALUES SHOWN ARE IN FOOT KIPS.

Fermi 2

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FIGURE 3.8–21

MOMENT DIAGRAM – DRYWELL FILLED WITH WATER

Figure Intentionally Removed
Refer to Plant Drawing C-2431

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FIGURE 3.8-22

SACRIFICIAL SHIELD DETAILS

Figure Intentionally Removed
Refer to Plant Drawing C-2431

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FIGURE 3.8-23

SECTION THROUGH THE REACTOR PRESSURE VESSEL SUPPORT PEDESTAL

Figure Intentionally Removed
Refer to Plant Drawing C-2431

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FIGURE 3.8-24

DETAIL OF REACTOR PRESSURE VESSEL CONNECTION TO REACTOR SUPPORT PEDESTAL

Figure Intentionally Removed
Refer to Plant Drawing C-2441

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FIGURE 3.8-25

TYPICAL PART PLAN OF THE
EARTHQUAKE-STABILIZER TRUSS SYSTEM

Figure Intentionally Removed
Refer to Plant Drawing C-2446

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FIGURE 3.8-26

PIPE BREAK SUPPORT TRUSS SYSTEM

Figure Intentionally Removed
Refer to Plant Drawing C-2358

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FIGURE 3.8-27

TYPICAL SECTION THROUGH THE BIOLOGICAL SHIELD SHOWING REINFORCING LAYOUT

Figure Intentionally Removed
Refer to Plant Drawing C-2360

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FIGURE 3.8-28, SHEET 1

LONGITUDINAL SECTION THROUGH THE SPENT FUEL STORAGE POOL, REACTOR REFUELING POOL, AND DRYER SEPARATOR STORAGE POOL SHOWING REINFORCING LAYOUT

Figure Intentionally Removed
Refer to Plant Drawing C-2361

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FIGURE 3.8-28, SHEET 2

LONGITUDINAL SECTION THROUGH THE SPENT FUEL STORAGE POOL, REACTOR REFUELING POOL, AND DRYER SEPARATOR STORAGE POOL SHOWING REINFORCING LAYOUT

Figure Intentionally Removed
Refer to Plant Drawing C-2400

FIGURE 3.8-29

TRANSVERSE SECTION THROUGH THE SPENT FUEL STORAGE POOL SHOWING REINFORCING LAYOUT

Figure Intentionally Removed
Refer to Plant Drawing C-2372

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FIGURE 3.8-30

TRANSVERSE SECTION THROUGH THE DRYER SEPARATOR POOL

Figure Intentionally Removed
Refer to Plant Drawing C-2348

Figure Intentionally Removed
Refer to Plant Drawing C-2349

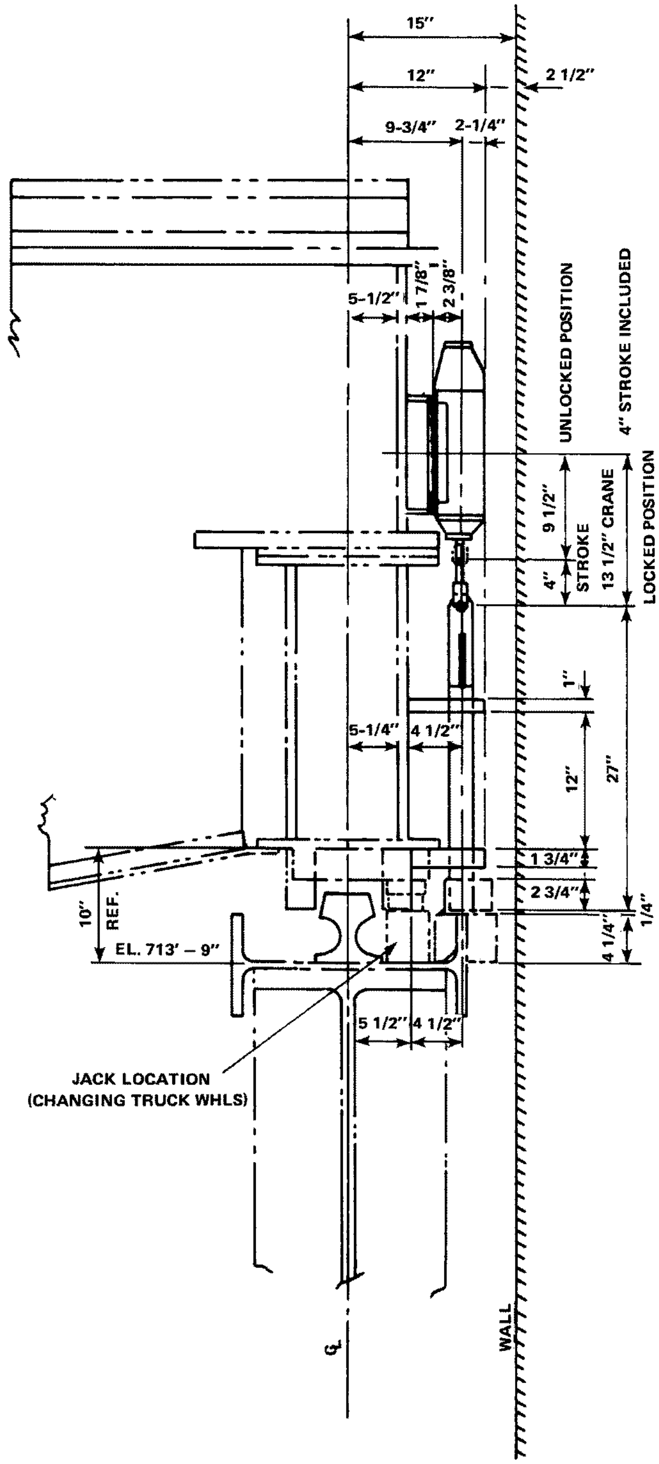

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FIGURE 3.8-32

REACTOR BUILDING CRANE SEISMIC AND TORNADO SAFETY FEATURES

Figure Intentionally Removed
Refer to Plant Drawing C-2415

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FIGURE 3.8-33

TYPICAL COLUMN REINFORCEMENT AND TIE SPACING

Figure Intentionally Removed
Refer to Plant Drawing C-2412

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FIGURE 3.8-34

TYPICAL WALL REINFORCING SPLICE DETAIL

Figure Intentionally Removed
Refer to Plant Drawing C-2413

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FIGURE 3.8-35

TYPICAL BEAM REINFORCING DETAILS

Figure Intentionally Removed
Refer to Plant Drawing C-2412

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FIGURE 3.8-36

TYPICAL ADDITIONAL SLAB REINFORCING AT RECTANGULAR OPENINGS

Figure Intentionally Removed
Refer to Plant Drawing C-2412

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FIGURE 3.8-37

TYPICAL SLAB REINFORCING DETAILS

Figure Intentionally Removed
Refer to Plant Drawing C-2412

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FIGURE 3.8-38

TYPICAL CONSTRUCTION JOINT DETAILS

Figure Intentionally Removed
Refer to Plant Drawing C-2313

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FIGURE 3.8-39

PLAN VIEW OF THE REACTOR/AUXILIARY BUILDING BASE MAT – TYPICAL REINFORCING DETAIL

Figure Intentionally Removed
Refer to Plant Drawing C-2315

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FIGURE 3.8-40

SECTION THROUGH THE DRYWELL PEDESTAL AND SUPPRESSION CHAMBER BASE SLAB TYPICAL REINFORCING DETAIL

Figure Intentionally Removed
Refer to Plant Drawing C-2313

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FIGURE 3.8-41

**TOP OF DRYWELL PEDESTAL
TYPICAL REINFORCING DETAIL**

Figure Intentionally Removed
Refer to Plant Drawing M-2836

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FIGURE 3.8-42

HIGH PRESSURE COOLANT INJECTION PUMP AND TURBINE FOUNDATIONS - TYPICAL REINFORCING DETAILS

Figure Intentionally Removed
Refer to Plant Drawing M-2840

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FIGURE 3.8-43

REACTOR CORE ISOLATION COOLING TURBINE PUMP AND BAROMETRIC CONDENSER FOUNDATIONS – TYPICAL REINFORCING DETAILS

Figure Intentionally Removed
Refer to Plant Drawing M-2734

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FIGURE 3.8-44

TYPICAL DETAILS OF THE RESIDUAL HEAT REMOVAL PUMP FOUNDATIONS

Figure Intentionally Removed
Refer to Plant Drawing M-2679

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FIGURE 3.8-45

TYPICAL DETAILS OF THE CORE SPRAY PUMP FOUNDATIONS

Figure Intentionally Removed
Refer to Plant Drawing C-2308

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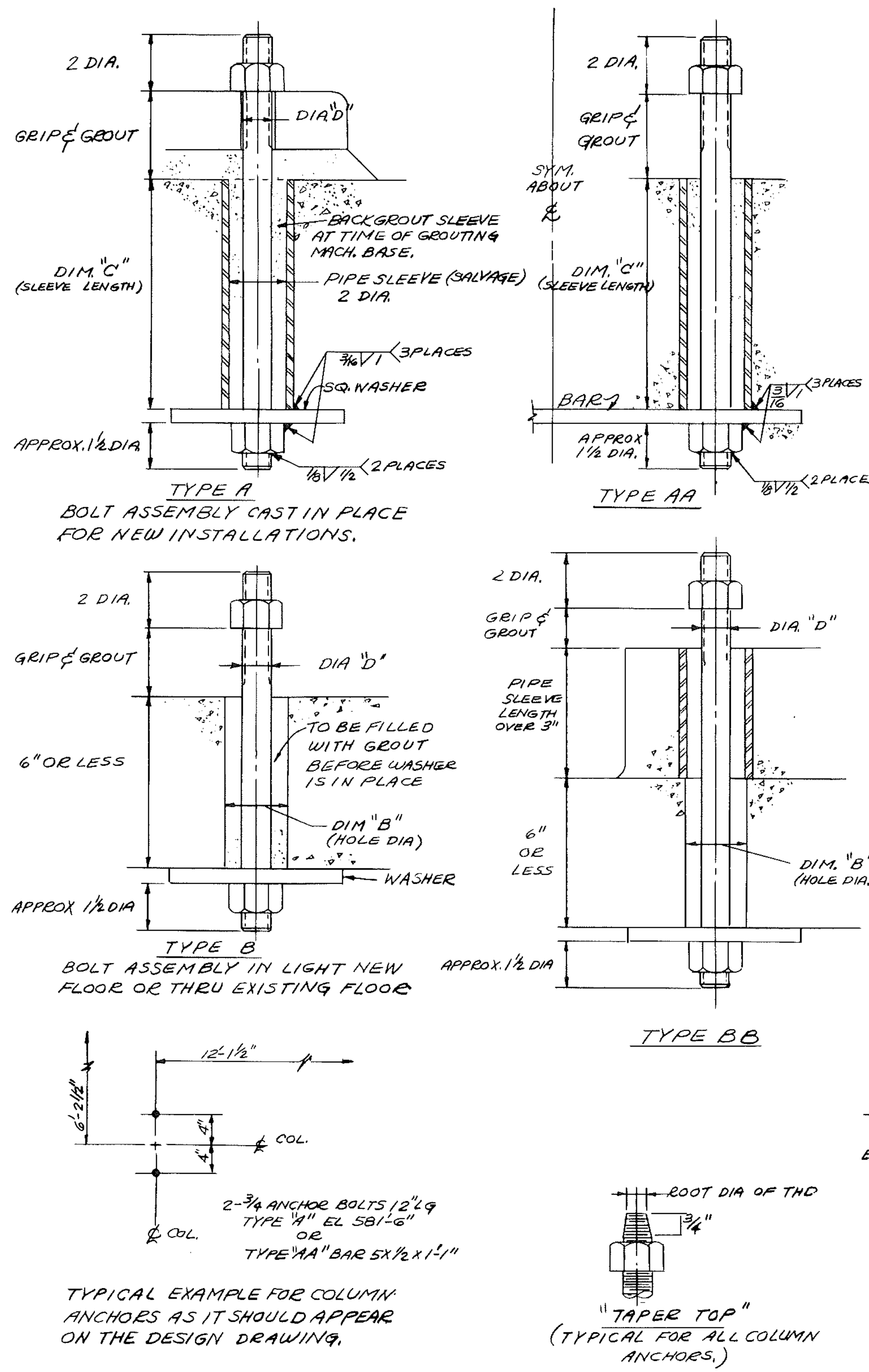
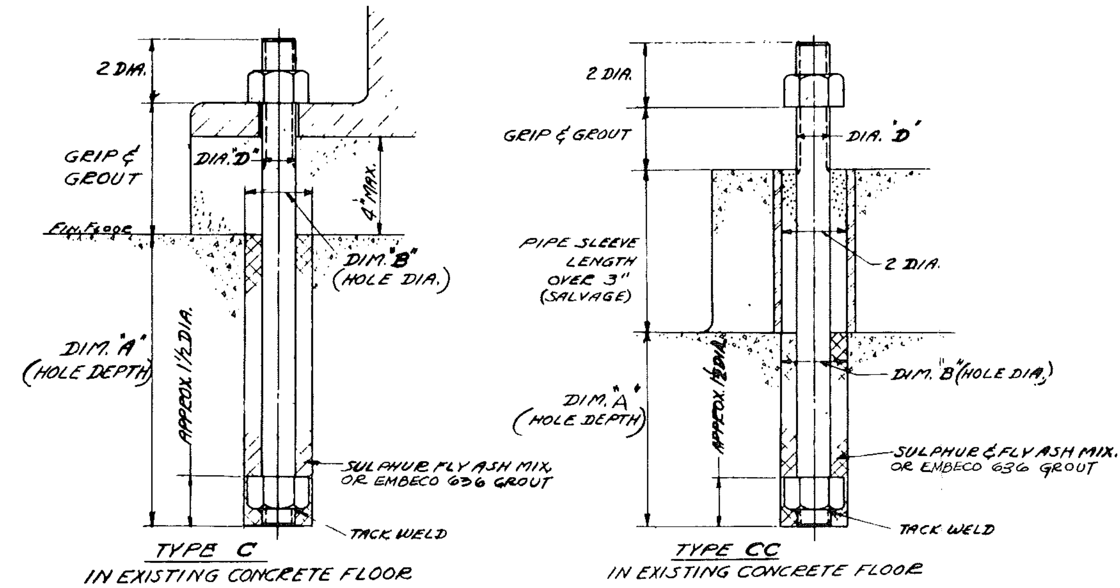
FIGURE 3.8-46

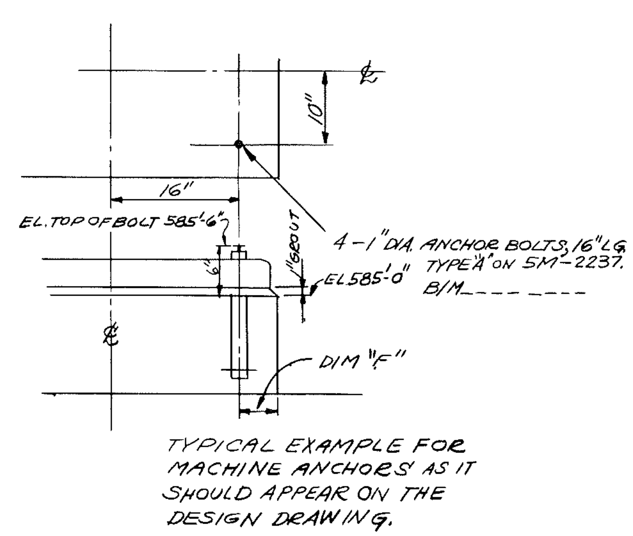
TYPICAL REINFORCING PATTERNS AT THE JUNCTION OF CONCRETE WALLS AND THE FOUNDATION MATS

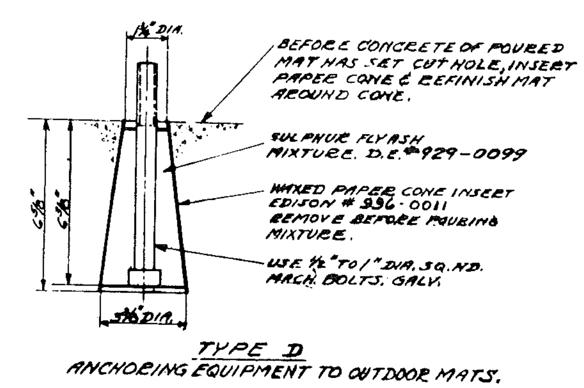




BOLT & SLEEVE SIZES ALL DIMENSIONS IN INCHES — WASHER SIZES — *SULPHUR & FLY ASH MIXTURE

BOLT SIZE "D" DIM.	HOLE DEPTH "A" DIM.	DRILL SIZE "B" DIM.	SLEEVE LENGTH "C" DIM.	EDGE CLEAR. "F" DIM.	WASHERS INCHES SQ.	WASHERS INCHES THK.	WASHERS HOLE DIA.	LBS MIX PER HOLE	Nº OF BOLTS PER 10 LBS
½	4	1½	8	4½	4	¼	9/16	.44	22.6
5/8	5	1 5/8	8	4½	4	3/8	11/16	.82	12.13
¾	6	1¾	8	4½	4	3/8	13/16	1.35	7.4
7/8	7	1 7/8	8	5½	6	½	15/16	2.10	4.78
1	8	2	8	5½	6	½	1 1/16	2.61	3.83
1¼	10	2½	9	5½	6	½	1 5/16	5.11	1.95
1½	12	3	11	7	8	5/8	1 9/16	8.81	1.13
1¾	14	3½	13	7	8	5/8	1 13/16	13.8	.72
2	16	4	15	7	8	5/8	2 1/16	16.2	.67





NOTES:

GENERAL DESIGN INSTRUCTIONS—(SEE SKETCH).

1. INDICATE ON DESIGN DRAWING THE LOCATION, ELEVATION OF TOP OF BOLT, DIAMETER LENGTH & TYPE OF ANCHOR (ALSO SLEEVE LENGTH FOR TYPE "CC" & BAR SIZE FOR TYPE "AA").
2. REFER TO THIS STANDARD DRAWING NO.
3. INDICATE ANY SPECIAL CONSIDERATIONS, IF OTHER THAN SHOWN IN TABLE, SUCH AS SLEEVE LENGTH, THREAD LENGTH EACH END, ETC.
4. KEEP LENGTH OF BOLT TO NEAREST ½" WHERE POSSIBLE.
5. THREAD TOP END OF ALL BOLTS TO A LENGTH EQUAL TO 4 x DIAMETER AND OTHER END TO A LENGTH EQUAL TO 1½ x DIAMETER—U.S. STANDARD COARSE THREAD — CLASS 3 (MEDIUM FIT).
6. USE HEAVY HEX NUTS, SEMI FINISHED, WASHER FACED.—CLASS 3 (MEDIUM FIT).
7. USE STANDARD HEX HEAD OR SQ. HD. BOLTS WHEREVER POSSIBLE.
8. ANCHOR BOLTS WILL BE ORDERED BY THE USING DIVISION.

SULPHUR & FLY ASH MIXTURE—
D.E. CO. STOCK #989-0099, IN 10# CANS. MAKES 1¼ QUARTS WHEN MELTED.
PREPARE HOLES IN CONCRETE AS INDICATED ABOVE & SET BOLTS IN PROPER POSITION. MELT PREMIXED MATERIAL IN MELTING POT SET AT 240°-250° F. STIR MELTED MATERIAL IN POT IMMEDIATLY BEFORE PURING AROUND BOLT. AVOID OVERHEATING, AT 270# F. MIX BEGINS TO THICKEN AND BECOMES DIFFICULT TO POUR TOO HIGH A TEMPERATURE WILL CAUSE MIX TO FUME EXCESSIVELY & TO CATCH FIRE. THIS MIXTURE HAS A HOLDING STRENGTH SEVERAL TIMES THAT OF LEAD. (D.E. CO. RESEARCH DEPT. REPORT 51H87.)

* THEORETICAL QUANTITIES, ADD APPROX. 10% WHEN ORDERING SULPHUR MIX.

DETROIT EDISON COMPANY DRAWING NO. 5M-2237, REV. E

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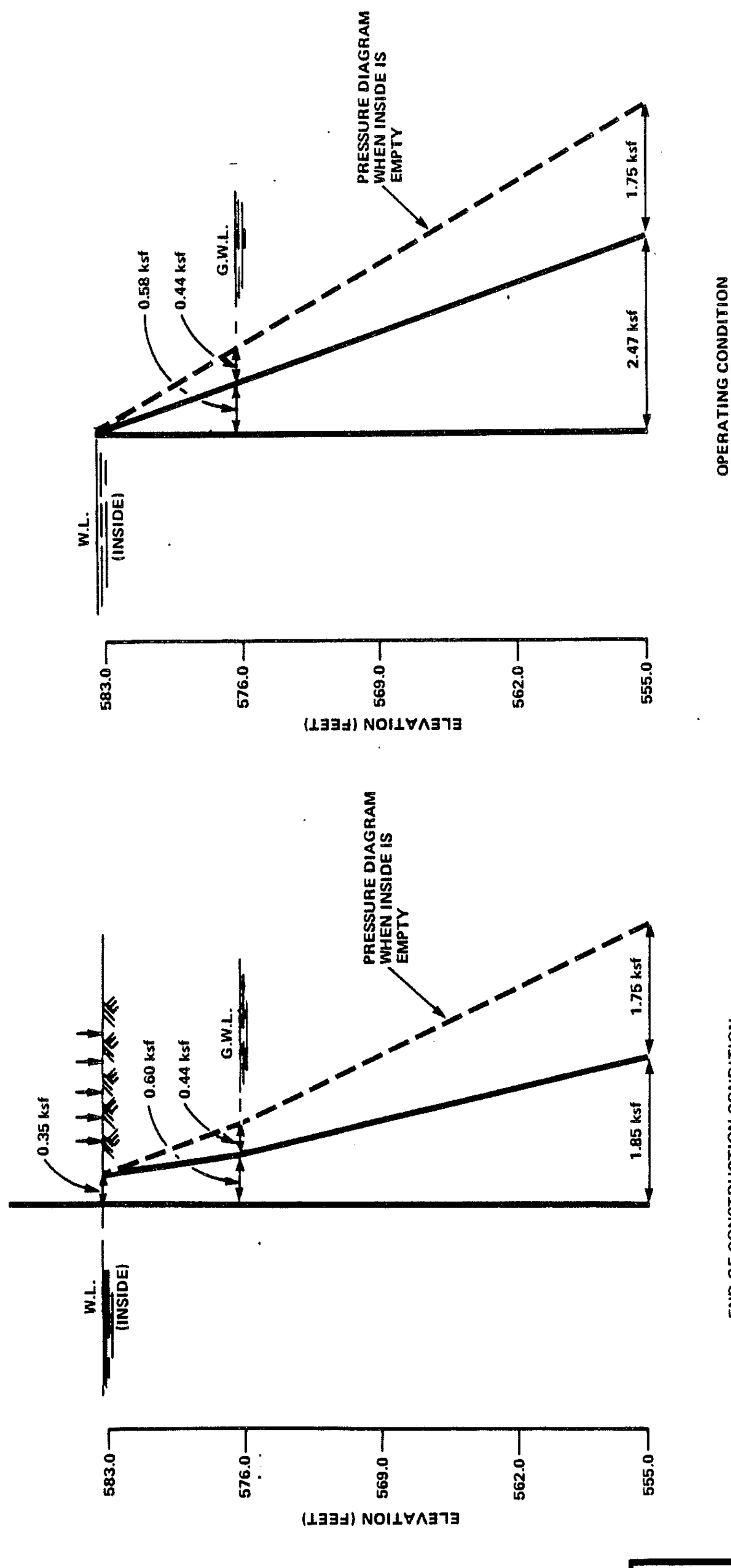
FIGURE 3.8-47

TYPICAL ANCHOR BOLT DETAILS FOR CATEGORY I EQUIPMENT



NOTE:
A SURCHARGE OF 0.500 ksf ON THE GRADE IS CONSIDERED FOR END-OF-CONSTRUCTION CONDITION ONLY.
FOR DYNAMIC LATERAL PRESSURE COMPUTATION TECHNIQUE; SEE TABLE 2.5-17.

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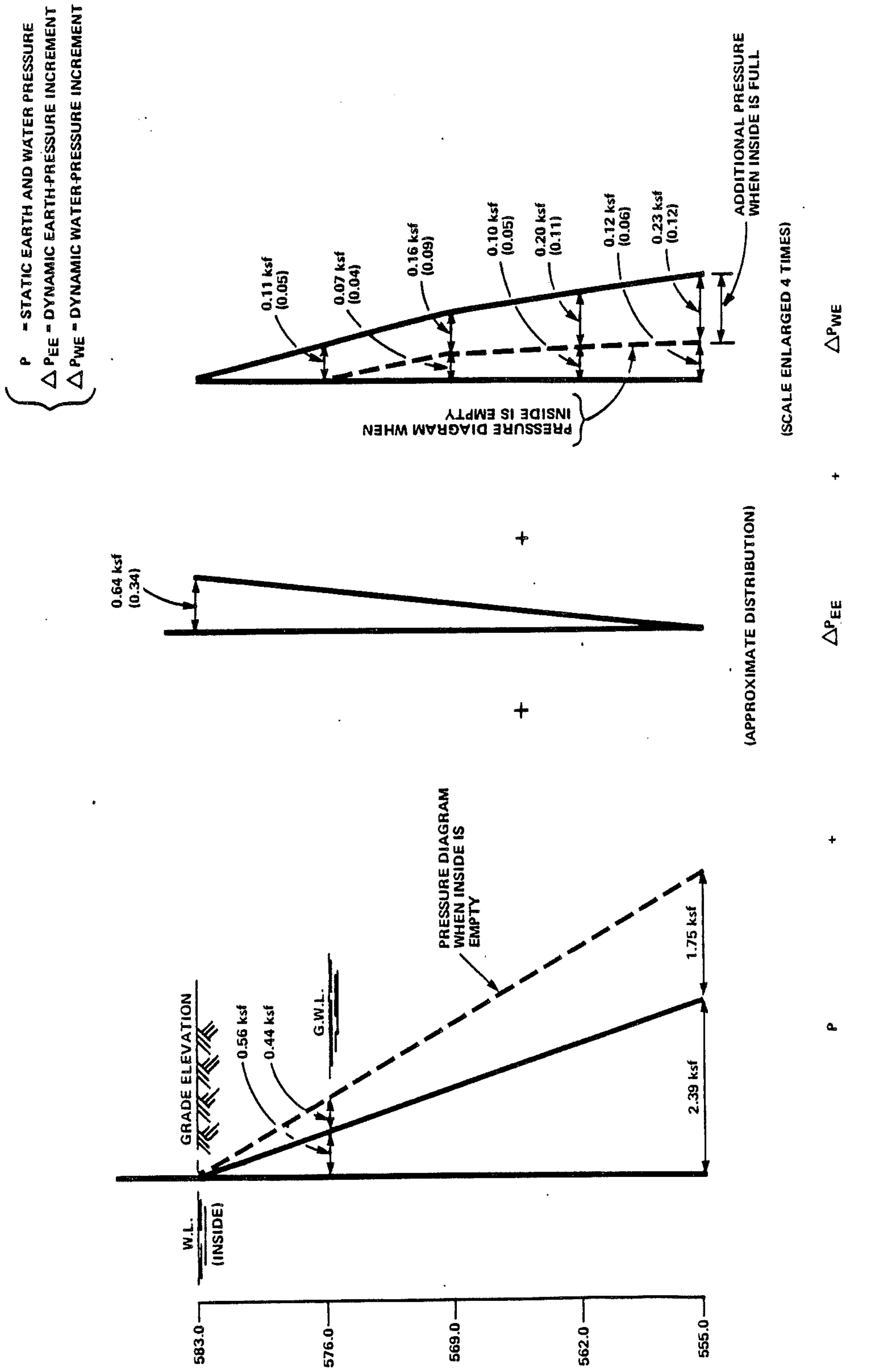
FIGURE 3.8-48, SHEET 1

EARTHQUAKE CONDITION – STATIC LATERAL PRESSURE ON SUBSURFACE WALL OF RESIDUAL HEAT REMOVAL BUILDING



NOTE:
FIGURES IN THE PARENTHESES ARE VALUES CORRESPONDING TO THE OBE (OPERATING BASIS EARTHQUAKE) CONDITION WITH k_h = 0.08 g; OUTSIDE FIGURES CORRESPOND TO THE DBE (DESIGN BASIS EARTHQUAKE) CONDITION WITH k_h = 0.15 g.

FOR DYNAMIC LATERAL PRESSURE COMPUTATION TECHNIQUE, SEE TABLE 2.5-17.

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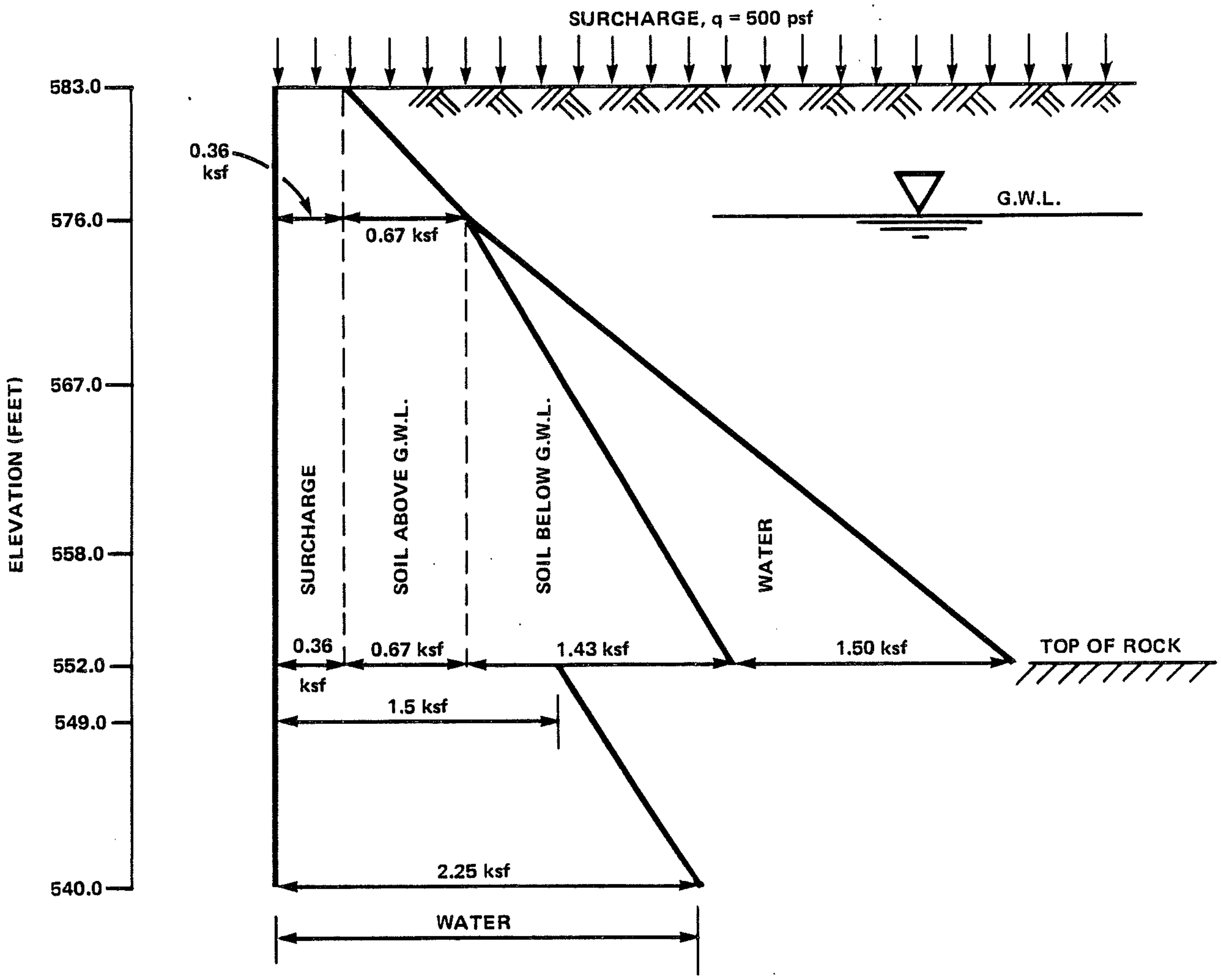
FIGURE 3.8-48, SHEET 2

EARTHQUAKE CONDITION – STATIC LATERAL PRESSURE ON SUBSURFACE WALL OF RESIDUAL HEAT REMOVAL BUILDING



CASE 1. END OF CONSTRUCTION CONDITION

NOTE:
FOR DYNAMIC LATERAL PRESSURE COMPUTATION TECHNIQUE, SEE TABLE 2.5-17.

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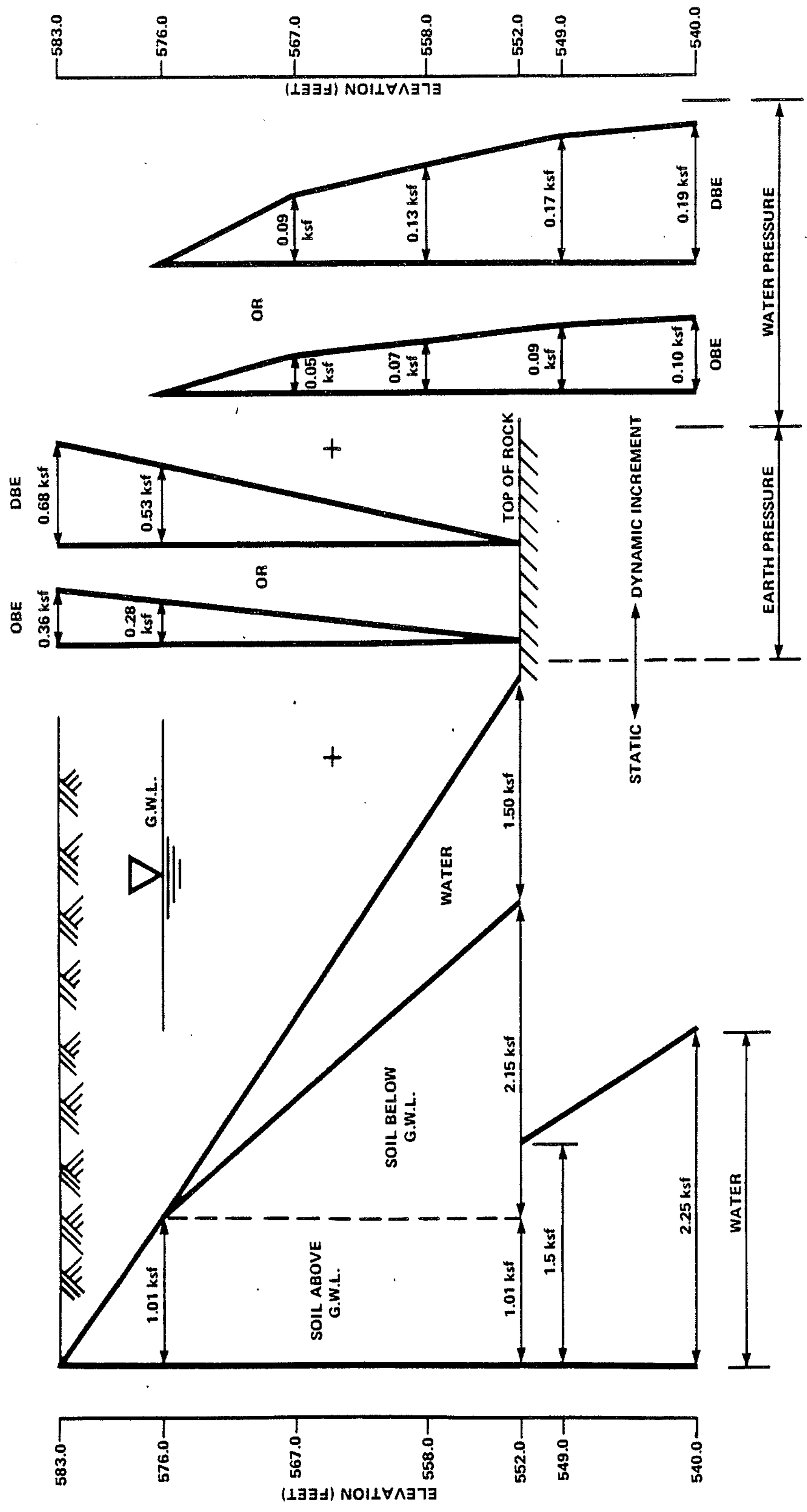
FIGURE 3.8-49, SHEET 1

REACTOR/AUXILIARY BUILDING STATIC AND DYNAMIC LATERAL PRESSURES – OUTSIDE WALL



NOTE:
FOR DYNAMIC LATERAL PRESSURE COMPUTATION TECHNIQUE, SEE TABLE 2.5-17.

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FIGURE 3.8-49, SHEET 2

REACTOR/AUXILIARY BUILDING STATIC AND DYNAMIC LATERAL PRESSURES – OUTSIDE WALL

3.9 MECHANICAL SYSTEMS AND COMPONENTS

3.9.1 Dynamic System Analysis and Testing

3.9.1.1 Piping and Rotating Equipment Test Program

3.9.1.1.1 Test Objectives

The piping of Fermi 2 is designed in conformance with the vibration requirements of the USAS B31.7-1969 Code for Pressure Piping and/or ASME Boiler and Pressure Vessel (B&PV) Code Section III, 1971 issue (including winter addenda). In accordance with the general objectives of this code, preoperational and startup phase vibration inspections will be conducted on piping systems and rotating equipment. These surveys will be performed with the following objectives in mind.

a. Observe that the vibration of the tested piping system is within acceptable limits

b. Provide baseline vibration signatures of rotating equipment which will serve as data for future comparison

c. Reveal potentially significant, equipment-induced resonances or pressure pulsations within the system and the operating modes during which they occur

d. Provide data to verify compliance with manufacturer's standards and tests, or existing Edison standards

e. Verify that the piping and support systems perform properly over the operating temperature range.

Table 3.9-1 lists the piping systems included in this test program and indicates the extent to which each system will be tested. Using the data collected during this testing and the acceptance criteria outlined in Subsection 3.9.1.1.5, each system will be evaluated for compliance with the original intent of the piping design criteria.

If the test results exceed the acceptance criteria for a given piping system, further evaluation will be performed to determine if it is necessary to modify the system. If the system is modified, additional testing of the modified system will be conducted if the modification significantly changes the vibratory behavior of the piping system.

Final design evaluation of safety-related piping systems has been performed in accordance with B&PV Code Section III after all modifications were completed.

Emergency and faulted-type transients, including such events as pump seizure, pipe rupture, etc., are not part of this testing program because these transients cannot be tested or simulated.

3.9.1.1.2 Rotating Equipment Vibration Testing

Vibration testing of the Fermi 2 rotating equipment was conducted during the preoperational and startup phases. The equipment tested is as follows.

Component	Quantity
Residual heat removal (RHR) and core spray pumps and motors (four each)	8
High pressure coolant injection pump and turbine	1
Reactor core isolation cooling pump and turbine	1
Reactor recirculation pumps and motors	2

The specific conditions for which vibration data has been obtained on each piece of equipment are as follows:

a. Design flow rate

b. Minimum normal flow rate

c. Maximum normal flow rate

d. Startup

e. Shutdown

To obtain vibration data for the rotating equipment, instrumentation has been installed temporarily on the various pumps and motors at locations that, based on the experience of Edison and the manufacturers, provide significant data. This instrumentation is used to measure bearing vibration or relative motion of the shaft, with respect to the case, in the axial and radial directions. Where possible, the vibration instrumentation is fastened to the machines using magnetic bases or some other temporary means. Instruments of an adequate type, number, and location already installed on machines can be used for testing.

Data is recorded on a multichannel, magnetic tape recorder. Narrow-band frequency spectrum analysis has been performed on these data to permit comparison of each frequency component with applicable criteria. The magnetic tape recording and its analysis is retained as permanent baseline data to permit identification of the deterioration of equipment performance.

In I&E Bulletin 79-15, the NRC identified concerns over the long-term operability of deep-draft pumps. In response to this, Edison described the steps being taken to ensure long-term operability of the pumps. These steps are

a. Quality verification of the pump and motor assembly during manufacture

b. Construction verification of the foundation and sump

c. Verification of proper installation and alignment of the pump assembly

d. Startup testing sufficient to verify pump capability and condition for long-term operability

e. Inservice surveillance testing using sophisticated vibration-measuring techniques to determine any degradation of internal components.

Inservice surveillance testing takes two forms: operational monitoring and diagnostic testing. Operational monitoring is performed by the operating instrumentation installed locally or in the control room. Thrust bearing temperature, on-off-auto control switches, and pump running status are all operationally monitored.

Surveillance testing consists of the following:

a. Determination of the total head developed by the pump

b. Measuring the flow from the pump

c. Measuring vibration of the pump-motor assembly using readings in velocity units.

These tests are aimed at providing the earliest possible detection of pump problems which exhibit the following symptoms:

a. Degradation of capacity or developed head

b. Excessive vibration

c. Excessive thrust bearing temperature.

Following repair and/or reassembly of a pump/motor unit, and/or during the Section XI inservice test, vibration base data will be taken prior to returning the unit to service.

The only safety-related deep-draft pumps used at Fermi 2 are the service water pumps.

3.9.1.1.3 Piping System Vibration Testing

Vibration surveys will be conducted on the piping systems listed in Table 3.9-1 during the preoperational and startup phases. For the majority of these systems, the system and plant conditions existing during the preoperational phase will be adequate to obtain vibration data representative of the piping vibration experienced during normal system operation.

Table 3.9-1 indicates the extent of vibration testing that will be performed on the piping systems and their supports. Normally, vibration data will be taken during steady-state operation of the system. Data will be taken also on portions of selected systems during specific transient events. These systems and the events are

a. Feedwater system piping from the feedwater pump discharge to the containment penetration, following a trip of a feedwater pump

b. High-pressure coolant injection (HPCI) system piping from the HPCI pump discharge to the feedwater system tee connection, after a rapid start of the HPCI turbine

c. Main steam piping from the turbine stop valve to the reactor vessel, after a turbine stop valve and control valve fast closure

d. Selected main steam safety/relief valve (SRV) discharge piping during SRV operation

e. Recirculation piping for a pump trip at 100 percent rated flow.

The vibration surveys will entail monitoring the overall system for indications of unacceptable vibratory response. Where appropriate, deflections, pressure pulsations, restraint forces, or accelerations will be monitored. The points that will be selected for monitoring will be, typically, those points which are predicted, either by experience or analysis, to undergo the highest deflections, pressure surges, operating stresses, or vibrations during system operation. Using the criteria of Subsection 3.9.1.1.5, the vibration data will be evaluated to determine the acceptability of the piping system design.

In addition to the piping systems listed in Table 3.9-1, safety- related small-bore piping and instrument lines will be included in the vibration surveys. Test, branch, bypass, and instrument lines attached to the piping systems in the areas selected for monitoring will be observed to ascertain that there will be no danger to personnel and no potential damage to the system under investigation.

Special attention will be given to ensure that these small lines are not in resonance with operating equipment or flow-induced vibrations of the attached large-bore lines.

Based on those observations, instrumentation and other lines 2 in. and smaller attached to the test system piping and to the system components in the piping areas selected for monitoring will be inspected visually for the following specific reasons:

a. To eliminate danger to personnel

b. To ensure that there will be no damage (such as fatigue failure) to the primary system at junctions with large piping and equipment.

Therefore, safety-related small-bore piping and instrument lines will be included in the test program, subject to the above considerations and, in general, covering only the junction points (taps, tees, etc.) with the main system piping under test as listed in Table 3.9-1. Such junction points are assumed to be the worst case for fatigue failure of the small-bore piping instrument lines. If the piping system itself is small-bore piping, as in the case of the control rod drive (CRD) lines, then the test program covers small-bore piping and instrument lines in its entirety (as limited by accessibility and personnel safety) at the system level.

For instrumentation lines that because of accessibility or personnel safety cannot be inspected during system operation, an inspection of the lines' routing and supports was completed prior to operation. The inspection verifies that the instrumentation lines have been adequately supported to resist vibrations caused by the header piping or equipment to which the lines are attached (as there is no flow in instrumentation lines, vibrations from header piping or equipment are the source of excitation). If it was determined that the lines were not adequately supported or routed, the routings were modified or supports were added to obtain an appropriate design.

3.9.1.1.4 Thermal Expansion Testing

The thermal expansion movements of piping systems identified in Table 3.9-1 will be monitored when these systems are heated initially to their normal operating temperatures. This testing will normally take place during the startup phase.

Prior to the heatup of a system, points of potential contact with other equipment will be identified. During heatup of the system, these points will be monitored to verify that free movement of the piping is not hindered.

The thermal expansion deflections of selected points of the piping systems will be monitored either visually or with test instrumentation. Normally, the points to be monitored will be those points that are predicted by the stress analyses to exhibit relatively large, thermally induced deflections. During heatup, data will be taken at temperature intervals that will allow abnormal conditions to be identified before specified limits are exceeded. An additional set of data will be taken when the monitored system returns to ambient temperature to verify that piping is free to contract during cooldown. The criteria of Subsection 3.9.1.1.5 will be used to evaluate the thermal expansion performance of the tested systems.

3.9.1.1.5 Acceptance Criteria for Piping Vibration and Thermal Expansion Testing

These vibration criteria apply only to the systems being monitored as part of the Vibration and Dynamic Effects Test Program (See Table 3.9-1). All piping systems are subject to various dynamic forces caused by fluid flow, some transient, some steady-state. Each piping system, because of its unique configuration, will vibrate at its own fundamental frequencies. These criteria are developed to detect any vibratory deflections of sufficient amplitude to cause the intent of the original design criteria to be violated.

Thermal expansion occurs as a result of any system heatup. When a piping system is designed, a flexibility analysis is performed that verifies analytically that the system configuration is not overstressed while undergoing the thermal growth expected to result from the change in system temperatures. The purpose of the thermal expansion testing is to verify that the actual thermal growth is reasonable and unrestricted and is within the parameters of the acceptance criteria contained herein.

3.9.1.1.5.1 Level 1 and Level 2 Criteria

When applicable, Level 1 and Level 2 acceptance criteria will be established. Violation of Level 1 acceptance criteria for those systems and locations being monitored indicates that the design limits of the piping may be exceeded during the tests. Further operation of the system in the offending mode of operation will be avoided. The system response will be evaluated and the violation will be resolved by analysis and/or corrective action.

Violation of Level 2 criteria indicates that stress levels exceed long-term operating criteria but that a short-term threat to the piping system integrity does not exist. Violations of Level 2 criteria will not require the halting of the test but will require post-test evaluation to be performed to ascertain if the apparent violation was of significance and to determine what, if any, system modifications may be necessary to bring the system into acceptable limits.

3.9.1.1.5.2 Steady-State Vibration Acceptance Criteria

The following allowable stress amplitude, S_a, will be used for steady-state piping vibration:

S_a = 7690 psi for carbon steels with UTS <80 ksi

S_a = 12,000 psi for stainless steels

These stress amplitudes represent values based on 80 percent of the alternating stress intensity at 10^6 cycles for carbon steels and 60 percent of the alternating stress intensity at 10^6 cycles for stainless steels divided by a factor of safety of 1.3. The values of alternating stress intensity are taken from Figures I-9.1 and I-9.2 of Appendix I of ASME B&PV Code Section III.

3.9.1.1.5.3 Transient Vibration Acceptance Criteria

Analyses have been completed for the piping systems that are expected to experience significant operational transients (main steam piping, main steam SRV discharge piping, and feedwater piping). For these systems the calculated responses are the basis of the acceptance criteria for the measured transient response.

For other systems which transient testing is to be completed, the piping will be instrumented and/or visually inspected during the transient. If the acceptance criteria are exceeded, the source of the transient will be eliminated, the piping or restraints will be modified, or it will be proved by detailed measurement or analysis that the stresses are acceptable.

3.9.1.1.5.4 Thermal Expansion Acceptance Criteria

The piping and its appurtenances will not be constrained from expanding or contracting. All interferences will be resolved. During heatup, actual expansion movements will be within the greater of a specified tolerance of the calculated values or ±0.25 in. Calculated or actual displacements of ±0.25 in. or less will be ignored. At steady-state operating temperatures, the actual movements will be within a specified tolerance of calculated values. Discrepancies from these criteria will be resolved.

3.9.1.2 Dynamic Testing Procedures

A description of the tests or analyses used in the design of safety-related mechanical equipment (e.g., pumps, valves, and heat exchangers) to withstand seismic loadings is given in Subsections 3.7.2 and 3.7.3.

Most of the safety-related mechanical equipment is situated in the secondary containment and isolated from the reactor coolant pressure boundary (RCPB) by two or more isolation valves. Fluid dynamics and associated vibrations generated in the RCPB cannot propagate beyond closed isolation valves and their rigid anchorages at the point of containment penetration. Consideration of dynamic hydraulic transients generated within an emergency core cooling system (ECCS) subsystem is provided by establishing the following design criteria.

a. Piping and components not designed to withstand the dynamic effects of pipe whip, must be part of redundant, physically separated subsystems so that single failure of one subsystem does not affect the operability of the redundant subsystem

b. Where systems are subjected to potential vibratory loadings due to the dynamic effects of fluid momentum changes (i.e., water hammer), the following measures are taken to avoid the causes of such changes:

    1. Motor-operated valves in the ECCS are not capable of closing or opening at speeds greater than 1.0 in./ sec. Catastrophic failure is improbable for motor- operated valves. Where exception to the above is probable (such

as a break occurring in the feedwater line and the instant flow reversal causing the check valves to slam closed), a detailed analysis was made, and the valves and piping have been designed to withstand such an event

2. The ECCS and feedwater pumps are not capable of fast starts under normal operating conditions, because the lines are filled with fluid. Seizure of the prime mover (motor or turbine) is considered a single failure in the ECCS and renders the complete subsystem inoperative. Pressures and fluid velocities in the ECCS systems, except HPCI and reactor core isolation cooling (RCIC), are such that a water hammer stemming from pump motor seizure can be tolerated within the ASME Code faulted limits. For the feedwater system, the circumferential pipe rupture is identified to be the controlling event. The feedwater flow reversal and check-valve-closure transient resulting from this event were analyzed and the pressure surges, or peak pressure, for this transient were calculated to be less than 2.8 times the system design pressure. Accordingly, a faulted design pressure transient of 2.8 times the system design pressure is used in the ASME B&PV Section III NB-3656 analysis of the Class 1 portion of the feedwater systems

   Transient pressure surges, or peak pressures, associated with pump seizure are less than those associated with pipe rupture and are, therefore, not limiting. Similarly, the calculated transient pressure surges, or peak pressures, associated with pump seizure in the HPCI and RCIC systems are less than 2.5 times the system design pressure. Thus, a faulted design pressure transient of 2.5 times the system design pressure is used in the NB-3656 analysis of these systems

3. Air and steam voids that may develop in a stagnant system due to leakage are prevented in the RHR and core spray systems by providing pump discharge check valves and automatic condensate or demineralized water charging on the pump discharge piping. The HPCI pump discharge piping, up to the normally closed injection valve, is kept charged with condensate water. See section 6.3.2.2.5 for further discussion of the HPCI keep fill system. The RCIC pump lines do not need a charging system because the condensate storage tank provides the same function. The pump suction piping is pressurized by the condensate storage tank. RCIC discharges to the feedwater line from the pump. Thus, the water in the discharge piping cannot leak into the higher pressure feedwater line

   Although system vents are located at the piping high points, air pockets resulting from poor or inadequate system drainage, filling and venting during and after maintenance or prior to startup, could result in severe water hammer. To preclude this, Edison has included appropriate cautions in the applicable system operating procedures

4. The dynamic effects of rapid check valve closure in the feedwater piping due to feedwater line break have been analyzed. The frequency of this transient is so much higher than the natural frequency of the system that vibratory amplification of the equipment responses will not occur.

c. The piping systems have been designed and analyzed to accommodate thermal expansion due to system operational transients. Procedures will be instituted during the preoperational testing phase to verify the validity of the analytical predictions of pipe displacements by measuring pipe movement and comparing the field data to analytical predictions (see Subsection 3.9.1.1.4). It will also be verified that pipe supports and restraints are loaded within their design range.

3.9.1.3 Dynamic System Analysis Methods for Reactor Internals

3.9.1.3.1 Forcing Functions and Dynamic Response of Reactor Internals

The major reactor internal components are subjected to extensive testing, coupled with dynamic system analyses, to properly describe the resulting flow-induced vibration phenomena incurred from normal reactor operation and from anticipated operational transients.

In general, the vibration-forcing functions for operational flow transients and steady-state conditions are not predetermined by detailed analysis. Special analysis of the response signals measured from reactor internals of similar designs are performed to predict amplitude and model contributions. Parameter studies useful for extrapolating the results from tests of internals and components of similar designs are performed. This vibration prediction method is appropriate where standard hydrodynamic theory cannot be applied because of the complexity of the structure and flow conditions. Elements of the vibration prediction method are outlined as follows.

a. Dynamic analysis of major components and subassemblies is performed to identify natural vibration modes and frequencies. The analysis models used for Category I structures are similar to those outlined in Subsection 3.7.2, Seismic System Analysis

b. Data from previous plant vibration measurements are assembled and examined to identify predominant vibration response modes of major components. In general, response modes are similar but response amplitudes vary among BWRs of differing size and design

c. Parameters are identified that are expected to influence vibration response amplitudes among the several reference plants. These include hydraulic parameters such as velocity and steam-flow rates, and structural parameters such as natural frequency and significant dimensions

d. Correlation functions of the variable parameters are developed that, when multiplied by response amplitudes, tend to minimize the statistical variability between plants. A correlation function is obtained for each major component and response mode

e. Predicted vibration amplitudes for components for the prototype plant are obtained from these correlation functions based on applicable values of the parameters for the prototype plant. The predicted amplitude for each dominant response mode is stated in terms of a range, taking into account the degree of statistical variability in each of the correlations. The predicted mode and frequency are obtained from the dynamic analysis of Item a. in this listing.

The dynamic model analyses also form the basis for interpretation of the prototype plant preoperational and initial startup test results (Subsection 3.9.1.3.2). Model stresses are calculated and relationships are obtained between sensor-response amplitudes and peak-component stresses for each of the lower normal modes. The allowable amplitude in each mode is that which produces a peak stress amplitude of $\pm$10,000 psi.

3.9.1.3.2 Preoperational Flow-Induced Vibration Testing of Reactor Internals

Fermi 2 reactor internals were tested in accordance with provisions of Regulatory Guide 1.20, Revision 2, for nonprototype Category I plants. The test procedure requires operation of the recirculation system at rated flow with internals installed (less fuel), followed by inspection for evidence of vibration, wear, or loose parts. The test duration was sufficient to subject critical components to at least 10^6 cycles of vibration during two- loop and single-loop operation of the recirculation system. At the completion of the flow test, the vessel head and shroud head were removed; the vessel was drained and major components were inspected on a selected basis. The inspection covered all components that were examined on the prototype design, including the shroud, shroud head, core support structures, the jet pumps, and the peripheral control rod drive and in-core guide tubes. Access was provided to the reactor lower plenum.

Reactor internals for Fermi 2 are substantially the same as the internals design configuration that was tested in prototype BWR/4 plants. Results of the prototype tests are presented in Reference 1. This report also contains additional information on the confirmatory inspection program.

3.9.1.4 Correlations of Reactor Internals Vibration Tests With the Analytical Results

Prior to initiation of the instrumented vibration test program for the prototype plant, extensive dynamic analyses of the reactor and internals were performed. The results of these analyses were used to generate the allowable vibration levels during the test. The results of the data analysis, vibration amplitudes, natural frequencies, and mode shapes were then compared to those obtained from the theoretical analysis.

Such comparisons provided the analysts with added insight into the dynamic behavior of the reactor internals. The additional knowledge gained was used in the generation of the dynamic models for seismic and LOCA analyses for Fermi 2. The models used for Fermi 2 were the same as those used for the vibration analysis of the prototype plant.

The vibration test data were supplemented by data from forced- oscillation tests of reactor internal components to provide additional information concerning the dynamic behavior of the reactor internals.

3.9.1.5 Analysis Method Under Loss-of-Coolant Accident Loading

Annulus pressurization refers to the loading on the sacrificial shield wall, reactor vessel, reactor vessel supports, and reactor internals caused by a postulated pipe rupture at the nozzle safe ends. The assumed break is an instantaneous guillotine rupture that allows mass and energy release into the drywell and annular region between the shield wall and the reactor pressure vessel (RPV).

The mass and energy released during this postulated pipe rupture results in the following:

a. An acoustic asymmetric loading on reactor internals, due to a rapid decompression of the annular region between the vessel and the shroud

b. A transient asymmetric pressurization of the annular region between the shield wall and the RPV

c. A jet stream release of the RPV and pipe inventory

d. A force against the restraint attached to the shield wall due to the impact and constraint of the ruptured pipe

The study was broken into four tasks:

a. Calculation of mass energy release

b. Calculation of annulus pressure distribution history

c. Structural design assessment of the sacrificial shield and pedestal

d. Structural design assessment of the reactor components.

The first three tasks are described in detail in Subsection 6.2.1.3.11. This section is a brief description of these tasks and the results of the assessment of reactor components.

3.9.1.5.1 Mass and Energy Release

The postulated pipe rupture at the weld between recirculation or feedwater piping and the reactor nozzle safe end leads to a high flow rate of water and steam mixture into the annulus between the RPV and the shield wall. Figure 3.9-1 illustrates the location of this break. Calculation of the mass and energy release is performed using the generic method for short-term mass releases. This method is described in Subsection 6.2.1.3.11. As mentioned previously, this mass energy release results in acoustic loads, pressure loads, and jet loads.

3.9.1.5.2 Acoustic Loads

The recirculation suction line break is the most limiting break relative to the generation of asymmetric pressure loads on the shroud. The following pressure loads are used for input to the reactor internals stress analysis. There are two types:

a. Acoustic decompression wave loads that last for less than 5 msec; the method of the modeling of this load is consistent with NEDO-24048, "Evaluation of Acoustic Pressure Loads on BWR/6 Internal Components," September 1978 (Reference 2)

b. Flow-induced pressure loads due to the flow out of the break; these are analyzed by a potential flow theory analysis of the reactor downcomer region.

   Because the BWR is a two-phase system that operates at or close to saturation pressure, the differential pressure across the reactor shroud is of short duration and the structural supports of the system are not subjected to a significant shock-type load. This short-duration acoustic load is confined to a bending moment and shear force on the reactor shroud and reactor shroud support. Typical results of the integrated force acting on the reactor vessel shroud are given in Table 3.9-2. (These typical results apply to the Fermi 2 reactor.)

3.9.1.5.3 Pressure Loads

The pressure responses of the RPV-shield wall annulus for a recirculation suction line and a feedwater line were investigated using the COMPARE computer code. The pressure histories generated by COMPARE were in turn used to calculate the loads on the sacrificial shield wall and the RPV. Time-force histories representing the resultant loads on the RPV in the structural model were generated by taking the product of the pressure in each pressure node and its effective area, and summing these to give the force of the geometric center of each structural node (See Figure 3.9-3).

3.9.1.5.4 Jet Loads

To completely address structural loads on the vessel and internals, jet thrust, jet impingement, and pipe whip restraint loads must be considered in conjunction with the pressure loads. Jet thrust refers to the vessel reaction force that results as the jet stream of liquid is released from the break. Jet impingement refers to the jet stream force that leaves the broken pipe and impacts the vessel. Jet impingement and jet thrust forces are modeled as suddenly applied constant forces rising from a value of zero at time zero to its full value in one time step (0.001 sec). The pipe whip restraint load is the force that results when the energy-absorbing pipe whip restraint restricts the pipe separation to less than one full pipe diameter. These jet loads are calculated as described in ANSI 176 (draft), "Design Basis for Protection of Nuclear Power Plants Against Effects of Postulated Pipe Ruptures," January 1977 (Reference 3).

The jet-load forces used for the recirculation suction-line-break analysis are shown in Figure 3.9-2 and Table 3.9-3. These values were also used for the feedwater load evaluation. This is conservative because the calculation of these jet effects depends largely on the area of the break, and because the recirculation line is about 2.5 times larger in area.

3.9.1.5.5 Structural Dynamic Analysis

The pressure loads and jet loads described in Subsections 3.9.1.5.3 and 3.9.1.5.4 are combined to perform a structural dynamic analysis. Both of these loads are distributed along the horizontal beam model shown in Figure 3.9-3. The force-time- histories are then applied to a composite lump mass model of the pedestal, shield wall, and a detailed representation of the RPV and internals.

In each analysis, a multiple force input time-history is performed. The DYSEA computer program, described in response to La Salle NRC Item 111.61 (La Salle County Stations, NRC Docket No. 50-373-374), was used for the analysis. The maximum forces and moments at each end of the element were calculated for evaluating the RPV and internals at uprated power conditions. Acceleration time histories and the broaden response spectra at all nodes were generated and used for subsystem analysis. Only the horizontal excitations were generated for this analysis, since the AP loads are all horizontal.

The peak loading on the major components used to establish the adequacy of the component design is shown in Tables 3.9-5 and 3.9-6. A new set of time histories from the 12" recirculation discharge line break was provided for uprated power. The new AP analysis was done by using the same model with combined AP and jet loads. The maximum forces and moments at the RPV, shield wall, and pedestal location were obtained. The loads on major components are shown in Tables 3.9-5 and 3.9-6 for power uprate conditions.

3.9.1.5.6 Annulus Pressurization With a Safe-Shutdown Earthquake

A design analysis has been performed to evaluate the effect of such loading on the Fermi 2 RPV and internals. This evaluation accounted for the load combination of normal loads (NL) and annulus pressurization (AP) with a safe-shutdown earthquake (SSE). The AP and SSE are combined by the square-root-sum-of-squares (SRSS) method and added directly to normal loads and internal pressure differentials due to the line break.

The following safety-related RPV components were evaluated:

a. Top guide

b. Shroud

c. Core support

d. Jet pumps

e. Core ΔP line

f. RPV support (ring girder)

g. RPV stabilizer

h. Shroud support

i. Vessel skirt

j. Vessel stabilizer bracket

k. CRD housing

l. Control rod guide tube

m. Fuel assembly.

A comparison of loads resulting from this evaluation and allowable loads and stresses appears in Tables 3.9-7, 3.9-8, and 3.9-9. No allowable stresses are exceeded.

The critical buckling stress in the support skirt is equal to the allowable compressive stress determined in accordance with Article I-1150 of ASME B&PV Code Section III, 1968 Edition. The skirt is treated as a cylinder of radius equal to the largest skirt radius, and thickness equal to the thickness of one support skirt plate.

L_1 = Radius of skirt

t_n = Plate thickness

$$\frac{L_1}{100\ t_n} = 0.415 \qquad (3.9\text{-}1)$$

From Figure 1-1100 (B), factor B for SA-516-Gr70 material at design temperature of 575°F:

B = $S_{critical}$ = maximum allowable compressive stress for design conditions = -11.5 ksi.

According to paragraph N-417-10 of ASME B&PV Code Section III, the allowable compressive stress for emergency and faulted condition is increased by the same ratio as for other conditions.

$$S_{critical}\ (\text{emergency and faulted}) = B\left(\frac{S_y}{S_m}\right) \qquad (3.9\text{-}2)$$

$$= -11.5 * \frac{28.76}{19.15}$$

$$= -17.25\ \text{ksi}$$

The axial stresses in the skirt for original loads are

$$O_x = -\left(v_1 + v_2 + \frac{2M}{L_1}\right)\frac{1}{2\pi L_1 t_n \cos^u} \qquad (3.9\text{-}3)$$

= -8.8 ksi < $S_{critical}$ = -11.5 ksi (design)

= -14.7 ksi < $S_{critical}$ = -17.25 ksi (emergency and faulted)

To show design adequacy of the RPV support skirt, the resultant loads from the combination of responses due to LOCA and SSE are applied to the highest stressed point on the skirt. The skirt knee is the highest stressed portion of the RPV support. In comparing the loads due to the combination of plant-unique LOCA and SSE responses, it was found that the loads calculated for the original design of the vessel skirt are not exceeded. The calculated and allowable stresses for the support skirt are shown in Table 3.9-10.

The load combinations and maximum tensile forces in the RPV pedestal bolts are given in SL-3647 (Reference 4). Table 15 from SL-3647 gives the maximum forces in the RPV anchor bolts.

For new-loads evaluation, effective vertical load on the support skirt ($v_1 + v_2 + 2M/L_1$) is compared with the original load. The faulted-condition values are as follows:

	Original Load	New Load
Load $v_1 + v_2$	5213 kips	5196.5 kips
Moment M	1,344,000 in-kips	530,553 in-kips
Effective vertical load $v_1 + v_2 + \frac{2M}{L_1}$	30,262 kips	15,085 kips

The axial stresses for the new-load faulted condition are less than half the value of design faulted loads.

The efficiency of the dome segment in the penetration region is 43.8 percent.

The fuel assembly is modeled by seven axial nodes. The maximum acceleration occurring at each node is separately determined for the pressure reaction (PR), jet reaction (JR), and SSE loading. This results in three acceleration profiles. The acceleration profiles are then combined by taking the SRSS of the individual PR, JR, and SSE profiles at each axial position along the length of the fuel assembly.

The resulting profile is then compared to the design-basis profile. If the resultant acceleration profile is less than the design-basis profile, the resultant loads, moments, stresses, and deflection will be less than those for the design-basis case and therefore are acceptable. The acceleration components for Fermi 2 are shown in Table 3.9-11. (None of the accelerations exceed the design-basis profile.)

In addition, GE licensing topical report, "BWR Fuel Assembly Evaluation of Combined SSE and LOCA Loadings," NEDE-21175-P (Amendment 3), July 1982 (Reference 5), provides a bounding evaluation of potential fuel assembly liftoff during such loadings. The evaluation shows the fuel response is within acceptable limits as shown in Table 3.9-12 for the methodology used in the topical report.

Loads on the RPV shroud were studied for asymmetric pressure in addition to SSE, normal loads, and concurrent symmetric pressure differentials. The shroud buckling stresses for this loading combination are approximately 13 percent higher. These are still well below allowable stress limits.

At the request of the NRC, some piping was reanalyzed. These reanalyses confirmed that the piping stress evaluations for the large-bore RCPB piping systems considered faulted condition loadings, including annulus pressurization. This report further indicated that these analyses adequately represent the as-built configurations of these piping systems.

The as-built analysis of the recirculation and drywell RHR piping for combined annulus pressurization and DBE loadings showed that all piping stresses are within code allowable values (3 S_m), and all support component loads are within their Level D component ratings (with one exception where the rating was exceeded by a negligible [4.4 percent] amount). However, Edison has made minor modification (weld size increase) to structural steel for three supports to bring all supports into compliance with code allowable weld stress limits.

In addition, Edison has reviewed the annulus pressurization analysis of all other large-bore (NPS ≥4 in.) RCPB piping systems, comparing the analysis input to the as-built configuration. For these piping systems, the existing analyses were found to adequately represent the as-built configurations.

3.9.1.5.7 Steam Line Break With a Safe-Shutdown Earthquake

The simultaneous occurrence of a steam line break and an SSE also was analyzed. The analysis for core support structures was performed conservatively using the symmetric internal pressure differentials for a steam line break, which are higher than the symmetric internal pressure differentials for a recirculation or feedwater line break. The results are presented in Table 3.9-7.

3.9.1.5.8 Conclusion

In conclusion, a dynamic analysis of the RPV and internals has been performed considering loads due to a LOCA with an SSE. The results of this evaluation show that no RPV and internals allowable stresses are exceeded.

The current practice for such an analysis is to use a high degree of conservatism for each of the key parameters. As these parameters are combined during the evaluation, the degree of conservatism becomes magnified and the final results of the evaluation contain very high total conservatism. The following are some conservatisms for key parameters.

a. Dynamic loads are very conservatively defined in terms of amplitudes, frequencies, and phasing

b. To reduce the number of analysis cases, multiple-load cases are frequently combined into one by enveloping the input response spectra, which are more critical than the worst of individual cases

c. Damping values are conservatively specified

d. Response spectra peaks are broadened by ±15 percent

e. Linear analyses are performed in cases where nonlinear analyses are justifiable. Note that the nonlinear analysis generally results in significantly lower responses because of stress redistribution and higher energy dissipation

f. Allowable stresses used, as specified in the ASME Code, are based on static reserve margins, while for dynamic loads there are considerable additional reserve margins. Instantaneous or brief excursions into the inelastic range are of no or little structural consequences.

In addition to the above, the Fermi 2 evaluation made the following conservative assumptions.

a. The RPV/internals loads and equipment response spectra for the SSE were assumed to be 1.875 times the operating-basis earthquake (OBE) loads, which in effect ignores the higher damping allowed for SSE

b. Dampings used in the AP analysis were the same as those for OBE, although SSE dampings are more appropriate for loads associated with the faulted conditions. The RPV, shroud, and support skirt used 2 percent for OBE, SSE, and AP. Regulatory Guide 1.61 suggests dampings of 2 percent for the OBE and 4 percent for the SSE. Furthermore, in transmittal of structural properties for the reactor building, containment, pedestal, and shield wall, the architect-engineer suggests use of 2 percent damping for the OBE and 5 percent damping for the SSE. General Electric used 2 percent damping for the architect-engineer structures for OBE, SSE, and AP

c. A further conservatism exists in the use of recirculating jet loads in combination with all of the postulated subcompartment histories.

3.9.1.6 Analytical Methods for ASME Code Class l Components

Both elastic and inelastic stress analysis techniques were used in the design of the reactor vessel core support and reactor internal structures to show that stress limits are not exceeded. If an inelastic stress analysis was performed on these components, the elastic (linear) system analysis was checked to see whether the analysis requires modification. The procedure is first to determine the equivalent element stiffness including the inelastic component. The equivalent linear element stiffness is determined by using the method of equivalent linearization of Krylov and Bogoliubov (Reference 6). In this method, the nonlinear differential equation is replaced by an equivalent linear differential equation such that the solutions of the two equations differ from each other by an error of the order of the square of the nonlinear parameter. An alternative method is to determine the equivalent linear system by means of orthogonal polynomials (Reference 7). In either case, the fundamental frequency of the equivalent linear system is then determined. If the fundamental natural frequency of the equivalent linear system deviates less than 15 percent from that of the original linear system, the original linear analysis is considered adequate. A nonlinear dynamic analysis or an equivalent nonlinear dynamic analysis is performed if the natural frequency of the system with reduced stiffness deviates by more than l5 percent from that of the original system.

The l5 percent deviation criterion is applied to the system response for the particular component of interest. This is a realistic approach, since it is difficult, if not impossible, to discuss localized frequencies in dynamic analysis. The whole system must be considered when determining eigenvalues and eigenvectors. The 15 percent deviation criterion was selected in view of the uncertainties in the analytical models of structures and systems. Such uncertainties are normally accounted for in design by introducing conservatisms in the whole analytical process. For example, in the seismic analysis of the structure, floor spectra are generally broadened by 10 to 15 percent to account for uncertainties in the structural models, in the soil structure, and the system modeling. Because of the uncertainties in the dynamic model of the structure and the equipment, it is pointless to refine the analysis beyond the input uncertainty range.

Results for selected RPV internals and associated equipment analyses are provided in Table 3.9-10 and in Tables 3.9-13 through 3.9-15.

3.9.1.6.1 Method of Load Combinations for Class 1 Piping

ASME Code Section III, Class 1 piping systems and components are analyzed by elastic stress analysis techniques. The main computer programs used are PIPSYS or AutoPIPE, described in Subsections 3.13.1.26 and 3.13.3.18, respectively, and the GE in-house verified computer programs PISYS and ANSI7.

Forces and moments in the three normal orthogonal directions are determined for each individual load condition. Forces and moments are then combined in accordance with the rules of the ASME B&PV Code Section III, NB-3652 and NB-3653, in each orthogonal direction. The stress is then calculated on the basis of a single moment after combining the three orthogonal moments by the SRSS such that

$$M_i = \left(M_x^2 + M_y^2 + M_z^2\right)^{1/2} \qquad (3.9\text{-}4)$$

The individual load and operating conditions used in the analysis are as follows:

Condition	Load	ASME Section III Criteria
Operating	Dead weight Design pressure	Primary stress intensity limit, Equation (9), NB-3652 ≤ 1.5 S_m
Upset	Dead weight Design pressure OBE	Primary stress intensity limit, Equation (9), NB-3652 ≤ 1.5 S_m (or 1.8 S_m depending on the code issue used)
	Thermal expansion Thermal displacement OBE	Primary plus secondary stress intensity range, Equation (10), NB-3653.1, or Equations (12) and (13), NB-3653.6
	Other upset occasional loads	Peak stress intensity range, Equation (11), NB-3653.2
	Operating and upset transients	Alternating stress intensity, Equation (14), NB-3653.6
Emergency	Dead Weight Design pressure SSE Other emergency occasional loads	Primary stress intensity limit, Equation (9), NB-3652 ≤ 2.25 S_m
Faulted	Dead weight SSE Other faulted occasional loads Design pressure	Primary stress intensity limit, Equation (9), NB-3652 ≤ 3.0 S_m

A fatigue analysis is performed in accordance with NB-3653.4 considering all cyclic load conditions, including pressure, hydrostatic testing, operating and upset transients, and OBE stress reversals. For some components, NB-3200 analysis is performed instead of the NB-3600 analysis described above. A typical listing of transients applied is given in Table 5.2-2.

The recirculation and main steam piping systems meet the requirements of the ANSI B31.7 Nuclear Power Piping Code Class 1. Other Class 1 piping systems meet the requirements of ASME Section III.

The analysis performed by GE consists of the recirculation loop and those portions of the main steam piping, the steam supply piping to the HPCI and RCIC turbines, the RHR supply and return piping, and reactor water cleanup (RWCU) piping inside the drywell. The analyses performed by GE include the optimization of suspension devices.

Other large bore (NPS ≥ 1-1/4 in.) Class 1 piping systems include the RCPB portions of the following:

a. Core spray system

b. Feedwater system (including HPCI, RCIC, and RWCU lines)

c. Main steam drains system

d. Standby liquid control system

e. RPV vent line

f. Outside containment portions of HPCI and RCIC steam lines, RHR supply and return lines, and RWCU line.

All of the above systems were analyzed to determine the forces and moments acting on each component as a result of thermal expansion, dead weight, and earthquake. In addition to the above, the main steam system was analyzed for relief valve lift and turbine stop valve closure. The moments obtained from these analyses were then used in conjunction with information obtained from an analysis of temperature gradients to determine the stress intensities and fatigue life for each component in the system.

3.9.1.6.2 Combination of Earthquake Response - Piping Systems

Modal responses and spatial components in seismic response analysis are combined using the methods described in Regulatory Guide 1.92, Revision 1.

3.9.1.6.3 Combination of Earthquake Loads With Other Occasional Mechanical Loads

Earthquake loads are combined with other occasional mechanical loads using the SRSS method.

3.9.1.6.4 Valves and Equipment

The requirements of the draft ASME Code for Pumps and Valves or ASME Section III were adhered to in the design of active Code Class 1 valves. Stress intensities were limited to 1.0 S_m for general membrane and 1.5 S_m for general membrane plus bending. These limits ensure that the valve stresses will remain within elastic limits and that no plastic deformation will occur. Representative analyses of Code Class 1 valves are summarized in Tables 3.9-17, 3.9-18, and 3.9-19.

The requirements of Section III of the ASME B&PV Code are adhered to in the design of Code Class 1 manually operated globe valves and check valves 2 in. in size and smaller.

Additional discussion relative to Code Class 1 equipment is provided in Section 5.2. Representative analyses of Code Class 1 pumps are summarized in Table 3.9-20, Recirculation Pumps.

3.9.1.6.5 Structural Supports

Structural supports for Class 1 components were generally designed using the same criteria as for Class 2 and 3 components as described in Subsection 3.9.2.2.4.1.

In the GE design of supplied supports where jet reactions from a break are included with SSE and normal loads, the calculated stress is less than the following:

a. Bending 0.9 yield

b. Tension 0.85 yield

c. Shear 0.50 yield

d. Compression 1.5 times the allowable stress from the AISC Specification Part 1, Paragraph 1.5.1.3.1.

Items that support components such as CRD housing supports and RPV stabilizers were designed using these acceptability criteria.

3.9.1.6.6 Stress Levels for Class 1 Piping Systems

The methods used to analyze Class 1 piping systems are discussed in Subsections 3.9.1.6.1 through 3.9.1.6.3. Typical results are presented here. As-built system data were used as input to the final stress analyses of these systems to ensure that the code- specified allowable stresses are not exceeded.

Piping isometrics, stress levels, and usage factors for the major Category I, Class l, systems are given in the following figures and tables:

System	Figure Numbers	Table Numbers
Main Steam	3.9-6 to 8	3.9-21 and 22
Recirculation – RHR	3.9-9 and 10	3.9-23 and 24
Feedwater	3.9-14	3.9-25
Core Spray	3.9-15	3.9-26

These isometrics and tables show the piping arrangement, stress levels, and usage factors at the high stress points, as well as at the locations of changes of flexibility. They are representative of the analyses and results for all Class 1 systems. The remaining Class 1 systems are not as critical as the previously listed systems, since failure or pipe rupture in these systems does not result in a design-basis LOCA. The Usage values listed in Tables 3.9-21 through 26 are based on original plant design. See FP FERM 310 (Ref. 19) for the fatigue usage accumulated for all monitored locations based on Fermi 2 operating history.

Any detailed information of specific results may be obtained from the certified stress reports for these systems.

3.9.2 ASME Code Class 2 and 3 Components

For Fermi 2 this refers to either ASME Code Class 2 and 3 components or similar non-RCPB safety-related pressure-retaining components designed to earlier codes.

3.9.2.1 Plant Conditions and Design Loading Combinations

These active and inactive components are identified and listed in Table 3.9-27. American Society of Mechanical Engineers Code Class 2 and 3 components of fluid systems were constructed in accordance with Section III of the ASME B&PV Code. Most components (piping, pumps, and valves) were ordered prior to July 1971 and were designed to other industry codes (see Table 3.2-1) when the effective Section III was not applicable. The specific quality group classification for each principal component is provided in Table 3.2-1. Tables 3.9-28 through 3.9-36 list the design loading combinations for the major components of representative safety-related systems.

Definitions of symbols used in the equations in these tables are contained in the applicable code referenced by the table.

3.9.2.2 Design Loading Combinations

The combination of design loadings for the components are categorized with respect to plant conditions identified as normal, upset, emergency, or faulted in Tables 3.9-28 through 3.9-36. The design stress limits associated with each of the plant conditions are specified in the subsections that follow.

3.9.2.2.1 Fluid System Components (Vessels Including Heat Exchangers and Pumps) and Piping Systems

ASME Code Class 2 and 3 safety-related fluid system components were designed considering the following load combinations:

Category	Loads	Pressure Boundary Stress Limits
Normal	Design pressure Design temperature	S = Allowable stress ASME Section III
Upset	Design pressure Design temperature	General membrane = 1.0 S
	Operating-basis earthquake Including nozzle loads	Local membrane/bending = 1.5 S
Emergency*	Design pressure Design temperature	General membrane = 1.2 S
	Safe-shutdown earthquake Including nozzle loads	Local membrane/bending = 1.8 S

* Inactive components may use the smaller of 0.7 S_u or 2.4 S

ASME Section III, Class 2 and 3, piping systems and components are generally analyzed by computerized elastic analysis techniques. The main computer programs used are PIPSYS, AutoPIPE, and NUPIPE, described in Subsections 3.13.1.26, 3.13.3.18, and 3.13.4.1, respectively.

Analysis is based on a single equivalent moment, evaluated as the SRSS combination of the three orthogonal moments generated in the pipe by the various loads, as described in Subsection 3.9.l.6.l. Earthquake response is calculated as described in Subsection 3.9.1.6.2. Earthquake loads are combined with other occasional mechanical loads as described in Subsection 3.9.1.6.3. The combined moments and resulting stresses are evaluated in accordance with the equations and allowable stress criteria of ASME III, Subsection NC-3652, for the various operating categories listed below.

Category	Loads	ASME III Criteria
Normal	Design pressure Dead weight Sustained mechanical loads	NC-3652.1 EQ (8) $\leq$ 1.0 S_h
Upset	Design pressure Dead weight Sustained mechanical loads Operating-basis earthquake OBE displacements* Occasional mechanical loads**	NC-3652.1 EQ (9) $\leq$ 1.2 S_h
Emergency	Design pressure Dead weight Sustained mechanical loads	NC-3652.2
	Safe-shutdown earthquake*** SSE displacements*, *** Occasional mechanical loads**	EQ (9) $\leq$ 1.8 S_h

* The earthquake terminal displacements may be neglected in EQ (9) if they are considered in Equation (10) or (11) as permitted by the Code.
** Such as relief valve blowdown loads.
*** As an alternative to using the SSE response in evaluating stresses under this category, 1.875 times the OBE response may be used.

In addition to the above primary loads, thermal expansion effects are considered by evaluation of Equation (10) or (11) of NC3652.3. The acceptance criteria for allowable stresses are as listed in the code.

Transients, that is, time-varying temperature or pressure changes, are not evaluated for Class 2 or 3 piping as they are for Class l piping. Transient phenomena, such as relief valve blowdown loads on the piping, are considered in the design when these events are specified in the System Design Specification.

The structural analyses for large- and small-bore torus-attached piping, piping supports, and related equipment are described in the Plant Unique Analysis Report and DC-6003 Vol I "Evaluation of New ECCS Suction Strainers on Existing TAP Analysis" for Torus-Attached Piping (Reference 8 & 20). Similarly, the structural analyses for the safety/relief valve discharge piping are described in Volume 5 of the Plant Unique Analysis Report (Reference 9) and in the piping stress reports. The criteria set forth in NUREG-0661 (Reference 10) have been used in the analysis methods and in the evaluation of the results for these systems.

3.9.2.2.2 Containment

Refer to Section 3.7 and Chapter 6.

3.9.2.2.3 Valves

The valve pressure-retaining parts designed to ASME III, Class 2 and 3, were designed to withstand seismic forces and pipe reactions of the SSE. If seismic consideration is necessary for other parts, the following applies:

Operating Condition	Loads
Upset	1. Normal operating 2. OBE
Emergency	1. Normal operating 2. SSE*

* As an alternative to using the SSE response, 1.875 times the OBE response may be used. Maximum horizontal ground acceleration for the SSE is 0.15g; for the OBE it is 0.08g. (see Subsection 3.7.1.1.)

The original design of ASME III, Class 2 and 3, valves is in accordance with MSS-SP-66 or ANSI-Bl6.5. Allowable stress limits are defined by ASME Section I. When more than one allowable stress value was listed in ASME Section I for an austenitic stainless steel material at a temperature, the lower value was used. The pressure-temperature ratings used for the design of valves are either the standard primary service pressure ratings of 150, 300, 400, 600, 900, 1500, or 2500 lb covered by ANSI-B16.5, or are determined by the following formula in compliance with the requirements of MSS-SP-66:

$$P_1 = \frac{PS_1}{S-P(y_1-y)} \qquad (3.9\text{-}5)$$

where

P_1 = maximum allowable pressure at desired temperature, psi

P = maximum allowable pressure at design temperature, psi

S_1 = allowable stress at desired temperature (ASME Section I)

S = allowable stress at design temperature (ASME Section I)

Y_1 = plastic stress distribution factor at desired temperature

Y = plastic stress distribution factor at design temperature

In no case do the pressure-temperature ratings used for a weld- end valve exceed those given for weld-end valves in ASME III, articles NB-3530 and NB-3541. Valves purchased in accordance with more recent editions or Addenda of ASME Section III are designed in accordance with ANSI B16.34.

3.9.2.2.4 Nonpressure Parts

Parts that are not pressure boundary meet the requirements herein for supports and structures (Subsection 3.9.2.2.4.1), provision for anchor bolts (Subsection 3.9.2.2.4.2) and pressure boundary bolting subject to external loads (Subsection 3.9.2.2.4.3) as applicable.

3.9.2.2.4.1 Supports and Structures

Piping and equipment supports are designed for stress levels less than shown below for the loading condition defined for the pressure boundary:

a. Normal and upset

  1. Plate and shells - Primary membrane. 1.0 S; primary membrane plus bending, 1.5 S, where S is the allowable stress limit of the applicable code

  2. Linear supports and bolts - Stress less than the allowable limits of Part I, Section 1.5 through Section 1.10, of the AISC Specifications for the design, fabrication, and erection of structural steel for buildings

  3. Standard support components - Manufacturers' normal and upset condition rated capacity

  4. Concrete expansion anchor bolts - The average ultimate tensile and shear loads established by test divided by the following factors of safety.

     a. Four for wedge-type anchor bolts

     b. Five for self-drilling-type anchor bolts in pipe supports

     c. Four for self-drilling-type anchor bolts in applications other than pipe supports.

b. Emergency

  1. Plates and shells - Stress less than 1.2 times the allowable stress limit values for normal and upset above

2. Linear supports and bolts - Stress less than 1.33 times the allowable stress limit values for normal and upset above

3. Standard support components - Manufacturers' emergency condition rated capacity

4. Concrete expansion anchor bolts - Same as normal and upset above.

c. Load combinations

The load combinations used in the analysis of structural support and anchor bolts for safety-related components are as follows:

1.	Normal and upset conditions active components	Passive components	
	D + E + H + O	D + E + H	(3.9-6)
2	Emergency conditions active components	Passive components	
	$D + E^1 + O + H$	$D + E^1 + H$	(3.9-7)

where

D = dead load (flooded)

H = operating thermal effects

E = operating-basis earthquake

E^1 = safe-shutdown earthquake

O = operational loads (nozzle reactions, pressure, motor torque, pump inertia, etc., as applicable)

In the design of structures and structural components for Fermi 2, it has been Edison's practice to specify the use of codes and related design guides applicable at the initiation of the design activity. In the course of the design process, the use of later editions of the codes and/or any supplements issued thereto has been allowed.

3.9.2.2.4.2 Provision for Anchor Bolts

Equipment mounted on concrete support structures is fastened with anchor bolts (in drilled and grouted holes) or with expansion anchors. Sufficient holes for anchor bolts are provided to limit anchor bolt stress to those allowable per the AISC Code. Equipment anchored to a steel foundation and equipment mounted using expansion anchors follow the provisions of supports and structures (see Subsection 3.9.2.2.4.1).

3.9.2.2.4.3 Pressure Bolting for Component Flanges Subject To External Load

Where appreciable loads can occur on equipment-gasketed pressure joints, the external loads are considered in calculations to determine required bolt area. Code allowable stresses are maintained consistent with the operating conditions associated with the external loads.

3.9.2.2.5 Pipe and Equipment Supports

3.9.2.2.5.1 Equipment Supports

Refer to Subsection 3.9.2.2.4.2 above.

3.9.2.2.5.2 Seismic and Dynamic Effects - Shock Suppressors

Shock suppressors (snubbers) are provided on Category I piping systems, where necessary, to prevent shock forces from causing damaging motion and concurrently to allow for the normal thermal motion of the piping. In general, the snubbers for piping located inside the primary containment (drywell) and inside the steam tunnel, as well as the snubbers for the field run piping described in Subsection 3.9.2.7, are of the mechanical type. The mechanical shock suppressors conform with the requirements of the ASME Code Section III, Subsection NF, 1974 issue up to and including the winter 1976 addendum. Snubbers for the balance of the plant piping are of the hydraulic type and are designed in accordance with the requirements of ANSI B31.7, 1969, and/or ANSI B31.1, 1967, as appropriate for the class of piping being restrained.

As a result of concern about the reliability of the hydraulic and mechanical snubbers used for piping, identified as 10 CFR 50(e), Item 69, Edison reviewed the use of such snubbers. The results of the study included the elimination of about 29 percent of the snubbers, either by replacement with rigid supports or by proving that no restraint was required.

3.9.2.2.6 Relief Valve Operation - ASME III Components

If, during relief valve operation, the pressure exceeds the design pressure, it shall be considered to be an emergency condition and 110 percent of the design stress limit is permitted for Class 2 and 3 components.

3.9.2.2.7 Structural Cast Iron

The following are acceptable allowable stress limits for cast iron used for structures (e.g., bearing housings):

	Unidentified Gray Cast Iron	ASTM Class 20
Tension	3.5 ksi	5 ksi
Shear	3.5	5
Bending	5.25	7.5
Compression	7.0	10

3.9.2.2.8 Nozzle Loads

Nozzles withstand the pipe reactions from dead weight, thermal expansion, earthquake, and relief valve operation.

3.9.2.3 Design Stress Limits

For safety-related non-RCPB pressure retaining components, representative design stress limits are listed in Tables 3.9-28 through 3.9-36. Inelastic methods of analysis are not used for these components.

3.9.2.4 Analytical and Empirical Methods for Design of Pumps and Valves

3.9.2.4.1 General

To ensure the functional performance of Class 2 and 3 active pumps and valves, the design requirements of Subsection 3.9.2.2 were applied. Operability will be further demonstrated by the Operability Assurance Program described in Subsection 3.9.4.

The design methods were a combination of analysis and past testing and operating experience. These methods are the responsibility of the vendor, who is responsible for meeting the requirements of the applicable codes and standards identified in the component specification.

3.9.2.4.2 Valves

Class 2 and 3 (1971 code language) active valves were designed as described in Section 3.9.2.2.3. In addition, an analysis of the extended structure was performed, generally using statically applied acceleration loads from the piping stress analysis, for valves that are required to function during or after an SSE. For this analysis, stresses were limited to values that restrict the maximum stress in the extended structure to within upset condition code stress limits. Deflections of the extended structure will thus be small and operability of the valves will not be impaired.

3.9.2.4.3 Pumps

Active pumps were designed in accordance with the ASME Code for Pumps and Valves or the ASME B&PV Code for Nuclear Power Plants, depending on which code was in effect at the time the purchase order was issued. Forces resulting from seismic accelerations in the horizontal and vertical directions are included in the analysis of the pumps and their supports.

3.9.2.5 Design and Installation Criteria, Pressure-Relieving Devices

3.9.2.5.1 General

All pressure vessels are protected by pressure-relieving devices to meet applicable code requirements, such as ASME Code Sections III and VIII, and ANSI B31.1.

A discussion of the design and installation criteria for Class 1 pressure-relieving devices is given in Chapter 5. The derivation of the forcing functions that govern the fluid thrust during valve operation is presented in Subsection 3.9.2.5.2.

All ASME Code Class 2 and 3 overpressure relief valves and their connecting piping are designed to withstand the maximum load due to the discharge reaction force calculated by the following formula, regardless of the arrangement of the discharge piping:

$$F = 2PA \tag{3.9-8}$$

where

F = reaction force, lbf

P = valve setpoint pressure, lbf/in.^{2}

A = cross-sectional area of the valve inlet nozzle, in.^{2}

The discharge thrust loads so calculated were applied simultaneously with the loads due to internal pressure, dead weight, and seismic (SSE or OBE as applicable). When more than one relief valve is attached to a piping system, the loads due to all relief valves discharging simultaneously were applied to the system along with the above-mentioned primary loads. In addition, the loads from the most critical combination of valves discharging were applied.

3.9.2.5.2 Forcing Functions

The analytical basis for the forcing functions used in the dynamic and static analysis of the relief valves and connected piping is given in the following subsections.

3.9.2.5.2.1 Basic Fluid Flow Equations

One-dimensional flow is assumed in every straight pipe section. The conservation equations used are the following.

Mass

$$\frac{\partial \rho}{\partial t} + \frac{\partial}{\partial t}(\rho v) = 0 \tag{3.9-9}$$

Momentum

$$\frac{\partial v}{\partial t} + v\frac{\partial v}{\partial Z} = \frac{-g_c}{\rho}\left(\frac{\partial P}{\partial Z} + F'''\right) \tag{3.9-10}$$

Energy

$$\frac{\partial S}{\partial t} + v\frac{\partial S}{\partial Z} = \frac{v}{\rho T}F''' \tag{3.9-11}$$

where

ρ = fluid density, lbm/sec

t = time, sec

v = velocity, fps

Z = displacement, ft

g_c = 32.2, lbm x ft/(lbf x sec^2)

P = pressure, lbf/ft^2

S = entropy, ft-lbf/(lbm x °F)

T = temperature, °F

and

$$F''' = \frac{f}{D}\frac{\rho}{2g_c} v\,|v| \qquad (3.9\text{-}12)$$

where

f = Darcy friction factor

D = hydraulic diameter, ft

3.9.2.5.2.2 Reaction Forces

Reaction forces are considered to act longitudinally on each straight section of pipe rather than at each bend or turn, as shown in Figure 3.9-16(a). Consider a general straight section of pipe bounded by two other sections, Figure 3.9-16(b), and consider three fluid volumes from the pipes, Figure 3.9-16(c). Equation 3.9-10 is integrated over the pipe length:

$$\int_0^L \rho\left(\frac{\partial v}{\partial t} + v\frac{\partial v}{\partial Z}\right)\partial Z = -g_c\int_0^L\left(\frac{\partial P}{\partial Z} + F'''\right)\partial Z \qquad (3.9\text{-}13)$$

From Equation 3.9-9,

$$\frac{\partial v}{\partial t} + v\frac{\partial v}{\partial Z} = \frac{\partial}{\partial t}(\rho v) + \frac{\partial}{\partial t}(\rho v^2) \qquad (3.9\text{-}14)$$

so that

$$P_a - P_b - \frac{F_D}{A} = \frac{1}{g_c}\int_0^L \frac{\partial}{\partial t}(\rho v)\,\partial Z + \frac{(\rho v^2)b}{g_c} - \frac{(\rho v^2)a}{g_c} \qquad (3.9\text{-}15)$$

$$\frac{F_D}{A} = \int_0^L F'''\partial Z \qquad (3.9\text{-}16)$$

It is assumed that the turn sections are small in volume (compared to the straight pipe sections), so that no storage terms apply. Furthermore, lossless flow occurs (no friction or other irreversibilities).

Reactions R_1 and R_2 are parallel to pipe section L; R_L and R_R are parallel to the adjoining pipes at the left and right ends. It follows that

$$\rho_a A_a v_a^2 - \rho_1 A_1 v_1^2 \cos\alpha_1 = g_c(R_1 - R_L\cos\alpha_1 + P_1A_1\cos\alpha_1 - P_aA_a) \qquad (3.9\text{-}17)$$

$$\rho_2 A_2 v_2^2 \cos\alpha_2 - \rho_b A_b v_b^2 = g_c(P_bA + R_R\cos\alpha_2 - R_2 - P_2A_2\cos\alpha_2) \qquad (3.9\text{-}18)$$

Equations 3.9-17 and 3.9-18 give momentum conservation at left and right ends parallel to pipe L. Moreover, momentum conservation for the left and right ends in a direction normal to L is

$$-\rho_1 A_1 v_1^2 \sin\alpha_1 = g_c(-R_L\sin\alpha_1 + P_1A_1\sin\alpha_1) \qquad (3.9\text{-}19)$$

$$-\rho_2 A_2 v_2^2 \sin\alpha_2 = g_c(-R_R\sin\alpha_2 + P_2A_2\sin\alpha_2) \qquad (3.9\text{-}20)$$

Equations 3.9-15 and 3.9-17 through 3.9-20 combine to give the net longitudinal force on fluid in section L as

$$R_1 - R_2 - F_D = \frac{A}{g_c}\int_0^L \frac{\partial}{\partial t}(\rho v)\,\partial Z \qquad (3.9\text{-}21)$$

Reactions R_L and R_R are included with longitudinal loads on the adjoining pipe sections. Equation 3.9-21 gives the net force of the pipe walls on the fluid. The pipe load is equal and opposite, or

$$R_{bounded} = -\frac{A}{g_c}\int_0^L \frac{\partial}{\partial t}(\rho v)\,\partial Z \qquad (3.9\text{-}22)$$

Equation 3.9-22 gives the reaction load on a straight pipe section that is bounded at each end by two other adjoining pipes. However, if pipe L is open at the end designated "2," it follows that Equations 3.9-18 and 3.9-20 do not apply, and the pipe reaction load is

$$R_{open} = -AP_b + \frac{\rho_b v_b^2}{g_c} + \frac{1}{g_c}\int_0^L \frac{\partial}{\partial t}(\rho v)\,\partial Z \qquad (3.9\text{-}23)$$

For steady-state flows, Equation 3.9-22 gives zero reaction, whereas Equation 3.9-23 gives

$$R_{open,steady} = -AP_b + \frac{\rho_b v_b^2}{g_c} \qquad (3.9\text{-}24)$$

3.9.2.6 Stress Levels for Class 2 and 3 Piping

Piping isometric sketches, stress levels, and allowable stress limits for selected portions of the below-listed Category I, ASME III, Subsection 2 and 3 subsystems, are given in the following figures and tables.

System	Figure No.	Table No.
EECW system pump suction from heat exchanger	3.9-17	3.9-37
RHR service water return from heat exchanger	3.9-18	3.9-38
RHR containment spray from return header to drywell	3.9-19	3.9-39

These figures and tables indicate the piping system arrangement and stress levels at terminal ends and locations of high change in flexibility. The stress levels given are based upon final analyses and are typical of the stress levels predicted for all Category I, Class 2 and 3 systems. Any detailed information or specific results should be obtained from the specific stress analysis design calculations.

3.9.2.7 Field Run Piping Systems

Piping classified under ASME Code Section III, Classes 2 and 3, size 4 in. and under, with design temperatures of 575°F or less, is analyzed using the computerized stress analysis techniques described in Subsection 3.9.2.2.1, or is analyzed in the field using the simplified approach described in this section. For the field-designed piping, simplified analysis techniques were used for thermal, weight, and dynamic analyses and to determine restraint locations and design loads. These techniques are based on the following criteria.

a. Extreme conservatism is economically practical

b. Uncertainties in manufacturing are present so that a more precise analysis would not be useful

c. The pipe is flexible so that thermal expansion and nozzle movements can be easily accommodated

d. Similarities in the systems allow for use of standard components and design characteristics.

Based on these criteria, simplified analysis techniques pre-sented in Subsections 3.9.2.7.1 through 3.9.2.7.3 are used in the seismic, deadweight, and thermal analyses of field run piping systems. In field run piping systems, the stresses determined by these methods do not exceed the following values.

Stress	Maximum Value (psi)
Thermal expansion	15,000
Anchor movements	15,000
Thermal expansion plus anchor movements	15,000
Weight	3,000
Seismic (OBE)	7,000

Full consideration is given to seismic, weight, and thermal loadings imposed upon equipment and header nozzles to ensure that the imposed loads are within allowable limits.

3.9.2.7.1 Seismic Analyses

Simplified seismic analysis and design procedures are used, treating piping spans between rigid supports and/or restraints as independent simple beams. The span period, maximum mid-span deflection, allowable mid-span deflection, and end restraint forces are determined for a series of span lengths for each pipe size. No restraint credit is taken for hangers or restraints not offering stiffness in the direction of the seismic excitation. The maximum mid-span deflection and restraint forces are a function of the floor response spectra of the building structure in the vicinity of the piping. The spectra used are for the OBE. To predict the effects of the SSE, the responses are doubled.

The resulting data were developed into a set of design curves that are used to

a. Ensure that seismic stresses are not greater than the allowable

b. Ensure that seismic deflections are not large enough to cause damaging contact between pipe and surroundings

c. Provide seismic restraint design loads.

To ensure that seismic stresses are not greater than the allowable, and that seismic deflections are not large enough to cause damaging contact between pipe and surroundings, seismic deflection versus span curves similar to Figure 3.9-20 are used. These curves show the first mode seismic deflection of a simply supported beam representing the pipe span. The response is based upon the most energetic response spectrum expected in the building of interest.

A significant feature of the seismic deflection versus span curves is a line showing the deflection needed to produce a bending stress of 7000 psi in the pipe span. To ensure that code allowable stresses will be met when seismic loading is combined with other appropriate loadings, the seismic deflection due to the OBE is never allowed to exceed that shown by the 7000-psi curve. In addition, to protect against damaging contact between pipe and surroundings, seismic deflections greater than 2 in. are not allowed.

To provide seismic restraint design loads, seismic restraint load versus span curves similar to Figure 3.9-21 are used. These curves give the seismic restraint reactions for a span. Again, the model is a simply supported beam and the response is based on the response spectra curve as used in determining the seismic deflection curves. To account for the continuity of the piping across a restraint attachment point, the reactions from all piping spans supported from a restraint are added.

The following factors are considered in applying the design curves to actual piping systems. The major excitation due to earthquake will be horizontal. However, since it is not known from which horizontal direction the loading will come, all horizontal spans are restrained in the lateral and axial directions. Application of the above criteria requires that the maximum span distance between seismic restraints in the reactor building for the various size pipes does not exceed those spans given below:

	Maximum Span (ft)	
Pipe Size (in.)	Vertical	Horizontal
½	6	9
¾	7	11
1	8	12
1½	10	15
2	12	17
3	14	21
4	16	24

The simplified design curves are based on the accelerations associated with the OBE. The piping design criteria require that Class 2 and those Class 3 piping systems that are designated Category I satisfy normal code stress requirements during an earthquake of this intensity. The 7000-psi seismic stress limit was selected to ensure that normal code stress requirements can always be satisfied. To provide a seismic restraint design that is compatible with the piping design, the Class 2 and 3 system seismic restraints are designed in accordance with the AISC Manual.

A further requirement of the piping design criteria is that the designer must make an assessment of the effect of an earthquake of twice the intensity of the OBE or equal in magnitude to the SSE. The design goal for the SSE is to maintain a safe-shutdown capability for the nuclear energy system. Since the design curves are based on the OBE, all deflections, stresses, and reactions, as determined from the curves, are doubled to obtain SSE values. The allowable seismic stress for the SSE is obviously two times the OBE allowable, or 14,000 psi. The maximum allowable seismic deflection, however, remained at 2 in. The 14,000-psi seismic stress limit ensures that code stress requirements can be met. To provide a seismic restraint design that is compatible with the piping design, the Class 2 and 3 system seismic restraints are designed in accordance with the AISC Manual, except that the restraint stress shall not exceed the AISC allowable by more than 33 percent.

3.9.2.7.2 Weight Analysis

The standard procedure for designing a weight support system involves the use of recommended span lengths, to limit the weight-induced bending stress. The requirements of ASME Code Section III are satisfied by this approach even though the governing equations of NC-3652 do not directly indicate an allowable weight stress level.

In using this method, it is only necessary to determine the fraction of the allowable stress that the weight load should contribute. Recommended spans based on this allowable stress are then calculated by elementary bending theory. The effect of the weight of thermal insulation is also considered. The recommended span length is given by

$$\text{span(ft)} = \sqrt{\frac{2000\text{Z}}{\text{W}}} - 1 \tag{3.9-25}$$

where

Z = section modulus, cubic in.

W = linear weight density, lb/ft

The span recommendations are listed in Table 3.9-40 for pipes filled with water and for gas-filled pipes. This formula is based on the assumption that the pipe element may be represented as a simply supported beam. The maximum bending moment for a continuous beam or for a beam with other end conditions cannot exceed the maximum for the chosen model. Therefore, although the analytical model may not always accurately represent the actual piping, it does establish an upper limit for the bending stress.

To accommodate concentrated weights, the spans are shortened to ensure that the allowable bending stress is not exceeded.

The following rules are used to determine span lengths.

a. A half-span of plain pipe must have a vertical support at one end

b. A half-span that includes an elbow must have a vertical support at both ends

c. The length of a half-span that includes a concentrated weight of less than 10 percent of the normal span load (Table 3.9-40) should not exceed 40 percent of the normal span length. It must have a vertical support on one end

d. A half-span that includes a concentrated weight of from 10 percent to 40 percent of the normal span load must have a vertical support on both ends

e. The length of a half-span that includes a concentrated weight of more than 40 percent but less than 250 percent of the normal span load should not exceed 10 percent of the normal span length and should have a vertical support on both ends. This length does not include the actual length of the concentrated weight

f. A concentrated weight that exceeds 250 percent of the normal span load should be supported directly rather than by the piping to which it is attached

g. The length of a half-span with one free end should not exceed 50 percent of the normal span length

h. A half-span with a concentrated weight should not have a free end

i. Supports not required by these rules should not be used.

3.9.2.7.3 Thermal Analysis

The object of the thermal expansion analysis was to ensure adequate flexibility so that nozzle movements and pipe expansion would not cause stresses in excess of the allowable. This allowable was determined by allocating a percentage of the allowable stress indicated by Equation (10) or (11) of NC-3652, to thermal expansion and anchor displacements.

Flexibility in a given direction is dependent upon the amount of pipe which is perpendicular to that direction. For instance, a component of nozzle movement in the X direction can be accommodated if the nozzle is separated from the first X direction restraint by enough piping in the Y and Z directions (Figure 3.9-22).

The bending stress in the perpendicular legs, B and D, must therefore be examined. These legs are conservatively modeled as a beam with guided ends subjected to a displacement (Figure 3.9-23). This model is conservative since it ignores the flexibility of the elbows and imposes more rigid end conditions than the actual supports.

The allowable stress is limited to 15,000 psi. Therefore the length of perpendicular pipe required to accommodate the component of nozzle movement is

$$\ell = 12\sqrt{\delta r_o} \qquad (3.9\text{-}26)$$

where

ℓ = length of perpendicular pipe required, ft

r_o = outside radius, in.

δ = deflection, in.

The recommended lengths for various values of δ and r are listed in Table 3.9-41. Also, a graph of r versus δ for various values of ℓ is given in Figure 3.9-24. In this analysis, nozzle movements are checked in three orthogonal directions.

The problem of pipe expansion can be handled in a similar manner, except that the movement, δ, is imposed by the expansion of a section of pipe.

As an example, the length of low-carbon steel (SA-106 grade B or equivalent) pipe required to accommodate the expansion of the length, ℓ', at 300°F is

$$\ell = 1.232\sqrt{\ell' r_o} \qquad (3.9\text{-}27)$$

where

ℓ' = expanding length of pipe, ft

ℓ = required offset, ft

r_o = outside radius of pipe, in.

Similar equations for both austenitic and ferritic steel at various design temperatures were developed. Values for different lengths and radii at several design temperatures for both austenitic and ferritic steels are listed in Table 3.9-42.

Where nozzle movement and pipe expansion can occur simultaneously, the sum of the lengths required for each is used as the total length of perpendicular pipe required.

3.9.3 Components Not Covered by the ASME Code

3.9.3.1 General

Safety-related mechanical components not covered by the ASME B&PV Code are identified in Table 3.9-43. The design codes for each principal component are identified and qualification methods for such equipment are summarized herein. This subsection specifically addresses (1) the details of the mechanical design and analytical procedures for the design of the fuel; (2) the methods and procedures used to determine the operability of the control rod drives and control rod insertability under LOCA and seismic loadings; and (3) mechanical and structural loading criteria for motors, the RCIC turbine, and active instrumentation designed to manufacturer's standards and design calculations.

3.9.3.2 Fuel Mechanical Design and Analytical Procedures

The fuel bundle performance history is specified by the cycle specific design reference fuel cycle as defined in Subsection 4.2.l. Performance of individual fuel rods is then determined from the fuel bundle performance history coupled with the exposure-dependent design, local and axial power, and exposure peaking factors. The most limiting fuel rods within the peak performance fuel bundle, with respect to power and exposure combination, are then analyzed to determine thermal and mechanical performance characteristics.

The performance of all fuel rods satisfies the requirements identified in Subsection 4.2.1. Satisfaction of these requirements for all fuel rods is demonstrated by analysis of the performance of the most limiting fuel rods, with respect to power and exposure level identified in the design reference fuel cycle.

Thermal design analyses performed include, but are not limited to, the determination of cladding (Zircaloy-2) and fuel (UO_2) temperatures, cladding and fuel thermal expansion, fuel irradiation swelling, and fuel fission gas generation and release as a function of time. Using these thermal analysis results, the mechanical design analyses are then performed to determine the most limiting cladding stress and/or strain due to such loadings as

a. Internal fuel rod pressure from gaseous fission product release to the fuel rod plenum plus initial fill gas

b. Differential fuel-cladding expansions

c. External coolant pressure

d. Flow-induced rod vibrations.

Finally, the limiting combinations of cladding stress in the categories summarized in Subsection 4.2.1 are identified and compared to the cladding design stress limits. All stresses are below the defined limits.

3.9.3.3 Control Rod Drive Operability and Control Rod Insertability Under LOCA and Seismic Loadings

In the event of a significant seismic disturbance and/or LOCA, only the rapid insertion mode (scram) is essential. Descriptions of the CRD and the CRD system operation during scram are presented in Subsection 4.5.2.2.

The hydraulic nature of the CRDs and their location relative to the reactor vessel provide scram operability that is insensitive to LOCA and seismic loadings. In addition, insertability of the control rods during seismic events is ensured by the generous control-rod-to-channel and control-rod-to-guide tube clearances. However, LOCA produces larger than normal pressure differentials across the reactor vessel internals, tending to reduce these clearances. These pressure differentials are considered in determining the insertability of the control rods.

The highest pressure differentials across the RPV internals occur as a result of a postulated steam line break. To ensure adequate control-rod-to-guide tube clearance, the guide tube must be capable of resisting the external to internal pressure difference without collapse. In addition, any increase of friction force due to channel bulging is shown to be small compared to the total force available to insert the control rods. The above are addressed in Subsections 4.2.2 and 4.2.3. The adequacy of the design margins of the control rod guides to prevent control tube collapse in the event of a main steam line break or recirculation line break (LOCA) was noted as a concern by the AEC in its Safety Evaluation Report on the Fermi 2 Construction Permit (Reference 11). The concern was identified as Post-Construction Permit Open Item No. 9. The Edison position on this open item was submitted to the AEC in May 1973 (Reference 12). The position was based on information supplied by GE and concluded that design margins of the control rod guide tubes were adequate and that no collapse under normal or abnormal conditions was expected. The AEC, after reviewing Reference 12, requested additional information in the form of five specific questions (Reference 13). Edison responded to these five questions on February 14, 1974 (Reference 14), and received AEC provisional approval to start construction by AEC letter dated June 25, 1974 (R. DeYoung to H. Tauber).

3.9.3.4 Mechanical and Structural Loading Criteria for Equipment Not Covered by ASME Code

For nonpressure-retaining equipment important to safety (i.e., motors, the RCIC turbine, and active instrumentation), the following criteria apply.

3.9.3.4.1 Reactor Core Isolation Cooling Turbine

The turbine mechanical and structural loading criteria are given in Table 3.9-35.

3.9.3.4.2 Motors, Motor Control Centers, Switchgear, and Diesel Generators

These components are designed to meet the support and structures criteria (Subsection 3.9.2.2.4.1) and provision for anchor bolts (Subsection 3.9.2.2.4.2) for the following.

Operating Conditions	Loads
Normal	Normal operating + dead weight
Upset	Normal operating + dead weight + OBE
Emergency and Faulted	Normal operating + dead weight + SSE

3.9.3.4.3 Air-Handling Equipment (Safety Related)

The following air-handling systems require equipment satisfying the requirements of this section:

a. Standby gas treatment train
   1. Exhaust fans
   2. Carbon dioxide tanks
   3. Decay heat removal fans
   4. Room cooling units.

b. Emergency equipment area cooling units
   1. ECCS pump room cooling units
   2. Switchgear room cooling units
   3. Emergency equipment cooling water (EECW) pump area cooling units
   4. Thermal recombiner area cooling units.

c. Control center air conditioning system (CCACS)
   1. Multizone unit
   2. Return air fans
   3. Chillers
   4. Chilled water pumps
   5. Equipment room cooling units
   6. Emergency makeup air filter
   7. Emergency recirculation air filter
   8. Emergency recirculation air filter fans.

The above equipment includes fans, housings, ducts, coils, dampers, drives, motors, and plenums (coils are ASME Section III items except for control center equipment room cooling units, and cooling coil in multizone unit). All associated safety-related components and accessories have been designed to Category I requirements.

These components have provisions for installation to meet support and structure criteria of Subsection 3.9.2.2.4.1 and provision for anchor bolts per Subsection 3.9.2.2.4.2. These components are located in Category I buildings and are supplied with electrical power sources and utility services (control air, water, and drains) of Category I classifications. In addition, the buildings provide flood, tornado, wind, missile, and dynamic effects of ruptured piping protection to the air-handling equipment.

3.9.4 Operability Assurance Program

3.9.4.1 General

Active mechanical equipment classified as Category I is designed to perform its function during the life of the plant under postulated plant conditions. Equipment with faulted-condition functional requirements includes active pumps and valves in fluid systems, such as the RHR system, core spray system, and the HPCI and RCIC systems. Operability has been ensured by a series of comprehensive preoperational tests.

Certain Category I valves and pumps were procured before Branch Technical Position MEB position papers concerning operability assurance (References 15 through 18) were available. The codes that were used in the procurement of these components are given in Tables 3.2-2 and 3.2-3. Table 3.9-44 provides a comparison of the Fermi 2 operability assurance program criteria to those provided in NRC Standard Review Plan 3.9.3.

3.9.4.2 ASME Code Class Valves

Safety-related active valves perform their mechanical motion in times of an accident. Assurance is therefore required that these valves will operate during a seismic event. Qualification tests accompanied by analyses have been conducted for all active valves in the GE scope-of-supply.

All other safety-related code Class 1, 2, and 3 active valves equipped with motor operators have been operationally qualified by a combination of test and analysis. Prototype tests have been performed for motor operators situated inside the primary containment and the steam tunnel and subjected to faulted environmental conditions associated with a LOCA. These tests are essentially consistent with the guidelines of IEEE-382, l972. The specific conditions are as follows.

Conditions	Test Results
Seismic operational capability	Up to 5.0g (two planes)
Radiation environment	2 x 10^8 rad
Pressure-temperature environment	IEEE-382, BWR profile
Humidity	100 percent steam atmosphere

Motor-operated active valves located outside the primary containment are equipped with identical motor operators, except that motor insulation is Class B NEMA rated for 130°C service and 100 percent humidity. The operability of the motor valve assembly is ensured by analytical methods.

Each valve type and size has been analyzed, as described in sections 3.9.1 and 3.9.2, to ensure that design loads do not render the valve inoperative. In addition, the below-described preservice and inservice testing is conducted.

The safety-related valves are subject to a series of stringent tests prior to service and during the plant life. Prior to installation, the following tests are performed: shell hydrostatic test to code requirements, backseat and main seat leakage tests, disk hydrostatic test, functional tests to verify that the valve will open and close within the specified time limits when subjected to the design differential pressure, and operability qualification of valve actuators.

Cold hydro-qualification tests, hot functional qualification tests, and periodic inservice operation are performed in situ to verify and ensure the functional ability of the valve. These tests and appropriate maintenance ensure operability of the valve for the design life of the plant.

Valves that are safety related, but can be classified as not having an overhanging structure, such as check valves and safety/ relief valves, are considered separately.

Because of the particularly simple characteristics of the check valves, they are qualified by a combination of the following tests and analysis:

a. Stress analysis including the seismic loads where applicable
b. In-shop hydrostatic test
c. In-shop seat leakage test
d. Periodic in-situ valve exercising and inspection, as applicable, to ensure the functional capability of the valve.

Safety/relief valves are also subjected to tests and analyses similar to check valves. These consist of stress analyses including the seismic loads, in-shop hydrostatic seat leakage, and performance tests. In addition to these tests, periodic in-situ valve inspection, as applicable and periodic valve removal, refurbishment, performance testing, and reinstallation are performed to ensure the functional capability of the valve (Technical Specifications).

During a seismic event, it is anticipated that the seismic accelerations imposed upon the valve may cause it to open momentarily and discharge under system conditions which otherwise would not result in valve opening.

Using the methods described, all the safety-related valves in the systems are qualified for operability during a seismic event. These analytical methods conservatively simulate the seismic event and ensure that the active valves will perform their safety-related function when necessary.

3.9.4.3 ASME Code Class Pumps

No active pumps are located inside the primary containment. Those active pumps located in the secondary containment and subject to adverse environmental conditions as a result of high- energy and moderate-energy pipe breaks outside the primary containment are discussed in Section 3.6.

All active pumps are qualified for operability by first being subjected to extensive tests, both prior to installation in the plant and after installation in the plant. The in-shop tests include the following:

a. Hydrostatic tests of pressure-retaining parts to 1.25 times the design pressure times the ratio of material allowable stress at the test temperature to the allowable stress value at the design temperature

b. Seal leakage tests

c. Performance tests, while the pump is operated with flow, to determine total developed head, minimum and maximum head, net positive suction head (NPSH) requirements, and other pump/motor parameters.

After the pump is installed in the plant, it undergoes the cold hydro-tests, functional tests, and the required periodic inservice inspection and operational tests. These tests demonstrate reliability of the pump for the design life of the plant.

In addition to these tests, the safety-related active pumps have been analyzed for operability during a seismic condition by ensuring that the pump will not be damaged during the seismic event, and the pump will continue operating despite the seismic loads. Performing these analyses, with the conservative loads stated and with the restrictive stress limits discussed in Subsection 3.9.2 as allowables, will ensure that critical parts of the pump will not be damaged during the seismic condition. Therefore, the reliability of the pump for postseismic-condition operation will not be impaired by the seismic event.

The pump/motor rotor combination is designed to rotate at a constant speed under all conditions. Because of the high rotary inertia in the operating pump rotor, and the nature of the random short duration loading characteristics of the seismic event, the seismic loading will cause only a slight increase in the torque necessary to drive the pump at the constant design speed.

Furthermore, a generic analysis was performed for motor-driven, vertically mounted RHR and core spray pump motor assemblies to determine shaft and rotor deflections associated with the SSE forces, and to assess the operability of rotating equipment during a seismic event. The results show negligible effect for perpendicular and axial rotor loads equivalent to l.5g static acceleration, which is significantly higher than the resonance equipment response peak of the applicable Fermi 2 floor response spectrum.

The HPCI pump is also analyzed, but because of its rigidity, the analysis of deflections is limited to alignment with the driver.

The functional ability of active pumps after a seismic condition is ensured, since only normal operating loads and steady-state nozzle loads exist. Since it is demonstrated that the pumps would not be damaged during the faulted condition, the postseismic-condition operating loads will be no worse than the normal plant operating limits. This is ensured by requiring that the imposed nozzle loads (steady-state loads) for normal conditions and postseismic conditions are limited by the magnitudes of the normal condition nozzle loads.

3.9 MECHANICAL SYSTEMS AND COMPONENTS

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15. MEB Position - Class I Valve Operability Assurance Program, USAEC, May 24, 1973.
16. MEB Position - Class 2 and 3 Valve Operability Assurance Program, USAEC, May 24, 1973.
17. MEB Position - Class 1 Pump Operability Assurance Program, USAEC, May 24, 1973.

3.9 MECHANICAL SYSTEMS AND COMPONENTS

REFERENCES

18. MEB Position - Class 2 and 3 Pump Operability Assurance Program, USAEC, May 24, 1973.

19. FP FERM 310, Fermi FP4-FERM-BUILD (1501462).

20. DC-6003 Vol I, “Evaluation of New ECCS Suction Strainers on Existing TAP Analysis”.

TABLE 3.9-1 VIBRATION AND DYNAMIC EFFECTS TEST PROGRAM SYSTEMS TEST LEVEL MATRIX

	System	Code Class (Note a)	Test Levels (Note b) Type A	Type B	Type C	Type D
1.0	Nuclear boiler system					
1.1	Selected main steam SRV discharge piping	III-3	--	X	C.2	--
1.2	Main steam piping from reactor to primary containment outboard isolation valves	B31.7-1	--	X	C.1, C.3	--
1.3	Feedwater piping within outermost isolation valves	III-1	--	X	C.1	--
2.0	Reactor recirculation system					
2.1	Piping	B31.7-1	--	X	C.1, C.3	X
3.0	CRD hydraulic system					
3.1	Scram discharge volume and header	III-2	A.1	--	--	--
3.2	Insert and withdraw lines	III-2	A.1	--	--	--
3.3	Water supply piping	B31.1.0	A.1	--	--	--
4.0	Standby liquid control system					
4.1	Piping within isolation valves	III-1	A.1	--	--	--
4.2	Pump discharge piping beyond isolation valves	III-3	A.1	--	--	--
4.3	Pump suction piping	III-3	A.1	--	--	--
5.0	Residual heat removal system					
5.1	Other piping within outermost isolation valves	III-1	A.1	X	--	--
5.2	Piping beyond outermost isolation valves	III-2	A.1	X	--	X
6.0	Core spray system					
6.1	Piping within outermost isolation valves	III-1	A.1	X	--	--
6.2	Piping beyond outermost isolation valves	III-2	A.1	--	--	X
7.0	High-pressure coolant injection system					
7.1	Turbine steam supply piping within outermost isolation valves	III-1	--	X	C.1	--
7.2	Turbine steam supply beyond outermost isolation valve and exhaust piping	III-2	A.2	X	--	X
7.3	Suction line from condensate storage tank	III-2	A.2	--	--	--
7.4	Return line to condensate storage tank	B31.1.0	A.2	--	--	--
7.5	HPCI pump discharge piping	III-2	A.2	--	C.3	X
8.0	Reactor core isolation cooling system					

TABLE 3.9-1 VIBRATION AND DYNAMIC EFFECTS TEST PROGRAM SYSTEMS TEST LEVEL MATRIX

	System	Code Class (Note a)	Test Levels (Note b) Type A	Type B	Type C	Type D
8.1	Turbine steam supply piping within outermost isolation valves	III-1	--	X	C.1	--
8.2	Turbine steam supply beyond outermost isolation valve and discharge piping	III-2	A.2	X	--	X
8.3	Suppression pool suction and pump discharge piping	III-2	A.2	--	--	X
8.4	Suction line from condensate storage tank	III-2	A.2	--	--	--
8.5	Return line to condensate storage tank	B31.1.0	A.2	--	--	--
9.0	Reactor water cleanup system					
9.1	Piping within outermost isolation valves	III-1	A.1	X	--	--
9.2	Piping from containment penetration to the heat exchangers	B31.1.0	A.1	X	--	--
10.0	Fuel pool cooling and cleanup system					
10.1	Cooling loop piping	III-3	A.1	--	--	--
11.0	RHR service water system			--	--	--
11.1	Piping	III-3	A.1			
12.0	Plant service and cooling water systems					
12.1	Emergency equipment cooling water system	III-3 (Note c)	A.1	--	--	--
12.2	Emergency equipment service water system	III-3	A.1	--	--	--
13.0	Emergency diesel generator systems					
13.1	Fuel oil system piping	III-3	A.1	--	--	--
13.2	Service water system piping	III-3	A.1	--	--	--
14.0	Power conversion system					
14.1	Main steam piping from outboard MSIV to turbine stop valve	B31.1.0	--	X	C.1, C.4	--
14.2	Main steam piping to RFP turbine	B31.1.0	A.2	X	--	--
14.3	Main steam dump line	B31.1.0	A.2	X	--	--
14.4	Feedwater piping from reactor feed pumps to outboard isolation valves	B31.1.0	A.2	X	C.3	--
14.5	Main steam drains	B31.1.0	A.2	X	--	--
15.0	Radwaste system					

TABLE 3.9-1 VIBRATION AND DYNAMIC EFFECTS TEST PROGRAM SYSTEMS TEST LEVEL MATRIX

	System	Code Class (Note a)	Test Levels (Note b)			
			Type A	Type B	Type C	Type D
15.1	Drywell and reactor building sump pumps discharge piping	III-2, B31.1.0	A.1	--	--	--
16.0	Offgas system					
16.1	Piping	B31.1.0	A.1	--	--	--
17.0	Control air system					
17.1	Piping	III-3	A.1	--	--	--
18.0	Control center air conditioning system					
18.1	Condenser piping	III-3	A.1	--	--	--
18.2	Chilled water piping	B31.1.0	A.1	--	--	--

NOTES:

a. System Code Class

Notations for principal construction codes are

III-1, 2, 3 - ASME Boiler and Pressure Code Section III, Class 1, 2, or 3

B31.7-1 - ANSI Nuclear Power Piping Code Class I

B31.1.0 - ANSI B31.1.0 Standard Code for Pressure Piping, Power Piping.

b. Levels of Testing - The designations in this table refer to the following specific paragraphs:

Type A: Visual Monitoring – The vibration surveys conducted will visually monitor deflections of selected points. Acceptable vibratory response of the overall system will be verified also. The vibration testing will be performed during:

A.1 – Preoperational test phase

A.2 – Startup test phase

Type B: Thermal Expansion

X – Observation or recording of the thermal expansion movements of key points on the piping will be made during startup test phase. Testing will be conducted during both heatup and cooldown phases of system operation.

c. That portion of EECWS piping between the outboard isolation valves and components inside primary containment is ASME Section III, Class 2.

Type C: Vibration Measurement - Acceptable overall vibratory response of the system will be verified. The vibration surveys conducted will entail the following:

TABLE 3.9-1 VIBRATION AND DYNAMIC EFFECTS TEST PROGRAM SYSTEMS TEST LEVEL MATRIX

C.1 – Steady-state vibration measurement, using mechanical devices, of maximum deflection at selected points during the startup test phase

C.2 – Measurement, using mechanical devices and remote recording devices, of vibration and deflection at selected main steam SRV discharge line

C.3 – Measurement of the piping system vibration and structural deflection, and piping system transient pressure levels and forces at selected points on the piping system, will be conducted during startup test phase transient tests

C.4 – Measurement of the piping system transient vibration and structural deflection and piping system transient pressure levels and forces at selected points on the piping system will be conducted during an inadvertent turbine trip after the startup test program is completed.

Type D: Rotating Equipment Vibration Testing

X – Baseline vibration data will be obtained for the rotating equipment associated with this piping. See Subsection 3.9.1.1.2 for an inclusive list of the rotating equipment that will be tested.

TABLE 3.9-2 ACOUSTIC LOADING ON REACTOR PRESSURE VESSEL SHROUD

Time (msec)	Acoustic Load (Kips)
0	0
1.2	0
1.6	150
2.0	320
2.5	650
2.8	250
3.0	100
3.2	0

TABLE 3.9-3 JET LOAD FORCE DATA

Characteristics	Measurements
Effective clearance (in.)	1.000
Pipe bending strain limit (in./in.)	0.08207
Impact velocity (fps)	15.42
Number of bars composing the restraint	2
Force on restraint in direction of thrust (lb)	765,924
Total energy absorbed by the restraint (ft-lb)	266,301
Energy absorbed by the top hinge (ft-lb)	0
Length from restraint to break (ft)	4.020
Pipe rotation stability limit (deg.)	7.0530
Deflection of structure in direction of thrust (in.)	0.7659
Force on structure in direction of thrust (lb)	765,924
Energy absorbed by the structure (ft-lb)	24,443
Restraint load (peak) components (lb)	
PD1	765,924
PD2	0
Restraint loading direction (deg.)	0
Maximum allowable bending moment (ft-lb)	1,943,235
Impact time (sec)	0.0098
Deflection of restraint in direction of thrust (in.)	5.1548
Time at peak dynamic load (sec)	0.0559
Energy absorbed by the bottom hinge (ft-lb)	10,195

TABLE 3.9-3 JET LOAD FORCE DATA

Restraint load (static) components (lb)	
PS1	200,266
PS2	0
Relative deflection of pipe end in the direction of the thrust (in.)	3.8487
Deflection time for pipe end after impact (sec)	0.0330
Energy absorbed by the restraint hinge (ft-lb)	158,535
Pipe deflection at restraint components (in.)	
XR1	6.9207
XR2	0
Total deflection of the pipe end in the direction of thrust (in.)	11.5563
Total time of movement (sec)	0.0559
Total absorbed energy (ft-lb)	459,474
Pipe deflection at the break components (in.)	
XP1	11.5563
XP2	0

TABLE 3.9-4 JET LOAD FORCES USED FOR RECIRCULATION SUCTION LINE BREAK ANALYSIS[a]

Time (sec)	Pipe Displacement at Restraint (in.)	Pipe Velocity at Restraint (fps)	Pipe Acceleration at Restraint (fps)	Relative Displacement of End (in.)	Total Displacement of End (in.)	Restraint Load Component PD1 (lb)	Restraint Load Component PD2 (lb)	Blowdown Force (lb)
0.00255	0.1000	5.102	1,458.	0	0.1114	0	0	476,820
0.00390	0.2000	7.050	1,437.	0	0.2227	0	0	476,820
0.00496	0.3000	8.564	1,428.	0	0.3341	0	0	476,820
0.00586	0.4000	9.845	1,423.	0	0.4455	0	0	476,820
0.00665	0.5000	10.98	1,419.	0	0.5569	0	0	476,820
0.00737	0.6000	12.00	1,416.	0	0.6682	0	0	476,820
0.00804	0.7000	12.94	1,414.	0	0.7796	0	0	476,820
0.00866	0.8000	13.82	1,412.	0	0.8910	0	0	476,820
0.00924	0.9000	14.64	1,410.	0	1.002	0	0	476,820
0.00980	1.000	15.42	1,409.	0	1.114	0	0	476,820
0.01080	1.184	15.24	-243.1	0.02330	1.342	151,025	0	476,820
0.01180	1.365	14.87	-427.8	0.08668	1.607	277,941	0	476,820
0.01280	1.541	14.43	-424.8	0.1848	1.900	346,631	0	476,820
0.01380	1.711	14.03	-372.2	0.3101	2.216	393,033	0	476,820
0.01480	1.878	13.70	-306.9	0.4583	2.550	427,999	0	476,820
0.01580	2.040	13.43	-242.3	0.6238	2.896	456,146	0	476,820
0.01680	2.200	13.22	-183.9	0.8021	3.252	479,808	0	476,820
0.01780	2.358	13.06	-133.5	0.9891	2.615	500,312	0	476,820
0.01880	2.514	12.95	-917.4	1.182	3.981	518,484	0	476,820
0.01980	2.669	12.88	-585.5	1.376	4.349	534,865	0	476,820
0.02080	2.823	12.84	-334.1	1.571	4.715	549,830	0	476,820
0.02180	2.977	12.81	-156.6	1.764	5.079	563,644	0	476,820
0.02280	3.131	12.80	-4.582	1.952	5.439	576,503	0	476,820
0.02380	3.284	12.80	-0.5496	2.135	5.793	588,552	0	476,820
0.02480	3.438	12.80	-0.4494	2.311	6.140	599,902	0	476,820
0.02580	3.592	12.80	-4.203	2.480	6.480	610,637	0	476,820
0.02680	3.745	12.79	-12.78	2.640	6.811	620,826	0	476,820
0.02780	3.899	12.77	-24.71	2.790	7.132	630,521	0	476,820
0.02880	4.052	12.74	-39.46	2.932	7.444	639,763	0	476,820
0.02980	4.204	12.69	-56.57	3.063	7.745	648,587	0	476,820
0.03080	4.356	12.63	-75.60	3.184	8.035	657,020	0	476,820
0.03180	4.507	12.54	-96.20	3.294	8.314	665,086	0	476,820

TABLE 3.9-4 JET LOAD FORCES USED FOR RECIRCULATION SUCTION LINE BREAK ANALYSIS[a]

Time (sec)	Pipe Displacement at Restraint (in.)	Pipe Velocity at Restraint (fps)	Pipe Acceleration at Restraint (fps)	Relative Displacement of End (in.)	Total Displacement of End (in.)	Restraint Load Component PD1 (lb)	Restraint Load Component PD2 (lb)	Blowdown Force (lb)
0.03280	4.657	12.43	-118.0	3.394	8.581	672,804	0	476,820
0.03380	4.805	12.30	-140.8	3.484	8.836	680,188	0	476,820
0.03480	4.952	12.15	-164.3	3.563	9.079	687,253	0	476,820
0.03580	5.097	11.97	-188.2	3.633	9.309	694,010	0	476,820
0.03680	5.239	11.77	-212.5	3.692	9.527	700,468	0	476,820
0.03780	5.379	11.54	-236.9	3.741	9.732	706,636	0	476,820
0.03880	5.516	11.29	-261.4	3.781	9.924	712,521	0	476,820
0.03980	5.650	11.02	-285.8	3.811	10.10	718,130	0	476,820
0.04080	5.780	10.72	-310.0	3.832	10.27	723,467	0	476,820
0.04180	5.907	10.39	-334.0	3.845	10.42	728,538	0	476,820
0.04280	6.030	10.05	-357.8	3.849	10.56	733,346	0	476,820
0.04688	6.454	7.501	-638.7	3.849	11.04	748,107	0	476,820
0.05403	6.878	2.924	-615.0	3.849	11.51	763,044	0	476,820

[a] Except for the restraint load components PD1 and PD2, all variables are in a direction parallel to the blowdown force.

TABLE 3.9-5 FERMI 2 MAXIMUM MEMBER FORCES DUE TO ANNULUS PRESSURIZATION

Component Description	Element Number[c]	28 Inch Recirculation	12 Inch Recirculation[d]	Feedwater	Jet Reaction
Top guide[a]	1	22.58	16.06	24.00	30.98
Core plate[a]	6	24.15	13.97	22.20	36.86
Fuel assembly[a]	7	14.49	61.00	47.00	20.48
Fuel assembly[b]	7	0.56	2.31	1.78	0.78
CRD housing[a]	59	15.68	16.51	9.23	21.32
CRD housing[b]	59	0.74	0.45	0.37	0.93
Shroud[a]	18	81.17	98.48	52.90	89.15
Shroud[b]	18	10.27	13.68	6.80	15.12
Shroud support[a]	27	140.01	255.90	183.90	340.20
Shroud support[a]	27	21.95	17.84	27.40	13.86
Vessel skirt[a]	52	737.52	1867.00	1467.40	1303.47
Vessel skirt[b]	52	98.60	203.90	283.50	124.53
Pedestal containment[a]	55	2213.30	1196.00	792.00	1382.43
Pedestal containment[b]	55	588.42	326.80	422.60	312.69
Stabilizer[a]	II	728.04	1171.54	1877.10	694.47
CRD restraint beam[a]	V	25.30	23.70	16.50	74.97

Notes:

(a) Load = 10^3 x lb.

(b) Moment = 10^6 x in-lb.

(c) Refer to Figure 3.9-3

(d) Combine pressure and jet load from 12” recirculation line break

TABLE 3.9-6 FERMI 2 MAXIMUM ACCELERATION DUE TO ANNULUS PRESSURIZATION (in./sec^2)

Component Description	Node Number[a]	28 Inch Recirculation	12 Inch Recirculation[b]	Feedwater	Jet Reaction
ΔP line	8	99.12	153.85	101.60	214.52
CRD guide tube	13	70.25	341.33	234.20	90.62
Feedwater sparger	43	157.29	262.29	179.80	192.89
Jet pump	45	165.90	249.95	169.80	220.61
RPV	51	97.02	181.21	120.20	271.43
RPV	55	149.10	135.13	79.30	257.57
RPV (bottom)	18	162.12	131.38	71.50	259.04
Shield Wall	63	363.09	1093.00	262.40	547.89
Top of shield wall	64	92.82	194.09	64.30	110.67

NOTES:

(a) Refer to Figure 3.9-3 for node number.

(b) Combine pressure and jet load from 12” recirculation line break.

TABLE 3.9-7 RPV INTERNALS ANALYSIS SUMMARY

	Stress (ksi)	
	Calculated	Allowable
Core support weld	11.414	20.28
Shroud buckling	4.82	12.497
Top guide	12.30	20.28
Jet pump	53.38	60.84
Head spray nozzle[b]	18.73	63.0
Core ΔP line	42.82	50.70
Fuel assembly (acceleration)	1.04g	3.12g[a]

[a] This is the design-basis acceleration rather than the allowable limit.

[b] Head spray piping is no longer attached to the reactor pressure vessel. Calculated stress value in this table is conservative.

TABLE 3.9-8 RPV EQUIPMENT ANALYSIS SUMMARY

Component		Stress (ksi) Calculated[a]	Allowable
RPV support (ring girder)	tension	94.0	125.0
	shear	18.01	33.4
RPV stabilizer	bending	21.16	36.0
	shear	6.3	21.5
CRD housing		13.15	20.0
Control rod guide tube		5.7	25.4

[a] The stress reported here is the highest of the dynamic load evaluation or the original design basis.

TABLE 3.9-9 RPV SUPPORT EQUIPMENT ANALYSIS SUMMARY

	Design	Calculated	Allowable
Shroud support (primary local plus bending)	16.2 ksi	53.9 ksi	55.9 ksi
Vessel skirt	23.6 ksi	14.5 ksi	a
Vessel stabilizer bracket	45.6 ksi	<45.6 ksi[b]	63.45 ksi

[a] Not calculated because the original design load produces a stress that is lower than the emergency allowable (28.7 ksi).

[b] Actual stress was not calculated because the calculated new load is lower than the original design load.

TABLE 3.9-10 RESULTS FOR REACTOR PRESSURE VESSEL AND INTERNALS

Shroud Support Gusseted Plate and Cylinder[a,b]

Criteria	Loading	Primary Stress Type	Allowable Stress (psi)	Calculated Stress (psi)
ASME B&PV Code Sec. III Primary Stress Limit for SB-168:				
For design condition: S_m = 23,300 psi 1.5 S_m = 35,000 psi	Design mechanical loads ≥ following: Normal and upset condition load 1. Dead weight 2. Design earthquake (operating-basis earthquake) 3. Design pressure differential	General membrane $P_L + P_B$	23,300 35,000	2900 23,500
For emergency condition: 1.2 S_m= 28,000 psi	Emergency-condition loads 1. Dead weight 2. Maximum credible earthquake (design-basis earthquake) 3. Normal pressure differential	General membrane $P_L + P_B$	28,000 42,100	4300 33,900
For faulted condition:[c]	Faulted-condition loads 1. Dead weight 2. Maximum credible earthquake 3. Pressure drop across core support plate due to LOCA blowdown	General membrane	c	4800[b] 39,600[b]

TABLE 3.9-10 RESULTS FOR REACTOR PRESSURE VESSEL AND INTERNALS

Vessel Support Skirt

Criteria	Loading	Primary Stress Type	Allowable Stress (psi)	Calculated Stress (psi)
ASME B&PVC Code Sec. III Primary Stress Limit for SA-516 Grade 70:				
For design condition: S_m = 19,150 psi	Design mechanical loads ≥ following: Normal- and upset-condition loads 1. Dead weight 2. Design earthquake (operating-basis earthquake)	General membrane	19,150	12,500
For emergency condition: S_y = 30,750 psi	Emergency-condition loads 1. Dead weight 2. Maximum credible earth- quake (design-basis earthquake)	General membrane	30,750	20,900
For faulted condition[c]	Faulted condition loads 1. Dead weight 2. Maximum credible earthquake 3. Jet reaction forces	General membrane	c	23,700[c]

TABLE 3.9-10 RESULTS FOR REACTOR PRESSURE VESSEL AND INTERNALS

Stabilizer Bracket-Adjacent Shell

Criteria	Loading	Primary Stress Type	Allowable Stress (psi)	Calculated Stress (psi)
ASME B&PV Code Sec. III Primary Local Membrane Plus Primary Bending Limit for SA-533 Grade B, Class I:				
For design condition: S_m = 26,700 1.5 x 26,700 = 40,050	Normal and upset condition load	General membrane Local membrane plus bending	26,700 40,050	26,500 28,400
	1. Design earthquake (operating-basis earthquake) 2. Design pressure			
For emergency condition: S_y = 42,600 1.5 S_y = 64,000	Emergency condition load	General membrane Local membrane plus bending	42,600 64,000	28,600 46,000
	1. Maximum credible earthquake (design earthquake) 2. Design pressure			
For faulted condition[c]:	Faulted-condition load	Local membrane plus bending	c c	26,500[c] 24,600[c]
	1. Maximum credible earthquake (design-basis earthquake) 2. Jet reaction forces 3. Design pressure			

[a] Gusseted support plate segments are sufficiently stiff that stability (buckling) would not be a predicted failure mode with increasing overturning (seismic) moment.

[b] Symbols are as defined in the ASME B&PV Code.

[c] Since the calculated stress for the faulted condition is less than the allowable stress for the emergency condition, and the allowable stress for the faulted condition is greater than the allowable stress for the emergency condition, the faulted allowable was not calculated.

TABLE 3.9-11 ACCELERATION (g) FOR FUEL ASSEMBLY

Node*	PR	JR	SSE	$(PR^2 + SSE^2 + JR^2)^{1/2}$	Design Basis
1 (top)	0.39	0.46	0.44	0.75	1.30
3	0.33	0.38	0.50	0.71	1.90
4	0.23	0.32	0.70	0.80	2.70
5	0.37	0.21	0.78	0.89	3.12
6	0.22	0.37	0.67	0.80	2.54
7	0.42	0.57	0.58	0.92	1.68
8	0.42	0.86	0.46	1.06	1.08

* See Figure 3.9-3.

TABLE 3.9-12 FUEL ASSEMBLY (INCLUDING CHANNEL)[a]

Acceptance Criteria	Loading	Primary Load Type	Calculated Peak Acceleration	Evaluation Basis Acceleration
Acceleration envelope	Horizontal direction	Horizontal acceleration profile	1.5 g	b
	1. Peak pressure 2. Safe-shutdown earthquake 3. Annulus pressurization			
	Vertical direction	Vertical accelerations	1.4 g	b
	1. Peak pressure 2. Safe-shutdown earthquake 3. Annulus pressurization			

[a] From an assessment comparing bounding limits (net holddown forces) to those for other BWR-4 plants already analyzed, a screening calculation was performed for Fermi 2. According to this analysis, Fermi 2 would experience virtually no fuel movement.

[b] Evaluation-basis accelerations and evaluations are contained in NPDE-21175-3-P.

TABLE 3.9-13 REACTOR PRESSURE VESSEL SUPPORT EQUIPMENT

Criteria	Loading	Location	Allowable Stress (psi)	Calculated Stress (psi)
RPV stabilizer Primary stress limit				
AISC specification for the construction, fabrication, and erection of structural steel for buildings	Upset condition 1. Spring preload 2. Operating-basis earthquake	Rod	90,000	f_{b+t} = 82,000[a]
		Bracket	22,000 14,000	f_b = 9200 f_v = 2730
For normal and upset conditions AISC allowable stresses, but without the usual increase for earthquake loads				
For emergency conditions 1.5 x AISC allowable stresses	Emergency condition 1. Spring preload 2. Design-basis earthquake	Bracket	33,000 21,000	f_b = 18,400 f_v = 5460
For faulted conditions Material yield strength	Faulted condition 1. Spring preload 2. Design-basis earthquake 3. Jet reaction load	Bracket	36,000 21,500	f_b = 21,160 f_v = 6300
RPV support (ring girder) Primary stress limit				
AISC specification for the design, fabrication, and erection of structural steel for buildings	Normal and upset condition 1. Dead loads 2. Operating-basis earthquake 3. Loads due to scram	Top flange	22,000	f_b = 10,000
		Bottom flange	22,000	f_b = 10,000
		Vessel to girder bolts	54,000 20,000	f_t = 35,200 f_v = 4450
For normal and upset conditions AISC allowable stresses, but without the usual increase for earthquake loads				
For emergency conditions 1.5 x AISC allowable stresses	Emergency condition 1. Dead loads 2. Design-basis earthquake 3. Loads due to scram	Top flange	33,000	f_b = 22,000
		Bottom flange	33,000	f_b = 20,000
		Vessel to girder bolts	81,000 30,000	f_t = 70,400 f_v = 8900
For faulted conditions 1.67 x AISC allowable stresses for structural steel members. Yield strength bolts (vessel to ring girder)	Faulted condition 1. Dead loads 2. Design-basis earthquake 3. Jet reaction load	Top flange	36,800	f_b = 28,000
		Bottom flange	36,800	f_b = 23,400
		Vessel to girder bolts	125,000 33,400	f_t = 94,000 f_v = 18,010

TABLE 3.9-13 REACTOR PRESSURE VESSEL SUPPORT EQUIPMENT

Criteria	Loading	Location	Allowable Stress (psi)	Calculated Stress (psi)
CRD housing support Primary stress limit				
AISC specification for the design, fabrication, and erection of structural steel for buildings	Faulted condition loads	Beams (top cord)	33,000 33,000	f_a = 12,200 f_b = 16,500
	1. Dead weight	Beams (bottom cord)	33,000 33,000	f_a = 10,300 f_b = 11,700
	2. Impact force from failure of a CRD housing	Grid structure	41,500 27,500	f_b = 40,700 f_v = 12,500
For normal and upset conditions $f_a = 0.60\ f_y$ (tension) $f_b = 0.60\ f_y$ (bending) $f_v = 0.40\ f_y$ (shear) For faulted conditions f_a limit = 1.5 f_a (tension) f_b limit = 1.5 f_b (bending) f_v limit = 1.5 f_v (shear) f_y = Material yield strength	(Dead weights and earthquake loads are very small as compared to jet force)			

[a] The ratio max. stress/stress limit is highest for upset loading conditions.

TABLE 3.9-14 REACTOR PRESSURE VESSEL INTERNALS AND ASSOCIATED EQUIPMENT

Criteria	Loading	Primary Stress Type	Allowable Stress (psi)	Calculated Stress (psi)
Top guide - highest stressed beam				
Primary stress limit - The allowable primary membrane stress plus bending stress is based on ASME B&PV Code Sec. III for type 304 stainless steel plate				
For normal and upset condition Stress Intensity SA = 1.5 S_m = 1.5 x 16,900 psi = 25,350 psi	Normal and upset - condition loads 1. Operating-basis earthquake 2. Weight of structure	General membrane plus bending	25,350	12,820
For emergency condition: S_{limit} = 1.5 S_A = 1.5 x 25,350 = 38,025 psi	Emergency condition loads 1. Design-basis earthquake 2. Weight of structure	General membrane plus bending	38,025	12,220
For faulted condition: S_{limit} = 2 S_A = 2 x 25,350 = 50,700 psi	Faulted-condition loads (same as emergency condition)	General membrane plus bending	50,700	20,250
Top guide beam end connections				
Primary stress limit - ASME B&PV Code Sec. III, defines material stress limit for type 304 stainless steel				
For normal and upset condition Stress Intensity S_A = 0.6 S_m = 0.6 x 16,900 psi = 10,140 psi	Normal and upset-condition loads 1. Operating-basis earthquake 2. Weight of structure	Pure shear	10,140	4,500
For emergency condition: S_{limit} = 1.5 S_A = 1.5 x 10,140 psi = 15,210 psi	Emergency-condition loads 1. Design-basis earthquake 2. Weight of structure	Pure shear	15,210	4,400
For faulted condition: S_{limit} = 2 S_A = 2 x 10,140 psi = 20,280 psi	Faulted-condition loads (same as emergency condition)	Pure shear	20,280	12,300

TABLE 3.9-14 REACTOR PRESSURE VESSEL INTERNALS AND ASSOCIATED EQUIPMENT

Criteria	Loading	Primary Stress Type	Allowable Stress (psi)	Calculated Stress (psi)
Top guide aligners				
Primary stress limit - The allowable primary membrane stress plus bending stress is based on ASME B&PV Code Sec. III for type 304 stainless steel plate				
For normal and upset condition Stress Intensity $S_A = 1.5\ S_m = 1.5 \times 16{,}900$ psi = 25,350 psi	Normal and upset-condition loads 1. Operating-basis earthquake 2. Weight of structure	General membrane plus bending	25,350	0[a]
For emergency condition: $S_{limit} = 1.5\ S_A = 1.5 \times 25{,}350 = 38{,}025$	Emergency-condition loads 1. Design-basis earthquake 2. Weight of structure	General membrane plus bending	38,025	0[a]
For faulted condition: $S_{limit} = 2\ S_A = 2 \times 25{,}350 = 50{,}700$ psi	Faulted-condition loads (same as emergency condition)	General membrane plus bending	50,700	0[a]
Core support			Allowable ΔP	Calculated ΔP
	Normal and upset-condition loads 1. Normal operation pressure drop 2. Operating-basis earthquake		27	18.9
For allowable stresses see top guide, longest beam, above	Emergency condition loads 1. Normal operation pressure drop 2. Design-basis earthquake		40.5	20.6

TABLE 3.9-14 REACTOR PRESSURE VESSEL INTERNALS AND ASSOCIATED EQUIPMENT

Criteria	Loading	Primary Stress Type	Allowable Stress (psi)	Calculated Stress (psi)
	Faulted-condition loads 1. Pressure drop after recirculation line rupture 2. Design-basis earthquake		54	27.7
Core support aligners				
Primary stress limit - ASME B&PV Code Sec. III, defines material stress limit for type 304 stainless steel	Normal and upset-condition loads 1. Operating-basis earthquake 2. Normal operation pressure drop	Pure Shear	10,155	0[b]
For allowable shear stresses, see top guide beam end connections, above	Emergency condition load 1. Design-basis earthquake 2. Normal operation pressure drop	Pure shear	15,232	0[b]
	Faulted condition load 1. Design-basis earthquake 2. Steam line rupture	Pure Shear	20,310	0[b]
Control rod drive housing				
Primary stress limit - The allowable primary membrane stress is based on ASME B&PV Code Sec. III, for Class I vessels, for type 304 stainless steel	Normal and upset-condition loads 1. Design pressure 2. Stuck rod scram loads 3. Operating-basis earthquake with housing lateral support installed	Maximum membrane stress intensity occurs at the tube-to-tube weld near the center of the housing for normal, upset and emergency conditions	16,660	13,150
For normal and upset condition S_m = 16,600 psi at 575°F				

TABLE 3.9-14 REACTOR PRESSURE VESSEL INTERNALS AND ASSOCIATED EQUIPMENT

Criteria	Loading	Primary Stress Type	Allowable Stress (psi)	Calculated Stress (psi)
For emergency conditions: S_{limit} = 1.2 S_m = 1.2 x 16,660 = 20,000 psi	Emergency condition loads 1. Design pressure 2. Stuck rod scram loads 3. Design-basis earthquake, with support installed		20,000	13,150
Control rod drive Primary stress limit - The allowable primary membrane stress plus bending stress is based on ASME B&PV Code	Normal and upset condition loads. Maximum hydraulic pressure from the control rod drive supply pump[c]	Maximum stress intensity occurs at a point on the Y-Y axis of the indicator tube	25,860	20,790
For normal and upset condition S_A = 1.5 S_m = 1.5 x 17,238 = 25,860 psi				
Control rod guide tube Primary stress limit- The allowable primary membrane stress plus bending stress is based on ASME B&PV Code Sec. III for type 304 stainless steel tubing				
For normal and upset conditions S_m = 16,925 psi				
For faulted condition: S_{limit} = 1.5 S_m = 1.5 x 16,295 = 25,400 psi	Faulted condition loads 1. Dead weight 2. Pressure drop across guide tube due to failure of steam line	The maximum bending stress under faulted loading conditions occurs at the center of the guide tube	25,400	5,701
In-core housing Primary stress limit- The allowable primary membrane stress is based on ASME B&PV Code Sec. III for Class 1 vessels for type 304 stainless steel				
For normal and upset conditions: S_m = 16,660 psi at 575°F				

TABLE 3.9-14 REACTOR PRESSURE VESSEL INTERNALS AND ASSOCIATED EQUIPMENT

Criteria	Loading	Primary Stress Type	Allowable Stress (psi)	Calculated Stress (psi)
For emergency condition: S_{limit} = 1.2 S_m = 1.2 x 16,600 = 20,000 psi	Emergency condition loads 1. Design pressure 2. Design-basis earthquake	Maximum membrane stress intensity occurs at the outer surface of the vessel penetration	20,000	15,290

[a] Thirty-two wedges that will resist the horizontal seismic top guide shear load are installed in the annulus between the top guide and shroud. Therefore there is no load on the top guide aligners

[b] The friction force between core support and core support flange due to the preload of the studs is greater than the shear load induced by the specified earthquake.

[c] Accident conditions do not increase this loading. Earthquake loads are negligible.

TABLE 3.9-15 INITIAL FUEL LOAD 100 MIL FUEL CHANNELS

Criteria	Loading	Primary Stress Type	Moment Limit Accounting for Pressure Loads (in.-lb)	Maximum Moment (in.-lb)
Fuel channels				
Primary stress limit – Design stress intensity S_m for zircaloy determined according to methods recommended by ASME B&PV Code Sec. III. Allowable moment determined by calculating limit moment, then applying SFmin for applicable loading conditions	Normal and upset condition load 1. Operating-basis earthquake 2. Normal pressure load	Membrane and bending	35,000	9550
(S = 9,000 psi; 1.5 S_m = 13,500 psi) (1.5 S_m = Allowable Stress)	Faulted condition load 1. Design-basis earthquake 2. Loss-of-coolant accident pressure	Membrane and bending	68,000	15,850

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TABLE 3.9-17 MAIN STEAM ISOLATION VALVES

Criteria	Method of Analysis	Allowable Stress (psi), Minimum Thickness (in.), or Minimum Area (in.^{2})	Calculated Stress (psi), Actual Thickness (in.) or Minimum Area (in.^{2})
Design of Pressure-Retaining Parts	All references are made to ASME Code for Pumps and Valves for Nuclear Power, dated November 1968. Reference the same code for explanation of the symbols used.		
Body Minimum Wall Thickness	Reference Article 452.1b(2), Nonstandard Pressure - Rated Valve, Table NB 451.4 For design condition of 1,250 psig and 575°F The primary service rating = 655 lb, based on a core diameter of 23 in. t_m= 1.925 in. (including a corrosion allowance of 0.12 in.)	1.925 in.	1.9375 in.
Body Shape Rules	Reference Article 452.2, Body Shape Rules		
Radius of Crotch	Reference Article 452.2a(1), Radius of Crotch Criterion: $r_2 > 0.3$ tm; $r_2 = 1.0$ in., $t_m = 1.925$ in., 0.3 x 1.925 = 0.578 <1.0; criterion satisfied	0.578 in.	1.0 in.
Out-of-Roundness	Reference Article 452.2e. Since no ovality was built into the valve body, the requirements of this article are satisfied.	Not applicable	Not applicable
Flat Wall Limitation	Reference Article 452.2g, Flat Wall Limitation. Since no flat sections were built into the valve body design, the requirements of this article are satisfied.	Not applicable	Not applicable
Primary Crotch Stress Due to Internal Pressure	Reference Article 452.3 Criterion: $P_m = \left(\frac{A_f}{A_m} + 0.5\right) P_s < S_m$ where $A_f = 504$ in.^{2}, $A_m = 58$ in.^{2}, $P_s = 1.375$ psig, $P_m = 12{,}650$ psi, $S_m = 19{,}400$ psi; since $S_m > P_m$, criterion satisfied	19,400 psi	12,650 psi
Valve Body Secondary Stress	Reference Article 452.4		
Primary Plus Secondary Stress Due to Internal Pressure	Reference Article 452.4a $Q_p = C_p \left(\frac{r_i}{t_e} + 0.5\right) P_s C_a$ where $C_p = 3$, $r_i = 11.625$ in., $P_s = 1{,}375$ psi, $t_e = 2.75$ in. for wye-type valve, $C_a = 1.33 \rightarrow Q_p = 25{,}965$ psi		
Secondary Stress Due to Pipe Reaction	Reference Article 452.4b, Figures 452.4b(3), 452.4b(4), 452.4b(5)		
Direct or Axial Load Effect	$P_{ed} = \frac{F_d S}{G_d}$, where S = 30,750 psi, $F_d = 30$ in.^{2}, $G_d = 183$ in.$^2 \rightarrow P_{ed} = 5{,}040$ psi	19,400 psi	5,040 psi
Bending Load Effect	$P_{eb} = C_b \frac{F_b S}{G_b}$ where S = 30,750 psi, $F_b = 340$ in.^{3}, i.d. = 23.25 in., $r_i = 11.625$ in., $t_e = 2.75$ in., $\bar{r} = 13.90$ in. as $\frac{t_e}{\bar{r}} = 0.197 > 0.19 \rightarrow C_b = 1$ $G_b = \frac{I}{r_i + t_e}$ where I = 15,028 in.^{4}, $r_i = 11.625$ in., $t_e = 2.75$ in. $\rightarrow G_b = 1{,}052$ in.$^3 \rightarrow P_{eb} = 9{,}940$ psi	19,400 psi	9,940 psi
Torsion Load Effect	Reference Article 452.4b $P_{et} = 2\,\frac{F_b S}{G_t}$ where $F_b = 340$ in.^{3}, S = 30,750 psi, $G_t = 2{,}162$ in.^{3}, $P_{et} = 9{,}670$ psi	19,400 psi	9,670 psi

TABLE 3.9-17 MAIN STEAM ISOLATION VALVES

Criteria	Method of Analysis	Allowable Stress (psi), Minimum Thickness (in.), or Minimum Area (in.^{2})	Calculated Stress (psi), Actual Thickness (in.) or Minimum Area (in.^{2})
Thermal Secondary Stress at Crotch Region	Reference Article 452.4C, Figures 452.4C(4), 452.4C(3), 452.4C(5) $Q_T = Q_{T_1} + Q_{T_2}$ where $T_{e_1} = 3$ in., $Q_{T_1} = 1{,}100$ psi, $Q_{T_2} = C_6C_2\Delta T_2$ where $C_2 = 0.21$, $C_6 = 220$, and $\Delta T_2 = 5.6$ $Q_{T_2} = 260$ psi, $Q_T = 1{,}360$ psi Criterion: $S_N = Q_p + P_e = 2\ Q_{T_2} \leq 3\ S_m$ where $Q_p = 25{,}965$, $P_e = 9{,}940$, $Q_T = 1{,}360$ as $38{,}625 \leq 58{,}200$, criterion satisfied	58,200 psi	38,625 psi
Normal Duty Valve Fatigue Requirements	Reference Article 452.5, Figure 452.5(a) Criterion $N_a \geq 2{,}000$ cycles. $S_{p_1} = \frac{2}{3}\ Q_p + \frac{P_{eb}}{2} + Q_{T_2} + 1.3Q_{T_1}, Q_{T_1} = 1{,}100$ psi $S_{P_2} = 0.4Q_p + \frac{K}{2}\ (P_{eb} + 2Q_{T_2})$ where $Q_p = 25{,}965$, $P_{eb} = 9{,}940$, $Q_{T_1} = 1{,}160$, $Q_{T_2} = 260$ psi, $K = 2 \rightarrow S_{p_1} = 23{,}970$ psi, $S_{P_2} = 20{,}845$ psi, S_a equal to the larger of S_{p_1} and $S_{P_2} \rightarrow S_a = 23{,}970$ psi $\rightarrow N_a = 55{,}000 \pm 2{,}000$, criterion satisfied	2,000 cycles	55,000 cycles
Cyclic Loading Requirements at Valve Crotch	Reference Article 454 Thermal Transients Not Excluded by Code Criterion: $\sum \frac{N_{ri}}{N_i} < 1$ Calculate the fatigue usage factor (I_t) as follows: $S_n\ \mathrm{Max} = Q_p + P_{eb} + C_6(C_3 + C_4)\Delta T_f\ \mathrm{max}$ $S_n \mathrm{max} = 105{,}810$ psi for $\Delta T_{fi} = 90$, $N_{ri} = 120$, $N_i = 2{,}700$ $\frac{N_{ri}}{N_i} = 0.044$ $\Delta T_{fi} = 122$, $N_{ri} = 10$, $N_i = 1{,}600$ $\frac{N_{ri}}{N_i} = 0.006$ $\Delta T_{fi} = 342$, $N_{ri} = 8$, $N_i = 42$ $\frac{N_{ri}}{N_i} = 0.19$ as $I_t = \sum \frac{N_{ri}}{N_i} = 0.240 < 1$, criterion satisfied	1	0.240[a]
Disk Design Calculation	From Roark's Formulas for Stress and Strain, third addition Disk design conditions, $P_s = 1{,}250$ psi at 575°F, $S_m = 17{,}800$ psi at 600°F Case No. 13: $S_t = \frac{3W}{4mt^2\,(a^2 - b^2)}\ [a^4\ (3m + 1) + b^4\ (m - 1) - 4_m a^2b^2 - 4\ (m + 1)a^2b^2\ \left(\ln\left(\frac{a}{b}\right)\right)]$ where W = 1,250 psi, m = 10/3, $t = 5.625$ in., a = 10.75 in., b = 1.75 in., $S_{t_{13}} = 10{,}354$ psi Case No. 14: $S = \frac{3\ W}{2\pi mt^2}\left[\frac{2a^2\,(m+1)}{a^2 - b^2}\ \ln\left(\frac{a}{b}\right) + (m - 1)\right]$ where $W = 59{,}044\ lb_f$, t = 5.625 in., m = 10/3 a = 10.75 in., b = 1.75 in., $S_{t_{14}} = 4{,}943$ psi Total stress = $S_{t_{13}} + S_{t_{14}} = 15{,}297$ psi, allowable stress = 17,800 psi	17,800 psi	15,297 psi

TABLE 3.9-17 MAIN STEAM ISOLATION VALVES

Criteria	Method of Analysis	Allowable Stress (psi), Minimum Thickness (in.), or Minimum Area (in.^{2})	Calculated Stress (psi), Actual Thickness (in.) or Minimum Area (in.^{2})
	Case No. 21: $S_r = \frac{3W}{4t^2}\left[\frac{4a^4(m+1)\ln\left(\frac{a}{b}\right)a^4(m+3)+b^4(m-1)+4a^2b^2}{a^2(m+1)+b^2(m-1)}\right]$ where W = 1,250 psi, m = 10/3, t = 3.125 in., a = 10.75 in., b = 7.25 in. → $S_{r_{21}}$ = 5760 psi		
	Case No. 22: $Sr = \frac{3W}{2^h t^2}\left[\frac{2a^2(m+1)\ln\left(\frac{a}{b}\right)+a^2(m-1)-b^2(m-1)}{a^2(m+1)+b^2(m-1)}\right]$ where W = 1,250 psi, m = 10/3, t = 3.125 in., a = 10.75 in., b = 7.25 in. → $S_{r_{22}}$ = 10,740 psi Total stress = $S_{r_{21}}$+ $S_{r_{22}}$ = 16,500 psi, allowable stress = 17,800 psi	17,800 psi	16,500 psi
Tensile Stress at Thread Relief Valve Stem	Valve open $S_A = \frac{F}{A_t}$ where F = 31,586 lb, A_t = 1.956 in.^{2}, S_{max} = 16,148 psi Valve closed F = 46,342 lb, S_{max} = 23,692 psi	30,600 psi	23,692 psi
Bonnet Design Calculations Including Seismic Accelerations for SSE	Paragraph UG – 34c(2) of ASME Code Section VIII		
Minimum Thickness	$P_{fd} = P + P_{eg}$, $P_{eg} = \frac{16M}{\pi G^3} + \frac{4F}{\pi G^2}$ where M = 335,253 in.-lb, F = 46,342 lb, G = 24.75 in., P_{eg} = 204 psi, P_{fd} = 1,459 psi $t = d\sqrt{\frac{CP_{fd}}{S} + \frac{(1.78W)(hg)}{Sd^3}}$ where C = 0.3, P_{fd} =1,459 psi, S = 17,800 psi, hg = 2.625 in., W = 910,144 lb, d = 24.75 in. → t = 4.975 in., t = 4.975 + 0.120 = 5.095 in. (corrosion allowance is 0.120 in.)	5.095 in.	5.344 in.
Reinforcement	Reference Paragraph I-704.41(c) of USAS B31-7 To account for the opening for stem in the bonnet Required reinforcement d x t x 0.5 = (d_3t_3 + d_4t_4)/2 d_3 = 1.875, t_4 = 2.223, t_3 = 2.875, d_4 = 3 Reinforcement = 6.030 in.^{2} required 6.6126 in.^{2} available	6.030 in.^{2}	6.6126 in.^{2}
Bonnet Studs Design Calculation	Reference Article E-1000 Bolt used 20 pieces of 2.652 in.^{2}/bolts Total bolt area = 53.04 in^2		
Normal Operation	1. Pressure stress at operating condition $S_1 = \frac{W_{m1}}{A_b} =$ 17,160 psi where W_{m1}= 910,144 lb A_b = 53.04 in.^{2}	27,700 psi	17,160 psi
	2. Gasket load at ambient condition with no internal pressure $S_2 = \frac{W_{m2}}{A_b} =$ 2,019 psi where W_{m2}= 107,065 lb_f A_b = 53.04 in.^{2} Maximum tensile stress = 17,160 psi Thermal stress is assumed negligible because the coefficients of thermal expansion of bonnet place and stud are the same.	35,000 psi	2,019 psi
Longitudinal Hub Stress	$S_H = \frac{fM_o}{Lg_1{}^2 B} + \frac{PB}{4g_o}$ = 21,773 psi < 1.5 S_{fo} = 26,700 psi	26,700 psi	21,773 psi

TABLE 3.9-17 MAIN STEAM ISOLATION VALVES

Criteria	Method of Analysis	Allowable Stress (psi), Minimum Thickness (in.), or Minimum Area (in.^{2})	Calculated Stress (psi), Actual Thickness (in.) or Minimum Area (in.^{2})
Radial Stress	Reference UA-51 (1), Equation (7) of Section VIII of ASME B&PV Code, 1971 Edition $S_R = \frac{(1.33t_e + 1)M_o}{Lt^2B}$ = 12,288 psi < 1.5 S_{fo} = 26,700 psi	26,700 psi	12,288 psi
Tangential	$S_T = \left(\frac{YM_o}{t^2B}\right) - ZS_R$ = 7,117 psi < 1.5 S_{fo} = 26,700 psi where Y = 4.5, t = 4.125 in., Z = 2.4, B = 21.75 in.	26,700 psi	7,117 psi
Body Flange Design Calculations	Reference Paragraph I-704.5.1 of USAS B31-7 Total flange moment under operating conditions $M_o = M_D + M_G + M_T$ $M_D = H_D h_D$, $H_D = 0.785\ B^2P$, $h_D = R + 0.5g$, where B = 21.75 in., P = 1,459 psi → H_D = 542,080 lb_f h_D = 2.813 in., M_D = 1,524,871 in.-lb $M_G = H_G h_G$, $H_G = W_{m1} - H$, $h_G = \frac{C-G}{2}$ where W is the higher of W_{m1} and W_{m2} W_{m1} = 910,144 lb W_{m2} = 107,065 lb H_G = 208,210 lb, h_G = 2.625 in. → M_G = 546,531 in.-lb $M_T = H_T h_T$ H_T = 159,854 lb, h_T = 3.375 in., M_T = 539,507 in.-lb M_o = 2,610,929 in.-lb Total flange moment under gasket seating condition $M_o = W\frac{(C-G)}{2}$, $W = \frac{(A_m + A_b)S_a}{2}$ where C = 30 in., A_b = 53.04 in.^{2}, G = 24.75 in., A_m = 32.857 in.^{2}, S_a = 35,000 psi at 100°F → W = 1,503,193 lb → M_o = 3,010,718 in.-lb Where w = design pressure, 1250 psi m = inverse of Poisson ratio, 3.3333 t = disk thickness, 5.875 in. a = outside radius of poppet, 10.75 in. b = inside radius of pilot hole, 1.75 in. St = Maximum stress at inner edge, 9,489 psi For a plate with a hole in the center, outer edge supported and uniformly loaded along the inner edge $St = \frac{3W}{2\pi mt^2}\left[\frac{2a^2(m+1)}{a^2 - b^2}\ln\left(\frac{a}{b}\right) + (m-1)\right]$ where W = operator, spring and internal pressure acting on pilot poppet, 59,044 < B S_t = Maximum stress at inner edge, 4531 psi Total stress = $St_1 + St_2$ = 14,020 as 17,800 > 14,020 criterion satisfied	17,800	14,020
	3. Disk Flexibility Roark's Formula for stress and strain, third edition, case 21 Max. Stress $\sigma_1 = \frac{3W}{4t^2}\left[\frac{4a^4(m+1)\ln\left(\frac{a}{b}\right) - a^4(m+3) + b^4(m-1) + 4a^2b^2}{a^2(m+1) + b^2(m-1)}\right]$ Deflection $\Delta_1 = \frac{3W(m^2-1)}{16m^2{E_t}^3}\left[\begin{matrix} a^6(7m+3) + b^6(m-1) - a^4b^2(m+7) - a^2b^4(7m-5) \\ -4a^2b^2[a^2(5m-1) + b^2(m+1)]\ln\frac{a}{b} \\ \frac{-16a^4b^2(m+1)(\ln\frac{a}{b})^2}{a^2(m+1)+b^2(m-1)} \end{matrix}\right]$ where E = modulus of elasticity, 25.7 x 10^6 psi at 600°F		

TABLE 3.9-17 MAIN STEAM ISOLATION VALVES

Criteria	Method of Analysis	Allowable Stress (psi), Minimum Thickness (in.), or Minimum Area (in.^{2})	Calculated Stress (psi), Actual Thickness (in.) or Minimum Area (in.^{2})
	σ_1 = 5760 psi		
	Δ_1 = 0.00035 in.		
	Roark's Formulas for Stress and Strain, third edition, Case 22		
	$\sigma_2 = \frac{3W_2}{2\pi t^2}\left[\frac{2a^2(m+1)\ln\left(\frac{a}{b}\right)+a^2(m-1)-b^2(m-1)}{a^2(m+1)+b^2(m-1)}\right]$		
	$\Delta_2 = \frac{3W_2}{4\pi m^2Et^3}\left[a^4(3m+1)-b^4(m-1)-2a^2b^2(m+1)\frac{-8ma^2b^2\ln\left(\frac{a}{b}\right)-4a^2b^2(m+1)\left(\ln\left(\frac{a}{b}\right)\right)^2}{a^2(m+1)+b^2(m-1)}\right]$		
	where W_2 = Operator, spring, and internal pressure acting on main disc, 252,755 lb		
	σ_2 = 10,740 psi		
	Δ_2 = 0.00086 in.		
	Total stress $\sigma_2 = \sigma_1 + \sigma_2$ = 16,500 psi		
	Total deflect $\Delta_t = \Delta_1 + \Delta_2$ = 0.0012 in.		
	as 17,800 > 16,500	17,800	16,500

For the above calculation:

W_1 = total applied load, 59,044 lb for St
W_2 = total applied load, 252,755 for St_2

w = design pressure, 1250 psi
a = large disc radius, 10.75 in.
b = smaller disc radius, 7.25 in.
t = larger disk thickness, 3.125 in
m = inverse of Poisson Ratio, 3.3333
E = Young's Modulus, 25.7 x 10^6 psi at 600 °F

TABLE 3.9-17 MAIN STEAM ISOLATION VALVES

Criteria	Method of Analysis	Allowable Stress (psi) of Minimum Thickness Required	Calculated Stress, Actual Thickness
Stem Analysis	1. Valve open Tension at undercut at back seat $S = \frac{W}{A} = 15{,}230$ psi Criterion satisfied	30,600	15,230
	Where W = total open force, 31,586 lb A = cross sectional area, 2.074 in.^{2}		
	Tension at undercut at thread $S = \frac{W}{A} = 16{,}148$ psi Criterion satisfied	30,600	16,148
	Where W = total open force, 31,586 lb A = cross sectional area, 1.956 in.^{2}		
	Tension at thread at root area $S = \frac{W}{A} = 15{,}953$ psi Criterion satisfied	30,600	15,953
	Where W = total opening load, 31,586 lb A = cross sectional area, 1.98 in.^{2}		
	Stress at thread $S = \frac{W}{A} = 5561$ psi Criterion satisfied	18,360	5,561
	Where W = total opening load, 31,586 lb A = cross sectional area, 5.74 in.^{2}		
	2. Valve closed Compression at undercut at back seat $S = \frac{W}{A} = 22{,}344$ psi Criterion satisfied	30,600	22,344
	Where W = total closed load, 46,345 lb A = cross sectional area, 2.074 in.^{2}		
	Compression at undercut at thread $S = \frac{W}{A} = 23{,}692$ psi Criterion satisfied	30,600	23,682
	Where W = total closed load, 46,342 lb A = cross sectional area, 1.956 in.^{2}		
	Compression at thread root area $S = \frac{W}{A} = 23{,}405$ psi Criterion satisfied	30,600	23,405
	Where W = total closed load, 46,342 lb A = cross sectional area, 1.98 in.^{2}		
	Shear at thread $S = \frac{W}{A} = 8{,}141$ psi Criterion satisfied	18,360	8,141
	Where W = total closed load, 46,342 lb A = root area of thread, 4.75 in.^{2}		

TABLE 3.9-17 MAIN STEAM ISOLATION VALVES

Criteria	Method of Analysis	Allowable Stress (psi) of Minimum Thickness Required	Calculated Stress, Actual Thickness
Cyclic Rating	Based on Article 454 1. Instantaneous fluid temperature $\Delta T_{fo} = \frac{3Sm-Qp-Peb}{C_6(C_3-C_4)} > 150\ °F$ Where C_3 = 0.625 from Figure 454.3b C_4 = 0.0105 from Figures 454.3a and 454.4c(4) C_6 = 220 from Figure 454.3 T_{fo} = 158 °F > 150 °F Criterion satisfied 2. Fatigue stress intensity resulting in step change at 300 °F Salt = 84,140 psi N_{300} = 900 cycles at 500 °F Salt = 155,540 psi N_{500} = 170 cycles at 158 °F Salt = 40,540 psi N_{158} = 8000 cycles applied the above to Figure 454.2, these points are above the thermal cyclic rating curve and therefore qualified for cyclic rating per article 454.3. 3. Thermal cyclic index (article 454.2) $It = \sum \frac{Nri}{Ni} < 1$ Where It = cyclic rating index Nri = Required number of fluid step changes at ΔTi Ni = Permissible number of fluid step changes at ΔTi It = 0.240 < 1 Criterion satisfied		
Special Requirement with Pipe Rupture	Based on Article 452.4b Secondary stresses due to pipe reaction, crotch secondary effect due to bending load; and crotch secondary effect due to pipe torsion. Reference item 4, part 2, except in this case the stress from connecting pipe is raised to 41,000 psi Ped = 6,722psi Peb = 13,251 psi Pet = 12,896 psi These are all below 1.5 Sm = 29,100 Criterion satisfied	24,100	13,251
	Valve Body Secondary Stresses Also Sn = Q_p + Pe + $2Q_T$ Sn= 41,936 psi < 3 Sm (= 58,200) Criterion satisfied	58,200	41,936
	So even at the high pipe connection load the crotch area maximum stress is still within code allowance		

[a] See FP FERM 310 (Ref. 19) for maximum Cumulative Usage Factor values using event number of cycles based on Fermi 2 operating history.

TABLE 3.9-18 STRUCTURAL AND MECHANICAL LOADING CRITERIA

Reactor Recirculation Gate Valve, 28-In. Discharge

Component Loads Design	Design Procedure	Required Design Value	Actual Design Value
Body and Bonnet			
Loads: Design pressure, design temp., pipe reaction, thermal effects			
Pressure rating, psi	Used Tables 451.4 & 451.5 of NPVC	P_r = 799 psi	P_r = 799 psi
Minimum wall thickness, in.	Used Table 452.1 of NPVC, dm = 22	$t_m \geq 2.205$ in.	$t_m = 2.205$ min.
Primary membrane stress, psi	Used Paragraph 452.3 of NPVC	$P_m \leq S_{m(500°F)} = 19{,}600$ psi	$P_m = 9512$ psi
Secondary stress due to pipe reaction	Used Paragraph 452.4b of NPVC (S = 16,600 psi)	P_e = greatest value of P_{ed} P_{eb} and $P_{et} \leq 1.5\ S_{m(500°F)}$ 1.5 (19,600) = 29,400 psi	$P_{ed} = 5502$ psi $P_{eb} = 12{,}550$ psi $P_{et} = 12{,}080$ psi $P_e = P_{eb} = 12{,}550$ psi
Primary plus secondary stress due to internal pressure	Used Paragraph 452.4a of NPVC	$S_n \leq 3\ S_{m(500°F)} = 58{,}800$ psi	$Q_p = 24{,}255$ psi
Thermal secondary stress	Used Paragraph 452.4c of NPVC	$S_n \leq 3\ S_{m(500°F)} = 58{,}800$ psi	$Q_T = 6560$ psi
Sum of primary plus secondary stress	Used Paragraph 452.4 of NPVC	$S_n \leq 3\ S_{m(500°F)} = 58{,}800$ psi	$S_n = Q_p + P_e + 2Q_T$ $S_n = 49{,}925$psi
Fatigue requirements	Used Paragraph 452.4 of NPVC	$N_a \geq 2000$ cycles	$N_a = 3.0 \times 10^5$ cycles
Cyclic rating	Used Paragraph 454 of NPVC	$I_t \leq 1$	$I_t = 0.006$ (normal duty)[a]

TABLE 3.9-18 STRUCTURAL AND MECHANICAL LOADING CRITERIA

Reactor Recirculation Gate Valve, 28-In. Discharge

Component Loads Design	Design Procedure	Required Design Value	Actual Design Value
Body and Bonnet Bolting			
Loads: Design pressure & temp., gasket loads, stem operational load, seismic load (design-basis earthquake)	USAS B31.7 Paragraph 1-704.5.1 Used ASME Section VIII, 1968 Paragraph UA-47 to UA-51 as required by Paragraph 453.1 of NPVC		
Bolt area	USAS B31.7 Paragraph 1-704.5.1 Used ASME Section VIII, 1968 Paragraph UA-47 to 51 as required by Paragraph 453.1 of NPVC	$A_b \geq 42.46$ in.^{2}	$A_b = 55.86$ in.^{2}
Body flange stresses	USAS B31.7 Paragraph 1-704.5.1 Used ASME Section VIII, 1968 Paragraph UA-47 to UA-51 as required by Paragraph 453.1 of NPVC	$S_b \leq 27{,}975$ psi	$S_b = 21{,}628$ psi
Operating condition	USAS B31.7 Paragraph 1-704.5.1 Used ASME Section VIII, 1968 Paragraph UA-47 to UA-51 as required by Paragraph 453.1 of NPVC	$S_H \leq 1.5\ S_{m(575°F)} = 28{,}837$ psi $S_R \leq 1.5\ S_{m(575°F)} = 28{,}837$ psi $S_T \leq 1.5\ S_{m(575°F)} = 28{,}837$ psi	$S_H = 25{,}970$ psi $S_R = 7909$ psi $S_T = 7909$ psi
Gasket seating condition	USAS B31.7 Paragraph 1-704.5.1 Used ASME Section VIII, 1968 Paragraph UA-47 to UA-51 as required by Paragraph 453.1 of NPVC	$S_H \leq 1.5\ S_{m(150°F)} = 30{,}000$ psi $S_R \leq 1.5\ S_{m(150°F)} = 30{,}000$ psi $S_T \leq 1.5\ S_{m(150°F)} = 30{,}000$ psi	$S_H = 29{,}225$ psi $S_R = 11{,}727$ psi $S_T = 11{,}918$ psi

TABLE 3.9-18 STRUCTURAL AND MECHANICAL LOADING CRITERIA

Reactor Recirculation Gate Valve, 28-In. Discharge

Component Loads Design	Design Procedure	Required Design Value	Actual Design Value
Bonnet flange			
Operating condition	Calculate bonnet flange thickness according to rules of ASME Section VIII, Art. UA-6, Fig. UA-6c	$S_{max} \leq 1.5\ S_{m(575°F)}$ = 19,600 psi	S = 5863 psi
Stresses in Stem Loads: Operator thrust and torque			
Stem thrust stress	Calculate stress due to operator thrust in critical cross section	S_T , C ≤ S_m = 44,100 psi	S_T , C = 28,512 psi
Stem torque stress	Calculate shear stress due to operator torque in critical cross section	$S_S \leq 0.8\ S_m$ = 35,280 psi	S_S = 23,011 psi
Disk Analysis			
Loads: Maximum differential pressure			
Maximum stress in the disk	Calculate maximum according to Table10 of Roark's "Formula for Stress and Strain"	$S_{max} \leq 1.5\ S_{m(575°F)}$ = 28,500 psi	Max. stress = 22,885 psi
Yoke and Yoke Connections			
Maximum stress in yoke	Calculate stresses in the yoke to acceptable structural analysis methods	$S_{max} \leq S_m$ = 19,400 psi	Max. stress = 8488 psi
Yoke - bonnet bolt stress	Calculate stresses in the yoke bolts	$S_{max} \leq S_m$ = 28,800 psi	Max. stress = 7940 psi

TABLE 3.9-18 STRUCTURAL AND MECHANICAL LOADING CRITERIA

Reactor Recirculation Gate Valve, 28-In. Discharge

Component Loads Design	Design Procedure	Required Design Value	Actual Design Value
Body and Bonnet			
Loads: Design pressure, design temp., pipe reaction, thermal effects			
Pressure rating, psi	Used Tables 451.4 & 451.5 of NPVC	P_r = 655 psi	P_r = 655 psi
Minimum wall thickness, in.	Used Table 452.1 of NPVC, dm = 22	$t_m \geq 1.70$ in.	$t_m = 1.70$ min.
Primary membrane stress, psi	Used Paragraph 452.3 of NPVC	$P_m \leq S_{m(500°F)} = 19,600$	$P_m = 8797$ psi
Secondary stress due to pipe reaction	Used Paragraph 452.4b of NPVC (S = 23,700 psi)	P_e = greatest value of P_{ed} P_{eb} and $P_{et} \leq 1.5$ $S_{m(500°F)}$ 1.5 (19,600) = 29,400 psi	P_{ed} = 5253 psi P_{eb} = 11,917 psi P_{et} = 11,573 psi $P_e = P_{eb}$ = 11,917 psi
Primary plus secondary stress due to internal pressure	Used Paragraph 452.4a of NPVC	$S_n \leq 3\ S_{m(500°F)}$ = 58,800 psi	Q_p = 20,580 psi
Thermal secondary stress	Used Paragraph 452.4c of NPVC	$S_n \leq 3\ S_{m(500°F)}$ = 58,800 psi	Q_T = 5815 psi
Sum of primary plus secondary stress	Used Paragraph 452.4 of NPVC	$S_n \leq 3\ S_{m(500°F)}$ = 58,800 psi	$S_n = Q_p + P_e + 2Q_T$ S_n = 44,127 psi
Fatigue requirements	Used Paragraph 452.4 of NPVC	$N_a \geq 2000$ cycles	$N_a > 10^6$ cycles
Cyclic rating	Used Paragraph 454 of NPVC	$I_t \leq 1$	I_t = 0.131 (normal duty)[a]

TABLE 3.9-18 STRUCTURAL AND MECHANICAL LOADING CRITERIA

Reactor Recirculation Gate Valve, 28-In. Discharge

Component Loads Design	Design Procedure	Required Design Value	Actual Design Value
Body and Bonnet Bolting Loads: Design pressure and temp., gasket loads, stem operational load, seismic load (design-basis earthquake)	USAS B31.7 Paragraph 1-704.5.1 Used ASME Section VIII, 1968 Paragraph UA-47 to UA-51 as required by Paragraph 453.1 of NPVC		
Bolt area	USAS B31.7 Paragraph 1-704.5.1 Used ASME Section VIII, 1968 Paragraph UA-47 to UA-51 as required by Paragraph 453.1 of NPVC	$A_b \geq 36.8$ in.^{2} $S_b \leq 27{,}975$ psi	$A_b = 55.86$ in.^{2} $S_b = 17{,}326$ psi
Body flange stresses	USAS B31.7 Paragraph 1-704.5.1 Used ASME Section VIII, 1968 Paragraph UA-47 to UA-51 as required by Paragraph 453.1 of NPVC		
Operating condition	Same as above	$S_H \leq 1.5\ S_{m(575°F)} = 28{,}837$ psi $S_R \leq 1.5\ S_{m(575°F)} = 28{,}837$ psi $S_T \leq 1.5\ S_{m(575°F)} = 28{,}837$ psi	$S_H = 20{,}891$ psi $S_R = 6336$ psi $S_T = 6336$ psi
Gasket seating condition	USAS B31.7 Paragraph 1-704.5.1 Used ASME Section VIII, 1968 Paragraph UA-47 to UA-51 as required by Paragraph 453.1 of NPVC	$S_H \leq 1.5\ S_{m(150°F)} = 30{,}000$ psi $S_R \leq 1.5\ S_{m(150°F)} = 30{,}000$ psi $S_T \leq 1.5\ S_{m(150°F)} = 30{,}000$ psi	$S_H = 27{,}887$ psi $S_R = 11{,}366$ psi $S_T = 11{,}647$ psi
Bonnet flange	Same as above		

TABLE 3.9-18 STRUCTURAL AND MECHANICAL LOADING CRITERIA

Reactor Recirculation Gate Valve, 28-In. Discharge

Component Loads Design	Design Procedure	Required Design Value	Actual Design Value
Operating condition	Calculate bonnet flange thickness according to rules of ASME Section VIII, Art. UA-6, Fig. UA-6(c)	$S_{max} \leq S_{m(575°F)}$ = 19,600 psi	S = 5960 psi
Stresses in Stem			
Loads: Operator thrust and torque			
Stem thrust stress	Calculate stress due to operator thrust in critical cross section	S_T, C ≤ S_m = 44,100 psi	S_T, C = 24,343 psi
Stem torque stress	Calculate shear stress due to operator torque in critical cross section	$S_S \leq 0.8\ S_m$ = 35,280 psi	S_S = 19,185 psi
Disk Analysis			
Loads: Maximum differential pressure			
Maximum stress in the disk	Calculate maximum according to Table10 of Roark's "Formula for Stress and Strain"	$S_{max} \leq 1.5\ S_{m(575°F)}$ = 28,500 psi	Max. stress = 19,432 psi
Yoke and Yoke Connections			
Maximum stress in yoke	Calculate stresses in the yoke to acceptable structural analysis methods	$S_{max} \leq S_m$ = 19,400 psi	Max. stress = 5552 psi
Yoke - bonnet bolt stress	Calculate stresses in the yoke bolts	$S_{max} \leq S_m$ = 28,800 psi	Max. stress = 4008 psi

[a] See FP FERM 310 (Ref. 19) for maximum Cumulative Usage Factor values using event number of cycles based on Fermi 2 operating history.

TABLE 3.9-19 MAIN STEAM SAFETY/RELIEF VALVES (PILOT OPERATED), FERMI 2
(ASME Code, Section III, 1968, Including Addenda through Summer 1970)

Topic	Method of Analysis	Target Rock 7567F Analysis	Allowable Value	Calculated
1. BODY INLET AND OUTLET FLANGE STRESSES Note, Topics 1 and 2: Design Pressures: P_d = 1375 psig (inlet) P_b = 625 psig (outlet) These are the equivalent maximum anticipated pressures under all operating conditions. Analyses include applied moments of M = 400,000 in.-lb (inlet) and M = 300,000 in.-lb (outlet) Actual tested capability (including accelerations and moments) is as described in Topic 11. The analyses also include consideration of seismic, operational, and flow reaction forces. Allowable vs. tested capabilities are provided in Topic 12.	$S_H = \frac{fMo}{Lg_1{}^2B} + \frac{PB}{4g_o} < 1.5\ Sm$ $S_R = \frac{(\frac{4te}{3}+1)Mo}{Lt^2B} < 1.5\ Sm$ $S_T = \frac{YM_o}{t^2B} - Z\,S_R < 1.5\ Sm$ where S_H = Longitudinal "hub" wall stress, psi. S_R = Radial "flange" stress, psi. S_T = Tangential "flange" stress, psi.	P_D(Target Rock) = P (codes) Body Material: A105 Gr. II Sm = 19,400 psi (500°F, equivalent inlet and outlet temperature)	1.5 Sm = 29,100 psi	Inlet: S_H = 1.2 Sm = 0.77(allowable) S_R = 0.52 Sm = 0.35 (allowable) S_T = 1.2 Sm = 0.76(allowable) Outlet: S_H = 0.36 Sm = 0.24(allowable) S_R = 0.5 Sm = 0.33 (allowable) S_T = 1.36 Sm = 0.91(allowable)
2. INLET AND OUTLET STUD AREA REQUIREMENTS	Total cross-sectional area shall exceed the greater of: $Am_1 = \frac{Wm_1}{Sb}$, or $Am_2 = \frac{Wm_2}{Sa}$ where Am_1 = total required bolt (stud) area for operating conditions Am_2 = total required bolt (stud) area for gasket seating	$\left.\begin{matrix} Am_1 = \frac{Wm_1}{Sb} \\ Am_2 = \frac{Wm_2}{Sa} \end{matrix}\right\}$ # Bolting Material: SA193 GR#B7 # Where Am (required minimum) is the greater of Am_1 and Am_2; and A_b (actual bolt area) must exceed Am.	Inlet: ($Am_1 > Am_2$) = 8.02 in.^{2} Outlet: Am = 4.73	Inlet: A_b (actual area) = 1.72 Am (required min.) Outlet: A_b = 2.04 Am
3. BODY WALL THICKNESS	1. Valve Wall Thickness Criterion: $t_{min} = t_A$ where t_{min} = minimum calculated thickness requirement, including corrosion allowance. t_A = Actual wall thickness. (Note: This t_{min} is t_m per notation of the codes.)	Section at inlet: $t_{RQD} < t_{ACT}$ Section at middle of body $t_{RQD} < t_{ACT_C}$	 t_{RQD} = 0.67 in. Actual thickness greater than t_m at the section under consideration.	t_{ACT} = 1.67 (t_{RQD}) t_{ACT_C} = 1.28 (t_{RQD})

TABLE 3.9-19 MAIN STEAM SAFETY/RELIEF VALVES (PILOT OPERATED), FERMI 2
(ASME Code, Section III, 1968, Including Addenda through Summer 1970)

Topic	Method of Analysis	Target Rock 7567F Analysis	Allowable Value	Calculated
	2. Cyclic Rating:	$It = \sum \frac{Nri}{Ni}$ (i = 1, 2 & 3)	It (max) = 1.0	It = 0.33[a] = 0.33 (allowable)
	Thermal $It = \sum \frac{Nri}{Ni}$	$N_a \geq$ 2,000 cycles, as based on $S_A = S_{P_2}$ ($>S_{P_1}$), where S_A (Target Rock) = Sa (codes)	Na ≥ 2,000 cycles	Na (based on S_{P_2}) = 1.8 x 10^5 cycles: ∴ satisfies criteria
	Fatigue Na ≥ 2,000 cycles, as based on Sa, where Sa is defined as the larger of $S_{P_1} = \left(\frac{2}{3}\right) Q_P + \frac{P_{eb}}{2} + Q_{T_2} + 1.3Q_{T_1}$ or $S_{P_2} = 0.4Q_P + \frac{K}{2}(P_{eb} + 2Q_{T_3})$ where S_{P_1} = Fatigue stress intensity at inside surface of crotch, psi. S_{P_2} = Fatigue stress intensity at outside surface of crotch, psi.	{(Uses same notation as codes)}		
4. BONNET FLANGE STRESS (BODY SIDE)	$S_{H_1} = \frac{PB_1}{4g_1} \mp \frac{6M_H}{\pi B_1 g_1^2}$ (longitude hub stress adjacent to flange) $S_{H_2} = \left(\frac{Q}{\pi B_1 t} + P\right)(Z + Y) + \frac{Et\theta_B}{B_1} + \frac{0.075PB_1}{g_1} \pm \frac{1.8M_H}{\pi B_1 g_1^2}$ (circumferential stress in hub adjacent to flange) $S_R = \frac{6(M_P + M_S)}{t^2(\pi C - nD)}$ (@ Bolt circle) $S_R = \left(\frac{Q}{\pi B_1 t} + P\right) \pm \frac{6M_S}{\pi B_1 t^2}$ (adjacent to hub) $ST = \left(\frac{Q}{\pi B_1 t} + P\right) Z \pm \left(\frac{Et\theta_B}{B_1} + \frac{1.8M_S}{\pi B_1 t^2}\right)$	$S_H < 1.5\ S_m$ $S_R < 1.5\ S_m$ $S_T < 1.5\ S_m$ P_{FD} (Target Rock) = P (codes) Material: A105 Gr. II. S_m = 19,400 psi (@500°F)	1.5 Sm = 29,100 psi	S_H = 0.82 Sm = 0.55 (allowable) S_R = 0.5 Sm = 0.33 (allowable) S_T = 0.27 Sm = 0.18 (allowable)

TABLE 3.9-19 MAIN STEAM SAFETY/RELIEF VALVES (PILOT OPERATED), FERMI 2
(ASME Code, Section III, 1968, Including Addenda through Summer 1970)

Topic	Method of Analysis	Target Rock 7567F Analysis	Allowable Value	Calculated
5. BONNET FLANGE STRESS (BONNET SIDE)	Using Roark's formula for stress and strain, Table X, 4th. Edition, superposition of case 2 and 3	$S_R < 1.5$ Sm $S_T < 1.5$ Sm	1.5 Sm = 29,100 psi	$S_R = S_T = 1.27$ = 0.85 (available)
	$S_R = S_T = \frac{-3W}{2\pi mt^2}\left[m + (m+1)\log\frac{a}{ro} - (m-1)\frac{r_o^2}{4a^2}\right]$ $S_R = S_T = \frac{-3W}{2\pi mt^2}\left[\frac{1}{2}(m-1) + (m+1)\log\frac{a}{r_o} - (m-1)\frac{r_o^2}{2a^2}\right]$	Material: A105 Gr II Sm = 19,400 (@500°F)		
6. BONNET STUD AREA REQUIREMENTS	Total cross-sectional area shall exceed: $Am_1 = \frac{Wm_1}{Sb}$ where Am_1 = total required bolt (stud) area	$Am_1 = \frac{Wm_1}{Sb}$ Bolting Material: SA 193 Gr B7	$Am_1 = 9.839$	Am (actual) = 1,044 (required minimum)
7. BONNET WALL THICKNESS	Using Roark's formula for stress and strain, Table XIII, case 35, considering the circumferential stress, S_2 (the governing stress), and setting equal to Sm. $S_2 = P\frac{b^2+a^2}{b^2-a^2}$ where P = design pressure a = inside diameter b = outside diameter	$t_m < t_a$	tm = 0.119 in.	ta = 3.75 t_m
8. PILOT VALVE HOUSING FLANGE	$S_H = \frac{fM_o}{Lg_1^2B}$ $S_R = \frac{(\frac{4te}{3}+1)M_o}{Lt^2B}$ $S_T = \frac{YM_o}{t^2B} - Z\,S_R$ where S_H = Longitudinal "hub" wall stress, psi S_R = Radial "flange" stress, psi S_T = Tangential "flange" stress, psi	$S_H < 1.5$ Sm $S_R < 1.5$ Sm $S_T < 1.5$ Sm Material A105 Gr II Sm = 19,400 psi (@500°F)	1.5 Sm = 29,100 psi	S_H = 0.54 Sm = 0.36 (allowable) S_R = 0.36 Sm = 0.24 (allowable) S_T = 0.30 Sm = 0.20 (allowable)

TABLE 3.9-19 MAIN STEAM SAFETY/RELIEF VALVES (PILOT OPERATED), FERMI 2
(ASME Code, Section III, 1968, Including Addenda through Summer 1970)

Topic	Method of Analysis	Target Rock 7567F Analysis	Allowable Value	Calculated
9. PILOT VALVE BODY FLANGE STRESS	Using Roark's formulas for stress and strain, 4th. edition, Table X case 2	$S_R = S_T < Sm$ Material: A105 Gr II Sm = 19,400 psi (@500°F)	Sm = 19,400 psi	$S_R = S_T$ =0.34 (available)

$$S_R = S_T = \frac{-3W}{2\pi m t^2}\left[m + (m+1)\log\frac{a}{r_o} - (m-1)\frac{{r_o}^2}{4a^2}\right]$$

where

W = applied load

m = reciprocal of Poisson's ratio

a = radius of flange

r_o = radius of applied load

Topic	Method of Analysis	Target Rock 7567F Analysis	Allowable Value	Calculated
10. MAIN DISC STRESS	Using Roark's formulas for stress and strain, 4th edition, page 250	$S_{max} < Sm$ Material: SA182 Sm = 13,600 psi (@ 500°F)	Sm = 13,600 psi	S_{max} = 0.68 (allowable)

$$S_{max} = \frac{\beta W a^2}{{t_o}^2}$$

where

β = 1.63

W = applied load

a = radius of disc

t_o = thickness at center

11. SEISMIC CAPABILITY: Stress analysis uses $F_{vertical}$ = (mass of valve) x (2.0g) and $F_{horizontal}$ = (mass of valve) x (3.0g), with concurrent 400,000 in.-lb and 300,000 in.-lb applied at the inlet and outlet, respectively. Valve operability has been verified by test, with applied moments of 800,000 in.-lb and 600,000 in.-lb at the inlet and outlet, respectively, and at actual acceleration levels of $a_{vertical}$ = 6g and $a_{horizontal}$ = 8g. Tests were per IEEE-344 (1975).

12. VALVE LOADS: For a comparison of calculated loadings and seismic capability see Tables 3.9-24 and 3.9-25.

[a] See FP FERM 310 (Ref. 19) for maximum Cumulative Usage Factor values using event number of cycles based on Fermi 2 operating history.

TABLE 3.9-20 RECIRCULATION PUMPS

Criteria	Method of Analysis	Analytical Results	Allowable Stress or Actual Thickness
1. Casing Minimum Wall Thickness Loads:	$t = \frac{PR}{SE-0.6P} + C$	t = 2.72 in.	$S_{allow.}$ = 15,114 psi $t_{act.}$ = 2.750 in.
	where		
Normal and Upset Condition	t = min. req'd. thickness, in.		
Design pressure and temperature	P = design pressure, psig R = max. internal radius, in. S = allowable working stress, psi E = joint efficiency C = corrosion allowance, in.		
Primary membrane stress limit:			
Allowable working stress per ASME Sec. III, Class C			
2. Casing Cover Minimum Thickness Loads:	$S_S = \frac{F}{A}$ F = force A = area at shear point	S_S = 3440 psi	$S_{alow.}$ = 8775 psi $t_{act.}$ = 3.5 in.
Normal and Upset Condition	$S_b = \frac{Kqa^2}{h^2}$		
Design pressure and temperature			
Primary Bending and Shear		S_b = 6050 psi	$S_{allow.}$ = 15,114 psi
Stress limit:	q = pressure load		$t_{act.}$ = 7in.
1.5 S_m per ASME Code for pumps and valves for Nuclear Power Class I	a = radius of O.D. b = radius of I.D. h = plate thickness		
3. Cover and Seal Flange Bolt Loads:	Bolting loads, areas, and stresses shall be calculated in accordance with "Rules for Bolted Flange Connections"	Cover Flange Bolts	

TABLE 3.9-20 RECIRCULATION PUMPS

Criteria	Method of Analysis	Analytical Results	Allowable Stress or Actual Thickness
		$S_{act.} = 18,178$ psi	$S_{allow.} = 20,000$ psi
Normal and Upset Condition	ASME Sec. VIII, Appendix II	$A_m = 91.8$ in.^{2}	$A_{allow.} = 101.0$ in.^{2}
Design pressure and temperature			
Design gasket load		Seal Flange Bolts	
		$S_{act.} = 18,050$ psi	$S_{allow.} = 20,000$ psi
Bolting Stress Limit:		$A_m = 10.0$ in.^{2}	$A_{allow.} = 11.1$ in.^{2}
Allowable working stress per ASME Sec. III, Class C			
4. Cover Clamp Flange Thickness Loads:	Flange thickness and stress shall be calculated in accordance with "Rules for Bolted Flange Connections" - ASME Sec. VIII, Appendix II	Flange Thickness	
		t = 9.05 in.	$t_{act.} = 9.25$ in.
Normal and Upset Condition		$S_{act.} = 16,870$	$S_{allow.} = 17,500$ psi
Design pressure and temperature			
Design gasket load			
Design bolting load			
Tangential Flange Stress Limit			
Allowable working stress per ASME Sec. III, Class C			
5. Seal Cover Loads:	See equation below	$S_r = 2540$ psi	$S_m = 18,750$ psi
Normal and Upset Condition			
Design pressure and temperature			
Design gasket load			

$$S_r = \frac{3w}{4t^2}\left[a^2 - 2b^2 + \frac{b^4(m-1) - 4b^4(m+1)\ln\left(\frac{a}{b}\right) + a^2b^2(m+1)}{a^2(m-1) + b^2(m+1)}\right] + \frac{3W}{2\pi t^2}\left[1 - \frac{2mb^2 - 2b^2(m+1)\ln\frac{a}{b}}{a^2(m-1) + b^2(m+1)}\right]$$

TABLE 3.9-20 RECIRCULATION PUMPS

Criteria	Method of Analysis	Analytical Results	Allowable Stress or Actual Thickness
	where S_r = radial stress at outer edge, psi w = pressure load, psi t = disk thickness, in. m = reciprocal of Poisson's ratio a = radius of disk, in. b = radius of disk hole, in. W = force, lb		
6. Seal Chamber Minimum Wall Thickness Loads	$t = \frac{PR}{SE-0.6P} + C$	t = 0.753 in.	$S_{allow.}$ = 15,114 psi $t_{act.}$ = 1.375 in.
Normal and Upset Condition Design pressure and temperature Piping reactions during normal operation	where t = min. required thickness, in. P = design pressure, psig R = max. internal radius, in. S = allowable working stress, psi E = joint efficiency C = corrosion allowance, in.		
Combined Stress Limit: 1.5 S_m per ASME Code for pumps and valves for Nuclear Power Class I			
7. Mounting Bracket Combined Stress Loads: Flooded weight SSE horizontal seismic force = 1.76 g	Bracket vertical loads shall be determined by summing the equipment and fluid weights and vertical seismic forces. Bracket horizontal loads shall be determined by applying the specified seismic force at mass center of pumping motor assembly (flooded)	Combined stress (shear plus tensile) Lug no.1 S_C = 6505 psi Lug no.2 S_C = 7976 psi Lug no.3 S_C = 10,762 psi	S_m = 15,150 psi S_y = 30,000 psi
SSE vertical seismic force = 0.67g			
Combined Stress Limit			
Yield stress	Horizontal and vertical loads shall be applied simultaneously to determine tensile, shear, and bending stresses in the brackets. Tensile, shear, and bending stresses shall be combined to determine max. combined stresses		

TABLE 3.9-20 RECIRCULATION PUMPS

Criteria	Method of Analysis	Analytical Results	Allowable Stress or Actual Thickness
8. Stresses Due to Seismic Loads Loads: Operation pressure and temperature SSE horizontal seismic force = 1.76g SSE vertical seismic force = 0.67g Combined Stress Limit: Yield stress	The flooded pump-motor assembly shall be analyzed as a free body supported by constant support hangers from the pump brackets. Horizontal and vertical seismic forces shall be applied at mass center of assembly and equilibrium reactions shall be determined for the motor and pump brackets. Loads, shear, and moment diagrams shall be constructed using live loads, dead loads, and calculated snubber reactions. Combined bending, tension shear stresses shall be determined for each major component of the assembly including motor support barrel, bolting and pump casing. The maximum combined tensile stress in the cover bolting shall be calculated using tensile stresses determined from loading diagram plus tensile stress from operating pressure	Motor Bolt Tensile Stresses $S_{act.}$= 10,703 psi Pump Cover Bolt Tensile Stress $S_{act.}$= 20,611 psi Motor Support Barrel Combined $S_{act.}$= 1606 psi	$S_{allow.}$ = 30,800 psi $S_{allow.}$ = 32,000 psi $S_{allow.}$ = 22,400 psi

TABLE 3.9-21 STRESS SUMMARY - HIGH-PRESSURE COOLANT INJECTION STEAM LINE AND MAIN STEAM LINE "A" (CODE USED FOR ANALYSIS: ASME III, CLASS 1, 1983 EDITION INCLUDING WINTER 1984 ADDENDA)

HPCI BRANCH LINE

	Equation 9			Equation 10	Usage[b]	
Node	Normal ($S<1.5S_m$)	Upset ($S<1.8S_m$)	Emergency ($S<2.25S_m$)	($S_n<3S_m$[a])	($U<1.0$)	(Equation 12 $S<3S_m$) / (Equation 13 $S<3S_m$)
029	8880	23278	28291	64649	0.09	11366/33486
402N	4516	11427	14087	21822	0.00	
402F	4508	7404	8941	15476	0.00	
408N	4460	8548	10408	16822	0.00	
408F	4350	8019	9598	15719	0.00	
418N	1711	7623	10235	21589	0.00	
418F	1837	7502	10330	21550	0.00	
424N	4347	6396	7404	13576	0.00	
424F	4267	6072	6936	13447	0.00	
426N	1505	6278	8719	24171	0.00	
426F	1777	6793	9373	23470	0.00	
430N	4421	7169	8437	15628	0.00	
430F	4411	7037	8358	15149	0.00	
434N	4383	7174	8611	15216	0.00	
434F	4324	7992	9989	16320	0.00	
440	4424	8852	11343	18189	0.00	
442	5204	9424	12021	18327	0.00	
448	5154	9616	12247	21501	0.00	
MAIN STEAM LINE A						
003	7715	11109	11329	26040	0.00	
004F	371	3536	4726	50897	0.03	

TABLE 3.9-21 STRESS SUMMARY - HIGH-PRESSURE COOLANT INJECTION STEAM LINE AND MAIN STEAM LINE "A" (CODE USED FOR ANALYSIS: ASME III, CLASS 1, 1983 EDITION INCLUDING WINTER 1984 ADDENDA)

	Equation 9			Equation 10	Usage[b]	
Node	Normal ($S<1.5S_m$)	Upset ($S<1.8S_m$)	Emergency ($S<2.25S_m$)	($S_n<3S_m$[a])	($U<1.0$)	(Equation 12 $S<3S_m$) / (Equation 13 $S<3S_m$)
011N	4203	5449	5778	24160	0.00	
011F	4235	5249	5519	25638	0.00	
014N	787	2559	3064	52201	0.03	
014F	737	3728	4679	47827	0.02	
017	7870	9817	10296	22607	0.00	
019	8084	10197	10709	21839	0.00	
021	8423	10154	10312	20581	0.00	
025	8348	10066	10473	20581	0.00	
030F	892	5944	8005	42402	0.02	
040N	681	5504	6674	34421	0.01	
040F	581	3963	5403	36438	0.01	
043	7795	9945	10052	26135	0.00	
051	8013	9878	9944	25238	0.00	
063	8112	9789	9833	24703	0.00	
100	8327	21309	23106	57569	0.64	15198/29490
200	8769	17618	19126	47047	0.16	
300	9174	15854	17623	42145	0.03	

[a] Per ASME Code Section III, NB-3653.6, If Equation 10 stress > $3S_m$, then Equation 12 stress must be < $3S_m$ and Equation 13 stress must be < $3S_m$

[b] See FP FERM 310 (Ref. 19) for maximum Cumulative Usage Factor values using event number of cycles based on Fermi 2 operating history.

TABLE 3.9-22 STRESS SUMMARY - REACTOR CORE ISOLATION COOLING STEAM LINE AND MAIN STEAM LINE "B" (CODE USED FOR ANALYSIS: ASME III, CLASS 1, 1983 EDITION INCLUDING WINTER 1984 ADDENDA)

	Equation 9			Equation 10	Usage[b]	Max. of Equation 12 & 13
Node	Normal ($S<1.5S_m$)	Upset ($S<1.8S_m$)	Emergency ($S<2.25S_m$)	($S_n<3.0S_m$)[a]	($U<1.0$)	($S<3S_m$)
RCIC line						
039	8704	13494	15217	51968	0.05	30112
605N	4621	6625	7643	18560	0.00	
605F	4132	5656	6299	22119	0.00	
611N	4132	6461	7182	15348	0.00	
611F	4554	7196	8482	18632	0.00	
617	5593	16871	20904	42782	0.02	
635N	1883	5557	7672	26045	0.00	
635F	1700	5526	7689	25774	0.00	
649N	1551	7211	10592	31150	0.01	
649F	1260	7057	10579	31573	0.01	
661	4514	8642	12459	22124	0.00	
663	3938	8408	12454	22469	0.00	
669	5654	9891	14072	28659	0.01	
Main Steam Line B						
003	7500	11540	11612	27372	0.01	
004F	547	4106	4547	40314	0.01	
009	16073	17389	17603	26460	0.03	
011N	4374	6560	6989	22753	0.00	
011F	4513	6397	6653	24335	0.00	
014N	1295	3898	4145	44176	0.02	
014F	636	3820	4139	44524	0.02	
019	7894	9444	9639	21963	0.00	

TABLE 3.9-22 STRESS SUMMARY - REACTOR CORE ISOLATION COOLING STEAM LINE AND MAIN STEAM LINE "B" (CODE USED FOR ANALYSIS: ASME III, CLASS 1, 1983 EDITION INCLUDING WINTER 1984 ADDENDA)

	Equation 9			Equation 10	Usage [b]	Max. of Equation 12 & 13
Node	Normal ($S<1.5S_m$)	Upset ($S<1.8S_m$)	Emergency ($S<2.25S_m$)	($S_n<3.0S_m$)[a]	($U<1.0$)	($S<3S_m$)
023	7762	9483	9667	21108	0.00	
025	7778	9417	9549	20792	0.00	
029	7772	8737	8864	20792	0.00	
030	7772	8656	8765	21006	0.00	
033	7865	8800	8883	21691	0.00	
040N	1073	3383	3646	43898	0.02	
040F	1118	3556	3836	42233	0.02	
050N	804	2499	2718	35175	0.01	
050F	1592	3360	3573	36374	0.01	
052	8005	8573	8646	25304	0.01	
059	7751	8247	8321	24636	0.00	
063	7898	8274	8315	24004	0.00	
100	9060	20770	21591	54219	0.65	31120
200	9104	20756	21718	61634	0.67	31340
300	7858	17399	17963	47002	0.26	28806
400	8160	14851	16447	48990	0.09	29426
500	8740	14811	15704	47700	0.05	30540

[a] Per ASME Code Section III, Subsection NB 3653.6, if Equation 10 stress > $3S_m$, then Equation 12 stress must be < $3S_m$, and Equation 13 stress must be < $3S_m$.

[b] See FP FERM 310 (Ref. 19) for maximum Cumulative Usage Factor values using event number of cycles based on Fermi 2 operating history.

TABLE 3.9-23 STRESS SUMMARY - RECIRCULATION LOOP "A" AND RESIDUAL HEAT REMOVAL SYSTEM RETURN (CODE USED FOR ANALYSIS: ASME III, CLASS 1, 1983 EDITION INCLUDING WINTER 1984 ADDENDA)

	Equation 9			Equation 10	
Node	Design ($S<1.5S_m$)	Upset ($S<1.8S_m /1.5S_y$)	Emergency ($S<2.25S_m /1.8 S_y$)	($S_n<3.0S_m$)	Usage[a] ($U<1.0$)
016	11642	13283	14489	18561	0.00
063	7441	9774	16247	30228	0.00
999	7532	10148	12882	27365	0.00
198	7497	14784	25057	33240	0.00
201	7496	13986	22721	32061	0.00
204	12244	15075	18306	19550	0.00
216	11888	13077	13113	27286	0.00
222	8057	17978	31134	44948	0.02
250	8378	14137	22401	41402	0.07
340	7766	13842	22286	47633	0.02
360	7699	12192	17891	43488	0.02
802	6118	9051	12553	31567	0.04
854	11735	15827	20864	27066	0.04

[a] See FP FERM 310 (Ref. 19) for maximum Cumulative Usage Factor values using event number of cycles based on Fermi 2 operating history.

TABLE 3.9-24 STRESS SUMMARY - RECIRCULATION LOOP "B" AND RESIDUAL HEAT REMOVAL SUPPLY AND RETURN (CODE USED FOR ANALYSIS: ASME III, CLASS 1, 1983 EDITION INCLUDING WINTER 1984 ADDENDA)

	Equation 9			Equation 10	
Node	Normal ($S < 1.5\ S_m$)	Upset ($S < 1.8\ S_m/1.5\ S_y$)	Emergency ($S < 2.25\ S_m/1.8\ S_y$)	($S_n < 3.0\ S_m$)	Usage[a] ($U < 1.0$)
016	15969	17698	18866	18224	0.00
018	8051	17355	26974	41148	0.02
204	12309	14089	15581	19432	0.00
216	11888	13084	13127	27286	0.00
222	8816	18800	30222	43070	0.02
340	7764	14019	21625	48809	0.02
250	8261	13444	19544	38727	0.07
360	7706	12398	18022	43664	0.02
508	2231	7395	12933	34571	0.00
558	19579	21191	22376	19803	0.03
516	8670	16573	24308	34188	0.09
546	8050	13238	19256	29529	0.09
602	6303	9232	12302	31696	0.04
656	11864	16541	22001	27298	0.04

[a] See FP FERM 310 (Ref. 19) for maximum Cumulative Usage Factor values using event number of cycles based on Fermi 2 operating history.

TABLE 3.9-25 STRESS SUMMARY - FEEDWATER SYSTEM INSIDE DRYWELL (FW01) (CODE USED FOR ANALYSIS: ASME III, CLASS 1, 1977 EDITION INCLUDING SUMMER 1979 ADDENDA)

	Equation 9			
Node	Normal and Upset ($S < 1.5\ S_m$)	Emergency ($S < 2.25\ S_m$)	Equation 10 ($S_n < 3.0\ S_m$)	Usage[a] ($U < 1.0$)
10	6017	6501	36969	0.02
15A	5804	6312	37725	0.04
25	6037	6509	46587	0.03
30	5950	6467	47054	0.03
40	9391	12387	44992	0.07
55	11769	16142	35201	0.05
60	13564	16534	35195	0.00
180B	8000	10531	37642	0.00
205A	7064	8792	49697	0.01
215B	9533	12997	48227	0.01

[a] See FP FERM 310 (Ref. 19) for maximum Cumulative Usage Factor values using event number of cycles based on Fermi 2 operating history.

TABLE 3.9-26 STRESS SUMMARY - CORE SPRAY SYSTEM INSIDE DRYWELL (CS-02) (CODE USED FOR ANALYSIS: ASME III, CLASS 1, 1977 EDITION INCLUDING SUMMER 1979 ADDENDA)

	Equation 9			
Node	Design ($S < 1.5\ S_m$)	Emergency ($S < 2.25\ S_m$)	Equation 10 ($S_n < 3.0\ S_m$)	Usage[a] ($U < 1.0$)
10B	7668	10,101	27,315	0.00
20A	7729	10,264	29,072	0.00
25B	8257	11,263	32,917	0.00
55	5919	6912	34,689	0.01
60A	9482	13,443	48,680	0.01
70	6499	7823	35,557	0.01
75B	7600	10,021	28,766	0.00
85A	7236	9366	29,113	0.00
90	10,831	12,000	41,422	0.03

[a] See FP FERM 310 (Ref. 19) for maximum Cumulative Usage Factor values using event number of cycles based on Fermi 2 operating history.

TABLE 3.9-27 ASME CODE CLASS 2 AND 3 COMPONENTS

		Code Class	Design Pressure(psi)	Design Temp. (°F)
I.	Deleted			
II.	Nuclear boiler system			
	Vessels, valve accumulators	3	150	340
	Piping, safety/relief valve discharge	2	570	575
III.	CRD hydraulic system			
	Valves, scram discharge volume lines, and portions of vent and drain lines	2	1250	280
	Valves, insert and withdraw lines	2	1750	150 (insert)
				280 (withdrawal)
	Piping, scram discharge volume lines	2	1250	280
	Piping, insert and withdraw lines	2	1750	150 (insert)
				280 (withdrawal)
IV.	Standby liquid control system			
	Pump	3	1400	150
	Valves, beyond isolation valves	3	1400	150
	Piping, beyond isolation valves	3	1400	150
	Valves, in test and flush lines	3	1400	150
	Piping, test and flush lines	3	1400	150
	Relief valve outlet line	3	150	150
	Storage and test tank outlets to pumps	3	150	150
V.	Deleted			
VI.	RHR system			
	Heat exchangers, primary side	2	450	470
	Heat exchangers, secondary side	3	450	470
	Pumps	2	450	360
	Pump discharge piping	2	480	335

TABLE 3.9-27 ASME CODE CLASS 2 AND 3 COMPONENTS

		Code Class	Design Pressure(psi)	Design Temp. (°F)
	Shutdown suction piping	2	150	335
	Test line and containment spray	2	480 and 150	335
	Pump suction piping	2	150	335
VII.	Core spray			
	Piping, beyond shutoff valves F004 A and B (pump discharge line, bypass line, and test line)	2	500	212
	(condensate and pump suction)	2	125	212
	Pumps	2	500	40-212
	Valves, beyond shutoff valves F004 A and B (pump discharge line, bypass line, and test line)	2	500	212
	(condensate and pump suction)	2	125	212
	Shutoff valves F004 A and B and piping between the shutoff valves and outboard isolation valves F005 A and B	2	1250	575
VIII.	High-pressure coolant injection			
	Piping, and valves, steam supply beyond outermost isolation valve, other	2	1250	575
	Main pump	2	1500	40-140
	Booster pump	2	450	40-140
	Piping and valves, steam exhaust	2	150	366
	Coolant supply to barometric condenser	2	460	170
	Coolant supply to barometric condenser	2	125	170
	Pump suction from condensate storage tank (including valves)	2	18	120
	Pump suction from suppression pool, piping and valves	2	125	170
	Pump discharge to feedwater, piping and valves	2	1330	170
	Pump discharge bypass line to suppression pool, piping and valves	2	125	340

TABLE 3.9-27 ASME CODE CLASS 2 AND 3 COMPONENTS

		Code Class	Design Pressure(psi)	Design Temp. (°F)
	Test line to condensate storage tank, piping and valves	2	1330	170
	Turbine exhaust vacuum breaker line	2	150	366
IX.	RCIC system			
	Pump	2	1500	40-140
	Piping and valves in steam line to turbine, outside isolation valve	2	1250	575
	Turbine exhaust to suppression pool, piping and valves	2	150	267
	Pump suction from condensate storage tank, piping and valves	2	18	120
	Pump suction from suppression pool, piping and valves	2	125	170
	Pump discharge to feedwater line, piping and valves	2	1280	170
	Pump minimum flow line, piping and valves	2	125 and 1280	212 and 170
	System test line, piping and valves	2	1280	170
	Turbine exhaust vacuum breaker line	2	150	267
X.	RPV service equipment			
	Refueling bellows	2*	12	140
	Drywell seal bellows	2*	12	140
XI.	Radwaste system			
	Valves, containment isolation	2	150	140
	Piping, containment isolation	2	150	140
	RWCU filter-demineralizer drains to phase separator	3	150	150
	Cleanup sludge pumps	3	150	150

* Belows were designed, fabricated, and installed as ASME Class 2 but were not N-Stamped.

TABLE 3.9-27 ASME CODE CLASS 2 AND 3 COMPONENTS

		Code Class	Design Pressure(psi)	Design Temp. (°F)
XII.	Reactor water cleanup system			
	Drain from filter-demineralizer unit	3	1300	150
	Line to chemical waste tank	3	150	150
XIII.	Fuel pool cooling and cleanup system			
	Vessels, filter-demineralizers	3	200	150
	Vessels, other	3	200	150 and 140
	Heat exchangers, tube side	3	200	150
	Heat exchangers, shell side	3	150	150
	Piping	3	200	150
	Pumps	3	200	150
	Valves	3	200	150
XIV.	Offgas system			
	None			
XV.	RHR service water system			
	Piping	3	175	125-155
	Pumps	3	150	40-100
	Valves	3	175	125-155
XVI.	Plant service and cooling water systems			
	Piping and valves forming part of primary containment boundary	2	150	150
	EECW system piping and valves	3	150	150
XVII.	Instrument air systems			
	Piping and valves in lines between above accumulators and safety-related systems	3	125	150
XVIII.	Diesel generator system			
	Day tanks	3	Atmospheric pressure	125

TABLE 3.9-27 ASME CODE CLASS 2 AND 3 COMPONENTS

		Code Class	Design Pressure(psi)	Design Temp. (°F)
	Piping and valves, Fuel oil system	3	75	125
	Diesel service water system	3	125	125
	Pumps, diesel service water system	3	75	100
XIX.	Primary containment	2	56	340
XX.	Primary containment atmospheric control system			
	Piping valves and other components	2	150	340
XXI.	Standby gas treatment system			
	None			
XXII.	Reactor building ventilation system			
	None			
XXIII.	Emergency equipment area cooling units			
	Fan-coil units (coils only)	3	150	150
	Drywell cooling coils	2	150	150

TABLE 3.9-28 STANDBY LIQUID CONTROL PUMP

	Criteria	Method of Analysis	Allowable Stress or Minimum Thickness Required (psi)	Calculation (psi)
1.	Closure Bolting Loads: Normal and Upset	Bolting loads and stresses calculated per "Rules for Bolted Flange Connections" ASME Section VIII, App. II	Stuffing box bolts 25,000	18,150
	Design pressure and temperature.		Cylinder head bolts 25,000	19,600
	Design gasket load			
	Bolting Stress Limit			
	Allowable working stress per ASME Section VIII			
2.	Wall Thickness	Pressure Area Method. Maximum stress point on fluid cylinder	16,500	9000
	Loads: Normal and Upset			
	Design pressure and temperature			
	Stress limit			
	ASME Section VIII			
3.	Motor Mount Bolts Loads: Emergency	Seismic forces acting on motor bolts subject to tension and shear	Tension 16,500 Shear 10,000	860 1220
	Design-basis earthquake			
	Stress Limit			
	0.9 yield tension and twice allowable shear ASME VIII			
4.	Nozzle Loads	For the maximum moment due to pipe reaction, the maximum force shall not exceed the allowable	Force in lb, moment in ft-lb	

TABLE 3.9-28 STANDBY LIQUID CONTROL PUMP

Criteria	Method of Analysis	Allowable Stress or Minimum Thickness Required (psi)	Calculation (psi)
Loads: Normal Plus Upset			
Design pressure and temperature, dead weight, thermal expansion and operating-basis earthquake	Total nozzle stress with this criterion does not exceed stress limits. Mount bolts do not exceed stress limits	Suction[a]	
		F = 730	F = 90
		M = 450	M = 75
		Discharge	
		F = 350	F = 220
		M = 108	M = 63
Loads: Emergency		Suction[a]	
Design pressure and temperature, dead weight, thermal expansion and design-basis earthquake		F = 875	F = 105
		M = 540	M = 80
		Discharge	
		F = 420	F = 284
		M = 130	M = 83
Stress Limit			
ASME Section VIII for normal and upset, 1.5 of allowable stress for emergency. Mount bolts 0.9 yield for tension and twice allowable shear for emergency	--	--	--

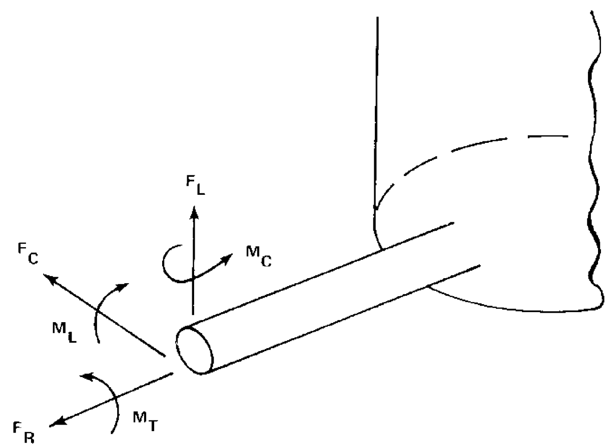
[a] Nozzle loads are the maximum allowable resultant loads applied simultaneously.

TABLE 3.9-29 STANDBY LIQUID CONTROL TANK

Criteria	Method of Analysis	Allowable Stress or Minimum Thickness Required (psi)	Calculation (psi)
1. Shell Thickness	Minimum thickness	0.015 in.	3/16 in. (actual)
Loads: Normal and upset	$t = \frac{2.6D(H-1)G}{SE}$ in.		
Design pressure and temperature	D = Nom. I.D.		
	H = Tank height		
Stress Limit	G = Specif. gravity		
Allowable working stress per ASME Section VIII	S = Allowable stress		
	E = Joint efficiency		
	Not less than 3/16 in.		
2. Shell Stress	Loads will not produce excessive tensile or compressive (buckling) stresses	Tensile	
Loads: Emergency		18,750	9716
Design-basis earthquake nozzle load		Compressive	
		18,750	2895
Stress Limit			
ASME Section VIII Compression 1/3 yield			

TABLE 3.9-29 STANDBY LIQUID CONTROL TANK

Criteria	Method of Analysis	Allowable Stress or Minimum Thickness Required (psi)	Calculation (psi)
3. Application of forces and moments by attaching pipe on outlet nozzle under combined maximum thermal expansion dead weight and design-basis earthquake loading reaction plus load due to internal pressure shall not produce an equivalent bending and torsional stress in the nozzles or shell in excess of the allowable stress as defined by the ASME B&PV Code Section III	Stresses will not be excessive if piping loads do not exceed the allowables	F_C = 235 lb F_L = 235 lb F_R = 105 lb M_C = 366 in.-lb M_L = 366 in.-lb M_T = 1050 in.-lb	F_C = 10 lb F_L = 50 lb F_R = 40 lb M_C = 160 in.-lb M_L = 1000 in.-lb[a] M_T = 75 in.-lb



[a] Equipment was requalified for the higher nozzle loadings.

TABLE 3.9-30 RESIDUAL HEAT REMOVAL PUMP

	Criteria	Method of Analysis	Allowable Stress psi	Calculation psi
1.	Closure Bolting Loads: Normal and Upset Design pressure and temperature Design gasket load Seismic acceleration, nozzle forces and/or moments, static mass forces Bolting Stress Limit Allowable working stress per ASME Section VIII	Bolting loads and stresses calculated per "Rules for Bolted Flange Connections" ASME Section VIII, App. II	Maximum allowable stress 20,000	Maximum calculated 16,370
2.	Wall Thickness Loads: Normal and Upset Design pressure and temperature Stress Limit ASME Section VIII	Per rules of Part UG Section VIII	Maximum allowable stress main pump 17,500	Maximum calculated 14,960

TABLE 3.9-30 RESIDUAL HEAT REMOVAL PUMP

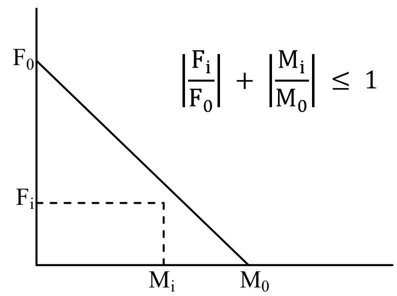
	Criteria	Method of Analysis	Allowable Nozzle Forces and Moments, Force in lb, Moment in ft – lb	Calculated Nozzle Forces and Moments
3.	Nozzle Loads Loads: Normal Plus Upset Design pressure and temperature Dead weight, force and/or moment, and operating-basis earthquake Loads: Emergency Design pressure and temperature Dead weight, force and/or moment, and design-basis earthquake Stress Limit ASME Section VIII primary local membrane stress 1.5 of allowable stress for normal and upset, 1.8 of allowable stress for emergency	For the maximum stresses due to the maximum loads	The following expression relates the allowable combination of forces and moments  $\left\lvert\frac{F_i}{F_0}\right\rvert + \left\lvert\frac{M_i}{M_0}\right\rvert \leq 1$ where Fi = Largest of the three actual external orthogonal forces (Fx, Fy, and Fz) that may be imposed by the pipe Mi = Largest of the three actual external orthogonal moments (Mx, My, and Mz) permitted from the pipe when they are combined simultaneously for any condition Fo = Allowable value of Fi when all moments are zero Mo = Allowable value of Mi when all forces are zero The values of Fo and Mo are given below Normal Plus Upset: Suction: Fo = 10,440 Mo = 49,190 Discharge: Fo = 7030 Mo = 26,410 Emergency:	Force in lb, moment in ft–lb Emergency Loads[a]: Suction (pump D):

TABLE 3.9-30 RESIDUAL HEAT REMOVAL PUMP

Criteria	Method of Analysis	Allowable Nozzle Forces and Moments, Force in lb, Moment in ft – lb		Calculated Nozzle Forces and Moments
		Suction:	Fo = 12,520 Mo = 59,030	F_R = 25,000 M_R =82,800
		Discharge:	Fo = 8430 Mo = 31,700	Discharge (Pump B): F_R = 23,200 M_R = 56,000

[a] Equipment was requalified for higher nozzle loadings.

TABLE 3.9-31 RESIDUAL HEAT REMOVAL HEAT EXCHANGER

	Criteria	Method of Analysis	Allowable Stress or Minimum Thickness Required (psi)	Actual (psi)
1.	Closure Bolting Loads: Normal and Upset Design pressure and temperature Design gasket load	Bolting loads and stresses are calculated per "Rules for Bolted Flange Connections" ASME Section VIII, App. II		
	Bolting Stress Limit Allowable working stress per ASME Section VIII	Shell-channel bolted joint	25,000	24,675
2.	Wall Thickness Loads: Normal and Upset Design pressure and temperature Stress Limit	Shell side ASME Section III C, TEMA Class C Tube side ASME Section VIII and TEMA Class C		
	ASME Section VIII	a. Shell	0.830 in.	1.125 in.
		b. Shell cover	0.805 in.	1.00 in.
		c. Channel ring	0.832 in.	1.00 in.
		d. Tubes	0.044 in.	0.049/0.053
		e. Channel cover	6.627 in.	6.625 in.
		f. Tube sheet	6.697 in.	6.750 in.
3.	Nozzle Loads Design Pressure and Temperature	The maximum moments due to pipe reaction and the maximum forces shall not exceed the allowable limits	(See below)	(See below and next page)
	Dead weight, thermal expansion design-basis earthquake	Primary stress less than 1.5 ASME Section VIII allowable		

TABLE 3.9-31 RESIDUAL HEAT REMOVAL HEAT EXCHANGER

Allowable limits

	N1	N2	N3	N4
F_x	2975 lb	2975 lb	5310 lb	2975 lb
F_y	6690	6690	2360	6690
F_z	6690	6690	5310	6690
M_x	179,600 in.-lb	179,600 in.-lb	47,200 in.-lb	179,600 in.-lb
M_y	59,460	59,460	142,600	59,460
M_z	59,460	59,460	47,200	59,460

Actual Emergency Loads – Heat Exchanger E1101B001A[a]

	N1	N2	N3	N4
F_x	2150 lb	3110 lb	530 lb	3320 lb
F_y	690	3380	8070	2370
F_z	3010	4050	2190	6270
M_x	73,690 in.-lb	55,780 in.-lb	48,550 in.-lb	129,840 in.-lb
M_y	80,290	68,560	25,660	30,480
M_z	34,460	40,990	20,580	113,280

Actual Emergency Loads – Heat Exchanger E1101B001B[a]

	N1	N2	N3	N4
F_x	4520 lb	2060 lb	4460 lb	1790 lb
F_y	2180	5070	4290	1410
F_z	2690	1580	870	1630
M_x	119,680 in.-lb	130,660 in.-lb	25,640 in.-lb	45,260 in.-lb
M_y	60,200	115,320	50,000	21,780
M_z	59,980	154,550	145,520	126,770

[a] Equipment was requalified for the higher nozzle loadings.

TABLE 3.9-32 CORE SPRAY PUMP

	Criteria	Method of Analysis	Allowable Stress psi	Calculation psi
1.	Closure Bolting Loads: Normal and Upset Design pressure and temperature Design gasket load Seismic acceleration, nozzle forces and/or moments, static mass forces Bolting Stress Limit Allowable working stress per ASME Section VIII	Bolting loads and stresses calculated per "Rules for Bolted Flange Connections" ASME Section VIII, App. II	Maximum allowable stress 20,000	Maximum calculated 18,000
2.	Wall Thickness Loads: Normal and Upset Design pressure and temperature Stress Limit ASME Section VIII	Per rules of Part UG Section VIII	Maximum allowable stress main pump 17,500	Maximum calculated 11,680

TABLE 3.9-32 CORE SPRAY PUMP

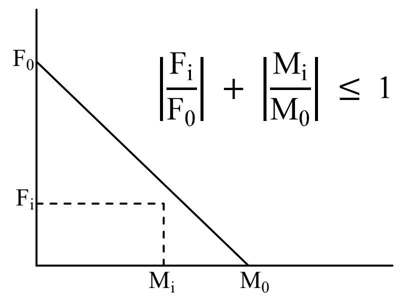
Criteria	Method of Analysis	Allowable Nozzle Forces and Moments, Force in lb, Moment in ft – lb	Calculated Nozzle Forces and Moments
3. Nozzle Loads Loads: Normal Plus Upset Design pressure and temperature Dead weight, force and/or moment, and operating-basis earthquake Loads: Emergency Design pressure and temperature Dead weight, force and/or moment, and design-basis earthquake Stress Limit ASME Section VIII Primary local membrane stress 1.5 of allowable stress for normal and upset, 1.8 of allowable stress for emergency	For the maximum stresses due to the maximum loads	The following expression relates the allowable combination of forces and moments  $\left\|\frac{F_i}{F_0}\right\| + \left\|\frac{M_i}{M_0}\right\| \leq 1$ where Fi = Largest of the three actual external orthogonal forces (F_x, F_y, and F_z) that may be imposed by the pipe Mi = Largest of the three actual external orthogonal moments (M_x, M_y, and M_z) permitted from the pipe when they are combined simultaneously for any condition Fo = Allowable value of Fi when all moments are zero Mo = Allowable value of Mi when all forces are zero	
		The values of Fo and Mo are given below Normal Plus Upset: Suction: Fo = 4540 Mo = 13,600 Discharge: Fo = 3550 Mo = 8800	Force in lb, moment in ft–lb Maximum Emergency Loads[a]: Suction (pump B): F_R = 21,000 M_R = 58,700

TABLE 3.9-32 CORE SPRAY PUMP

Criteria	Method of Analysis	Allowable Nozzle Forces and Moments, Force in lb, Moment in ft – lb		Calculated Nozzle Forces and Moments
		Emergency:		
		Suction:	Fo = 5450 Mo = 16,320	Discharge (Pump A): F_R = 7600 M_R = 25,200
		Discharge:	Fo = 4260 Mo = 10,570	

[a] Equipment was requalified for the higher nozzle loadings.

TABLE 3.9-33 HIGH-PRESSURE COOLANT INJECTION TURBINE

	Criteria	Method of Analysis	Allowable Stress or Minimum Thickness Required (psi)	Calculation (psi)
1.	Closure Bolting Loads: Normal and Upset Design pressure and temperature Design gasket load Bolting Stress Limit Allowable working stress per ASME Section VIII	Bolting loads and stresses calculated per "Rules for Bolted Flange Connections" ASME Section VIII, App. II	Maximum allowable stress 20,000	Maximum calculated 18,290
2.	Casing Wall Thickness Loads: Normal and Upset Design pressure and temperature Stress Limit ASME Section VIII	Per rules of Part UG Section VIII	Maximum allowable stress 17,500	Maximum calculated 7200
3.	Nozzle Loads	For the resultant moment due to pipe reaction, the resultant force shall not exceed the allowable Detailed design analysis has demonstrated the acceptability of these values	Force in lb, moment in ft - lb	
	Loads: Normal Design pressure and temperature Dead weight and thermal expansion		Inlet F = (7570 – M)/3	F_R = 1320 M_R = 3370
			Exhaust F = (9930 – M)/3	F_R = 1090 M_R = 3560
	Loads: Normal plus Upset Design pressure and temperature		Inlet F = (16,000 – M)/4	F_R = 1970 M_R = 4690
	Dead weight, thermal expansion, and operating-basis earthquake		Exhaust F = (20,000 – M)/0.8	F_R = 2280 M_R = 9770
	Loads: Emergency Design pressure and temperature		Inlet F = (16,000 – M)/4	F_R = 1970 M_R = 4690
	Dead weight, thermal expansion, and design-basis earthquake		Exhaust F = (20,000 – M)/0.8	F_R = 2590 M_R = 11,600

TABLE 3.9-33 HIGH-PRESSURE COOLANT INJECTION TURBINE

Criteria	Method of Analysis	Allowable Stress or Minimum Thickness Required (psi)	Calculation (psi)
Stress limits Specified by vendor for normal, ASME Section VIII for upset, increased 20 percent for emergency			
4. Turbine Mounting Bolts (turbine to baseplate) Loads: Normal and Upset Operating-basis earthquake Nozzle loads for OBE, dead weight and thermal expansion Loads: Emergency Design-basis earthquake Nozzle loads for design-basis earthquake, dead weight, and thermal expansion Stress limits ASME Section VIII allowable for normal and upset. For emergency 0.9 yield and twice allowable shear	Vertical and horizontal forces on mounting bolts calculated as the sum of seismic accelerations on the turbine and the pipe reaction forces and moments on the nozzles	Tensile and shear stress for bolting materials as specified in ASME Section VIII	By meeting the nozzle load criteria of 3 above, the detailed seismic analysis indicates the mounting bolts satisfy the allowable stress requirements

TABLE 3.9-34 HIGH-PRESSURE COOLANT INJECTION PUMP

	Criteria	Method of Analysis	Allowable Stress Thickness Required (psi)	Calculation (psi)
1.	Closure Bolting	Bolting loads and stresses calculated per "Rules for Bolted Flange Connections" ASME Section VIII, App. II	Main	Maximum calculated
	Loads: Normal and Upset		Maximum allowable stress 20,000	19,950
	Design pressure and temperature		Booster 20,000	17,400
	Design gasket load			
	Bolting Stress Limit			
	Allowable working stress per ASME Section VIII			
2.	Casing Wall Thickness	Per rules of Part UG Section VIII nozzle stress maximum case stress	Maximum allowable stress	Maximum calculated
	Loads: Normal and Upset		main pump 14,000 booster pump 14,000	12,050 3650
	Design pressure and temperature			
	Stress Limit			
	ASME Section VIII			
3.	Nozzle Loads	For the maximum resultant moment due to pipe reaction, the maximum resultant force shall not exceed the allowable	Force in lb, moment in ft-lb	
	Loads: Normal Plus Upset			
	Design pressure and temperature	Total nozzle stress with this criterion does not exceed stress limits	Suction F = 33,000 – 0.79M	F_R = 6370 M_R = 22,240
	Dead weight, thermal expansion, and operating-basis earthquake		Discharge F = 32,000 – 1.54M	F_R = 4730 M_R = 15,630

TABLE 3.9-34 HIGH-PRESSURE COOLANT INJECTION PUMP

Criteria	Method of Analysis	Allowable Stress Thickness Required (psi)	Calculation (psi)
Loads: Emergency			
Design pressure and temperature Dead weight, thermal expansion, and design-basis earthquake		Suction F = 43,000 – 0.74M	F_R = 10,690 M_R = 28,890
		Discharge F = 47,000 – 1.23M	F_R = 7020 M_R = 24,220
Stress Limit			
ASME Section VIII for normal and upset, 1.5 of allowable stress for emergency			

TABLE 3.9-35 REACTOR CORE ISOLATION COOLING TURBINE

	Criteria	Method of Analysis	Allowable Stress or Minimum Thickness Required (psi)	Calculation (psi)
1.	Closure Bolting Loads: Normal and Upset Design pressure and temperature Design gasket load Bolting Stress Limit Allowable working stress per ASME Section VIII	Bolting loads and stresses calculated per "Rules for Bolted Flange Connections" ASME Section VIII, App. II	Maximum allowable stress 20,000	Maximum calculated 6400
2.	Casing Wall Thickness Loads: Normal and Upset Design pressure and temperature Stress Limit ASME Section VIII	Per rules of Part UG Section VIII	Maximum allowable stress 17,500	Maximum calculated 12,700
3.	Nozzle Loads	For the resultant moment due to pipe reaction, the resultant force shall not exceed the allowable	Force in lb, moment in ft-lb	
	Loads: Normal Design pressure and temperature Dead weight and thermal expansion	Detailed design analysis has demonstrated the acceptability of these values	Inlet $F = (2,620 - M)/3$	$F_R = 50$ $M_R = 250$
			Exhaust $F = (6,000 - M)/3$	$F_R = 790$ $M_R = 2550$
	Loads: Normal plus Upset Design pressure and temperature		Inlet $F = (7,000 - M)/4.7$	$F_R = 620$ $M_R = 530$
	Dead weight, thermal expansion, and operating-basis earthquake		Exhaust $F = 3(10,000 - M)$ but not to exceed 10,000 lb	$F_R = 1710$ $M_R = 5350$

TABLE 3.9-35 REACTOR CORE ISOLATION COOLING TURBINE

	Criteria	Method of Analysis	Allowable Stress or Minimum Thickness Required (psi)	Calculation (psi)
	Loads: Emergency		Inlet	
	Design pressure and temperature		F = (7,000 – M)/4.7	F_R = 630 M_R = 550
	Dead weight, thermal expansion, and design-basis earthquake		Exhaust F = 3(10,000 – M) but not to exceed 10,000 lb	F_R = 3420 M_R = 8470
	Stress limits			
	Specified by vendor for normal, ASME Section VIII for upset, increased 20 percent for emergency			
4.	Turbine Mounting Bolts (turbine to baseplate)	Vertical and horizontal forces on mounting bolts calculated as the sum of seismic accelerations on the turbine and the pipe reaction forces and moments on the nozzles		
	Loads: Normal and Upset			
	Operating-basis earthquake Nozzle loads for operating-basis earthquake, dead weight and thermal expansion		Tensile and shear stress for bolting materials as specified in ASME Section VIII	By meeting the nozzle load criteria of 3 above, the detailed seismic analysis indicates the mounting bolts satisfy allowable stress requirements
	Loads: Emergency			
	Design-basis earthquake Nozzle loads for design-basis earthquake, dead weight, and thermal expansion		Tensile stress less than 0.9 yield and shear stress less than twice allowable of ASME Section VIII	

TABLE 3.9-35 REACTOR CORE ISOLATION COOLING TURBINE

Criteria	Method of Analysis	Allowable Stress or Minimum Thickness Required (psi)	Calculation (psi)
Stress Limits			
ASME Section VIII allowable for normal and upset. For emergency 0.9 yield and twice allowable shear			

TABLE 3.9-36 REACTOR CORE ISOLATION COOLING PUMP

	Criteria	Method of Analysis	Allowable Stress or Minimum Thickness Required (psi)	Calculation (psi)
1.	Closure Bolting Loads: Normal and Upset Design pressure and temperature Design gasket load	Bolting loads and stresses calculated per "Rules for Bolted Flange Connections" ASME Section VIII, App. II	Maximum allowable stress 25,000	Maximum calculated 22,600
	Bolting Stress Limit Allowable working stress per ASME Section VIII			
2.	Casing Wall Thickness	Per rules of Part UG Section VIII	Maximum allowable stress	Maximum calculated
	Loads: Normal and Upset Design pressure and temperature	Nozzle Stress	Main pump 17,500	5350
	Stress Limit ASME Section III	Volute stress is calculated per Roark's "Formulas for Stress and Strain"	Main pump 17,500	9200
3.	Nozzle Loads	For the maximum moment due to pipe reaction, the maximum force shall not exceed the allowable	Force in lb, moment in ft-lb	
	Loads: Normal plus Upset Design pressure and temperature Dead weight, thermal expansion and operating-basis earthquake	Total nozzle stress with this criterion does not exceed stress limits	Suction F = 9400 – 2.50M Discharge F = 9400 – 4.33M	F_R = 420 M_R = 910 F_R = 980 M_R = 1420
	Loads: Emergency Design pressure and temperature		Suction F = 19,000 – 2.42M	F_R = 750 M_R = 1670

TABLE 3.9-36 REACTOR CORE ISOLATION COOLING PUMP

Criteria	Method of Analysis	Allowable Stress or Minimum Thickness Required (psi)	Calculation (psi)
Dead weight, thermal expansion, and design-basis earthquake		Discharge $F = 19{,}000 - 5.05M$	$F_R = 1060$ $M_R = 1890$
Stress limit ASME Section VIII for normal and upset, 1.5 of allowable stress for emergency			

TABLE 3.9-37 STRESS SUMMARY - EMERGENCY EQUIPMENT COOLING WATER SYSTEM[a,b,c]

(Code used for analysis: ASME III, 1977 Edition, including Winter 1978 Addenda, Class 3)

Node	Equation 8	Equation 9, Upset	Equation 9, Emergency
40	1110	1430	1450
45A	1310	1690	1720
45B	1090	1290	1310
65	1250	2120	2190
80	1380	1660	1680
85	1520	2550	2610
90	1060	1390	1410
130	990	1120	1130
135A	1000	1230	1250
135B	987	1140	1160
200	1570	2760	2810
201	1620	2650	2680
330	1150	1390	1390
335A	1360	2210	2260
335B	1330	2000	2020
340	1170	1410	1400
345A	1380	1810	1790
345B	1030	1490	1480
352	1610	2190	2200
353	1610	2150	2160
358	1050	1410	1420
360A	1110	1690	1710
360B	974	1290	1300
365B	951	1370	1390

TABLE 3.9-37 STRESS SUMMARY - EMERGENCY EQUIPMENT COOLING WATER SYSTEM[a,b,c]

(Code used for analysis: ASME III, 1977 Edition, including Winter 1978 Addenda, Class 3)

Node	Equation 8	Equation 9, Upset	Equation 9, Emergency
370	1040	1580	1610
375	1040	1390	1410
Allowable	15,000	18,000	27,000

Reference: Stress Report DC – 2955.

[a] See Figure 3.9-17.

[b] In accordance with our snubber reduction program criteria, systems with low design temperatures are not subjected to rigorous thermal expansion analysis.

[c] Stresses are in pounds per square inch.

TABLE 3.9-38 STRESS SUMMARY - RHR SERVICE WATER RETURN LINE[a,b]

(Code used for analysis: ASME III, 1977 Edition, including Summer 1979 Addenda, Class 3)

Node	Equation 8	Equation 9, Upset	Equation 9, Emergency	Equation 10
600A	2840	4943	4574	3752
600B	3315	5562	5134	1706
602B	3337	5702	5291	2147
615A	3601	7336	6623	5703
615B	3162	5138	4846	5049
630	4034	5203	5236	4464
640A	3540	7244	7040	7494
640B	2935	6308	6001	8405
655A	3067	5910	5511	3633
655B	2943	6705	6126	2013
656B	2901	7293	6637	2348
682A	3214	9629	8584	3667
682B	4017	7149	6677	3225
684	3168	8383	7529	927
710A	3191	5336	5072	1174
710B	3406	5287	5007	490
716A	3576	5658	5314	783
716B	2880	4183	3969	1087
718A	2929	4442	4203	1372
718B	3101	5546	5231	1411
730	2977	4948	4729	1021
Allowable	15,000	18,000	27,000	22,500

Reference: Stress Report DC-2965.

[a] See Figure 3.9-18.

[b] Stresses are in pounds per square inch.

TABLE 3.9-39 STRESS SUMMARY - RHR CONTAINMENT SPRAY SYSTEM[a,b]

(Code used for analysis: ASME III, 1977 Edition, including Winter 1978 Addenda, Class 2)

Node	Equation 8	Equation 9, Upset	Equation 9, Emergency	Equation 10	Equation 11
8	3920	5650	5410	1730	5650
10A	4060	5620	5410	1920	5980
10B	3790	4790	4650	1640	5430
15A	4250	6320	6020	3240	7490
15B	4200	6160	5860	4070	8270
20A	3870	4760	4590	5530	9400
20B	3810	4500	4430	5420	9230
40A	4320	6150	5790	5050	9370
40B	4330	5830	5530	5630	9960
42	4390	5830	5510	3920	8300
62	4420	7080	6630	13,500	17,900
75A	6400	9920	9110	13,100	19,500
75B	6180	9590	8750	11,300	17,500
80	8460	15,000	13,400	19,400	27,800
91	4740	7410	6870	5320	10,100
100A	5010	6770	6470	15,500	20,500
100B	5020	6970	6620	15,400	20,500
115	4260	7390	6950	11,500	15,800
Allowable	15,000	18,000	27,000	22,500	37,500

Reference: Stress Report DC – 2972 Vol IA DCD1 Rev B

[a] See Figure 3.9-19.

[b] Stresses are in pounds per square inch.

TABLE 3.9-40 RECOMMEDED SPAN FOR DEADWEIGHT SUPPORTS

		Water-Filled		Gas-Filled		
Nominal Diameter	Schedule	Span[a]	Load (lb)	Span[a]	Load (lb)	Rod Diameter
1/2	40	6 ft 5 in.	12	6 ft 5 in.	10	
	80	6 ft 6 in.	12	6 ft 10 in.	12	3/8
	160	6 ft 6 in.	14	6 ft 7 in.	14	
3/4	40	7 ft 7 in.	16	8 ft 4 in.	16	
	80	7 ft 11 in.	20	8 ft 4 in.	18	3/8
	160	7 ft 10 in.	22	8 ft 1 in.	22	
1	40	9 ft 0 in.	26	9 ft 10 in.	24	
	80	9 ft 2 in.	32	9 ft 10 in.	30	3/8
	160	9 ft 2 in.	38	9 ft 6 in.	38	
1-1/4	40	10 ft 5 in.	42	11 ft 7 in.	38	
	80	10 ft 9 in.	50	11 ft 6 in.	46	3/8
	160	10 ft 10 in.	58	11 ft 5 in.	56	
1-1/2	40	11 ft 4 in.	52	12 ft 10 in.	48	
	80	11 ft 9 in.	64	12 ft 10 in.	58	3/8
	160	11 ft 10 in.	80	12 ft 6 in.	76	
2	40	12 ft 9 in.	82	14 ft 9 in.	72	
	80	13 ft 2 in.	102	14 ft 9 in.	94	3/8
	160	13 ft 6 in.	136	14 ft 4 in.	128	
2-1/2	40	14 ft 6 in.	138	16 ft 9 in.	120	
	80	15 ft 0 in.	168	16 ft 7 in.	152	1/2
	160	15 ft 1 in.	202	16 ft 2 in.	190	

TABLE 3.9-40 RECOMMEDED SPAN FOR DEADWEIGHT SUPPORTS

		Water-Filled		Gas-Filled		
Diameter	Diameter	Diameter	Diameter	Diameter	Diameter	Diameter
3	40	15 ft 6 in.	210	18 ft 1 in.	180	
	80	16 ft 2 in.	248	18 ft 1 in.	232	1/2
	160	16 ft 7 in.	326	17 ft 10 in.	306	
3-1/2	40	16 ft 7 in.	272	19 ft 9 in.	232	
	80	17 ft 5 in.	340	19 ft 9 in.	302	5/8
	XXS	17 ft 11 in.	520	18 ft 11 in.	496	
4	40	17 ft 7 in.	346	21 ft 2 in.	290	
	80	18 ft 7 in.	436	21 ft 3 in.	384	5/8
	160	19 ft 2 in.	584	20 ft 6 in.	542	

[a] The actual span should not exceed the recommended value by more than 1 ft.

TABLE 3.9-41 MINIMUM OFFSET NEAR NOZZLES WITH EXPANSION MOVEMENT[a]

Nominal Diameter (in.)	Deflection (in.) 1/4	1/2	3/4	1	1-1/4	1-1/2	1-3/4	2	2-1/4	2-1/2
1/2	3ft 11in.	5ft 6in.	6ft 9in.	7ft 9in.	8ft 9in.	9ft 6in.	10ft 3in.	11ft 0in.	11ft 8in.	12ft 4in.
3/4	4ft 4in.	6ft 2in.	7ft 6in.	8ft 9in.	9ft 9in.	10ft 8in.	11ft 6in.	12ft 4in.	13ft 0in.	13ft 9in.
1	4ft 10in.	6ft 11in.	8ft 5in.	9ft 9in.	10ft 11in.	11ft 11in.	12ft 11in.	13ft 9in.	14ft 7in.	15ft 5in.
1-1/4	5ft 6in.	7ft 9in.	9ft 6in.	10ft 11in.	12ft 3in.	13ft 5in.	14ft 6in.	15ft 6in.	16ft 5in.	17ft 4in.
1-1/2	5ft 10in.	8ft 3in.	10ft 2in.	11ft 9in.	13ft 1in.	14ft 4in.	15ft 6in.	16ft 6in.	17ft 6in.	18ft 6in.
2	6ft 6in.	9ft 3in.	11ft 4in.	13ft 1in.	14ft 7in.	16ft 0in.	17ft 4in.	18ft 6in.	19ft 7in.	20ft 8in.
2-1/2	7ft 2in.	10ft 2in.	12ft 6in.	14ft 4in.	16ft 1in.	17ft 8in.	19ft 0in.	20ft 4in.	21ft 7in.	22ft 9in.
3	7ft 11in.	11ft 3in.	13ft 9in.	15ft 10in.	17ft 9in.	19ft 5in.	21ft 0in.	22ft 5in.	23ft 10in.	25ft 1in.
3-1/2	8ft 6in.	12ft 0in.	14ft 9in.	17ft 0in.	19ft 0in.	20ft 9in.	22ft 6in.	24ft 0in.	25ft 6in.	26ft 10in.
4	9ft 0in.	12ft 9in.	15ft 7in.	18ft 0in.	20ft 2in.	22ft 0in.	23ft 10in.	25ft 6in.	27ft 0in.	28ft 6in.

[a] This is the minimum length of pipe which is installed perpendicular to the direction of nozzle movement between the nozzle and the first restraint which acts in that direction. Movements in three orthogonal directions are considered.

TABLE 3.9-42 MINIMUM OFFSET REQUIRED TO ACCOMMODATE THERMAL EXPANSION OF PIPING

Nominal Diameter (in.)	Expanding Length (ft)	Design Temp. (°F)	Piping Material	Offset Required (ft – in.)
1/2	5	500	LCS[a]	2 ft 7 in.
3/4	10	325	LCS	3 ft 1 in.
1	15	150	LCS	2 ft 3 in.
1-1/4	20	575	LCS	7 ft 10 in.
1-1/2	25	475	LCS	8 ft 3 in.
2	30	450	LCS	9 ft 9 in.
2-1/2	35	275	LCS	8 ft 3 in.
3	40	175	LCS	6 ft 10 in.
3-1/2	45	225	LCS	9 ft 6 in.
4	50	300	LCS	13 ft 1 in.
1/2	5	500	AUS[b]	3 ft 0 in.
3/4	10	325	AUS	3 ft 6 in.
1	15	150	AUS	2 ft 9 in.
1-1/4	20	575	AUS	9 ft 3 in.
1-1/2	25	475	AUS	9 ft 7 in.
2	30	450	AUS	11 ft 4 in.
2-1/2	35	275	AUS	9 ft 11 in.
3	40	175	AUS	8 ft 4 in.
3-1/2	45	225	AUS	11 ft 6 in.
4	50	300	AUS	15 ft 8 in.

[a] LCS = Low carbon steel (SA-106 grade B or equivalent).

[b] AUS = Austenitic steel (SA-312 TP304L or 316L or equivalent).

TABLE 3.9-43 SAFETY-RELATED MECHANICAL COMPONENTS NOT COVERED BY ASME CODE

	Principal Component	Table or Subsection Number[a]	Design Code	Qualification Method
I.	Reactor system			
	CRD housing supports	-	AISC	Analytical
	Reactor internal structures, engineered safety features	4.5	NA	Analytical, empirical
	Control rods	4.5	NA	Prototype tests
	Control rod drives	4.5	NA	Analytical and prototype tests
	Core support structure	4.5	NA	Analytical
	Reactor vessel stabilizer	-	AISC	Analytical
	Fuel assemblies	4.5		
II.	Recirculation system			
	Pipe restraints, recirculation line	3.9.2.1 - 3.9.2.2	AISC	Analytical and tests
III.	CRD hydraulic system			
	Hydraulic control unit	4.5.2.3	ASME, ANSI	Analytical, prototype tests
IV.	Standby liquid control system[b]		API-620	Seismic analyses
	Atmospheric storage tank		API-650	
V.	High-pressure coolant injection		ASME Section VIII	Analytical
	Turbine			
VI.	RCIC System		ASME Section VIII	Analytical
	Turbine			

TABLE 3.9-43 SAFETY-RELATED MECHANICAL COMPONENTS NOT COVERED BY ASME CODE

	Principal Component	Table or Subsection Number[a]	Design Code	Qualification Method
VII.	RHR service water system		AISC, ACI	Analytical
	Mechanical draft cooling towers			
VIII.	Diesel generator systems		DEMA, ANSI, IEEE, NEMA	Analytical
	Diesel generators			
IX.	Standby gas treatment system All components with safety functions		AMCA, SMACNA, ORNL-NSIC-65	Analytical, prototype tests
X.	Reactor building ventilation		AMCA, SMACNA	Analytical
	All components with safety function			
XI.	Emergency equipment area cooling units		AMCA, SMACNA	Analytical
XII.	Reactor building crane		CMAA, ASTM	Analytical, testing

[a] Location of summary of stress and dynamic calculations or experimental testing.

[b] SLCS was not originally intended, procured, designed or classified as safety-related, but it is maintained and tested as a safety-related system.

TABLE 3.9-44 OPERABILITY ASSURANCE PROGRAM CRITERIA COMPARISON

NRC Criteria (SRP 3.9.3.-II.2)	Fermi Criteria (UFSAR Section)	Comments, Subject
(2)(a)	3.9.4.2	SSE per IEEE 344, Environmental per IEEE 382-1972
(2)(b)i, ii	3.7.3.1(b)	Seismic stress cycling (valves)
	3.7.3.16.1	Seismic analysis, static-peak floor response or dynamic - actual eigen frequencies
	3.9.4.2	Valve seismic operability
	3.9.4.3	Pump seismic operability
	Tables 3.9-17 through 3.9-20, 3.9-28 through 3.9-36	Seismic and stress analysis details for pumps and valves
(2)(b)iii	3.9.1.2.b.4	Feedwater check valve disk analysis
(2)(b)iv	N/A	No essential primary coolant pump in BWRs
(2)(b)v	N/A See above	ECCS pumps are not LOCA-affected
(2)(b)vi	Tables 3.9-17 through 3.9-20, 3.9-28 through 3.9-36	Stress analysis details and wall thickness calculations
(2)(b)vii	3.7.3.16.1	See also above under (2)(b)i, ii
	3.9.2.2.1	Class 2 and 3 pumps, design criteria
	3.9.2.4	Analytical and empirical design methods for Class 2 and 3 pumps and valves
(3)(b)	3.9.2.2.4.1	Design analysis for supports and anchor bolts Based on AISC Criteria which is the basis for ASME Section III Subsection "NF."

TABLE 3.9-45 MAXIMUM CUMULATIVE USAGE FACTORS (CUF) BASED ON PLANT OPERATING HISTORY

Table 3.9-45 has been deleted.

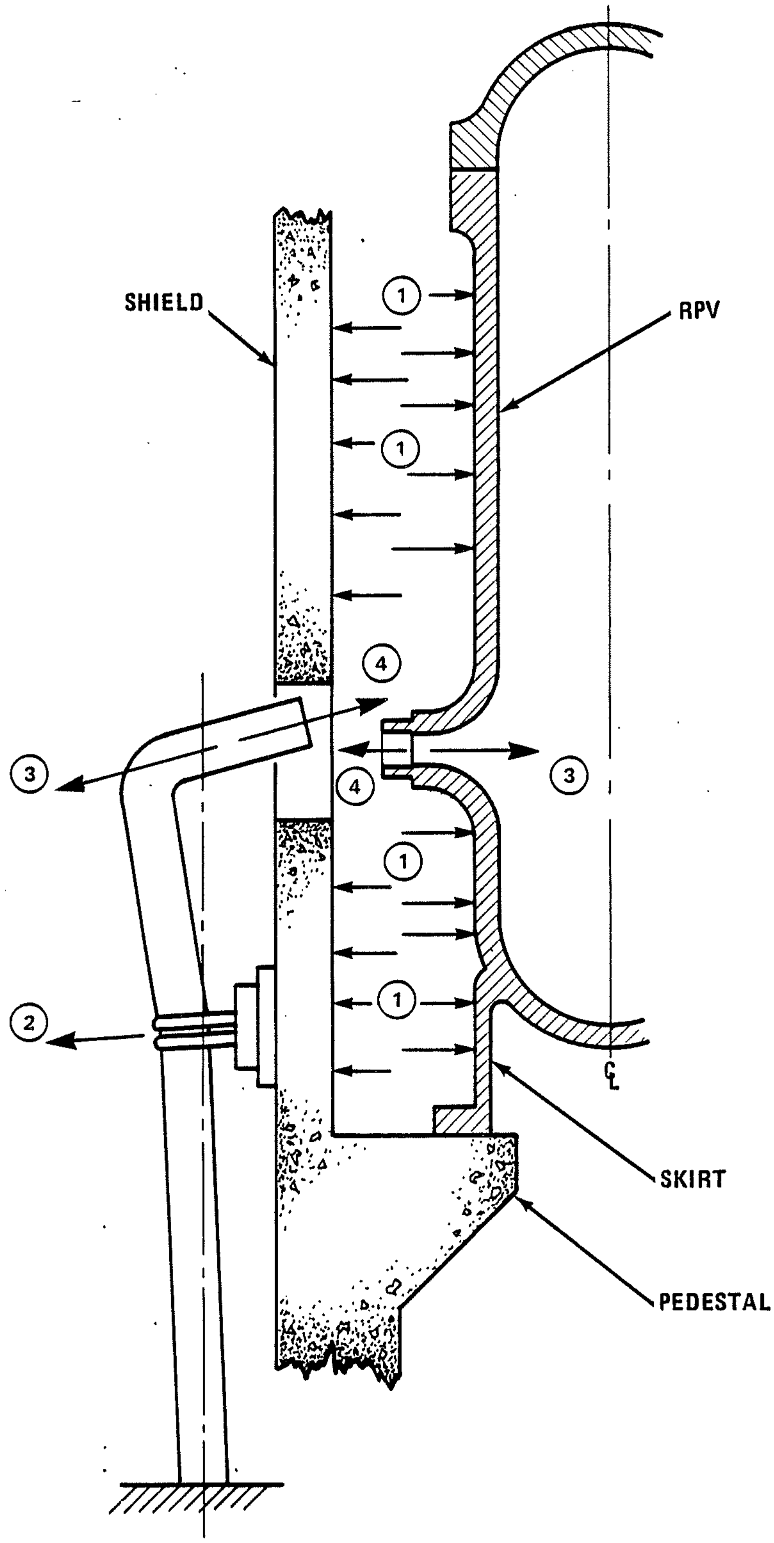


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FIGURE 3.9-1

LOADING DESCRIPTION

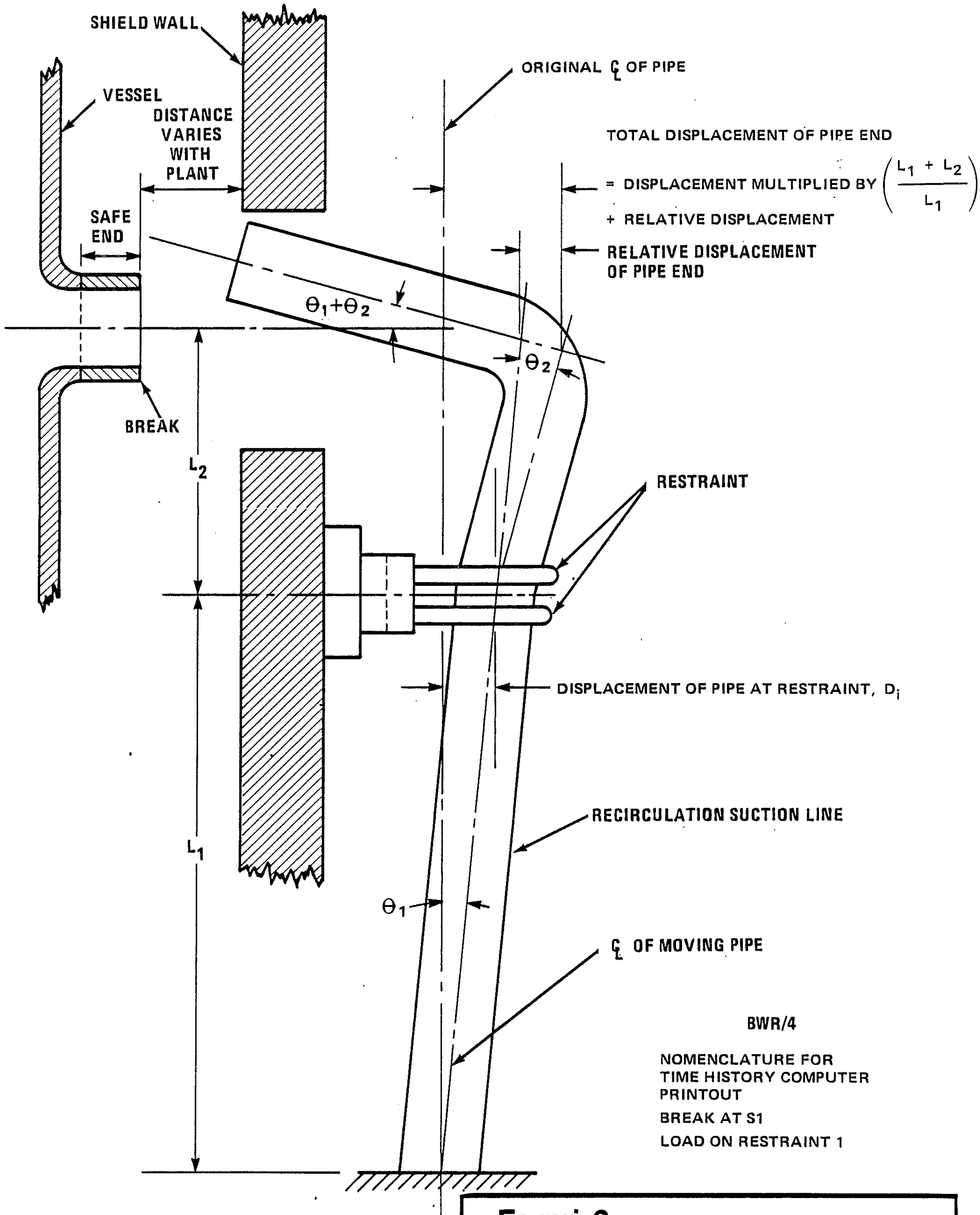

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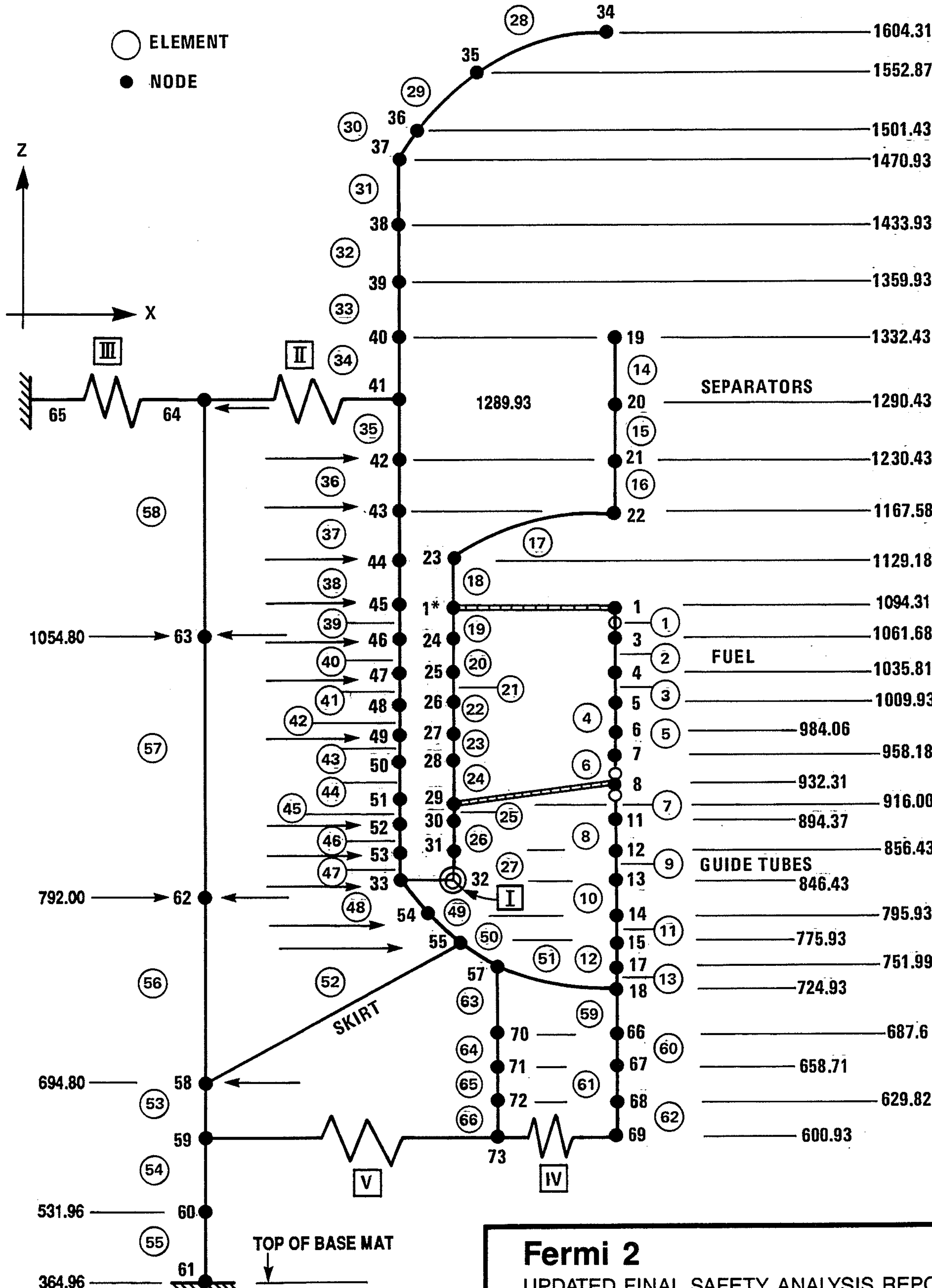
FIGURE 3.9-2

NOMENCLATURE FOR JET LOAD CALCULATION



NOTE: MODEL NODAL ELEVATION IS IN INCHES. ADD 6095.04 INCHES TO OBTAIN ACTUAL SITE ELEVATION.

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FIGURE 3.9-3

HORIZONTAL BEAM MODEL

FIGURES 3.9-4 AND 3.9-5 HAVE BEEN DELETED

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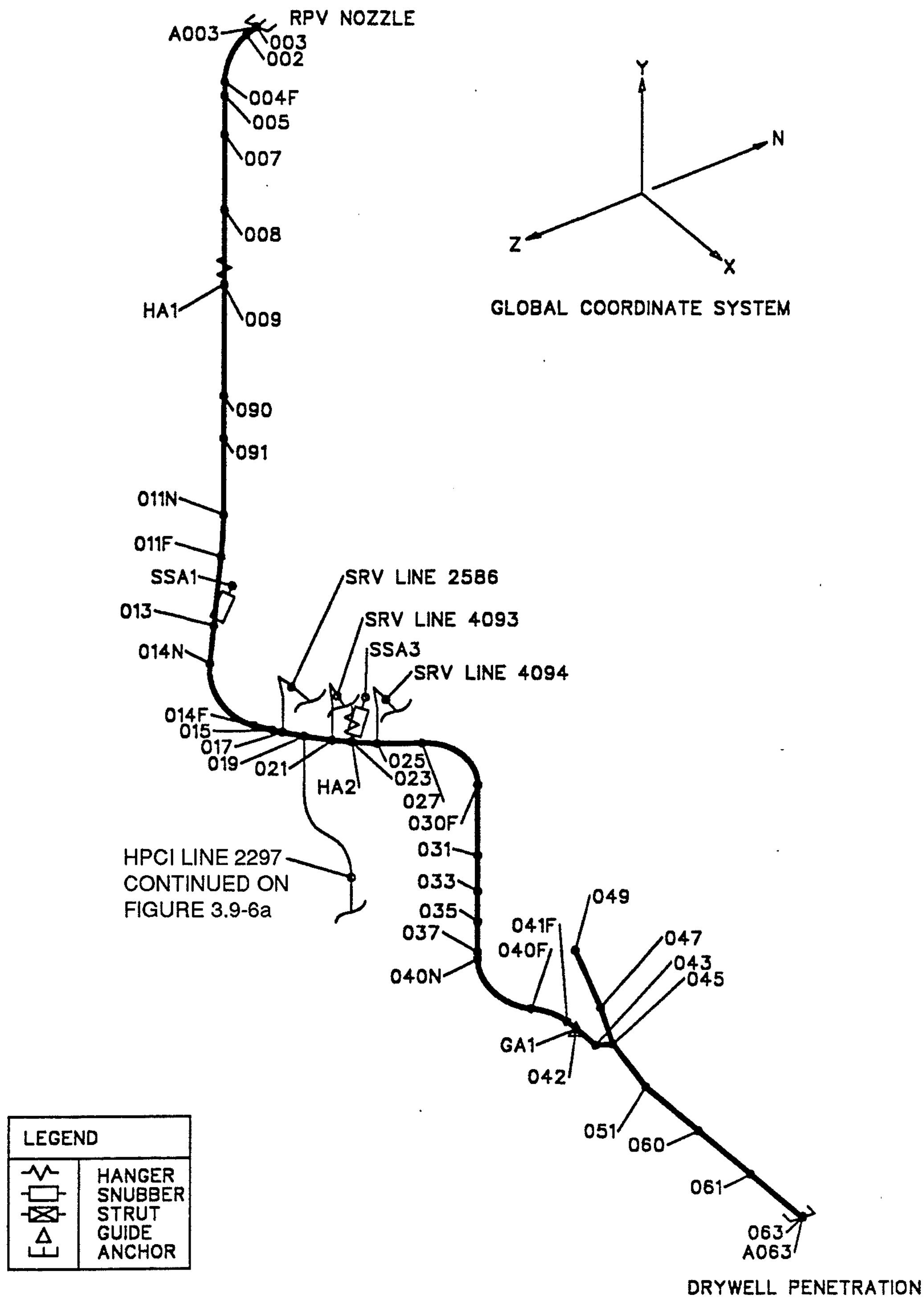

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FIGURE 3.9-6

MAIN STEAM LINE A
STRESS ISOMETRIC NODE DIAGRAM

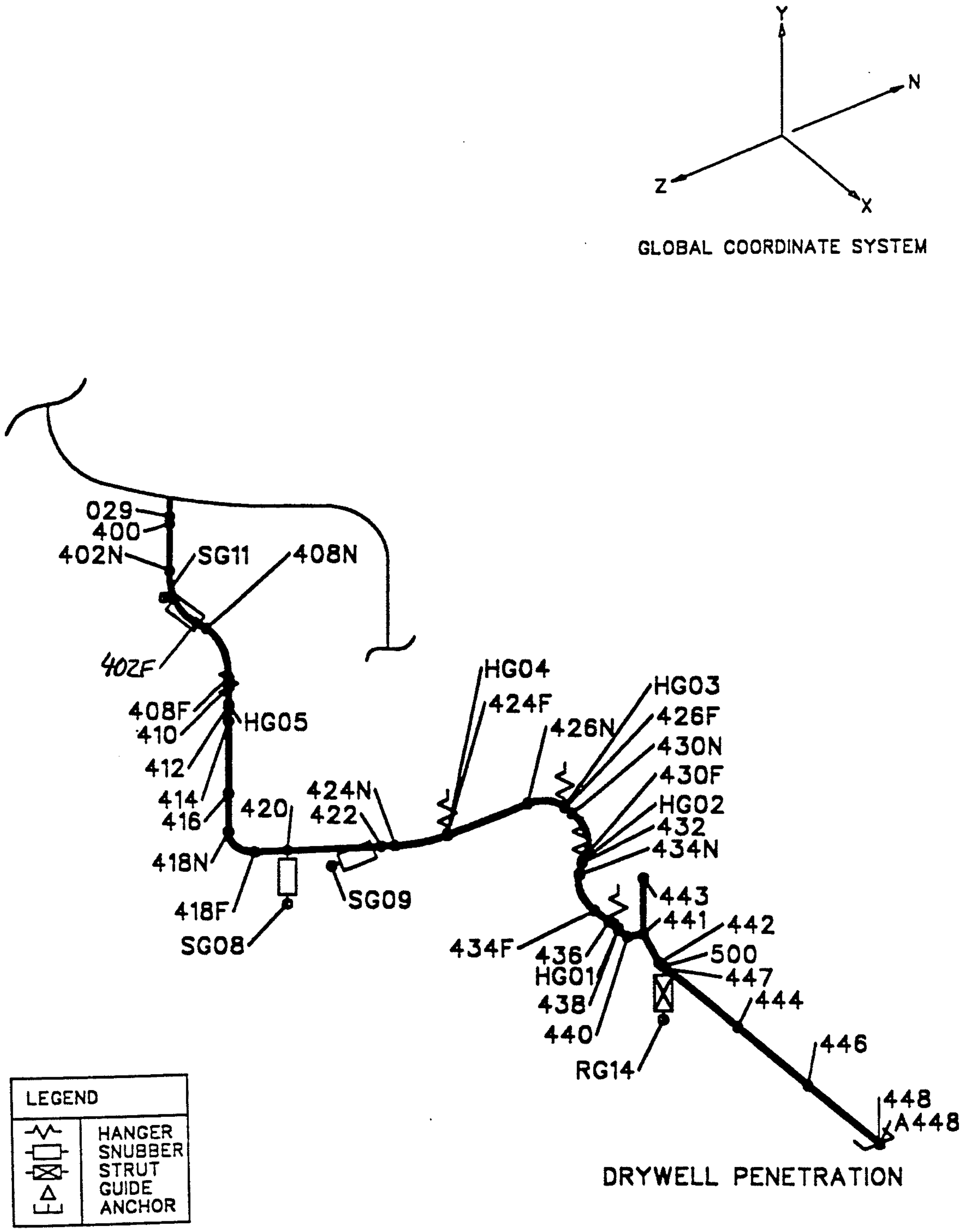

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FIGURE 3.9-6a

HPCI LINE 2297
STRESS ISOMETRIC NODE DIAGRAM

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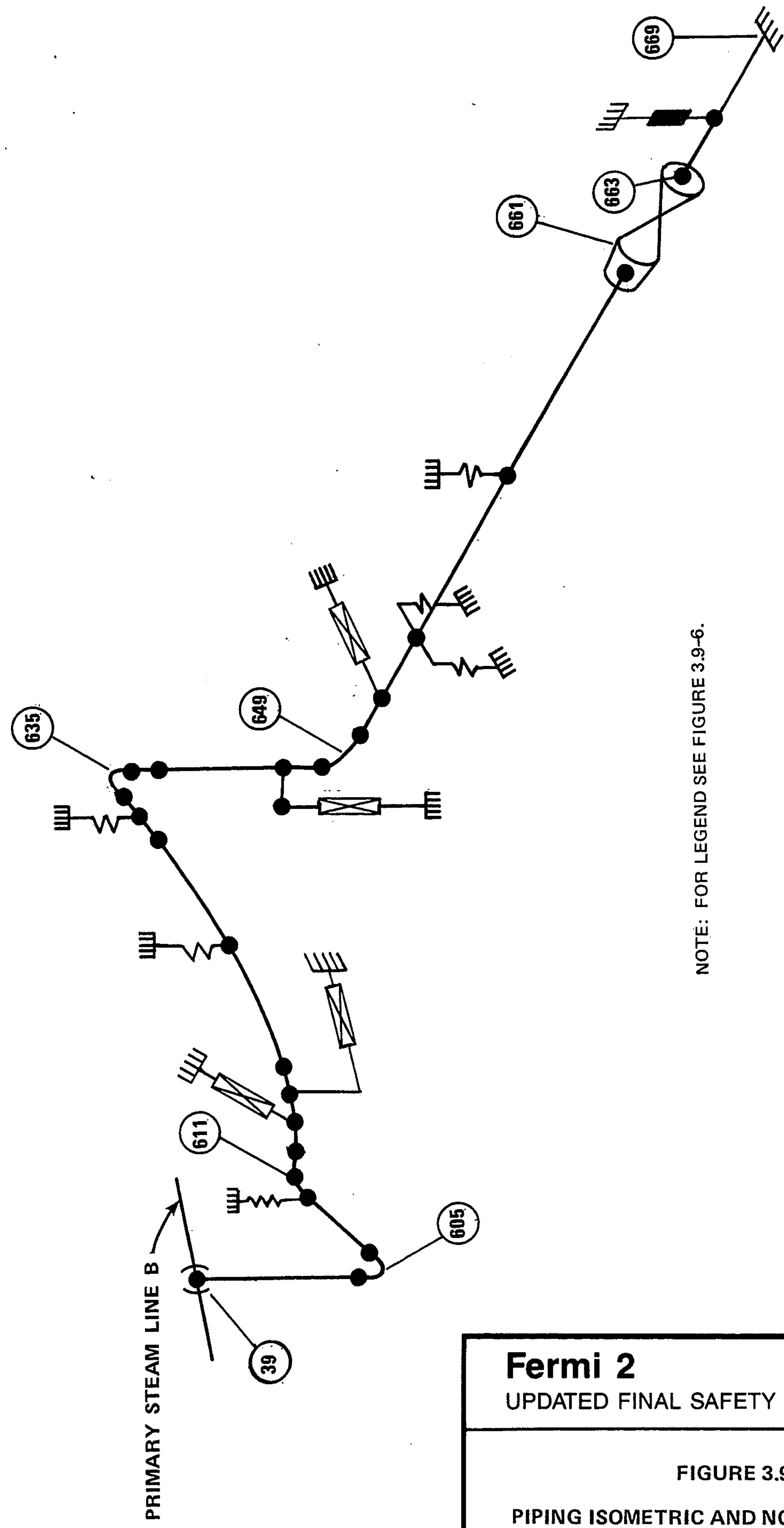

NOTE: FOR LEGEND SEE FIGURE 3.9-6.

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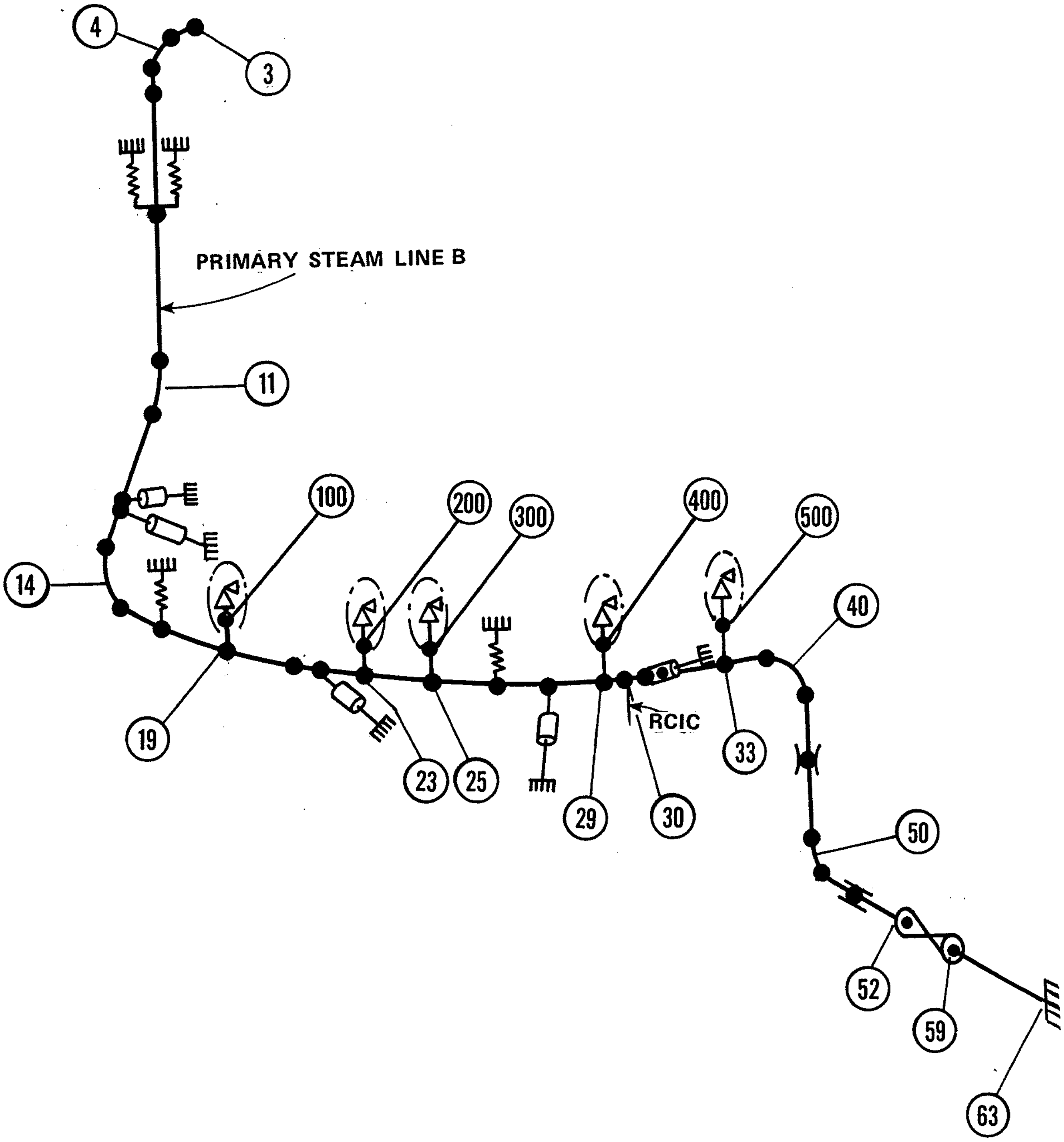
FIGURE 3.9-7

PIPING ISOMETRIC AND NODE DESIGNATION
REACTOR CORE ISOLATION COOLING SYSTEM



NOTE: S/RVD LINES ARE INCLUDED IN THE ANALYSIS MODEL TO ACCOUNT FOR THEIR EFFECT ON THE MAIN STEAM LINE. FOR LEGEND SEE FIGURE 3.9-6.

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FIGURE 3.9-8

PIPING ISOMETRIC AND NODE DESIGNATION
MAIN STEAM LINE "B"

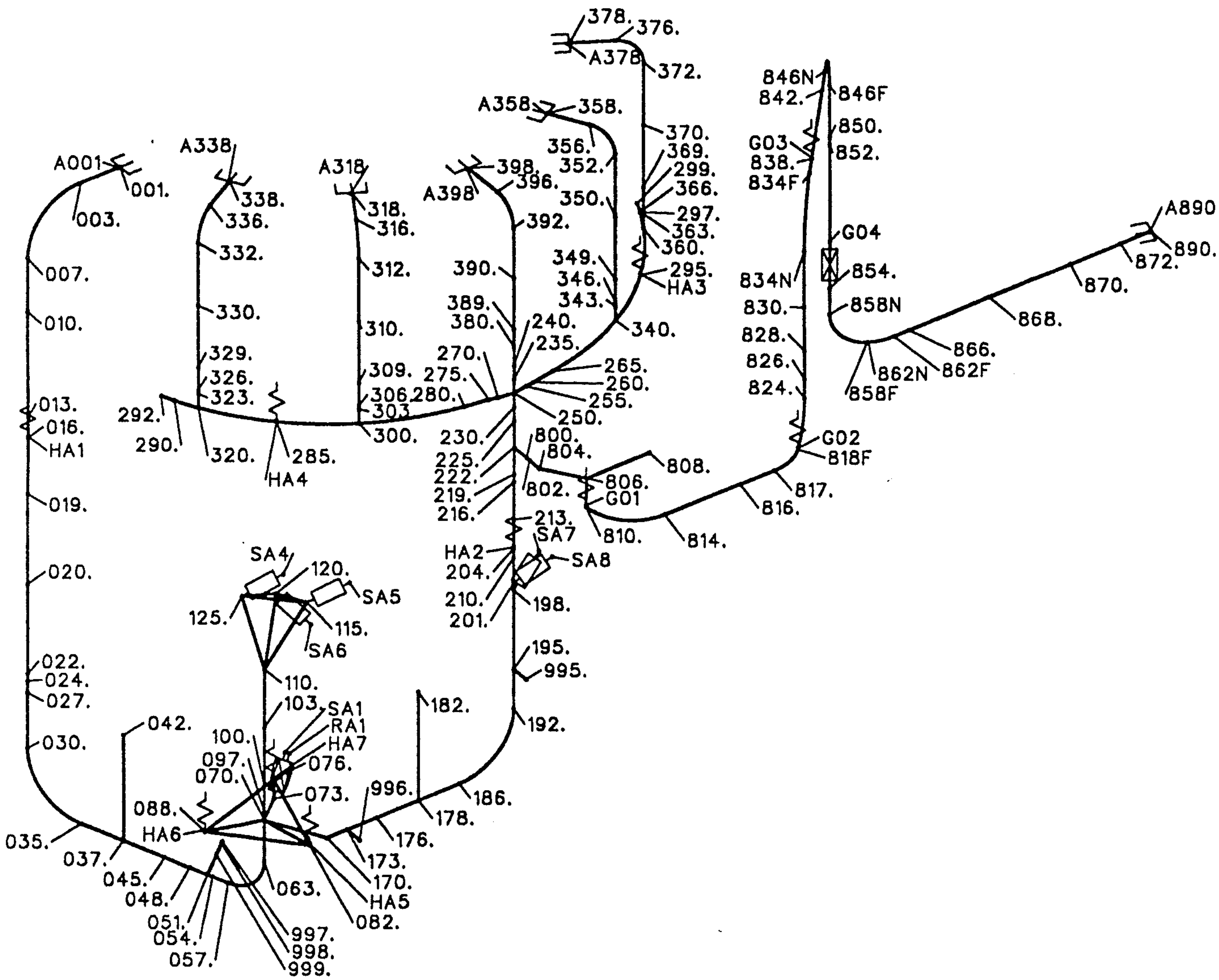

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FIGURE 3.9-9

PIPING ISOMETRIC AND NODE DESIGNATION RECIRCULATION SYSTEM LOOP "A"

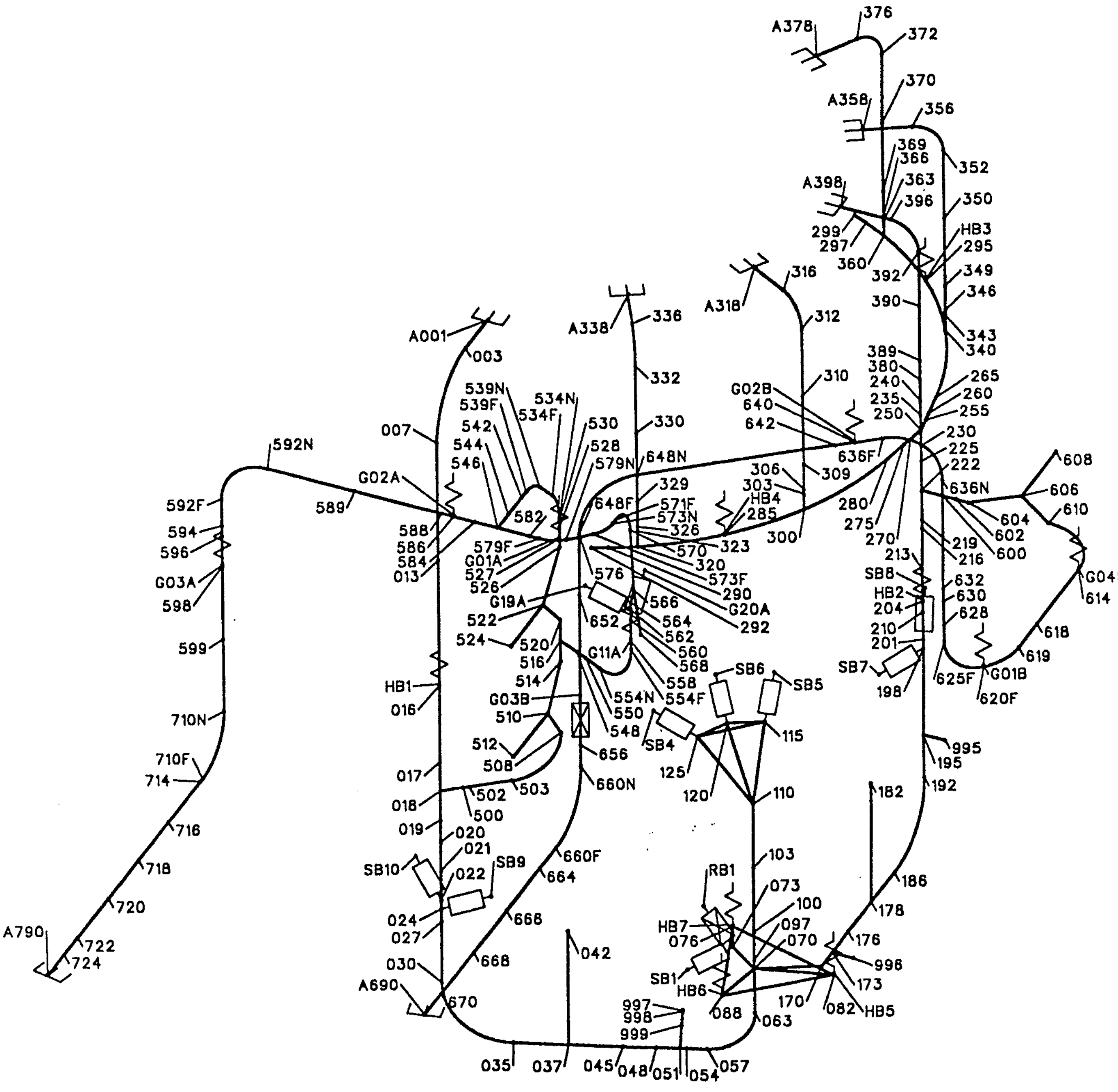

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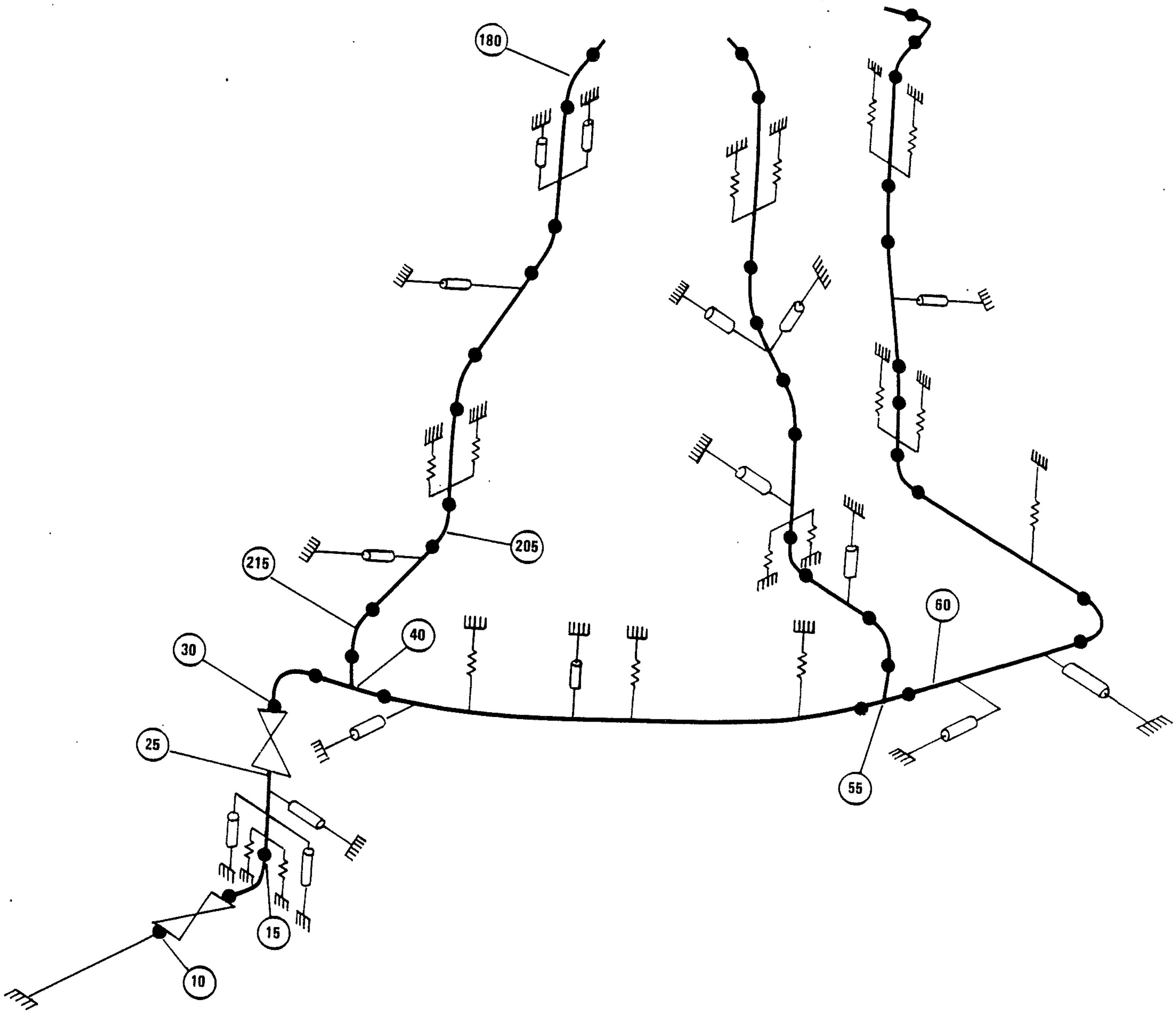
FIGURE 3.9-10

PIPING ISOMETRIC AND NODE DESIGNATION RECIRCULATION SYSTEM LOOP "B"

FIGURES 3.9-11 THROUGH 3.9-13

ARE INTENTIONALLY DELETED



NOTE: FOR LEGEND SEE FIGURE 3.9-6.

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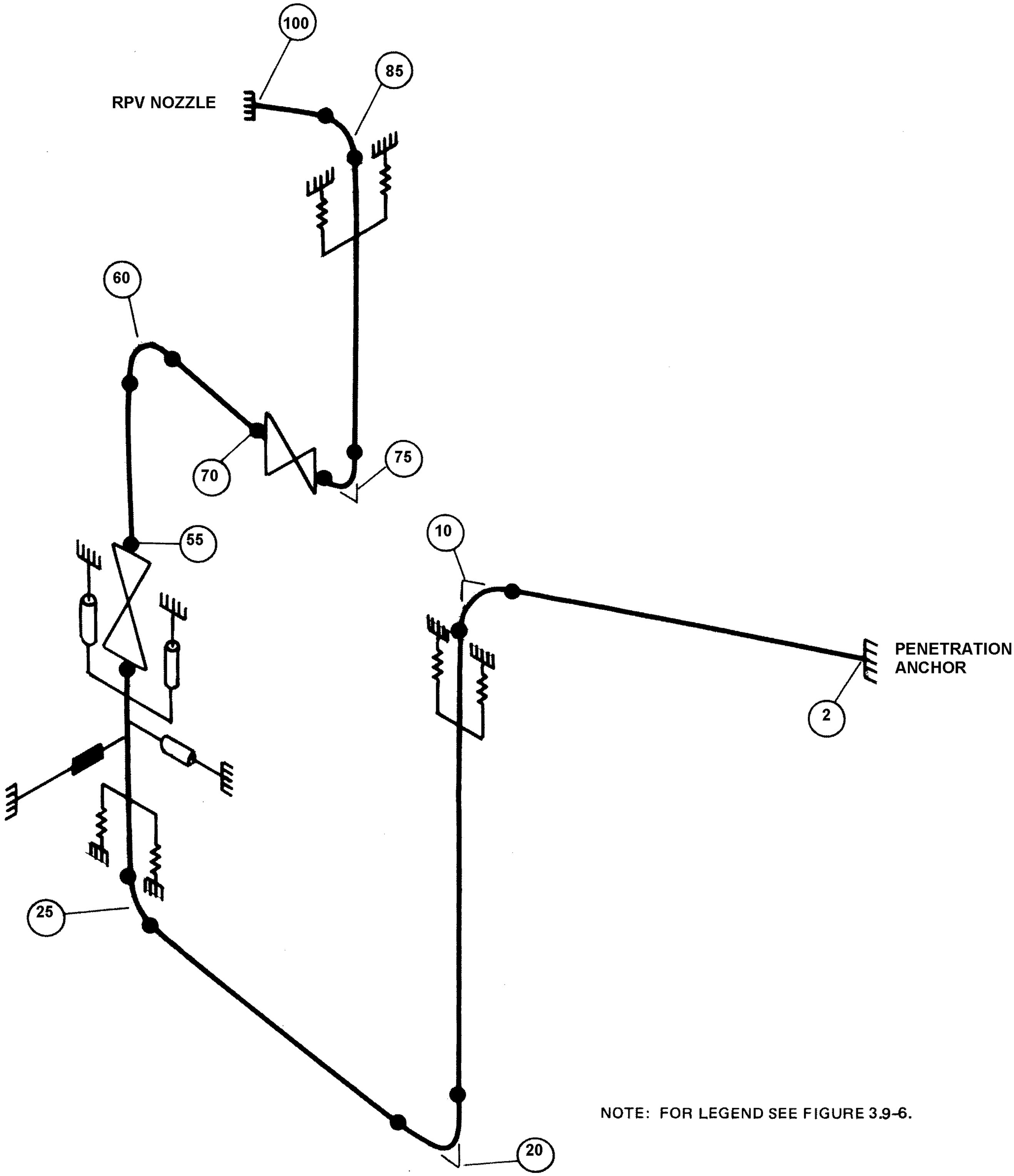
FIGURE 3.9-14

PIPING ISOMETRIC AND NODE DESIGNATION FEEDWATER SYSTEM FROM REACTOR PRESSURE VESSEL TO CONTAINMENT



NOTE: FOR LEGEND SEE FIGURE 3.9-6.

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FIGURE 3.9-15

PIPING ISOMETRIC AND NODE DESIGNATION CORE SPRAY SYSTEM INSIDE DRYWELL

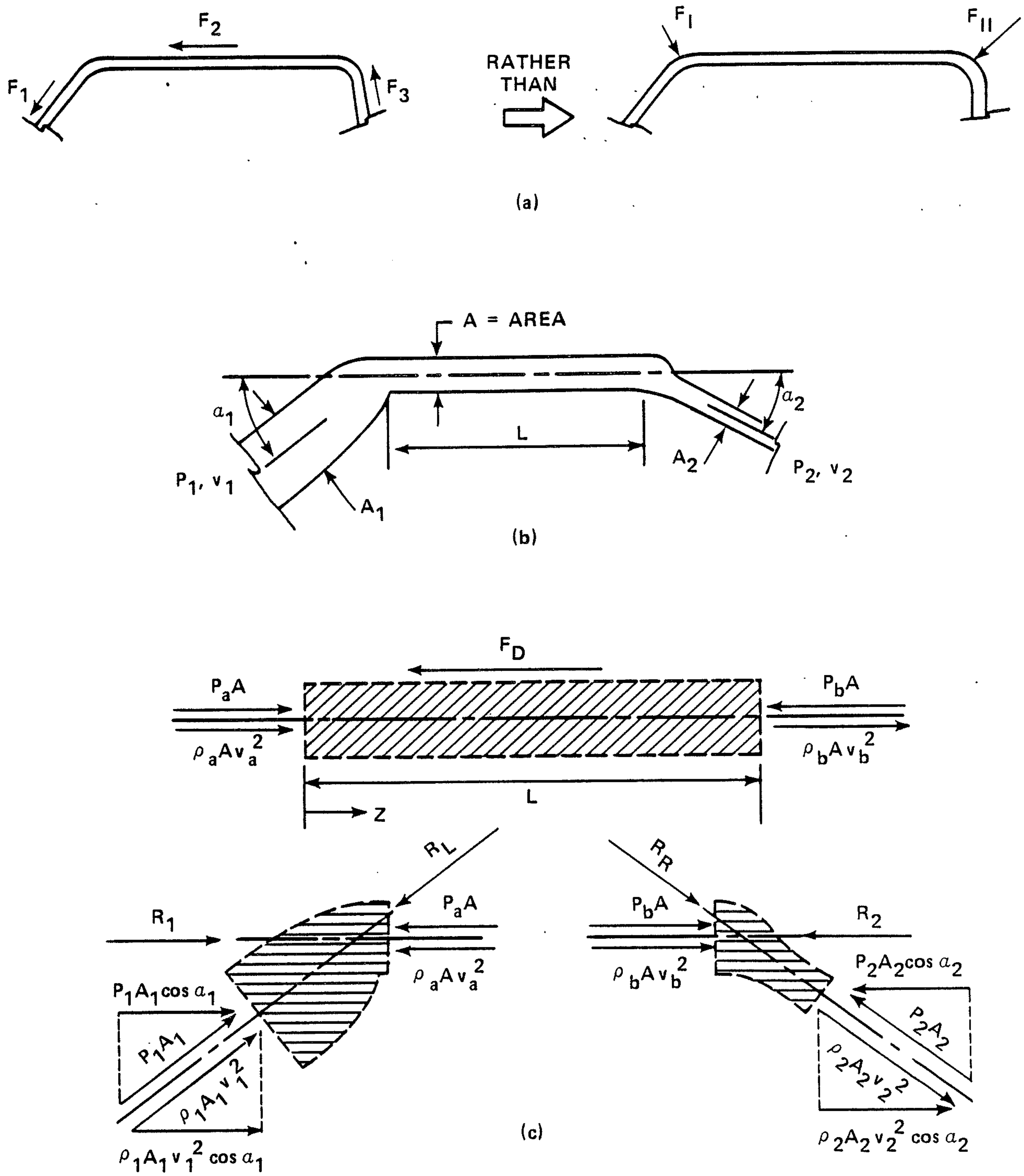

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FIGURE 3.9-16

RELIEF VALVE FORCING FUNCTIONS

Figure Intentionally Removed
Refer to Plant Drawing M-3084-2

FIGURE 3.9-17

STRESS ANALYSIS DIAGRAM - EMERGENCY EQUIPMENT COOLING WATER SYSTEM PUMP SUCTION FROM HEAT EXCHANGER

Figure Intentionally Removed
Refer to Plant Drawing M-3184-2

FIGURE 3.9-18

STRESS ANALYSIS DIAGRAM – RESIDUAL HEAT REMOVAL SERVICE WATER RETURN LINE FROM HEAT EXCHANGER

Figure Intentionally Removed
Refer to Plant Drawing M-3159-2

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FIGURE 3.9-19

STRESS ANALYSIS DIAGRAM - RESIDUAL HEAT REMOVAL CONTAINMENT SPRAY RETURN TO DRYWELL

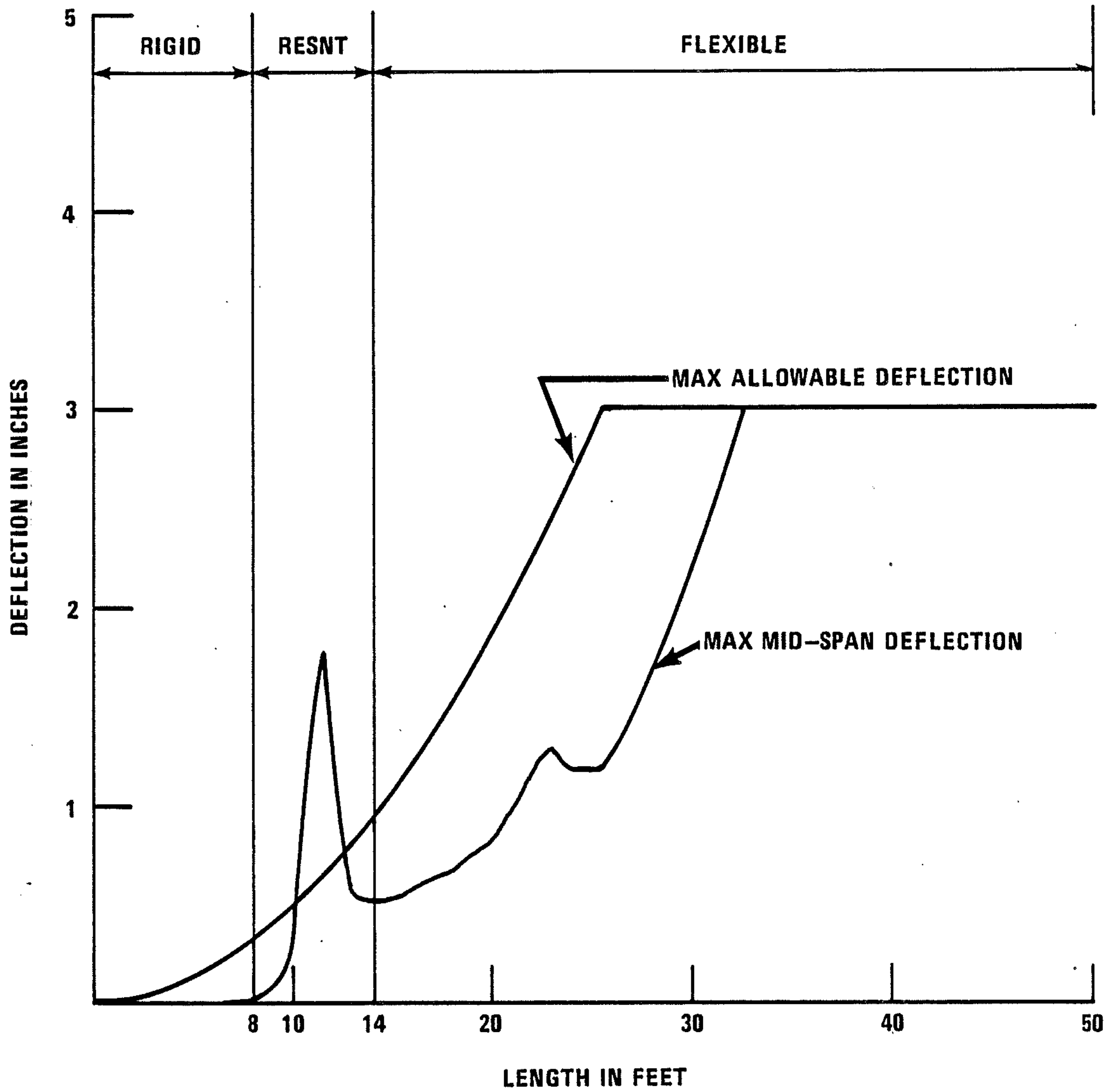

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FIGURE 3.9-20

SEISMIC DESIGN CURVES – ½ IN. PIPE SEISMIC DEFLECTION VERSUS SPAN

SARGENT & LUNDY DRAWING

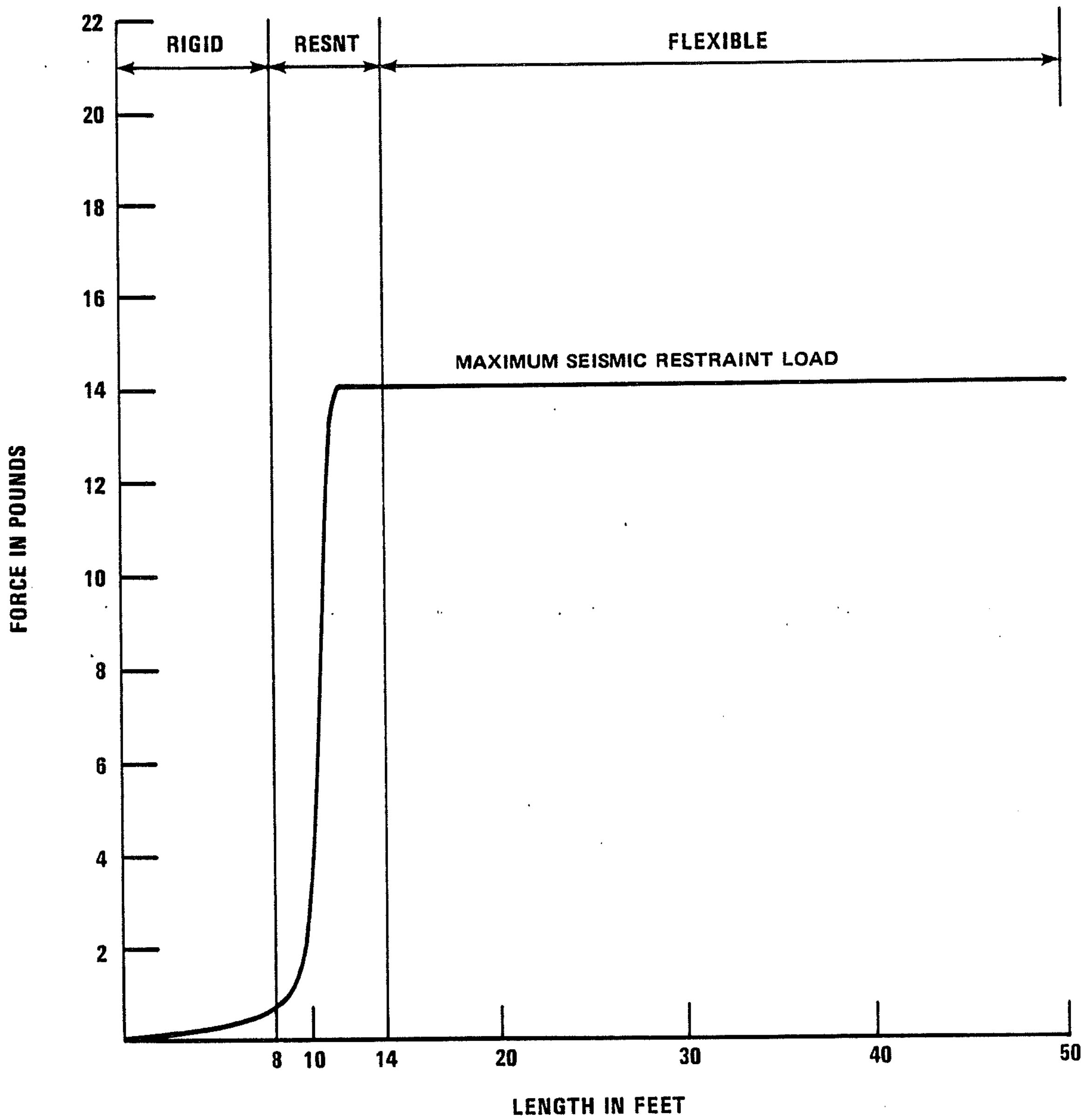

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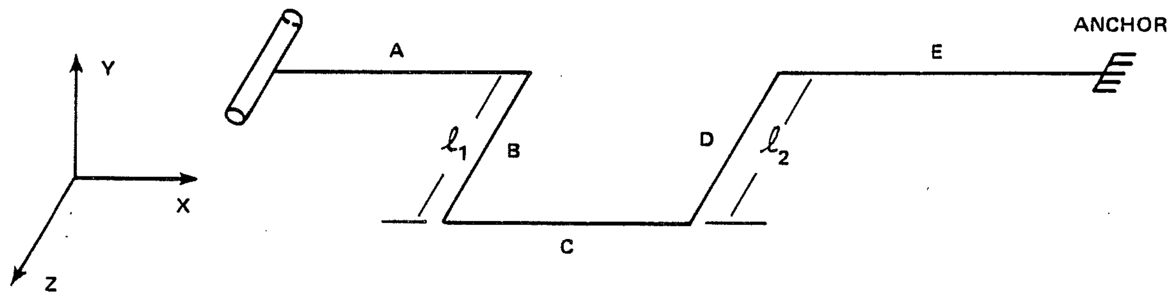
FIGURE 3.9-21

SEISMIC DESIGN CURVES – ½ IN. PIPE SEISMIC RESTRAINT VERSUS SPAN

SARGENT & LUNDY DRAWING



SARGENT & LUNDY DRAWING

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FIGURE 3.9-22

FLEXIBILITY ANALYSIS OF PIPING SYSTEM SCHEMATIC

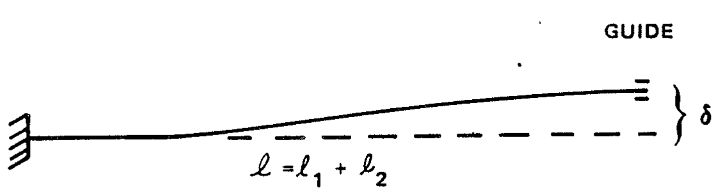

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FIGURE 3.9-23

NOZZLE FLEXIBILITY MODEL SCHEMATIC

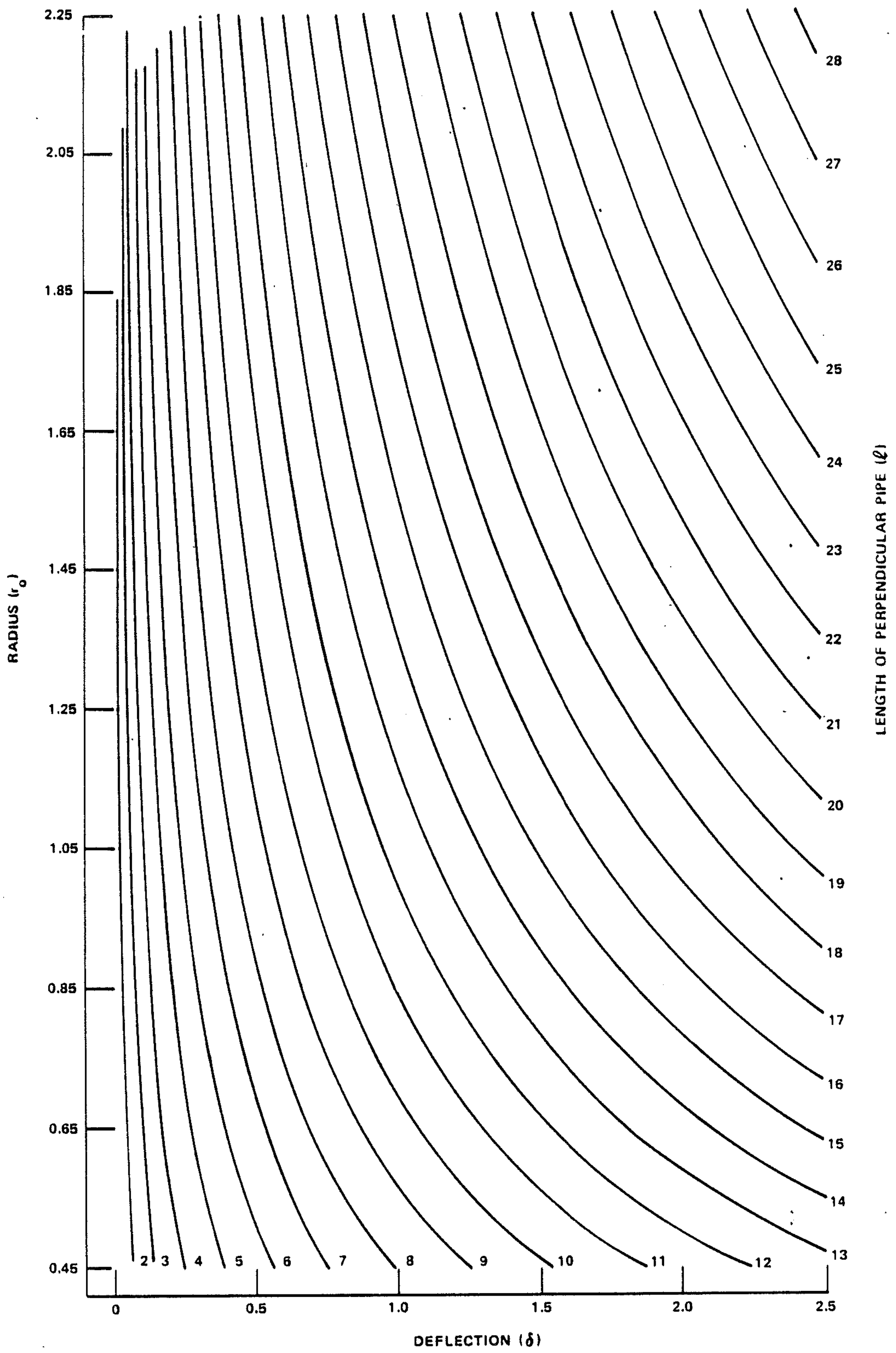

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FIGURE 3.9-24

LENGTH OF PERPENDICULAR PIPE REQUIRED TO ACCOMODATE THERMAL DEFLECTION

SARGENT & LUNDY DRAWING

3.10 SEISMIC DESIGN OF CATEGORY I INSTRUMENTATION AND ELECTRICAL EQUIPMENT

3.10.1 Seismic Design Criteria

3.10.1.1 Introduction

All Category I instrumentation and electrical equipment is designed to resist and withstand the effects of the two postulated Fermi 2 earthquakes, the safe-shutdown earthquake (SSE) and the operating-basis earthquake (OBE).

Category I instrumentation and electrical equipment is designed to withstand the effects of the SSE as defined in Section 3.7 without functional impairment. A list of major Category I instrumentation and electrical equipment is included in Table 3.2-1.

From the basic input ground motion data described in Sections 2.5 and 3.7, a series of response spectra at various floor elevations in both the vertical and horizontal directions was developed. After the dynamic analysis of the building was completed, the maximum seismic loadings derived from the appropriate spectra were included in the purchase specifications of Category I systems and equipment.

All vendors are required to qualify their equipment for both the SSE and the OBE using the response curves applicable to the particular building location of their equipment.

Suppliers of Category I equipment such as batteries, racks, local process-connected instrument panels, and control consoles are required to submit test data, operating experience, and/or calculations to substantiate that their components and systems would not suffer loss of function during and/or (as required) after seismic loadings as a result of the SSE. Before the equipment was accepted by Edison, proof of compliance with the accepted seismic qualifications procedures was provided to the Fermi 2 project for approval.

Since the construction permit application for Fermi 2 was docketed before October 27, 1972, the seismic qualification of Category I instrumentation, electrical equipment, and supports is required to meet the requirements of IEEE 344-1971 (Reference 1). The NRC staff conducted a review (Seismic Qualification Review Team (SQRT) audit to ensure that such components have an adequate margin to perform their intended design functions during the seismic event. During the review period, 1981 through 1984, Edison provided the SQRT with information regarding the seismic qualification of specific pieces of installed equipment and confirmed that all safety-related equipment identified to be installed at the time of fuel load was seismically qualified. Fermi 2 has a seismic qualification program to address design changes related to Category I equipment.

Category I components purchased after the issuance of IEEE 344-1975 (Reference 2) are specified to be qualified to the requirements of that standard.

As stated in Subsection 3.7.1.2, all structures, systems, and components required for cold shutdown were reaffirmed to be acceptable with respect to the Fermi 2 site-specific earthquake excitation.

Nuclear steam supply system (NSSS) items were qualified to acceleration levels that were selected to envelop potential facility excitation predictions at the time of initiation of the

Fermi 2 design. Although these acceleration levels do not envelop all facility accelerations at the time of fuel load, detailed evaluations of NSSS items have revealed significant excess aseismic design capabilities rendering the equipment quite satisfactory for Fermi 2 use. In addition, all NSSS item site-specific earthquake acceptability affirmations have been documented as satisfactory.

3.10.1.2 Reactor Protection System and Engineered Safety Feature Circuits

The Category I instrumentation and electrical equipment associated with the reactor protection system (RPS), engineered safety feature (ESF) circuits, nuclear safety systems circuits, and the emergency power system include instruments, sensory equipment, control equipment, power supplies, diesel generators, drywell penetrations, batteries, underground ducts, motor control centers (MCCs), switchgear, cable trays and conduits, consoles, local instrumentation panels, and anchorage systems. These systems maintain functional operability during and following any pre- or postaccident SSE excitation at the equipment location.

The design of the building and the electrical equipment support structures has used the applicable floor response spectra shown in Section 3.7 in determining the response spectra at the equipment locations in the RPS, nuclear safety features, and in the ESF circuits.

The seismic criterion used in the design and subsequent qualification of all Class 1E instrumentation and electrical equipment supplied by GE was as follows:

> The Class IE equipment shall be capable of performing all safety related functions during normal plant operation, during anticipated transients, during design-basis accidents, and during postaccident operation while being subjected to, and after the cessation of the accelerations resulting from, the SSE at the point of attachment of the equipment to the building or supporting structure.

The specific criteria for each of the many Class 1E systems are covered in Chapter 7. The criteria for each of the devices used in the many Class 1E systems depend on the use in a given system; for example, a relay in one system may have as its safety function to deenergize and open its contacts within a certain time, while in another system it must energize and close its contacts. Since GE supplies many devices for many applications, the approach taken was to test the device in all modes that might be used. In this way, the capability of protective action initiation and the proper operation of safety-feature circuits are ensured.

Non-GE Category I equipment will also maintain functional operability during and/or (as required) after the SSE, as dictated by the response spectra for the equipment location. Proof of this is shown by the vendor seismic qualification and confirmatory review of each item.

If a seismic disturbance occurs after a major accident, the emergency core cooling will not be interrupted. The control circuits, switchgear, and diesel-generator design are such that the system will not be shut down once it is initiated, except by operator-initiated signal or by some other protective device signal.

3.10.1.3 Extent of Compliance With IEEE 344-l97l

3.10.1.3.1 General Electric-Supplied Equipment

The compliance of GE-supplied Class 1E equipment with IEEE 344-1971 (Reference 1) can be summarized as follows:

a. Scope - Compliance not applicable

b. Definition - Compliance not applicable

c. Procedures - General Electric-supplied Class 1E equipment meets the requirement that the seismic qualification should demonstrate the capability to perform the required function during and after the SSE. In addition, those items necessary for shutdown after loss of offsite power were reaffirmed to be acceptable for the site-specific earthquake situation. Both analysis and testing were used, but most equipment was tested. Analysis was used to determine the adequacy of mechanical strength (mounting bolts, etc.) after operating capability was confirmed by testing

   1. Analysis - General Electric-supplied Class 1E equipment with primarily mechanical safety functions (pressure boundary devices, etc.) was analyzed, since the passive nature of its critical safety role usually made testing impractical. Analytical methods sanctioned by IEEE 344-l97l were used in such cases

   2. Testing - General Electric-supplied Class 1E equipment having primarily active electrical safety functions was tested in compliance with Section 3.2 of IEEE 344-1971.

d. Documentation - The documentation is that which verifies that the seismic qualification of GE-supplied Class 1E equipment is in accordance with the requirements of Section 4 of IEEE 344-1971.

3.10.1.3.2 Non-General Electric-Supplied Equipment

The qualification and documentation procedures used for non-GE-supplied Category I equipment and systems are specified in Subsection 3.10.1.3.3, which encompasses and amplifies the requirements of IEEE 344-1971.

3.10.1.3.3 Criteria for Seismic Qualification of Category I Equipment (Non-General Electric-Supplied)

The criteria for qualification of Category I instrumentation and electrical equipment (non-GE-supplied) are established in this subsection. The IEEE Guide for Seismic Qualification of Class I Electric Equipment for Nuclear Power Generating Stations is a basic part of these criteria except as specified and amended below. Paragraph numbers in parentheses conform to the paragraph numbers in IEEE 344-1971. Equipment purchased after 1971 conforms to this or later versions of this standard.

3.10.1.3.3.1 Scope (1)

All Category I instrumentation and electrical systems and equipment (assemblies and devices) supplied for this plant must withstand the postulated seismic occurrence specified herein. The equipment vendor is responsible for ensuring that the equipment and systems operate safely under the postulated seismic conditions, and he must verify that the equipment will meet the stated functional requirements for continued operation without any malfunction or loss of function during and/or (as required) after the specified events.

3.10.1.3.3.2 Category I Equipment (2.1)

Class I, as defined in Paragraph 2.1 of IEEE 344-1971, is synonymous with Category I equipment.

3.10.1.3.3.3 Safe-Shutdown Earthquake (2.2)

For Fermi 2, the design-basis earthquake, as defined in Paragraph 2.2 of IEEE 344-1971, is synonymous with SSE.

3.10.1.3.3.4 Malfunction (2.8 - Additional Definition)

Equipment malfunction or functional impairment is the failure of equipment to operate in the same manner in which it would have operated in the absence of a seismic disturbance. For protective systems, malfunction is the loss of capability to initiate a protective action, or the initiation of a spurious protective action.

3.10.1.3.3.5 Procedures (3)

When the malfunction of Category I equipment is considered, testing is the method recommended to verify the functional requirements. Table 3.10-1 summarizes seismic qualification testing of typical non-GE-supplied equipment.

3.10.1.3.3.6 Analysis (3.1)

The number of masses should be sufficient to define the dynamic behavior of the equipment. The mathematical model should be shown even for a single degree of freedom.

3.10.1.3.3.7 (Additional 3.1.6)

The analysis shall include the combined effect of gravity loads, and other loads included in the specification, combined with the appropriate seismic loads. The seismic stresses may be computed independently for the vertical and horizontal directions. The horizontal excitation may be based on an envelope encompassing the maximum acceleration levels of the N-S and E-W components of the horizontal spectra given in the Edison electrical equipment specifications. The vertical and horizontal responses are considered to act simultaneously in combining the stresses.

The normal operating primary stresses, combined with the SSE stresses, are not to exceed the minimum guaranteed American Society for Testing and Materials (ASTM) yield strength at the appropriate temperature. Combinations of primary, local, and self-limiting secondary stresses may exceed yield stress levels to the extent permitted by the appropriate codes as long as malfunction is prevented. Where biaxial or triaxial loads are involved, the principal stresses shall be calculated and kept within the allowable material stress levels.

3.10.1.3.3.8 Testing (3.2.2.4.2)

The test shall be conducted over a minimum frequency range of 1 to 33 Hz.

3.10.1.3.3.9 Test Data (4.3)

If proof of performance is obtained by testing, the test data shall contain the following information:

a. Equipment identification

b. Equipment specification

c. Test facility

    1. Location

    2. Test equipment.

d. Test method

e. Test data

f. Data analysis and evaluation (including the floor acceleration versus frequency spectra for the surface upon which the equipment was mounted when tested)

g. Summary and conclusions

h. Certifying signature of a registered professional engineer and date of signature, if the test is performed on ASME Code items

i. Calibration history of test equipment.

3.10.1.3.3.10 Certification of Compliance (4.4)

All test data submitted by the vendor to satisfy the requirements of this specification are witnessed and reviewed to determine that the data adequately demonstrate that the equipment satisfies the intent of these specifications.

3.10.2 Seismic Analyses, Testing Procedures, and Restraint Measures

3.10.2.1 Amplification of Floor Inputs by Supports

Response spectra for floors and walls where Category I equipment is located were supplied to the vendors. If the vendor chose to test or analyze a certain device or component not directly supported on the floor for which the spectra are applicable, account was taken of possible amplification through the support structure.

3.10.2.2 Cable Tray and Cable Support System

The cable trays and cable tray support system were verified to withstand forces caused by dead-load, live-load, and seismic conditions.

The following combinations of dead load, live load, and earthquake load were investigated and checked to determine the most severe condition:

a. Dead load of various components with allowable stresses according to American Iron and Steel Institute (AISI) Specifications

   The dead load on cable trays consists of cables plus tray. In the case of hangers, it includes the dead weight of hangers also. Originally, the cable tray loading within the relay room, cable spreading room, and directly below the relay room floor was 50 lb/ft^2. All other cable trays were designed to a dead load of 40 lb/ft^2. An on-going program was later established to monitor the actual weight of cables in the trays and to account for fire wrap, conduit and air drop loads. Cable tray design load is adjusted to reflect these actual loads

b. Dead load plus a concentrated live load of 200 lb at the mid-span to AISC allowable stresses for reactor, aux building and RHR complex. The concentrated live load is 250 lb for the drywell cable trays

c. Dead load plus seismic load.

The cable trays and the support system were modeled as a multidegree-of-freedom system with the mass of the cables plus tray lumped at the levels at which they are supported. Figure 3.10-1 shows typical models for a three-layer hanger with one, two, and three diagonal members for horizontal excitation.

For vertical excitation, the fundamental period of vibration was computed by using a simplified model of continuous beam with hinged ends. This approximation was found to be consistent with the numerous models studied for this purpose.

The response spectra obtained from the analysis of the building were used in determining the response of the cable tray support.

The horizontal and vertical seismic excitations were assumed to be acting simultaneously along the principal axis of the cable tray system. The seismic response was computed by taking the sum of the individual responses.

It was observed that contribution due to nonfundamental modes was negligible, and hence the effect of closely spaced modes was negligible also.

The design was based on the l968 edition of the "Specifications For the Design of Cold-Formed Steel Structural Members."

For the trays in the drywell, a concentrated live load of 250 lb was specified. As stated in Subsections 3.7.3.17.2 and 8.3.1.4.3, in the design specification for cable trays, dead-weight loading did not include the weight of fire wrapping material or any other attachments, such as top hat cover, which were subsequently added. Accordingly, hanger modifications were made where necessary, and the structural adequacy of the cable trays was verified.

3.10.2.3 Battery Racks, Battery Chargers, Instrument Racks, and Control Consoles

Response spectra for floors and walls where Category I equipment is located have been supplied to the vendor. The vendors were required to submit test data, operating experience, and/or calculations to verify that battery racks, battery chargers, instrument racks, and control consoles would not suffer any loss of function during or after the SSE. For equipment in the GE scope of supply, procedures are in accordance with GE Topical Report NEDO-10678 (Reference 3). For non-GE-supplied equipment, testing procedures are in accordance with IEEE 344-1971, as modified in Subsection 3.10.1.3.3, with the exception of the equipment purchased prior to the issuance of IEEE 344-1971. Equipment purchased prior to the issuance of IEEE 344-1971 is designed to withstand the SSE postulated by the response spectra for its location during and/or (as required) after such an event.

3.10.3 Seismic Analysis and Testing Procedures for General Electric-Supplied Equipment

3.10.3.1 Seismic Analysis

Very few of the GE-supplied Class 1E devices were completely qualified by analysis alone. A sample of such an analysis is shown in Appendix B of NEDO-10678 (Reference 3). Besides being used for passive mechanical devices, analysis was used in combination with testing for larger assemblies containing Class 1E devices. For instance, a test might have been run to determine whether there were natural frequencies in the equipment within the critical seismic frequency range (see Paragraph 3.2.2.3.1 of IEEE 344-1971). If the equipment was determined to be free of natural frequencies, then it was assumed to be rigid, and a static analysis was performed as shown in Appendix C of NEDO-10678 (see Paragraph 3.2.3.4 of IEEE Standard 344-1971. If it had natural frequencies in the critical frequency range, then calculations of transmissibility and responses to varying input accelerations were made to determine whether Class 1E devices mounted in the assembly would operate without malfunctioning.

3.10.3.2 Testing Procedures

Since the Class 1E equipment supplied by GE was and is used in many systems on many different plants under widely varying seismic requirements, the seismic qualification tests were performed using an expected worst-case envelope of 1.5g horizontal and 0.5g vertical at all frequencies from 5 to 33 Hz. (The actual qualification range was 0.25 to 33 Hz, but, since test facility capability usually limited the lower frequency test to 5 Hz, a combination of test and analysis was used to ensure that there were no untested resonances. A sample analysis is shown in Appendix B of NEDO-10678.) In general, Class 1E equipment was tested by the procedures described below.

3.10.3.2.1 Devices

The test procedure for devices required that the device be mounted on the table of the vibration machine in a manner similar to that in which it was to be installed. The device was tested in the operating states in which it was to be used while performing its Class 1E functions, and these states were monitored before, during, and after the test to ensure proper function and absence of spurious function. In the case of a relay, both energized and deenergized states and normally open and normally closed contact configurations were tested if the relay is used in those configurations in its Class 1E functions.

The seismic excitation was a single-frequency "continuous" test in which the applied vibration was a sinusoidal table motion at a fixed peak acceleration and a discrete frequency at any given time. Each frequency and acceleration combination was maintained for about 30 sec, except when a resonance search was made (see IEEE Paragraph 3.2.2.4.1 of Standard 344-1971). The vibratory excitation was applied in three orthogonal axes individually, with the axes chosen as those coincident with the most probable mounting configuration.

The first step was to search for resonances in each device. This was done since resonances cause amplification of the input vibration and are the most likely cause of malfunction. The resonance search was usually run at low acceleration levels (0.2g) to avoid destroying the test sample in case a severe resonance was encountered. The resonance search was run at frequencies from 5 to 33 Hz in accordance with IEEE 344-1971 in no less than 7 minutes; if the device was large enough, the vibrations were monitored by accelerometers placed at critical locations from which resonances were determined by comparing the acceleration level with that at the table of the vibration machine. Usually, the devices were either too small for an accelerometer, had their critical parts in an inaccessible location, or had critical parts that would be adversely affected by the mounting of an accelerometer. In these cases, the resonances were detected by visual (strobe light) or audible observation, or performance.

After the frequency scan and resonance determination, the devices were tested to determine their malfunction limit. This test was a necessary adjunct to the assembly test. The malfunction limit test was run at each resonant frequency as determined by the frequency scan. In this test, the acceleration level was gradually increased until either the device malfunctioned or the limit of the vibration machine was reached. If no resonances were detected (as was usually the case), the device was considered to be rigid (all parts move in unison) and the malfunction limit was therefore independent of frequency. To achieve maximum acceleration from the vibration machine, rigid devices were malfunction tested at the upper test frequency (33 Hz) since this procedure allowed the maximum acceleration to be obtained from deflection-limited machines.

Typical results of tests on the devices used in Class 1E applications are given in Table 3.2 of NEDO-10678 and include the malfunction limit and resonant frequencies for each device tested.

The above procedures were required of purchased devices as well as those made by GE. Vendor test results were reviewed, and if the results were unacceptable, the tests were repeated either by GE or the vendor. If the vendor tests were adequate, the device was considered to be qualified to the limits of the test.

3.10.3.2.2 Assemblies

Assemblies (e.g., control panels) containing devices whose seismic malfunction limits had been established were tested by mounting the assembly on the table of a vibration machine, in the manner it was to be mounted when in use, and vibration-testing it by running a low-level resonance search. Like the devices, the assemblies were tested in the three orthogonal axes. The resonance search was run in the same manner as described for devices. If resonances were present, the transmissibility between the input and the location of each Class 1E device was determined by measuring the accelerations at each device location and calculating the magnification between it and the input. Once known, the transmissibilities could be used analytically to determine the response at any Class 1E device location for any given input. (It was assumed that the transmissibilities were linear functions of acceleration even though they actually decrease as acceleration is increased. This assumption is therefore a conservative one.) If the input accelerations to the device were determined to be below its malfunction limit, the assembly was assumed to be qualified. If no resonances existed, the assembly was considered to be a rigid body with a transmissibility equal to 1, so that a device mounted on it would be limited directly by the assembly input acceleration.

Since control panels and racks constitute the majority of Class 1E electrical assemblies supplied by GE, seismic qualification testing of these will be discussed in more detail. There are four generic types, as shown in Table 3.10-2. One or more of each type was tested by the procedures described above.

Figures 3-1 through 3-4 of NEDO-10678 illustrate the panel types referenced in Table 3.10-2 and show typical accelerometer locations. Table 3.10-3 lists typical seismically tested panels supplied by GE.

The full-acceleration level tests described above disclosed that most of the panel types had more than adequate mechanical strength and that a given panel design acceptability was simply a function of its amplification factor and the malfunction levels of the devices mounted on it. Subsequent panels were, therefore, tested at lower acceleration levels and the transmissibilities to the various devices measured as described above. By dividing the devices' malfunction levels by the panel transmissibility between the device and the panel input, the panel seismic qualification level could be determined. Several high-level tests have been run on selected generic panel designs to ensure the conservatism in using the transmissibility analysis described.

3.10.3.2.3 Purchased Equipment

The seismic qualification of equipment supplied to GE by others was required to follow the same procedures as used by GE. The qualification data were supplied to and reviewed by GE for conformance with the required procedures.

3.10 SEISMIC DESIGN OF CATEGORY I INSTRUMENTATION AND ELECTRICAL EQUIPMENT

REFERENCES

1. IEEE Standard 344-1971, "IEEE Guide for Seismic Qualification of Class I Electric Equipment for Nuclear Power Generating Stations."
2. IEEE Standard 344-1975, "IEEE Recommended Practices for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations."
3. GE Topical Report, Seismic Qualification of Class I Electric Equipment, NEDO-10678, General Electric Company, November 1972.

TABLE 3.10-1 SEISMIC QUALIFICATION SUMMARY: TYPICAL AUXILIARY POWER SYSTEM CATEGORY I EQUIPMENT (NON-GENERAL ELECTRIC)

Part Identification System No.	Description	Qualification Method[a]
	4160-V Switchgear Buses	
R1400S001B	64B	Combination of seismic prototype test and supporting analysis
R1400S001C	64C	
R1400S001E	65E	
R1400S001F	65F	
R1400S002A	11EA	
R1400S002B	12EB	
R1400S002C	13EC	
R1400S002D	14ED	
Mounting Configuration of 4160-V Switchgear		Analysis
	480-V Switchgear Buses	
R1400S022	72B	Seismic prototype test
R1400S023	72C	
R1400S020	72E	
R1400S021	72F	
R1400S036	72EA	
R1400S037	72EB	
R1400S038	72EC	
R1400S039	72ED	
	480-V Unit Substation Transformers	
R1400S022A	72B	Seismic prototype test
R1400S023A	72C	
R1400S020A	72E	
R1400S021A	72F	
R1400S036A	72EA	
R1400S037A	72EB	
R1400S038A	72EC	
R1400S039A	72ED	
	480-V Unit Substation Voltage Regulators	
R1400S020B	72E	Fermi 2 equipment seismically tested
R1400S021B	72F	
R1400S038B	72EC	
R1400S039B	72ED	
Mounting Configuration of 480-V Switchgear, Transformers, and Voltage Regulators		Analysis

TABLE 3.10-1 SEISMIC QUALIFICATION SUMMARY: TYPICAL AUXILIARY POWER SYSTEM CATEGORY I EQUIPMENT (NON-GENERAL ELECTRIC)

Part Identification System No.	Description	Qualification Method[a]
	480-V Motor Control Centers	
R1600S002A	72B-2A	Seismic prototype test
R1600S002B	72B-3A	
R1600S003A	72C-2A	
R1600S003B	72C-3A	
R1600S003D	72C-F	
R1600S004B	72E-5A	
R1600S005A	72F-2A	
R1600S005C	72F-4A	
R1600S005D	72F-5A	
R1600S016A	72EA-2C	
R1600S017A	72EC-2D	
R1600S018A	72EC-2C	
R1600S019A	72ED-2D	
Mounting Configuration for Motor Control Centers		Analysis
	130/260-V-dc Power and Control Batteries	
R3200S003	Battery 2PA	Seismic prototype test
R3200S004	Battery 2PB	
	24/48-V-dc Instrument Batteries	
R3200S001	Battery 2IA	Seismic prototype test
R3200S002	Battery 2IB	
Battery Support Racks and Mounting Configuration		Analysis
R3200S020A-C	130-V Battery Chargers, Battery 2PA	Seismic prototype test
R3200S021A-C	130-V Battery Chargers, Battery 2PB	
R3200S023A, B	24-V Battery Charges, Battery 2IA	
R3200S024A, B	24-V Battery Charges, Battery 2IB	
R3200S025	Standby 24-V Battery Charger	
	130/260-V-dc Distribution Cabinets	
R3200S026	Main Distribution Cabinet 2PA-2	Analysis
R3200S027	Main Distribution Cabinet 2PB-2	
R3200S061A,B	Relay Room Distribution Panels	
R3200S064A, B	Relay Room Distribution Panels	
R3200S062, 65	Switchgear Room Distribution Panels	
R3200S063, 66	RHR Complex Distribution Panels	

TABLE 3.10-1 SEISMIC QUALIFICATION SUMMARY: TYPICAL AUXILIARY POWER SYSTEM CATEGORY I EQUIPMENT (NON-GENERAL ELECTRIC)

Part Identification System No.	Description	Qualification Method[a]
	24/48-V-dc Distribution Cabinets	
R3200S029	Relay Room Distribution Cabinet	Analysis
R3200S030	Relay Room Distribution Cabinet	
	260-V-dc Motor Control Centers	
R3200S015	DC Motor Control Center 2PA-1	Seismic prototype test
R3200S016	DC Motor Control Center 2PB-1	
	Battery Main Fuse Cabinets	
R3200S007A	Battery 2A-1 Dual Main Fuse Cabinet	Analysis
R3200S007B	Battery 2A-2 Dual Main Fuse Cabinet	
R3200S008A	Battery 2B-1 Dual Main Fuse Cabinet	
R3200S008B	Battery 2B-2 Dual Main Fuse Cabinet	
R3200S010	Battery 2PA Single Main Link Cabinet	
R3200S011	Battery 2PB Single Main Link Cabinet	
	Raceways	
	Conduit Supports	Analysis
	Underground Ducts	
	Primary Containment Penetrations	
	Cable Tray Hangers	
	120-V-ac I&C Power Supplies	
R3101S001	Division I Power Supply Unit	By analysis; some components by seismic prototype test
R3101S002	Division II Power Supply Unit	

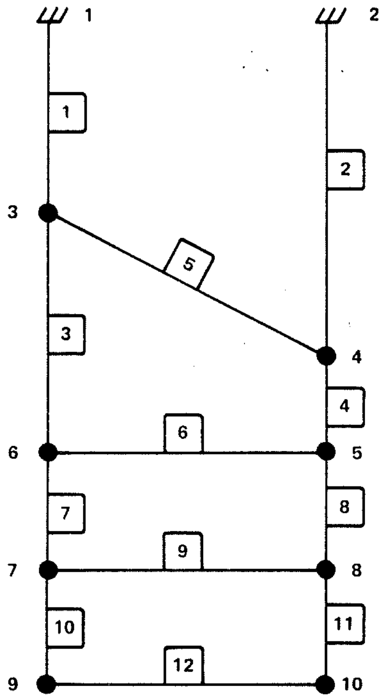
[a] Seismic prototype tests are tests of similar or identical equipment.

TABLE 3.10-2 PANEL TYPES

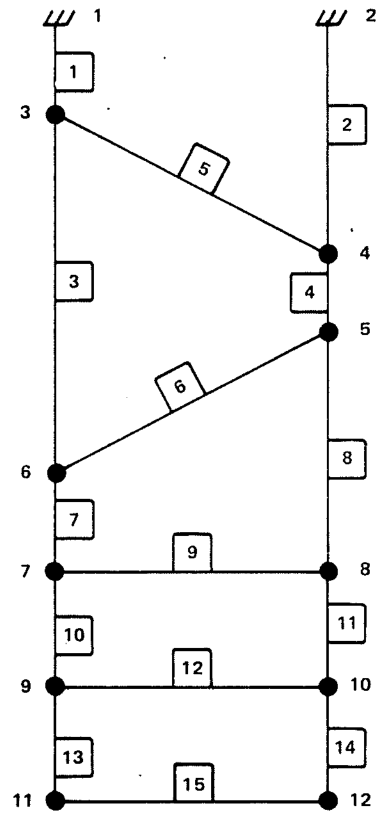
Panel Type	Use
Benchboards	Operating information and controls
Instrument and relay cabinets	Nuclear steam supply monitoring instrumentation
Local racks	Process instruments
NEMA enclosures	Miscellaneous

TABLE 3.10-3 TYPICAL SEISMICALLY QUALIFIED CONTROL PANELS, LOCAL PANELS AND RACKS (Supplied by General Electric)

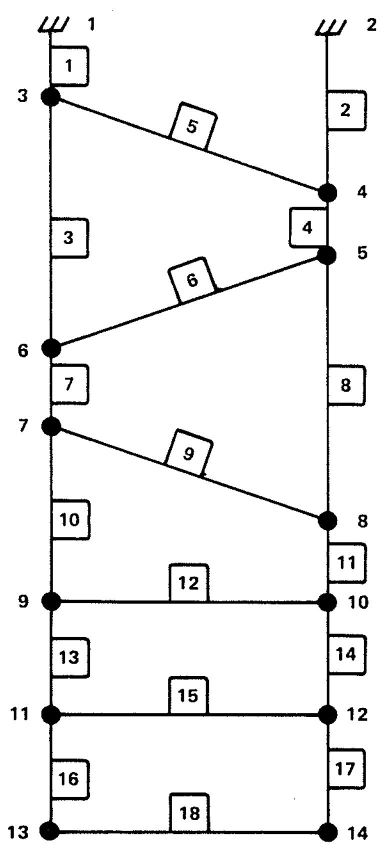
Control Panel	Description	Type	Class 1E Equipment Description
H11-P601	Reactor cooling and isolation (ECCS Div. I)	Benchboard	CR2940, MS ind. switches, CMC switches
H11-P602	Reactor water cleanup and recirculation (ECCS Div. II)	Benchboard	CR2940, MS ind. switches, CMC switches
H11-P603	Reactor control	Benchboard	Mode switch, IRM range switches, MS ind. switch CR 2940
H11-P606	Startup neutron monitor	Instrument cabinet	Trip auxiliary unit, indicator and trip unit, IRM, LRM
H11-P608	Power range neutron monitor	Instrument cabinet	APRM
H11-P609	Reactor protection system	Relay cabinet	HFA and HGA relays, magnetic contactor
H11-P611	Reactor protection system	Relay cabinet	HFA and HGA relays, magnetic contactor
H11-P612	Process instrumentation rack	Instrument cabinet	GEMAC instruments
H11-P613	Process instrumentation rack	Instrument cabinet	GEMAC instruments
H11-P614	Steam temperature recorders	Relay cabinet	CR2940 switches, HGA relay, timers, temperature monitor, inverter
H11-P617	RHR relays	Relay cabinet	HFA, HGA and HMA relays
H11-P618	RHR relays	Relay cabinet	HFA, HGA and HMA relays
H11-P620	HPCI relays	Relay cabinet	HFA and HGA relays
H11-P621	RCIC relays	Relay cabinet	HFA and HGA relays
H11-P622	Inboard isolation valve relays	Relay cabinet	HFA and HGA relays
H11-P623	Outboard isolation valve relays	Relay cabinet	HFA and HGA relays
H11-P626	Core spray	Relay cabinet	CR2940 switches, Agastat GP relays, HFA, HGA and HMA relays
H11-P627	Core spray	Relay cabinet	CR2940 switches, Agastat GP relays, HFA, HGA and HMA relays
H11-P628	Automatic depressurization relays	Relay cabinet	HFA and HGA relays
H21-P001	Core spray system A	Local rack	Barton 288, 289, and Barksdale pressure switch
H21-P002	Reactor water cleanup system	Local rack	Pressure transmitter
H21-P014	HPCI instruments	Local rack	Pressure transmitter, pressure switch, flow transmitter
H21-P015	Main steam flow	Local rack	Differential pressure switch, pressure transmitter
H21-P016	Core spray/HPCI leak detection	Local rack	Pressure switch, differential pressure switch
H21-P017	RCIC panel A	Local rack	Pressure transmitter, pressure switch, flow transmitter, flow switch
H21-P018	RHR – channel A	Local rack	Pressure switches, pressure transmitter, flow transmitter
H21-P019	Core spray channel B rack	Local rack	Pressure transmitter, pressure switch, flow transmitter
H21-P021	RHR – channel B	Local rack	Pressure switch, pressure transmitter, flow transmitter
H21-P025	Main steam flow	Local rack	Differential pressure switch, pressure transmitter
H21-P030 A thru D	SRM-IRM preamplifiers	Local NEMA enclosures	SRM-IRM preamplifiers
H21-P034	HPCI leak detection	Local rack	Pressure switch
H21-P035	RCIC leak detection	Local rack	Pressure switch, differential pressure switch
H21-P036	HPCI leak detection	Local rack	Differential pressure switch, pressure switch
H21-P037	RCIC instrument B	Local rack	Pressure switch
H21-P038	RCIC leak detection	Local rack	Pressure switch, differential pressure switch



1–DIAGONAL FRAME



2–DIAGONAL FRAME



3–DIAGONAL FRAME

Fermi 2

UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 3.10-1

TYPICAL MASS MODEL

3.11 ENVIRONMENTAL DESIGN OF MECHANICAL AND ELECTRICAL EQUIPMENT

3.11.1 Equipment Identification

Mechanical, electrical, and instrumentation portions of the engineered safety feature (ESF) systems, nuclear safety features, and reactor protection system (RPS) are designed to operate properly for the period required over a range of environmental conditions. The environmental conditions range from those of normal operation to those resulting from postulated accidents. The environmental design criteria established in Subsections 3.11.1 through 3.11.4 form the basis for the original Fermi 2 design. This information was derived from the parameters established by GE as part of their original design criteria. After performing their required functions, the systems can withstand these environmental conditions without functional impairment of the system involved, or other plant systems.

Table 3.11-1 lists the safety equipment and components inside the primary containment, which are designed to operate or be in a fail-safe condition during and following any accident up to the design-basis accidents (DBAs). Design environmental conditions and the associated duration of these conditions are also identified. The design environmental conditions envelop the maximum temperatures, pressures, humidity, and durations for the equipment over a wide variety of accident conditions up to a DBA, but the conditions will not necessarily occur coincidentally. Table 3.11-2 explains the significance of the design temperatures, pressures, and durations.

Safety-related equipment and components outside the primary containment that are designed to operate or fail into a safe condition during and following any accident, including the DBAs, are listed in Table 3.11-3. Design environmental conditions and associated durations of conditions are also given in this table. The design environmental and duration envelopes provided were used as guidelines for the selection of equipment and components used outside the primary containment. These conditions do not occur coincidentally during postulated accident conditions nor for all specific zone locations within the general areas listed.

Portions of the ESF systems, nuclear safety features, and RPS are located in a controlled environment which is considered an integral part of the ESF system, nuclear safety feature, or RPS. These areas and the controlled parameters are given in Table 3.11-4.

Fan-coil cooling units using water from the emergency equipment cooling water (EECW) system are used to control the environment to within the limits specified. These units are described in Section 9.4. Redundancy of units and equipment precludes the loss of the controlled environment as discussed in Subsection 3.11.4.

The RPS and ESF equipment is capable of functioning for the required design duration and, subsequently, remains in a fail-safe condition when subjected to the local environmental conditions (e.g., close proximity to the break) if the equipment is

a. Required to detect a steam line accident condition

b. Required to perform a steam line isolation function

c. Required to perform a water line isolation function and could be subjected to the environment, such as electrical cable or valve operator

d. Required for safety system operation, and is located so a steam line break in some other system exposes the safety system equipment to the local accident environment

e. Required to track the postaccident environment condition, such as pressure, temperature, hydrogen, oxygen, and radiation monitors.

Isolation valves and associated equipment required to perform the isolation function, per Items b. and c. above, will perform their required accident mitigation function in the local steam environment, and subsequently remain in a safe (closed) condition. Isolation valves inside the primary containment have been type- tested and have satisfied IEEE 382-1972.

Both equipment required for postaccident surveillance and ESF and RPS equipment, exposed to the local steam environment and required to be functional for the entire duration of the accident (items d. and e. above), will remain functional for a 100-day postaccident environment.

For equipment specified in Items a. through e. above, rotating machinery components such as pumps, motors, or operators in a safety system (i.e., emergency core cooling system [ECCS], reactor core isolation cooling [RCIC]) with a leak, are designed to function in the local environment caused by the leak.

3.11.2 Qualification Tests and Analysis

3.11.2.1 Environmental Criteria and Design Bases

The environmental conditions expected to exist during routine plant operations, both inside and outside the primary containment, are given in Table 3.11-5. Also included in Table 3.11-5 is the accident-basis radiation environment along with the DBA type. The accident-basis environmental conditions are defined as those which deviate from the routine plant operations environmental conditions given in Table 3.11-5. The accident-basis environment is specified as an envelope, which is not based upon one specific DBA, but on all postulated accidents relevant to an envelope. The worst-case environment was derived from Reference 1. The accident-basis environmental envelope is outlined in Table 3.11-2 for inside the primary containment. The ESF systems and RPS have been designed to remain operational or fail into a safe condition when subjected to the temperatures listed in Tables 3.11-2 and 3.11-5, unless such equipment is physically separated from the accident-basis environment.

The worst-case design environment for mechanical and Class 1E electrical equipment outside the primary containment is dependent on the location within the plant. Each location has been analyzed for different types of postulated accidents to define the maximum values of temperature, pressure, relative humidity, and radiation environment values. These values, which may differ between locations, are specified as the accident environment.

The radiation-accident-basis design environment has been calculated using conservative fission product inventories. The worst-case radiation-accident design environment is that resulting from the LOCA as derived from the AEC publication TID-14844, March 23, 1962.

In calculating doses on equipment and materials, fission products assumed to be in the recirculated water were 50 percent of the core halogen inventory and 1 percent of the core solid fission product inventory.

In calculating the range of radiation monitors and radiation doses to equipment in the containment atmosphere, fission products assumed to be in the primary containment atmosphere were 25 percent of the core halogen inventory, 1 percent of the core solid fission product inventory, and 100 percent of the noble gases.

With the implementation of the plant Hydrogen Water Chemistry program, normal radiation levels in those sections of the plant subject to main-steam environments will increase. Such increases have been taken into account in the overall environmental design of equipment and in the plant Environmental Qualification Program.

3.11.2.2 Qualification Tests

All Class 1E equipment and components were evaluated with respect to IEEE 323-1971. Since many of these items are used in several systems and in different plant locations, they were tested or analyzed for the worst-case situation. Wherever possible, the tests were performed to determine the malfunction limits for the critical parameters of the instruments for different applications. On the other hand, where the environmental conditions were known to have no effect on the equipment (i.e., reactor building pressure transients and radiation on solid-state electronic equipment), the tests were not performed. Class 1E equipment and components purchased after November 15, 1974, were evaluated with respect to IEEE 323-1974 (see also Subsection 3.11.5).

The Class 1E equipment supplied by GE was qualified by testing and was first described by equipment specifications that included or enveloped the intended application environment. Type tests were performed on pilot units to show conformance to the requirements of the equipment specifications. The test results were documented in a qualification test report.

In general, the Class 1E equipment supplied by GE was qualified by type tests; however, where the equipment's primary safety function is nonelectrical, such as forming a portion of a pressure boundary, calculations of the type contained in an ASME Boiler and Pressure Vessel (B&PV) Code stress analysis were used to establish qualification.

The four drywell cooler fans, which can also serve for post-LOCA atmosphere mixing, are the only continuous duty Class 1E motors inside the drywell. These motors have been tested beyond the requirements of IEEE 334-1971. Testing for these motors has included short-term transient testing at pressures up to 85 psig and temperatures up to 340°F in a saturated steam environment, and long-term testing at reduced pressure (20 psig) and temperature (250°F). Motor insulation has also been tested for radiation damage resistance.

General Electric-supplied mechanical equipment has either been qualification tested or analyzed for temperature effects to ensure that the material properties are not degraded by the environment of temperature, pressure, humidity, and radiation. Qualification testing has been done either by tests on that particular piece of mechanical equipment or on similar mechanical equipment.

The standby gas treatment system (SGTS) is designed to operate in the accident environment. Normal operation has a negligible effect on the SGTS, as indicated in Table 3.11-4. Periodic testing ensures operability of the system. Other non-GE-supplied equipment such as the control center heating, ventilation and air conditioning (HVAC) system, is located in areas not affected by the accident. The control center HVAC operation, including operation under accident conditions, is described in Subsection 9.4.1.

3.11.3 Qualification Test Results

Test results for GE-supplied Class 1E electric equipment are covered by GE Topical Report NEDO-10698, previously referenced, and in particular, Table 3.1 of that report.

The drywell cooler fans use two classes of insulation, "RN" for two-speed fans and "RH" for the single-speed fans. A motor with "RN" insulation has been tested in a saturated steam environment as indicated and has been shown to be suitable for the duty required. The tests show that the motors can withstand a temperature of at least 340°F for 3 hr, and a temperature of 320°F for an additional 4 hr, and at least 250°F indefinitely. A dosage of 10^9 rad of gamma radiation during the life of the motor can also be tolerated. Insulation breakdown occurs faster as conditions become more severe. Thermal endurance tests of 100 hr at 213°C indicate that the insulation will survive an insulation temperature (not ambient) of 105°C for 40 years.

3.11.4 Loss of Ventilation

3.11.4.1 Control Center

a. The control center is served by the control center air conditioning system (CCACS) as described in Subsection 9.4.1. The CCACS and the directly associated systems are designed to perform their intended functions during LOCA conditions, with the simultaneous occurrences of the safe-shutdown earthquake (SSE) as defined in Section 3.7, and the loss of all offsite power as described in Subsections 8.2.2.2 and 9.4.1.3. The CCACS is designed to provide fresh, filtered, and tempered ventilating air and/or air conditioning to all spaces within the control center. Space temperature inside the control center is maintained at a nominal temperature of 75°F [except for the mechanical equipment room (MER) and SGTS room which are discussed in Subsection 9.4.1.1], and the relative humidity is maintained at 50 percent on a year-round basis to ensure personnel comfort and satisfy safety-related control and electrical equipment requirements

   The reliability of the CCACS is achieved by providing two redundant air conditioning systems. The two systems separately supply air to the control center and, except for the common passive ductwork, are physically separated to preclude simultaneous loss of safety function that might occur as a consequence of a single accident. The return fans are used either to recirculate conditioned air or to discharge it to the outdoors. The supply fans in the multizone units provide the motive power to circulate the air to the various rooms. The two separate chilled water loops, each containing a liquid chiller and a pump, provide chilled water to the multizone units through two physically separated circuits

b. In the event of a failure of any major equipment component of the CCACS, the 100 percent standby system is available to preclude any adverse effect on the main control room and relay room environs. The standby air conditioning system is started manually from the main control room

c. The probability of losing both the 100 percent-capacity air conditioning systems, consisting of multizone units and liquid chillers at the same time, is remote. Only one multizone unit, liquid chiller, and chilled water pump is required for either the normal air conditioning or 100 percent recirculation modes. However, the CCACS is capable of providing fresh air from 100 percent outside air, which under certain outside temperature conditions (winter temperatures), could provide adequate cooling. The outside air can be supplied by either of the two 100 percent multizone units, and on occasions in conjunction with the two 100 percent return air fans, can recirculate the conditioned air in the rooms without outside air

d. The performance of the CCACS is verified while the system is in operation. The system ductwork and its components are subjected to leak and noise tests during manufacture and erection. Chillers, pumps, and piping systems are subjected to hydrostatic test during their manufacture and erection as well as being subjected to a manufacturing performance test

   Filters and filter housings are subjected to manufacturers' performance and production tests before installation as well as DOP and the appropriate tracer gas tests after installation. In addition, the complete air conditioning, heating, cooling, and ventilation systems are subjected to preoperational testing to demonstrate capability of maintaining the control center at 75°F and 50 percent relative humidity [except for the mechanical equipment room (MER) and SGTS room which are discussed in Subsection 9.4.1.1]

e. In the extremely unlikely event that the control center must be vacated, a remote shutdown panel located on the second floor of the auxiliary building provides remote control of the reactor systems needed to carry out the shutdown function. This panel is described in Section 7.5.

3.11.4.2 Engineered Safety Feature Switchgear Rooms

Two separate rooms are provided to house the Class IE electrical equipment. The Class 1E equipment provided in each ESF switchgear room is 100 percent redundant and satisfies IEEE-279-1971 and IEEE-308-1971 design criteria. The ESF switchgear heat-removal system is described in Subsection 9.4.2.

Each ESF switchgear room is provided with two 50 percent-capacity fan-coil units. Cooling water is supplied by the reactor building closed-cooling water/EECW (RBCCW/EECW) systems. These units are used to limit room temperature to less than 120°F, which is less than the maximum temperature for which equipment operation has been evaluated. Since the switchgear rooms are redundant, the two 50 percent heat-removal units in each room satisfy the single-failure criteria.

In the event of failure of a switchgear heat-removal unit, the ESF systems' function can be performed by the redundant equipment in the other essential switchgear room, and safe shutdown of the reactor is achievable.

3.11.4.3 Reactor/Auxiliary Building Safety-Related Ventilation Systems

During normal operation, the reactor/auxiliary building ventilation system provides ventilation for safety-related equipment in these buildings except for areas served by the CCACS. However, in the event the reactor building is isolated because of an abnormal condition, fan-coil cooling units provide the cooling for safety-related equipment. One unit of 100 percent capacity is furnished for each of the following:

a. Each division of residual heat removal (RHR) pumps
b. Each division of core spray pumps. The Division I unit also cools the RCIC pump
c. The high-pressure coolant injection (HPCI) pump room
d. Each division of the SGTS filter unit room
e. Each division of EECW pumps
f. Deleted

In addition, two units, each of 50 percent capacity, are furnished for each division switchgear room.

The fan-cooling units are physically separated and are located in Category I structures. Because of the separation, redundancy, and number of fan-coil cooling units supplied, it is extremely unlikely that cooling to both divisions of the same safety-related equipment would be lost.

The redundant battery rooms are ventilated by exhaust fans (one of two 100 percent capacity fans per room) which are required to operate during a DBA. Thus again, complete loss of battery room ventilation is unlikely. The fan-coil cooling units and exhaust fans are discussed further in Subsection 9.4.2.

3.11.4.4 Residual Heat Removal Complex Safety-Related Ventilation Systems

As described in Subsection 9.4.7, the RHR complex is composed of two identical divisions with the safety-related equipment in one division l00 percent redundant to that in the other division. Each division has two diesel generator rooms, two diesel-oil-storage rooms, two switchgear rooms, and a pump room.

To maintain conditions below the limits specified in Table 3.11-4, each diesel generator room, switchgear room, and pump room is ventilated with two 50 percent-capacity supply air fans. The intake air for the switchgear and pump rooms is filtered by medium-efficiency filters. These ventilation systems are of Category I design and are powered from the same ESF bus supplying equipment in the room being cooled. They are not required unless the equipment served is required, and are designed to start when the associated diesel generator starts, or a preset high room temperature is reached. Because a separate ventilation system is provided for each of the above rooms, the loss of a ventilation system does not affect safe shutdown of the plant. Each diesel-fuel-oil-storage room ventilation system purges air from a diesel generator room, a CO_2 storage room, and a ventilation equipment room to the outside. Each system is of Category I design and powered from the ESF bus corresponding to the diesel generator served. This system is designed to run continuously for all modes of operation. Again, as a system is supplied for each set of redundant rooms, loss of a system does not affect safe shutdown of the plant. With the redundancy and independence of ventilation systems described above, it is obvious that the probability of losing ventilation in both divisions of safety-related equipment is extremely small.

3.11.5 Environmental Qualification of Safety-Related Electrical Equipment Related To 10 CFR 50.49

All electrical equipment important to safety and exposed to a harsh environment has been reviewed to ensure that equipment required to perform necessary safety functions is capable of maintaining functional operability under all service conditions, including postulated accident conditions. This review was based on the criteria delineated for Category II plants as defined by NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety Related Electrical Equipment," and 10 CFR 50.49. Details of the Fermi 2 harsh environment qualification program are found in Reference 2. This document is maintained and updated periodically.

Environmental envelopes were developed specifically for this harsh-environment review, using NUREG-0588 as the source document for developing the environmental profiles. Areas inside and outside the containment containing equipment important to safety were divided into environmental zones, which included the drywell, all rooms and areas in the reactor building, the auxiliary building, and the RHR complex. The temperatures, pressures, humidities, and radiation levels were determined for each of these zones. The environments defined include the most limiting environments for the most severe postulated accident events in all applicable areas, as well as the environments expected during normal operation for the life of the plant.

The information established in Subsections 3.11.1 through 3.11.4 forms the basis for the original Fermi 2 EQ program. This information was derived from GE as part of their original design criteria. All environmental qualification activities performed for Fermi 2 related to 10 CFR 50.49 will incorporate the information contained in Reference 2.

3.11.6 DELETED IN PREVIOUS REVISION

3.11 ENVIRONMENTAL DESIGN OF MECHANICAL AND ELECTRICAL EQUIPMENT

REFERENCES

1. Dresden Nuclear Power Station, Unit 2, "Supplementary Information to Special Report of Incident of June 5, 1970," (submitted to the AEC, in response to its questions on the original report, by Commonwealth Edison Company).
2. Detroit Edison document, "Environmental Qualification of Safety-Related Electrical Equipment for Harsh Environment," (Identification, DTC: TEQSR; DSN: NE-1.16.9-EQE).
3. Deleted.
4. Detroit Edison document, “Summary of Environmental Parameters Used for the Fermi 2 EQ Program”, (Identification, DTC: TEGEN; DSN EQ0-EF2-018).
5. GE Specification, “BWR Equipment Environmental Requirements” (DTC: TSVEND; DSN: 22A3019).

TABLE 3.11-1 ACCIDENT ENVIRONMENT - INSIDE PRIMARY CONTAINMENT

NOTE: COMPONENTS ARE DESIGNED TO BE OPERABLE UNDER THE FOLLOWING CONDITIONS:

Component	Duration[a]	Temperature	Pressure[b]	Relative Humidity
1 Core spray injection check valve; LPCI/RHR injection check valve, reactor shutdown cooling suction valve, including operator and cable; relief valve, including operator and cable; RPV level indicator; structural components (e.g., loop restraints, RPV skirts, etc.)	45 Sec 3 hr 6 hr 1 day 100 days	340°F 340°F 320°F 250°F 200°F	-2 to 56 psig[c] -2 to 35 psig -2 to 35 psig 0 to 25 psig 0 to 20 psig	100% 100% 100% 100% 100%
2 Feedwater check valve; HPCI steam line isolation valve, including operator and cable; RCIC steam line isolation valve, including operator and cable; reactor water cleanup suction valve, including operator and cable. Lines 2 in. and smaller (isolation valves, operators, cabling); reactor vessel head spray isolation valve, including operator and cable	45 sec 3 hr 6 hr	340°F 340°F 320°F	-2 to 56 psig[c] -2 to 35 psig -2 to 35 psig	100% 100% 100%
3 Main steam isolation valves, including operator and cable; main steam drain isolation valves, including operator and cable; standby liquid control injection check valve	45 sec 1 hr	340°F 340°F	-2 to 56 psig -2 to 35 psig	100% 100%
4 Recirculation valves (main[d] valves, equalizer valve) including operators and cables	45 sec 30 minutes	310°F 285°F	-2 to 56 psig[c] -2 to 35 psig	100% 100%

NOTE: VALVES ARE DESIGNED NOT TO BE OPERABLE BUT MUST NOT FAIL OPEN UNDER THE FOLLOWING CONDITIONS:[e]

5 Feedwater check valve; HPCI and steam line isolation valves, including operators and cables; recirculation valves (main valves, bypass valves, equalizer valves), including operator and cables; reactor vessel head spray isolation valve, including operator and cable; reactor water sample line valves, including operator and cable. Lines 2 inches and smaller (isolation valves, operators, cabling)	1 day 100 days	250°F 200°F	-2 to 25 psig -2 to 20 psig	100% 100%

TABLE 3.11-1 ACCIDENT ENVIRONMENT - INSIDE PRIMARY CONTAINMENT

Component	Duration[a]	Temperature	Pressure[b]	Relative Humidity
6 Main steam isolation valves, including operator and cable; main steam drain isolation valves, including operator and cable; standby liquid control injection check valve	3 hr	340°F	-2 to 35 psig	100%
	6 hr	340°F	-2 to 35 psig	100%
	1 day	250°F	-2 to 25 psig	100%
	100 days	200°F	-2 to 20 psig	100%
7 Drywell cooling system	45 Sec	340°F	-2 to 56 psig	100%
	3 hr	340°F	-2 to 35 psig	100%
	6hr	320°F	-2 to 35 psig	100%
	1 day	250°F	0 to 25 psig	100%
	100 days	200°F	0 to 20 psig	100%

[a] Durations shown are termination times measured from the initiation of the postulated accident; (i.e., Condition 1, the 3-hr duration, is the period from 45 sec through 3 hr, the 1-day duration is the period from 6 hr through 1 day (24 hr).

[b] The equipment inside the primary containment will be subjected to 56 psig and 135°F for a maximum of 3 days during periodic leak testing.

[c] 56 psig is 90 percent of maximum containment internal pressure of 62 psig, as allowed by ASME B&PV Code Section III, Article 13, Paragraph N-1312, Sub-Paragraph (2).

[d] For the recirculation valves to perform their safety function they must close following a recirculation line break, so that the core flooding can be carried out in the required time. For this safety requirement the environmental conditions will not exceed 310°F at 56 psig for ½ hr. The specified conditions in (4) above are to enable a normal vessel shutdown cooling procedure during a steam leak.

[e] Some of the equipment identified in Items 5, 6, and 7 is also required to operate at the beginning of the event. This equipment is therefore also shown in Items 2 through 4 above.

TABLE 3.11-2 DESIGN-BASIS ACCIDENT ENVIRONMENTAL ENVELOPE

Temperatures	
340°F	Upper boundary on maximum superheat temperature for a steam leak with the RPV at 400-500 psig, containment at 35 psig.
320°F	Maximum superheat temperature during shutdown cooling line flush after reactor has been depressurized to 150 psia.
250°F	Maximum long-term temperature in the containment during the first day following a postulated DBA.
200°F	Extended long-term temperature in the containment following a postulated DBA.
Pressures	
-2 psig	Assumed negative design pressure of the primary containment.
56 psig	Positive design pressure of the primary containment, coinciding with the 281°F design temperature.
35 psig	Containment pressure corresponding to all the noncondensables initially in the drywell being transferred to wetwell.
25 psig	Upper boundary on extended long-term pressure at one day and shorter following a postulated DBA.
20 psig	Upper boundary on extended long-term pressure at longer than one day following a postulated DBA.
62 psig	Assumed peak containment pressure.
Durations	
45 sec	Conservative time duration to cover positive design pressure.
1 hr	Time duration during which valves that must isolate automatically on low RPV level or high drywell pressure must be operable.
3 hr	Time duration to depressurize the RPV at a rate not exceeding 100°F/hr, down to 150 psia.
4.5 hr	Time at which shutdown cooling system flush is complete. Normal shutdown cooling necessitates closure of recirculation line valves.
6 hr	Time duration to complete RPV depressurization to approximate containment pressure. This time includes RPV depressurization to 150 psia not exceeding a rate 100°F/hr, flushing of system, and depressurization to approximate containment pressure.
100 days	Maximum postulated accident duration.

TABLE 3.11-3 DESIGN-BASIS ENVIRONMENT - OUTSIDE PRIMARY CONTAINMENT[a]

NOTE: COMPONENTS ARE DESIGNED TO BE OPERABLE UNDER THE FOLLOWING CONDITIONS:

Component	Duration	Temperature[b]	Relative Pressure	Humidity
1. HPCI pump, turbine, control, instrumentation and electrical equipment; RCIC pump, turbine, controls, instrumentation, and electrical equipment (other than in steam tunnel).	1 hr[c,g]	148°F[c]	7 in. H_2O gage[c]	100%[c]
2. RHR system isolation valves, including operators and cable; RHR pumps, heat exchanger, controls instrumentation and electrical equipment; core spray systems isolation valves, including operator and cable; core spray pumps, controls, instrumentation, and electrical equipment.	6 months[d] 1 hr	148°F[d,e] 148°F[d,e]	Zero in. H_2O gage 7 in. H_2O gage	90% 100%

NOTE: VALVES ARE DESIGNED NOT TO BE OPERABLE BUT MUST NOT FAIL OPEN UNDER THE FOLLOWING CONDITIONS:

Component	Duration	Temperature[b]	Relative Pressure	Humidity
3. HPCI system isolation valves, including operator and cable; RCIC system isolation valves, including operator and cable; main steam isolation valves in steam tunnel, including operators; feedwater isolation valves, including operator and cable; reactor water cleanup isolation valves, including operator and cable	13 sec[f] 1 hr	228°F 220°F	5.1 psig[f] 2.0 psig	100%[f] 100%

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[a] Design condition where operation is required. Note that these are design conditions and the actual conditions to which this equipment is environmentally qualified under the Fermi 2 EQ Program are documented in EQ0-EF2-018.

[b] Temperatures given do not take into account any temperature rise caused by direct steam impingement.

[c] 148°F, 100 percent R.H., and 7 in. static pressure may occur concurrently for the 1 hr as given, but R.H. and static pressure will decay after this period.

[d] Temperature based on RHR equipment operating. RHR pump basement and sub-basement quadrants: 153°F peak.

[e] Motors rated for continuous operation in an ambient temperature of 104°F will operate in a higher ambient temperature with decreased life expectancy. Space cooling may be required to limit the ambient to an acceptable level.

[f] Steam tunnel transient conditions due to main steam line rupture.

[g] These time frames are retained for historical purposes. HPCI is environmentally qualified to support a 3-hr mission time.

TABLE 3.11-4 ENVIRONMENTAL DESIGN OF AREAS CONTAINING SAFETY-RELATED EQUIPMENT AND COMPONENTS – OUTSIDE CONTAINMENT[b]

Location	Temperature	Relative Humidity
1. Control center[a]	75 °F	60% max.
2. ESF switchgear room	< 120°F max.	90% max.
3. Core spray, RCIC, RHR, HPCI emergency equipment rooms	148 °F max.[c]	90% max.
4. Standby gas treatment system room	104 °F max.	90% max.
5. Thermal recombiner area[d]	104 °F max.	90% max.
6. Emergency equipment cooling water pump room	104 °F max.	90% max.
7. Diesel Generator rooms (RHR complex)	65 °F min. 122 °F max.	-
8. Switchgear room (RHR complex)	65 °F min. 104 °F max.	-
9. Pump room (RHR complex)	104 °F max.	100% max.
10. Diesel-generator fuel-oil-storage room, and CO_2 storage room (RHR complex)	65 °F min. 125 °F max.	
11. Ventilation equipment rooms (RHR complex)	65 °F min. 104 °F max.	

Note a-Temperature for mechanical equipment room (MER) is 95°F.

Note b-These are design conditions and the actual conditions to which the equipment in this area is environmentally qualified under the Fermi 2 EQ Program are documented in EQ0-EF2-018.

Note c-RHR pump basement and sub-basement quadrants: equipment qualified to 153°F peak temperature.

Note d-The thermal recombiner units are retired in place, de-energized, and isolated from primary containment with redundant locked-closed isolation valves. The associated area coolers are retained and credited as a heat sink for post-accident environmental conditions.

TABLE 3.11-5 DESIGN ENVIRONMENTAL CONDITIONS (PLANT OPERATIONAL)[l,m]

Area	Pressure (as noted)	Temperature (°F)	Relative Humidity (Precent)	Radiation Type	Operating Dose Rate[a] Plant Operation	Operating Dose Rate[a] System Operation	Integrated Dose Normal[b]	Integrated Dose Accident[c]	DBA Type[d]	DBA Dose Rate
I. Primary containment[e]										
Drywell, with sacrificial shield	-0.5 to 2.0 psig	135° average[k] --- minimum	40-50 normal 90 maximum ----- minimum	Gamma neutron		--				
1. Above Core	Same as above	Same as above	Same as above	Same as above	25.0 5x10^4	--	8.8 x10^6 6.3x10^{13}	2.6x10^7	LOCA	1.3x10^6
2. Core region	Same as above	Same as above	Same as above	Same as above	50.0 1.4x10^5	--	1.8x10^7 1.8x10^{14}			
3. Under reactor pressure vessel	Same as above	135° average[k] 100° minimum[f] 185° maximum[g]	Same as above	Same as above	7.2 <1	--	2.5x10^6 <1.3x10^9	2.6x10^7	LOCA	1.3x10^6
4. Vicinity recirculation pump motors	Same as above	128° average ---- minimum 135° maximum[k]	Same as above	Same as above	25.0 2x10^3	--	8.8x10^6 2.5x10^{12}	2.6x10^7	LOCA	1.3x10^6
5. 15 ft from recirculation pump motors	Same as above	135° average[k] ---- minimum 150° maximum	Same as above	Same as above	4.0 2x10^3	--	1.4x10^6 2.5x10^{12}	2.6x10^7	LOCA	1.3x10^6
6. Suppression pool	Same as above	Same as above	Same as above	Same as above	0.1 2x10^2	--	3.5x10^4	2.6x10^7	LOCA	
II. Secondary containment (reactor building)										
General floor area	-0.10 in. to -1.0 in. Water gage static pressure	70° normal 104° maximum 40° minimum	40 normal 90 maximum	Same as above	0.001	--	3.5x10^2	1.7x10^5	LOCA	6.5x10^2
HPCI & RCIC area	Same as above	70° normal 104° maximum[h] 60° minimum	Same as above[h]	Same as above	0.015	0.200	5.3 x10^3	4.5x10^4	LOCA	1.6x10^2

TABLE 3.11-5 DESIGN ENVIRONMENTAL CONDITIONS (PLANT OPERATIONAL)[l,m]

Area	Pressure (as noted)	Temperature (°F)	Relative Humidity (Precent)	Radiation Type	Operating Dose Rate[a] Plant Operation	Operating Dose Rate[a] System Operation	Integrated Dose Normal[b]	Integrated Dose Accident[c]	DBA Type[d]	DBA Dose Rate
Core spray & RHR equipment area[i]	Same as above	70° normal 104° maximum 40° minimum	Same as above[h]	Same as above	0.015	0.030	5.3 x10^3	4.5x10^4	LOCA	1.6x10^2
Steam Tunnel	-0.10 in. to 1.0in.	125° normal	40-50 normal	Gamma	5	--	1.8x10^6	4.5x10^4	LOCA	1.6x10^2
	Water gage static pressure	140° maximum 40° minimum	90-98 maximum					>2.5x10^2	Rod drop	2.5x10^2
Standby liquid control area	Same as above	100° maximum 70° minimum	40 normal 90 maximum							
24-in. Pipe containing suppression pool H_20 (typical pipe)	Same as above	70° normal 104° maximum 40° minimum	Same as above	Gamma	0.0	--	0.0	7.9x10^5	LOCA	1.4x10^4
Cleanup systems	Same as above	Same as above	Same as above							
1. Heat exchangers				Gamma	15.0	--	5.4x10^6	1.7x10^5	LOCA	6.5x10^2
2. Pump room				Gamma	>0.05	--	1.8x10^4	1.7x10^5	LOCA	6.5x10^2
3. Filters & tanks				Gamma	10.0	--	3.6x10^6	1.7x10^5	LOCA	6.5x10^2
SGTS	Same as above	Same as above	Same as above	Gamma	0.001	--				
III. Turbine building[j]										
General areas protected by shields	0.0 in. to -0.25 in. H_20 gage static pressure	70° normal (winter) 104° maximum (elect) 40° minimum 90° normal (Summer) 120° maximum (non-elect)	40 normal 90 maximum	Gamma	0.001	--	4x10^3	--		
Operating floor, General	Same as above	Same as above	Same as above	Gamma	0.005-0.020	--	77.0x10^4	--		

TABLE 3.11-5 DESIGN ENVIRONMENTAL CONDITIONS (PLANT OPERATIONAL)[l,m]

Area	Pressure (as noted)	Temperature (°F)	Relative Humidity (Precent)	Radiation Type	Operating Dose Rate[a] Plant Operation	System Operation	Integrated Dose Normal[b]	Accident[c]	DBA Type[d]	Dose Rate
Contact high-pressure Turbine	Same as above	Same as above	Same as above	Gamma	0.5	--	$1.8x10^5$	--		
Contact low-pressure Turbine	Same as above	Same as above	Same as above	Gamma	0.1	--	$3.5x10^4$	--		
Equipment bay (htrs., condensers, etc)	Same as above	Same as above	Same as above	Gamma	0.05-5.0	--	$1.8x10^6$	--		
Steam-jet air ejector	Same as above	Same as above	Same as above	Gamma	15	--	$5.3x10^6$	--		
Condensate treatment	Same as above	Same as above	Same as above	Gamma	10	--	$3.5x10^6$	--		
IV. Radwaste building [j]										
Equipment cells (valve & pump rooms)	0.0 in. to -0.5 in. H_20 gage static pressure	70° normal 120° maximum 40° minimum	40 normal 90 maximum	Gamma	0.020	--	$7.0x10^3$	--		
Main control room	0.0 in. to -0.25 in. H_20 gage static pressure	75° normal 80° maximum 70° minimum	Same as above	Gamma	0.001	--	$3.5x10^2$	--		
Storage tanks (unprocessed) (unprocessed)	Same as above	Same as above	Same as above	Gamma	20.0		$7.0x10^6$	-- 0		
Centrifuge	Same as above	Same as above	Same as above	Gamma		100	$1x10^7$	--		
V. Main control room	0.10 in. to 0.5 in. H_20 gage static pressure	75° normal 95° maximum 60° minimum	50 normal 60 maximum	Gamma	0.0005	--	$1.75x10^2$	$3.0x10^0$		

TABLE 3.11-5 DESIGN ENVIRONMENTAL CONDITIONS (PLANT OPERATIONAL) [l,m]

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[a] Gamma dose rate — Rads/hr
Neutron Flux — Neutrons/cm^2/sec

[b] Gamma dose — Rads
Neutron fluence — Neutrons/cm^2 (NVT)
Normal conditions — Integrated over 40years – 100% load factor @ rated power

[c] Gamma dose — Rads
Neutron fluence — Neutrons/cm^2 (NVT)
Accident conditions — Integrated over 6 months

[d] LOCA analysis was based upon the assumption that 100% of the noble gases, 50% of the halogens, and 1% of the solid fission products were released from the core.

[e] Primary containment atmosphere during normal operation may be inerted with nitrogen.

[f] Components located in the turbine building or radwaste building required to operate under normal conditions, if any, should be designed for equivalent conditions as shown for reactor building.

[g] The same minimum temperature (100°F), shall apply at the inside base of the shield wall. Air velocity over vessel insulation and exposed vessel parts shall be approximately 6 ft./sec.

[h] During the loss of offsite power, and emergencies, except during DBA, temperature of area underneath the RPV will be maintained at 185°F or lower for up to 30 minutes.

[i] Whenever the residual heat removal and core spray motor and emergency core cooling systems are running, during test periods, area space coolers may be required to maintain the ambient temperature listed.

[j] The maximum temperature and humidity will occur simultaneously in these spaces less than 1% of the time.

[k] The drywell volumetric average temperature may increase over 135°F and up to 145°F.

[l] These are design conditions and the actual conditions to which the equipment in this area is environmentally qualified under the Fermi 2 EQ Program are documented in EQ0-EF2-018.

[m] The environmental conditions documented in this table were established by GE as part of the original Fermi 2 design criteria as documented in GE specification 22A3019 (Reference 5).

3.12 SEPARATION CRITERIA FOR SAFETY-RELATED MECHANICAL AND ELECTRICAL EQUIPMENT

3.12.1 Introduction

This section defines separation criteria for safety-related mechanical and electrical equipment. Safety-related equipment to which the criteria apply is that equipment necessary to mitigate the effects of abnormal operational transients or accidents. The objective of the criteria is to delineate the separation requirements necessary to achieve true independence of safety-related functions compatible with the redundant equipment provided.

The sections to follow individually address mechanical and electrical equipment separation. The specific systems and equipment to which the criteria apply are listed, followed by the corresponding criteria.

3.12.2 Mechanical Systems and Equipment

3.12.2.1 Affected Systems and Equipment

The mechanical systems and related equipment (i.e., piping, valves, pumps, and heat exchangers) affected by the criteria of Subsection 3.12.2.2.1 are

a. Emergency core cooling system (ECCS)

   1. Low pressure coolant injection (LPCI) system
   2. Core spray system
   3. High pressure coolant injection (HPCI) system
   4. Automatic depressurization system (ADS).

b. Reactor core isolation cooling (RCIC) system

c. Deleted

d. Standby gas treatment system (SGTS)

e. Emergency equipment cooling water (EECW) system

f. Control center air conditioning system (CCACS)

g. Fan-coil unit ventilation systems

   1. ECCS equipment pump rooms
   2. SGTS filter unit rooms
   3. EECW pump area
   4. Hydrogen recombiner area
   5. Engineered safety feature (ESF) switchgear rooms
   6. CCACS equipment room

7. Residual heat removal (RHR) complex equipment rooms.

h. Nuclear pressure relief system

i. Main steam isolation valves (MSIVs)

j. Containment cooling mode of RHR system

k. Emergency equipment service water (EESW) system

l. Standby liquid control system (SLCS)

m. RHR service water system

n. Emergency diesel generator (EDG) and oil systems

o. Control air system.

3.12.2.2 Criteria

3.12.2.2.1 General

Separation of the affected mechanical systems and equipment is accomplished in such a manner that the substance and intent of 10 CFR 50 are fulfilled.

Consideration is given to the redundant and diverse requirements of the affected systems.

Consideration is given to the type, size, and orientation of possible breaks of the reactor coolant pressure boundary (RCPB) specified in Section 3.6.

The protection afforded by the ECCS network satisfies the single failure criterion. A single failure means an occurrence that results in the loss of capability of a component to perform its intended safety functions. Multiple failures resulting from a single occurrence are considered part of the single failure. Fluid systems are considered to be designed against an assumed single failure, if a single failure of any active component (assuming passive components function properly) does not result in a loss of capability of the system to perform its safety function.

The affected mechanical systems and equipment, along with their associated structures, are appropriately separated so that, by virtue of separation or other adequate provisions, systems important to safety are adequately protected against:

a. The LOCA dynamic effects outlined in Section 3.6

b. Missiles as defined in Section 3.5

c. Fires capable of damaging redundant mechanical safety equipment.

The need for and the adequacy of separation are determined in conjunction with the criteria specified in Sections 3.5 and 3.6.

3.12.2.2.2 System Separation

Piping for a redundant safety system is run independently of its counterpart. Supports, restraints, and mechanical components of redundant piping of the same system are not shared in common, unless it can be shown that such sharing does not significantly impair their ability to perform their safety functions.

Containment penetrations are separated so that damage to or failure of one branch of a system will not render its redundant counterpart(s) inoperable.

3.12.2.2.3 Physical Separation

Mechanical equipment and piping, including control system conduit and tubing for the ECCS, are separated so that no single credible event, such as a LOCA, is capable of disabling sufficient equipment to prevent reactor shutdown, removal of decay heat from the core, or isolation of the containment to the extent that an offsite dose in excess of 10 CFR 50.67 or 10 CFR 100 requirements results.

The ADS is separated from the HPCI system such that no portion of the HPCI influent line or HPCI steam supply line is located within jet impingement damage distance or pipe movement damage distance of any component considered essential to the operation of the ADS.

Provisions are made to ensure that no single failure could incapacitate both the HPCI and RCIC.

The RHR service water system, EESW system, and EDGs, all located in the RHR complex, are split into two divisions separated by a common wall that also serves as a missile barrier (see Section 3.5). The divisions are identical and each division is capable of performing the intended system safety function independent of the other division. The equipment of each system is housed in a Category I structure that also provides protection against natural phenomena such as tornadoes and floods. Piping between the RHR complex and the reactor/auxiliary building is provided for each division and is separated so that no single event is capable of damaging the piping in both divisions.

The CCACS likewise consists of two redundant, full-capacity systems, separated such that no single failure can incapacitate both divisions.

Independent fan-coil units are provided for each redundant piece of equipment and are separated in the same manner and provide the same protection as the equipment they serve.

3.12.3 Electrical Systems and Equipment

3.12.3.1 Affected Systems

The systems with electrical portions that might be affected by the criteria of Subsection 3.12.3.2.1 are those listed in Subsection 3.12.2.1 plus the reactor protection system (RPS) and other systems required for safe shutdown of the reactor. Affected equipment included in these systems are instrument channels, trip systems, trip actuators, standby power sources, average power range monitors (APRMs), and intermediate range monitors (IRMs).

3.12.3.2 Criteria

These systems have been fabricated in accordance with the intent of Institute of Electrical and Electronics Engineers (IEEE) 279-1971 and IEEE 308-1971 as applicable. Explicit criteria are given in Subsection 3.12.3.2.1.

3.12.3.2.1 General

As a consequence of the design of these systems and components and the separation provided, the single-failure criterion defined in accordance with Paragraph 4.2 of IEEE 279-1971 is satisfied. In addition, several potentially adverse effects are considered in the determination of the degree of separation. These are:

a. Electrical fires in wireways that could cause failure of unprotected insulation on other cables in the same wireway

b. Gross failure of electrical equipment in any single compartment of an instrument or control panel

c. Mechanical damage of equipment in a single location, the area of which is limited by the damaging potential of surrounding equipment

d. Damage caused by earthquakes of the safe-shutdown earthquake (SSE) magnitude

e. Single events that could disable an automatic protective function, i.e., reactor scram, containment isolation, or core cooling. Also, single failures that could incapacitate both the HPCI and RCIC systems, with initiation of the ADS and ECCS resulting during an abnormal operational transient.

Equipment associated with the RPS, safe shutdown systems (systems required for safe shutdown), and ESF systems are identified so that two facts are physically apparent to operating and maintenance personnel: first, that the equipment is part of the RPS, safe shutdown systems, or the ESF system engineered equipment; and second, the grouping (or division) of enforced segregation with which the equipment is associated, is identified. Identification and divisions conform to the following:

a. Panels and racks associated with the RPS, safe-shutdown systems, and ESF systems are labeled with marker plates that are conspicuously different in color from those for other panels or racks. The marker plates include identification of the proper division (I or II, for example). The equipment identification number and applicable segregation code, both numerical and color code, are applied to each piece of safety-related equipment

b. Junction and/or pull boxes enclosing wiring for the RPS, safe-shutdown systems, and ESF systems have identification similar to and compatible with the panel and racks considered above

c. Cables external to cabinets and/or panels for the RPS, safe shutdown systems, and ESF systems have color-coded jackets to distinguish them in color from other cables and to identify their separation division, as applicable. The color coding system is used throughout the plant for identification. For instance, Division I cable is orange, Division II cable is blue, and balance- of-plant (BOP) cable is black. The exceptions to cable color loading are described in Section 8.3.1.5.1. Reactor protection system cables are colored black since they are routed through their own exclusive, totally enclosed raceway system, as described in Subsection 3.12.3.2.2. The raceways are clearly identified with RPS channel numbers

d. Raceways that carry RPS wiring are identified at entrance points of each room they pass through (and exit points unless the room is small enough to facilitate convenient following of cable), and at intervals along the raceways, by markers indicating their separation division. The raceways have alpha-numeric fire resistant painted identification with color coding as described in Item c. above

e. Redundant sensory equipment is identified by suffix letters in accordance with Tables 3.12-1 and 3.12-2 for the RPS and Table 3.12-3 for the ESF systems. These tables also show the allocation of sensors to separated divisions. Allocations for safe shutdown systems sensors are given in Table 3.12-1 for the deenergize-to-operate type and in Table 3.12-3 for the energize-to-operate type.

3.12.3.2.2 System Separation

The following apply specifically to the RPS; however, the wiring guidelines also apply to the safe shutdown systems:

a. Wiring for the RPS, including the neutron monitoring system (NMS), outside the control system cabinets is run in enclosed raceway, with each of the four channels monitoring each variable being physically separated. Under-vessel neutron monitoring cables are exempted from this wireway requirement because of space limitations and the need for flexibility of IRM cables. The IRM and source range monitor (SRM) cables may be combined in the same wireway; however, the four- divisional separation is maintained.

b. Wiring to duplicate sensors on a common process tap is run in separate wireways to separate destinations

c. Wiring for sensors of more than one variable in the same trip channel can be, and is, run in the same wireway

d. Wires from both RPS trip system trip actuators to a single group of scram solenoids may be run in a single wireway. However, a single wireway does not contain wires to more than one group of scram solenoids. Wiring for two solenoids on the same control rod may be run in the same wireway

e. Cables through the containment penetrations are so grouped that failure of all cabling in a single penetration cannot prevent a scram. Conduits inside the dry-well are grouped so that failure of any one conduit will not result in disabling any APRM channel

f. Power supplies to systems that deenergize to operate require only that separation which is deemed prudent to give continuity of operation. Therefore, even though the load circuits go to separated panels, the protection system flywheel motor-generator sets and load circuit breakers are not required to comply with the separation criteria of this subsection for safety reasons

g. Even though the load circuits go to separated panels, the RPS wiring is run and/or protected in such a manner that no common source of potentially damaging energy (e.g., electrical fire in non-RPS wireways) could reasonably result in loss of ability to scram when required

h. The RPS has four independent input instrument channels for each measured variable. The four separate wireways for the four sensors for a specific variable are, in some cases, combined into two groupings or divisions for routing purposes by combining Divisions IA and IB as shown in Table 3.12-1 and Figure 3.12-1. However, under permitted bypass conditions, there is no case in which the total disabling of equipment within a single division is capable of preventing a required scram action.

3.12.3.2.3 Physical Separation

Electrical equipment and wiring for the ESF systems are segregated into separate divisions that are designated I and II, so that no single credible event is capable of disabling sufficient equipment to prevent reactor shutdown, removal of decay heat from the core, or isolation of the primary containment in the event of an accident. Separation requirements apply to control power and motive power for all systems concerned. In addition, the RCIC and HPCI systems are treated as functionally redundant counterparts and are divisionally separated, the RCIC system being in Division I, the HPCI system in Division II.

Arrangement and/or protective barriers are such that no locally generated force or missile can destroy both redundant safe shutdown and ESF system functions. In addition, because of treatment as functionally redundant systems, the same is true for the HPCI and RCIC systems. In the absence of confirming analysis to support less stringent requirements, the following rules apply:

a. In rooms or compartments having heavy rotating machinery, such as the main turbine generator, or the reactor feedwater pumps; or in rooms containing high-pressure feedwater piping or high-pressure steam lines such as those between the reactor and the turbine, at least one cable is run in metal (rigid or flexible) conduit if cables of different divisions are located in the room or compartment

b. Switchgear associated with redundant safety systems that are located in a potential mechanical damage zone such as that discussed above have a minimum horizontal separation of 20 ft or are separated by a protective wall equivalent to a 6-in.-thick reinforced-concrete wall

c. In any compartment containing an operating crane such as the turbine building, main floor, and the region above the reactor pressure vessel (RPV), there is a minimum horizontal separation of 20 ft or a 6-in.-thick reinforced-concrete wall between trays containing cables of the two divisions

d. Each RPS motor-generator set is housed in its own reinforced-concrete room with 12-in.-thick walls. The only path a missile such as a flywheel could take (to leave the room) would be through the door, but the position of the flywheel with respect to the door opening eliminates that possibility. Therefore, redundant safety-related systems cannot be failed due to such an event. The damage would be limited to the associated equipment located inside the room where the flywheel failure occurred. In addition, the RPS system cabling in this location will be contained in conduit

e. In the battery rooms, the only equipment is the batteries themselves and the only cabling is the main dc power cables to the main distribution cabinets located outside the battery rooms. The main power cables in the battery room, in addition to being fire retardant, are contained in conduit.

Arrangement of wiring and cabling ensures that fire will not propagate from one division to another. Cables have been tested and certified to be fire retardant (i.e., cable burning will stop when flame is removed). In addition, cables have been tested and certified to remain operating for 5 minutes during a fire. In addition, arrangement of wiring cabling of the HPCI and RCIC systems ensures that both systems are not disabled by a single failure. In the absence of confirming analysis to support less stringent requirements, the general guidelines used to determine the allocation of electrical wiring between segregated divisions of the safe shutdown and ESF systems are

a. Separation is such that no single failure can prevent operation of an ESF function (e.g., core cooling). Redundant (even dissimilar) systems are, in some cases, needed to perform the required function to satisfy the single-failure criteria. Table 3.12-4 illustrates the separation of subsystems of the nuclear safety and ESF systems valves. Figures 3.12-2 through 3.12-4 illustrate the ESF equipment separation into divisions and the allowable interconnections through isolating devices. Interconnecting wireways are assigned to the same division as the power for the contained circuits, and separation between divisions is maintained except at the immediate area of entrance to the cabinet of the other division, where steel barriers are provided

b. The inboard isolation system valve wiring between the control panel and the valve proper is separated from the outboard isolation valve wiring. (Figure 3.12-3 illustrates this requirement.) The manual controls for the isolation valves may be treated as an exception to this inboard division, if deemed necessary from an operational point of view, provided that no single failure can prevent the required automatic operation of at least one of an inboard/outboard pair of isolation valves

c. Routing of cables for RPS safe shutdown and ESF systems power through rooms or spaces where there is potential for accumulation of large quantities (gallons) of oil or other combustible fluids through leakage or rupture of lube oil or cooling systems is avoided. Where such routing is practically unavoidable, only one division of these cables is allowed in any such space

d. In any room or compartment in which the only source of fire is of an electrical nature, cable trays have a minimum horizontal separation of 3 ft, if no physical barrier exists between trays. If a horizontal separation of 3 ft is unattainable, a fire-resistant barrier is provided, extending at least 1 ft above (or to the ceiling) and 1 ft below (or to the floor) line of sight between the two trays. These trays are of the open-bottom type (ladder type) for power/control cable and solid-bottom-covered type for instrumentation

e. For subject cable trays, there is a minimum vertical separation of 5 ft between horizontal trays stacked one above the other; however, vertical stacking of trays is avoided wherever possible. In cases where trays must be run stacked one above the other, and where the trays meet the 5-ft vertical separation requirement, the lower tray has a solid-metal cover. Where the 5-ft separation can not be met, the upper tray also has a solid-metal bottom and a fire-resistant barrier is placed between the redundant trays

f. In the case of crossover of one tray over another (or over a panel), there is a minimum vertical separation of 18 in. (tray bottom to tray bottom), with the bottom tray covered with a metal cover, and the top tray provided with a metal bottom for a distance of 5 ft on each side of the tray crossover point

g. Any openings in floors for vertical runs of cables are sealed with fire-resistant material

h. There are two sets of Category I ductbanks between the RHR complex and the Reactor/Auxiliary building, with a Division I and Division II ductbank in each set. In each case, the buried cable ducts between the RHR complex and the Reactor/Auxiliary building provide adequate cable separation to maintain independence of redundant circuits.

   The first set of ductbanks was installed during plant construction. The buried cable runs between the RHR complex and reactor/auxiliary building are housed in reinforced- concrete ducts below grade and are physically separated by a distance of at least 20 ft. The separation is 30 ft at the point the cable ducts leave the reactor/ auxiliary building. The ducts make a sweeping bend with a minimum separation of 20 ft. The ducts then run parallel with a separation of 24 ft. This separation increases until the ducts enter (still below grade) the RHR complex. 4160-V essential power circuits are not routed within these ductbanks.

   The second set of ductbanks and associated manholes is installed above the maximum ground water elevation of 576.0 ft with ducts sloped to the manholes, such that circuits contained are not subject to continuous wetting. These are also cast-in-place, rectangular reinforced concrete ductbanks, but are located with the ductbank top approximately six inches below the surface and manhole covers at grade level. The Division I and Division II 4160-V ductbanks are separated by approximately 25 feet at the Auxiliary building entrance. The separation narrows to approximately 10’-6” at the closest point as they make a sweeping turn and widens to approximately 20 feet at the entrance to manholes 16946A and 16947A. The ductbank separation again narrows to approximately 7’-8” at a top elevation of approximately 580’-6” (three feet below grade) and runs underneath the ISFSI Transfer Pad to manholes 16946B and 16947B. The ductbanks exit manholes 16946B and 16947B with a separation of approximately 15 feet that increases to a separation of greater than 20 feet after approximately 30 feet from the manholes. The separation increases to approximately 115 feet during the run from manholes 16946B and 16947B to manholes 16946C and 16947C, located near the RHR building. Ductbank separation for the ductbank run between manholes 16946C and 16947C and the RHR Building cable vaults is greater than 80 feet. 4160-V essential power circuits are routed within these ductbanks.

The Division II 4160-V ductbank crosses above the original Division I ductbank at two locations:

1. Approximately 15 feet south of the Auxiliary building, with the Division I ductbank at a top elevation approximately 8'-9" below grade and a vertical separation between the ductbanks of approximately five feet, with an additional twenty inches of reinforced concrete separating the closest conduits in each ductbank.

2. Approximately forty feet north-west of manhole 16947B, with the Division I ductbank approximately five feet below grade and a vertical separation between the ductbanks of approximately eighteen inches, also with an additional twenty inches of concrete between the closest conduits in each ductbank.

The 4160-V RHR cable vaults and the manholes and ductbanks between these cable vaults and the Reactor/Auxiliary building cable vaults are designed as tornado missile barriers per the requirements of Regulatory Guide 1.76 Revision 1. Because of the tornado missile barrier design, the redundant cables will not be subject to a common mode failure from a tornado missile and, due to the separation provided, a redundant division cable will not cause a failure in the surviving divisional cable. (See Section 3.5 for a discussion of tornado missile protection.)

The minimum horizontal and vertical separation and/or barrier in the cable spreading room is

a. Where cables of different separation divisions approach the same or adjacent control panels with spacing less than the 3-ft minimum, at least one cable is run in metal (rigid or flexible) conduit to a point where 3 ft of separation exists

b. A minimum horizontal separation of 3 ft is provided between trays containing cables of different separation divisions if no physical barrier exists between trays. If a horizontal separation of less than 3 ft is not attainable, a fire-resistant barrier is provided extending at least 1 ft above (or to the ceiling) and 1 ft below (or to the floor) line-of-sight distance between the two trays. These trays may be of the open-bottom type (ladder type) or solid-metal-bottom type

c. Vertical stacking of trays carrying cables of different divisions is avoided wherever possible. There is a minimum vertical separation of 5 ft between horizontal trays running parallel one above the other. In situations where 5 ft of separation cannot be maintained, the top trays have solid metal bottoms and the bottom trays have solid covers with a fire-resistant barrier provided between the trays

d. In the case of crossing of a tray of one separation division over a tray of the other division, there is a minimum vertical separation of 18 in. (tray bottom to tray bottom), and the bottom tray is covered with a metal cover and the top tray is provided with a metal bottom for a distance of 5 ft on each side of the intersection (identical to Item f. above).

No single control panel (or local panel or instrument rack) includes wiring essential to the protective function of two systems that are backups for each other, except as allowed by the applicable paragraphs below:

a. If two panels containing circuits of different separation divisions are less than 3 ft apart, there is a steel barrier between the two panels. Panel ends closed by steel end plates are considered acceptable barriers, provided that terminal boards and wireways are spaced a minimum of 1 in. from the end plate

b. Floor-to-top of panel fireproof barriers are provided between adjacent panels of different divisions

c. Penetrations of separation barriers within a subdivided panel where they occur are sealed so that an electrical fire could not reasonably propagate from one section to the other and destroy the protective function

d. For operational reasons, the mode switch, scram discharge volume (SDV) high-water-level-trip bypass switch, scram reset switch, and manual scram switch (all manual switches) are located on one panel. In this case, each device is mounted in a can with a sufficient number of barrier devices to maintain adequate separation. Also, conduit is provided from the cans to the logic cabinets

e. A specific set of separation criteria must be met by the internal wiring of individual operating panels, logic cabinets, or instrument racks that contain components (control devices and wiring) of both ESF divisions. Generally, the criteria specify the use of separate terminal boards and spacing of terminal boards and wiring to preclude the possibility of fire propagation from one division of wiring to another. Separation of control devices is accomplished by physical location or a suitable metallic barrier. Whenever possible, the redundant control devices are located on opposite sides of the barrier formed by the end enclosures of adjacent panels to effect the desired separation and immunity to fire damage. Alternatively, separation of a pair of redundant control devices that must be located in close proximity is achieved by totally enclosing the wiring to one of the devices within a fire-resistant material. In a few specific cases the criterion for separation within the metallic enclosure (cabinet or panel) is relaxed. This relaxation of the criterion is allowable since an analysis for the particular system shows that the complete failure of the equipment within the enclosure will not compromise the system's redundant counterpart or the redundant power supply (refer to the single-failure analysis in GE Report NEDO-10139, Compliance of Protection Systems to Industry Criteria: General Electric BWR Nuclear Steam Supply System)

f. Logic wiring associated with the plant annunciator and sequential recorders in some instances runs between divisional areas of a subdivided panel. An example would be the electrical connection of relay isolated contacts in each section of the RPS to provide an alarm function for the plant annunciator system. Interposing relays or equivalent isolation means are incorporated to effect the required degree of electrical separation. If practical design constraints tend to compromise the ability to provide the desired degree of separation, the design is analyzed to establish the existence of single-failure design adequacy

g. In response to an NRC concern where BOP cables tied electrically into Division II cables, Edison reviewed about 550 schematics where 1E and non-1E circuits interfaced electrically without the intrinsic separation provided by isolation devices as described in Regulatory Guide 1.75. As a result of this review, several cases where 1E and non-1E circuits interface electrically were identified, and the cases were categorized into representative samples for the purpose of analysis and documentation. The analysis of the representative samples of 1E and non-1E circuits showed that the ability of the 1E system to perform its assigned function was not impaired by the postulated electrical faults on the non-1E circuits that are associated with them, or the circuits were revised to provide additional protection or isolation. These analyses are maintained as a controlled design calculation. Future design changes must meet these conditions or additional analyses will be performed to the same criteria as established in these initial cases.

h. Single-fuse isolation between 1E and non-1E loads is acceptable if the following conditions are met:

    1. The fuse must be safety related and thus meet commensurate quality and qualification standards

    2. The fuse must be mounted in a safety-related enclosure

    3. It must be shown that the single-failure criterion is satisfactorily met assuming an accident and the single failure in the safety-related fuse; i.e., if an accident occurs and an assumed fault occurs in the non-1E load, it must be demonstrated that given a single failure of the safety-related fuse under the worst fault in the non-1E load and assuming all the potential cascading consequences of that fault/ failure, adequate safe shutdown may still be achieved by alternative safety-related means.

3.12.4 Comparison With Regulatory Guide 1.75

Fermi 2 design criteria were developed and electrical systems designed prior to issuance of Revision 1 of Regulatory Guide 1.75 in January 1975. The Fermi 2 design has, however, been reviewed, and the following differences have been identified:

a. Section 3 of IEEE Standard 384-1974 classifies associated circuits as non-Class 1E circuits that share power supplies, enclosures, or raceways with Class 1E circuits or are not physically separated from Class 1E circuits by acceptable separation distances or barriers. The Fermi 2 circuits are divided into three categories: Division I, Division II, and BOP. Divisional separation of redundant safety equipment is maintained throughout. However, no attempt is made to uniquely identify BOP cables that would fall into the "associated" category.

Fermi 2 separation criterion does state that, once a BOP cable comes in contact with a divisional tray, it cannot cross over to the other divisions. This is maintained by a computerized cable-routing program that does not allow a cable to be routed to the other division

The degradation of Class 1E circuits is avoided by the following design features:

1. The insulating materials and cable ratings are the same for BOP cables as Class 1E cables, the only exception being the fiber-optic cables. These cables are non-conducting cables, carrying light pulses, i.e., carry no fault energy and therefore cannot create shorts between circuits. The cable insulation is non-flame propagating, and certified to IEEE-383-1974, Paragraph 2.5.

2. The cable insulation is selected and tested not to propagate fire, thus eliminating the danger of a cable propagating a failure from one tray to another.

b. Balance-of-plant loads that are fed from Class 1E buses use breakers as a separation device. These breakers are fully qualified Class 1E devices. The cabling from the breakers to the load and to the control panel is BOP cabling. The breakers have full fault protection, but they are not opened on a LOCA signal. The incidence of reported false LOCA signals, notably due to high drywell pressure, indicates that this would cause unnecessary degradations in plant operational flexibility. As an added precaution, the large loads handled by 4160-V breakers have the external control circuit operated by a BOP battery, while the internal breaker control, including fault clearance, is operated by Class 1E battery power. The interfacing devices are Class 1E relays located in the switchgear (see Figure 3.12-5). The 480-V breakers feeding BOP loads from Class 1E buses are controlled entirely from the Class 1E battery. Since these are nonessential loads, the control cables between the switchgear and control room are treated as BOP cables. Control fuses in the switchgear protect the Class 1E battery. The Class 1E 480 volt distribution panel on each EDG, which feed BOP loads, is protected by 1E fuses located in the Class 1E MCC feeding the distribution panels. These Class 1E fuses provide isolation of the BOP load, assuming a failure of the distribution panels Class 1E overcurrent protective devices on faults on the non-1E circuit. The consequences of the loss of the Class 1E distribution panel have shown that EDG operability is not impacted.

c. Section 5.1.2 of IEEE 384 states that exposed Class 1E raceways be marked at intervals not to exceed 15 ft. Edison Specification 3071-128, standard EE, calls for markings "at point of entry into a room. . .." In addition, a standard note on all Fermi 2 cable tray identification drawings states that "tray numbers should occur at close intervals to enable any section to be readily and accurately identified"

d. Section 5.6.3 of IEEE 384 calls for Class 1E wire bundles or cables internal to control boards to be distinctly identified

These boards have already been manufactured, and no such marking has been provided. Division I and Division II circuits have been carefully isolated. Where a Division I circuit enters a Division II panel, it is run in metallic conduit, and the Division I device is canned. The same applies to Division II circuits entering a Division I panel. There is, however, no attempt to separate the BOP wiring or devices from the Class 1E wiring. The materials of the wiring are the same, which ensures that the reliability of the safety functions is not degraded.

TABLE 3.12-1 REACTOR PROTECTION SYSTEM AND DEENERGIZE-TO-OPERATE SENSOR SUFFIX LETTERS AND DIVISION ALLOCATION (INCLUDING PRIMARY CONTAINMENT ISOLATION CONTROL SYSTEM)

Total Sensors	Division IA Trip Logic A1	Division IB Trip Logic B1	Division IIA Trip Logic A2	Division IIB Trip Logic B2
4	A	B	C	D
	Part of Trip System A	Part of Trip System B	Part of Trip System A	Part of Trip System B

TABLE 3.12-2 FOUR DIVISION GROUPING OF THE NEUTRON MONITORING SYSTEM UTILIZING FOUR DRYWELL PENETRATIONS

Penetration Designation[a]	F IRM A & E APRM 1	G IRM B & F APRM 2	A IRM C & G APRM 3	B IRM D & H APRM 4
Wireway	NA	NB	NC	ND
Neutron monitoring channel				
APRM channel[b]	1	2	3	4
APRM 2-out-of-4 Trip Voter[b]	1	2	3	4
IRM	A & E	B & F	C & G	D & H
RPS trip logic	A1	B1	A2	B2

[a] Penetrations across top of table for four penetrations grouping carry cables for neutron monitoring channels shown and each channel serves RPS trip logic directly below it.

[b] Each APRM channel provides inputs to all four 2-out-of-4 trip voters.

TABLE 3.12-3 ENGINEERED SAFETY FEATURES SYSTEM SENSOR SUFFIX LETTERS AND DIVISION ALLOCATION[a,b]

Total Sensors for Each Parameter	Division I Sensor Suffix Letters		Division II Sensor Suffix Letters	
4	A	C	B	D
	Operate system A directly, and system B through isolation devices		Operate system B directly, and system A through isolation devices	

[a] For systems required for safe shutdown energize-to-operate sensors, use this table. For systems required for safe shutdown deenergize-to-operate sensors (using RPS power), use Table 3.12-1.

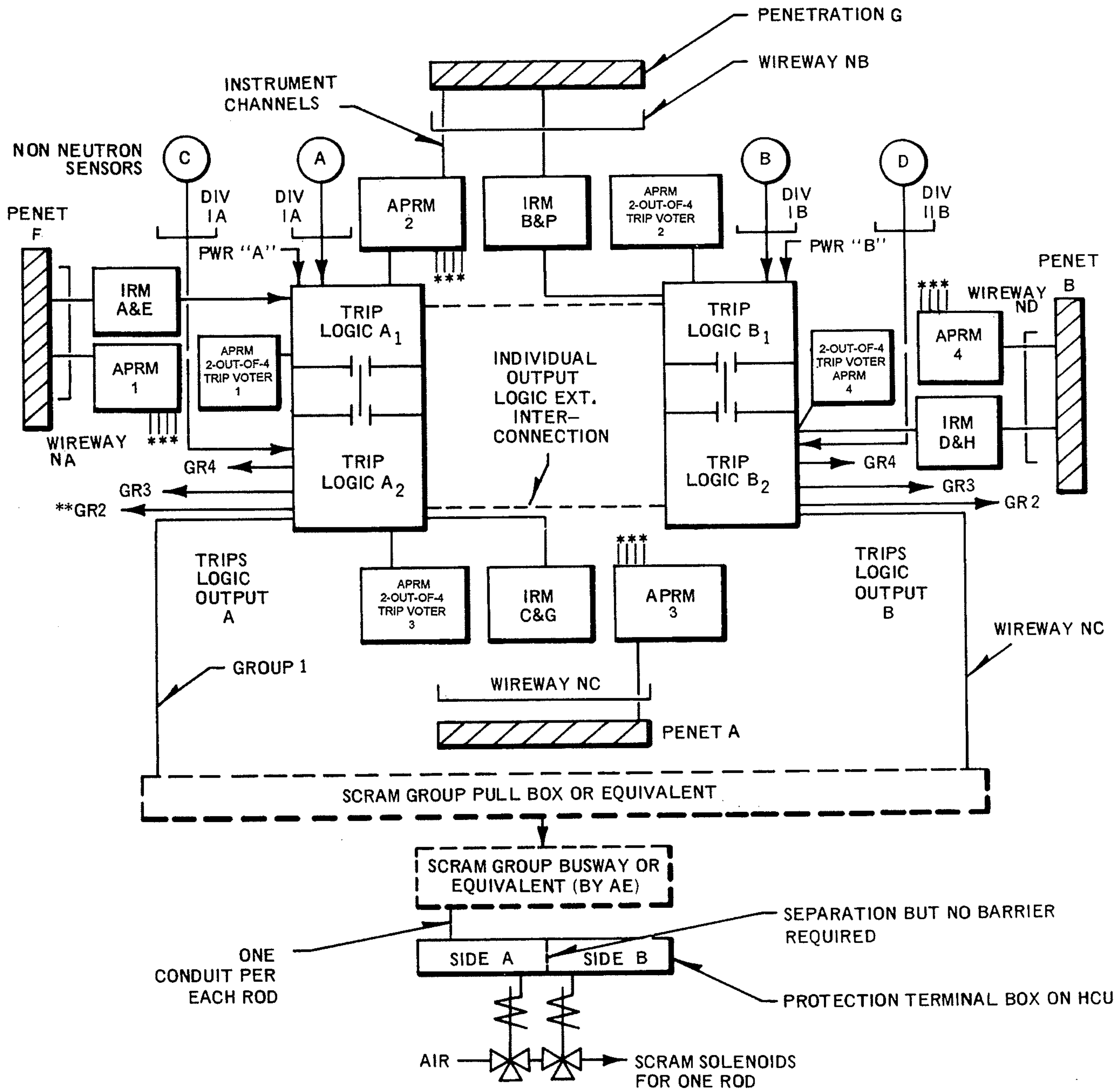
[b] ESF initiation is similar to RPS initiation, i.e., one of two times two (see Table 3.12-1 and Section 7.3).

TABLE 3.12-4 SYSTEM AND SUBSYSTEM SEPARATION

Division I	Division II
Core spray A	Core spray B
Automatic depressurization[a]	HPCI
RHR A (pumps A and C)	RHR B (pumps B and D)
Inboard safe shutdown system valves (except RCIC)[b]	Outboard safe shutdown system valves (except RCIC)[b]
Emergency equipment cooling water A	Emergency equipment cooling water B
RCIC	

[a] Wiring to each ADS valve inside the drywell is in a separate rigid conduit. All ADS valves wiring is separated as far as practical from HPCI piping inside the drywell.

[b] The inboard HPCI isolation valve control is independent of the outboard HPCI valve and of all RCIC isolation valve wiring.



*RPS SENSORS A&B OR C&D MAY BE CONNECTED TO A COMMON PROCESS TAP.
RPS SENSORS A&C OR B&D MUST NOT BE CONNECTED TO A COMMON PROCESS TAP.
**WIREWAYS NA, NB, ETC. MAY BE ASSIGNED TO SEPARATE DIVISIONS AS APPROPRIATE TO PLANT LAYOUT.
***EACH APRM CHANNEL PROVIDES INPUTS TO ALL FOUR 2-OUT-OF-4 TRIP VOTERS

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FIGURE 3.12-1

FOUR PENETRATION REACTOR PROTECTION SYSTEM SEPARATION CONCEPT

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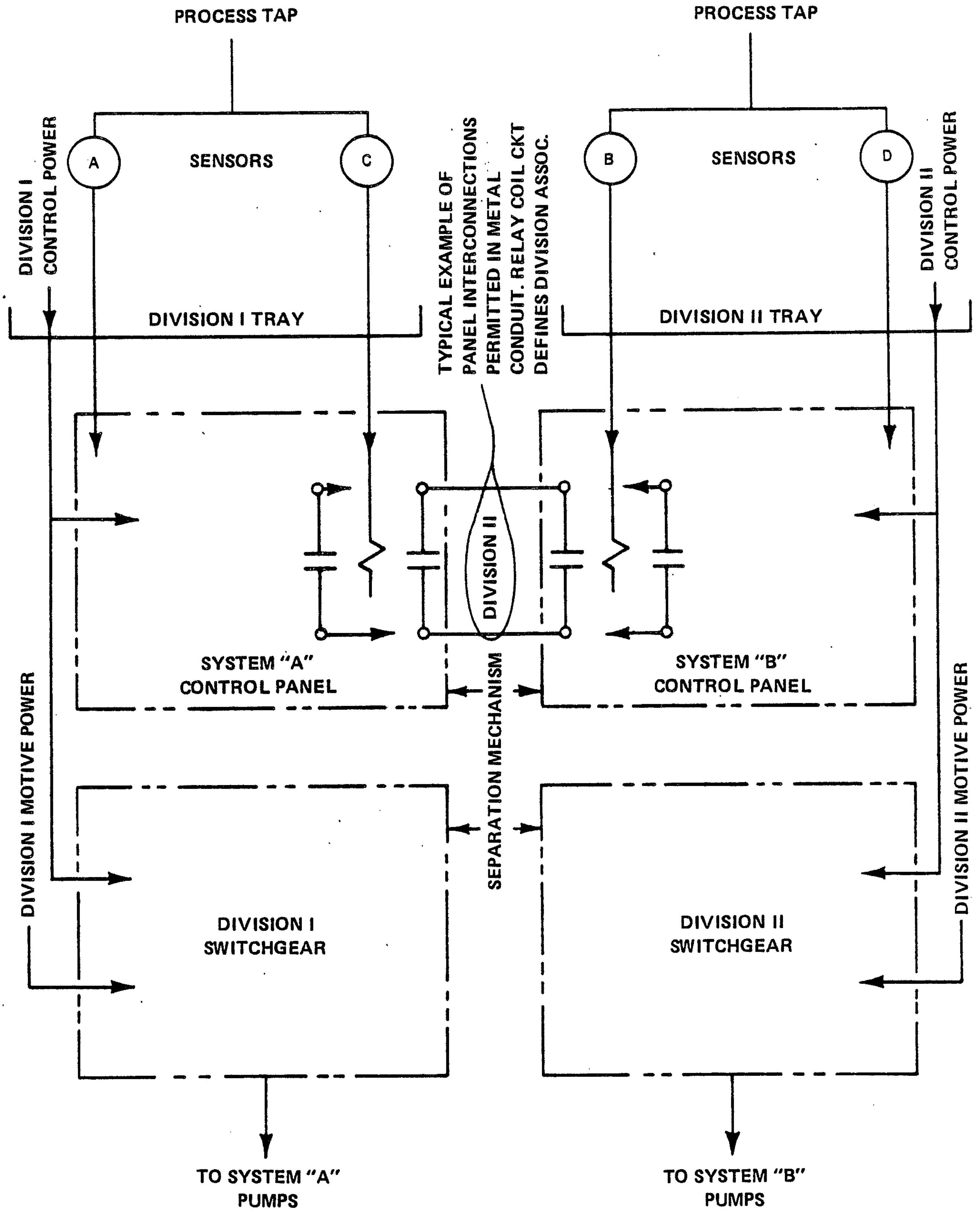

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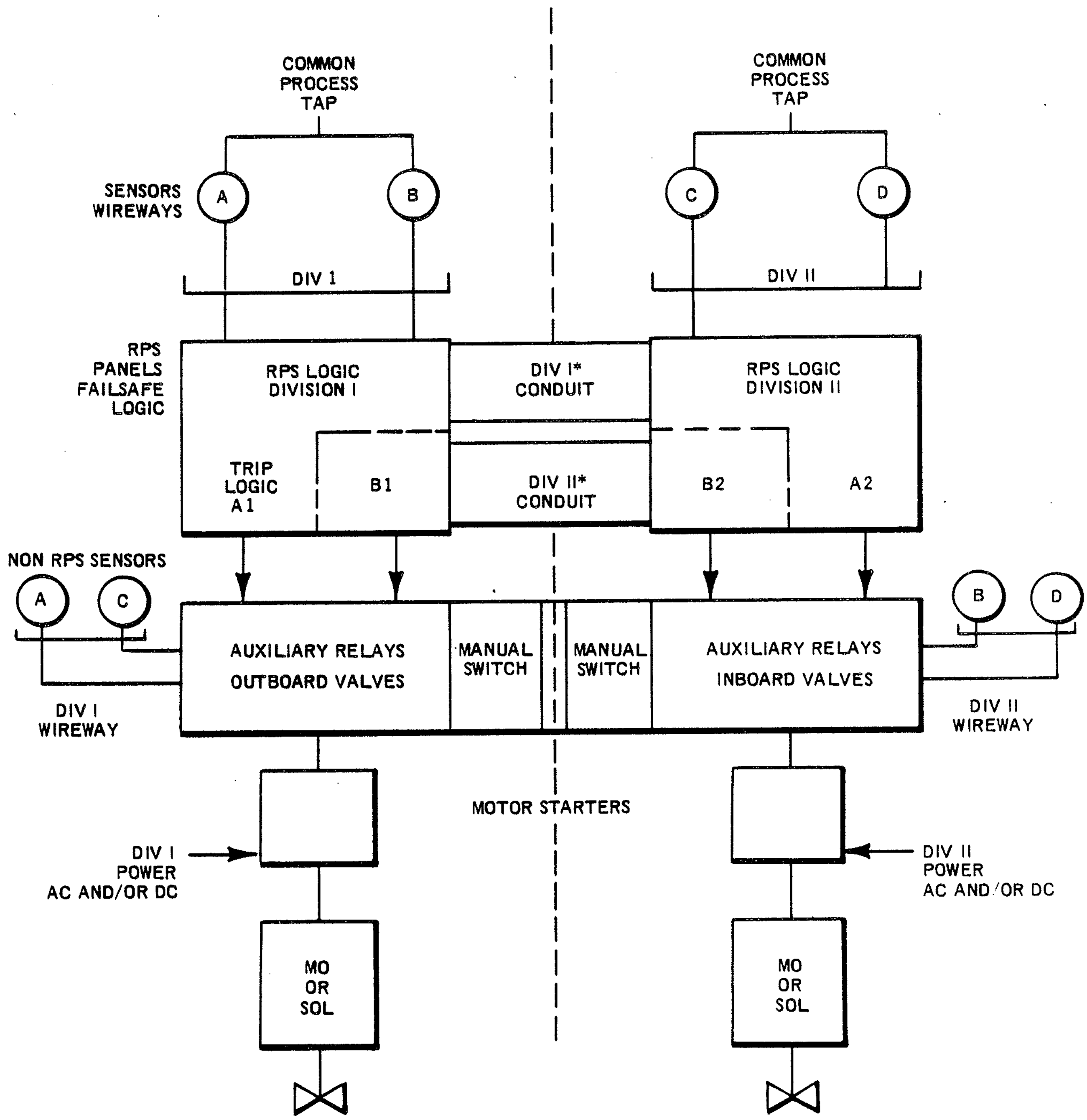
FIGURE 3.12-2

ENGINEERED SAFETY FEATURE SYSTEM SEPARATION SCHEME



*INTERCONNECTING CONDUITS USED FOR MAIN STEAM ISOLATION VALVE LOGIC ONLY

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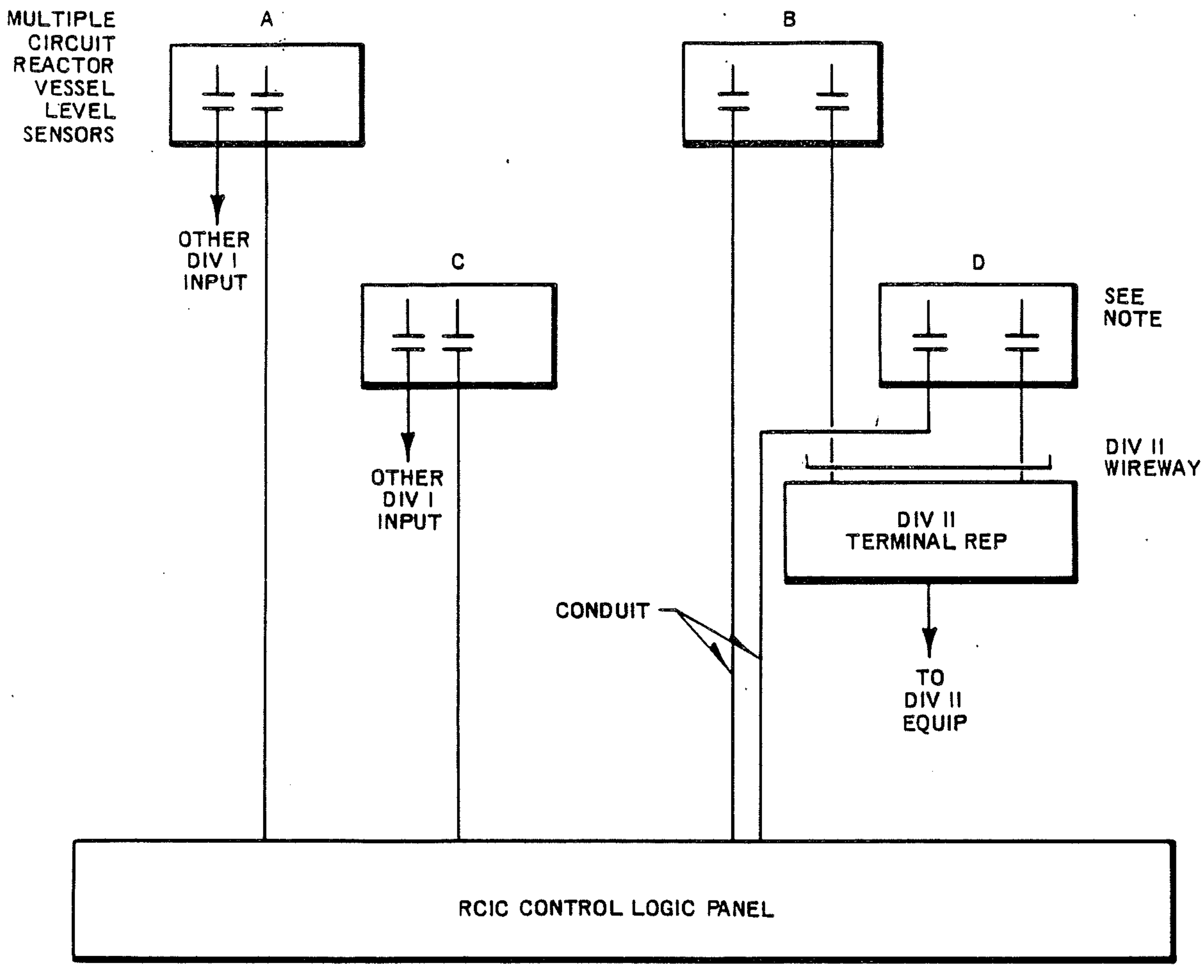
FIGURE 3.12-3

NUCLEAR SAFETY FEATURES
REACTOR PROTECTION SYSTEM AND SAFE SHUTDOWN SYSTEM – SEPARATION CONCEPT



NOTE: CIRCUITS FOR RCIC INITIATIONS UTILIZE CONTACTS ELECTRICALLY SEPARATE FROM THOSE USED FOR DIV II INPUTS.

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FIGURE 3.12-4

REACTOR CORE ISOLATION COOLING SENSOR SEPARATION SCHEME

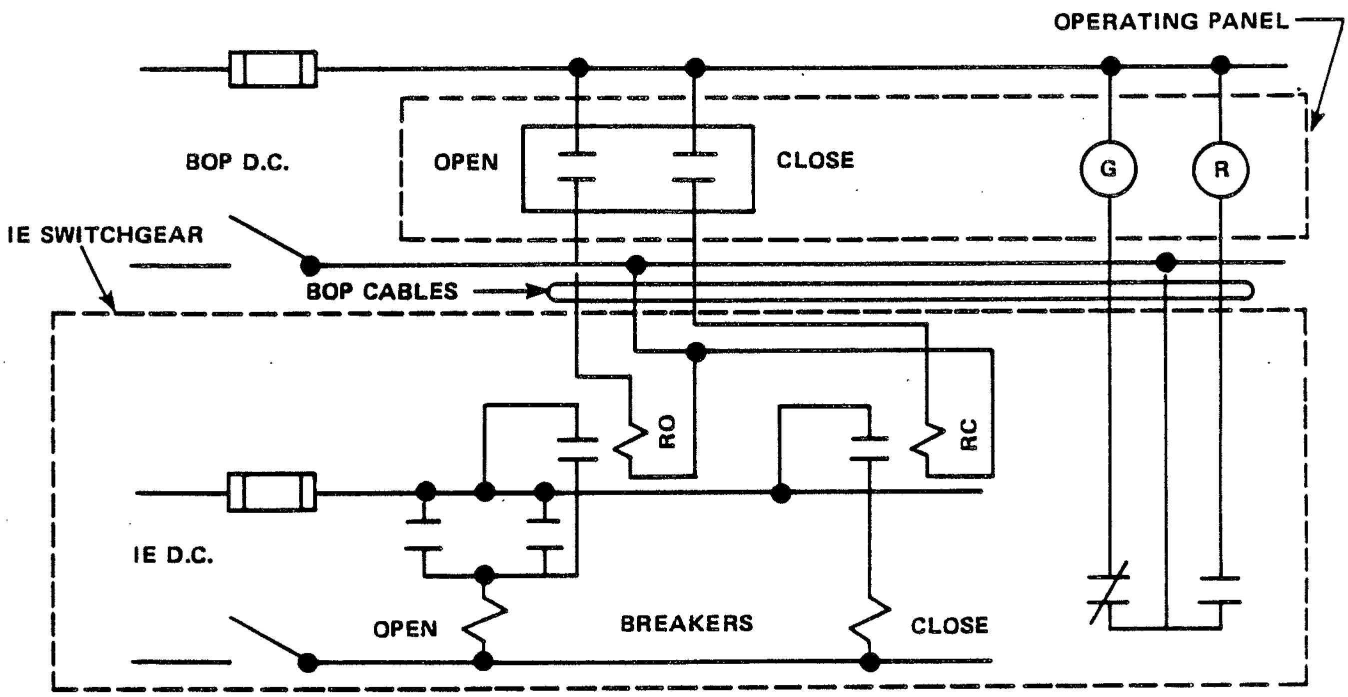

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FIGURE 3.12-5

CLASS 1E – BALANCE-OF-PLANT INTERFACE

3.13 COMPUTER PROGRAMS FOR STRUCTURAL ANALYSIS AND DESIGN

The computer programs referred to in Sections 3.7 and 3.8 are described herein. All programs have been verified, within the stated assumptions and limitations, for the correctness of the theory used and the validity of the results obtained for a wide variety of typical problems. Results have been checked against known solutions or solutions obtained from other programs using a different analytical approach. Furthermore, whenever applicable, internal checks, such as equilibrium and orthogonality checks, are printed out for each problem. Subsection 3.13.1 describes the computer programs used by Sargent & Lundy (S&L). Subsection 3.13.2 describes the computer programs used by Chicago Bridge & Iron (CBI). Subsection 3.13.4 describes the computer programs used by Stone & Webster, Michigan (S&W). Major computer programs used by others are described in Subsection 3.13.3.

3.13.1 Computer Programs Used by Sargent & Lundy

Subsections 3.13.1.1 through 3.13.1.32 describe computer programs used by S&L. The building structures to which each were applied are shown parenthetically following each program title.

3.13.1.1 AFEM - Axisymmetric Finite Element Method (Reactor/Auxiliary Building)

The Axisymmetric Finite Element Method (AFEM) is used for analysis of axisymmetric thick shells of revolution subjected to axisymmetric loads. The analysis is done using the finite element method with axisymmetric solid triangular elements. The analysis may be done for nodal loads, normal and shear pressures, and thermal loadings. For force or displacement-type boundary conditions, oblique or skewed restraints may be used.

The program output includes the displacements of each node, and the direct stresses, shear stresses, and principal stresses with their associated directions for each element. Boundary stresses are obtained through an extrapolation procedure, and the section stress resultants are obtained using a numerical integration procedure.

The Axisymmetric Finite Element Method is a modified version of the finite element program AMG032, developed by Rohm & Haas Company for the Redstone Arsenal Research Division, Huntsville, Alabama. It was obtained and modified by S&L in 1971. It is currently maintained on a UNIVAC 1106 operating under EXEC 8.

Three of the problems used to validate AFEM are presented here. Results obtained from AFEM are compared with hand calculations.

3.13.1.1.1 Problem 1

Problem 1 concerns the analysis of a uniformly loaded circular plate as shown in Figure 3.13-1. The solution from AFEM is compared to an evaluation of equations given by Timoshenko and Goodier in Reference 1.

Two computer runs using different grid sizes were used. As shown in Figures 3.13-2 through 3.13-5, the theoretical and computer solutions compare favorably.

3.13.1.1.2 Problem 2

Figure 3.13-6 shows the geometry for problem 2. A thick cylinder is loaded with its own weight and the body force is kept constant with the depth. For this problem the expressions for stresses are

$$\sigma_Z = \int_Z^h k\, d_Z = -kh\left[1-\left(\frac{Z}{h}\right)\right] \tag{3.13-1}$$

and

$$\sigma_r = \sigma_\theta = \tau_{r\theta} = \tau_{rZ} = 0 \tag{3.13-2}$$

K = material density = 200 lb/in.^{3}

As shown in Figure 3.13-7, the results from AFEM are within 5 percent of the theoretical solution.

3.13.1.1.3 Problem 3

The third problem is a temperature distribution problem. The thick cylinder in Figure 3.l3-8 is subjected to a steady-state temperature gradient. The inside temperature of the cylinder is 10°F higher than the outside temperature. A steady state is assumed in this long cylinder with a concentric hole. If T_i is the temperature on the inner surface of the cylinder and the outer surface temperature is zero, the temperature T at any distance r from the center is represented by the expression

$$T = \frac{T_i}{\log\left({}^{b}/_{a}\right)}\log\frac{b}{r} \tag{3.13-3}$$

The expressions for stresses are given in Reference 1. Properties for this problem are

a. Radius of the cylinder a = 5 in.

b. Radius of the hole b = 1 in.

c. Modulus of elasticity E = 10^6 psi

d. Poisson's ratio $\upsilon = 0.2$

e. Thermal coefficient α = 1/3000 in./in./°F

f. Inside temperature Ti = 10°F

As shown in Figures 3.13-9 and 3.13-10, the results compare favorably.

3.13.1.2 DSASS - Dynamic Seismic Analysis of Shear Structures (Reactor/Auxiliary Building)

Dynamic Seismic Analysis of Shear Structures (DSASS) is used for dynamic analysis of structures that could be modeled as slabs interconnected with springs. The masses are lumped at the slab levels and the springs offer resistance to relative displacements at their ends. The program considers the combined effects of translational, torsional, and rocking motion. The program uses either the response spectrum or time-history method of analysis. In the case of time-history analysis, the decoupled differential equations of motion are numerically integrated using Newmark's β-method (Reference 2). The program output includes modal responses, probable maximum time history of structural response, and response spectrum at any slab.

The DSASS program was developed by S&L in 1967. Version V is currently maintained on a UNIVAC 1106 operating under EXEC 8. This version has been used successfully since 1971.

To demonstrate the validity of the program, a three-story shear frame is analyzed and compared to a solution obtained by Biggs. The structure is represented by the closed-coupled system shown in Figure 3.13-11. The masses and stiffness values used are also given in the figure.

For the analysis, the following response spectrum was used:

Frequency (Hz)	Displacement (in.)
1.00	3.30
2.18	1.40
3.18	0.66

Table 3.13-1 represents a comparison of results obtained from DSASS and by Biggs. As demonstrated in this comparison, results obtained from DSASS are accurate.

3.13.1.3 DYNAS - Dynamic Analysis of Structures (Reactor/ Auxiliary Building and Residual Heat Removal Complex)

Dynamic Analysis of Structures (DYNAS) is designed for performing dynamic analysis of structures that can be idealized as three- dimensional space frames or rigid slabs connected by translational or torsional springs. The program considers the combined effects of translational, torsional, and rocking motions on the structure. The program uses either the response spectrum or time-history method of analysis, depending on the type of forcing function available. Both methods use the normal mode approach. In the case of time-history analysis, the decoupled differential equations of motion are numerically integrated using Newmark's β-method (Reference 2).

The program can be used for analyzing structures with parts having different associated dampings. The option is also available to analyze a large structural system using the modal synthesis technique. The system is divided into subsystems whose modal characteristics are computed separately, and then synthesized to obtain the response of the complete system. The base motion can be applied simultaneously in two orthogonal directions. Response spectra can be generated at specified slabs or joints. The program output includes modal responses, probable maximum responses, time history of structural response, and response spectrum at specified joints.

The DYNAS program, developed by S&L in 1970, is currently maintained on a UNIVAC 1106 operating under EXEC 8. Two examples of the problems used for validating the program are presented herein.

3.13.1.3.1 Problem 1

In the first problem, a three-story shear building is analyzed and compared to a solution obtained by Biggs (Reference 3). The structure is represented by the closed-coupled system shown in Figure 3.13-11, as are masses and stiffness values used. For the analysis, the following response spectrum was used:

Frequency (Hz)	Displacement (in.)
1.00	3.30
2.18	1.40
3.18	0.66

The results obtained by Biggs and from DYNAS are compared in Table 3.13-1.

3.13.1.3.2 Problem 2

In the second example, results of DYNAS are compared to those obtained by Wilson et al. (Reference 4) using the SAP IV program. At the fixed end of a cantilever beam (Figure 3.13-12), an acceleration is applied (Figure 3.13-13). The natural periods calculated by both SAP IV and DYNAS are shown in Table 3.13-2.

A comparison of the bending moment at the fixed end of the cantilever beam is shown in Figure 3.13-14. As demonstrated in both examples, DYNAS performs an accurate analysis.

3.13.1.4 DYNAX - Dynamic Analysis of Axisymmetric Structures (Reactor/Auxiliary Building and Residual Heat Removal Complex)

Dynamic Analysis of Axisymmetric Structures (DYNAX) is a finite element program for performing both static and dynamic analyses of axisymmetric structures. Its formulation is based on a small displacement theory.

Three types of finite elements are available: quadrilateral, triangular, and shell. The geometry of the structure can be general as long as it is axisymmetric. Both the isotropic and orthotropic elastic material properties can be modeled. Discrete and distributed springs are available for modeling elastic foundations.

For static analysis, input loads can be structure weight, nodal forces, nodal displacements, distributed loads, or temperatures. Loads can be axisymmetric or nonaxisymmetric. For the solids of revolution, the program outputs nodal displacements and element and nodal point stresses in the global system (radial, circumferential, and axial). In the case of shells of revolution, the output consists of nodal displacements, and element and nodal point shell forces in a shell coordinate system (meridional, circumferential, and normal).

For dynamic analysis, three methods are available: direct integration, modal superposition, and response spectrum. In the case of dynamic analysis by direct integration or modal superposition, a forcing function can be input as

a. Nodal force components versus time for any number of nodes

b. Vertical or horizontal ground acceleration versus time.

For nonaxisymmetric loads, the equivalent Fourier expansion is used. In the case of dynamic analysis by response spectrum method, spectral velocity versus natural frequency for up to four damping constants is input. The output of dynamic analysis is in terms of nodal displacements, element stresses, and resultant forces and moments at specified time steps. When the modal superposition method is used, and in the case of earthquake response analysis, the requested numbers of frequencies and mode shapes are computed and printed together with the cumulative response of all the specified modes, as computed by the root sum square method and the absolute sum method.

DYNAX was developed under the acronym ASHAD by S. Ghosh and E. L. Wilson of the University of California, Berkeley, in 1969 (Reference 5). It was acquired by S&L in 1972 and is operating under EXEC 8 on a UNIVAC 1106.

To validate the major analytical capabilities of DYNAX, documented results from six problems are compared with DYNAX results. As shown in these six problems, DYNAX is capable of producing accurate results for both static and dynamic analyses of shells.

3.13.1.4.1 Problem l

The first problem is taken from S. Timoshenko, Theory of Plates and Shells (Reference 6). A clamped shallow spherical shell (Figure 3.13-15) is analyzed for displacements and stresses produced by a uniform pressure applied on its outside surface. DYNAX and Timoshenko's solutions are compared in Figures 3.13-16 and 3.13-17.

3.13.1.4.2 Problem 2

The second problem, taken from Theory of Elasticity by Timoshenko and Goodier (Reference 1) is a plane strain analysis of a thickwalled cylinder subjected to external pressure. The finite element idealization and the loading system used for this case are shown in Figure 3.13-18. Results of the DYNAX analysis are compared with the exact solution in Figure 3.13-19. The agreement for both stresses and displacements is excellent.

3.13.1.4.3 Problem 3

The third problem was presented in an article by Budiansky and Radkowski in an August 1963 issue of the AIAA Journal (Reference 7). The structure (Figure 3.13-20), is a short, wide cylinder with a moderate thickness-to-radius ratio. The applied loads and the output stresses are pure uncoupled harmonics. For this finite element analysis, the cylinder is divided into 50 elements of equal size. This problem checks the harmonic deflections, element stresses, and forces. Figure 3.13-21, Sheets 1 and 2, compares DYNAX results with the results given in the article.

3.13.1.4.4 Problem 4

The fourth problem is taken from an article by Reismann and Padlog (Reference 8). A ring (line) load of magnitude P (500 lb) is suddenly applied to the center of a freely supported cylindrical shell. The dimensions of the shell and the time history of load are shown in Figure 3.13-22. Because of symmetry, only one-half of the cylinder is modeled, using 80 elements of equal size. The time history of radial deflection and meridional moments from DYNAX and from Reismann and Padlog are compared in Figures 3.13-23 and 3.13-24 respectively.

3.13.1.4.5 Problem 5

For the fifth problem, the method of mode superposition is used to solve a shallow spherical cap with clamped support under the action of suddenly applied, uniformly distributed load. The dimensions of the shell and the load time history are shown in Figure 3.13-25. The first 12 modes were considered to formulate the uncoupled equations of motion. Each of these equations was solved by the step-by-step integration method using a time step of 0.1×10^{-4} sec. The results are compared with those obtained by S. Klein (Reference 9); see Figures 3.13-26 and 3.13-27.

3.13.1.4.6 Problem 6

The sixth problem is a hyperbolic cooling tower (Figure 3.13-28). The tower is analyzed for horizontal earthquake motion. A response spectrum for 2 percent damping (Figure 3.13-29) was used for this analysis. The root mean square values of the meridional force are compared with those obtained by Abel et al. (Reference 10) in Figure 3.13-30.

3.13.1.5 EASE - Elastic Analysis for Structural Engineering (Reactor/Auxiliary Building)

The Elastic Analysis for Structural Engineering (EASE) was developed by Engineering Analysis Corporation, Redondo Beach, California. The program is maintained by Control Data Corporation and is in the public domain. It performs static analysis of two- and three-dimensional trusses and frames, plane elastic bodies, and plate-and-shell structures. The finite element approach is used with the standard linear or beam elements, the plane stress triangular element, and a triangular plate bending element.

The program accepts temperature loads, as well as pressure, gravity, or concentrated loads. A plot feature of the input is available.

The program output includes joint displacements, beam forces, and triangular element stresses and moments.

3.13.1.6 INDIA - Interaction Diagram for Reinforced Concrete Members (Reactor/Auxiliary Building and Residual Heat Removal Complex)

INDIA (Load-Moment Interaction Diagram) is a program used to compute the coordinates and to plot the bending moment-axial load interaction diagram for a rectangular, reinforced-concrete section. The program will plot interaction curves for ultimate strength, yield strength, and working stress methods. Both compression and tension axial loads are considered, as well as positive and negative moments for appropriate cross sections.

The procedures used for the working stress and yield stress methods are taken from American Concrete Institute (ACI) 3l8 Code. Equations used for the ultimate stress method are taken from a University of Illinois civil engineering study. INDIA was originally developed at S&L on the IBM 1130 in 1971. It was converted to a UNIVAC 1106, where it has been successfully operating under EXEC 8 since 1972.

To demonstrate the validity of the program, a sample problem, shown in Table 3.13-3 and Figure 3.13-31, was executed. Calculations were made by hand, and all results were found to be consistent with the theoretical approach.

3.13.1.7 KALSHEL - Kalnins' Shell of Revolution (Reactor/Auxiliary Building)

Kalnins' Shell of Revolution (KALSHEL) is a computer program used to analyze thin axisymmetric shells of revolution for arbitrary load conditions. The solution is obtained by transforming the H. Reissner-Neisser equations to eight first-order ordinary differential equations. An Adams method of numerical integration is used as a basis for the solution of transformed equations. Since the program is based on classical shell theory, it has the same limitations.

The shell wall may vary in thickness along the meridian. It consists of up to four layers of different isotropic or orthotropic materials. Branch shells may be connected to the main shell. Surface loads and line loads in the radial, tangential, or meridional directions, meridional moments, and temperature distributions may be considered in the analysis. The temperature distributions are assumed to vary linearly across the thickness. All loads may be asymmetric.

The program output includes shell displacements in the radial, tangential, and meridional directions, meridional rotations, meridional moment, hoop moment, meridional force, hoop force, transverse-shear force, and twist-shear force. In addition, outer fiber stresses calculated from the stress resultants may be obtained.

The program was originally developed by A. Kalnins of Lehigh University (Reference ll). It was acquired by S&L in l969. This version was modified by S&L to sum displacements and stress resultants of the individual Fourier harmonics along meridians at specified angles. The program is currently maintained on the S&L UNIVAC 1106 operating under EXEC 8.

A number of test cases were run to check the program options and validity of solution. One of the practical problems included here is the analysis of conical shell subjected to eccentric line load. The shell is made of two parts, cylindrical and conical, and both are of reinforced concrete with different thicknesses as shown in Figure 3.13-32. The problem has been analyzed by this program and also by the public domain program SABOR III.

Results from the two programs are compared in Figures 3.13-33 through 3.13-36. Figures 3.13-33 and 3.13-34 show a comparison of shell forces along a meridian at 0° (symmetric with respect to the load). Figures 3.13-35 and 3.13-36 show a comparison of shell forces around the circumference at an elevation where the load is applied. As shown in these figures, the results compare favorably.

3.13.1.8 MASS IV - Matrix Analysis of Seismic Stresses (Reactor/Auxiliary Building)

Matrix Analysis of Seismic Stresses (MASS) IV is used for performing seismic analysis of plane and space trusses and frames and plane grids. Either the response spectrum method or the time-history method can be used, depending on the forcing function available. Both methods use the normal mode approach. In the case of time-history analysis, the decoupled differential equations of motion are integrated numerically using Newmark's β-method (Reference 2). Included in the program are input options allowing for member releases, input stiffness between two nodes, and rigid members. The program output includes

a. Stiffness
b. Mass and mass-stiffness triple product matrices
c. Modal periods
d. Eigenvectors and participation factors
e. Modal displacements
f. Member and joint forces
g. Probable and absolute maxima of displacements and forces.

The MASS program was developed by S&L in 1968. Version IV is currently maintained on a UNIVAC 1106 operating under EXEC 8. It has been used successfully since 1971. Two problems for validating the program are presented.

3.13.1.8.1 Problem 1

In the first problem, a three-story shear building is analyzed and compared to a solution obtained by Biggs (Reference 3). The structure is represented by the closed-coupled system shown in Figure 3.13-11. The masses and stiffness values used are also shown. For the analysis, the following response spectrum was used:

Frequency (Hz)	Displacement (in.)
1.00	3.30
2.18	1.40
3.18	0.66

The results obtained by Biggs and from MASS IV are compared in Table 3.13-1.

3.13.1.8.2 Problem 2

In the second problem, results of MASS IV are compared to those obtained by Wilson (Reference 4) using the SAP IV program. At the fixed end of a cantilever beam, an acceleration is applied (Figure 3.13-37). The natural periods calculated by both SAP IV and MASS IV are shown in Table 3.13-2. A comparison of the bending moment at the fixed end of the cantilever beam is shown in Figure 3.13-38. As demonstrated in both examples, MASS IV performs an accurate analysis.

3.13.1.9 PLFEM II - Plate Finite Element Method (Reactor/Auxiliary Building)

Plate Finite Element Method (PLFEM II) is used to analyze plane elastic bodies, plates, and shell structures by the stiffness matrix method. The program uses two finite elements, rectangular and triangular.

Elastic spring supports or an elastic foundation may be considered in the analysis. Orthotropic materials may also be considered in conjunction with the rectangular element. Pressure loads, concentrated forces, nodal displacements, and temperature loads may be considered in the analysis. All loading cases may be factored or combined in any manner.

The program output includes deflections and rotations of all joints and membrane stresses (normal, shearing, and principal) at the center of each element; the resultant moments (x, y, twisting, and principal); and shears and reaction forces. An equilibrium check is made to determine the accuracy of the results.

PLFEM II, developed on a UNIVAC 1108 in 1966, is maintained by S&L. Since May 1972, it has been operating successfully on the S&L UNIVAC 1106 under EXEC 8.

Three sample problems are presented to demonstrate the validity of PLFEM. Plots of the computer results obtained are compared with theoretical results and results obtained by other methods.

3.13.1.9.1 Problem 1

The first problem is an analysis of a rectangular tank filled with water, which was presented by Y. K. Cheung and J. D. Davies in an article in May 1967 (Reference 12). The finite element used was presented by Zienkiewicz and Cheung in the Proceedings of the Institute of Civil Engineers in August 1964 (Reference 13). Experimental results obtained agreed exactly with the finite element results except at a few isolated points where very small differences were noted. The PLFEM grid and loading for the tank problem are shown in Figure 3.13-39. The grid used is the same size as that used by Cheung and Davies. Moments in three regions of the tank are plotted along with the PLFEM results in Figures 3.13-40 through 3.13-42.

3.13.1.9.2 Problem 2

In the second analysis, a rectangular plate with a circular hole in its center is subjected to a uniform plane stress. The grid used in the PLFEM analysis is shown in Figure 3.13-43. Because of double symmetry, only one-quarter of the plate is analyzed. Results obtained from the PLFEM analysis are plotted in Figure 3.13-44 against the exact values as given by Timoshenko and Goodier in Reference 1.

3.13.1.9.3 Problem 3

In the third problem, a square plate having a rectangular hole in its center is analyzed for the effect of a temperature gradient through the plate. The grid used in the PLFEM analysis is shown in Figure 3.13-45. Only one-quarter of the plate is analyzed because of double symmetry. Moment values obtained by PLFEM are plotted for two regions of the plate in

Figure 3.13-46. For comparison, values of the moments obtained by an analysis based on the Hrennekoff framework analogy are also shown.

3.13.1.10 SLSAP - Sargent & Lundy Structural Analysis Program (Reactor/Auxiliary Building and Residual Heat Removal Complex)

The S&L Structural Analysis Program (SLSAP) was developed by E. Wilson of the University of California at Berkeley. It is maintained by S&L. The program uses the stiffness matrix method to analyze two- and three-dimensional frames, trusses, and grids; three-dimensional elastic solids; and axially symmetric solids, plates, and shells, for arbitrary static loads. Dynamic analyses for frequencies and mode shapes, spectral analysis, and numerical integration analyses are also possible.

The program allows materials with arbitrary elastic constants, combined loadings, rigid members, elastic supports, and a combination of different element types.

Included in the program output are displacement and rotations of all joints, nodes, forces, or stresses in members or elements; frequencies and mode shapes; and dynamic response in terms of displacements and forces.

The original version of SLSAP dates back to 1968. S&L currently maintains the SLSAP IV version. The program can successfully operate on either a UNIVAC 1106 or a CDC 6600 computer. It is primarily used for static analysis. Results from the program have been compared with several other static and dynamic computer programs and classical solutions. Two examples of these validation problems are presented.

3.13.1.10.1 Problem 1

The first problem is a cantilever beam under both uniform and concentrated load (the beam was modeled for SLSAP using 10 equal-length beam elements). It has a cross-sectional area of 1 x 2 in., length 10 in., and a Young's modulus of 30 x 10^3 ksi. A uniform load q = 2 kips/in. and a concentrated load of 10 kips at one end of the beam are applied. The results from the program are compared to analytical results obtained by Timoshenko and Gere. Figure 3.13-47 shows excellent agreement for the bending moment obtained in both solutions.

3.13.1.10.2 Problem 2

In the second problem, a simply supported square plate under uniform loading is analyzed. A 10-in.-square by 1-in.-thick square plate with Poisson's ratio = 0.3 and Young's modulus = 30 x 10^3 ksi, was loaded with 1-ksi pressure. The results obtained were compared to those presented by S. Timoshenko and S. Woinowsky-Krieger. The bending moments M_{xx} and M_{yy} for both the x and y symmetry lines obtained in the two solutions are shown in Figure 3.13-48. The maximum bending moment that occurs at the center of the plate differs by only 1.05 percent.

3.13.1.11 SOR III - Shell of Revolution (Reactor/Auxiliary Building)

The Shell of Revolution (SOR III) was developed by Knolls Atomic Power Laboratory for the AEC. It is maintained by S&L. This program analyzes thin shells of revolution subjected to axisymmetric loading by numerically integrating the governing differential equations, using a generalized Adams-Moulton method.

Arbitrary distribution of normal, tangential, and moment surface loadings, as well as edge forces and deflections, may be considered in the axisymmetric loadings. Input of boundary conditions allows the consideration of elastic support conditions. The effect of temperature variations along the meridian or across the thickness also is considered.

The program output includes shell displacements, outer fiber stresses and strains, and stress resultants. Version III was acquired by S&L in 1969 and is currently maintained on S&L's UNIVAC 1106 computer. The S&L version has been modified to punch data for plotting.

Results from this program have been frequently compared with other available solutions and other computer programs to test the validity of the program. One of these comparisons is the analysis of a circular, flat, reinforced-concrete plate. The details of the problem and the boundary conditions are shown in Figure 3.13-49. Results of the SOR III analysis were compared with the finite element program, SABOR III. Figure 3.13-50 shows the bending moment in the meridional and hoop directions. Figure 3.13-51 shows the comparison of radial shear. As shown in these figures, results compare favorably.

3.13.1.12 SSANA - Spring-Slab Analysis (Reactor/Auxiliary Building and Residual Heat Removal Complex)

Spring-Slab Analysis (SSANA) was written to facilitate the reduction of a reinforced-concrete shear building and the equipment in the building to a system of rigid slabs interconnected by weightless linear springs. The program calculates the centroid, total weight, and the weight moment of inertia about the vertical and two horizontal centroidal axes of each slab. The program also calculates the spring stiffness of concrete walls and its distance from the mass centroid.

Spring constants of shear walls are computed based on the following equation:

$$K = \frac{1}{DT}$$

where

DT = DF + DS

DF = Flexural deflection/unit load

DS = Shear deflection/unit load

SSANA was written and is maintained by S&L. It currently operates on a UNIVAC 1106 operating under EXEC 8.

Hand calculations were used to validate the program. As an example of this validation, stiffness and rotary mass were calculated for elements of the structure shown in Figure 3.13-

52. A comparison of results from SSANA and hand calculations shown in Tables 3.13-4 and 3.13-5 demonstrates the accuracy of the program.

3.13.1.13 STRESS-II - Structural Engineering Systems Solver (Reactor/Auxiliary Building)

The Structural Engineering Systems Solver (STRESS-II) was developed by the Massachusetts Institute of Technology. It is maintained by the University Computing Company and is in the public domain. The program uses the stiffness matrix method to analyze plane and space trusses and frames, and plane grids.

The structure can be analyzed for arbitrary joint loads, member loads, temperature changes, and joint displacements. A plotting feature is available with the program. The output includes joint displacements, equilibrium checks and reactions, and member forces.

The version currently used by S&L was adapted to the UNIVAC 1100 Series computer by the Chi Corporation, Cleveland, Ohio, which has maintained it since 1972.

3.13.1.14 STRUDL II - Structural Design Language (Reactor/ Auxiliary Building and Residual Heat Removal Complex)

The Structural Design Language (STRUDL II) was developed by the Massachusetts Institute of Technology. It is maintained by McDonnell Douglas Automation Company. Linear, static, or dynamic analyses may be performed for finite element representations of structures using stiffness matrix methods. Nonlinear static problems and stability problems also may be treated.

The program is capable of analyzing plane trusses and frames, grids and elastic bodies, space trusses and frames, or three- dimensional elastic solids subjected to arbitrary loads, temperature changes, or specified displacements. Either earthquake accelerations or time-history force may be used. In addition to analysis, the program is capable of doing structural steel design according to the American Iron and Steel Institute (AISI) Code, and reinforced or prestressed concrete design according to the ACI Code.

The program output depends on the type of finite element used and the analysis that was performed. Included in the output are displacements and member forces and moments, or element stresses and moments. Eigenvalues, eigenvectors, and time-history response or nodal response may be obtained for dynamic analyses. Member sizes may be obtained if the design portion is used.

This program has been in the public domain since 1968. Two versions are currently being used: one is maintained by the McDonnell Douglas Automation Company on IBM 370 Series hardware, and one is maintained by UNIVAC on the 1100 Series hardware.

3.13.1.15 TEMCO III - Reinforced Concrete Sections Under Eccentric Loads and Thermal Gradients (Reactor/ Auxiliary Building and Residual Heat Removal Complex)

TEMCO analyzes reinforced-concrete sections subject to separate or combined action of eccentric loads and thermal gradients. The effect of temperature is induced in the section by reactions created by the curvature restraint.

The analysis may be done assuming either a cracked or an uncracked section. Material properties can be assumed to be either linear or nonlinear. The program is capable of handling rectangular as well as nonrectangular sections. The program input consists of section dimensions, areas and location of each layer of reinforcing steel, loads, load combinations, and material properties.

The curvature and axial strain corresponding to the given eccentric loads (axial load and bending moment) are determined by an iterative procedure. Thermal gradient is applied on the section by inducing reactions created by the curvature restraint, i.e., there is no curvature change due to a thermal gradient on the section. The axial expansion is assumed to be free after thermal gradient is applied. An iterative procedure is again used for finding the final strain distribution in which equilibrium of internal and external loads is satisfied.

The program output consists of the echo of input, combined loads, final location of neutral axis, final stresses in steel and concrete, and final internal forces. Similar intermediate results (before thermal gradient is applied) can also be output if desired. The program has applications to a wide variety of reinforced-concrete beams and columns, slabs, and containment structures subject to various combinations of external loads and thermal gradients. The program was developed and is maintained by S&L. Since February 1972, the program has been extensively used at S&L on UNIVAC 1106 hardware operating under EXEC 8.

To demonstrate the validity of TEMCO, program results are compared with hand-calculated results. Three example problems are considered. The section and material properties for each problem are given in Table 3.13-6, along with the applied external forces and thermal gradients.

The first problem considered involves a section with two layers of steel under the action of a compressive force applied at the centerline of the section, a bending moment, and a thermal gradient. A cracked analysis of the section is required, assuming nonlinear material properties.

The second problem considered involves a section with two layers of steel under the action of a tensile force applied at the centerline of the section, a bending moment, and a thermal gradient. A cracked analysis of the section is required, assuming nonlinear material properties.

The third problem considered involves a section with two layers of steel under the action of a tensile force applied at the centerline of the section, a bending moment, and a thermal gradient. A cracked analysis of the section is required, assuming linear material properties. The hand-calculated solution was obtained according to the following outlined procedure:

a. Assume the location of neutral axis and the stress distribution to be the same as those given by the program under the given mechanical loading

b. Compute the strain distribution under the given mechanical loading

c. Compute the stress resultants by integration and using the proper stress-strain relationships

d. Check for equilibrium with external mechanical loads

e. If equilibrium is satisfied, compute the curvature imposed on the section by the given thermal gradient

f. Compute the final curvature by subtracting the thermal curvature from the mechanical curvature

g. Compute the new axial strain so that equilibrium is satisfied, keeping the curvature constant

h. Compute the final stress resultants by integration, using the proper stress-strain relationships

i. Compute the thermal moment

j. Check for equilibrium and compare program results with hand-calculated results.

Results obtained using this procedure, together with those computed by TEMCO, are presented in Table 3.13-7. It is concluded that results given by the program agree very well with results obtained by hand calculations, and that equilibrium between internal and external forces is satisfied for all three problems.

3.13.1.16 CAPAN - Cable Pan Analysis (Reactor/Auxiliary Building and Residual Heat Removal Complex)

Cable Pan Analysis (CAPAN) is a computer program used in the analysis of continuous cable pan systems. Section properties of cable pans and allowable stresses for bending about both axes for both seismic and nonseismic conditions are computed. Given a pair of response spectra for any slab, allowable pan support spacing can also be computed.

Peak accelerations (both horizontal and vertical) are used in computing the moments due to seismic loads. The allowable spacing is computed for dead load, dead load plus live load, and dead load plus earthquake. The minimum value is chosen as allowable pan spacing.

CAPAN was developed by S&L in 1972. It is currently maintained on a UNIVAC 1106 operating under EXEC 8.

As an example of validation, the support spacing of a pan 12 in. wide, 4 in. deep, and 14 gage thick was analyzed. CAPAN results and those from hand calculations were compared. As shown in Table 3.13-8, the results are in good agreement.

3.13.1.17 MVI - Matrix Analysis for Seismic Stresses Input Generator (Reactor/Auxiliary Building and Residual Heat Removal Complex)

Mass V Input Generator (MVI) is a computer program that generates data on cable pan hangers. These data are stored on magnetic tape and later used as input to S&L program MASS V (Matrix Analysis for Seismic Stresses) to perform seismic analysis. It is written in Fortran V language and represents the first step of Method l in the design of cable pan hanger systems that support Category I cables.

For a given width and height of hanger, number of levels, and member properties, MVI generates frame geometry and other necessary data in a format acceptable to the MASS V program. Each hanger is loaded with unit mass per level, and subjected to unit horizontal acceleration. Since this is an input-generation program for MASS V, the program is validated by checking generated input for MASS V.

3.13.1.18 ELHAN - Elastic Hanger Analysis (Reactor/Auxiliary Building and Residual Heat Removal Complex)

Elastic Hanger Analysis (ELHAN) is a postprocessor program used in the design of hangers to support Category I cables. It represents Step 3 in the design of Type l cable pan hangers. The hangers described in the program MVI are designed by using ELHAN. The various functions performed by ELHAN are as follows.

a. Reads variations of dead load and horizontal and vertical response spectra for all slabs. The response spectra should be obtained from the project seismic report. For horizontal excitation, the response spectra used is the envelope of maximum response due to north/ south and east/west

b. Reads results of MASS V program from tape as described in Step 2

c. Forces and deflections obtained as above are modified to represent actual load on the hangers and actual floor acceleration (results are stored for unit load and unit acceleration)

d. Computes forces induced due to dead load and vertical excitation

e. Combines and checks stresses.

The program has an option to design vertical members with or without compression criteria. If compression criteria are used, the members with (KL/r) ratios greater than 200 are omitted from the tabulation. The program also has an option to print the data stored on the tape for checking purposes. The program was checked against hand calculations. In all cases the program correctly selected all failing members.

3.13.1.19 RIGHAN - Rigid Hanger Analysis (Reactor/Auxiliary Building and Residual Heat Removal Complex)

Rigid Hanger Analysis (RIGHAN) is a program used for the analysis and design of laterally supported cable pan hangers. Input to the program consists of variations of dead load and hanger widths, member properties, and a set of horizontal and vertical response spectra for each slab. The program is used to compute stresses due to the combined dead load and horizontal and vertical excitations.

Rigid Hanger Analysis was developed by S&L in 1972. It is currently maintained on a UNIVAC 1106 operating under EXEC 8.

A typical hanger used for validation is shown in Figure 3.13-53. Results of the program were compared with hand calculations. As shown in Table 3.13-9, RIGHAN correctly analyzes and designs rigid hangers.

3.13.1.20 MASS V - Matrix Analysis for Seismic Stresses (Reactor/Auxiliary Building and Residual Heat Removal Complex)

Matrix Analysis for Seismic Stresses (MASS V) is used to perform seismic analysis of plane and space trusses and frames and plane grids. Either the response spectrum method or the time-history method can be used, depending on the forcing function available. Both methods use the normal mode approach. In the case of time-history analysis, the decoupled differential equations of motion are integrated numerically using Newmark's β-method (Reference 2).

Included in the program are input options allowing for member releases, input stiffness between two nodes, and rigid members. The program output includes

a. Stiffness

b. Mass and mass-stiffness triple product matrices

c. Modal periods

d. Eigenvectors and participation factors

e. Modal displacements

f. Member and joint forces

g. Probable and absolute maxima of displacements and forces.

The MASS program was developed by S&L in 1968. Version V is currently maintained on a UNIVAC 1106 operating under EXEC 8. It has been used successfully since 1972. Two examples of the problems for validating the program are presented.

3.13.1.20.1 Problem 1

In the first example, a three-story shear building is analyzed and compared to a solution obtained by Biggs (Reference 3). The structure is represented by the closed-coupled system shown in Figure 3.13-11. The masses and stiffness values used are also given in Figure 3.13-11. For the analysis, the following response spectrum was used:

Frequency (Hz)	Displacement (in.)
1.00	3.30
2.18	1.40
3.18	0.66

The results obtained by Biggs and from MASS V are compared in Table 3.13-1.

3.13.1.20.2 Problem 2

In the second example, results of MASS V are compared to those obtained by Wilson et al. (Reference 14) using the SAP IV program.

At the fixed end of a cantilever beam (Figure 3.13-12), an acceleration is applied (Figure 3.13-13). The natural periods calculated by both SAP IV and MASS V are shown in Table 3.13-2. A comparison of the bending moment at the fixed end of the cantilever beam is shown in Figure 3.13-54. As demonstrated in both examples, MASS V performs an accurate analysis.

3.13.1.21 PCAUC - Portland Cement Association, Ultimate Strength Design of Reinforced Concrete Columns (Residual Heat Removal Complex)

Portland Cement Association, Ultimate Strength Design of Reinforced Concrete Columns (PCAUC) is used to design or to investigate reinforced-concrete columns using the ultimate strength theory in accordance with ACI 318-71 Code. The program is capable of designing or investigating tied columns subjected to an axial load combined with uniaxial or biaxial bending moments. The program input consists of the dimensions of sections, material properties, reinforcement requirements, and loading data. The slenderness effect is not included in the present program.

Output from the design part of the program includes the steel reinforcement arrangement, ultimate capacity for all loading cases, and interaction control points data. Output from the investigation part of the program includes either biaxial or uniaxial interaction data. Sargent & Lundy has modified the original PCA program to follow the 1971 ACI building code and to provide more design options and greater capacity.

PCAUC is a modified version of the program "Ultimate Strength Design of Concrete Columns," developed by the Portland Cement Association. The program was obtained by S&L in 1972 and modified. It is currently maintained on the UNIVAC 1106 operating under EXEC 8.

To validate PCAUC, documented results from several problems were compared with PCAUC results. Three of these problems are presented herein.

3.13.1.21.1 Problem 1

The first problem is taken from Wang and Salmon, Reinforced Concrete Design (Reference 15). The reinforcement for a 17 x 17-in. square tied column is designed for compression control loads. The loads include a deadload axial load of 214 kips and bending moment of 47 ft-kips, and a liveload axial load of 132 kips and a bending moment of 23 ft-kips. The reinforcement is designed according to the ACI Code with $f_c' = 3000$ lb/in.^{2} and $f_y = 40{,}000$ lb/in.^{2}

The solution as given in Reference 15 is identical to the solution obtained from PCAUC, shown in Figure 3.13-55. It should be noted that the ultimate capacity provided by PCAUC has been reduced by a factor of 0.7.

3.13.1.21.2 Problem 2

The second problem is also taken from Reference 15. The reinforcement for a tied column 14 in. wide and 20 in. deep is designed for tension control loads with a deadload axial load of 43 kips and bending moment of 96 ft-kips, and a liveload axial load of 32 kips and bending moment of 85 ft-kips. The reinforcement is designed according to ACI Code using symmetrical reinforcement with respect to its width, and with $f_c' = 4500$ lb/in.^{2} and $f_y = 50{,}000$ lb/in.^{2}. The solution given in Reference l5 is identical to the solution obtained from PCAUC, shown in Figure 3.13-56.

3.13.1.21.3 Problem 3

The third problem is taken from Notes on ACI 318-71 Building Code Requirements With Design Applications, by the Portland Cement Association (Reference 16). A square tied column 28 in. x 28 in. is designed for biaxial bending loads for the following service loads.

Service Load	Dead Load	Live Load
Axial	550 kips	300 kips
M_x	320 ft-kips	200 ft-kips
M_y	160 ft-kips	100 ft-kips

The bending is designed according to the ACI Code with $f_c' = 5{,}000$ lb/in^2 and $f_y = 60{,}000$ lb/in.^{2}.

The selected reinforcement obtained from PCAUC, shown in Figure 3.13-57, is identical to that from Reference 16. It should also be noted that the interaction control points obtained by both show good agreement.

3.13.1.22 STAND - Structural Analysis and Design (Reactor/ Auxiliary Building)

Structural Analysis and Design (STAND) is an integrated system programmed to perform analysis and design of structural steel members according to the 1969 AISC Specification. It consists of the following subsystems:

a. Beam edit
b. Rolled beam design
c. Composite beam design
d. Plate girder design
e. Column edit
f. Column design
g. Column baseplate design.

The program input consists of member geometry and basic loadings. The design is performed for specified combinations of basic loadings and overstress factors. For floor framing systems, the program is capable of automatically transferring reactions from tributary beams to supporting members. There are many design control parameters available, such as minimum and maximum depth limitations, shape of the rolled section, location of the lateral support of the compression flange, material grade of yield stress, deflection limitations, flange cutoff criterion, and location of stiffeners.

For columns, the program can be used to account for axial loading as well as uniaxial or biaxial bending. For column baseplate design, only axial load and column combinations are considered.

The program output includes the complete final design and provides the designer with sufficient intermediate information to enable him to evaluate the results. For rolled and composite beam designs, complete details of shop-welded and field-bolted end connections are contained in the output. Supplementary information for economic evaluation of the design is also provided.

STAND was developed and is maintained by S&L. Since May 1972, the program has been extensively used at S&L on UNIVAC 1106 hardware operating under EXEC 8. Some of the principal applications include the design of steel floor framing using various types of horizontal structural elements, and the design of columns or beam columns.

To validate STAND, results from the program were compared with results from example design problems in the Manual of Steel Construction (Reference 17). Four problems are given herein.

3.13.1.22.1 Problem 1

The first problem is a rolled beam design problem (Example 1, pp. 2-4, 5). A beam of 36 ksi steel is designed for a 125 kip-ft angling moment, assuming its compression flange is braced at 6.0-ft intervals. The results, listed in Table 3.13-10, show that STAND selects a more efficient section.

3.13.1.22.2 Problem 2

The second problem is a composite beam design problem (Example 1, pp. 2-143, 144). A non-coverplated composite interior floor beam is designed. Limits of 1.5 in. for deadload deflection and 1.2 in. for liveload deflection are imposed. The results, shown in Table 3.13-11, are nearly identical.

3.13.1.22.3 Problem 3

The third problem is a column design problem with three examples, (Examples 1, 2, and 5, pp. 3-4, 5, 9). The first is the design of a W12 column of 36-ksi steel that will support a concentric load of 670 kips. The effective length with respect to its minor axis is 16 ft, and to its major axis, 31 ft.

The second is the design of an 11-ft-long W12 interior bay column of 36-ksi steel that will support a concentric load of 540 kips. The column, rigidly framed at the top by 30-ft-long, W30 x 116 girders connected to each flange, is braced normal to its web at the top and the base.

The third is the design of a Wl4 column of 36-ksi steel for a tier building, 18-ft story height, that will support a 600-kip gravity load and a 190-kip-ft maximum wind moment, assuming K = l relative to both axes and bending is about the major axis.

The results from all three checks are identical to those in the AISC Manual, and are shown in Table 3.13-12.

3.13.1.22.4 Problem 4

The fourth problem is a plate girder design problem (Example 1, p. 2-108). A welded plate girder is designed to support a uniform load of 3 kips/ft and two concentrated loads of 70 kips as shown in Figure 3.13-58. The compression flange of the girder is laterally supported only at points of concentrated load. The close results are shown in Table 3.13-13.

3.13.1.23 PLGIRD - Plate Girder Design (Reactor/Auxiliary Building)

Plate Girder Design (PLGIRD) is used to design welded plate girders according to specified loadings and geometries. The design criteria are in accordance with the AISC Specification for the Design of Structural Steel for Buildings, 1969. The program can automatically account for variations in steel stress according to the material thickness for seven types of structural steel. The program also takes into account the variation of the weight of the girder along the span due to flange cutoffs. Input to the program consists of the specified minimum or maximum web depth, maximum flange width, maximum plate thickness, and vertical loadings.

PLGIRD was developed by S&L in 1967. It is currently maintained on a UNIVAC 1106 operating under EXEC 8.

To validate PLGIRD, results from the program were compared with results from example design problems in the Manual of Steel Construction (Reference 17). One of these problems is given.

A welded plate girder (Example 1, p. 2-108) is designed to support a uniform load of 3 kips/ft and two concentrated loads of 70 kips, as shown in Figure 3.13-58. The compression flange of the girder is laterally supported only at points of concentrated load. The close results are shown in Table 3.13-13.

3.13.1.24 MESHG (Reactor/Auxiliary Building and Residual Heat Removal Complex)

The program MESHG is written for the UNIVAC 1106/130k machine. It is used as a preprocessor for finite element programs that are currently available. Its main function is to check the geometry of the input by plotting the mesh. Options are available allowing the user to scale the plot, number elements and/or nodes, draw different isometric views of three-dimensional data, rotate axes for two-dimensional data, and plot a vector field. This program is repeatedly verified by inspection of each plotted mesh.

3.13.1.25 COGO (Reactor/Auxiliary Building and Residual Heat Removal Complex)

COGO is a problem-oriented computer language and programming system for solving geometric problems in civil engineering on a digital computer. Each problem is solved by writing a "COGO program," consisting of a series of commands that describe the operations to be performed in order to effect a solution. Data needed to perform each operation are included as part of the command. COGO was developed at the Massachusetts Institute of Technology, and is in the public domain.

3.13.1.26 PIPSYS (Reactor/Auxiliary Building and Residual Heat Removal Complex)

Integrated Piping Analysis System (PIPSYS) is used to analyze piping systems of power plants for static and dynamic loadings, and to compute the combined stresses. The following analyses are performed:

a. Static - analysis of thermal, displacement, distributed, and concentrated weight loadings on piping systems

b. Dynamic - analysis of piping system response to seismic and fluid transient loads

c. Stress combination - computation of the combined stresses in the piping components in accordance with the ASME Boiler and Pressure Vessel (B&PV) Code Section III (Reference 18).

The static, dynamic, and stress combination analyses can be performed independently or in sequence. Results of the static and dynamic analyses can be stored on magnetic tape for use at a later date to perform the stress combination analysis. The piping configuration can be plotted on a Calcomp plotter.

The input consists of the piping system geometry, material properties, and static and dynamic loadings. Various options exist to control the length of the output. The default option generally prints only the summary of input data and final results.

PIPSYS was developed by S&L in 1972. It is currently maintained on a UNIVAC 1106 operating under EXEC 8. To demonstrate the validity of the PIPSYS program, three problems are presented.

3.13.1.26.1 Problem 1

To illustrate the validity of the static portion of PIPSYS, the problem shown in Figure 3.13-59 was analyzed and the results compared to those given in Reference 19. Table 3.13-14 shows the comparison of member end moments. As shown, the results from PIPSYS and Reference 19 are in good agreement.

3.13.1.26.2 Problem 2

To illustrate the validity of the stress combination analysis portion of PIPSYS, the problem outlined in Reference 20 was reanalyzed on the PIPSYS program. The layout of the piping system is shown in Figure 201 of Reference 21. The stress analysis is performed at location 19. The summary of load sets and descriptions is presented in Table 3.13-15. The results of the stress analysis are presented in Tables 3.13-16 and 3.13-17. The notations and equation numbers correspond to the ASME B&PV Code (Reference 18). The PIPSYS results are in very close agreement with those presented in Reference 20.

3.13.1.26.3 Problem 3

To illustrate the validity of the dynamic analysis portion of PIPSYS, a problem was analyzed and the results obtained from PIPSYS were compared with those from two public domain computer programs. These are DYNAL (Reference 22) and NASTRAN (References 23 and 24).

Figure 3.13-60 shows a schematic representation of the piping system analyzed. The system is modeled with simple beam elements with a total of 136 degrees of freedom. Figure 3.13-61 shows the time-dependent blowdown forces at the relief valve locations. Results of PIPSYS are compared with DYNAL and NASTRAN in Table 3.13-18 and in Figure 3.13-62. The results from all three programs are in quite close agreement.

3.13.1.27 NOHEAT

Sargent & Lundy's NOHEAT computer program is used to determine the code quantities $(\Delta T_1)_I$, $(\Delta T_2)_I$, and $(\alpha ATA\text{-}\alpha BTB)_I$, resulting from fast fluid temperature changes. It can be used for piping products and dissimilar metal joints.

Each fitting is modeled using an axisymmetric solid finite element mesh, with a time-dependent forced-convection heat flow boundary condition forced on the inside surface of the pipe. The meshes are internally generated using user-supplied dimensions. The forced-convection boundary conditions are determined using the design thermal transient definitions associated with Envelope Load Set. The following procedure is then used to determine the time-dependent (ΔT_1), (ΔT_2), and $(\alpha ATA\text{-}\alpha BTB)$ quantities:

a. The time-dependent temperature distribution on the fitting is determined by direct time integration of the finite element heat conduction equations

b. Integrations of the temperature distribution at every instant in time are then performed using the code definitions in NB-3653 to determine the quantities (ΔT_1), (ΔT_2), $(\alpha ATA\text{-}\alpha BTB)$.

3.13.1.28 AXTRAN

Sargent & Lundy's AXTRAN computer program is used to determine the code quantity $(\alpha ATA\text{-}\alpha BTB)_I$ resulting from axial temperature distribution along stagnant lines.

The program models the piping as an infinitely long cooling fin. Heat loss from the fin is governed by insulation characteristics that are obtained from the insulation vendor. Input to the program consists of a temperature-versus-time description of the thermal transient to be forced on the model, and a physical description of the model. Output from the program consists of a time history of the temperature distribution along the pipe and a time history of the code nominal stress $Eab(\alpha ATA\text{-}\alpha BTB)_I$.

3.13.1.29 SEISHANG

3.13.1.29.1 SEISHANG (Version 3) (Reactor/Auxiliary Building and Residual Heat Removal Complex)

SEISHANG (Seismic Analysis of Hangers) is used for the analysis and design of electrical cable and heating, ventilation and air conditioning (HVAC) duct support systems. The program computes the allowable spans for cable trays and selects the proper member sections for various types of supports. The input load functions can be in the form of dead load, live load, or dynamic response spectra.

Program input consists of geometric data, material properties, member properties, and external loadings. Program output consists of allowable spans, member sizes, and mechanical response.

SEISHANG was developed at S&L in 1976. It is currently maintained on UNIVAC 1100 Series hardware under EXEC 8.

To demonstrate the validity of the program, two problems are presented.

3.13.1.29.1.1 Problem 1

A typical cable tray, shown in Figure 3.13-63, is analyzed and compared to the solution obtained by hand calculation. The results obtained from SEISHANG and by hand calculation are compared in Table 3.13-19. The results show good agreement.

3.13.1.29.1.2 Problem 2

Two typical HVAC supports, shown in Figures 3.13-64 and 3.13-65, are analyzed and compared to the solution obtained from the DYNAS (09.7.090-9.0) computer program, Reference 25. The results obtained from SEISHANG and from DYNAS are compared in Tables 3.13-20 and 3.13-21. The HVAC support shown in Figure 3.13-64 is also analyzed by the PIPSYS (09.5.065-3.4) computer program, Reference 26. The results obtained from SEISHANG and from PIPSYS are compared in Table 3.13-22. The results show good agreement.

3.13.1.29.2 SEISHANG (Version 4)

SEISHANG (Seismic Analysis of Hangers) is used for the analysis and design of electrical cable and HVAC duct support systems. The program computes the allowable spans for cable trays and selects the proper member sections for various types of supports. The input load functions can be in the form of dead load, live load, or dynamic response spectra.

Program input consists of geometric data, material properties, member properties, and external loadings. Program output consists of allowable spans, member sizes, and mechanical response.

SEISHANG was developed at S&L in 1976. It is currently maintained on UNIVAC 1100 Series hardware under EXEC 8.

To demonstrate the validity of the program, two problems are presented.

3.13.1.29.2.1 Problem 1

A typical cable tray, shown in Figure 3.13-63, is analyzed and compared to the solution obtained by hand calculation. The results obtained from SEISHANG and by hand calculation are compared in Table 3.13-19. The results show good agreement.

3.13.1.29.2.2 Problem 2

A typical cable tray support, shown in Figure 3.13-66, is analyzed and compared to the solution obtained from the PIPSYS (09.5.065-6.1) computer program, Reference 27. The analysis results obtained from SEISHANG and from PIPSYS are compared in Table 3.13-23. For member stress calculation, the results obtained from SEISHANG and from hand calculations are compared in Table 3.13-24. The results show good agreement.

3.13.1.30 SUPS (Reactor/Auxiliary Building and Residual Heat Removal Complex)

The SUPS program includes the PFRAME, CONNECTIONS, CINCH, and APLAN modules discussed below.

3.13.1.30.1 PFRAME

PFRAME (Interactive Plane Frame Analysis) is an interactive program that analyzes two-dimensional frames for static loads, using the stiffness approach. Joint movements are allowed only three degrees of freedom. Members are considered as prismatic beam elements. Loads are defined as global joint forces or member end forces.

Input consists of joint coordinates, fixities, member incidence, material/section properties, and joint/member forces. All input is free format and prompted by the program.

Output consists of joint displacements, rotations, support reactions, member end forces, and moments.

PFRAME is a module of the SUPS package and was developed at S&L in 1982. It is maintained on UNIVAC 1100 Series hardware operating under EXEC 8.

The program's validity is demonstrated by two problems. The first is a continuous beam problem shown in Figure 3.13-67. Table 3.13-25 compares PFRAME's results with the solution shown in Beer and Johnston, Reference 28. The second problem is the frame shown in Figure 3.13-68. Table 3.13-26 compares PFRAME's results with the solution shown in Gere and Weaver, Reference 29. The tables show good comparison.

3.13.1.30.2 CONNECTIONS

CONNECTIONS (Connections Investigation Program) aids in checking the adequacy of connections. The program checks the design of sliding- and friction-type Framed Beam Connections.

Design procedures used are given in Structural Design Standard E7 (Reference 30) and conform to the requirements of the AISC Manual of Steel Construction, 1978 Edition (Reference 31). Criteria for reassessing connections on nuclear projects are discussed in Reference 32. The program is interactive with self-documenting input, and prints out a summary of results. References 33 and 34 are applicable for general information.

The program is a module of the SUPS package and was developed at S&L in 1982. It is currently maintained on UNIVAC 1100 Series hardware operating under EXEC 8.

Two problems have been selected to validate the program for each type of connection except for Connection Detail No. 7.7.5 for which three problems are used. Results obtained from the program were compared with hand-calculation results; the results are identical.

The following examples were selected to validate the program for bolted/bolted sliding-type connections (Detail No. 7.7.1 of Reference 30).

3.13.1.30.2.1 Problem 1

Example 1a - Uncoped Connection (L2 = E3)

General criteria with operating-basis earthquake (OBE) load case. W10x39 beam (A36) and two 7 x 4 x 3/8 x 6 angles (A36) with 7/8-in.-diameter bolts (A325) (two bolts with pitch equal to 3 in. on instanding leg, four bolts in two rows with pitch equal to 3 in. on outstanding leg). The connection is subjected to a vertical load (R_y = 3.83K), a lateral load (R_x = 1.98K), and a torsional moment (M_z = 4.02K-in.).

The dimensions for connection angles are as follows:

L1	=	6.0 in.	E2	=	7.0 in.
L3	=	0.0 in.	E3	=	3.0 in.
OL	=	4.0 in.	E1	=	1.5 in.
			S	=	0.375 in.

On the outstanding angle, the gage is equal to 5.5 in. and the surface condition is Type A.

Results obtained by hand calculation and program analysis are compared in Table 3.13-27.

Example 1b - Coped Connection

All the parameters are the same as in Example 1a, except the coped distances on the top flange are L2 = 5.5 in. and L3 = 1.25 in. Results obtained by hand calculation and program analysis are compared in Table 3.13-28.

3.13.1.30.2.2 Problem 2

The following examples were selected to validate the program for bolted/welded sliding type connection with side plates (Detail No. 7.7.2 of Reference 30).

Example 2a - Uncoped Connection General Criteria

W8x35 member and plate with two bolts, 7/8-in.-diameter and an allowable tension of 44 (ksi). The connection is subjected to a vertical load of 8.0 (K), a lateral load of 2.27 (K), and a torsional moment of 3.05 (K-in.). The material type for the member is A36 steel and for the plate is A588 steel. The dimensions for the connection plate are distance L1 = 5.50 in. and thickness Tp = 0.375 in.

Slot and pitch sizes are 0.25 in. and 3.0 in. respectively. Distances E1 and E3 are 0.5 in. and 2.75 in. respectively. Use a full penetration weld and consider general criteria with OBE load case.

Results obtained by hand calculation and program analysis are compared in Table 3.13-29.

Example 2b - (Coped Connection)

Same as Example 2a, but the member is coped. Distances L2 and L3 are 5.5 in. and 1.25 in. respectively.

Results obtained by hand calculation and program analysis are compared in Table 3.13-30.

3.13.1.30.2.3 Problem 3

The following examples were selected to validate the program for framed shop-welded/field-bolted-type connections (Detail No. 7.2.9 of Reference 30).

Example 3a - Uncoped Connection (L2=E3)

General criteria with OBE load case. W8x24 beam (A36) and two 4 x 3-1/2 x 3/8 x 5.5 angles (A36) with 7/8-in.-diameter bolts (A325) (fillet weld on instanding leg, weld size equal to 5/16 in., four bolts in two rows with pitch equal to 3.0 in. on outstanding leg). The connection is subjected to a vertical load (R_y = 1.98K), a lateral load (R_x = 0.44K), and an axial load (R_z = 1.38K).

The dimensions for the connection angle are as follows:

E3	=	1.25 in.	L1	=	5.5 in.
E	=	3.5 in.	L3	=	0.0 in.
B	=	0.0 in	OL	=	4.0 in.

On the outstanding angle, the gage is equal to 5.25 in., and the surface condition is Type A.

Results obtained by hand calculation and program analysis are compared in Table 3.13-31.

Example 3b - Coped Connection

All the parameters are the same as in Example 3a, except the coped distances on the top flange are L2 = 5.5 in. and L3 = 1.25 in. Results obtained by hand calculation and program analysis are compared in Table 3.13-32.

3.13.1.30.2.4 Problem 4

The following examples were selected to validate field-welded/ shop-welded friction-type connections (Detail No. 7.2.11 of Reference 30).

Example 4a - Uncoped Connection

General criteria with OBE load case. W10x39 beam (A36) and two 4 x 3-1/2 x 3/8 x 5.5 angles (A36) with 5/16-in. fillet weld (E70) on both instanding and outstanding legs. The connection is subjected to a vertical load (R_y = 2.60K), a lateral load (R_x = 1.50K), an axial load (R_z = 1.50K), and a torsional moment (M_z = 5.0 kip-in.).

The dimensions for the connection angle are as follows:

L1	=	5.5 in.	E3	=	1.25 in.
L3	=	0.0 in	E1	=	4.0 in.
E2	=	3.5 in.	B	=	0.0 in.

Results obtained by hand calculation and program analysis are compared in Table 3.13-33.

Example 4b - Coped Connection

All the parameters are the same as in Example 4a, except that the beam is coped on top with distance L2 = 5.5 in. and L3 = 1.25 in. Results obtained by hand calculation and program analysis are compared in Table 3.13-34.

3.13.1.30.3 CINCH

CINCH (Anchor Plate Assembly Analysis) is an interactive prompting program that analyzes individual expansion anchored plates with a single attachment and concrete expansion anchors. Design procedures are given in Structural Design Standard E11 (Reference 35). The program with its assumptions and limitations is consistent with this standard. The program is self-documenting and prints out a summary of results.

The program is a module of the SUPS package and was developed at S&L in 1984. It is currently maintained on UNIVAC 1100 Series hardware operating under EXEC 8.

The program was validated by comparing the program results to detailed hand calculations. Two problems used for this comparison are shown in the following. The CINCH results are compared with hand calculations in Tables 3.13-35 and 3.13-36.

3.13.1.30.3.1 Problem 1 (Initial Design)

Concrete thickness = 18 in.

Attachment size:

X-dimension = 8 in.

Y-dimension = 8 in.

The center of the attachment area is at the center of the plate. The C.G. of the attachment is at the center of the attachment area.

Default material properties are used.

Loading

SSE Case			OBE Case		
M_x	=	10,000 in-lb	M_x	=	8,400 in-lb
M_y	=	12,000 in-lb	M_y	=	10,000 in-lb
M_z	=	5,000 in-lb	M_z	=	4,200 in-lb
F_x	=	800 lb	F_x	=	670 lb
F_y	=	2,000 lb	F_y	=	1,670 lb
F_z	=	11,000 lb	F_z	=	9,200 lb

3.13.1.30.3.2 Problem 2 (As-Built Reassessment)

18 in. x 18 in. x 1 in. plate with 8-3/4-in.-diameter anchors in reinforced concrete.

Attachment size:

X-dimension = 10 in.

Y-dimension = 10 in.

The center of the attachment area is at X = 8.5 in. Y = 9.5 in. The C. G. of the attachment is offset from the center of the attachment area by X offset = -0.5 in., Y offset = 0.5 in.

OBE Load Case

M_x	=	25 kip-in.	F_x	=	5 kips
M_y	=	37 kip-in.	F_y	=	13 kips
M_z	=	20 kip-in.	F_z	=	15 kips

Loads are not reversible.

An edge of concrete is defined parallel to the x-axis at 3 in. above the top of the plate.

Concrete thickness = 18 in.

3.13.1.30.4 APLAN

APLAN (Attachment Plate Analysis) is a finite element program that can analyze rectangular attachment plates mounted on reinforced-concrete or concrete masonry by means of expansion anchors, headed welding studs, or wire embedments.

APLAN communicates with the user through a simple command- oriented language. It uses free-format input that consists of one or more key words interspersed with its arguments. This command language is used to define plate geometry, anchor location, and loading configurations, and to perform finite element analysis. The material properties for standard expansion anchored and embedded plates, as defined by Standard SDS E11 (Reference 35), have default values in the program, but the user can change these.

Efficient finite elements permit the analysis to be performed interactively. These finite elements are used to perform decoupled bending and plane stress analysis of the attachment plate. The bending analysis includes the partial contact of the plate with the concrete wall, which can result in prying and amplification of anchor tension forces. Plane-stress analysis is performed to determine the shear reactions on the anchors.

The output is printed at the terminal. This program has the capability to print out all the finite element solutions for every element and node of the plate. Because the comprehensive information requires enormous printout time, the program is defaulted to echo out all user input data, equilibrium check, all anchor reactions, and maximum element stress location. The user has the option to request the full output.

The program is a module of the SUPS package and was developed at S&L in 1985. It is currently maintained on UNIVAC 1100 Series hardware operating under EXEC 8.

The program was validated by comparing the program results to those generated by the ADINA program (Reference 36). Three problems were used for this comparison.

3.13.1.30.4.1 Problem 1

17 in. x 19 in. x 3/4 in. plate, shown in (a) of Figure 3.13-69.

8-3/4-in.-diameter concrete expansion anchors.

Concentrated load applied at x = 5 in., y = 13 in.

Loads:	F_z	=	2.50 kips
	M_x	=	50.20 kip-in.
	M_y	=	40.0 kip-in.

Comparison of results showed:

Anchor Number	APLAN Reaction	ADINA Reaction
1	0.19	0.19
2	0.04	0.05
3	0.00	0.00
4	1.34	1.35
5	0.00	0.00
6	3.19	3.20
7	1.35	1.36
8	0.48	0.48

3.13.1.30.4.2 Problem 2

15 in. x 15 in. x 1 in. plate.

Four studs 7/8-in.-diameter, 8 in. long at 1 1/2-in. edge distance.

Concentrated load applied at x = 9 in., y = 9 in.

Loads:	F_z	=	4.00 kips
	M_x	=	40 kip-in.
	M_y	=	50 kip-in.

Comparison of results showed:

Stud Number	APLAN Reaction	ADINA Reaction
1	1.17	1.23
2	0.01	-0.0003
3	4.51	4.49
4	2.93	3.0

3.13.1.30.4.3 Problem 3

12 in. x 22 in. x 1/2 in. plate, shown in (b) of Figure 3.13-69.

Twenty-one deformed wire anchors 0.302-in.-diameter, 1 ft-7 in. long.

Loads: F_z = 24 kips

Comparison of results showed the APLAN stress as 17.13 ksi, and the ADINA stress as 17.49 ksi.

3.13.1.31 ADINA (Reactor/Auxiliary Building)

ADINA (Automatic Dynamic Incremental Nonlinear Analysis) is a computer program for the static and dynamic displacement and stress analysis of solids, structures, and fluid-structure systems. The program can be used to perform linear and nonlinear analyses. The structural systems can be composed of combinations of different finite elements. The program presently contains the following element types:

a. Three-dimensional truss element

b. Two-dimensional plane stress or plane strain element

c. Three-dimensional plane stress element

d. Two-dimensional axisymmetric shell or solid element

e. Three-dimensional solid or thick shell elements

f. Three-dimensional two-node beam element

g. Curved beam element

h. Three-node thin plate/shell element

i. Thin shell element

j. Two- and three-dimensional fluid elements.

The nonlinearities may be due to large displacements and non-linear material behavior. The material descriptions presently available are:

For the Truss Elements

a. Linear elastic

b. Nonlinear elastic

c. Thermo-elastic

d. Elastoplastic (isotropic or kinematic hardening)

e. Thermo-elastic-plastic and creep (isotropic or kinematic hardening).

For the Two-Dimensional Elements

a. Isotropic linear elastic

b. Orthotropic linear elastic

c. Isotropic thermo-elastic

d. Curve description model

e. Concrete model

f. Elastic-plastic materials, von Mises (isotropic or kinematic hardening) and Drucker-Prager yield conditions

g. Thermo-elastic-plastic-creep, von Mises condition (isotropic or kinematic hardening)

h. Mooney-Rivlin material.

<u>For the Three-Dimensional Elements</u>

a. Isotropic linear elastic

b. Orthotropic linear elastic

c. Isotropic thermo-elastic

d. Curve description model

e. Concrete model

f. Elastic-plastic materials, von Mises (isotropic or kinematic hardening) and Drucker-Prager yield conditions

g. Thermo-elastic-plastic-creep, von Mises isotropic or kinematic hardening yield condition.

<u>For the Two-Node Beam Element</u>

a. Linear elastic

b. Elastic-plastic, von Mises yield condition.

<u>For Curved Beam Element</u>

a. Linear elastic

b. Elastic-plastic, von Mises yield condition (isotropic or kinematic hardening).

<u>For Three-Node Plate/Shell Element</u>

a. Linear elastic

b. Elastic-plastic, Ilyushin yield condition isotropic hardening.

<u>For the Shell Element</u>

a. Linear elastic

b. Elastic-plastic, von Mises yield condition (isotropic hardening).

The ADINA program is an out-of-core solver, so very large finite element systems can be considered. Also, all structure matrices are stored such that only nonzero elements are processed, resulting in maximum system capacity and solution efficiency.

In dynamic analysis, the frequencies of the system can be calculated, and the system response can be evaluated using mode superposition or implicit direct-time integration (the Newmark method or the Wilson method), or explicit direct-time integration (the central difference method).

In nonlinear analysis, the finite-element system response is evaluated using an incremental solution of the equations of equilibrium. The incremental equilibrium schemes that can be used are an accelerated modified Newton iteration or the BFGS method. Substructuring can be used to increase the solution efficiency.

ADINA was developed by Klaus-Jurgen Bathe (Reference 37) at the Massachusetts Institute of Technology. It is currently maintained by S&L on the UNIVAC 1100 Series hardware operating under EXEC 8. To demonstrate the validity of the major analytical capabilities of ADINA, the test problems are taken from the ADINA User's Manual and are compared with solutions of the S&L version.

3.13.1.31.1 Problem 1

Frequency Analysis of a Tower Cable

The cable stretched between a ground anchor point and tower attach point, shown in Figure 3.13-70, was analyzed for frequencies of vibration. The cable was modeled using 12 truss elements of linear elastic material, as shown in Figure 3.13-70. The cable had an initial tension of 7520 lb. Insulators weighing 510 lb each were located at nodes 2, 4, and 6, and a cluster of six insulators totaling 3060 lb was located at node 8. Nodes 3, 5, 7, and 9 through 12 are intermediate nodes located along the cable without insulators. The total vertical load acting on the cable nodes was 5677.83 lb, which includes the insulator weights and the cable self-weight.

For the frequency analysis, a lumped-mass matrix of the cable has been assumed to which the masses of insulators have been added. The periods of vibration of the cable about the static equilibrium configuration are given in Table 3.13-37.

3.13.1.31.2 Problem 2

Large Displacement Analysis of an Elastic Simply Supported Plate

The simply supported square plate subjected to a uniformly distributed pressure shown in Figure 3.13-71 was analyzed for its large deflection response. One single 16-node shell element was used to model one-quarter of the plate.

Figure 3.13-71 shows the displacement response predicted in the finite element analysis. The computed displacement response compares very closely to the solutions given by Levy (Reference 38). The effect of using different assumptions on the plate edge in-plane displacements was modeled using the constraint equation option in ADINA.

3.13.1.31.3 Problem 3

Thermo-Elastic Static Analysis of a Cantilever Beam

The cantilever beam shown in Figure 3.13-72 was subjected to a linearly varying temperature gradient in the Z-direction. No mechanical loads were applied. The beam was modeled using three 16-node, three-dimensional elements. Since displacements and strains are small, the analysis was carried out for material non-linearities only, and by using appropriate displacement boundary conditions, only the portion of the beam above the neutral surface was included in the finite element model.

Figure 3.13-73 shows the displacement response of the cantilever neutral surface. Excellent agreement with the solution by Boley and Weiner was obtained (Reference 39).

3.13.1.31.4 Problem 4

Static Analysis of a Reinforced-Concrete Beam

The simply supported reinforced-concrete beam subjected to two symmetric concentrated loads, as shown in Figure 3.13-74, was analyzed using ten 6-node, concrete plane-stress elements and 10 steel truss elements. The material properties of the concrete were idealized using the concrete model with the parameters given in Figure 3.13-74. Materially nonlinear-only response was assumed, i.e., large-displacement effects were neglected.

Figure 3.13-75 gives the calculated transverse displacements at the midspan of the beam, for A_{st} = 2.00 in.^{2} for nonlinear static response. The loading scheme used is also shown in this figure. Other results on analysis for A_{st} = 0.62 in.^{2} are compared with the response predicted by Suidan and Schnobrich (Reference 40), who assumed a linear stress-strain relationship for the concrete with the constant Young's modulus equal to E_0 of this analysis, and who modeled the steel reinforcement as a smeared stiffness added to the concrete.

3.13.1.31.5 Problem 5

Analysis of a Beam Subjected to a Traveling Load

The simply supported beam in Figure 3.13-76 was analyzed for its dynamic response. The beam was subjected to a constant-magnitude force traveling across its span at a constant velocity. In the analysis, 20 beam elements were used to model the structure, and small displacements and elastic material conditions were assumed. To model the traveling load, the time function and arrival time option were used in ADINA.

Figure 3.13-76 shows the midspan lateral deflection during the period the load is acting on the beam. The analysis results using ADINA are also compared with one-mode analytical solution given by Biggs (Reference 3).

3.13.1.32 FRAME (Reactor/Auxiliary Building and Residual Heat Removal Complex)

FRAME (Integrated Frame Analysis System) analyzes frames for static and dynamic loadings, performs load combinations, and checks stresses against allowable stresses.

The following analyses are performed:

a. Static: Analysis of distributed and concentrated weight loadings and reaction loadings on frames

b. Dynamic: Analysis of frame response to seismic loads using pseudo-static methods.

The static and dynamic analyses can be performed independently or in sequence.

The input consists of the frame geometry, material properties, and static and dynamic loadings. Various options exist to control the length of the output. The default option generally prints only the summary of input data and final results.

The load combinations are done per user specification. Three methods of combination are used: (1) combination by addition considering signs; (2) combination by addition of absolute values; and (3) combination by square-root-of-the-sum-of-the-squares (SRSS). Loads designated as WT (self-weight of the members and additional lumped weights) are combined considering the signs. Loads designated as RO (reaction loads) or SE (seismic) are combined by either summation of absolute values or by SRSS, as specified by the user. To account for the sign reversal inherent in the RO and SE loads, these loads are combined with the absolute value of the result of the WT-type load combination to give the "worst case" final loads. Two values of the load combination are also obtained for the axial load: the combined WT load with the sign is combined with the combined RO and SE terms with both plus and minus signs. These two values are used in determining the tension and compression stresses.

The stress-checking provisions follow those of the 1978 AISC Specification (Reference 41), and Structural Design Standard E-37 for Mechanical Component Auxiliary Support Steel Framing (Reference 42). AISI Specifications (Reference 43) are used to check the stress levels in Unistrut members (Reference 44).

Allowable stresses calculated using the above-referenced documents are multiplied by an overstress factor (input by the user). However, these stresses are limited to "SLIM*FY", where 'SLIM', defined as stress limiting factor, is calculated as follows:

a. For axial stresses (direct or bending)

$$\text{SLIM} = \frac{1}{\text{Minimum Factor of Safety}} \leq 1.0$$

b. For shear stress

$$\text{SLIM} = \frac{1}{\sqrt{3}\,(\text{Minimum Factor of Safety})} \leq 0.57$$

Minimum factor of safety is input by the user. Overstress factor is 1.0 for normal load combinations.

Presently the program can check member design for Unistrut wide flange, structural tube sections, and single angle members.

FRAME was developed at S&L in 1983. It is currently maintained on UNIVAC 1100 Series hardware operating under EXEC 8.

To demonstrate the validity of the analysis performed by the FRAME program, the following two examples are presented.

To illustrate the validity of the static portion of FRAME, the problem shown in Figure 3.13-77 was analyzed and the results compared to those given in Reference 45. Table 3.13-38 shows comparison of member end forces; the results are in good agreement. To illustrate the validity of the dynamic analysis portion of FRAME, which uses a pseudo-dynamic method of analysis in which the system is analyzed for a static loading equivalent to the mass times the specific acceleration applied at all mass points, the problem shown in Figure 3.13-78 was analyzed. A static selfweight-loading analysis was performed for each of the three global directions. The results for each direction loading were multiplied by the corresponding direction g level to obtain the individual direction-excitation results. The final result is taken as the SRSS of the three direction-excitation results. The results for the program and independent calculations are compared in Table 3.13-39; the results agree.

To demonstrate the validity of the load combinations performed by the FRAME program, the following example is presented. The frame shown in Figure 3.13-77 was analyzed for three loadings: self- weight, WT1; reaction loading as shown in Figure 3.13-77, R01; and seismic OBE, SE1. Two load combinations were generated: WT plus absolute sum of reaction load and seismic; and WT plus SRSS of reaction load and seismic. The individual analysis results at select locations are given in Table 3.13-40. Also shown in Table 3.13-40 is the comparison of the load combination results from FRAME and hand calculations; the results agree.

To demonstrate the validity of the member design portion, the following examples (one for each shape of member) have been selected.

3.13.1.32.1 Problem 1 - Tube Section

A 6 x 4 x 3/8 tube section under the loading shown in Figure 3.13-79 was used to validate the design check for tube sections. Additional data are given in Table 3.13-41. FRAME output is compared with hand calculations in Table 3.13-41; they are in close agreement.

3.13.1.32.2 Problem 2 - Wide Flange Section

A W12x40 section under the loading shown in Figure 3.13-80 was used to validate the design check for wide-flange sections. Additional data are given in Table 3.13-42. FRAME output is compared with hand calculations in Table 3.13-41; they are in close agreement.

3.13.1.32.3 Problem 3 - Unistrut Section

A P1000 Unistrut section under the loading shown in Figure 3.13-81 was used to validate the design check for Unistrut sections. Additional data are given in Table 3.13-42. FRAME output is compared with hand calculations in Table 3.13-41; they are in close agreement.

3.13.1.32.4 Problem 4 - Single Angle Section

A 3 x 2 x 3/8 angle section under loading shown in Figure 3.13-82 was used to validate the design check for single-angle sections. Additional data are given in Table 3.13-42. FRAME output is compared with hand calculations in Table 3.13-41; they are in close agreement.

To demonstrate the validity of the connection module, five problems were selected. The problem data given are in Table 3.13-43. These problems were validated by comparing the FRAME results to the results obtained from hand calculations. A comparison of results is given in Table 3.13-44.

3.13.2 Computer Programs Used by Chicago Bridge & Iron

Subsections 3.13.2.1 through 3.13.2.9 provide a description of the CBI computer programs used for general analysis and design work. Computer program information beyond that included herein, or in the Stress Report and Calculations, is proprietary. However, test problems and verifications are on file and available at CBI.

The description of programs used by CBI includes a discussion on the design of the drywell and torus. There have been extensive modifications to the torus subsequent to its original installation. The details of modifications to the torus are presented in the Fermi 2 Plant Unique Analysis report. See References 46 through 51.

3.13.2.1 Program 405

This is a program used for the analysis of a ring with a constant moment of inertia and modulus of elasticity. The loads are in the ring. The mathematics are based upon the Hardy-Cross column analysis for rings as referenced in Theory of Modern Steel Structures, Vol. II, by Grinter, page 259. The loads can be moments, tangential, or radial to the ring. The printouts are coefficients at incremental distances around the ring. The printout titles for the output are as follows:

X	=	Angle and degrees as measured from a reference axis
V	=	A radial shear with force units acting in a radial direction through the ring
T	=	An axial thrust in the ring with units of force
M/R	=	A coefficient with units of force which when multiplied by the radius to the centroid will equal a moment
EI/RR	=	A coefficient which when multiplied by the radius^2 will equal the rotation of the ring at the point
REI/RRR	=	A coefficient which when multiplied by the radius^3 equals the radial deflection of the point
CEI/RRR	=	A coefficient which when multiplied by the radius^3 will equal the tangential deflection of the point.

3.13.2.2 Program 601

This program is based on the mathematics of Program 405. In addition, the coefficients have been multiplied by the proper radius. This means that the thrust and moment only have to be divided by the area and section modulus, respectively, to find the stresses at the point.

3.13.2.3 Program 655

This program is based on the theory and equations presented in NASA-TN 1219. In the program the influence of the loads on any ring is not evaluated beyond the adjacent rings. Basically, the only difference between this program and the previous ring programs is that the shear in the ring with loads is transferred into the shell between the rings.

3.13.2.4 Program 7 - 81N - Kalnins' Shell Program

This program was developed by Aerturs Kalnins at Yale University, based on a method of analysis published in Reference 11. The program is used for shell stresses at discontinuities, with the exception of nozzles.

3.13.2.5 Program 772

This is a program for checking nozzle reinforcing. It is designed essentially for containment vessels, and adheres to area replacement criteria specified by ASME Sections III and VIII. The program does no design work, merely checking the adequacy of preselected reinforcing plate dimensions and weld sizes.

3.13.2.6 Program 6 - 20 Cookbook Nozzles

This program computes the local stresses in cylindrical and spherical shells due to a load or a combination of loads acting on a nozzle that penetrates the shell. The solution for local shell stresses is made using the dimensionless parameters (input) from the graphs in the Welding Research Council Bulletin No. 107. When reinforcing is present, these parameters are found using the procedures of Bijlaard, as outlined in Welding Research Council Bulletins 49 and 50.

If a solution for unit loads is desired, the card for loads is left blank. The program assigns unit loads of 1000 lb to the radial load and the shears, and 100 in.-lb to the moments.

Tests are performed in the cylinder and sphere subroutines to see if either an insert or pad plate or no reinforcing is present. Depending on the results of these tests, a particular set of denominators is computed for use in the stress calculations in the stress subroutine. When reinforcing is present, the program checks the stress at the edge of the reinforcing. The thicknesses used in the computation of stresses are described in the following subsection.

3.13.2.7 Program 860 - Rigid Attachment to Spherical Shell

3.13.2.7.1 General

This program computes shell stresses around a rigid attachment to a spherical shell due to any combination of loading, radial, shear, or moment. The program uses the nomenclature, the curves for coefficients, and the mathematics of the Welding Research Council Bulletin No. 107. Given the basic geometry of the attachment, the program will compute the parameters as required from Figures SR-2 and SR-3 and the shell stresses around the attachment.

If the load card is blank, the program assigns unit loads of 1000 lb to P and U1, and 100 in.-lb to M1. There is one printout for each of the unit loads.

If the width of reinforcing is less than 1.65 times the square root of the spherical radius, times either the thickness of the insert or an equivalent thickness for pads, the stresses are also checked at the edge of the reinforcing. All induced moments at the nozzle-to-shell junction and the induced moment M_x at the edge of reinforcing, are increased by 20 percent to satisfy the requirements of Welding Research Council Bulletins 49 and 50 (References 52 and 53) by Bijlaard. If the width of reinforcing is greater than 1.65 times the square root of the spherical radius, times either the insert thickness or equivalent thickness, only the stresses at the nozzle-to-shell junction are computed. None of the induced moments are increased. The thickness used in the solution of stresses about a reinforced nozzle is determined as follows.

3.13.2.7.2 Reinforced Nozzle Parameters For Bijlaard Analysis

At Nozzle-to-Shell Junction

a. T = Thickness of insert or equivalent thickness for pad-type reinforcing. T equivalent = 1/2 $\{(TS + TP)^3 + (TP)^3 + (TS)^3\}^{1/3}$ where TP is the thickness of the pad and TS is the shell thickness without reinforcing. The quantity under the cube root is the average of the moment of inertia of the total thickness of the shell plus pad and the sum of the individual moments of inertia of the shell and the pad

b. All parameters are found using T. The stresses are computed using T. The programs compute the membrane stress using the total thickness of the pad plus shell. However, the parameters contain the equivalent thickness which is divided out to obtain N_x, N_y, or N first

Example: $\frac{N_X T}{P} \quad \frac{P}{T(TS+TP)}$

c. If the width of reinforcing, W, is less than C RT, where R is the mean radius of the shell, T is the thickness defined in item 1, and C is normally assumed to equal 1.65, the reinforcing is assumed to act as a rigid plug and the induced moments M_x and M_y for spheres or M_x and M for cylinders are increased by 20 percent because of effects of reinforcing (References 52 and 53). If W is greater than $C\sqrt{RT}$, the reinforcing is assumed to act as a shell plate with no increase in induced moments.

At Edge of Reinforcing

a. TS = Thickness of shell without reinforcing

T = Thickness of insert or equivalent thickness for pad-type reinforcing. See Item b. above.

b. Parameters for induced moment M_x are found using T. All other parameters are found using TS. The shell stresses are computed using TS. The programs divide out the only equivalent thickness in the parameters containing M_x only

Example: $\frac{M_X RT}{M_1} \quad \frac{6M_1}{(TS)^2 RT}$

c. Increase the parameters containing the induced moment M_x by 20 percent.

3.13.2.8 Program 7-78, Drywell Primary Membrane Stress Analysis

The drywell shell is analyzed for stresses due to the customer- specified loading combinations. Primary membrane stresses are computed for each of the loading combinations, and the resulting stresses are compared to the ASME Code allowables. In addition, the compressive stresses are compared to an allowable buckling stress, and a buckling ratio is computed.

The drywell primary membrane stresses are found using the general equations for an axisymmetrically loaded shell of revolution. The derivation of the general equations can be found in Chapter 14 of Theory of Plates and Shells by Timoshenko (Reference 6). The equations are as follows:

General Equation No. 1: $\frac{N_\phi}{R_\phi} + \frac{N_\theta}{R_\theta} = P$

General Equation No. 2: $2\pi r_o N_\phi \sin\phi + Z = 0$

where

N_ϕ	=	meridional membrane stress resultant
N_θ	=	circumferential membrane stress resultant
R_ϕ	=	radius of curvature in meridional plane
R_θ	=	radius of curvature in circumferential plane
P	=	pressure
ϕ	=	angle between pole of revolution and point
Z	=	resultant of total load on shell
r_o	=	$R_\theta \sin\phi$

It should be noted that the stress resultants at structural discontinuities, such as the cylinder-to-knuckle and knuckle-to- sphere, are the maximum stress resultants. The stress resultants are found using the appropriate equations for the smaller thickness at the point of discontinuity.

Pressure

Top Head - The top head is designed for stresses due to internal and external pressure. The thickness required for internal pressure is found using the formulas in Paragraph UA-4(c) of Section VIII of the ASME Code, while the allowable external pressure is found according to the requirements of Paragraph UG-33 of Section VIII of the ASME Code. This design is in accordance with Code Case 1392.

The top head is also designed for stresses due to a jet load. The stresses resulting from this jet load are computed using Case 20 on page 304 of Reference 54.

Cone - The top cone, if one exists, is designed according to the requirements of Paragraph UA-5 of Section VIII of the ASME Code. This analysis is in compliance with Code Case 1392.

Knuckle - The knuckle pressure stress resultants are analyzed in this section, using the "pressure area method" as outlined in Reference 55.

Cylinder - The cylinder is designed for both internal and external pressure, in accordance with Code Case 1392. The design for internal pressure is made using the equations for thickness of UG-27(c) of Section VIII of the ASME Code.

The external pressure design is made using the method described in Paragraph UG-28 of Section VIII of the ASME Code. The curves in Figure UCS-38.2, which are referred to in Paragraph UG-28, are defined by the following equation:

$$\text{Allowable External Pressure} = \frac{2.6\,E\,[T/D]^{2.5}}{4\left[L/D - 0.45\left[T/D^{0.5}\right]\right]}$$

where

E = modulus of elasticity of steel

T = thickness of cylinder

D = diameter of cylinder

L = length of cylinder including one-third the vertical height of the knuckle and the lesser of one-third of the length of the cone to its apex or length to the flange

Sphere - The sphere is analyzed for both internal and external pressure. The stress resultants due to internal pressure are found using the general equations reduced to the following form:

$$N_\phi = N_\theta = \frac{PR}{2}$$

where

R = radius of sphere

The sphere is also checked for buckling stresses when subjected to external pressure. A discussion of this buckling analysis is found in the discussion of allowables for compressive stress resultants. The buckling stress resultant due to external pressure is considered in conjunction with the stress resultants due to dead loads and the effects of seismic loading on these dead loads.

Vertical Loads

The vertical loads include, but are not limited to, the weight of the penetrations, compressible material, shell steel, jet deflectors, refueling water, and spray headers. Also included with the vertical loads is the effect of vertical earthquake acting on the above loads. The stress resultants for these loads are found using the general equations reduced to the following forms for the various shapes.

Cylinder

General Equation No. 2 $\quad N_\phi = \frac{\text{Vertical Load}}{\text{Circumference}} = \frac{\text{Load}}{2\pi R_\theta}$

General Equation No. 1 $\quad N_\theta = 0$

where

P = 0

R_ϕ = ∞

R_θ = circumferential radius

Knuckle

General Equation No. 2 $N_\phi = \frac{\text{Load}}{\text{Circumference} * \sin\phi}$

$= \frac{\text{Load}}{2\pi L_1 (\sin\phi)^2}$

General Equation No. 1 $N_\theta = N_\phi \frac{L_1}{-R_2}$

where (refer to [a] in Figure 3.13-83)

P = 0 for all loads except shell weight and compressible material

R_2 = knuckle radius (negative number)

L_1 = distance from pole to point as measured on the normal

Special consideration is given to the weight of the shell and compressible material. N_ϕ is computed using General Equation No. 2 above. However, the density of the shell is considered to act as a pressure in the radial direction in finding N_θ. Therefore, the General Equation No. 1 for N_θ due to shell weight or compressible material is as follows:

General Equation No. 1 $N_\theta = -\rho + L_1 \cos\phi + N_\phi \frac{L_1}{R_2}$

where

P = $-\rho t \cos\phi$

ρ = density of steel or compressible material

t = thickness of shell

L_1 = distance from pole to point as measured on normal

R_2 = knuckle radius (negative number)

Sphere

General Equation No. 2 $N_\phi = \frac{\text{Weight}}{2\pi R(\sin\phi)^2}$

General Equation No. 1 $N_\theta = -N_\phi$

where

P = 0 for all loads except shell weight and compressible material

R = radius of sphere

The weight of the shell and the weight of the compressible material is again treated as a pressure in the radial direction for finding the stress resultant N_θ.

General Equation No. 1 $N_\theta = -\rho t R \cos\phi - N_\phi$

where

R = radius of sphere

P = $-\rho t \cos\phi$

ρ = density of steel or compressible material

t = thickness of shell

Horizontal Earthquake

The effect of the horizontal earthquake is to produce a shear load acting on the shell at the elevation of the load. This shear is found by multiplying the load by the horizontal earthquake factor for the elevation of the load. This factor is taken from curves for horizontal earthquake given in the customer specifications. From statics the shear load can be considered to produce a moment at a lower elevation. This moment tends to rotate the drywell shell about the plane under consideration.

In the earthquake analysis, the drywell is analyzed as a free- standing, cantilevered column. However, the drywell can be supported by the surrounding building at the stabilizer elevation. This support is separated from the stabilizer of the drywell by a l0 mil-gap. Thus, during the incidence of an earthquake, the vessel may generate a shear in the opposite direction of the shear of the applied loads. This shear is the reaction at the stabilizer elevation, which is treated in the same manner as the other shear loads. The reaction is found using a combination of Castigliano's First Theorem and the unit load method using the following equations:

$$\Delta = \frac{1}{E}\int \frac{M}{I}\frac{\delta M}{\delta P}\,dx + \frac{1}{G}\int \frac{V}{A}\frac{\delta V}{\delta P}\,dx$$

ΔImposed = ΔHorizontal Earthquake Acting on Vessel + ΔUnit Load x Reaction

The stress resultants due to moment are computed using the general equations. These equations have been reduced as follows for the three general shapes in the drywell.

Cylinder

General Equation No. 2 $$N_\phi = \frac{\text{Moment}}{\text{Section Modulus}} = \frac{\text{Moment}}{\pi R^2}$$

General Equation No. 1 $$N_\theta = 0$$

where

P = 0

R_ϕ = ∞

R_θ = radius of curvature in circumferential plane

Knuckle (refer to [b] in Figure 3.13-83)

General Equation No. 2 $$N_\phi = \frac{\text{Moment}}{\text{Section Modulus}* \sin\phi}$$

$$N_\phi = \frac{\text{Moment}}{\pi(L_1 \sin\phi^2 * \sin\phi)}$$

General Equation No. 1 $$N_\theta = -N_\phi \frac{L_1}{R_2}$$

where

$P = 0$

$L_1 =$ distance from pole to point as measured on the normal

$R_2 =$ knuckle radius (negative number)

Sphere

General Equation No. 2

$$N_\phi = \frac{\text{Moment}}{\text{Section Modulus} \times \sin\phi^*}$$

$$N_\phi = \frac{\text{Moment}}{(R\sin\phi)^2 \times \sin\phi}$$

General Equation No. 1 $\quad N_\theta = -N_\phi$

where

$P = 0$

$R =$ radius of sphere

* sin ϕ used to transfer stress resultant into plane of shell.

Drywell Flooded

In the flooding of the drywell, the stress analysis is made for stresses both in the meridional and circumferential directions (Figure 3.13-84). In the meridional direction, floodwater weight adds to the other gravity loads and causes an increase in the compressive stress. These other loads are the weight of the shell steel, the weight of the compressible material (if applicable), the weight of the penetrations, dead loads, and live loads. In the consideration of the meridional stress, the buckling of the shell is the limiting factor. In the circumferential direction, the hydrostatic pressure due to the floodwater increases the total circumferential stresses. The stresses in each direction are analyzed both with and without seismic effect.

Meridional Stress - In the analysis of the meridional stresses, there are two conditions considered critical, and therefore an analysis is made for each.

One condition exists when the floodwater reaches its maximum elevation as specified by the customer. This condition is considered critical because it obviously involves the largest amount of floodwater in the drywell shell, and also because it involves the greatest hydrostatic pressure that the drywell shell will experience under the flooding condition.

The second condition occurs instantaneously as the drywell is filled and the water reaches the critical point P (see Figure 3.13-85). This point P is considered critical for two reasons:

a. With reference to Figure 3.13-85, it can be seen that the maximum water weight that the shell will carry will exist when the water level is at point P or higher. No matter how high the water floods above point P, only the overhanging water (bounded by the shell, point P, and embedment) can be carried by the shell. The remaining water is carried by the internal concrete through the shell into the foundation

b. With reference to Figure 3.13-86, it can be seen that there is an unbalanced hydrostatic pressure acting on the drywell shell between point P and the vertical cylindrical shell. This unbalanced pressure is a buoyant force that is calculated based on Volume (B) with respect to Archimedes' principle. This buoyant force acts upward and thereby reduces the buckling stress.

Considering the above two reasons, it can be seen that the worst loading condition, that is, the maximum water load at embedment, and the minimum bouyant force (equal to 0) will both be attained with the water level at point P.

While the additional weight of the floodwater will increase the buckling stress, the water pressure inside the vessel will permit increasing the critical buckling stress. A calculation for this increase is made, and the result is added to the normal shell allowable buckling stress to give the critical buckling stress.

By combining the compressive meridional stress due to the floodwater with those stresses due to the normal loads, and then dividing this total into the increased critical buckling stress, a factor of safety is calculated.

Circumferential Stress - In the analysis of the circumferential stresses, the general membrane equation from Page 39 of Reference 56 is used:

$$N_\theta = PR - N_\phi$$

where

P	=	hydrostatic pressure due to floodwater
R	=	drywell sphere radius
N_ϕ	=	meridional stress resultants

Allowables

Tensile - The stress that results from the combination of loading for each condition of loading is compared to the allowable general membrane stress intensity. This is in accordance with the requirements of Section III of the ASME Code for Class B vessels.

Compressive - The compressive stress resultants are compared to allowables obtained according to the paragraphs titled "Biaxial Compression-Equal Unit Forces" and "Biaxial Compression-Unequal Unit Forces" of the Welding Research Council Bulletin No. 69. The allowables used are found by assuming that the sphere reacts as a cylinder with a radius equal to the radius of the sphere. There are three cases of loading considered. The allowables for these three cases are

a. Uniaxial compressive stress resultant

$$N_{ALL} = 1.8 * 10^6 \frac{t^2}{R}$$

b. Biaxial equal compressive stress resultants

$$N_{ALL} = 0.9 * 10^6 \frac{t^2}{R}$$

c. Biaxial unequal compressive stress resultants. This case is treated as the summation of a uniaxial condition with the biaxial condition with equal stress resultants (see [c] of Figure 3.13-83)

$$\frac{N_\theta - N_\phi}{1.8*10^6 \frac{t^2}{R}} + \frac{N_\phi}{0.9*10^6 \frac{t^2}{R}} \leq 1$$

3.13.2.9 Program 7-71

As stated in Subsection 3.13.2, the description of programs used by CBI includes a discussion on the design of the drywell and torus. There have been extensive modifications to the torus subsequent to its original installation. The details of modifications to the torus are presented in the Fermi 2 Plant Unique Analysis report. See References 47 through 52.

3.13.2.9.1 Torus Columns and Column "Stubs" Design

The inner and outer columns and the inner and outer column "stubs" that connect the columns to the torus ring are designed by the computer program using the approach illustrated in Figure 3.13-87.

The column "stubs" are welded to the columns by full fusion welds.

Coefficient of friction for lubrite = 0.1

Friction Force = 0.1P (resisted by column knee braces)

Shear due to horizontal seismic force taken by the torus seismic ties.

The inner and outer columns and column "stubs" (which are usually built-up sections) may have different cross-sectional properties but these must qualify as "compact" sections in accordance with AISC specifications.

The inner and outer columns may have different lengths.

The total length of the columns is taken as the distance from the top surface of the column baseplates (PT.C) to the point where the vertical centerline of the corresponding column "stub" intersects the outer surface of the torus ring (PT.D).

To determine the value of the "effective slenderness ratio" under axial compression only, the values of "K" adopted are K = 1.20 for buckling in radial direction and K = 0.65 for buckling in tangential direction (refer to Section 1.8 of AISC Commentary).

The total axial load and bending moment is taken to be the same for the outer column and outer column "stub," and for the inner column and inner column "stub."

The inner column and column "stub" have been designed for an axial load consisting of the dead load of torus and contents, vertical seismic load, and vertical component of inner brace load which is transferred to the column by the torus ring.

The outer column and column "stub" have been designed for an axial load consisting of dead load of torus and contents, vertical seismic load, vertical component of outer knee brace load, and the overturning effect of horizontal seismic force which is conservatively assumed to be applied directly to the outer columns.

The principal factor causing bending moment is the differential temperature expansion 'Δ' between the column "stub" attachment and the attachment of the knee bracing to the torus shell (Figure 3.13-88).

The differential movement of these two points as a result of pressure-induced stresses has been neglected as these are very small compared to the temperature-induced differential movement of these two points.

The column baseplates rest on a lubrite pad, and are free to slide and compensate for the overall expansion of the torus without causing any bending to be induced in the columns and column "stubs."

The bending moment in the columns and column "stubs" is produced by the differential movement of the column stub attachment to the torus ring radially outward with respect to the column base.

This bending moment is given by

$$M = \frac{6EI\Delta}{L^2}$$ (Refer to AISC, P. 2-127, Case 23)

Here it is assumed that the knee brace transmits the radial movement of the brace attachment to the column baseplates which slide on the lubrite pads; after which the columns are assumed to be fixed at the column bases and the corresponding column "stub" attachments then undergo the differential expansion radially outward with respect to the torus without any rotation at the junction with the torus ring.

The program computes the actual axial and bending stresses for the inner and outer columns and column "stubs" which are shown on the computer printout. Allowable stresses are also calculated per Sections 1.5.1.3 and 1.5.1.4 of the AISC Specification which are also shown on printout. These actual stresses are compared to the corresponding allowable stresses using the ratios per Section 1.6.1 of the AISC Specifications.

In addition, the program also checks the outer and inner column "stub" attachment welds to the torus ring.

<u>Column Baseplate (refer to [a] of Figure 3.13-89.)</u>

The column baseplate is designed for the column axial load per page 3-75 of the AISC Specifications. The program assumes 3000 psi concrete for calculations.

Allowable concrete bearing F_P = 0.25x3000 x F

F = Factor for increasing allowable stress during flooded condition

Required area = $\text{Col Load}/F_P$

Actual Bearing F_{PA} = $\text{Col Load}/\text{Furnished Area}$

Allow bending F_B = (0.75) (yield F)

Required plate thickness = $\sqrt{\frac{3F_{PA}X^2}{F_B}}$

X = Larger of M or N

Column Knee Braces (see [b] of Figure 3.13-89.)

The column knee braces consist of two angles back to back and are designed to take the friction force due to the column base sliding on the lubrite pad with a coefficient of friction equal to (0.1).

The allowable compressive stress is calculated per Section 1.5.1.3 of the AISC Code and is shown on the printout. The maximum distance (L_s) between spacers is calculated per Section 1.18.2.4 and is shown on the printout.

3.13.2.9.2 Torus Support Ring

The stresses in the torus support ring are analyzed by a computer program using the approach as outlined in the following discussion:

The ring is subjected to the following loadings:

a. Column stub reactions

b. Column deflections

c. Column knee brace reactions

d. Header dead load

e. Downcomer jet thrust

f. Internal pressure.

The reaction loads are broken into components so that the three basic loadings (other than internal pressure) are radial, tangential, and bending moment. The magnitude of the loads applied to the ring and their point of application (angular location) are shown on the printout and are specified as radial, tangential, or moment with respective signs. The loads are applied as shown in Figure 3.13-90.

The sign conventions for the ring loads are as follows:

a. Radial = positive when acting inward

b. Tangential = positive when acting clockwise

c. Moment = positive when acting clockwise.

The column stub reactions and moments are broken into two parts and assumed to act 10° apart as shown in Figure 3.13-90. The header dead load and the downcomer jet loads are assumed as radial loads due to their very small angle with the centerline.

The ring loads, as shown on the printout, may be checked by referring to the following:

a.	Column stub axial load	Printout from column stub design section
b.	Column stub bending moment	Printout from column stub attachment weld
c.	Brace axial load	Printout from brace design
d.	Header dead load	See sheet
e.	Downcomer jet load	See customer specifications

For the stress analysis of the ring, the suppression chamber has been assumed as a ring-stiffened cylinder with fixed ends made up of four similar bays. The ring loads as discussed above are placed on the second ring and bending, thrust, and pressure stresses on this ring are calculated by computer program No. 655 based on theory derived in NASA Technical Note No. 1219. Stresses from the internal pressure are calculated by the "pressure area method" from Reference 55.

The computer prints out the component stresses (bending, thrust, and pressure) in addition to the total stresses on the inner and outer flanges of the ring.

3.13.3 Computer Programs Used by Others

Computer programs used by S&L, CBI, and S&W, Michigan, are described in Subsections 3.13.1, 3.13.2, and 3.13.4, respectively. Other significant computer programs used by these and other support organizations (including Edison) are described in this section. A number of computer programs were used by NUTECH Engineers, Inc., in the plant-unique analysis required by the NRC (NUREG-0661, Safety Evaluation Report, Mark I Containment Long-Term Program). The major computer programs used in these analyses are described in the Fermi 2 Plant Unique Analysis reports (References 46 through 51), which were submitted in response to NUREG-0661 requirements.

3.13.3.1 ADLPIPE - Arthur D. Little, Inc.

There are three types of documentation for ADLPIPE. The first is the multitude of hand checks made during the development and change of the program. The second is by the many user groups who have their own method of evaluation and documentation, both analytical and experimental. These groups have contributed immeasurably to the current state of ADLPIPE reliability. The third type is the documentation and internal checks that Arthur D. Little, Inc., has generated.

This third type of documentation and internal checks is in four forms:

a. Fifty-two common errors are checked for and automatically reported
b. All internal program data may be printed during problem solution
c. Sample problems (benchmarks) are compared to other solutions
d. Mathematical techniques used are described.

3.13.3.1.1 Input Check

Automatic message for 52 different types of input error. See Input Preparation Manual.

3.13.3.1.2 Intermediate Data

a. Force vectors are printed prior to inversion of the stiffness matrix
b. Deflection vector is printed after stiffness matrix inversion
c. Member data are printed out after input is read
d. Contracted stiffness matrix is printed prior to inversion

e. Eigenvectors of dynamical matrix are printed after eigenvalue routine

f. Eigenvalues of dynamical matrix are printed after eigenvalue routine

g. Dynamical matrix is printed after formation from stiffness matrix

h. Flexibility matrix is printed after inversion of stiffness matrix

i. Reduced stiffness matrix and mass vector are printed after reduction of stiffness matrix to order of dynamical matrix

j. Contents of logic unit 14, flags, properties, stress coefficients, and moments for each member

k. Modal effective mass for dynamic model/solution evaluation.

3.13.3.1.3 Typical Benchmark Calculations

This section defines and references eight benchmark calculations typical of the verification that has been done with ADLPIPE. The solution to each problem from other sources is compared to the ADLPIPE solution.

Type of Analysis	Checks	Reference
Thermal and dead weight combined	Forces, moments, and deflections through the system	Pressure Vessel and Piping/1972 Computer Program Verification ASME, page 6-1
Dynamic	Natural frequencies of a three-dimensional structure. Mode shapes are checked (not published)	Pressure Vessel and Piping/1972 Computer Program Verification ASME, page 1-1
Stress and usage factor	Checks stress range calculation and fatigue usage factor	Sample Analysis of a Piping System – ASME Class 1, Nuclear
Thermal and dead weight (separate)	Checks for forces, moment, deflections, and stresses, per B31.1	“Stress in Three Dimensional Pipe Bends” by W. Hovgaard, Trans. ASME, Volume 57, 1935, pages 401-465
Thermal	Thermal stress per B31.1. Anchor reactions	Design of Piping Systems, M. W. Kellogg Company, page 47
Dynamic	Natural frequencies, model shapes, and response spectra deflections and moments	Shock and Vibration by Young, ASME

Type of Analysis	Checks	Reference
Stress	All stress coefficients (product of stress indices and geometry) used in Section III Class 1 piping Analysis Checks “either/or” logic specified in footnotes to stress indices	Hand calculations
Stress	Checks all stress components and their sum on selected piping	Hand calculations

3.13.3.1.4 Analytical Description Technique

See Reference 21 and 57 through 60.

3.13.3.2 PASS Teledyne Materials Research

3.13.3.2.1 Introduction

The PASS computer program is a postprocessor to the ADLPIPE computer program which provides an elastic analysis of redundant piping systems subjected to thermal, static, and dynamic loads. The program accepts, as input, the ADLPIPE Math Model describing the piping geometry, and the internal forces, moments, and deflections resulting from the flexibility analysis for various load conditions (dead weight, hydrotest, thermal, seismic inertia, and attachment displacements).

The PASS program also functions as a report generator for the hanger selection summary reports. The summary defines the support system and summarizes in a tabular report style format:

a. Nozzle and anchor loads

b. Hanger and restraint loads

c. A stress summary of selected data points in accordance with the rules of NC-3652 for sustained loads - Equation (8); occasional loads - Equation (9); thermal expansion -Equation (10); and Equation (11) for Class 1 and Class 2 components

d. A stress summary in accordance with the rules of NB-3652 for the primary stress-intensity limit - Equation (9), for Class 1 components only.

3.13.3.2.2 Purpose

The purpose of this program is to determine the adequacy of the piping support system for a given ADLPIPE Math Model by evaluating stresses for sustained loads, occasional loads, and thermal expansion in accordance with the design and analysis philosophy of subsections

NB-3652 and NC-3652 in Section III of the ASME B&PV Code. The program also provides load summaries for anchors and restraints, and reports the maximum loads for each load condition and the required net design load.

3.13.3.2.2.1 Method of Solution

The PASS program is designed to read the ADLPIPE Math Model and determine all network point restraints from the restraint cards. Those points restrained in the six degrees of freedom are considered anchors; other restraint points are defined by a restraint code in the respective X, Y, and Z direction on the network point identification cards of the ADLPIPE Math Model. The program then prints out the ADLPIPE Math Model and a restraint summary table of all network point restraints indicating the direction and type of restraint. The outside diameter and thickness for each member, and bend radii for all elbows, are then determined and a table of member geometries printed. Points to be analyzed are subsequently read by the program, which must include all restraint points in the same sequence as they appear in the ADLPIPE Math Model.

The internal forces, moments, and deflections for each load condition are then read by the program and stored for those data points defined on the network point restraint cards and for those points undergoing stress evaluation. As the data for each load condition are read, the program performs a check on the deflection data such that if a card is missing for a point, the forces will be read as deflections causing a diagnostic to be printed for that load condition. If the data check encounters deflections greater than 20 in., the program finishes reading the input data and then terminates the job. The analyst must then correct his data and resubmit the job.

Once the input data have been read in for all load conditions, the net design loads are determined for each anchor point in the following manner.

a. The deadweight loads and hydrotest loads are retrieved for the point of interest

b. The loads for all thermal conditions are scanned and the maximum positive (+) and maximum negative (-) loads for each direction determined

c. The resultants of the deadweight loads, plus maximum positive thermal and maximum negative thermal, are evaluated and the magnitudes compared to the hydrotest loads, if applicable. The greater of the dead-weight plus-thermal or the hydrotest is used in the computation of the net design load

d. The maximum static load, dead-weight-plus-thermal or hydrotest, is summed up with the maximum seismic load (SSE) plus end effects (SSE, inertial plus building movements). Note: See Revision E changes to above (Subsection 3.13.3.2.2.2).

The same procedure is followed for evaluating the net design load on restraints with the exception of springs and snubbers. Only deadweight and hydrotest loads are considered for a spring and only seismic loads for a snubber.

Thermal and seismic displacements are then determined for all restraint points. The thermal displacements are defined by a maximum and minimum range, while the seismic displacements are to be considered plus (+) and minus (-), since for a normal mode analysis the resultant internal forces and moments are computed from the square root of the sum of the squares of the modal forces and moments.

a. Option 1

$$(F_i)^2 = (F_i)_X^2 + (F_i)_Z^2 + |F_i|_Y$$

$$(M_i)^2 = (M_i)_X^2 + (M_i)_Z^2 + |M_i|_Y$$

$$(\delta_i)^2 = (\delta_i)_X^2 + (\delta_i)_Z^2 + |\delta_i|_Y$$

b. Option 2

$$(F_i)^2 = (F_i)_X^2 + (F_i)_Y^2 + (F_i)_Z^2$$

$$(M_i)^2 = (M_i)_X^2 + (M_i)_Y^2 + (M_i)_Z^2$$

$$(\delta_i)^2 = (\delta_i)_X^2 + (\delta_i)_Y^2 + (\delta_i)_Z^2$$

where

i	=	x, y, z
x, y, z	=	response directions
X, Y, Z	=	shock directions

The program then evaluates stresses for Class 2 specified data points in accordance with the rules of NC-3652.

a. Sustained loads (NC-3652.1)

$$\frac{PD_o}{4t} + 0.75i\left(\frac{M_A}{Z}\right) \leq 1.0\ S_h \qquad (8)$$

b. Occasional loads (NC-3652.2)

$$\frac{P_{max}D_o}{4t} + 0.75i\frac{(M_A + M_B)}{Z} \leq 1.2\ S_h \qquad (9)$$

c. Thermal expansion (NC-3652.3)

$$i\left(\frac{M_c}{Z}\right) \leq S_A \qquad (10)$$

$$\frac{PD_o}{4t} + 0.75i\left(\frac{M_A}{Z}\right) + i\frac{M_c}{Z} \leq (S_h + S_A) \qquad (11)$$

The primary stress-intensity limit Equation (9) of NB-3652 is evaluated for design conditions of all Class 1 data points specified in the node list for stress analysis.

$$B_1\left(\frac{PD_o}{2t}\right) + B_2\left(\frac{D_o}{2I}\right)M_i \leq 1.5\ S_m \qquad (9)$$

For a complete definition of the preceding equations, refer to subsections NB-3652 and NC-3652 of Section III in the ASME B&PV Code. The program currently evaluates Equations (9), (10), and (11) of NC-3652 with and without moments due to secondary end effects (building or equipment movements). The moments produced by such displacements from seismic inertia effects are included with earthquake moments in the evaluation of Equation (9) in NC-3652.1 and Equation (9) in NB-3652.

The stress intensification factor, i, of NC-3652 is determined by the program in accordance with Figure NC-3672.9(a)-1 for Class 2 components, and stress indices B_1 and B_2 of NB-3652 are determined in accordance with Table NB-3683.2-1 for Class 1 components. If the stress intensification factor, i, or stress indices B_1 and B_2 are provided with the stress input data, these factors will override standard values computed by the program. In addition to printing stress summary tables for all specified stress points, the program determines critical points as those points with the greatest stress to allowable ratio for Eqauations (8) and (9) of NC-3652 (Class 2) and Equation (9) of NB-3652 (Class 1).

3.13.3.2.2.2 Revision E - Design Loads

The PASS program has been updated by Revision E to reflect the following method of computing design loads for nozzle/anchor reactions and hanger/restraint reactions:

Maximum Design Load (+):

DL1 = + SEISMIC (DBE) + E.E. (DBE)

DL2 = + SEISMIC (DBE) + E.E. (DBE) + DYNAMIC (+) + DEAD WEIGHT

DL3 = + SEISMIC (DBE) + E.E. (DBE) + DYNAMIC (+) + THERMAL (+)
+ DEAD WEIGHT

DL4 = MAX.(+) OF (DEAD WEIGHT OR HYDRO) (+) DESIGN LOAD

= MAX. (+) OF DL1, DL2, DL3, DL4

Minimum Design Load (-):

DL1 = - SEISMIC (DBE) - E.E. (DBE)

DL2 = - SEISMIC (DBE) - E.E. (DBE) + DYNAMIC (-) + DEAD WEIGHT

DL3 = - SEISMIC (DBE) - E.E. (DBE) + DYNAMIC (-) + THERMAL (-)
+ DEAD WEIGHT

DL4 = MAX. (-) OF (DEAD WEIGHT OR HYDRO) (-) DESIGN LOAD

= MAX. (-) OF DL1, DL2, DL3, DL4

3.13.3.2.3 PASS Verification

This section contains the solution comparisons between PASS and independent hand calculations for a sample problem. The comparisons of (1) anchor and nozzle reactions, (2) hanger/restraint reactions and displacement tolerances, and (3) the Class 2 stress evaluation are presented in Tables 3.13-45 through 3.13-48. The results show very close, if not exact, agreement. The tabulated PASS values, except hanger/restraint reactions in Table 3.13-46, apply to both D and E Revisions of PASS. The hanger/restraint reactions shown in Table 3.13-46 were taken from the Revision E version of the program.

The Revision D version of PASS can overcompute hanger/restraint reactions where there are seismic end effects (seismic anchor movements) load cases. For the seismic end effects case, the Revision D version computes the hanger/restraint reactions by taking the absolute sum of resulting pipe loads on either side of these supports, which is conservative, whereas the Revision E version uses the more correct algebraic sum.

3.13.3.3 Dynamic Analysis of Piping Systems

See Reference 61.

3.13.3.4 SAMIS

See Reference 61.

3.13.3.5 MEL

See Reference 61.

3.13.3.6 SAP

See Reference 61.

3.13.3.7 Time-Dependent Pipe Forces

See Reference 61.

3.13.3.8 SAP IV - Structural Analysis Program

See Reference 61.

3.13.3.9 CVPT Report

Refer to Subsection 3.6.3.1.6.

3.13.3.10 TMRSAP

TMRSAP, a computer program owned by Teledyne Engineering Services (TES), is assigned to perform an elastic analysis of complex piping systems subjected to thermal, static, and dynamic loads.

The piping systems are modeled using either of two element types, namely, boundary element or pipe element (tangent and bend). These elements may be used in a static or dynamic analysis. The pipe element is represented by a straight segment (tangent) or a circularly curved segment (bend); both elements require a uniform section and uniform material properties. Elements can be directed arbitrarily in space. The member stiffness matrices account for bending, torsion, axial, and shear deformations. In addition, the effect of internal pressure on the stiffness of curved pipe elements is considered.

The loads contributed by the pipe elements include gravity in the global directions and loads due to thermal distortions and deformations induced by internal pressure. Forces and moments acting at the member ends and at the center of each bend are calculated in coordinate systems aligned with the member's cross section.

The input consists of the piping system geometry, material properties, and static and dynamic loadings.

Various benchmark problem solutions have been used to verify and qualify the TMRSAP program. The solutions of benchmark problems have been compared with closed-form solutions available in the literature or with solutions obtained using other similar codes.

3.13.3.11 TMRPASS

The TMRPASS computer program determines the adequacy of the piping support system for a given TMRSAP structural model by evaluating stresses for sustained loads, occasional loads, and thermal expansion in accordance with the design and analysis philosophy of Subarticles NB-3652 and NC-3652 in Section III of the ASME B&PV Code. The program also provides design load summaries for anchors and restraints, and reports the maximum loads for each load condition and the required net design load.

The program requires as input the TMRSAP structural model describing the piping geometry, as well as the internal forces, moments, and deflections resulting from the flexibility analyses for various load conditions (dead weight, hydrotest, thermal, seismic inertia, and attachment displacements).

The verification and qualification of TMRPASS were performed by comparing TMRPASS output with the results of hand calculations for a typical piping system.

3.13.3.12 ANSYS

ANSYS, engineering analysis system, is a general-purpose computer program with capabilities for transient heat-transfer analyses; static elastic, plastic, creep, dynamic, and dynamic plastic analyses; large deflection and stability analyses; and one- dimensional fluid-flow analyses. The output from the transient heat-transfer analyses is in the form required to do thermal stress analyses at selected time points in the transient with the same analyses models. The program was formulated and developed by Swanson Analysis Systems, Inc.

3.13.3.13 STAAD-III/STAAD.Pro

STAAD-III is a general-purpose structural analysis program marketed by United Information Systems of Kansas City. It performs a static structural analysis of framed structures using the stiffness method of solution. A natural frequency calculation of a structure can be performed by the program as a user option. Internal structure forces, moments, and stresses and nodal displacements and rotations can be output from the analysis portion of the program.

STAAD-III has a postprocessor that performs an evaluation in accordance with the AISC Specification for Structural Steel. It also performs an evaluation of welded connections.

STAAD.Pro is a comprehensive and integrated finite element analysis and design program capable of analyzing structures exposed to static loading, a dynamic response, wind, earthquake, and moving loads. Its analytical capabilities include linear static, response spectra, time history, cable, imperfection, pushover and non-linear analyses. The program is developed by Bentley Systems, Inc. and is an updated version of the STAAD-III program which they obtained when they acquired Research Engineers International.

3.13.3.14 DYNAFLEX

DYNAFLEX is a computer program used to analyze piping systems for static and dynamic loads and to compute the combined stresses. The following analyses are performed:

a. Static - analysis of distributed and concentrated weight, displacement, and thermal loadings on piping systems

b. Dynamic - analysis of piping system response to seismic loads using the uniform response spectrum method

c. Stress combination - computation of the combined stresses in piping components in accordance with the ASME Code Section III, Subarticle NC-3650, or with the ANSI B31.1 Code for Power Piping.

DYNAFLEX is a proprietary program owned, maintained, and supported by Intercomp, Inc., Houston, Texas, and marketed by United Information Systems of Kansas City.

Test problems verifying the accuracy of the results obtained from DYNAFLEX have been run, comparing results with other piping analysis programs such as ADLPIPE and PIPESD. In addition, program updates are verified using a standard series of problems and also specific problems designed to verify the specific updates made to the program.

3.13.3.15 BASEPLT

The program BASEPLT is a preprocessor to the STARDYNE computer code developed for the specific purpose of analyzing flexible baseplates. The BASEPLT preprocessor generates the input runstream, including control cards, for a STARDYNE/SPRING nonlinear solution of a baseplate analysis. The program is marketed and supported by Control Data Corporation, Minneapolis, Minnesota, and available in the public domain.

3.13.3.16 PISYS/ANSI7

These computer programs are used by GE for piping stress analyses and were written by and meet the Quality Assurance Standards of GE. The programs have been approved for production use by a special committee after independent review and verification. All changes to these programs require verification and approval by this committee. The computer program master files are stored in the GE Energy Division archive tapes.

PISYS performs static and dynamic analyses of piping systems. The analysis modules of PISYS were taken directly from the SAP4G program. The ANSI7 program calculates stresses (and cumulative usage factors) for Class 1, 2, and 3 piping components in accordance with Article NB-3600 and Subarticle NC-3652 of ASME Code Section III. This program also calculates combined loads on piping equipment in accordance with the equipment load combinations given in the Piping Design Specification and compares them with the allowable loads.

3.13.3.17 Holtec Computer Programs

All computer programs utilized by Holtec International to perform the analyses documented in this safety analysis report are benchmarked and verified in accordance with Holtec International's Quality Assurance procedures. The significant programs employed are listed and described below.

3.13.3.17.1 DYNARACK

DYNARACK performs dynamic simulations on systems and structures. It is used to simulate rack structure response to seismic excitation.

3.13.3.17.2 ONEPOOL

ONEPOOL is used to predict SFP bulk temperatures. All discharge scenarios and heat exchanger performances can be modeled.

3.13.3.17.3 FLUENT

FLUENT is a computational fluid dynamics code used to determine fluid motion in the SFP.

3.13.3.17.4 THERPOOL

THERPOOL is utilized to evaluate local pool water and fuel cladding temperatures.

3.13.3.17.5 NITAWL

Part of Oak Ridge National Laboratory's SCALE system of computer codes. It collects cross sections from the 238 group master library for specified materials and compiles them into the proper format for input to KENO-5a. It also calculates the shielded resonance cross sections for U-238.

3.13.3.17.6 KENO-5a

KENO-5a calculates the k-effective of spent fuel storage racks in three dimensions.

3.13.3.17.7 MCNP-4A and MCNP-05P†

MCNP is used to evaluate criticality and shielding problems with a high degree of accuracy.

†Original HOLTEC criticality analyses performed using MCNP-4A were subsequently updated using GNF version of MCNP-05.

3.13.3.17.8 CASMO-4

CASMO-4 is used for spatial and burnup calculations.

3.13.3.17.9 ANSYS

ANSYS is used in conjunction with the dynamics simulation code DYNARACK in spent fuel pool structure evaluations. ANSYS has also been used to evaluate seismic class I Reactor Building 1st and 5th floor stresses in response to seismic excitation with ISFSI loads, as well as for analysis of ISFSI component internal structure and support stresses. Also refer to section 3.13.3.12.

3.13.3.18 AutoPIPE

AutoPIPE is a computer aided engineering (CAE) program for calculation of piping stresses, flange analysis, pipe support design, and equipment nozzle loading analysis under static and dynamic loading conditions. In addition to piping codes, AutoPIPE incorporates ASME, British Standard, API, NEMA, ANSI, ASCE, AISC, UBC, and WRC guidelines and design limits to provide comprehensive analysis of the entire system.

AutoPIPE provides unique capabilities for process, power, oil and gas, nuclear, underground, offshore floating, production, storage, and offloading (FPSO) platform and subsea pipeline areas with international piping codes. Advanced AutoPIPE capabilities include built-in wave loading, buried pipeline analysis, jacketed piping, dynamic loadings, orthotropic fiberglass reinforced plastic (FRP/GRP), and high-density polyethylene (HDPE) plastic piping analysis. It also includes thermal stratification or bowing, thermal transient, pipe/structure interaction, fluid transient with closure time and relief valve utilities, advanced load sequencing, non-linear support gaps and friction and jacketed piping. Local stress calculation to WRC 107, WRC 297, PD 5500, KHK, API 650 is available using AutoPIPE Nozzle.

AutoPIPE quality assurance program has been subjected to numerous nuclear and Nuclear Procurement Issues Committee (NUPIC) audits to 10 CFR 50 App. B, ISO9001, CSA N286.7-99, ASME NQA-1, and ANSI N45.2 standards. AutoPIPE Nuclear provides design of critical safety pipework to ASME Class 1, 2, or 3.

3.13.3.19 GT STRUDL

GT STRUDL is a large-scale general purpose structural analysis computer program. The matrix displacement method of analysis based upon finite element idealization is used throughout the program. GT STRUDL has the ability to perform static and dynamic analysis for framed structures and three-dimensional solid structures.

GT STRUDL is used in the analysis and design of nuclear and nonnuclear linear type pipe supports and seismic Category I duct supports.

3.13.4 Computer Programs Used by Stone & Webster, Michigan, Incorporated

Subsections 3.13.4.1 through 3.13.4.4 describe four computer programs used by S&W. They were applied to piping and support design only.

3.13.4.1 NUPIPE - Elastic Piping Analysis with NB, NC 3600 Solutions

NUPIPE is a program for thermal, deadweight, and seismic analysis done in accordance with Subarticle NB3600, NC3600, or ND3600 of Reference 62. It considers stress intensities as specified in Equations 9 through 14 given in the above-mentioned Subarticle NB3600, and also determines the usage factors for points undergoing analysis of normal, upset, emergency, and faulted conditions. This program accepts the complete geometric and physical description of the piping system, provides a complete error and coordinate check for the inputs, and computes internal forces and moments, support and equipment reactions, and displacements and stress values for a variety of loading cases including weight, thermal expansion, applied forces, applied displacements, and earthquakes.

The NUPIPE program has been verified with ADLPIPE (Reference 63) for thermal, weight, and response spectrum seismic analysis. The results from both the programs are presented in Tables 3.13-49 through 3.13-55. The model used for this comparison is presented in Figure 3.13-91.

The comparison is made also with ASME Benchmark Solution (see Reference 64, Problem 5) for force time-history dynamic response. The model used for this comparison is shown in Figure 3.13-92. The results for comparisons are presented in form of plots in Figure 3.13-92. The natural frequencies are given in Table 3.13-56.

The Class 1 piping stress conforms with the hand calculations. The model used is shown in Figure 3.13-93. The results are tabulated in Tables 3.13-57 and 3.13-58.

3.13.4.2 HTLOAD - Heat Loads

3.13.4.2.1 General Description

HTLOAD is a computer program that performs a finite difference method analysis of piping system response to thermal transients of its contained fluid. The output gives overall thermal growth, linear and nonlinear temperature distribution through the pipe wall, gross discontinuity information (T_A-T_B), and Equations 10 and 11 results of Article NB3600 of ASME Section III.

HTLOAD can analyze piping, with or without a thermal sleeve, that is subject to changes in fluid temperature, velocity, and/or state. The properties of subcooled or saturated water and superheated or saturated steam are taken from the ASME steam tables (Reference 65). The pressure range is from 0.45 psia to 6210 psia.

This computer program also performs thermal analysis for pipes with different insulating conditions, ranging from noninsulated to perfectly insulated. It has stored properties for insulation such as unibestos, asbestos, reflective aluminum, reflective stainless, and calcium silicate. Provision is further made for hand input properties of other insulation types.

Also stored in the program are the piping material properties of carbon steel, austenitic stainless, low-chrome steel, high-chrome steel, and nickel-chrome iron for the temperature range of 32°F to 1600°F.

Program input includes piping material insulation information, time lapse for initial to final fluid temperature, calculation time limit, fluid velocities, initial and final temperature and pressure, and pipe and thermal sleeve dimensions.

HTLOAD requires that each thermal transient be input as a step change, a ramp change, or as a twelve-point arbitrary function.

Output results are used in the calculation of piping stress in accordance with Article NB3600 of ASME Section III. HTLOAD also performs the primary, plus secondary, stress intensity range check (Equation 10) and the peak stress intensity range calculation (Equation 11) from Article NB3600.

3.13.4.2.2 Program Verification

The sample problem selected for solution by HTLOAD consists of a 2-in. Schedule 160, stainless steel pipe with one end connected to a 1/2-in.-thick socket-welded fitting. Saturated water flowing within the piping system changes temperature from 400°F to 500°F in a period of 10 sec. Velocity of fluid is 7560 ft/hr. Input properties are listed in Tables 3.13-59 and 3.13-60.

Reynolds number and heat-transfer coefficients are compared with hand calculations (Reference 66) and are given in Table 3.13-61.

Comparison between HTLOAD and Brock and McNeill's charts (Reference 67) for ΔT_1 and ΔT_2 is given in Table 3.13-62. Table 3.13-63 represents the comparison between TRHEAT (Reference 68) and HTLOAD for ΔT_1, ΔT_2, and T_A-T_B.

3.13.4.3 PITRUST

PITRUST is a program to calculate local stresses in the pipe caused by cylindrical welded attachments under external loadings. This program uses the Bijlaard method, as published in Reference 69, to calculate local stresses in the pipe wall caused by cylindrical welded attachments under external loadings, including pressure, dead load, and combinations of maximum seismic reactions.

Program PITRUST has been verified by comparing its solution of a test problem to the solution of the same problem by an independently written piping local stress program, CYLNOZ, in the public domain. The CYLNOZ piping local stress program was written by Franklin Institute (Philadelphia, Pennsylvania) and is used presently by engineering companies. The test problem is of a 72.375-in. O.D. x 0.375-in.-thick run pipe, reacting under an external loading condition of 1000 lb force (normal and shear) and 1000 in.-lb bending and torsional moments transmitted by a 16-in.-O.D. nozzle. A comparison of results is tabulated in Table 3.13-64. Program PITRUST has been verified also by comparing its solution of the test problem to the experimental results obtained in Reference 70. A comparison of these results is tabulated in Table 3.13-65.

3.13.4.4 PILUG

PILUG is a program to calculate local stresses in the pipe wall caused by rectangular welded attachments under external loadings. This program uses the Bijlaard method, as described in

Reference 69, to calculate local stresses in pipe walls caused by rectangular welded attachments under external loadings, including pressure, dead load, and combinations of maximum seismic reactions.

Program PILUG has been verified by comparing its solution of a test problem to results obtained by hand calculations using the formulations specified in Reference 69. A comparison of results is tabulated in Table 3.13-66.

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TABLE 3.13-1 COMPARISON OF DSASS V, DYNAS, MASS IV, AND MASS V RESULTS WITH BIGGS

Mode Number	Biggs	DSASS V, DYNAS MASS IV, MASS V
Structural Frequency (Hz)		
1	1.00	1.00
2	2.18	2.18
3	3.18	3.18
Probable Maximum Story Displacement (in.)		
1	1.50	1.51
2	3.22	3.20
3	4.86	4.68
Absolute Maximum Story Shear (kip)		
1	3020	3010
2	2080	2068
3	1345	1353
Probable Maximum Story Shear (kip)		
1	2250	2262
2	1740	1757
3	895	902

TABLE 3.13-2 NATURAL PERIODS FOR THE EIGHT LOWEST FLEXURAL MODES

	Periods in Seconds	
Mode Number	SAP IV	DYNAS, MASS IV, MASS V
1	525.79	525.69
2	85.368	85.369
3	30.965	30.964
4	16.059	16.060
5	9.9006	9.9010
6	6.8276	6.8279
7	5.1865	5.1866
8	4.3777	4.3778

TABLE 3.13-3 INDIA SAMPLE PROGRAM

INTERACTION DIAGRAM AXIAL LOAD VS. BENDING MOMENT REFERRED TO THE PLASTIC CENTROID OF THE SECTION.

LIST OF SYMBOLS

B	= WIDTH OF SECTION, IN.
T	= HEIGHT OF SECTION, IN.
D	= DEPTH OF TENSILE STEEL, IN.
AS	= AREA OF TENSILE STEEL, SQ IN.
DC	= DEPTH OF COMPRESSION STEEL, IN.
ASC	= AREA OF COMPRESSION STEEL, SQ IN.
ES	= MODULUS OF ELASTICITY OF REINFORCING STEEL, KSI
SSY	= YIELD STRESS OF REINFORCING STEEL, KSI
SSU	= ULTIMATE STRESS OF REINFORCING STEEL, KSI
PRESTR	= INITIAL PRESTRAIN OF REINFORCING STEEL
ULTSTR	= ULTIMATE STRAIN OF REINFORCING STEEL
CUS	= 28 DAY STRENGTH OF CONCRETE CYLINDER, KSI
EPSZ	= CONCRETE STRAIN FOR MAXIMUM STRESS
EPSU	= CONCRETE STRAIN AT CRUSHING
NSTESS	= NUMBER OF POINTS IN INTERACTION DIAGRAM
EPEL	= MAXIMUM TOP STRAIN FOR WHICH ID IS COMPUTED

INPUT DATA

B = 12.0000	T = 43.0000	D = 45.0000	AS = 2.7500	DC = 10.0000	ASC = 1.2500
SS = 23000.0000	SSY = 80,0000	SSU = 30,000	ULTSTR = 0.020000	PRESTR = 0.000000	
CUS = 4.5000	EPSZ = 0.002000	EPSU = 0.004000			
NSTESS = 20	EPSL = 0.003000				

RESULTS GIVEN IN THE FOLLOWING ORDER

COUNTER	CURVATURE	TOP STRAIN	AXIAL LOAD (KIP)	BENDING MOMENT (KIP-FT)	AXIAL LOAD DIMENSIONLESS	BENDING MOMENT DIMENSIONLESS	C.R. FACTOR PHI	REDUCED AXIAL LOAD (KIP)	REDUCED BENDING MOMENT (KIP-FT)
INITIAL POINT UNDER UNIFORM COMPRESSION STRAIN + EPSZ									
1	0.00000000	0.00200000	2419.3999	6.0875	1.0984	0.0007	0.8981	2173.3915	5.4674
2	0.00001762	0.00225000	2349.4036	96.0163	1.0654	0.0109	0.8982	2110.2042	86.2406
3	0.00003125	0.00250000	2216.4314	258.0801	1.0080	0.0293	0.8983	1990.9977	231.8123
4	0.00004667	0.00275000	2023.3391	485.1479	0.9184	0.0562	0.8984	1817.8463	444.8601
5	0.00003268	0.00000000	1770.1285	807.2801	0.8034	0.0916	0.8985	1590.8962	725.4495
PRECEDING POINT HAD BOTTOM FIBER STRAIN = ZERO									
6	0.00007316	0.00300000	1377.5877	1191.7730	0.6253	0.1352	0.8389	1238.3646	1071.3288
7	0.00000966	0.00300000	1163.2063	1325.1268	0.5280	0.1504	0.8991	1045.2417	1191.4245
8	0.00010115	0.00300000	385.3843	1400.5915	0.4472	0.1589	0.8992	386.6782	1259.4674
9	0.00011264	0.00300000	833.6598	1447.7928	0.3764	0.1043	0.8904	743.7575	1362.0929
BALANCED POINT, TENSILE STEEL STRAIN = -EPSY									
10	0.00016243	0.00300000	518.9094	1288.7116	0.2355	0.1462	0.3996	466.8167	1159.3245
11	0.00021226	0.00300000	339.3652	1137.9047	0.1540	0.1291	0.8997	305.3398	1023.8163
12	0.00020267	0.00300000	218.2740	1021.0822	0.0991	0.1159	0.8998	195.4099	919.7340

TABLE 3.13-3 INDIA SAMPLE PROGRAM

13	0.00031188	0.00300000	127.3296	930.6383	0.0573	0.1056	0.9999	114.5042	637.4870
14	0.00038159	0.00300000	52.4308	857.1847	0.0230	0.0973	0.9000	47.1876	771.4405
15	0.00041143	0.00300000	-11.2036	797.4842	-0.0051	0.0905	0.9000	-10.0834	717.7247
16	0.00043130	0.00300000	-67.2224	747.8149	-0.0305	0.0849	0.9001	-80.0000	673.0722
PRECEDING POINT HAD TENSILE STEEL STRAIN = -ULSTR									
17	0.00044047	0.00200001	-174.2335	571.9126	-0.0791	0.0649	0.9001	-156.8736	514.7982
18	0.00041954	0.00100000	-269.5452	392.8982	-0.1223	0.0446	0.9002	-242.6467	353.6981
19	0.00038380	0.00000000	-317.0636	209.7994	-0.1439	1.6329	0.9002	-285.4348	269.8928
20	0.00000000	-0.02000000	-360.0000	273.9367	-0.1634	0.0311	0.9003	-380.0080	273.9357

DISTANCE OF PLASTIC CENTROID TO BOTTOM FIBER, IN. = 24.9313

AS AND ASC CHANGED VALUES, READ MOMENT WITH OPPOSITE SIGN ************************************

INPUT DATA

B = 12.0000	T = 48.0000	D = 45.0000	AS = 1.2500	DC = 10.0000	ASC = 2.7500
ES = 29000.0000	SSY = 60.0000	SSU = 90.0000	ULTSTR = 0.020000	PRESTR = 0.000000	
CUS = 4.5000	EPSZ = 0.002000	EPSU = 0.004000			
NSTESS = 20	EPSL = 0.003000				

RESULTS GIVEN IN THE FOLLOWING ORDER

COUNTER	CURVATURE	TOP STRAIN	AXIAL LOAD (KIP)	BENDING MOMENT (KIP-FT)	AXIAL LOAD DIMENSIONLESS	BENDING MOMENT DIMENSIONLESS	C.R. FACTOR PHI	REDUCED AXIAL LOAD (KIP)	REDUCED BENDING MOMENT (KIP-FT)
INITIAL POINT UNDER UNIFORM COMPRESSION STRAIN + EPSZ									
1	0.00000000	0.00200000	2419.8999	-1.8527	1.0984	-0.0002	0.8981	2173.3915	-1.6640
2	0.00001562	0.00225000	2371.9226	64.3211	1.0766	0.0073	0.8982	2130.3883	57.7713
3	0.00003125	0.00225000	2258.0534	206.7475	1.0249	0.0235	0.8983	2038.3176	185.7126
4	0.00004537	0.00275000	2083.4750	431.3483	0.9457	0.0489	0.8984	1871.7781	387.5200
5	0.00008250	0.00300000	1843.1875	738.1239	0.8389	0.0838	0.8986	1660.7331	663.2580
PRECEDING POINT HAD BOTTOM FIBER STRAIN = ZERO									
6	0.00007816	0.00300000	1484.8191	1109.2716	0.6739	0.1259	0.8989	1334.6381	997.0735
7	0.00008866	0.00300000	1292.5999	1224.0333	0.5867	0.1389	0.8990	1162.0587	1100.4092
8	0.00010115	0.00300000	1133.6276	1273.4436	0.5145	0.1445	0.8991	1819.2732	1144.9354
9	0.00011264	0.00300000	999.4452	1290.4057	0.4536	0.1464	0.8992	898.7299	1150.3700
BALANCED POINT, TENSILE STEEL STRAIN = -EPSY									
10	0.00016245	0.00300000	669.1896	1129.0560	0.3037	0.1281	0.8995	601.9251	1015.5674
11	0.00021226	0.00300000	474.8520	963.1077	0.2155	0.1093	0.8996	427.1928	866.4440
12	0.00026207	0.00300000	339.6791	826.0203	0.1542	0.0937	0.8997	305.6222	743.2018
13	0.00031189	0.00300000	234.6630	712.3114	0.1065	0.0808	0.8998	211.1542	640.9513
14	0.00038169	0.00300000	143.7225	611.7068	0.0652	0.0694	0.8999	129.3743	550.4683
15	0.00041149	0.00300000	64.0464	523.6752	0.0291	0.0594	0.9000	57.8385	471.2818
16	0.00046130	0.00300000	-8.0140	444.9537	-0.0036	0.0505	0.9000	-7.2127	400.4611
PRECEDING POINT HAD TENSILE STEEL STRAIN = -ULTSTR									

TABLE 3.13-3 INDIA SAMPLE PROGRAM

17	0.00044047	0.00200001	-135.5442	255.9720	-0.0615	0.0290	0.9001	-122.0039	230.4015
18	0.00041964	0.00100000	-232.6858	84.0563	-0.1056	0.0095	0.9002	-209.4590	75.6658
19	0.00038880	0.00000000	-282.0341	-6.7816	-0.1280	-0.0369	0.9002	-253.8921	-6.1048
20	0.000000	-0.02000000	-360.0000	-83.3721	-0.1634	-0.0035	0.9003	-360.0000	-93.3721

DISTANCE OF PLASTIC CENTROID TO BOTTOM FIBER, IN. = 23.7166

SARGENT & LUNDY
ENGINEERS
CHICAGO

INTERACTION DIAGRAM - P VS. M ABOUT C.G. OF UNCRACKED TRANSFORMED SECTION

YIELD-STRENGTH THEORY

WIDTH OF SECTION (IN.)	=	12.000	AREA OF TENSILE STEEL (IN.)	=	2.750
HEIGHT OF SECTION (IN.)	=	48.000	DEPTH OF TENSILE STEEL (IN.)	=	45.000
ELASTIC MODULUS, STEEL (KSI)	=	29000.	AREA OF COMPRESSIVE STEEL (IN.)	=	1.250
ELASTIC MODULUS, CONCRETE (KSI)	=	3865.	DEPTH OF COMPRESSIVE STEEL (IN.)	=	10.000

28-DAY STRENGTH OF CONCRETE CYLINDER (KSI)	=	4.500
YIELD STRESS FOR REINFORCING STEEL (KSI)	=	54.000
DEPTH OF C.G. OF UNCRACKED TRANSFORMED SECTION (IN.)	=	24.435
MODULAR RATIO	=	8.000
MAXIMUM STRESS OF CONCRETE (KSI)	=	3.925
MAXIMUM STRESS OF REINFORCING STEEL (KSI)	=	48.600
UNIT WEIGHT OF CONCRETE (LB/CU FT)	=	145.000

PHI1 IS THE CAPACITY REDUCTION FACTOR

POSITION NO.	AXIAL LOAD (KIP)	BENDING MOMENT (KIP-FT)	PHI1	REDUCED AXIAL LOAD (KIP)	REDUCED BENDING MOMENT (KIP-FT)
1	2302.69	0.00	0.8992	2068.33	0.00
2	1130.49	796.74	0.8891	1016.45	716.37
3	1056.93	841.20	0.8992	950.38	756.39
4	262.26	846.88	0.8398	235.88	752.02
5	-147.15	212.81	0.0001	-132.45	191.55
6	-194.40	155.97	0.9001	-174.99	140.40
7	-71.30	-54.99	0.9001	-04.18	-49.50
8	-51.38	-90.70	0.9000	-48.24	-81.83
9	316.89	-674.33	0.8998	285.12	-805.73
10	940.50	-908.37	0.8983	845.77	-817.77
11	1172.20	-796.81	0.8091	1053.92	-716.23
12	2302.69	0.00	0.8982	2068.33	0.00

TABLE 3.13-3 INDIA SAMPLE PROGRAM

SARGENT & LUNDY
ENGINEERS
CHICAGO

INTERACTION DIAGRAM - P VS. M ABOUT C.G. OF UNCRACKED TRANSFORMED SECTION

WORKING STRESS DESIGN METHOD

WIDTH OF SECTION (IN.)	=	12.000	AREA OF TENSILE STEEL (IN.)	=	2.750
HEIGHT OF SECTION (IN.)	=	48.000	DEPTH OF TENSILE STEEL (IN.)	=	45.000
ELASTIC MODULUS, STEEL (KSI)	=	29000.	AREA OF COMPRESSIVE STEEL (IN.)	=	1.250
ELASTIC MODULUS, CONCRETE (KSI)	=	3865.	DEPTH OF COMPRESSIVE STEEL (IN.)	=	10.000

ALLOWABLE STRESS OF CONCRETE IN BENDING (KSI)	=	2.700
ALLOWABLE STRESS IN REINFORCING STEEL (KSI)	=	20.000

POSITION NO.	AXIAL LOAD (KIP)	BENDING MOMENT (KIP-FT)
1	1717.20	0.00
2	824.64	618.32
3	768.37	653.56
4	340.10	659.09
5	-60.58	34.98
6	-80.00	60.75
7	-29.34	-23.89
8	-21.14	-38.23
9	389.06	-827.77
10	718.18	-704.17
11	892.56	-618.00
12	1717.20	0.00

TABLE 3.13-4 COMPARISON OF STIFFNESS

Element	Stiffness Program (SSANA) (kip-ft)	Hand Calculations (kip-ft)
1	398821	398880
2	398821	398880
3	398821	398880
4	398821	398880

TABLE 3.13-5 COMPARISON OF WEIGHT MOMENT OF INERTIA ABOUT X-AXIS (Ip)

Element	Weight Inertia Program (SSANA)	Hand Calculations (Ip)
1	2005	2005
2	531	531.25
3	531	531.25
4	32	31.5

TABLE 3.13-6 TEMCO SAMPLE PROBLEM

Section and Material Properties	Problem Number 1	2	3
Thickness, in.	42.0	30.0	42.0
Width, in.	12.0	12.0	12.0
Area of 1st steel layer, in.^{2}	6.25	2.25	3.12
Distance of 1st steel layer, in.	3.0	3.0	3.0
Area of 2nd steel layer, in.^{2}	6.25	4.0	3.12
Distance of 2nd steel layer, in.	37.0	25.0	37.0
Concrete unit weight, lb/ft^3	150.0	150.0	150.0
Concrete compressive strength, lb/in.^{2}	4000.0	4000.0	4000.0
Concrete coef. of thermal expansion, in./°F	5.56×10^{-6}	5.56×10^{-6}	5.56×10^{-6}
Steel yield strength, kip/in.^{2}	45.0	45.0	45.0
Steel modulus of elasticity, kip/in.^{2}	29000.0	29000.0	29000.0
Material properties	Nonlinear	Nonlinear	Linear
Applied axial force, kip	-38.25	76.53	34.65
Applied bending moment, kip-ft	129.75	-9.49	206.25
Inside temperature, °F	82.50	67.50	247.50
Outside temperature, °F	52.50	0.0	115.50

TABLE 3.13-7 TEMCO SAMPLE PROBLEM - RESULTS

Results	Problem Number		
	1	2	3
Equilibrating axial force given by program, kip	-38.25	76.53	34.65
Equilibrating axial force computed by hand, kip	-38.253	76.53	34.65
Equilibrating bending moment given by program, kip-ft	129.75	-9.49	206.25
Equilibrating bending moment computed by hand, kip-ft	129.752	-9.493	206.25
Thermal moment given by program, kip-ft	-54.58	-21.07	-137.75
Thermal moment computed by hand, kip-ft	-54.585	-21.071	-137.757

TABLE 3.13-8 CABLE PAN ANALYSIS

		Section Modulus	
	Area (in.^{2})	S_x Vert. (in.^{3})	S_y Horiz. (in.^{3})
CAPAN	1.62	1.18	5.96
Hand calculation	1.62	1.12	5.96

TABLE 3.13-9 COMPUTED STRESSES IN MEMBERS

Member	Results (ksi) RIGHAN	Results (ksi) Hand Calculation
Vertical	30.053	30.016
Horizontal	29.237	29.210

TABLE 3.13-10 ROLLED BEAM DESIGN PROBLEM

	Maximum Moments(kip-ft)	Section Selected	Section Modulus(in.^{3})
AISC	125	W16x40	64.6
STAND	125.58	W18x40	68.4

TABLE 3.13-11 COMPOSITE BEAM DESIGN PROBLEM

	Bending Moments (kip - ft)		Maximum	Steel	No. of Shear
	Construction Load	Design Load	Shear (kip)	Section	Connectors
AISC	71.3	237.2	26.4	W21x44	42
STAND	71.3	236.5	26.3	W21x44	42

TABLE 3.13-12 COLUMN DESIGN PROBLEM

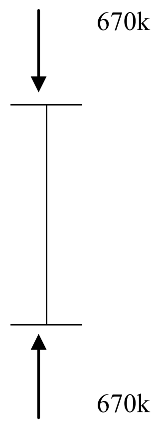
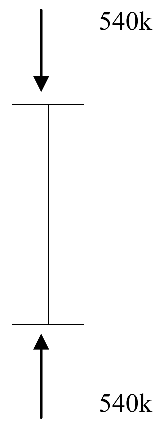
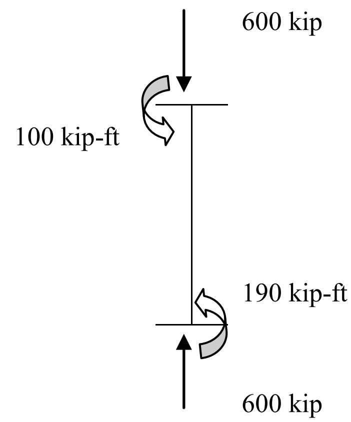
Items	AISC Example 1	AISC Example 2	AISC Example 5
Column design parameters			
AISC solution	W12x161	W12x99	W14x142
STAND solution	W12x161	W12x99	W14x142

TABLE 3.13-13 PLATE GIRDER DESIGN PROBLEM

Results	AISC	STAND
Maximum bending moment (kip-ft)	2054	2045
Maximum vertical shear (kip)	142	141.3
Web Section	1 plate, 70x5/16	1 plate, 70x5/16
Flange section	2 plates, 18x3/4	2 plates, 18x3/4
Stiffener end spacing (ft)	3.5	3.56
Stiffener intermediate spacing (ft)	6.75	6.72
Area of stiffeners furnished (in.^{2})	2.0	1.88

[a] Required area is 1.78 in.^{2}

TABLE 3.13-14 COMPARISON OF MEMBER AND MOMENTS

Stress Lag	Moments from Reference 19 (kip-ft)	Moments from PIPSYS (kip-ft)
M_{AB}	106.0	102.8
M_{BA}	72.0	72.5
M_{BC}	133.0	131.8
M_{CB}	133.0	131.8
M_{CD}	-133.0	-131.8
M_{DC}	-133.0	-131.8
M_{DE}	133.0	131.8
M_{ED}	86.0	84.2
M_{BE}	-158.0	-156.6
M_{EB}	-158.0	-156.6
M_{FE}	106.0	102.8
M_{EF}	72.0	72.5

TABLE 3.13-15 SUMMARY OF LOAD SETS AT GIRTH BUTT WELD WITH CHANGE IN MATERIAL AND WALL THICKNESS, LOCATION 19

Load Set No.	Load Set Description	No. of Transients	F	M_x	M_y	M_z	ΔT_1	T_f (Valve)	T_b (Pipe)	ΔT_2
1	Zero	5	0	0	0	0	0	70	70	0
2	Cold Hydro Test		3590	0	0	0	0	70	70	0
3	Hot Hydro Test, Up	40	2200	251.7	141.6	-7.1	2.4	400	400	0.3
4	Hot Hydro Test, Down		0	0	0	0	-2.4	70	94	-0.3
5	Plant Startup	100	2200	337.2	184.9	-936.0	0	70	70	0
6	Plant Shutdown		0	0	0	0	0	70	70	0
7	Plant Loading	18,300	2200	381.6	204.4	-1169.6	0	70	70	0
8	Plant Unloading		2200	337.2	184.9	-936.0	0	70	70	0
9	Loss of Load, 4.1	80	2515	384.2	204.4	-1183.4	0	70	70	0
10	Loss of Load, 4.2		1500	345.7	186.4	-1011.4	0	70	70	0
11	M.O. + Earthquake	50	2200	408.6	463.3	-1134.1	0	70	70	0
12	M.O. - Earthquake		2200	265.8	-93.5	-737.9	0	70	70	0

TABLE 3.13-16 SIX HIGHEST VALUES OF S_n, GIRTH BUTT WELD WITH CHANGE IN MATERIAL AND WALL THICKNESS, LOCATION 19

Load Set Pair		Values from Reference 20				PIPSYS program			
		S_n	Eq. (12)	Eq. (13)	K_a	S_n	Eq. (12)	Eq. (13)	K_a
3	4	52549	(*)[a]	(*)	1.000	52600	(*)	(*)	1.000
3	9	49883	(*)	(*)	1.000	49900	(*)	(*)	1.000
3	10	49620	(*)	(*)	1.000	49600	(*)	(*)	1.000
3	6	48013	(*)	(*)	1.000	48000	(*)	(*)	1.000
1	3	48013	(*)	(*)	1.000	48000	(*)	(*)	1.000
3	11	47728	(*)	(*)	1.000	47700	(*)	(*)	1.000

[a] Because S_n, calculated by Equation (10), is less than $3S_m$, Equations (12) and (13) are satisfied.

TABLE 3.13-17 SUMMARY OF CALCULATIONS OF CUMULATIVE USAGE FACTOR, GIRTH BUTT WELD WITH CHANGE IN MATERIAL AND WALL THICKNESS, LOCATION 19

Load Set Pair		Values Based On Reference 20		Values from PIPSYS Program	
i	j	$\frac{S_p K_e}{2}$	Usage Factor	$\frac{S_p K_e}{2}$	Usage Factor
3	9	40338	0.0050	40300	0.005
4	9	34400	0.0029	34400	0.003
1	11	29806	0.0002	29800	0.000
6	11	29806	0.0020	29800	0.002
6	7	29163	0.0023	29200	0.002
2	10	26254	0.0002	26300	0.000
10	12	93170	0.0000	93200	0.000
Cumulative Usage Factor			0.0126		0.0124

TABLE 3.13-18 MODAL FREQUENCIES (Hz)

Mode No.	PIPSYS	NASTRAN	DYNAL
1	6.07	6.085764	6.0821088
2	10.69	10.94144	10.936468
3	11.48	11.66862	11.666215
4	14.76	15.20947	15.204282
5	20.12	22.25613	22.135260
6	23.87	28.53255	28.505264
7	25.32	30.58105	30.530972
8	28.80	31.22073	31.190062
9	30.00	32.27319	32.199679
10	42.39	43.14653	43.135100
11	42.95	43.50436	43.497053
12	58.02	58.19336	57.991710
13	77.78	76.62025	71.996751
14	90.74	93.69710	92.12974
15	91.8	96.04482	95.167976
16	93.39	97.81956	97.410131
17	96.96	99.40727	98.209594
18	101.42	104.6169	101.64513
19	102.14	105.4910	103.80206
20	103.03	107.7136	107.52304

TABLE 3.13-19 ALLOWABLE SHEAR, MOMENT, AND SPAN OF CABLE TRAY - COMPARISON OF RESULTS FROM SEISHANG AND HAND CALCULATION

	SEISHANG	Hand Calculation
Vertical shear, static, kip	16.05	16.05
Positive bending moment, static, kip-in.	50.64	50.83
Negative bending moment, static kip-in.	57.62	57.64
Vertical shear, seismic, kip	20.84	20.81
Horizontal shear, seismic, kip	12.84	12.83
Positive bending moment, seismic kip-in.	67.51	67.61
Negative bending moment, seismic kip-in.	76.83	76.82
Horizontal bending moment, seismic kip-in.	153.61	153.59
Span, ft	20.78	20.75

TABLE 3.13-20 CEILING-MOUNTED SUPPORT - COMPARISON OF RESPONSES FROM SEISHANG AND DYNAS

		SEISHANG	DYNAS
Horizontal period, sec		0.1742	0.1765
Vertical period, sec		0.0092	0.0093
Forces and moments due to horizontal seismic			
Vertical element (No. 1)	axial, lb	1600	1607
	shear, lb	770	772
	bending, lb-in.	17100	17208
Horizontal element (No. 9)	axial, lb	25	26
	shear, lb	302	304
	bending, lb-in.	10900	10944
Forces and moments due to vertical seismic			
Vertical element (No. 1)	axial, lb	383	340
	shear, lb	0	2
	bending, lb-in.	30	24
Forces and moments due to dead load			
Vertical element (No. 1)	axial, lb	776	774
	shear, lb	0	0
	bending, lb-in.	30	0

TABLE 3.13-21 WALL-MOUNTED SUPPORT - COMPARISON OF RESPONSES FROM SEISHANG AND DYNAS

		SEISHANG	DYNAS
Horizontal period, sec		0.0067	0.0067
Vertical period, sec		0.1065	0.1080
Forces and moments due to horizontal seismic			
Vertical element (No. 6)	axial, lb	0	1
	shear, lb	2	2
	bending, lb-in.	35	48
Horizontal element (No. 11)	axial, lb	101	105
	shear, lb	2	2
	bending, lb-in.	23	24
Forces and moments due to vertical seismic			
Vertical element (No. 6)	axial, lb	39	0
	shear, lb	131	128
	bending, lb-in.	2700	2676
Forces and moments due to dead load			
Vertical element (No. 1)	axial, lb	717	702
	shear, lb	303	329
	bending, lb-in.	4910	5208

TABLE 3.13-22 INTERACTION COEFFICIENTS OF THE CEILING - MOUNTED SUPPORT - COMPARISON OF RESULTS FROM SEISHANG AND PIPSYS

INTERACTION COEFFICIENT	SEISHANG	PIPSYS
Vertical element (No. 2)	0.617	0.620
(No. 5)	0.520	0.516
Horizontal element (No. 6)	0.683	0.678
Brace element (No. 3)	0.569	0.553

TABLE 3.13-23 COMPARISON OF SEISHANG AND PIPSYS

ANALYSIS RESULTS FOR HANGER SHOWN IN FIGURE 3.13-66

				SEISHANG	PIPSYS
Highest period, sec				0.2349	0.2349
Lowest period calculated, sec				0.0281	0.0281
Forces/moments/disp.					
Load	Element/Node	End	Force/Moment/Disp.		
Dead load	1	i	Axial, lb	-1047	-1047
(a vertical element)		i	Shear, b, lb	1	1
		i	Bending, c ft-lb	0	0
	9	j	Axial, lb	361	361
(a horizontal element)		j	Shear, c, lb	0	0
		j	Bending, c, ft-lb	5	5
	Node 36		y-disp	-0.013	-0.013
Seismic	1	i	Axial, lb	933	933
(a vertical)		i	Shear, b, lb	460	460
		i	Bending, c ft-lb	2596	2596
	9	j	Axial, lb	517	517
(a horizontal)		j	Shear, c, lb	463	463
		j	Bending, b, ft-lb	515	515
	Node 36		z-disp	0.123	0.123

TABLE 3.13-24 INTERACTION COEFFICIENT CALCULATED FOR HANGER SHOWN IN FIGURE 3.13-66: COMPARISON OF SEISHANG RESULTS AND HAND CALCULATIONS

Loading	Type Interaction Equation	Member	Interaction SEISHANG	Interaction Hand Calculation
Dead weight and dynamic	Tension and bending	1- end i	0.549	0.549
	Compression and bending	1- end i	0.514	0.514
	Compression and bending	9- end j	0.244	0.243
Dead weight	Tension and bending	1- end i	0.030	0.030

TABLE 3.13-25 COMPARISON OF PFRAME VERSUS BEER AND JOHNSTON FOR CONTINUOUS BEAM PROBLEM

Supports	Support Reactions (k)	
	PFRAME	Beer & Johnston
B	23	23
E	7	7

Forces at Joints	Shear (k)		Bending Moment (k-ft)	
	PFRAME	Beer & Johnston	PFRAME	Beer & Johnston
A	-8	-8	-0.0000095	0
B	+15	+15	-40	-40
C	+5	+5	+50	+50
D	-7	-7	+70	+70
E	+7	+7	+0.0000019	0

TABLE 3.13-26 COMPARISON OF PFRAME VERSUS GERE AND WEAVER FOR PLANE FRAME PROBLEM

	Joint Displacements/Rotations (in.)					
		PFRAME			Gere & Weaver	
Joints	D_x	D_y	R_3	D_x	D_y	R_3
1(A)	0	0	0	0	0	0
2(B)	-0.020261	0.099359	-0.0017976	-0.02026	-0.09936	-0.001797
3(C)	0	0	0	0	0	0

	Support Reactions (k, in.)					
Support		PFRAME			Gere & Weaver	
Joints	F_x	F_y	M_z	F_x	F_y	M_z
1(A)	20.261	13.138	436.64	20.26	13.14	436.6
2(B)	-20.261	40.862	-889.52	-20.26	40.86	-889.5

		Member Force (k, in.)					
Member			PFRAME			Gere & Weaver	
	Joint	F_x	F_y	M_z	F_x	F_y	M_z
M1	2(B)	20.261	13.138	436.64	20.26	13.14	436.6
	1(A)	-20.261	10.862	-322.86	-20.26	10.86	-322.9
M2	1(A)	28.726	-4.5333	-677.14	28.72	-4.52	-677.1
	3(C)	-40.726	20.533	-899.52	-40.73	20.53	-899.5

TABLE 3.13-27 UNCOPED SLIDING CONNECTION FIELD BOLTED ANGLE DETAIL NO. 7.7.1 (GENERAL CRITERIA - OBE)

			Connections			Hand Calculation		
Item	Member	Units	Actual	Allowable	Ratio	Actual	Allowable	Ratio
	Bolt in-leg	kips	1.92	10.08	0.19	1.92	10.08	-
	Bolt out-leg	kips	2.52	10.52	0.24	2.52	10.50	-
	Angle in-leg (FY)	ksi	2.80	14.40	0.19	2.80	14.40	-
	Angle in-leg (FU)	ksi	4.07	17.40	0.23	4.07	17.40	-
	Angle out-leg(FY)	ksi	2.79	14.40	0.19	2.79	14.40	-
Shear (forces/stresses	Angle out-leg(FU)	ksi	4.06	17.40	0.23	4.06	17.40	-
	Beam web (FY)	ksi	3.37	14.40	0.23	3.37	14.40	-
	Beam web (FU)	ksi	5.43	17.40	0.31	5.43	17.40	-
Bending and axial	Angle out-leg	-		-	2.64		-	2.640
	Beam Web	-		-	0.89		-	0.894
Prying action	Angle out-leg	kips	4.17	26.46	-	4.17	26.45	-

	Member	Actual Minimum	Required Minimum
Edge distance	Beam (parallel to slot)	1.50 in.	1.50 in.
	Beam (normal to slot)	3.47 in.	1.13 in.
	Angle in-leg (rolled edge)	2.50 in.	1.34 in.
	Angle in-leg (sheared edge)	1.50 in.	1.25 in.
	Angle out-leg (rolled edge)	1.41 in.	1.13 in.
	Angle out-leg (sheared edge)	1.50 in.	1.28 in.

Connection adequacy = not adequate

TABLE 3.13-28 COPED SLIDING CONNECTION FIELD BOLTED ANGLE DETAIL NO. 7.7.1 (GENERAL CRITERIA - OBE)

			Connections			Hand Calculation		
Item	Member	Units	Actual	Allowable	Ratio	Actual	Allowable	Ratio
	Bolt in-leg	kips	1.92	10.08	0.19	1.92	10.08	-
	Bolt out-leg	kips	2.52	10.52	0.24	2.52	10.50	-
	Angle in-leg (FY)	ksi	2.80	14.40	0.19	2.80	14.40	-
	Angle in-leg (FU)	ksi	4.07	17.40	0.23	4.07	17.40	-
Shear (forces/stresses	Angle out-leg (FY)	ksi	2.79	14.40	0.19	2.79	14.40	-
	Angle out-leg (FU)	ksi	4.06	17.40	0.23	4.06	17.40	-
	Beam web (FY)	ksi	3.44	14.40	0.24	3.44	14.40	-
	Beam web (FU)	ksi	5.43	17.40	0.31	5.43	17.40	-
Bending and axial	Angle out-leg	-	-	-	4.44		-	4.44
	Beam Web	-	-	-	2.75		-	2.75
Prying action	Angle out-leg	kips	4.17	26.46	-	4.17	26.46	-

	Member	Actual Minimum	Required Minimum
Edge distance	Beam (parallel to slot)	1.50 in.	1.50 in.
	Beam (normal to slot)	2.22 in.	1.50 in.
	Angle in-leg (rolled edge)	2.50 in.	1.34 in.
	Angle in-leg (sheared edge)	1.50 in.	1.25 in.
	Angle out-leg (rolled edge)	1.41 in.	1.13 in.
	Angle out-leg (sheared edge)	1.50 in.	1.25 in.

Block Shear	Beam web	-	-	-	0.12	-	-	0.124

Connection adequacy = not adequate

TABLE 3.13-29 UNCOPED SLIDING CONNECTION FIELD WELDED PLATE DETAIL NO. 7.7.2 (GENERAL CRITERIA - OBE)

Edge Distance Results
Connections versus Hand Calculations

Member	Actual		Allowable		Ratio	
	Hand Calc	Connections	Hand Calc	Connections	Hand Calc	Connections
Bolt in-leg	4.00 k	4.00 k	12.17 k	12.17 k	0.33	0.33
Plate (FY)	3.34 ksi	3.34 ksi	20.00 ksi	20.00 ksi	0.17	0.17
Plate (FU)	5.06 ksi	5.06 ksi	21.00 ksi	21.00 ksi	0.24	0.24
Beam web (FY)	4.50 ksi	4.50 ksi	14.40 ksi	14.40 ksi	0.31	0.31
Beam web (FU)	12.92 ksi	12.92 ksi	17.40 ksi	17.40 ksi	0.74	0.74

Shear (Force/Stress) Results
Connections versus Hand Calculations

Member	Interaction Ratio	
	Hand Calc	Connections
Full penetration weld	1.294	1.29
Beam web	1.074	1.07

Bending & Axial Load Results
Connections versus Hand Calculations

Member		Actual Minimum	Required Minimum
Edge distance	Beam (Parallel to slot)	0.50 in	1.50 in
	Beam (Normal to slot)	2.56 in.	1.13 in.
	Plate (Parallel to slot)	1.50 in.	1.63 in.
	Plate (Normal to slot)	1.25 in.	1.50 in.

TABLE 3.13-30 COPED SLIDING CONNECTION FIELD WELDED PLATE DETAIL NO. 7.7.2 (GENERAL CRITERIA - OBE)

Member	Actual		Allowable		Ratio	
	Hand Calc	Connections	Hand Calc	Connections	Hand Calc	Connections
Bolt in-leg	4.00 k	4.00 k	12.17 k	12.17 k	0.33	0.33
Plate (FY)	3.34 ksi	3.34 ksi	20.00 ksi	20.00 ksi	0.14	0.14
Plate (FU)	5.06 ksi	5.06 ksi	21.00 ksi	21.00 ksi	0.24	0.24
Beam web (FY)	4.91 ksi	4.91 ksi	14.40 ksi	14.40 ksi	0.34	0.34
Beam web (FU)	12.92 ksi	12.92 ksi	17.40 ksi	17.40 ksi	0.74	0.74

Shear (Force/Stress) Results
Connections versus Hand Calculations

Member	Interaction Ratio	
	Hand Calc	Connections
Full penetration weld	3.600	3.60
Beam web	3.563	3.56

Bending & Axial Load Results
Connections versus Hand Calculations

	Member	Actual Minimum	Required Minimum
Edge distance	Beam (Parallel to slot)	0.50 in	1.50 in
	Beam (Normal to slot)	1.31 in.	1.50 in.
	Plate (Parallel to slot)	1.50 in.	1.63 in.
	Plate (Normal to slot)	1.25 in.	1.50 in.

	Ratio	
	Hand Calc	Connections
Block Shear in Beam Web	0.430	0.43

TABLE 3.13-31 UNCOPED FRICTION CONNECTION SHOP WELDED/FIELD BOLTED DETAIL NO. 7.2.9 (GENERAL CRITERIA - OBE)

		Connections				Hand Calculation		
Item	Member	Units	Actual	Allowable	Ratio	Actual	Allowable	Ratio
Shear (forces/stresses	Weld A in-leg	K/in.	0.75	4.50	0.17	0.75	4.50	-
	Bolt out-leg	Kips	0.85	10.49	0.08	0.85	10.49	-
	Angle in-leg (FY)	Ksi	0.82	14.40	0.06	0.82	14.40	-
	Angle out-leg (FY)	Ksi	0.49	14.40	0.03	0.49	14.40	-
	Angle out-leg (FU)	Ksi	0.75	17.40	0.04	0.75	17.40	-
	Beam web (FY)	Ksi	1.79	14.40	0.12	1.79	14.40	-
Bending and axial	Angle out-leg	-	-	-	0.44		-	0.444
	Beam Web	-	-	-	0.59		-	0.590
Prying action	Angle out-leg	Kips	0.11	26.46	-	0.110	26.458	-

	Member	Actual Minimum	Required Minimum
Edge distance	Angle out-leg (shear edge)	1.25 in.	1.25 in.
	Angle out-leg (rolled edge)	1.50 in.	1.13 in.

Connection adequacy = O.K.

TABLE 3.13-32 COPED FRICTION CONNECTION SHOP WELDED/FIELD BOLTED DETAIL NO. 7.2.9

			Connections			Hand Calculation		
Item	Member	Units	Actual	Allowable	Ratio	Actual	Allowable	Ratio
	Weld A in-leg	K/in.	0.75	4.50	0.17	0.75	4.50	-
	Bolt out-leg	Kips	0.85	10.49	0.08	0.85	10.49	-
	Angle in-leg (FY)	Ksi	0.82	14.40	0.06	0.82	14.40	-
Shear (forces/stresses	Angle out-leg (FY)	Ksi	0.49	14.40	0.03	0.49	14.40	-
	Angle out-leg (FU)	Ksi	0.75	17.40	0.04	0.75	17.40	-
	Beam web (FY)	Ksi	1.79	14.40	0.12	1.79	14.40	-
Bending and axial	Angle out-leg	-	-	-	0.86	-	-	0.864
	Beam Web	-	-	-	0.88	-	-	0.880
Prying action	Angle out-leg	Kips	0.11	26.46	-	0.110	26.458	-

	Member	Actual Minimum	Required Minimum
Edge distance	Angle out-leg (rolled edge)	1.25 in.	1.25 in.
	Angle out-leg (sheared edge)	1.50 in.	1.13 in.

Connection adequacy = O.K.

TABLE 3.13-33 UNCOPED FRICTION CONNECTION SHOP WELDED/FIELD WELDED DETAIL NO. 7.2.11 (CONNECTIONS VERSUS HAND CALCULATIONS)

		Connections				Hand Calculation		
Item	Member	Units	Actual	Allowable	Ratio	Actual	Allowable	Ratio
	Weld A in-leg	K/in.	1.19	4.50	0.26	1.19	4.50	-
	Bolt B out-leg	K/in.	1.83	4.50	0.41	1.83	4.50	-
Shear (forces/stresses	Angle in-leg	Ksi	3.43	14.40	0.24	3.43	14.40	-
	Angle out-leg	Ksi	0.73	14.40	0.05	0.73	14.40	-
	Beam web	Ksi	4.29	14.40	0.30	4.29	14.40	-
Bending and axial	Angle out-leg	-	-	-	1.52	-	-	1.519
	Beam Web	-	-	-	1.20	-	-	1.201

Connection adequacy = not O.K.

TABLE 3.13-34 COPED FRICTION CONNECTION SHOP WELDED/FIELD WELDED DETAIL NO. 7.2.11 (CONNECTIONS VERSUS HAND CALCULATIONS)

		Connections				Hand Calculation		
Item	Member	Units	Actual	Allowable	Ratio	Actual	Allowable	Ratio
	Weld A in-leg	K/in.	1.19	4.50	0.26	1.19	4.50	-
	Bolt B out-leg	K/in.	1.83	4.50	0.41	1.83	4.50	-
Shear (forces/stresses	Angle in-leg	Ksi	3.43	14.40	0.24	3.43	14.40	-
	Angle out-leg	Ksi	0.73	14.40	0.05	0.73	14.40	-
	Beam web	Ksi	4.29	14.40	0.30	4.29	14.40	-
Bending and axial	Angle out-leg	-	-	-	3.41	-	-	3.408
	Beam Web	-	-	-	2.86	-	-	2.862

Connection adequacy = not O.K.

TABLE 3.13-35 CINCH VALIDATION PROBLEM 1 OBE CASE

Item	CINCH	Hand Calc
Total M_x including increases	27,720 in-lb	27,720 in-lb
Total M_y including increases	29,320 in-lb	29,320 in-lb
Total M_z including increases	--	9,114 in-lb
Amplified anchor forces		
T_1	1.322 kips	1.33 kips
T_2	1.895 kips	1.89 kips
T_3	2.468 kips	2.47 kips
T_4	0.716 kips	0.71 kips
T_5	1.862 kips	1.86 kips
T_6	0.110 kips	0.11 kips
T_7	0.683 kips	0.68 kips
T_8	1.256 kips	1.26 kips
Maximum shear per anchor	0.338 kips	0.338 kips
Maximum total anchor force	2.95 kips	2.95 kips
Plate bending stresses		
M_y left	7.253 ksi	7.2 ksi
M_y right	2.614 ksi	2.6 ksi
M_x top	7.126 ksi	7.1 ksi
M_x bottom	2.741 ksi	2.7 ksi
Maximum concrete stress	0.0 ksi	0.0 ksi
Allowable anchor force	3.40 ksi	3.4 kips
Allowable bending stress	27 ksi	27 ksi

TABLE 3.13-36 CINCH REASSESEMENT PROBLEM RES02

Item		CINCH	Hand Calc
Pullout area anchor	#1	83.74 in^2	83.74 in^2
	2	78.46 in^2	78.46 in^2
	3	54.12 in^2	54.12 in^2
	4	78.46 in^2	78.46 in^2
	5	51.58 in^2	51.59 in^2
	6	83.74 in^2	83.74 in^2
	7	78.46 in^2	78.46 in^2
	8	54.12 in^2	54.12 in^2
Ultimate tension force anchor	#1	20.684 kips	20.68 kips
	2	15.129 kips	15.13 kips
	3	10.435 kips	10.44 kips
	4	15.129 kips	15.13 kips
	5	9.946 kips	9.95 kips
	6	20.684 kips	20.68 kips
	7	15.129 kips	15.13 kips
	8	10.435 kips	10.44 kips
Ultimate shear force anchor	#1	21.561 kips	21.56 kips
	2	15.771 kips	15.77 kips
	3	10.877 kips	10.88 kips
	4	15.771 kips	15.77 kips
	5	10.368 kips	10.37 kips
	6	21.561 kips	21.56 kips
	7	15.771 kips	15.77 kips
	8	10.877 kips	10.88 kips
Allowable plate bending stress		27.0 ksi	27.0 ksi
Allow. conc. compres. stress		4.091 ksi	4.090 ksi

TABLE 3.13-36 CINCH REASSESEMENT PROBLEM RES02

Item		CINCH	Hand Calc
Amplification factor			
Moment		1.04	1.04
Tension		1.13	1.13
Resultant anchor tension anchor	#1	2.421 kips	2.42 kips
	2	3.338 kips	3.33 kips
	3	4.255 kips	4.26 kips
	4	1.227 kips	1.23 kips
	5	3.061 kips	3.05 kips
	6	0.034 kips	0.04 kips
	7	0.951 kips	0.95 kips
	8	1.868 kips	1.86 kips
Resultant anchor shear anchor	#1	1.857 kips	1.858 kips
	2	1.908 kips	1.908 kips
	3	1.973 kips	1.974 kips
	4	1.685 kips	1.685 kips
	5	1.812 kips	1.813 kips
	6	1.515 kips	1.514 kips
	7	1.576 kips	1.576 kips
	8	1.655 kips	1.655 kips
Shear-tension interaction anchor	#1	0.159	0.159
	2	0.273	0.273
	3	0.514	0.514
	4	0.147	0.147
	5	0.385	0.384
	6	0.07	0.07
	7	0.135	0.135
	8	0.258	0.258

TABLE 3.13-36 CINCH REASSESMENT PROBLEM RES02

Item		CINCH	Hand Calc
Edge check interaction anchor	#3	3.339	3.345
	5	2.723	2.719
	8	1.968	1.966
Plate bending moments			
Right face		-6.45 kip-in.	-5.66 kip-in.
Left face		-18.082 kip-in.	-17.98 kip-in.
Top face		-16.491 kip-in.	-16.5 kip-in.
Bottom face		-8.836 kip-in.	-8.81 kip-in.
Plate Bending Stresses			
Right face		2.150 ksi	1.89 ksi
Left face		6.027 ksi	5.99 ksi
Top face		5.497 ksi	5.50 ksi
Bottom face		2.945 ksi	2.94 ksi

NOTE: Difference in values for the plate bending moments and stresses are due to the approximation used in the hand calculations. Considering this, the program results are concluded to be correct.

TABLE 3.13-37 VIBRATION PERIODS OF CABLE IN STATIC EQUILIBRIUM CONFIGURATION (ADINA - Validation Problem 1)

Mode Number	Period (sec) Manual	Period (sec) S&L'S ADINA
1	4.42	4.42
2	2.31	2.309
3	1.21	1.211
4	1.16	1.164
5	0.929	0.9294

TABLE 3.13-38 COMPARISON OF RESULTS AT SELECTED LOCATIONS FOR STATIC ANALYSIS FROM FRAME AND REFERENCE 45

	Results from FRAME	Results from Reference 45
Shear force at node 2, member 2 (LOCAL)	31 lb	30 lb
Moment at node 3 member Z	948 ft-lb	950 ft-lb
Shear at node 4 member 3	104 lb	100 lb

TABLE 3.13-39 COMPARISON OF RESULTS AT SELECTED LOCATIONS FOR DYNAMIC ANALYSIS FROM FRAME AND HAND CALCULATIONS

	X-Direction Loading		Y-Direction Loading		Z-Direction Loading		1.5x SRSS	
	Static Analysis	Acceleration (g)	Static Analysis	Acceleration (g)	Static Analysis	Acceleration (g)	FRAME	Calculator
X-displacement at node 2, in.	0.00654	1.3	-0.00148	2.1	0	1.3	0.0136	0.0136
Axial force, (local) member 3, node 4	-1574	1.3	-1878	2.1	0	1.3	6666	6665
Moment about Z axis, member 1 node 1, ft-lb	10570	1.3	2865	2.1	0	1.3	22501	22501
Moment about Y member 3, node 4, ft-lb	0	1.3	0	2.1	7263	1.3	14164	14163

TABLE 3.13-40 COMPARISON OF RESULTS AT SELECTED LOCATIONS FOR LOAD COMBINATIONS FROM FRAME AND HAND CALCULATIONS

Member 2, node 3 local coordinates	Axial		Shear		Moments		
Analysis results	F_a lb		F_b lb	F_c lb	M_a ft-lb	M_b ft-lb	M_c ft-lb
WT1	-895		687	0	0	0	-6593
R01	4868		31	0	0	0	948
SE1	2250		2374	1253	458	3152	12860
Load combination	Tension compression for stress calculations						
WT + R01 + SE							
FRAME	6223	8013	3092	1253	458	3152	20402
Hand calculations	6623	8013	3092	1253	458	3152	20401
WT + RO^2 + SE^2							
FRAME	4467	6258	3061	1253	458	3152	19488
Hand calculations	4468	6258	3061	1253	458	3152	19488

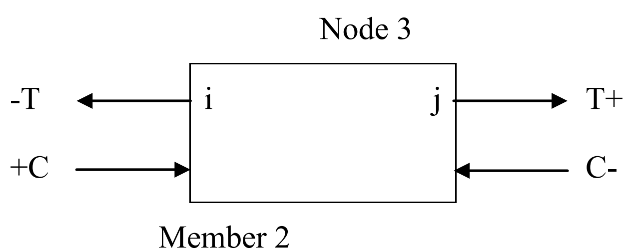


TABLE 3.13-40 COMPARISON OF RESULTS AT SELECTED LOCATIONS FOR LOAD COMBINATIONS FROM FRAME AND HAND CALCULATIONS

Node 3 Displacements, in. analysis results	X	Y	Z	θ_x	θ_y	θ_z
LOT	0.652-02	0.295-02	0	0	0	-.283.03
RO	0.765-03	0.230-02	0	0	0	0.195.03
SE	0.137-01	0.672-02	0.562-01	0.228-01	0.485-02	0.185-02
Load combination						
WT + R01 + SE						
FRAME	0.209-01	0.120-01	0.562-01	0.228-01	0.485-02	0.233.02
Hand calculations	0.209-01	0.120-01	0.562-01	0.228-01	0.485-02	0.233.02
WT + R0^2 + SE^2						
FRAME	0.202-01	0.101-01	0.562-01	0.228-01	0.485-02	-0.214.02
Hand calculations	0.202-01	0.101-01	0.562-01	0.228-01	0.485-02	-0.214.02

TABLE 3.13-41 COMPARISON OF FRAME STRESS CHECK OUTPUT AND HAND CALCULATION

	Problem 1				Problem 2				Problem 3				Problem 4			
	FRAME		Hand Calc		FRAME		Hand Calc		FRAME		Hand Calc		FRAME		Hand Calc	
	ACT	ALL	ACT	ALL	ACT	ALL	ACT	ALL	ACT	ALL	ACT	ALL	ACT	ALL	ACT	ALL
Minor axis bending stress (ksi)	0.45	32.73	0.45	32.73	1.82	27.5	1.82	37.5	20.41	21.6	20.41	21.60	58.39	21.06	58.38	21.06
Major axis bending stress (ksi)	0.61	32.73	0.61	32.73	0.87	30.0	0.87	30.0	22.16	21.6	22.7	21.60	39.03	17.69	39.37	17.68
Axial stress(ksi)	1.22	32.73	1.22	32.73	4.24	22.34	4.24	22.34	18.02	15.43	18.02	15.43	1.45	1.92	1.45	1.92
Shear stress(ksi)	2.46	18.9	2.46	18.09	6.01	20.0	6.03	20.0	23.44	14.40	23.45	14.40	54.33	14.04	53.04	14.04
Maximum interaction ratio	0.130	-	0.13	-	0.301	-	0.30	-	4.651	-	4.65	-	14.30	-	14.30	0

TABLE 3.13-42 DESIGN PARAMETERS FOR FRAME STRESS CHECK VALIDATION PROBLEMS

	Problem 1	Problem 2	Problem 3
Unbraced length in 2-direction	25 in.	120 in.	20 in.
Effective length factor in 2-direction	1.0	1.0	1.0
Unbraced length in 3-direction	40 in.	120 in.	40 in.
Effective length factor in 3-direction	1.0	1.0	1.0
Effective length in bending	40 in.	120 in.	40 in.
Overstress factor	1.6	1.0	1.0
Minimum factor of safety	1.1	1.0	1.0
Yield stress	36 ksi	50 ksi	36 ksi

	Problem 4
Unbraced length in 1-direction	120 in.
Effective length factor in 2-directions	1.0
Unbraced length in 3-direction	120 in.
Effective length factor in 3-direction	1.0
Effective length in bending	120 in.
Overstress factor	1.0
Minimum factor of safety	1.0
Yield stress	36 ksi

TABLE 3.13-43 INPUT DATA FOR VALIDATION PROBLEMS FOR THE CONNECTION CHECK MODULE OF FRAME

Problem No.	Member Size	Weld Type	Weld Size	Forces (kip and kip - in.) F_a	F_b	F_c	M_a	M_b	M_c
5	W 5x16	4	1/4"	0.31	0.72	2.47	12.33	44.03	12.22
6	L 3x3x1/4	2	3/16"	0.15	0.17	0.08	0.21	2.04	4.22
7	Z 3x9.8	3	1/4"	0.9	0.34	0.09	0.22	2.15	10.77
8	T 6x4x.25	1	1/4"	1.0	2.0	3.0	4.0	5.0	6.0
9	C 4x5.4	1	1/4"	0.045	0.355	0.045	0.030	1.03	11.26

TABLE 3.13-44 COMPARISON OF FRAME AND HAND-CALCULATED RESULTS FOR CONNECTION MODULE

	FRAME OUTPUT			HAND CALCULATION			
				Connection			
Problem No.	Actual Weld Stress (ksi)	Allowable Weld Stress (ksi)	Ratio	Actual Weld Stress (ksi)	Allowable Weld Stress (ksi)	Ratio	Adequacy
5	5.85	4.72	1.239	5.854	4.724	1.239	Fail
6	1.99	3.54	0.561	1.986	3.543	0.5605	Pass
7	1.17	4.72	0.247	1.166	4.724	0.2468	Pass
8	0.47	4.72	0.1	0.47	4.724	0.0996	Pass
9	1.49	4.72	0.315	1.488	4.724	0.315	Pass

TABLE 3.13-45 PASS - COMPARISON OF NOZZLE AND ANCHOR REACTIONS

Node 901	F_x (lb)		$F_{y\,b}$ (lb)		F_z (lb)	
	PASS	HAND	PASS	HAND	PASS	HAND
Design load (+)	1616	1617	1386	1385	719	719
Design load (-)	-499	-501	-348	-347	-2676	-2676

	M_x (in. – lb)		M_y (in. – lb)		M_z (in. – lb)	
	PASS	HAND	PASS	HAND	PASS	HAND
Design load (+)	87192	87192	24819	24820	17033	17031
Design load (-)	-31632	-31632	-87739	-87740	-35747	-35745

Node 910	F_x (lb)		F_y (lb)		F_z (lb)	
	PASS	HAND	PASS	HAND	PASS	HAND
Design load (+)	30	29	329	331	57	57
Design load (-)	-51	-50	-168	-170	-35	-35

	M_x (in. – lb)		M_y (in. – lb)		M_z (in. – lb)	
	PASS	HAND	PASS	HAND	PASS	HAND
Design load (+)	3632	3633	971	971	3510	3508
Design load (-)	-6267	-6268	-964	-963	-6151	-6149

TABLE 3.13-46 PASS - COMPARISON OF HANGER/RESTRAINT LOADS

Node	Restraint Type and Direction	Design Load (+)		Design Load (-)	
		PASS	HAND	PASS	HAND
65	Y RIGID	2538	2538	-835	-835
65	Z RIGID	2279	2280	-745	-745
395	Y RIGID	222	222	-104	-104
430	Y RIGID	388	388	-158	-158
430	Z RIGID	341	339	-389	-387

TABLE 3.13-47 PASS - COMPARISON OF HANGER/RESTRAINT DISPLACEMENTS

Thermal Displacements

	DX (in.)		DY (in.)		DZ (in.)	
Node	PASS	HAND	PASS	HAND	PASS	HAND
65 (+)	0.000	0.000	0.000	0.000	0.000	0.000
65 (-)	-0.034	-0.034	-0.000	-0.000	-0.000	-0.000
395 (+)	0.097	0.097	0.000	0.000	0.000	0.000
`395 (-)	-0.000	-0.000	-0.000	-0.000	-0.158	-0.158
430 (+)	0.000	0.000	0.000	0.000	0.000	0.000
430 (-)	-0.004	-0.004	-0.000	-0.000	-0.000	-0.000

Seismic Displacements (±)

	DX (in.)		DY (in.)		DZ (in.)	
Node	PASS	HAND	PASS	HAND	PASS	HAND
65	0.120	0.120	0.000	0.000	0.000	0.000
395	0.213	0.212	0.000	0.000	0.388	0.386
430	0.148	0.148	0.000	0.000	0.000	0.000

TABLE 3.13-48 PASS - CLASS 2 STRESS EVALUATION COMPARISON[a]

Node	Component Type	Equation 8		Equation 9 With End Effects		Equation 10 Without End Effects	
		PASS	HAND	PASS	HAND	PASS	HAND
15	Tee-run	2390	2390	5352	5351	15698	15697
15	Tee-branch	2465	2464	4948	4947	6894	6893
15	Tee-run	1645	1645	5969	5968	9485	9484
90	Run	1653	1653	2684	2685	1323	1323
100	Elbow	1295	1295	3695	3696	5807	5807
110	Run	1117	1118	3151	3151	1128	1128
125	Tee-run	1897	1897	5509	5509	3781	3781
125	Tee-branch	1281	1280	6969	6967	1991	1991
125	Tee-run	1863	1863	6041	6041	3448	3448
155	Run at restraint	745	745	1081	1106	405	406
380	Reducer	1641	1641	3570	3575	1883	1886
395	Run at restraint	1045	1045	3885	3890	1922	1925
410	Elbow	1112	1112	4584	4590	6187	6196
910	Anchor	2889	2889	4520	4522	24	24

[a] Refer to NC - 3652 of Section III of ASME B&PV Code, winter 1972 addenda.

TABLE 3.13-49 COMPARISON OF SUPPORT REACTION DUE TO THERMAL, ANCHOR MOVEMENT, AND EXTERNAL FORCE LOADING

Node	Program	Forces (lb)			Moments (in. - lb)		
		FX	FY	FZ	MX	MY	MZ
170	NUPIPE	-9154	7541	4492	-5952	-823420	1241512
	ADLPIPE	-9178	7540	4492	-5529	-823420	1241512
218	NUPIPE		16650				
	ADLPIPE		16622				
330	NUPIPE	34532	-33620	-31750	-486338	-1516811	573673
	ADLPIPE	34511	-33608	-31736	-486386	-1519359	573438
390	NUPIPE		8631				
	ADLPIPE		8678				
430	NUPIPE	1702	798	12553	-28147	164346	248852
	ADLPIPE	1746	768	12541	-26917	166180	250956

TABLE 3.13-50 COMPARISON OF DEFLECTIONS AND ROTATIONS DUE TO THERMAL, ANCHOR MOVEMENT, AND EXTERNAL FORCE LOADING

Node	Program	Deflection (in.)			Rotation (rad)		
		DX	DY	DZ	RX	RY	RZ
197	NUPIPE	0.348	-0.141	0.230	-0.0026	0.0025	-0.0084
	ADLPIPE	0.348	-0.141	0.229	-0.0026	0.0025	-0.0084
212	NUPIPE	1.120	0.052	-0.023	-0.0092	-0.0051	-0.0115
	ADLPIPE	1.120	0.052	-0.023	-0.0092	-0.0051	-0.0115
230	NUPIPE	1.276	-0.028	-0.548	-0.0066	-0.0044	0.0024
	ADLPIPE	1.276	-0.027	-0.548	-0.0066	-0.0044	0.0024
260	NUPIPE	0.512	-0.001	-0.520	-0.0034	-0.0005	0.0035
	ADLPIPE	0.512	-0.000	-0.520	-0.0035	-0.0005	0.0035
390	NUPIPE	0.066	-0.000	0.249	-0.0010	0.0026	-0.0020
	ADLPIPE	0.067	-0.000	0.248	-0.0010	0.0026	-0.0020
420	NUPIPE	-0.029	-0.079	0.011	-0.0002	-0.0002	-0.0007
	ADLPIPE	-0.029	-0.079	0.011	-0.0002	-0.0002	-0.0007

TABLE 3.13-51 COMPARISON OF STRESS DUE TO THERMAL, ANCHOR MOVEMENT, AND EXTERNAL FORCE LOADING

Node	NUPIPE	ADLPIPE
180	18989	19013
199	17703	17731
214	23958	23955
236	14427	14416
265	6254	6251
305	12539	12532
344	11845	11838
370	6295	6296
395	3476	3473
430	3282	3308

TABLE 3.13-52 COMPARISON OF INTERNAL FORCES DUE TO DEADWEIGHT ANALYSIS

		Forces (lb)			Moments (in.-lb)		
Node	Program	FX	FY	FZ	MX	MY	MZ
197	NUPIPE	295	2337	14	-35864	5218	51979
	ADLPIPE	290	2341	15	-35108	5231	52081
212	NUPIPE	295	3306	14	59390	-5394	14010
	ADLPIPE	299	3310	15	59735	-5500	14542
360	NUPIPE	330	2781	-29	30930	-22748	-84971
	ADLPIPE	326	2783	-32	31920	-23105	-82784
390	NUPIPE	330	4933	-29	-255351	701	126476
	ADLPIPE	336	4707	-32	-256444	916	126716
420	NUPIPE	330	-492	-29	-8972	27075	82202
	ADLPIPE	336	-497	-32	-9181	27724	80676

TABLE 3.13-53 COMPARISON OF DEFLECTIONS AND ROTATION DUE TO DEAD WEIGHT

Node	Program	Deflection (in.)			Rotation (rad)		
		DX	DY	DZ	RX	RY	RZ
197	NUPIPE	0.007	-0.014	-0.004	0.0001	0.0001	0.0002
	ADLPIPE	0.007	-0.014	-0.004	0.0001	0.0001	0.0002
212	NUPIPE	-0.005	-0.013	0.013	0.0006	0.0001	0.0004
	ADLPIPE	-0.005	-0.013	0.013	0.0006	0.0001	0.0004
360	NUPIPE	-0.008	-0.068	0.024	0.0004	-0.0000	-0.0004
	ADLPIPE	-0.009	-0.069	0.024	0.0004	0.0000	-0.0004
390	NUPIPE	-0.014	-0.000	-0.003	0.0002	-0.0002	-0.0005
	ADLPIPE	-0.015	-0.000	-0.003	0.0002	-0.0002	-0.0005
420	NUPIPE	-0.001	0.002	-0.001	-0.0000	-0.0001	-0.0002
	ADLPIPE	-0.001	0.002	-0.001	-0.0000	-0.0001	-0.0002

TABLE 3.13-54 COMPARISON OF STRESSES DUE TO DEAD WEIGHT

NODE	NUPIPE (psi)	ADLPIPE (psi)
180	685	694
199	448	458
214	667	679
236	2472	2449
265	530	524
305	515	522
344	635	631
370	679	677
395	575	580
430	1101	1091

TABLE 3.13-55 COMPARISON OF NATURAL FREQUENCIES (NUPIPE VERSUS ADLPIPE)

Node	1st	2nd	3rd	4th	5th
NUPIPE	7.109	9.328	12.297	14.681	18.043
ADLPIPE	7.118	9.329	12.492	14.427	17.714

TABLE 3.13-56 COMPARISON OF NATURAL FREQUENCIES (NUPIPE Versus BENCHMARK Pr.)

Node	1	2
NUPIPE	2.407	13.537
Benchmark Pr.	2.3288	13.0808

TABLE 3.13-57 NUPIPE VERSUS HAND CALCULATION

Point No.: 20	Hand Calculation	NUPIPE
Min. wall thickness	0.032 in.	0.032 in.
Primary stress (Eq. 9)	3,713 psi	3,712 psi
Primary and secondary stress (Eq. 10)	16,041 psi	16,038 psi
Alternating stress (Eqs. 11 & 14)	13,468 psi	13,465 psi
Usage factor	0.0654	0.0631
Point No.: 30		
Min. wall thickness	0.047 in.	0.047 in.
Primary stress (Eq. 9)	8,748 psi	8,741 psi
Primary and secondary stress (Eq. 10)	117,655 psi	117,546 psi
Expansion stress (Eq. 12 and Eq. 13)	99,884 psi 18,252 psi	99,781 psi 18,246 psi
Alternating stress (Eq. 14)	218,258 psi	217,811 psi
Usage factor	Out of Range	

TABLE 3.13-58 INDIVIDUAL PAIR USAGE FACTOR FOR POINT NO. 30

	Hand Calculation	NUPIPE
Pair (1,5)	0.183	0.1803
Pair (1,8)	1.660	1.7361
Pair (1,9)	0.0001	0.0001
Pair (1,10)	Out of Range	
Pair (5,8)	Out of Range	
Pair (5,9)	0.221	0.2646
Pair (5,10)	0.747	0.8051
Pair (8,9)	0.857	0.8832
Pair (8,10)	5.5518	5.8608
Pair (9,10)	0.0001	0.0001

TABLE 3.13-59 PIPE MATERIAL PROPERTIES

Property	Temperature (°F)	Value
Thermal conductivity	450	10.01 Btu/°F/hr/ft
Thermal diffusivity	450	0.164 ft^2/hr
Young's modulus	70	28.3 x 10^6 psi
Coefficient of thermal expansion	70	9.11 x 10^6 in./in.°F

TABLE 3.13-60 FLUID MATERIAL/THERMAL PROPERTIES

Property	Temperature (°F)	Value
Density	450	51.300 lb/ft^3
Viscosity	450	0.2920 lb/hr/ft
Specific heat	450	1.135 Btu/lb/°F
Conductivity	450	0.3650 Btu/°F/hr/ft
Volume expansion coefficient	450	0.0009/°F

TABLE 3.13-61 COMPARISON OF HTLOAD WITH HAND CALCULATION

	HTLOAD	Hand Calculation
Reynolds number	186,700	186,700
Heat transfer coefficient	946.8 Btu/°F/hr/ft^2	946.8 Btu/°F/hr/ft^2

TABLE 3.13-62 COMPARISON OF HTLOAD WITH CHARTS OF BROCK AND MCNEILL

Parameter	Charts	HTLOAD
Maximum ΔT_1	43.31 °F	45.14 °F
Maximum ΔT_2	8.50 °F	8.36 °F

TABLE 3.13-63 COMPARISON OF HTLOAD WITH TRHEAT

Parameter	TRHEAT	HTLOAD
Maximum ΔT_1	44.70 °F	45.14 °F
Maximum ΔT_1	8.69 °F	8.36 °F
Maximum $T_A - T_B$	19.03 °F	19.08 °F

TABLE 3.13-64 COMPARISON OF PITRUST WITH FRANKLIN INSTITUTE PROGRAM CYLNOZ AND HAND CALCULATION

Source of Stress	Franklin Institute Corrected Values	Output from PITRUST	Hand Calculation
Circumferential			
p (Normal)	395.	399.	399.99
p (Bending)	1,875	1,883	1,877.3
Mc (Normal)	35.85	35.57	36.06
Mc (Bending)	364.7	366.6	354.3
Ml (Normal)	79.05	79.66	79.54
Ml (Bending)	90.52	80.57	79.42
Axial			
p (Normal)	813.	812.	814.8
p (Bending)	812.3	827.	810.6
Mc (Normal)	91.79	105	95.45
Mc (Bending)	158.8	160	158.8
Ml (Normal)	37.06	37.0	37.12
Ml (Bending)	117.9	105.	103.85
Shear stress by Mr	6.63	6.63	6.63
Shear stress by Vc	106.1	106.1	106.1
Shear stress by Vl	106.1	106.1	106.1

TABLE 3.13-65 COMPARISON OF PITRUST WITH REF. 70 RESULTS

Location and Cause	PITRUST Results	Exp. Results (Ref. 70)
Element "A"		
Longt. Moment		
Circumf. stress	20,438.9 psi	20,000 psi (Fig. 16, Ref. 70)
Axial stress	26,292.6 psi	25,000 psi
Element "B"		
Circumf. Moment		
Circumf. stress	22,016.2 psi	24,000 psi (Fig. 15, Ref. 70)
Axial stress	13,105.8 psi	13,000 psi

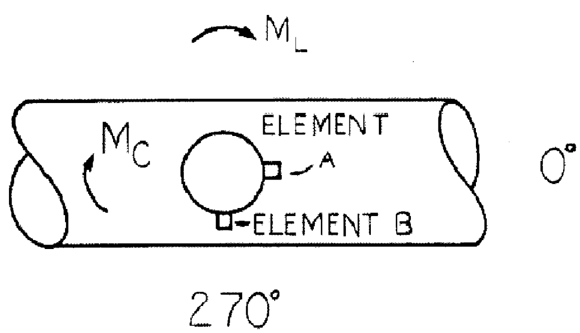


TABLE 3.13-66 COMPARISON OF PILUG COMPUTER PROGRAM OUTPUT WITH HAND CALCULATIONS

Test Problem: Run pipe OD = 17 in.; Run pipe thickness = 0.812 in.;
Axial Length of Lug = 12 in.;
Width of lug along circumf = 3 in.;

Loads: P=3399 lb; Vc = -1788 lb; Vl = 2478 lb;
Mc = 81834 in.-lb; Ml = 103320 in.-lb;
Mt=76284 in.-lb

Stress in Circumferential Direction

Figure	β	Stress from Hand Cal.	Computer Output	Remarks
3C	0.5485	387	330	Membrane stress due to P
1C	0.326	2165	2160	Bending stress due to P
3A	0.294	671	629	Membrane stress due to Mc
1A	0.388	18976	19904	Bending stress due to Mc
3B	0.467	3014	2961	Membrane stress due to Ml
1B	0.416	6143	5969	Bending stress due to Ml

Stress in Axial Direction

Figure	β	Stress from Hand Cal.	Computer Output	Remarks
4C	0.4447	683	690	Membrane stress due to P
2C	0.4632	773	792	Bending stress due to P
4A	0.294	1897	1864	Membrane stress due to Mc
2A	0.550	6357	5942	Bending stress due to Mc
4B	0.467	2365	2328	Membrane stress due to M1
2B	0.582	4989.7	4842	Bending stress due to M1

Shear Stress

Figure	β	Stress from Hand Cal.	Computer Output	Remarks
		1304.8	1304.8	Shear stress due to Mt
		-366.99	-366.99	Shear stress due to V1
		127.15	127.16	Shear stress due to V
		127.15	127.16	Shear stress due to V

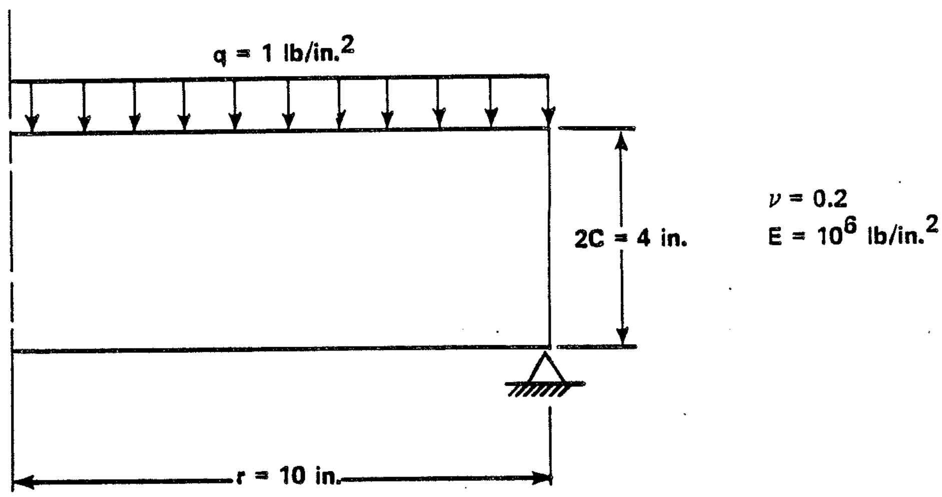


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FIGURE 3.13-1

UNIFORMLY LOADED THICK CIRCULAR PLATE

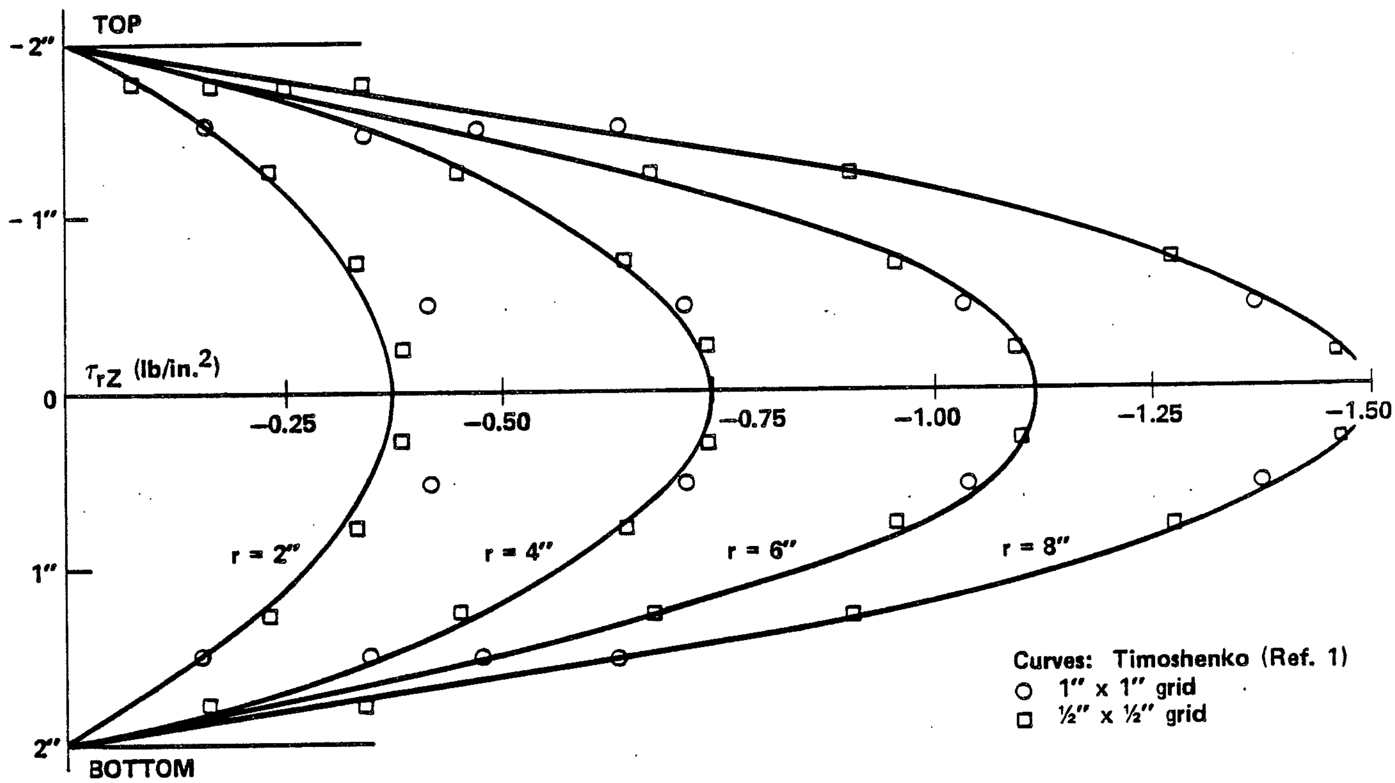

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FIGURE 3.13-2

UNIFORMLY LOADED THICK CIRCULAR PLATE
τ_{rz} STRESSES

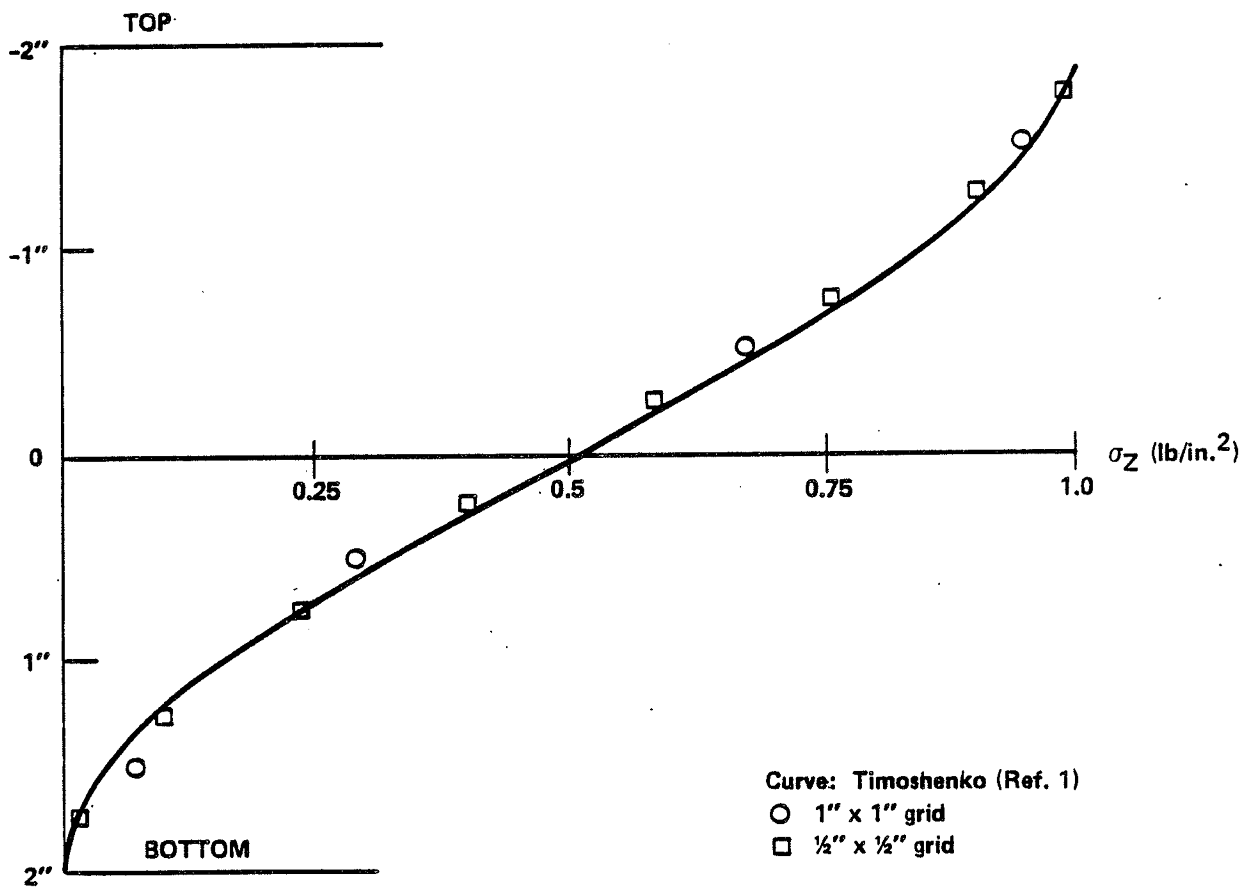

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FIGURE 3.13-3

UNIFORMLY LOADED THICK CIRCULAR PLATE
σ_Z STRESSES – PSI

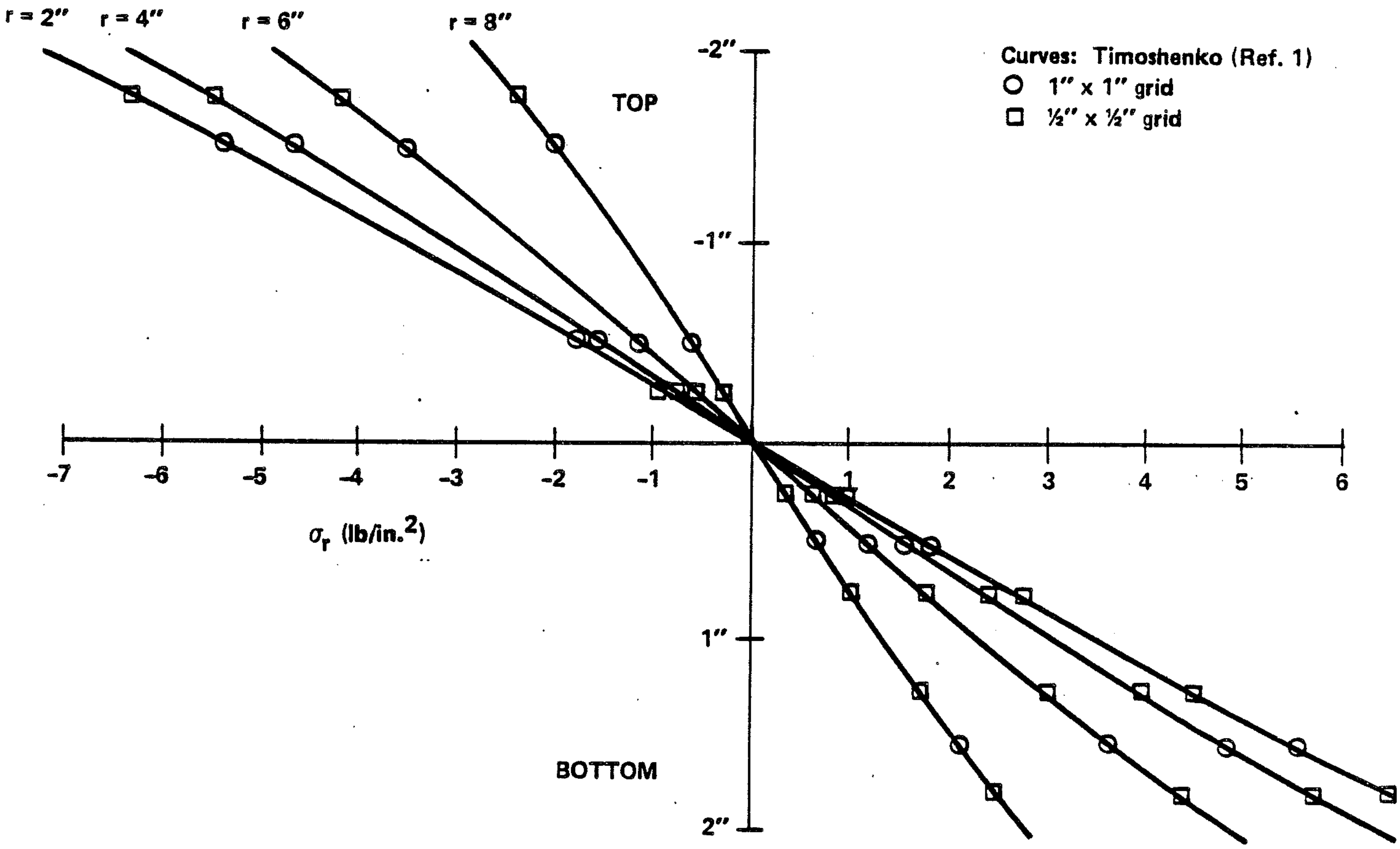

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FIGURE 3.13-4

UNIFORMLY LOADED THICK CIRCULAR PLATE
σ_r STRESSES

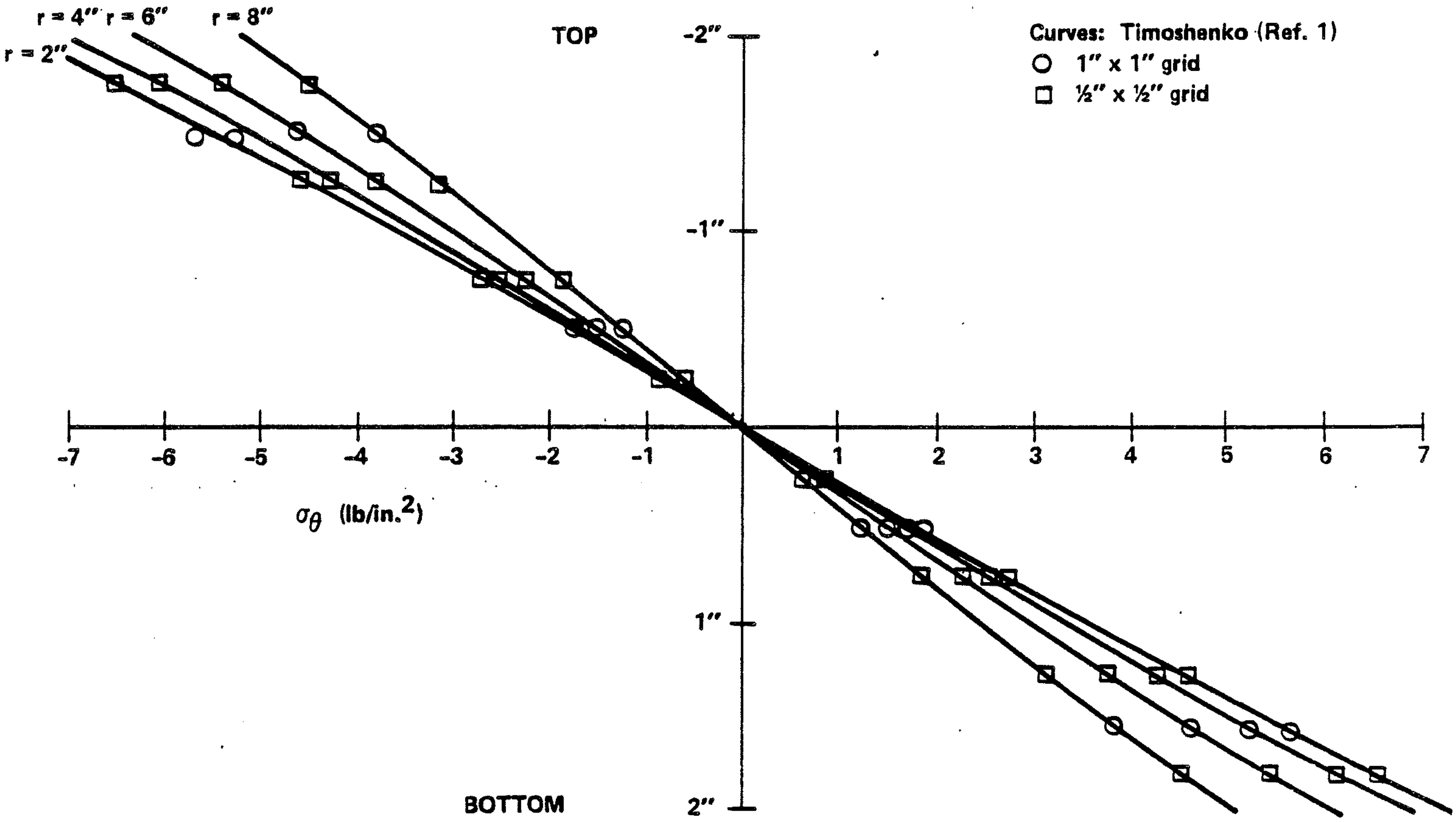

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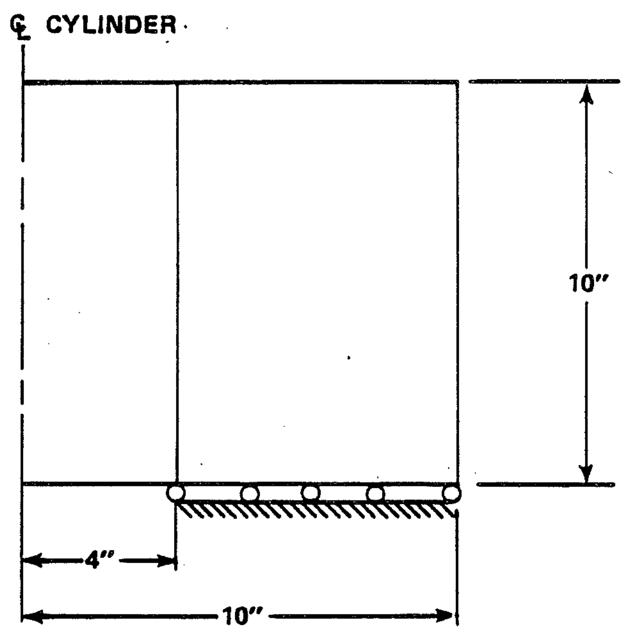
FIGURE 3.13-5

UNIFORMLY LOADED THICK CIRCULAR PLATE σ_θ STRESSES



γ = 200 lb/in.^{3}
ν = 0.2
E = 10^6 lb/in.^{2}

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FIGURE 3.13-6

THICK CYLINDER GEOMETRY AND MATERIAL PROPERTIES

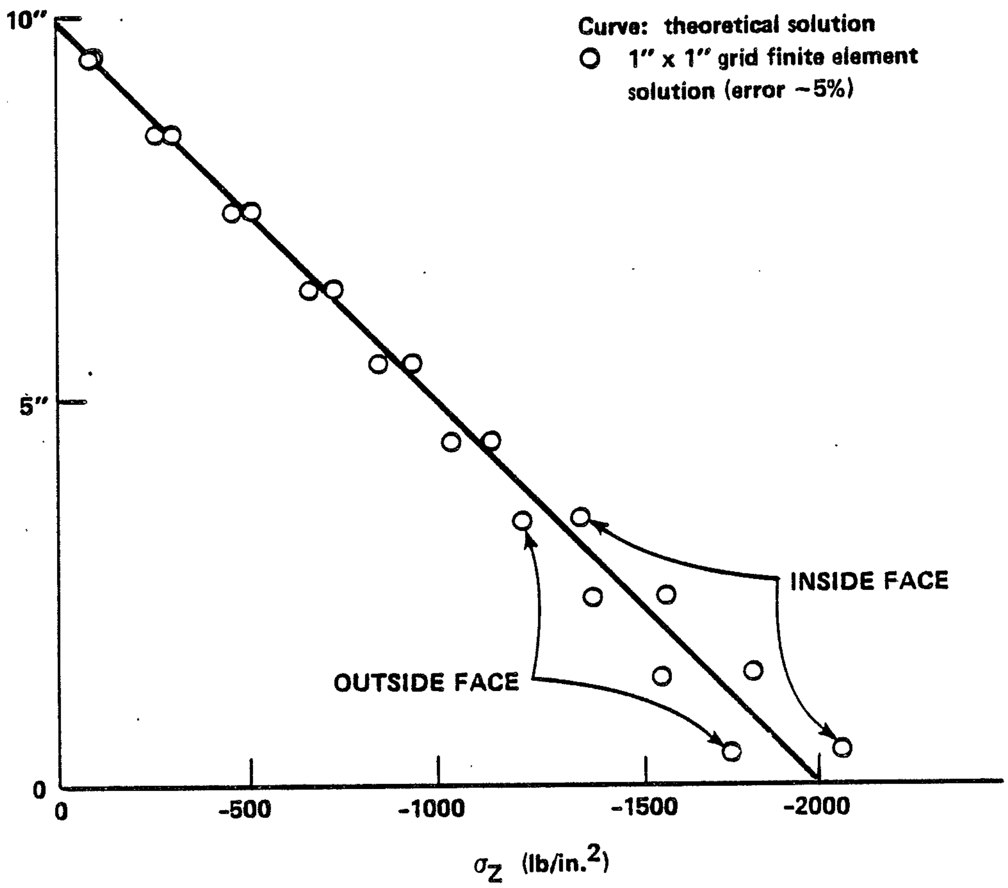

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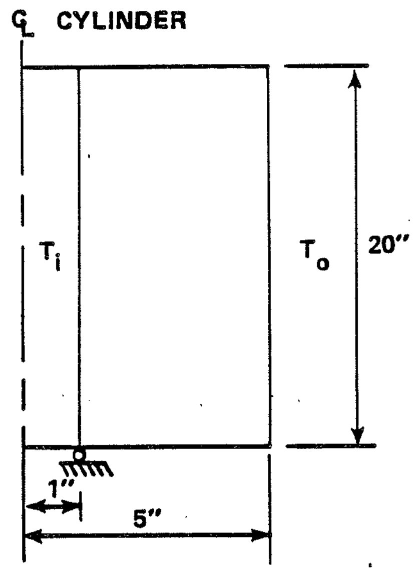
FIGURE 3.13-7

THICK-CYLINDER σ_Z DUE TO DEAD WEIGHT



ν = 0.2

E = 10^6 lb/in.^{2}

α = 1/3000 in./in.-°F

T_i = 10°F

T_o = 0°F

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FIGURE 3.13-8

THICK-CYLINDER GEOMETRY FOR THE TEMPERATURE PROBLEM

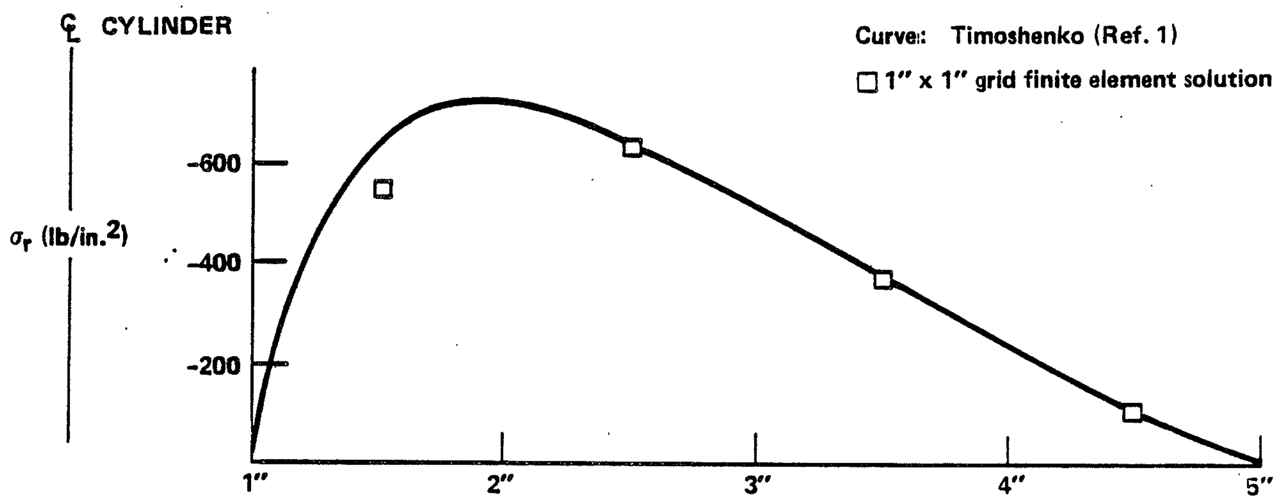

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FIGURE 3.13-9

THICK-CYLINDER σ_r STRESSES DUE TO TEMPERATURE GRADIENT

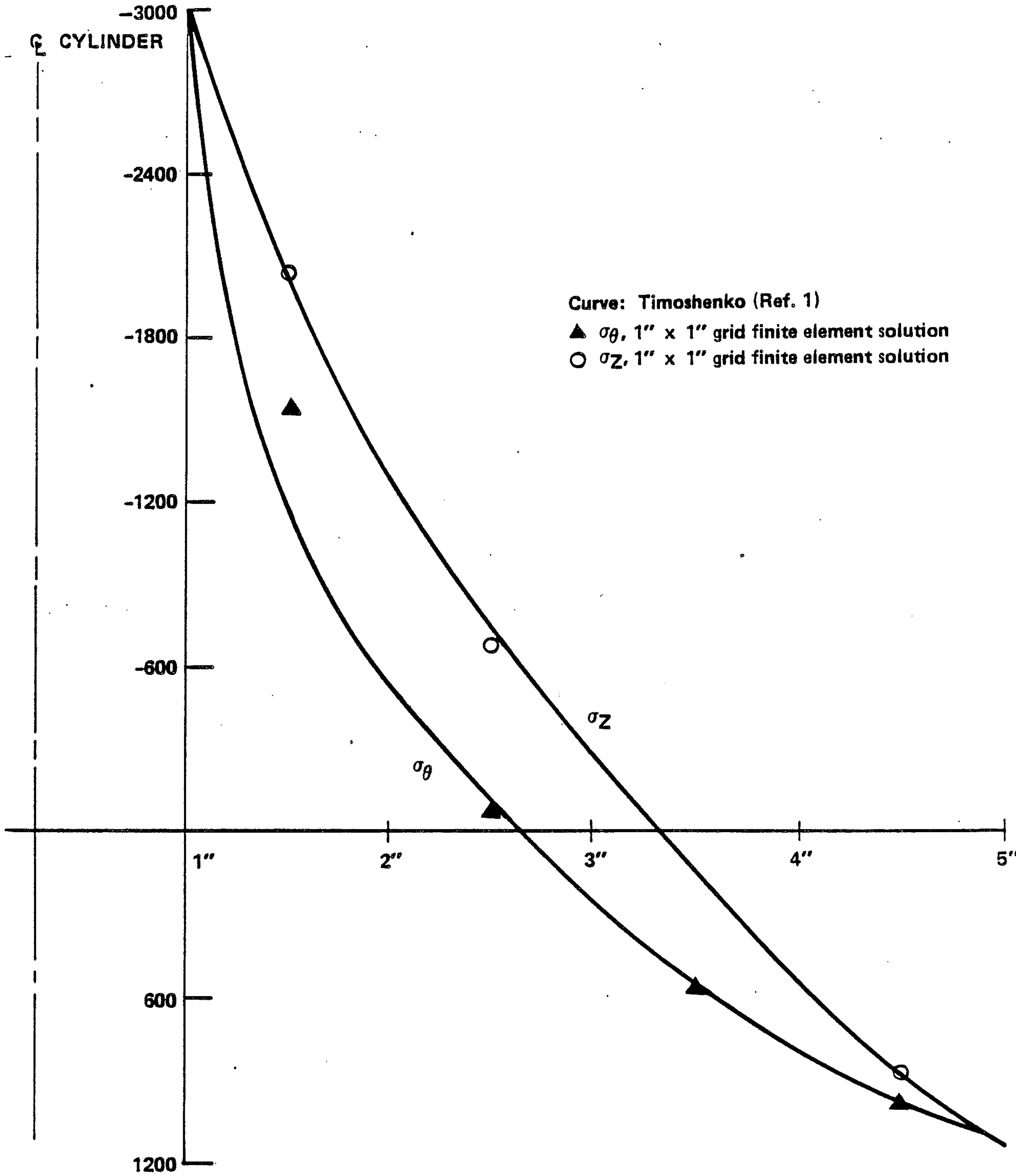

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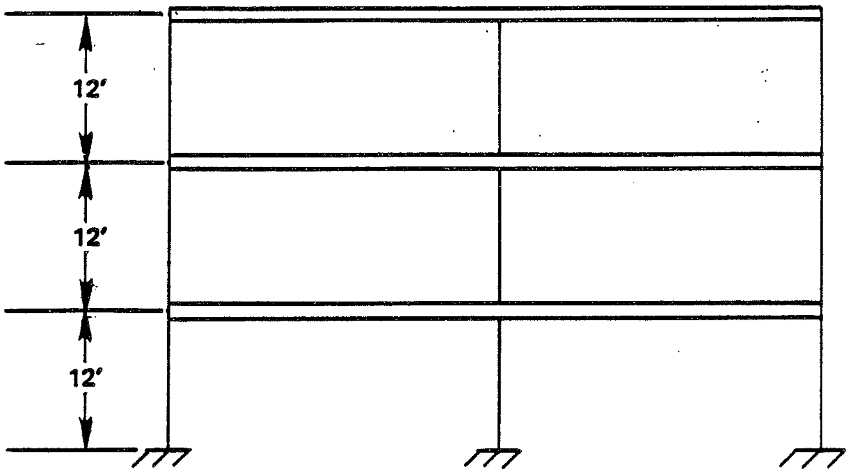
FIGURE 3.13-10

THICK-CYLINDER σ_Z AND σ_θ STRESSES DUE TO TEMPERATURE GRADIENT



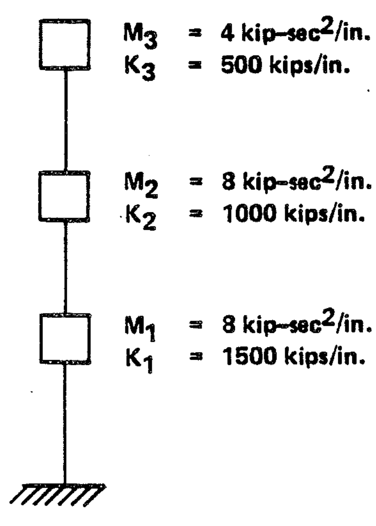


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FIGURE 3.13-11

THREE-STORY SHEAR BUILDING

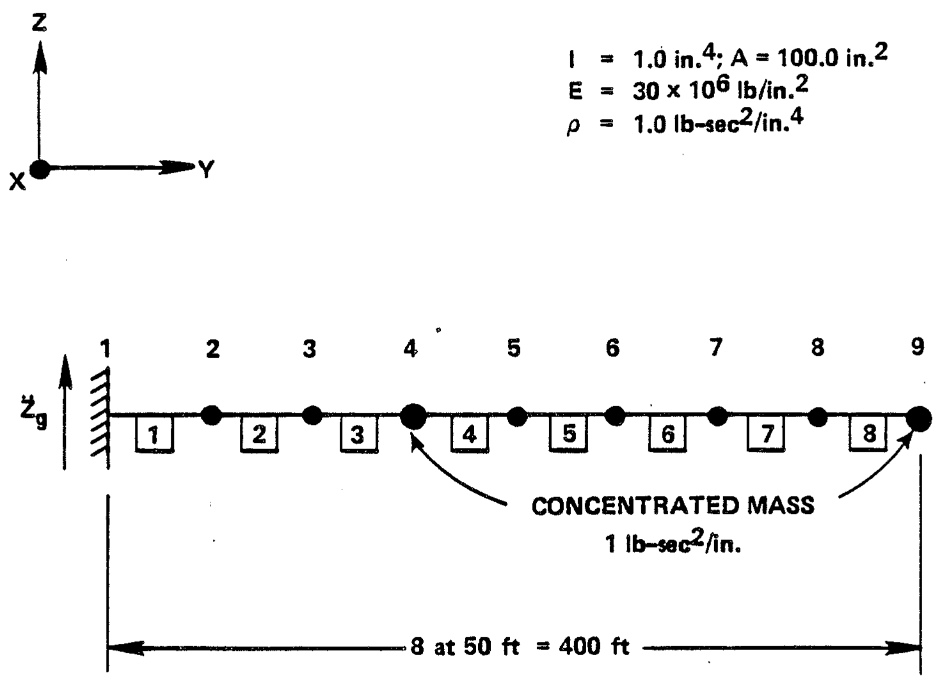

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FIGURE 3.13-12

NODE AND BEAM NUMBER ASSIGNMENTS FOR THE CANTILEVER MODEL

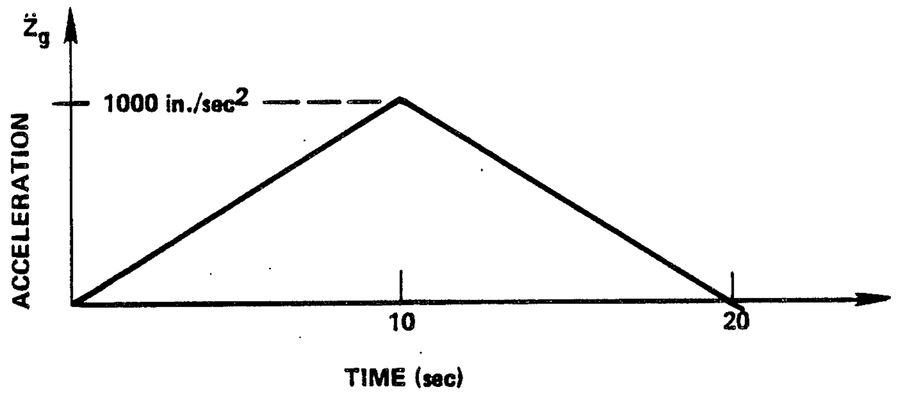

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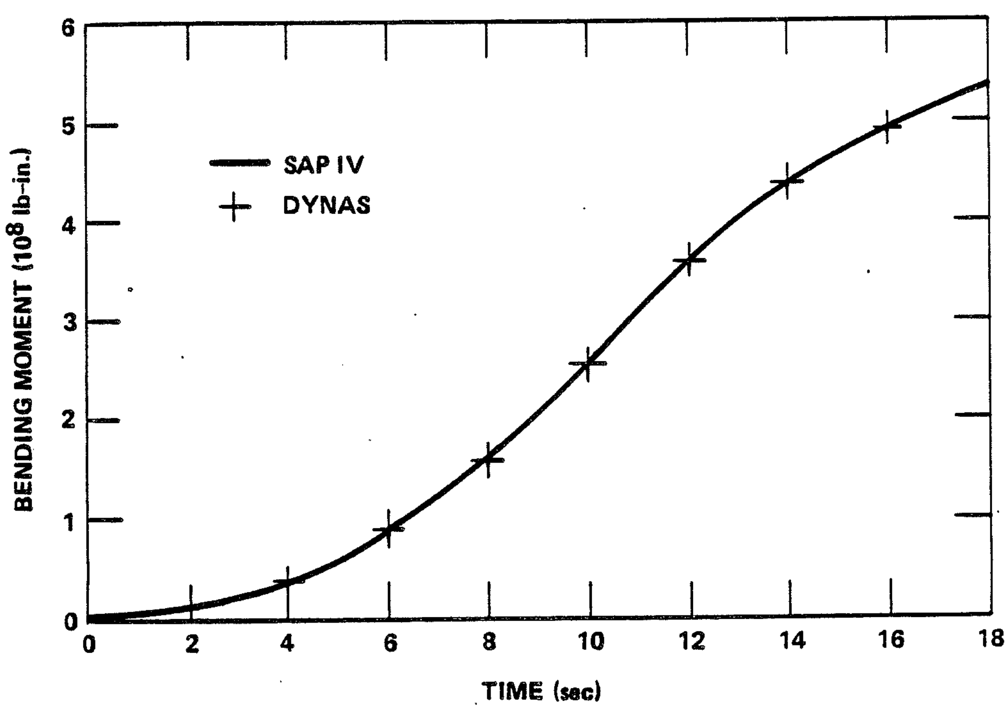
FIGURE 3.13-13

GROUND ACCELERATION APPLIED AT NODE 1



MOMENT AT NODE 1 (FIXED END OF CANTILEVER)

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FIGURE 3.13-14

CANTILEVER RESPONSE

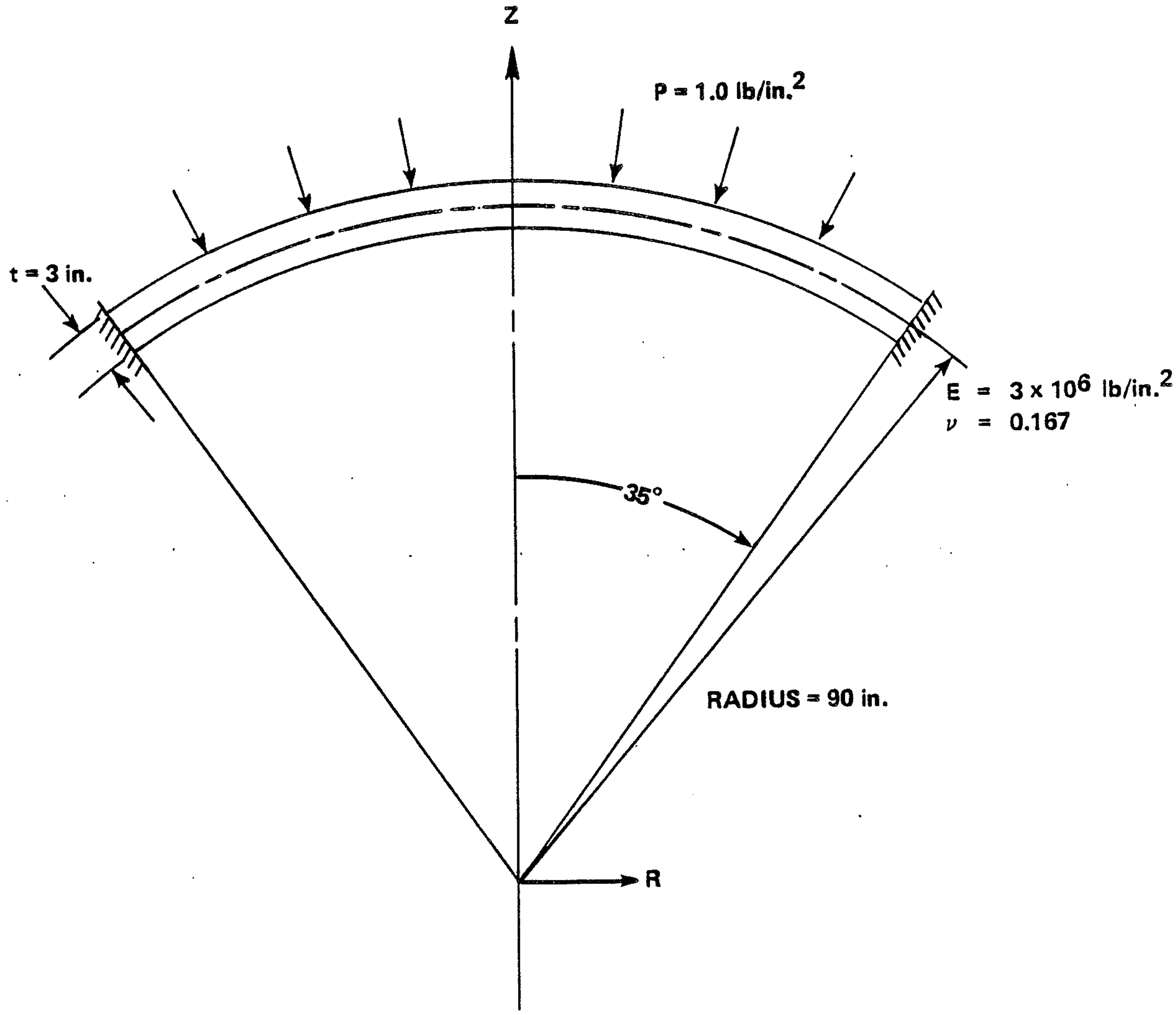

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FIGURE 3.13-15

SHALLOW SPHERICAL SHELL

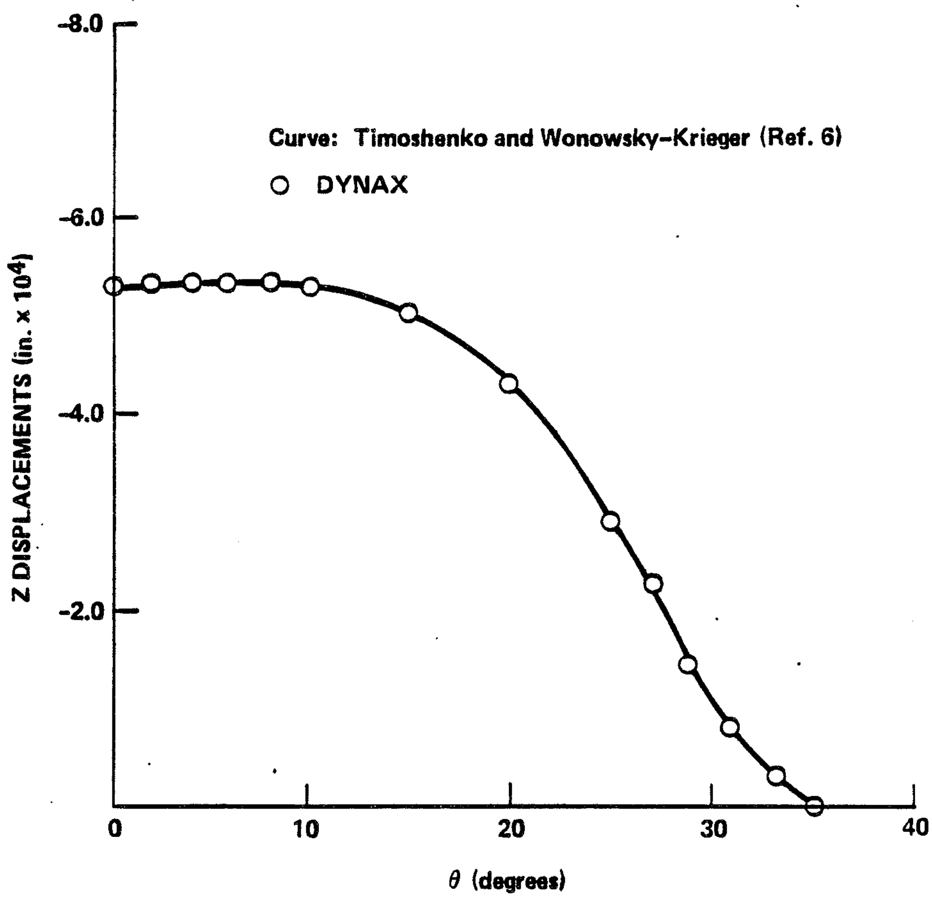

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FIGURE 3.13-16

AXIAL DISPLACEMENT – SHALLOW SPHERICAL SHELL

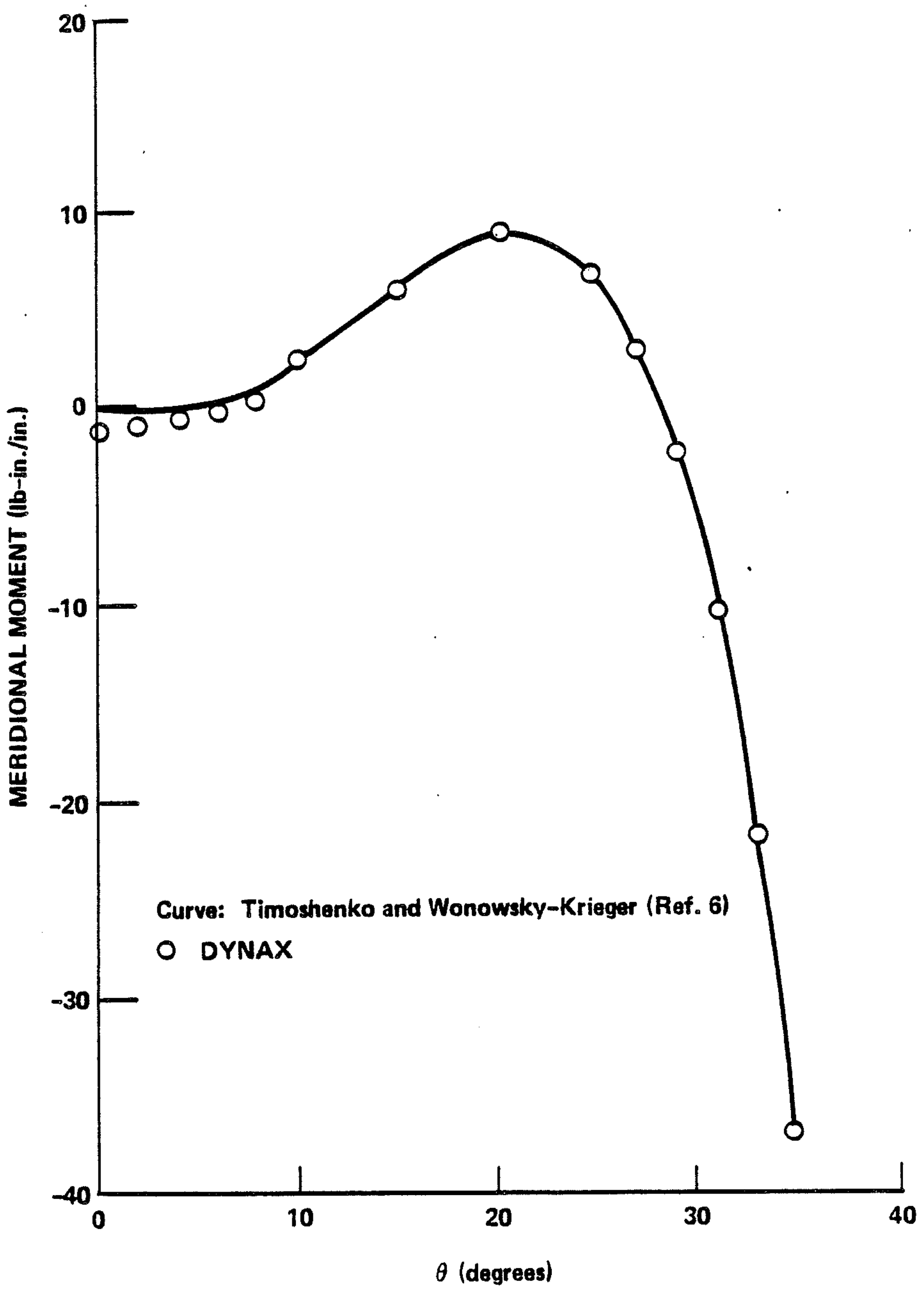

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FIGURE 3.13-17

MERIDIONAL MOMENT – SHALLOW SPHERICAL SHELL

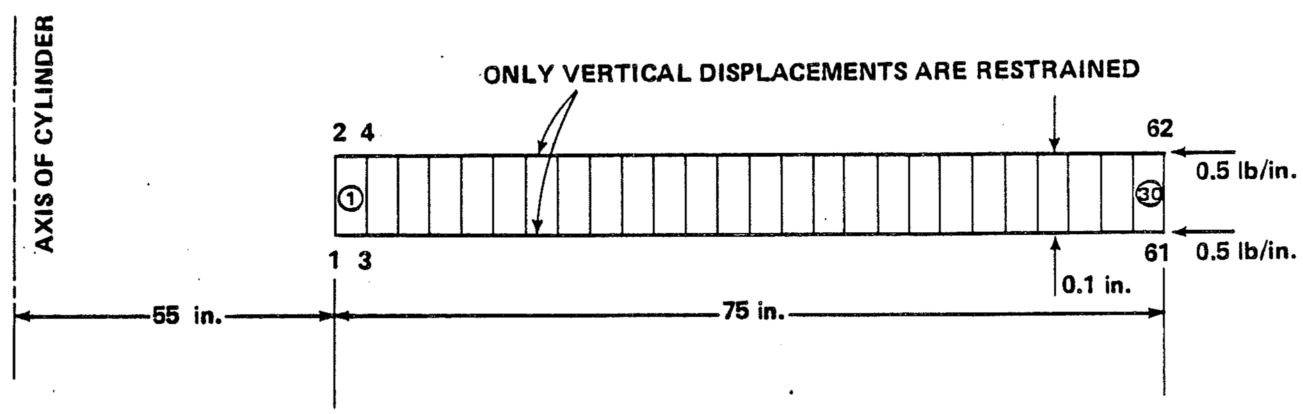

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FIGURE 3.13-18

FINITE ELEMENT IDEALIZATION OF THICK-WALLED CYLINDER

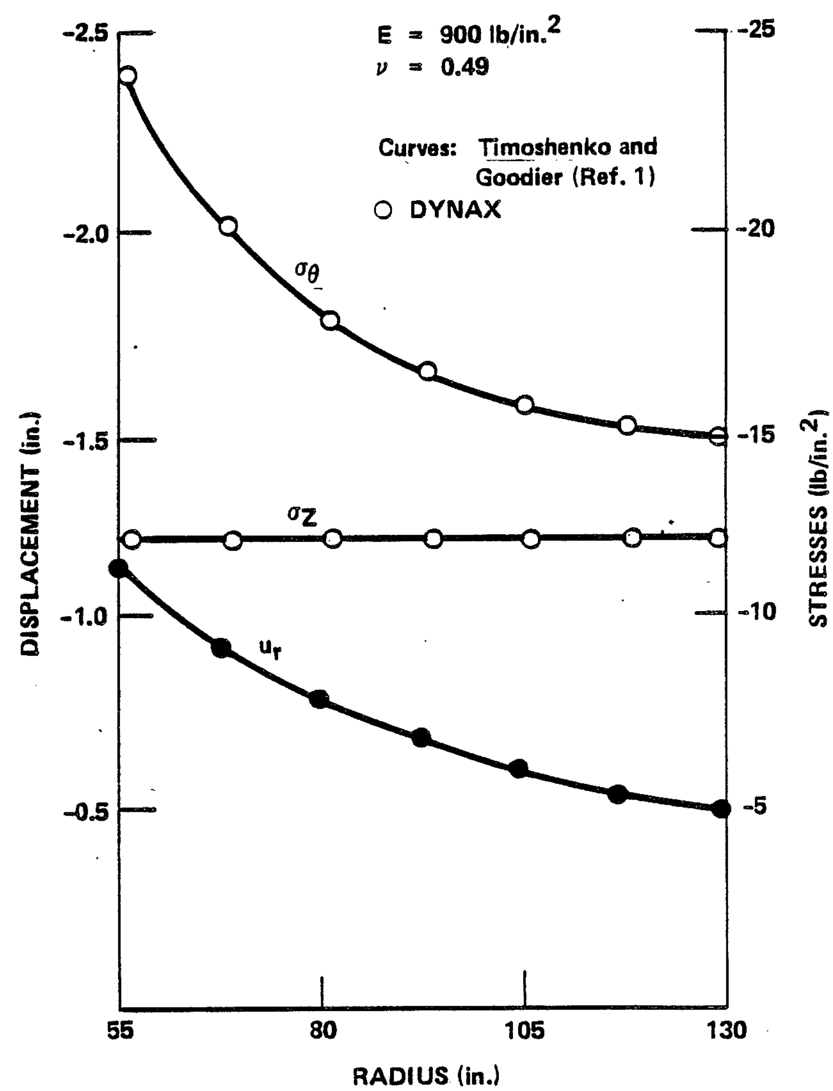
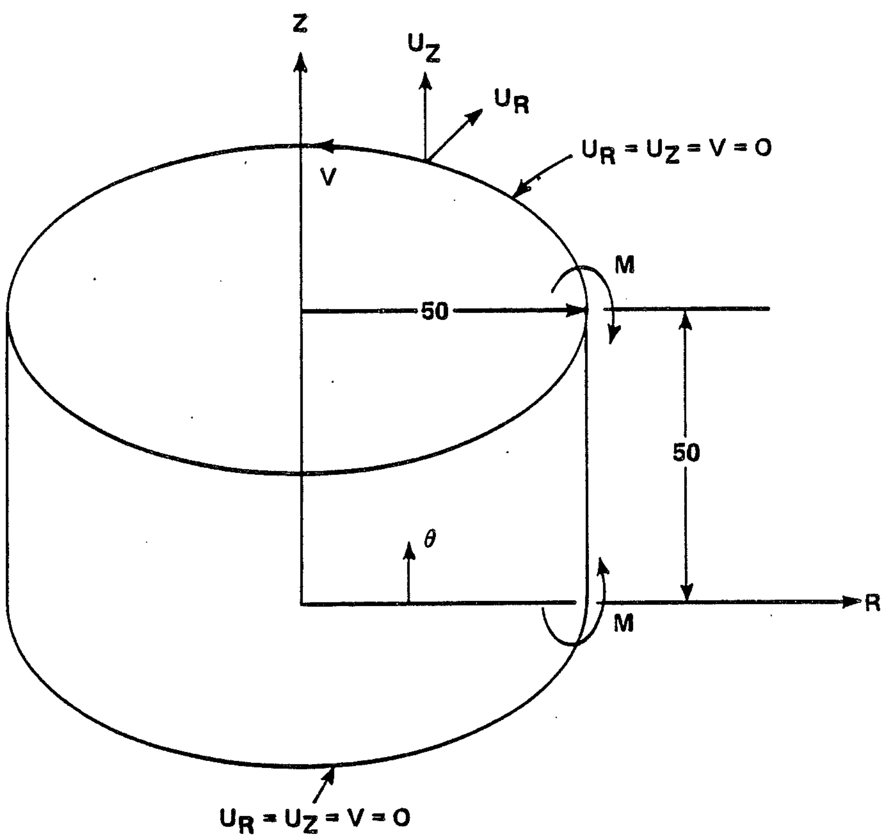


FIGURE 3.13-19

STRESSES AND DISPLACEMENTS
THICK-WALLED CYLINDERS



T = Shell thickness = 1 in.
M = 1 lb-in./in.
E = 91 lb/in.^{2}
ν = 0.3
N = Fourier harmonic number

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FIGURE 3.13-20

CYLINDER UNDER HARMONIC LOADS

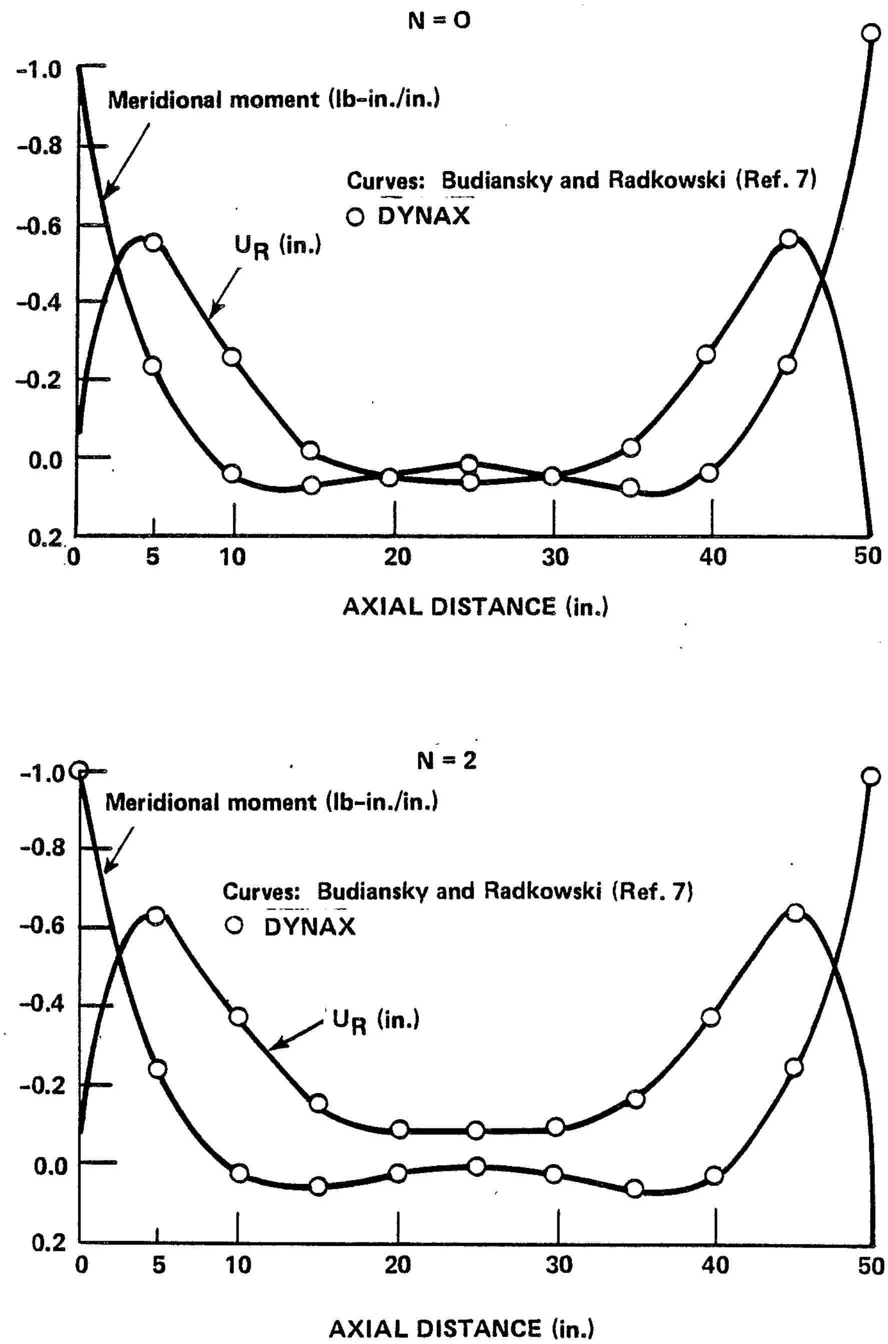

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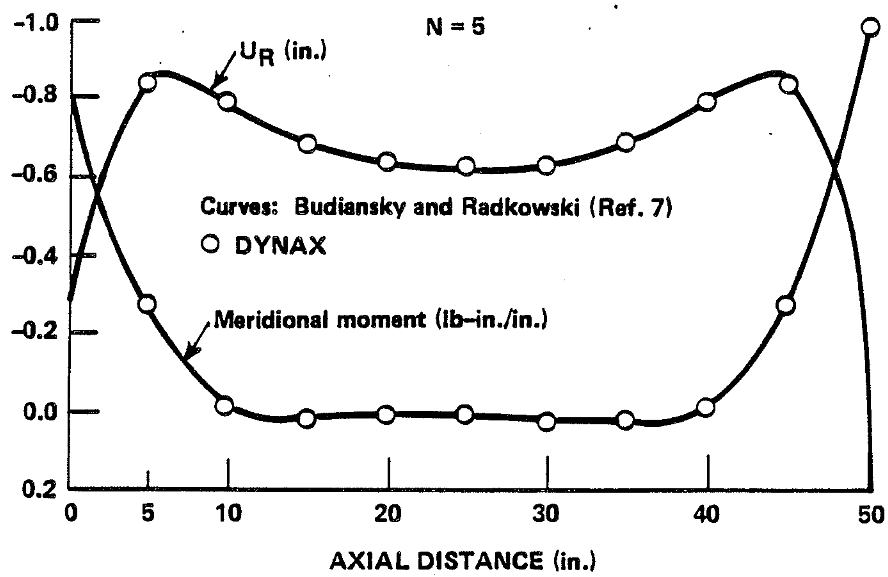
FIGURE 3.13-21, SHEET 1

MERIDIONAL MOMENTS AND DEFLECTIONS OF CYLINDER



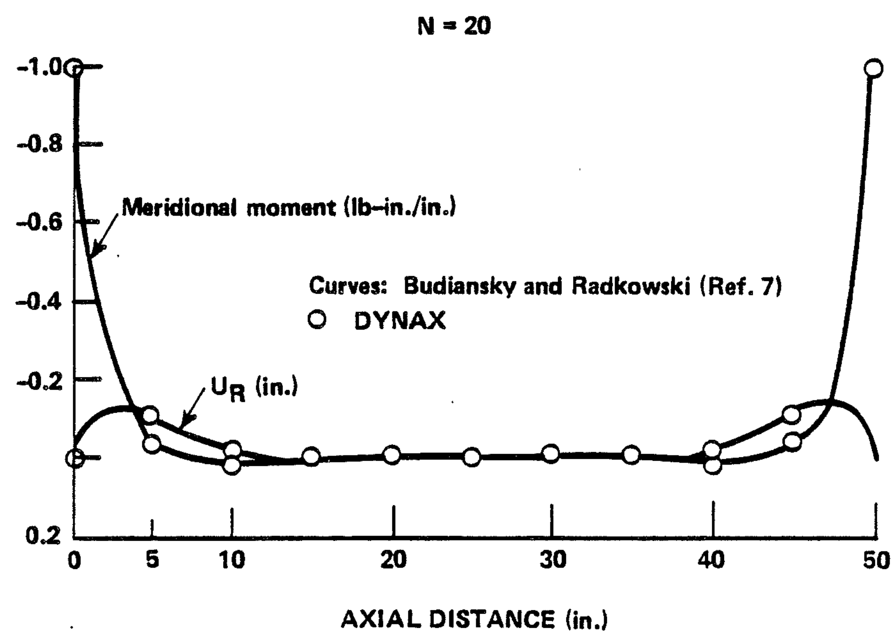


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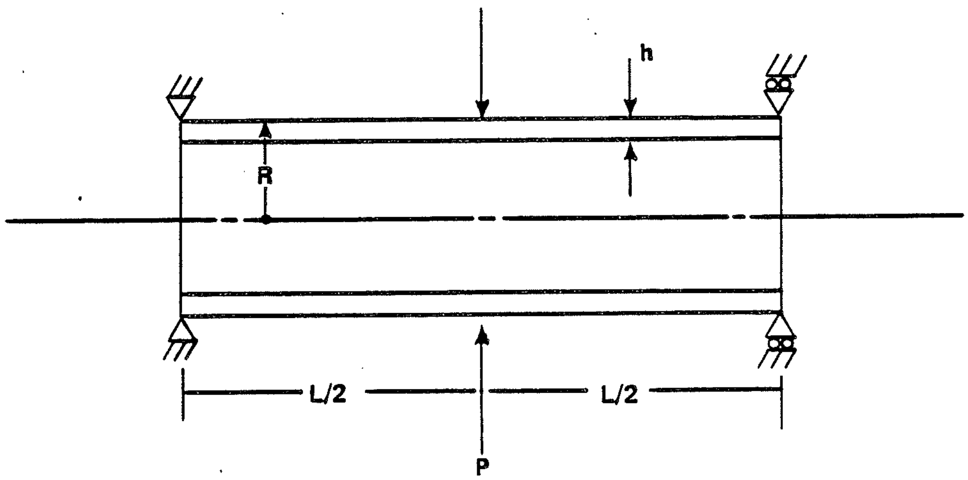
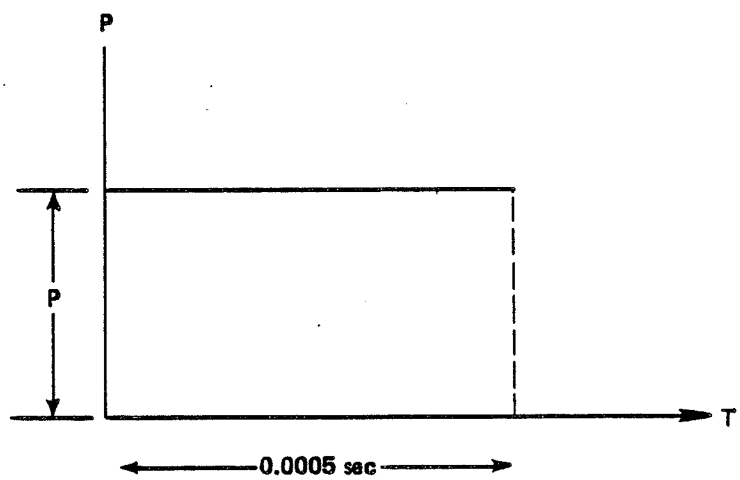
FIGURE 3.13-21, SHEET 2

MERIDIONAL MOMENTS AND DEFLECTIONS OF CYLINDER





TIME HISTORY LOADING

L = 18 in.
P = 500 lb
R = 3 in.
h = 0.3 in.
E = 30×10^6 lb/in.^{2}

Mass density (ρ) = 0.0187 lb–sec^2/in.^{4}

$\nu = 0.3$

Time step = 0.000005 sec

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FIGURE 3.13-22

SUDDENLY APPLIED RING (LINE) LOAD

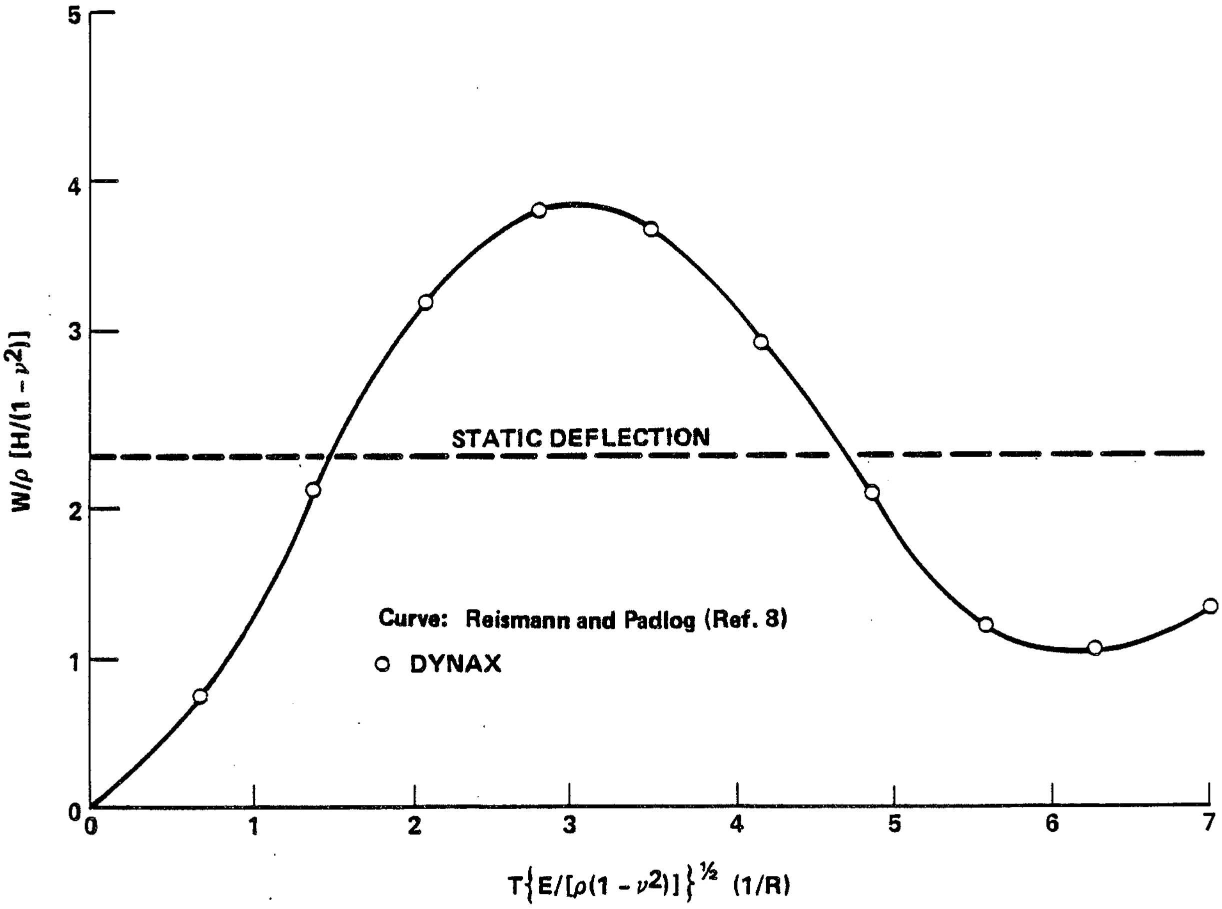

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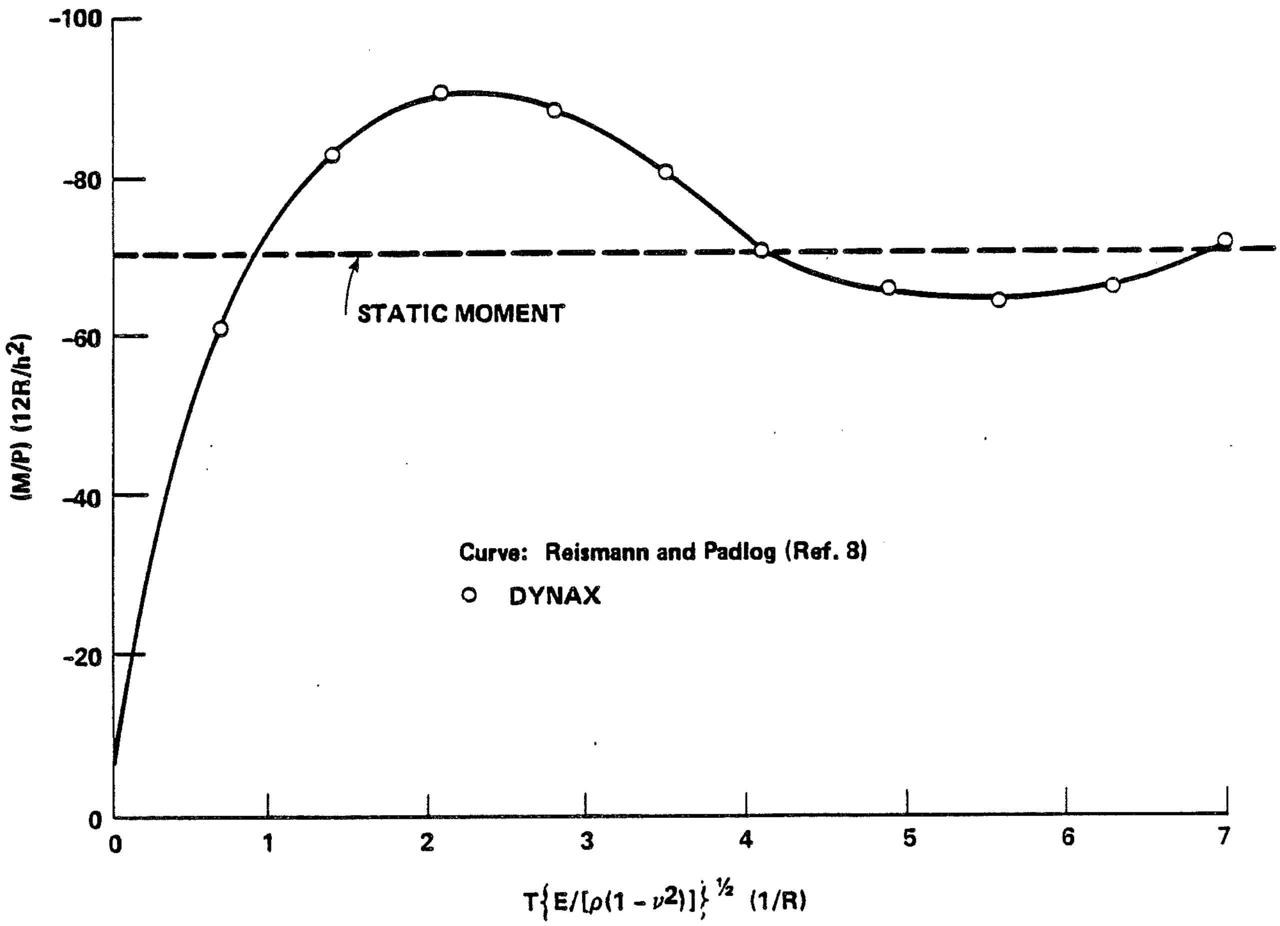
FIGURE 3.13-23

RADIAL DISPLACEMENT (W) VERSUS TIME



M = Meridional moment

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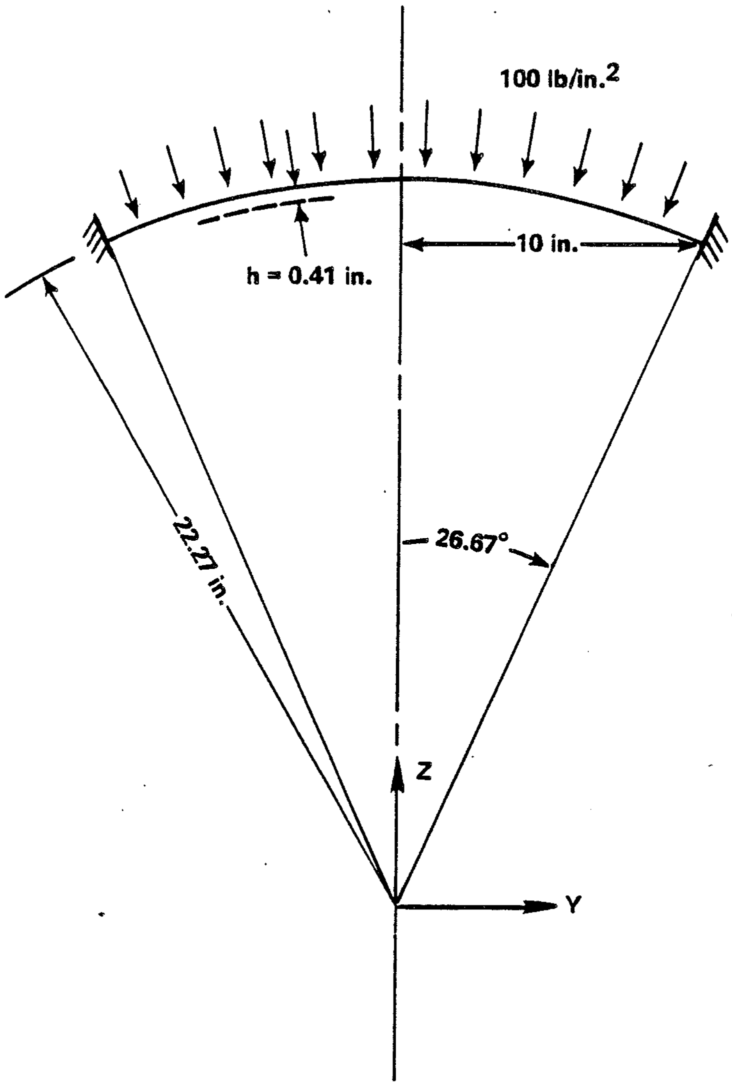
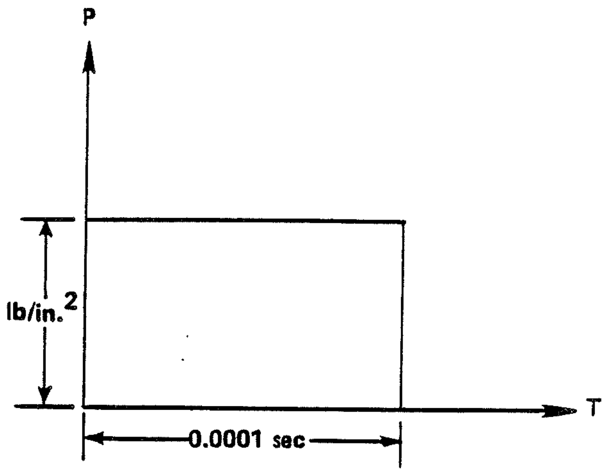
FIGURE 3.13-24

BENDING MOMENT VERSUS TIME
SUDDENLY APPLIED RING (LINE) LOAD



SPHERICAL CAP



TIME HISTORY LOADING

$E = 10.5 \times 10^6$ lb/in.^{2}
$\nu = 0.3$
$\rho = 2.46 \times 10^{-4}$ lb-sec^2/in.^{4}

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FIGURE 3.13-25

DIMENSIONS AND TIME HISTORY OF LOADING FOR SHALLOW SPHERICAL CAP WITH CLAMPED SUPPORT UNDER SUDDEN UNIFORM LOAD AS ANALYZED IN PROBLEM 5 (DYNAX)

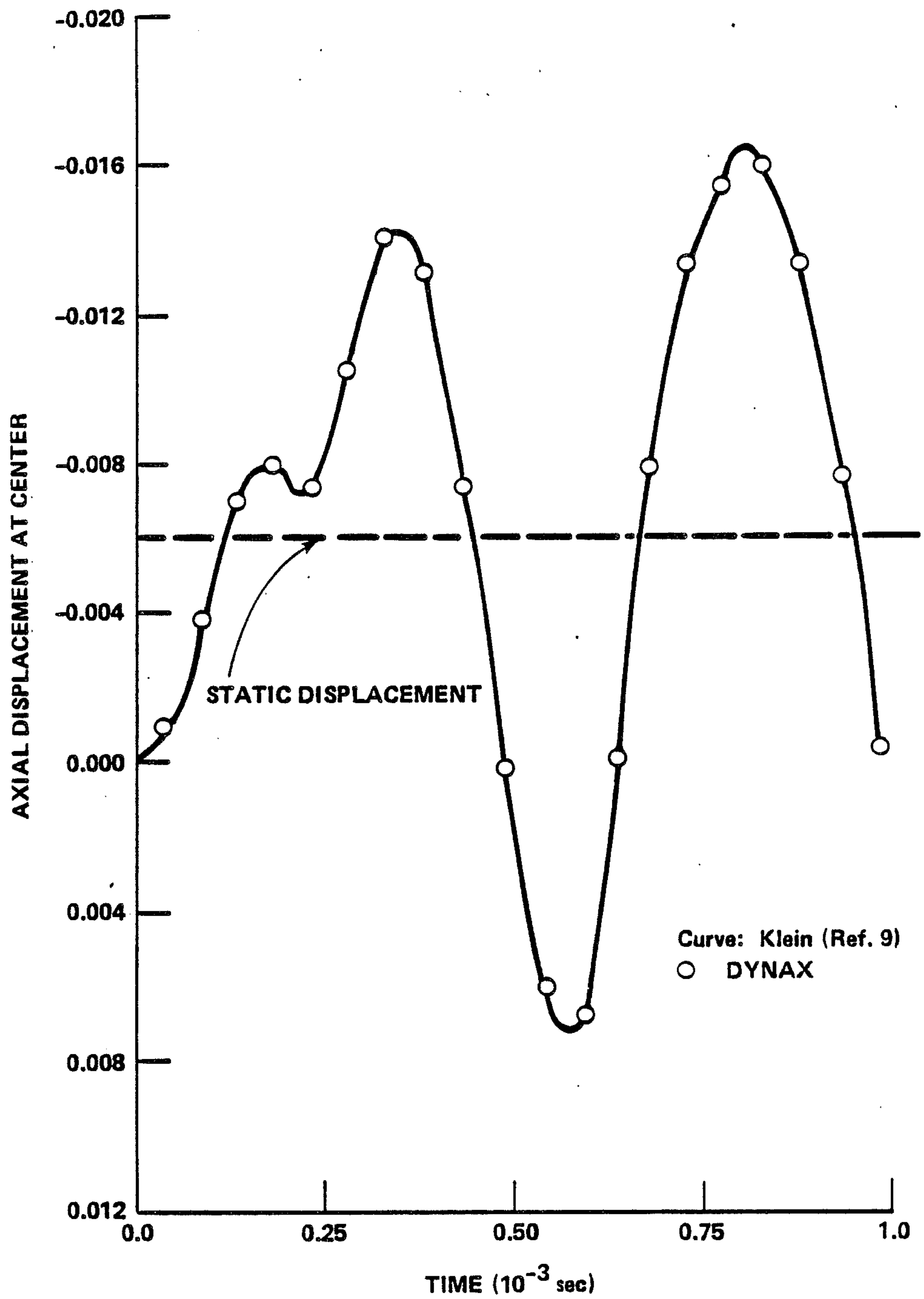

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FIGURE 3.13-26

AXIAL DISPLACEMENT OF SPHERICAL CAP
UNDER DYNAMIC LOAD

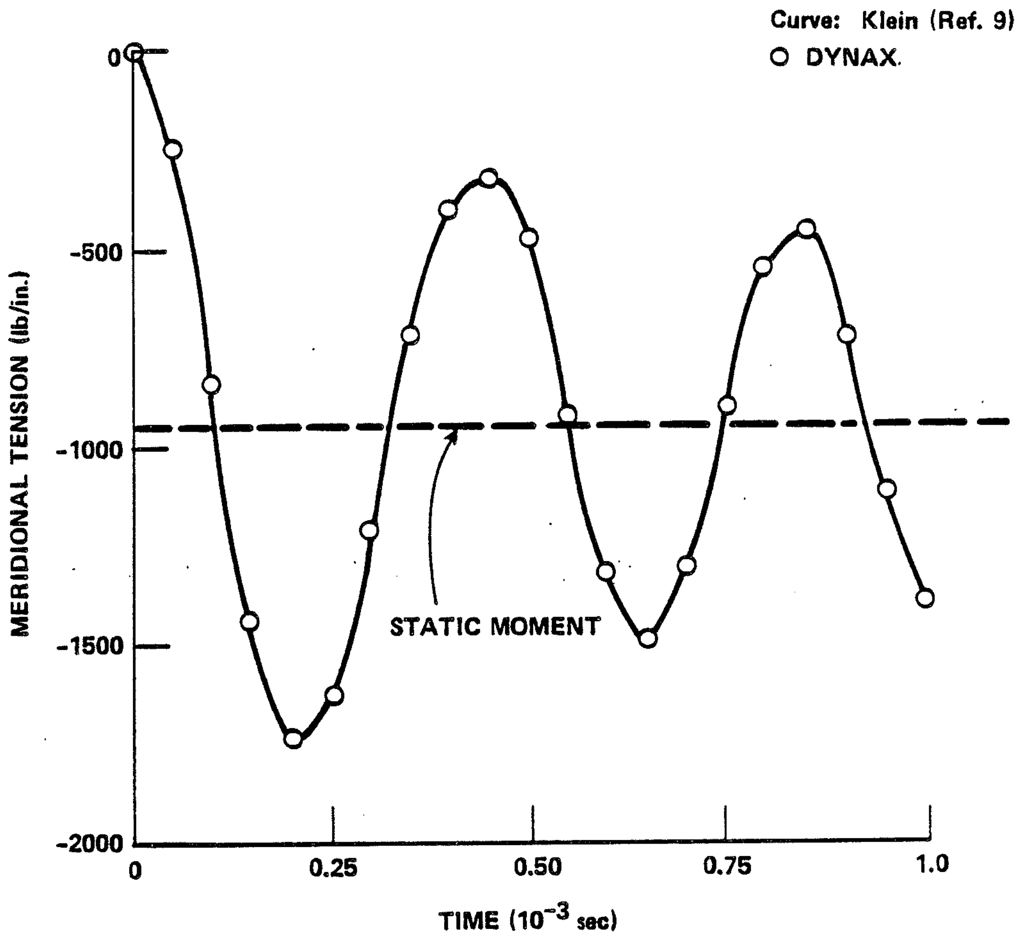

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FIGURE 3.13-27

MERIDIONAL TENSION OF SPHERICAL CAP UNDER DYNAMIC LOAD

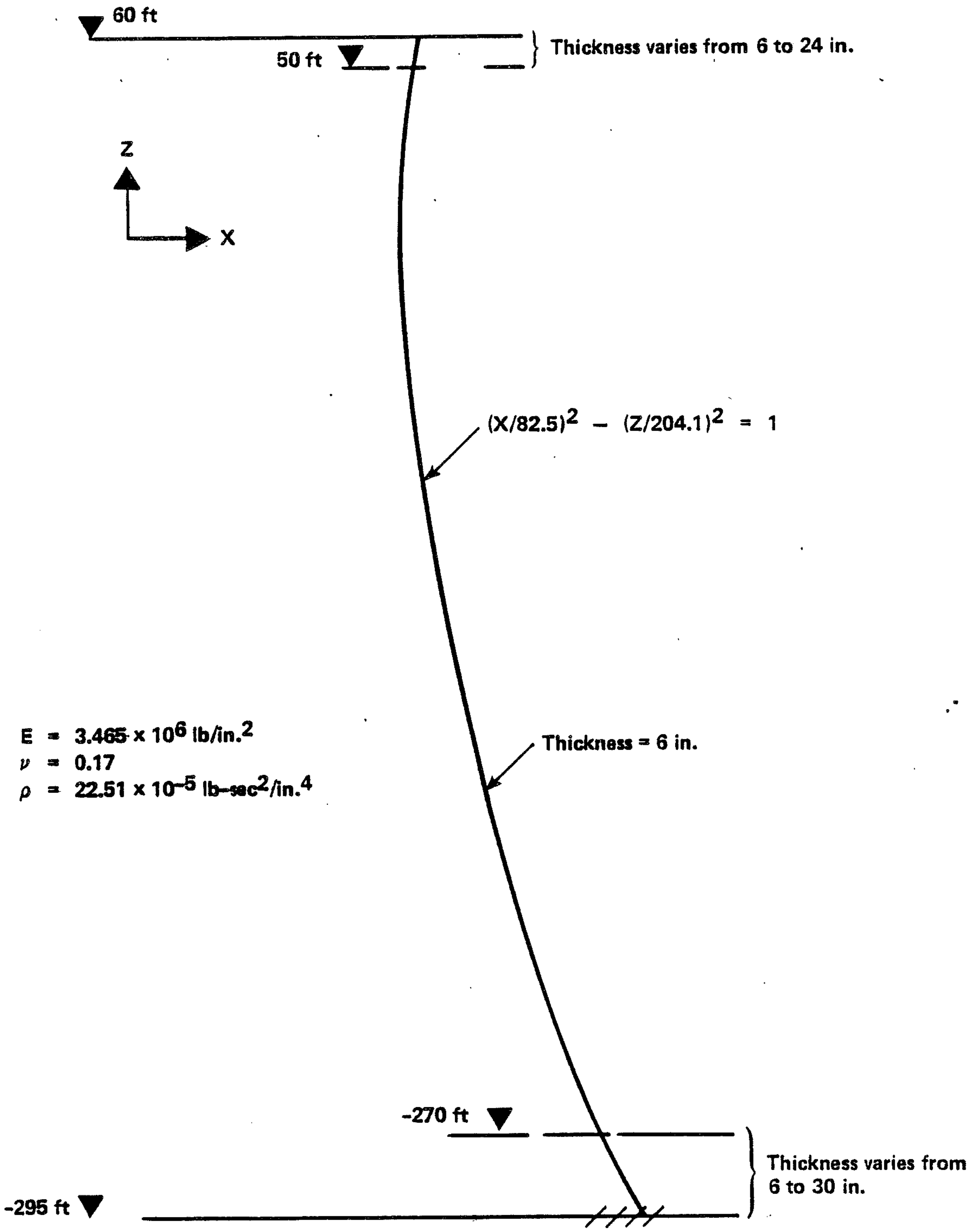

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FIGURE 3.13-28

HYPERBOLIC COOLING TOWER

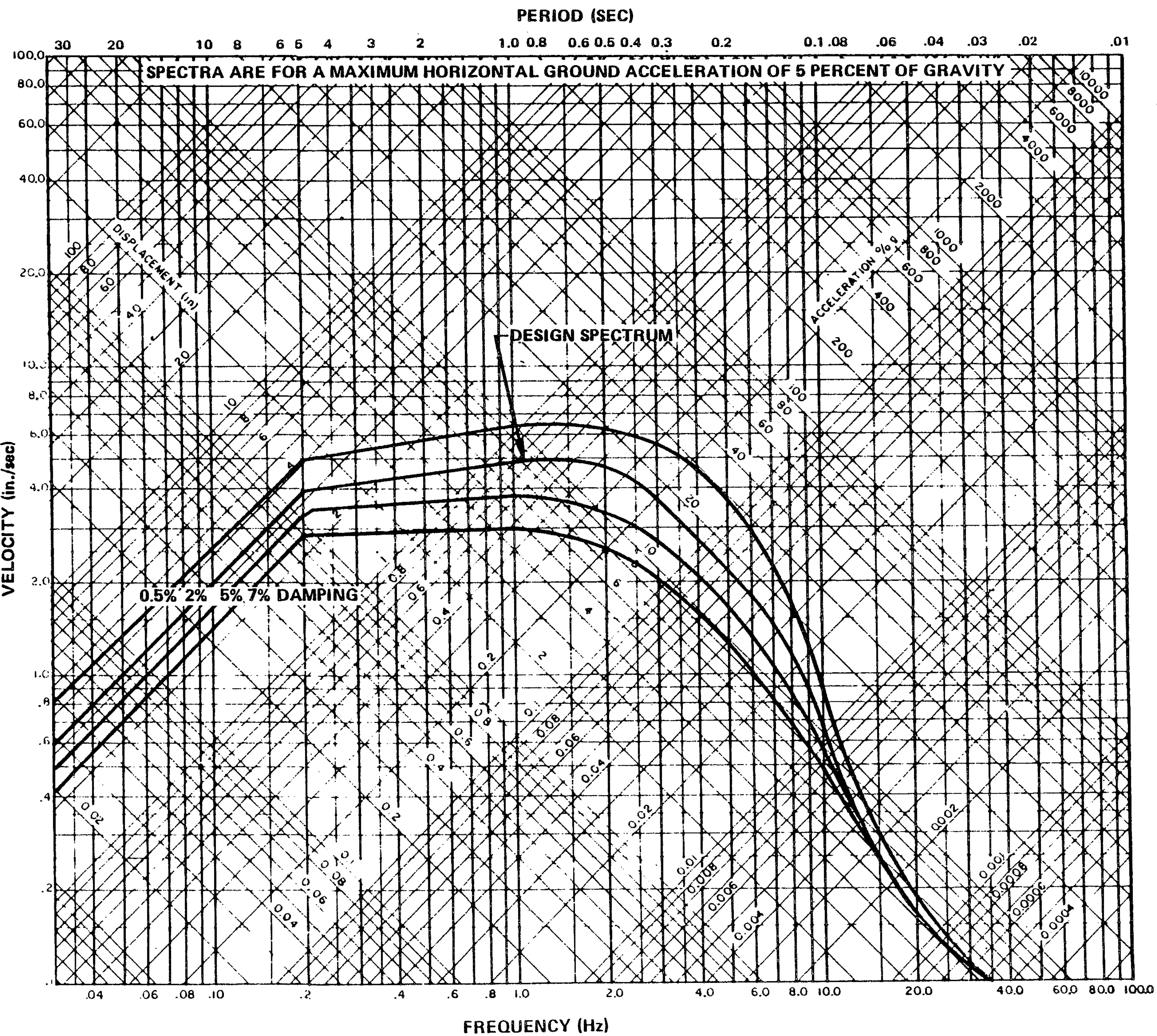

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FIGURE 3.13-29

SPECTRUM OF DESIGN EARTHQUAKE

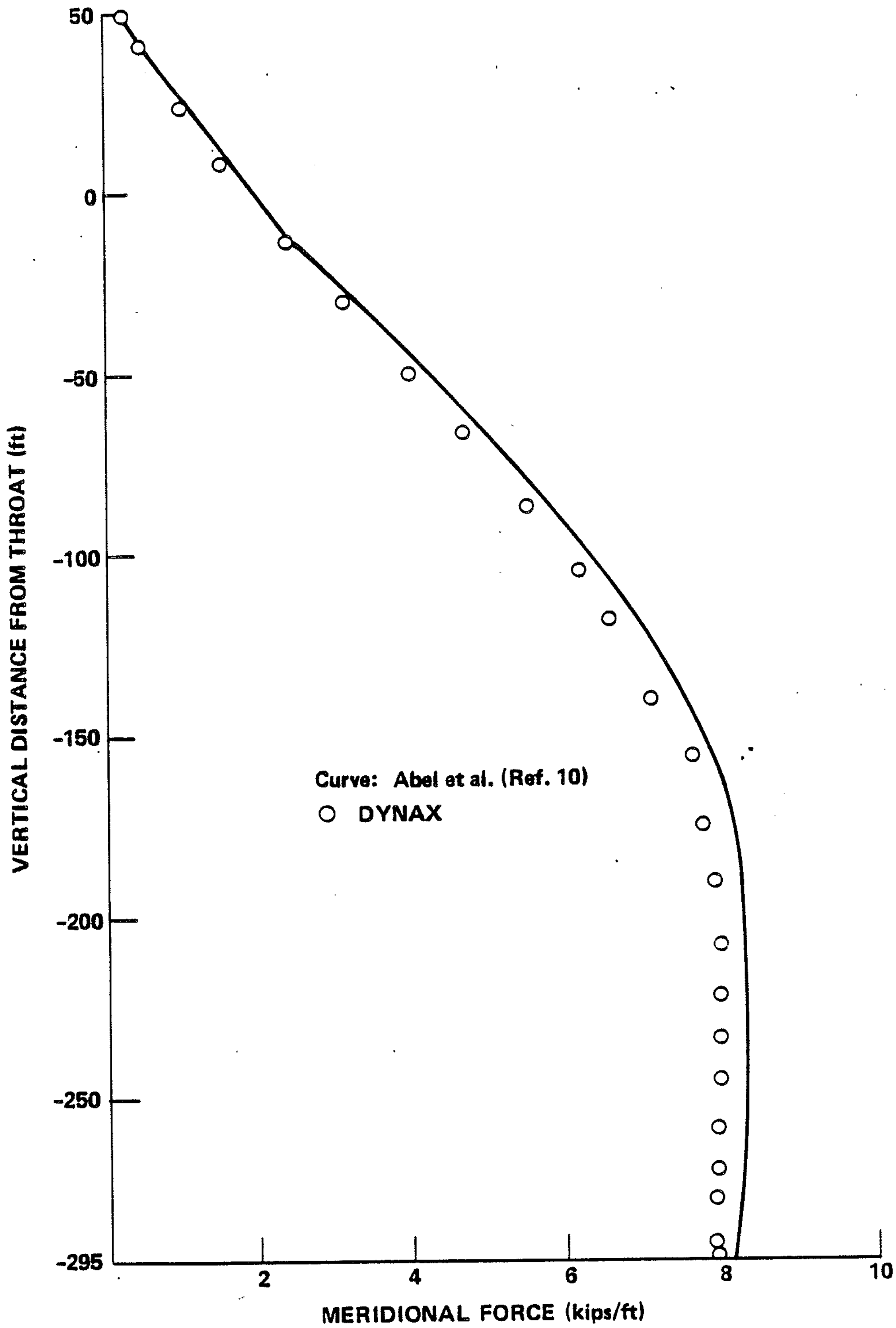

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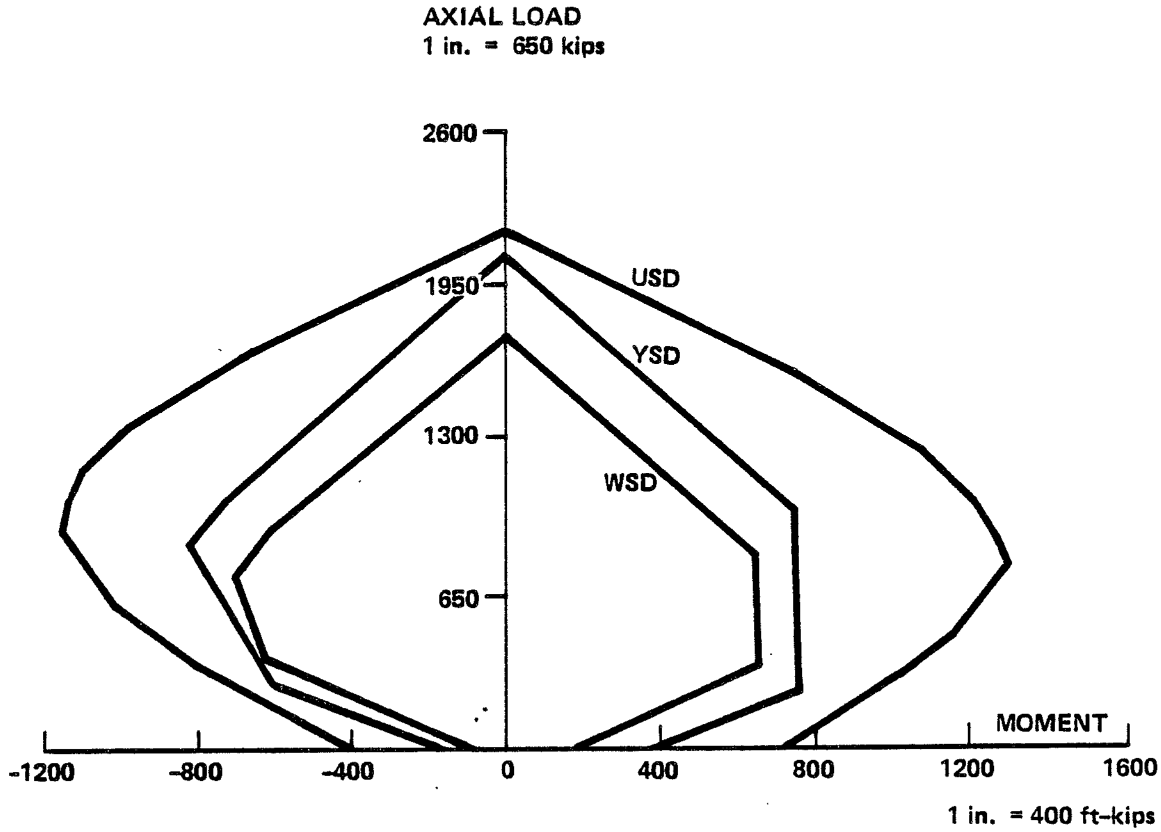
FIGURE 3.13-30

COOLING TOWER MERIDIONAL FORCE



LEGEND (see Table 3.13–3)

TEST 4 48 x 12 STEEL
T = 2.75/40
C = 1.25/10
FCP = 4.5
FP = 60

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FIGURE 3.13-31

INTERACTION DIAGRAM – AXIAL LOAD VERSUS BENDING MOMENT

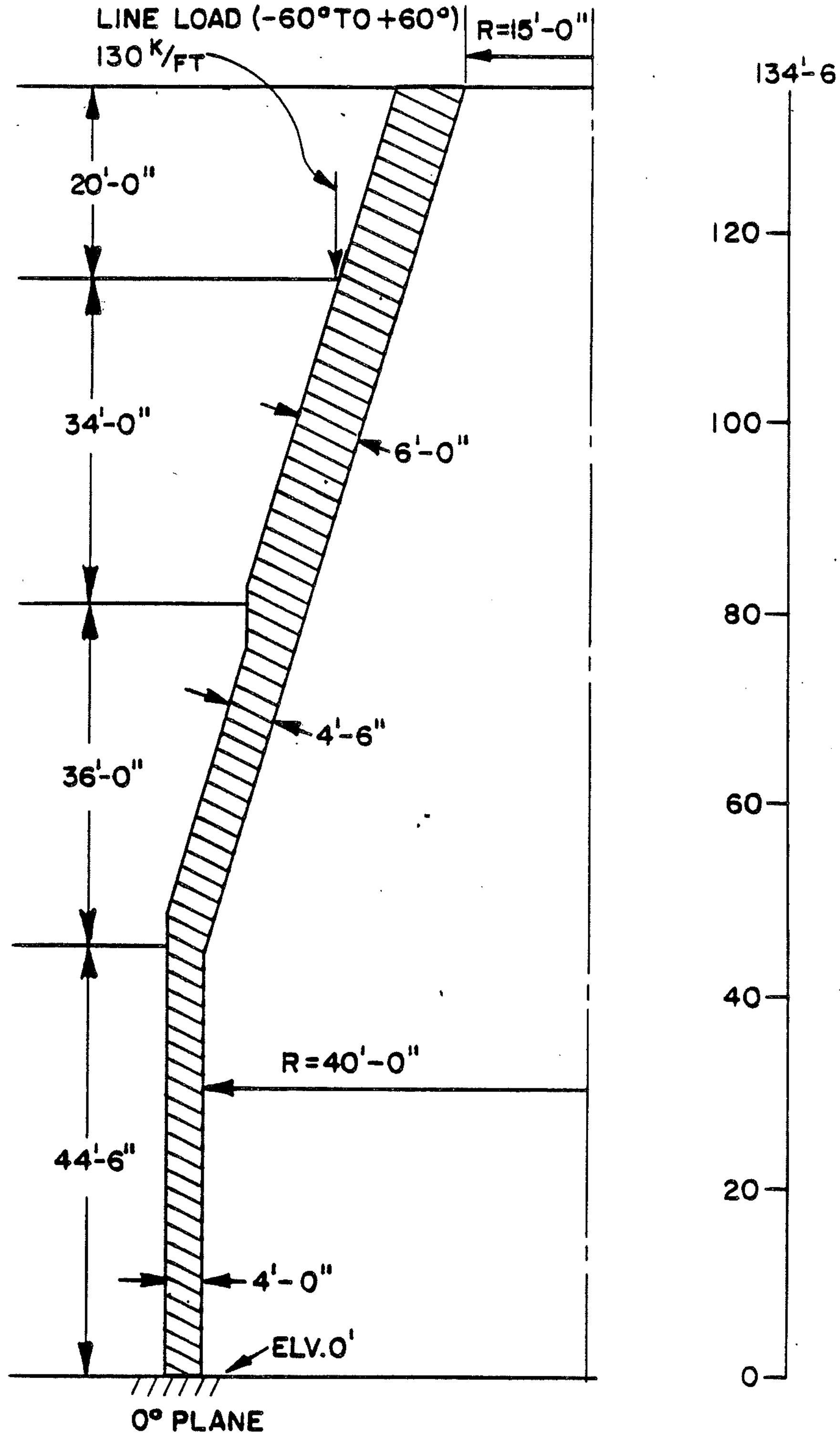

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FIGURE 3.13-32

KALSHEL VALIDATION EXAMPLE
ECCENTRIC LINE LOAD

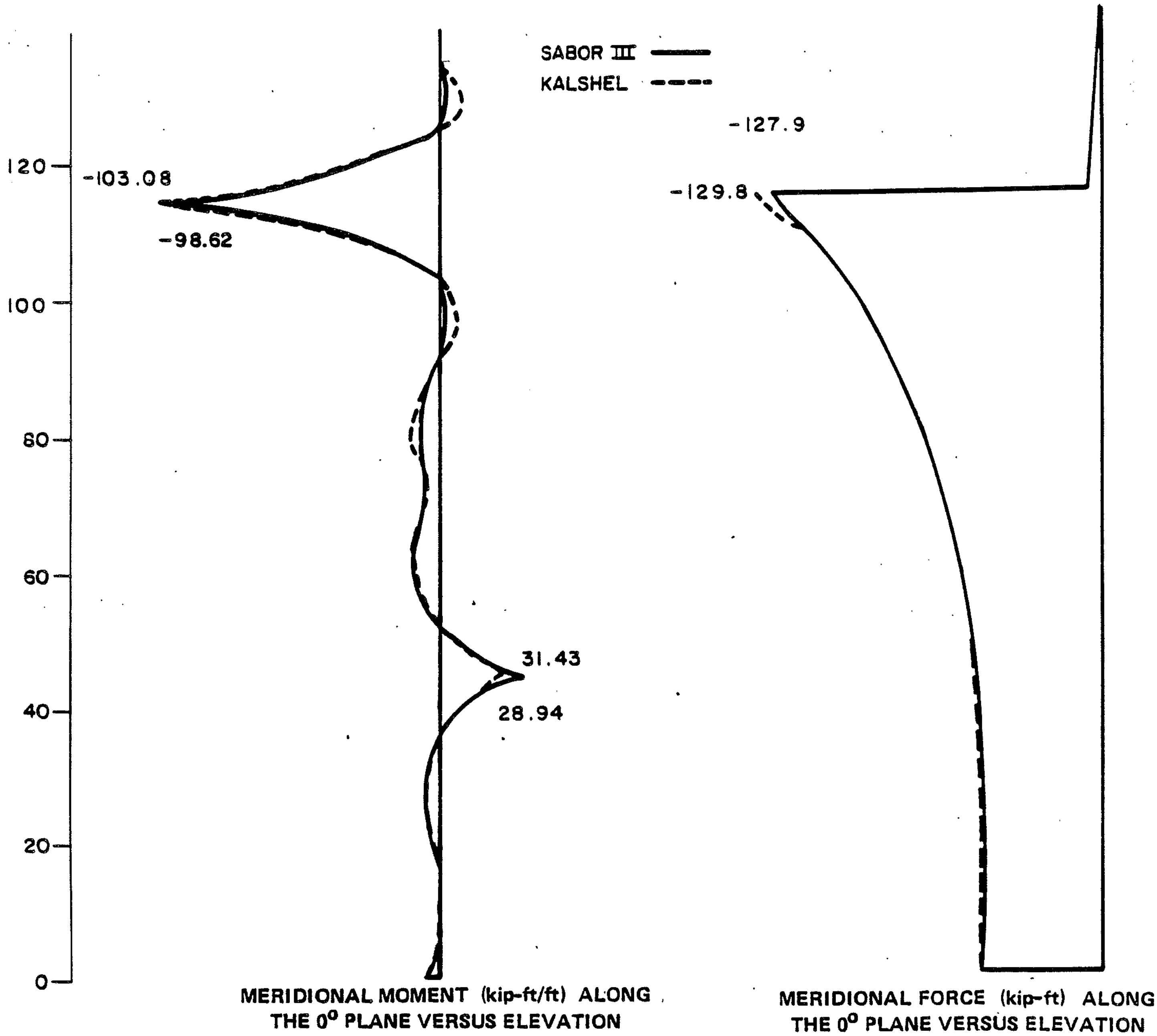

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FIGURE 3.13-33

SABOR III AND KALSHEL
VALIDATION EXAMPLE
MERIDIONAL MOMENT AND FORCE

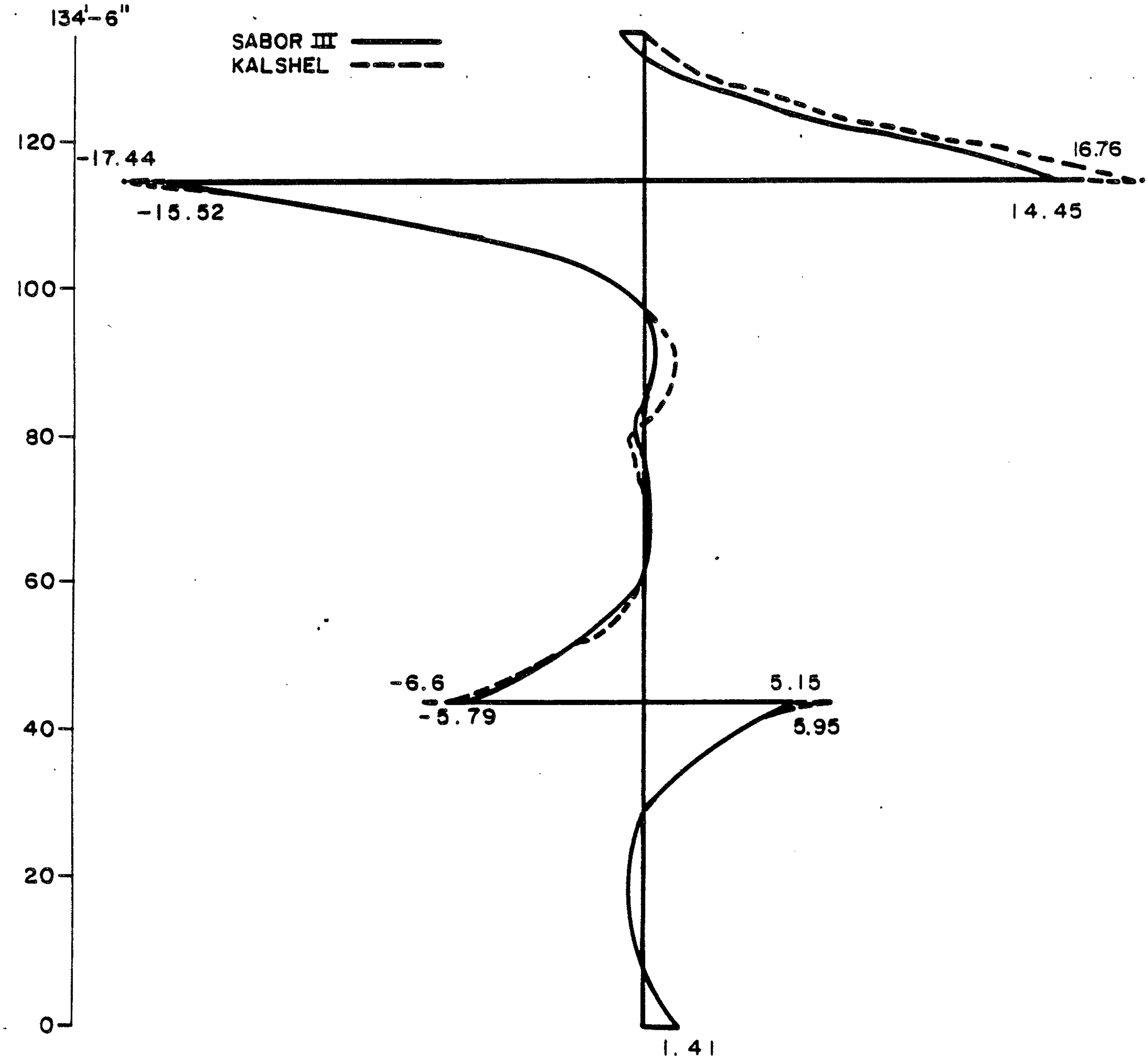

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FIGURE 3.13-34

RADIAL SHEAR (KIP/FT) ALONG THE 0° PLANE VERSUS ELEVATION (FT)

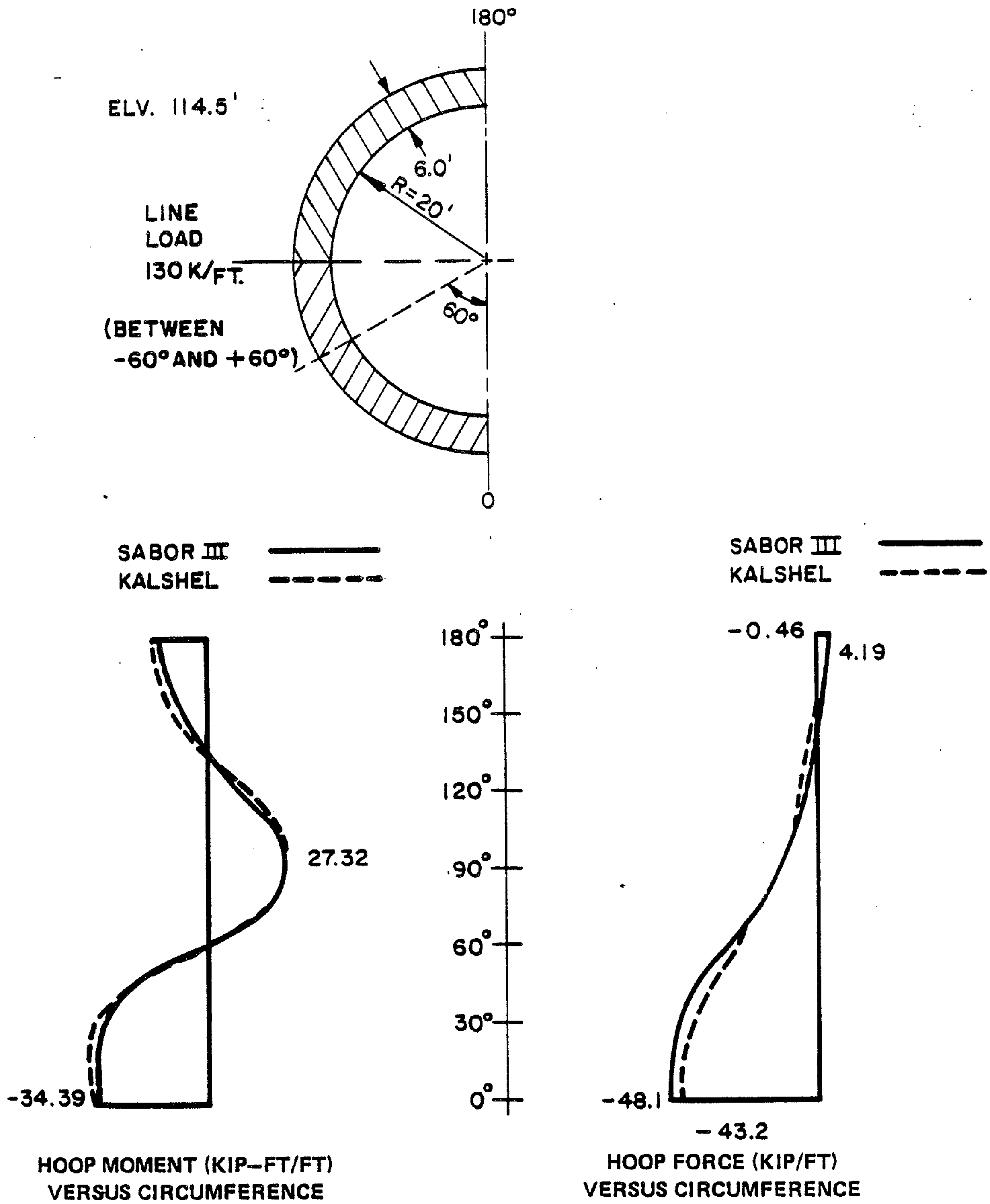

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FIGURE 3.13-35

SABOR III AND KALSHEL
VALIDATION EXAMPLE
HOOP MOMENT AND FORCE

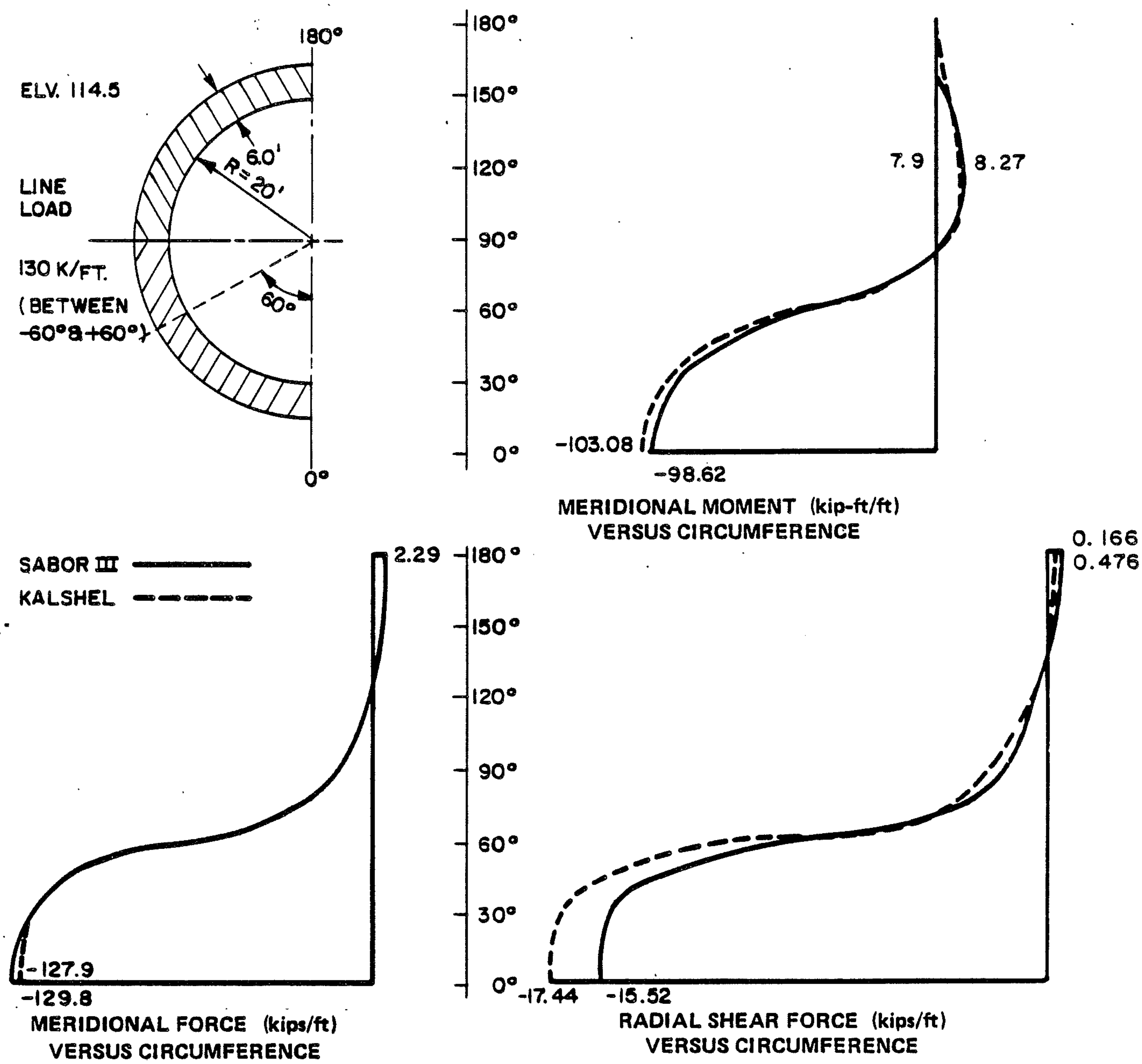

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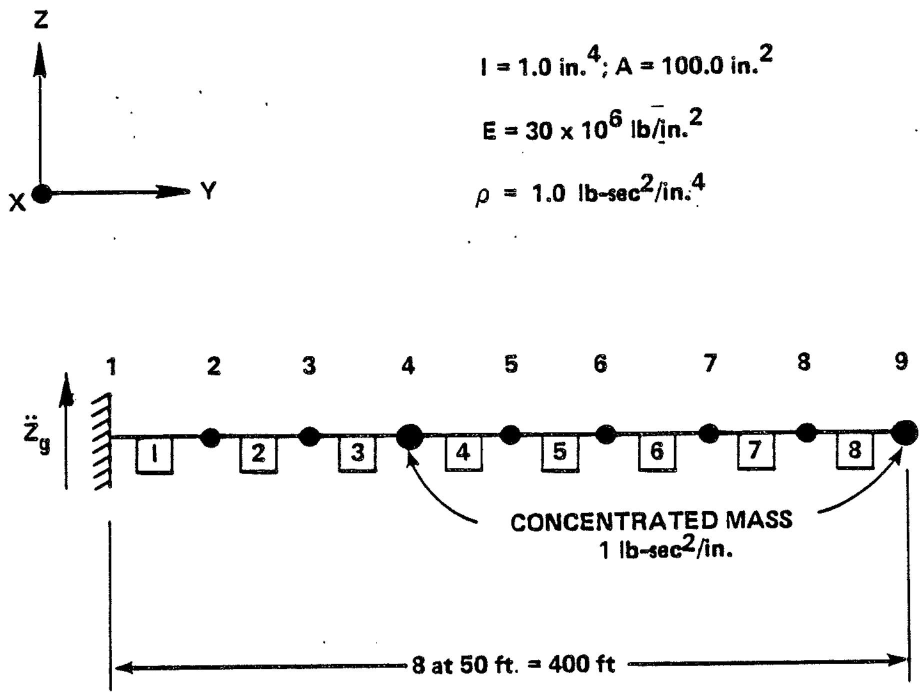
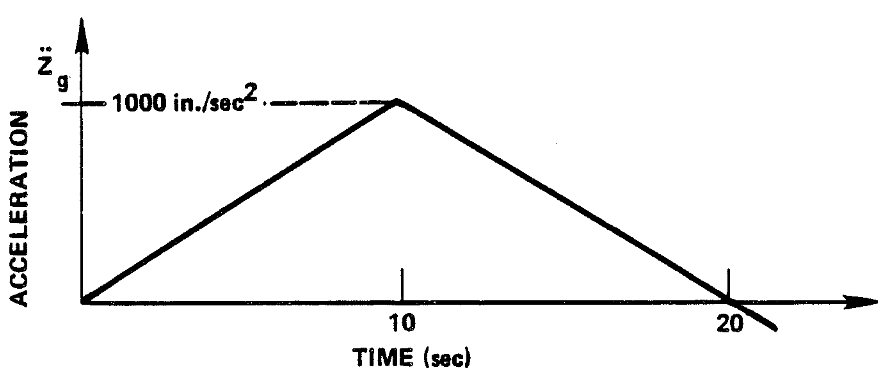
FIGURE 3.13-36

SABOR III AND KALSHEL
VALIDATION EXAMPLE
MERIDIONAL MOMENT AND FORCE AND
RADIAL SHEAR FORCE



(a) NODE AND BEAM NUMBER ASSIGNMENTS FOR THE CANTILEVER MODEL



(b) GROUND ACCELERATION APPLIED AT NODE 1

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FIGURE 3.13-37

RESPONSE HISTORY ANALYSIS OF CANTILEVER BEAM

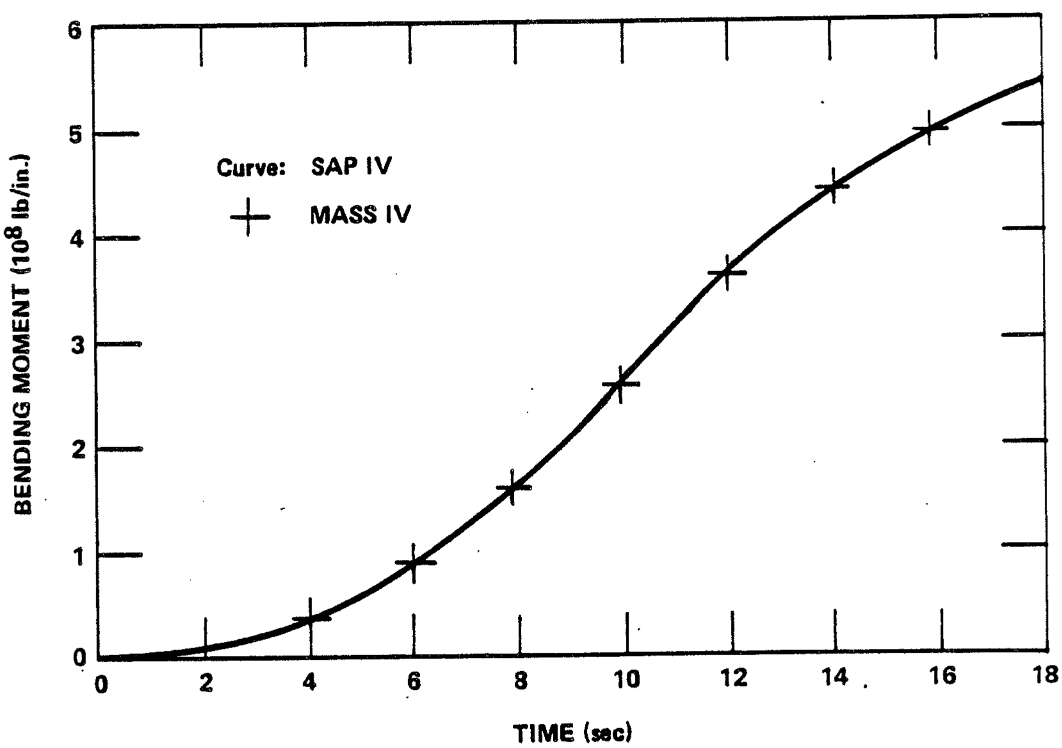

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FIGURE 3.13-38

CANTILEVER RESPONSE
MOMENT AT NODE 1
FIXED END OF CANTILEVER

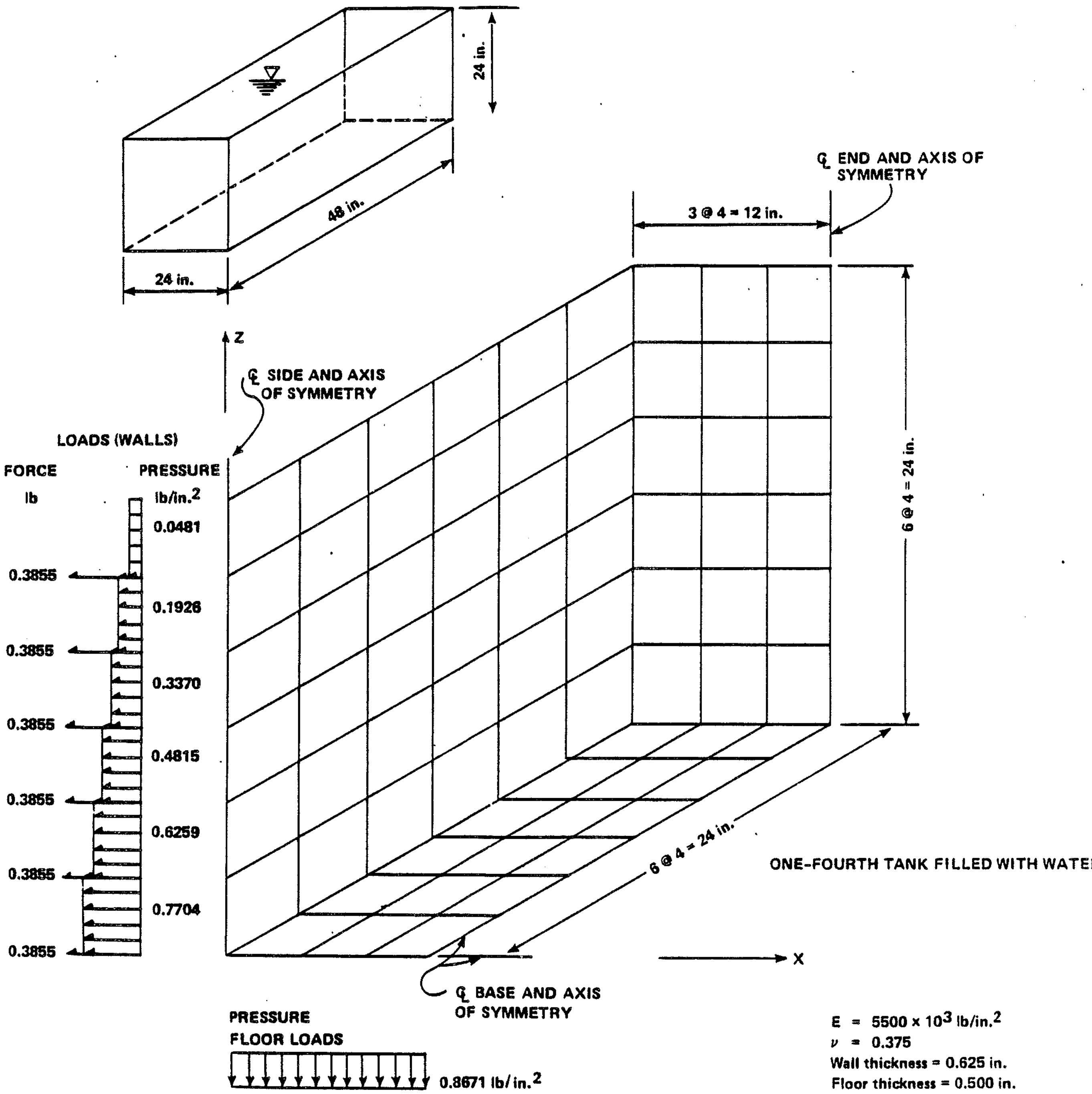

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FIGURE 3.13-39

RECTANGULAR TANK FILLED WITH WATER

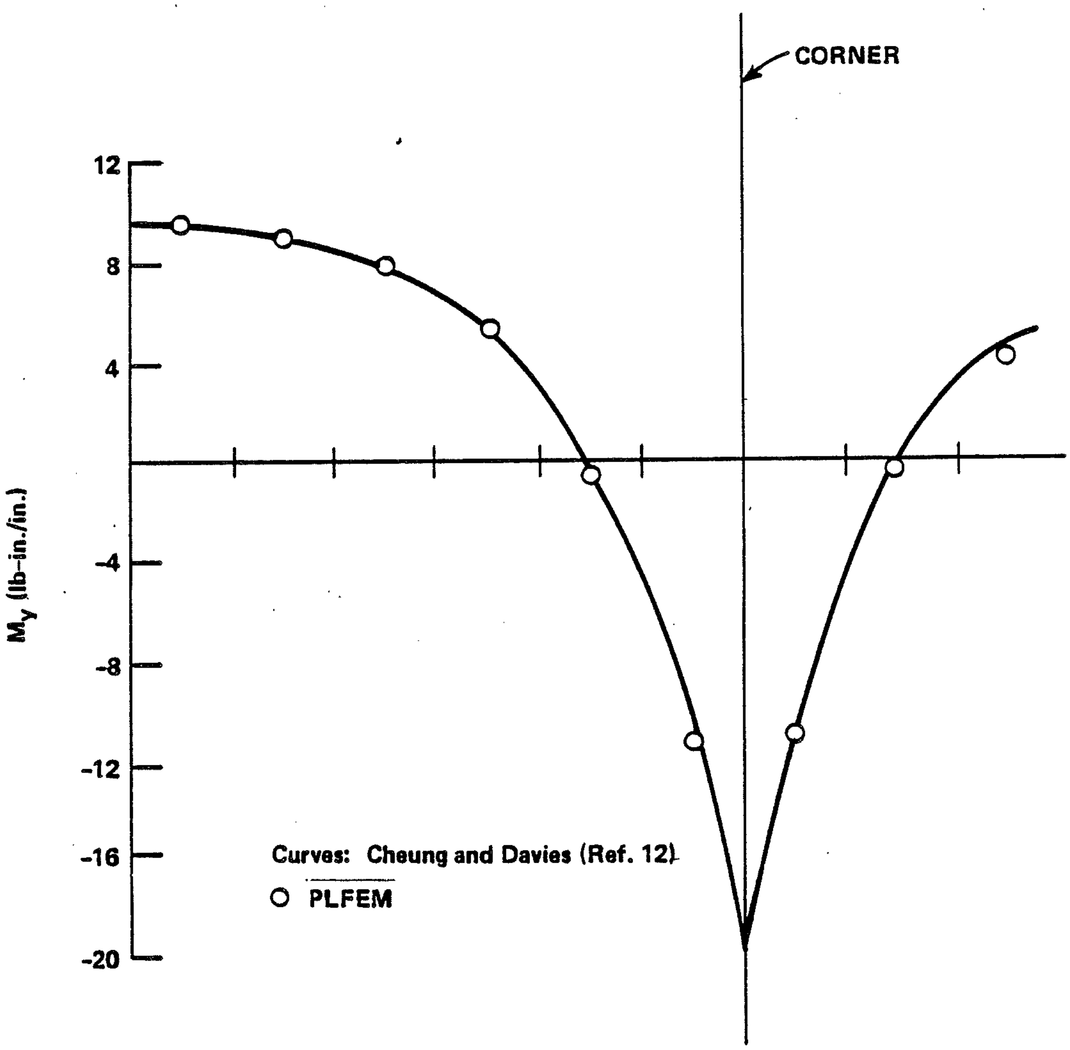

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FIGURE 3.13–40

MOMENT M_y AT HORIZONTAL CENTERLINE OF WALLS

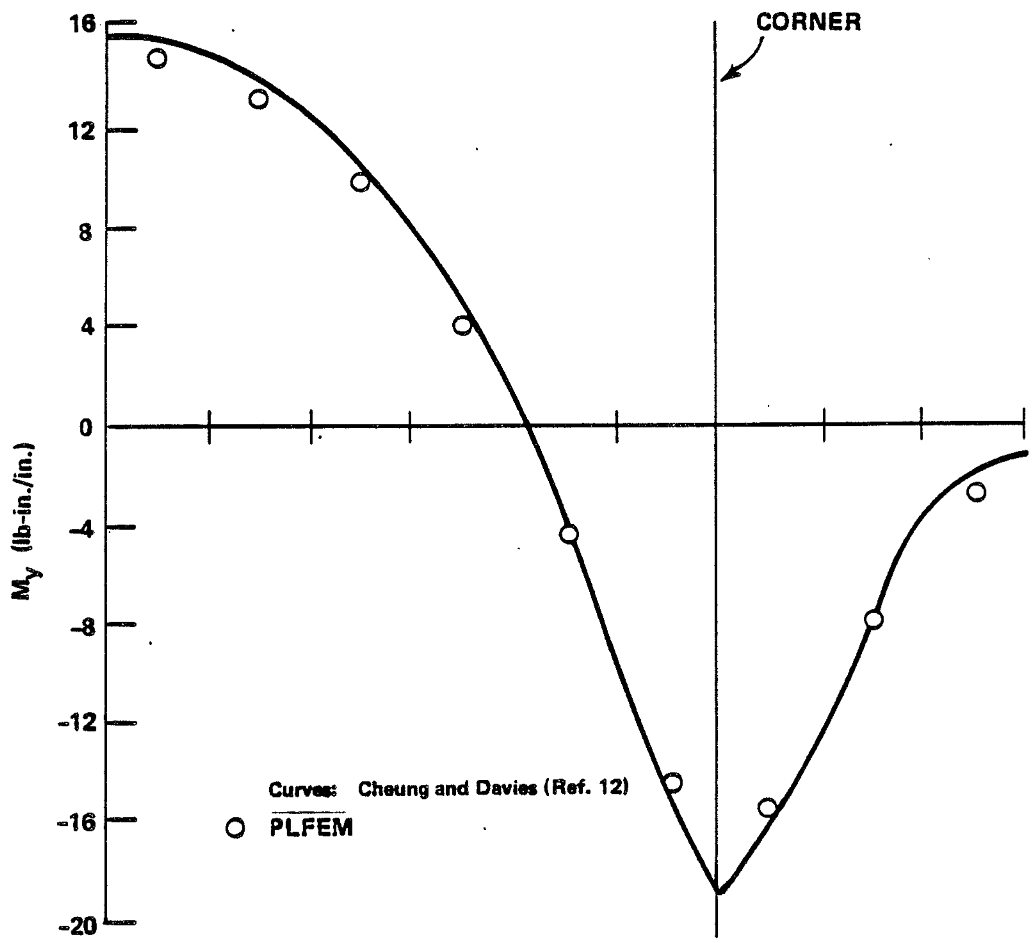

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FIGURE 3.13-41

MOMENT M_y AT TOP OF WALL

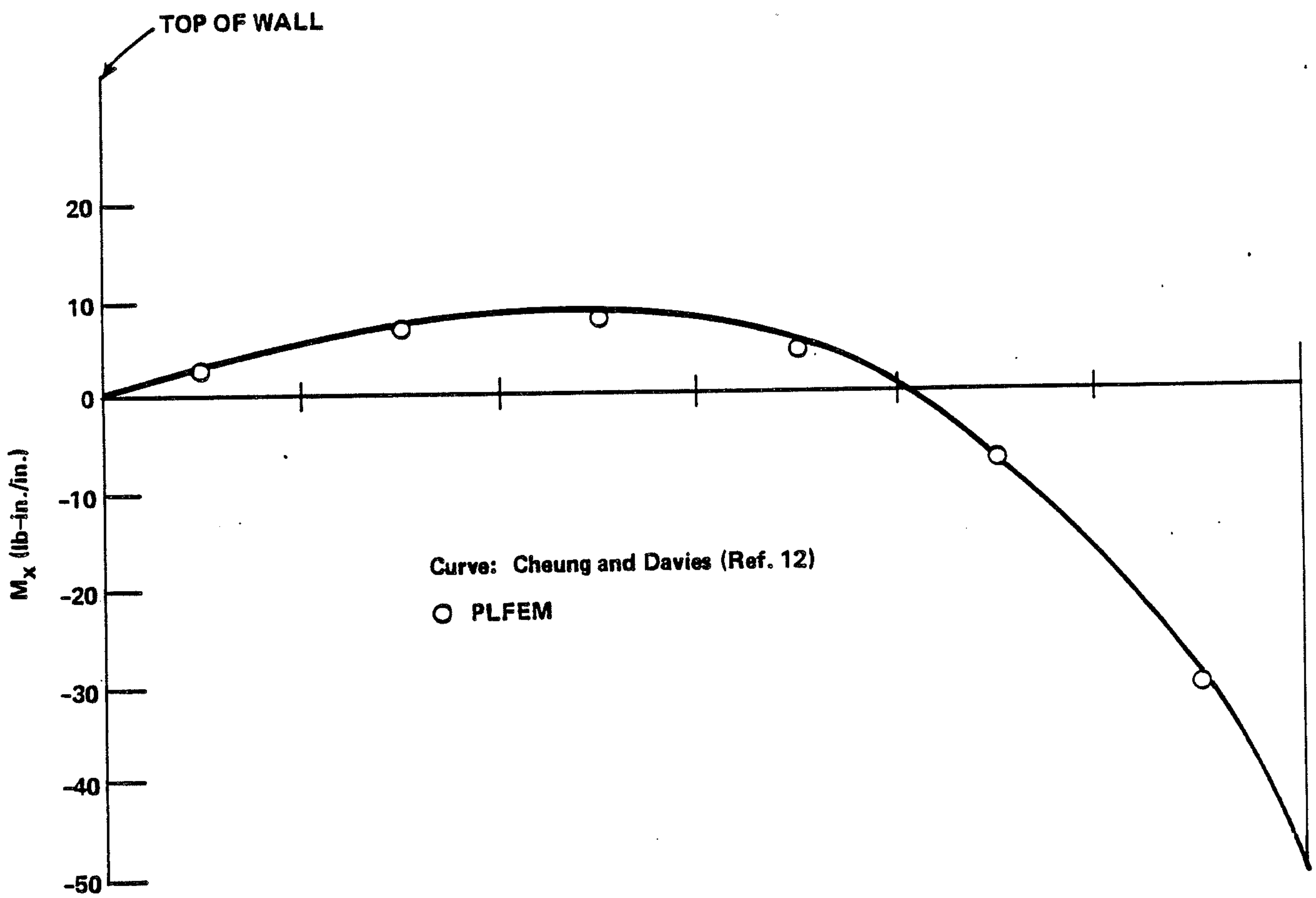

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FIGURE 3.13-42

MOMENT M_X ALONG THE CENTERLINE OF LONG WALL

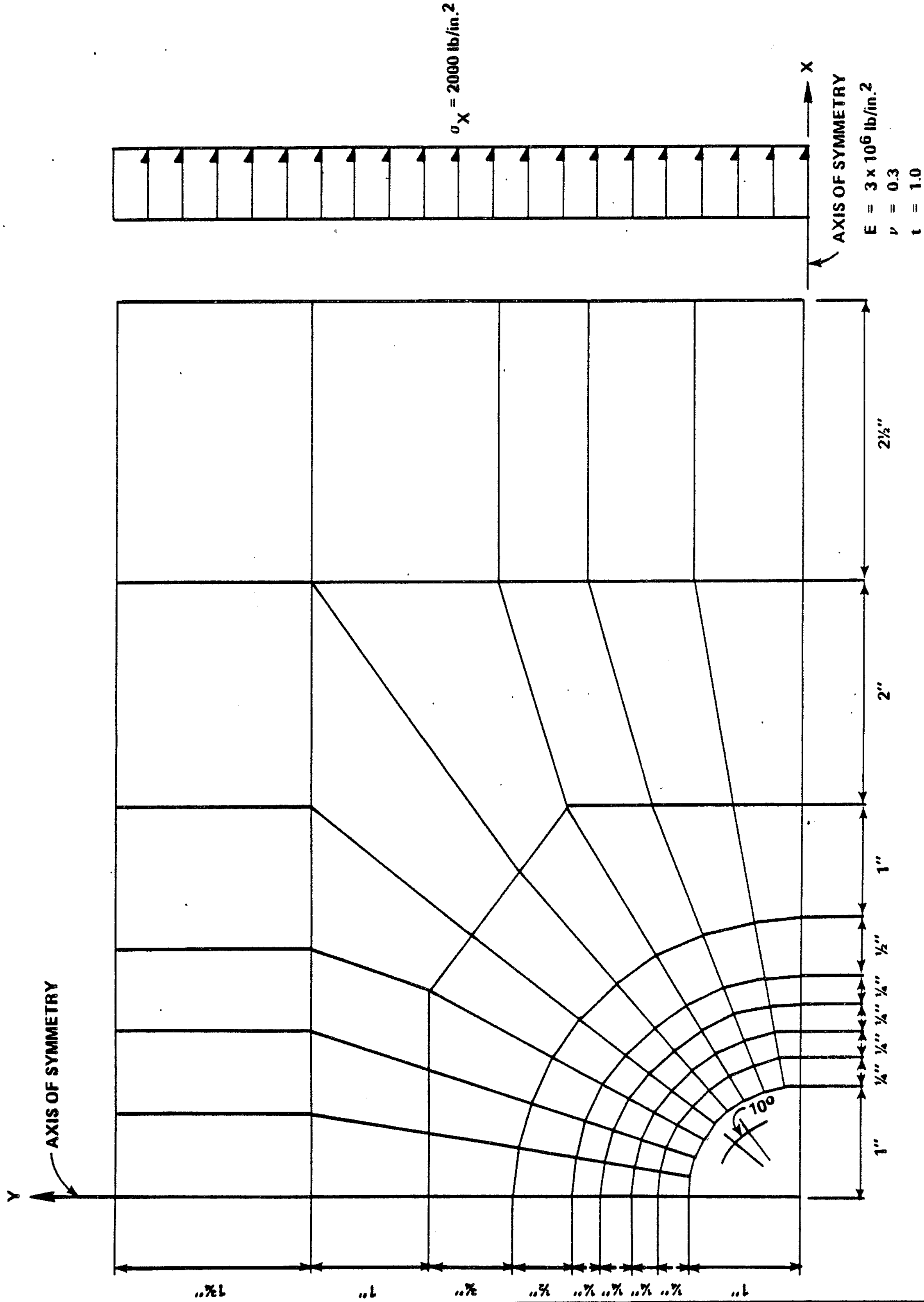

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FIGURE 3.13-43

PLATE WITH CIRCULAR HOLE UNDER UNIFORM TENSION

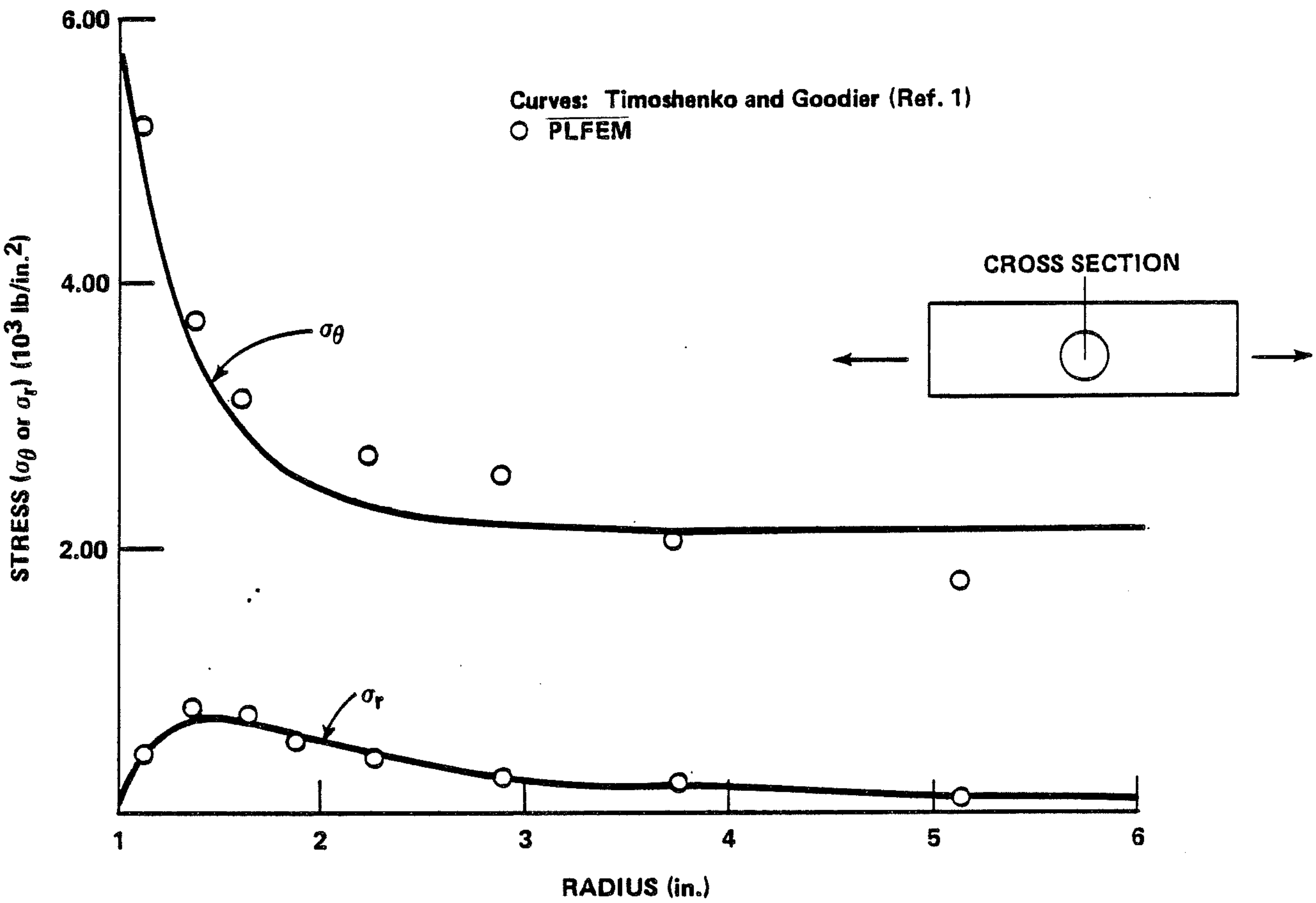

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FIGURE 3.13-44

STRESSES IN PLATE WITH CIRCULAR HOLE UNDER UNIFORM TENSION

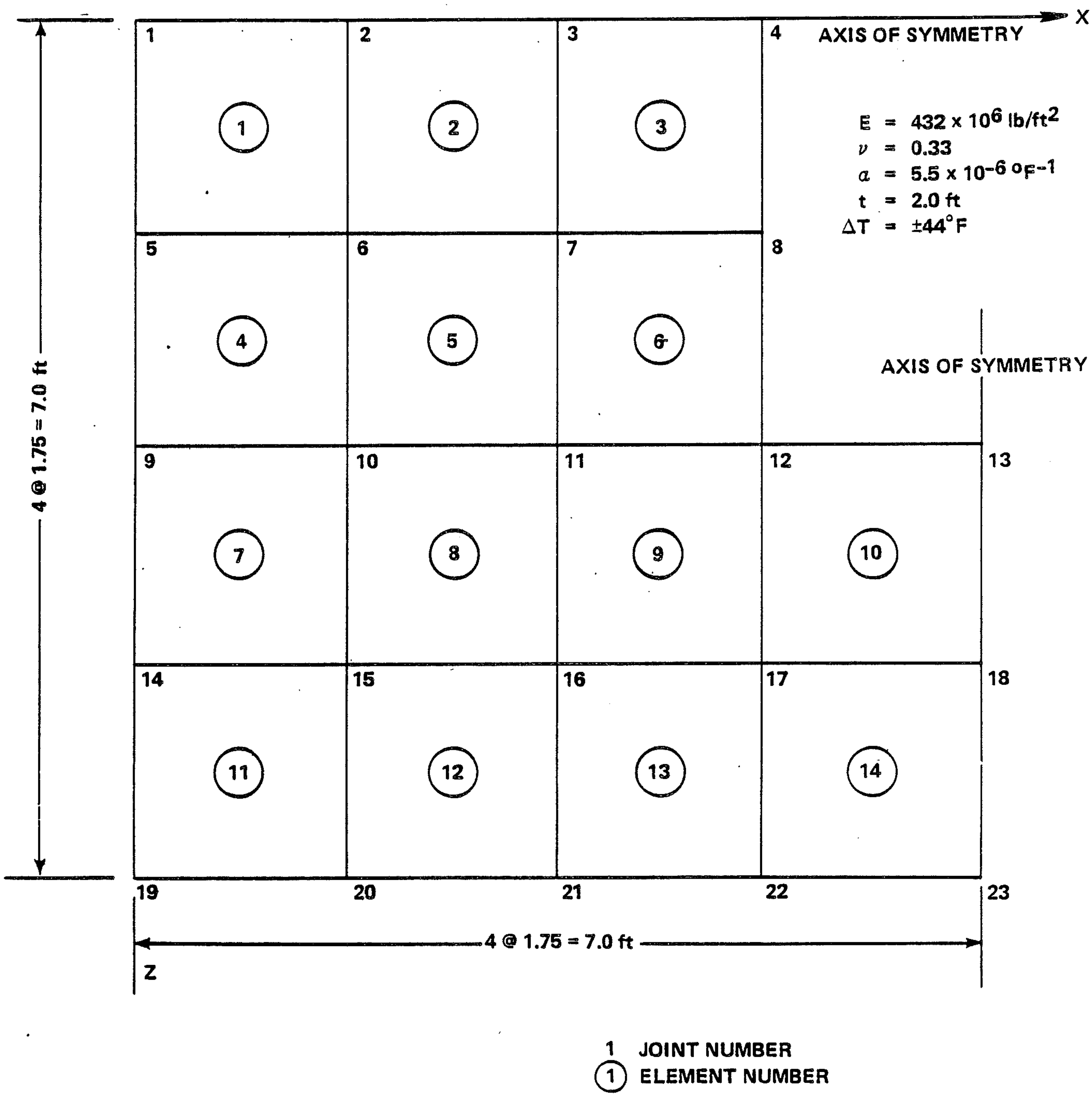

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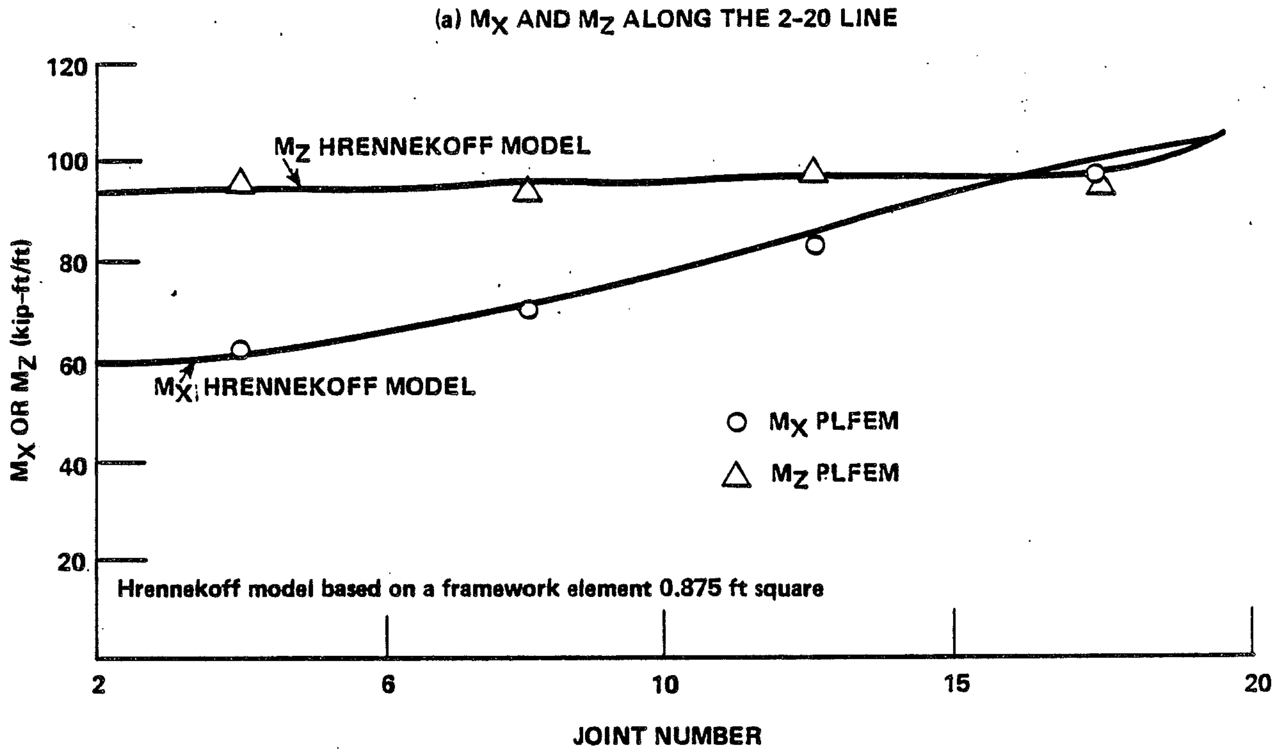
FIGURE 3.13-45

SQUARE PLATE WITH RECTANGULAR HOLE SUBJECTED TO TEMPERATURE VARIATION



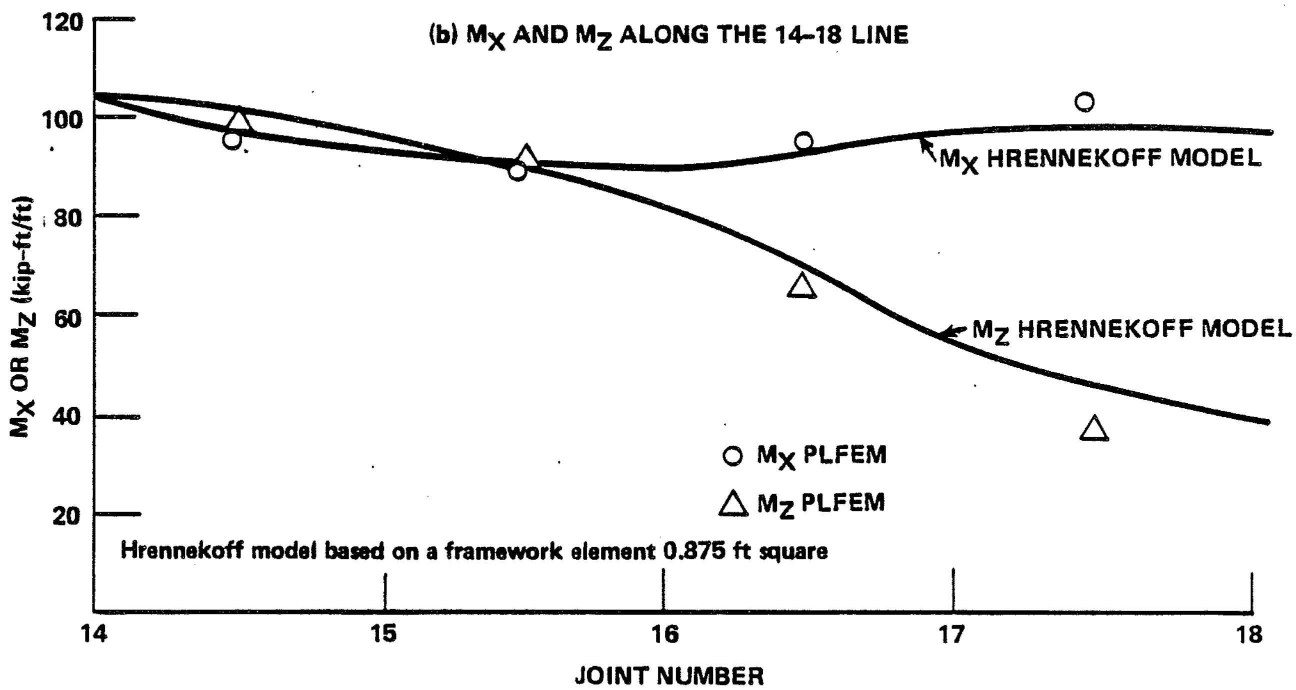


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FIGURE 3.13-46

MOMENTS IN PLATE DUE TO TEMPERATURE VARIATION

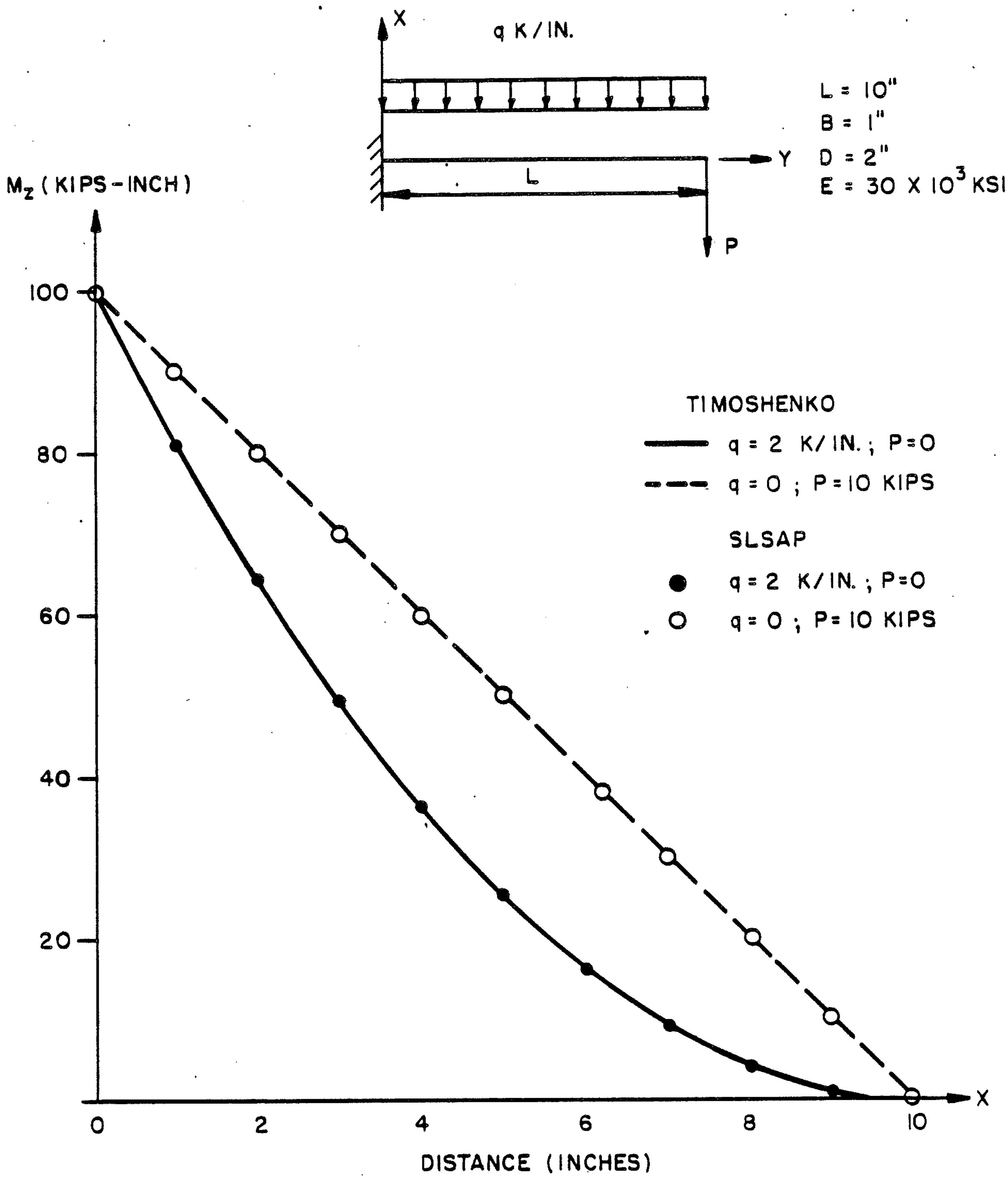

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FIGURE 3.13-47

BENDING MOMENTS IN A CANTILEVER BEAM

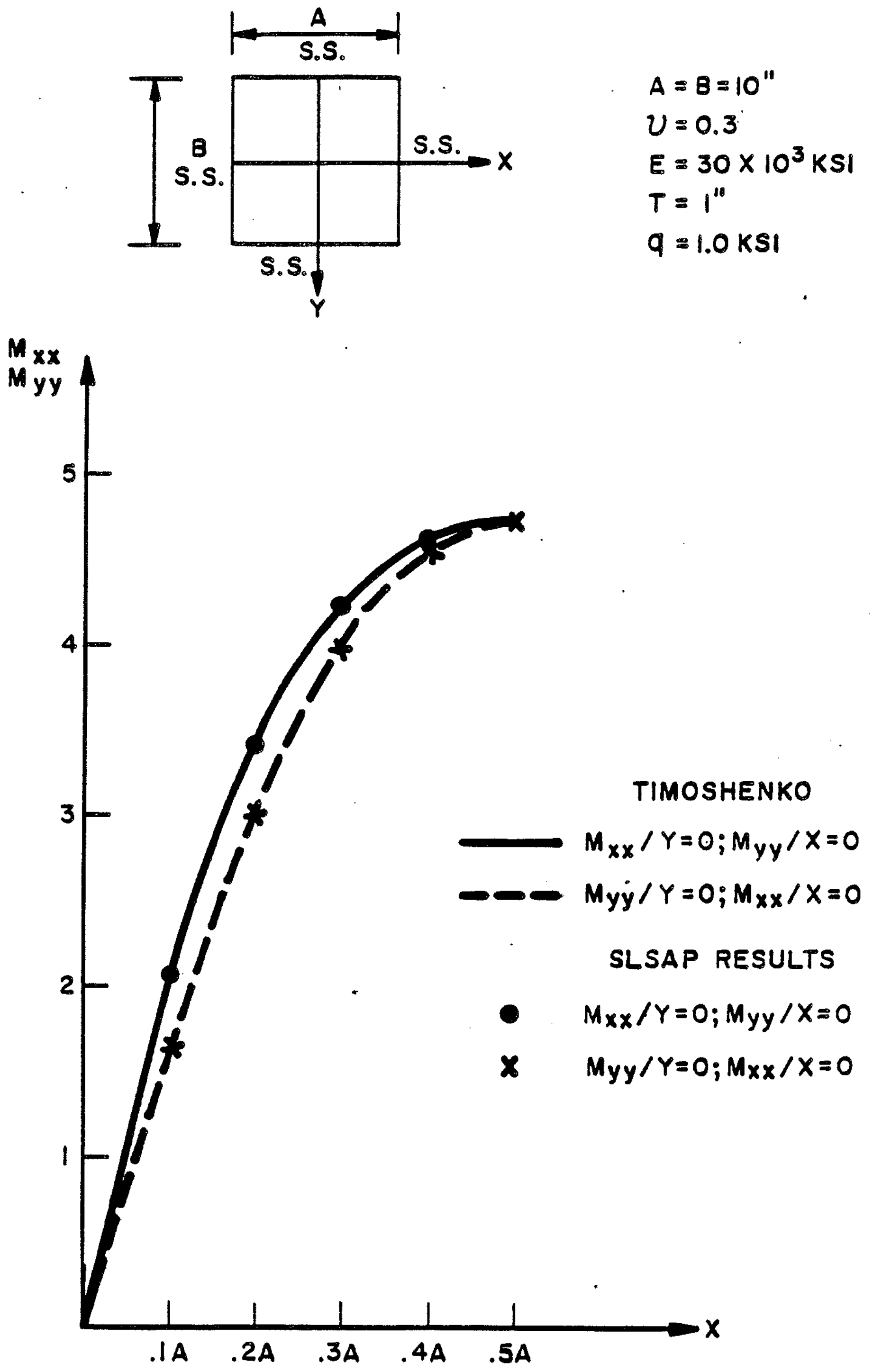

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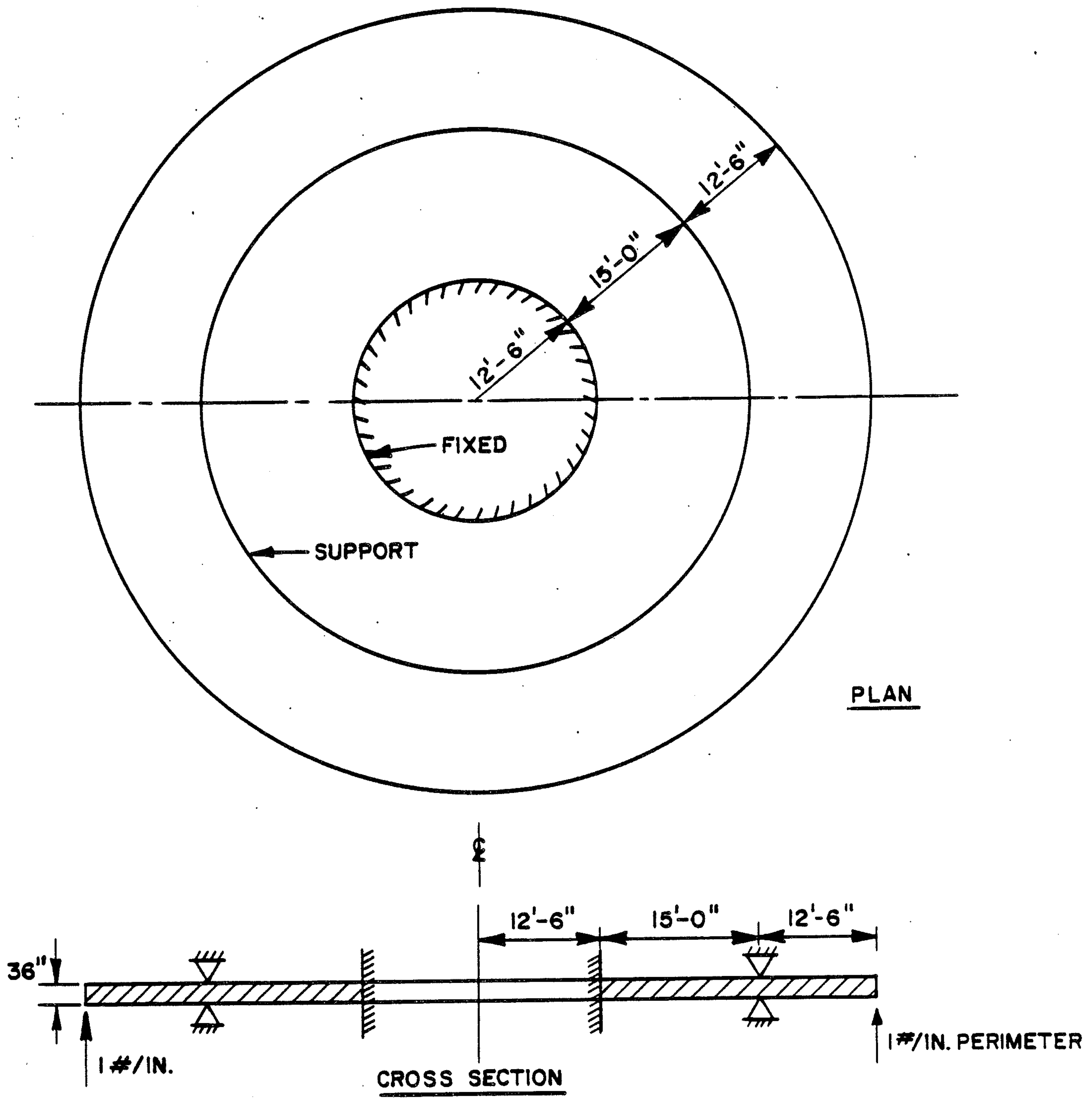
FIGURE 3.13-48

BENDING MOMENTS IN A SIMPLY SUPPORTED PLATE



MATERIAL PROPERTIES

$\nu = 0.17$
$E = 4 \times 10^6$ PSI

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FIGURE 3.13-49

CIRCULAR PLATE FOR SOR III EXAMPLE

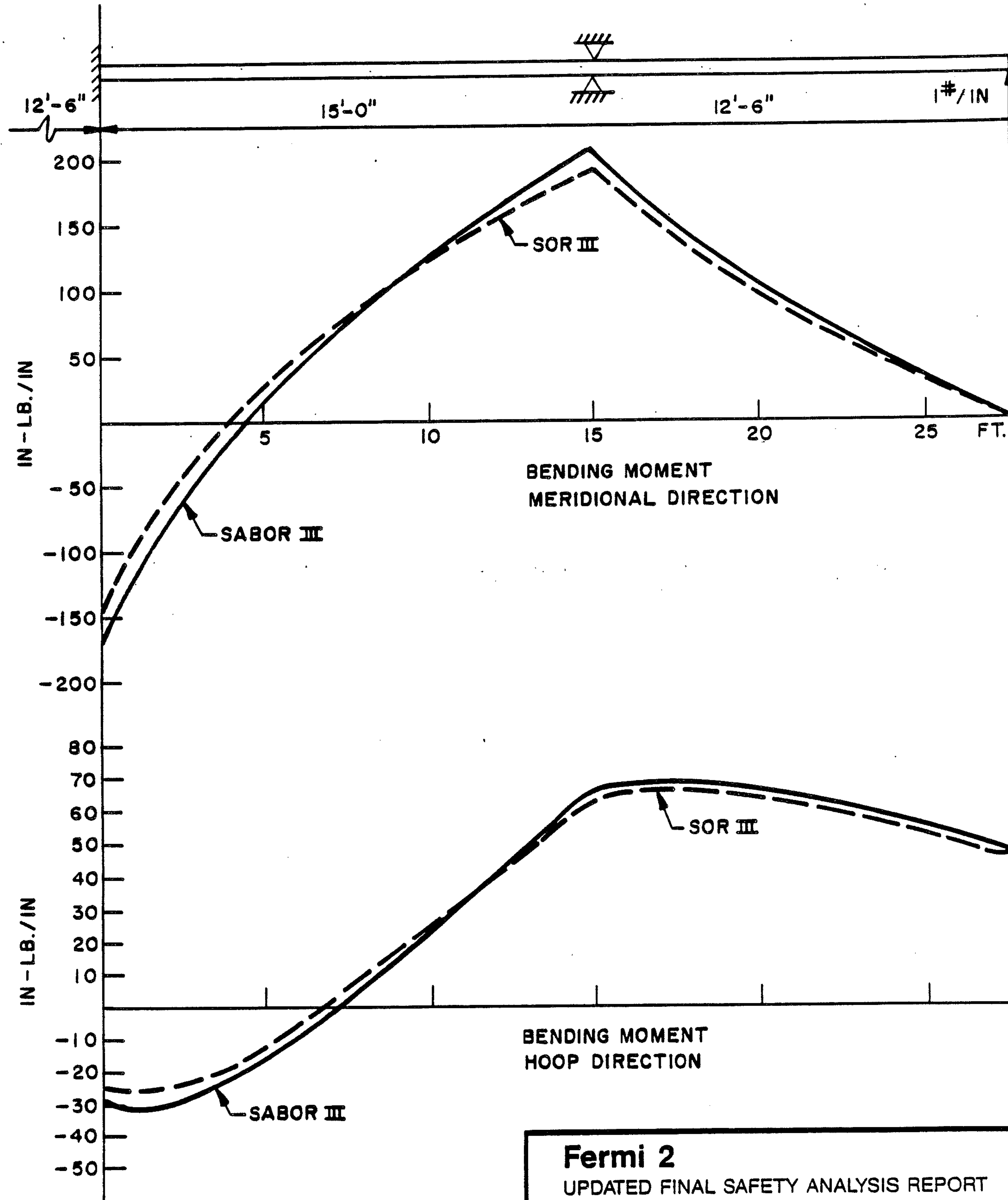

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FIGURE 3.13-50

MOMENT COMPARISON, SABOR III AND SOR III

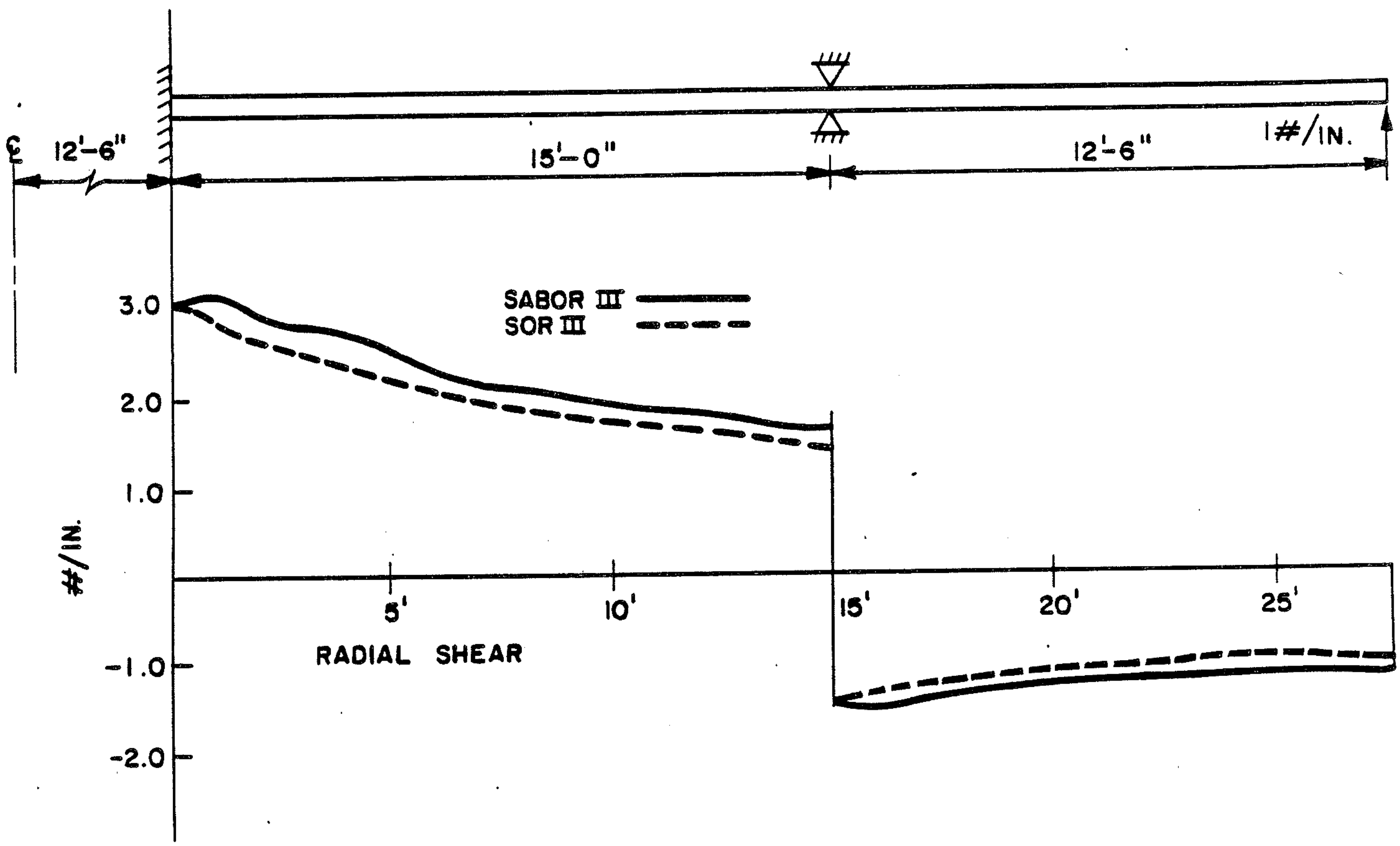

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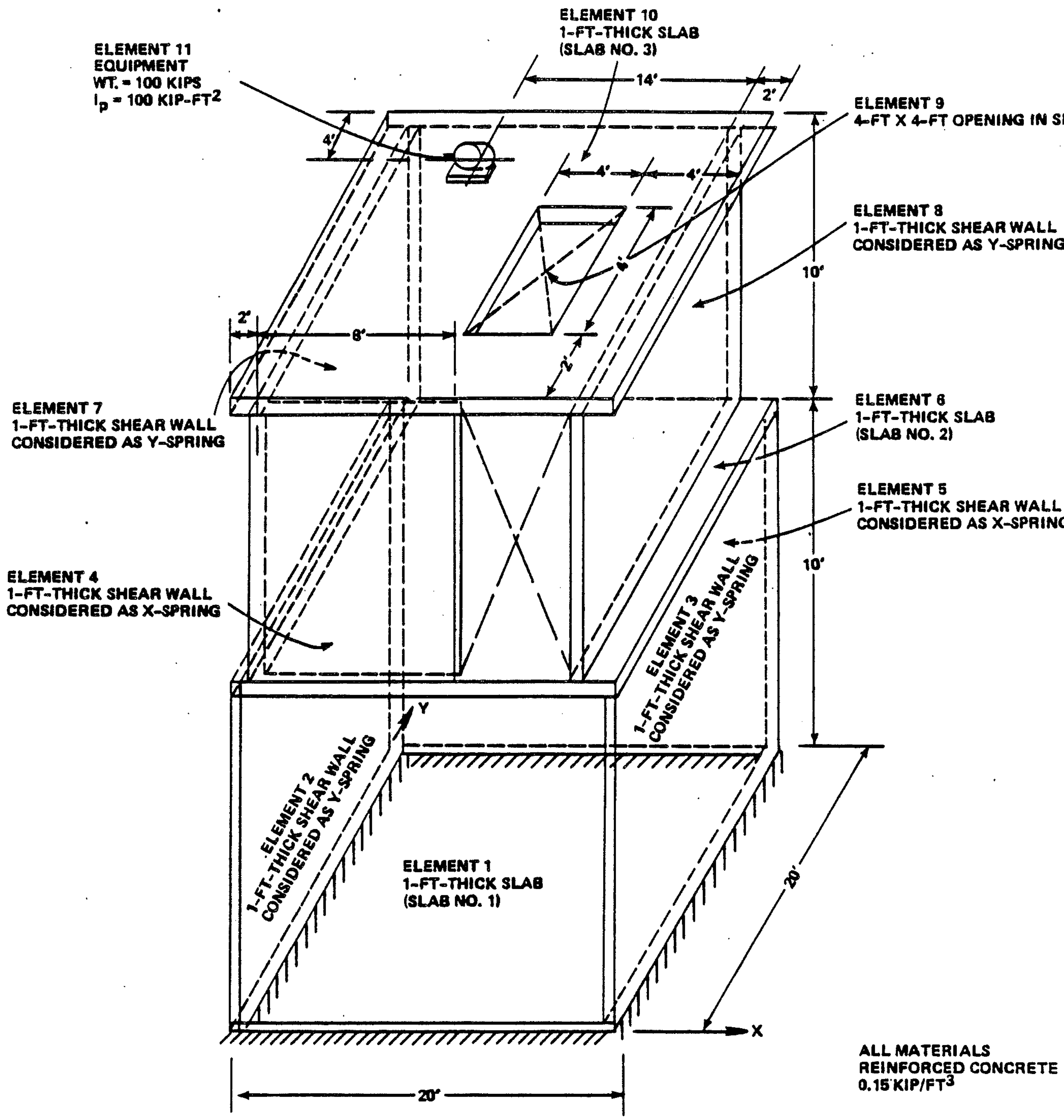
FIGURE 3.13-51

RADIAL SHEAR COMPARISON FOR SABOR III AND SOR III



ALL MATERIALS
REINFORCED CONCRETE
0.15 KIP/FT^3

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FIGURE 3.13-52

BUILDING COMPLEX

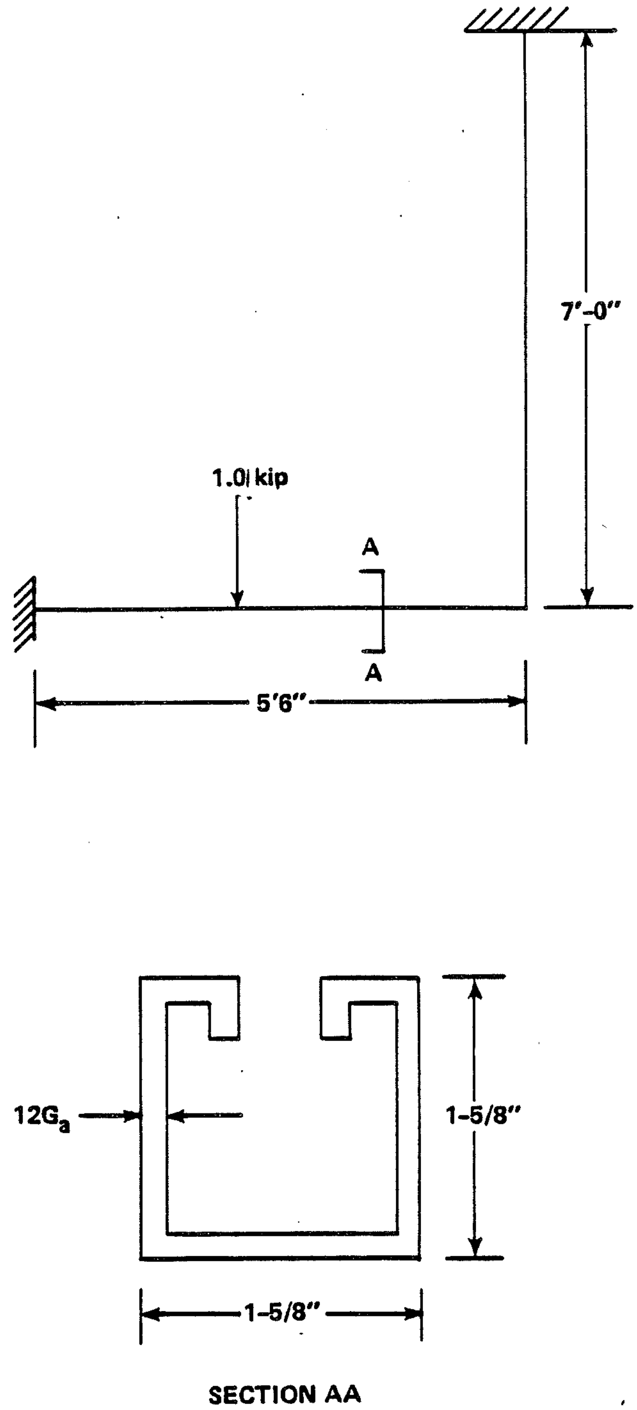

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FIGURE 3.13-53

TYPICAL CABLE PAN HANGER

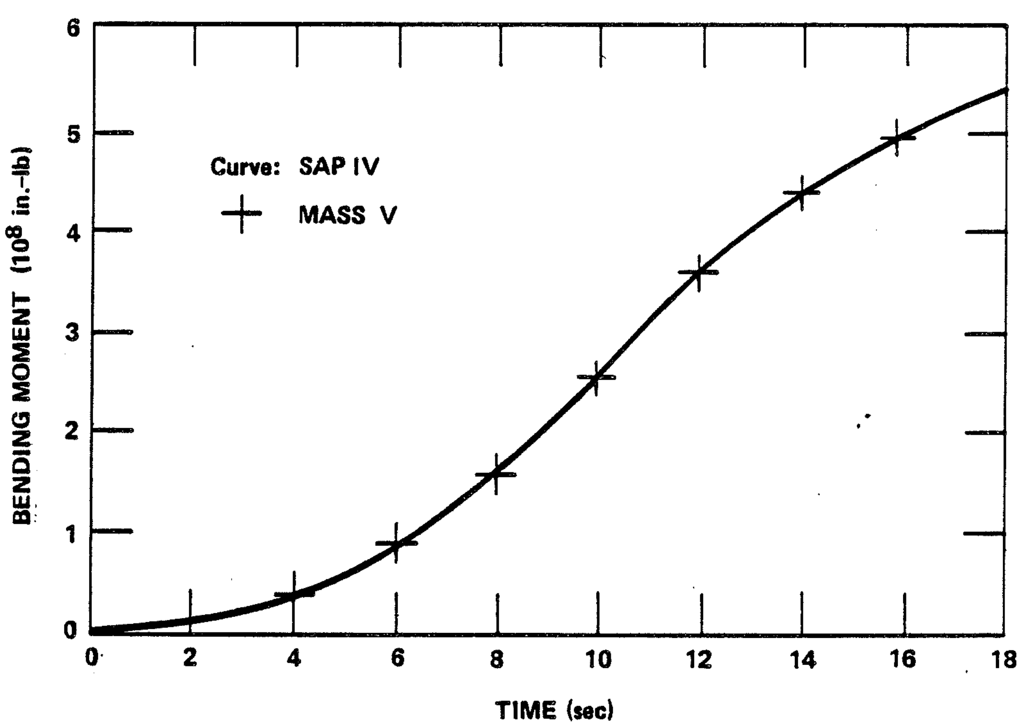

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FIGURE 3.13-54

CANTILEVER RESPONSE
MOMENT AT NODE 1
FIXED END OF CANTILEVER

DESIGN OF TIED COLUMN

B= 17.00 T= 17.00 FC= 3.000 FY=40.000 PHIC= 0.700 PHIB= 0.0900

USE- 10 NO. 9 BARS. AST = 10.00 SQ. IN. = 3.47 PCT. COVER = 1.500 IN.

	ROW 1	ROW 2	ROW 3	ROW 4
NO. OF BARS	2	2	3	3
COVER	1.500	1.500	1.500	1.500

LOAD	APPLIED FORCES			ULTIMATE CAPACITY			
CASE	AP	AMX	AMY	UP	UMX	UMY	UP/AP
1	525.	0.	105.	563.	0.	113.	1.072
2	525.	75.	0.	603.	86.	0.	1.148

INTERACTION CONTROL POINTS REQUESTED

	PZ	PB	MB	MZ
X -AXIS	778.0	304.7	166.2	176.2
Y -AXIS	778.0	245.8	234.6	199.7
Z -AXIS	778.0	314.6	167.2	193.7

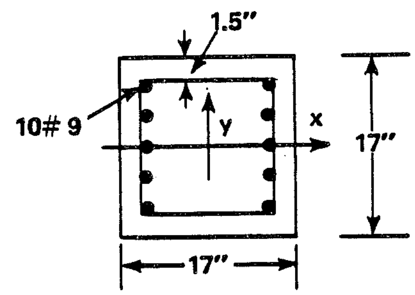

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FIGURE 3.13-55

VALIDATION PROBLEM 1
DESIGN OF A TIED COLUMN
COMPRESSION CONTROL

DESIGN OF
TIED COLUMN

B= 14.00 T= 20.00 FC= 4.500 FY=50.000 PHIC= .700 PHIB= .900

USE- 6 NO.11 BARS. AST = 9.36 SQ.IN. = 3.35 PCT. COVER= 1.500 IN.

	ROW 1	ROW 2	ROW 3	ROW 4
NO. OF BARS	3	3	0	0
COVER	1.500	1.500	1.500	1.500

LOAD CASE	APPLIED FORCES AP	AMX	AMY	ULTIMATE CAPACITY UP	UMX	UMY	UP/AP
1	115.	279.	0.	122.	295.	0.	1.057
2	115.	0.	14.	801.	0.	94.	6.966

INTERACTION CONTROL POINTS REQUESTED

	PZ	PB	MB	MZ
X -AXIS	1052.2	317.9	353.8	282.8
Y -AXIS	1052.2	315.4	187.2	180.3
Z -AXIS	1052.2	310.9	231.3	254.0

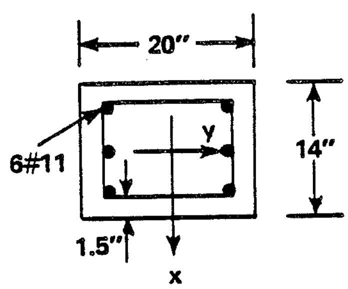

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FIGURE 3.13-56

VALIDATION PROBLEM 2
DESIGN OF A TIED COLUMN
TENSION CONTROLS

DESIGN OF
TIED COLUMN

B= 28.00 T= 28.00 FC= 5.000 FY=60.000 PHIC= .700 PHIB= .900

USE- 12 NO.11 BARS. AST = 18.72 SQ.IN. = 2.39 PCT. COVER = 1.500 IN.

	ROW 1	ROW 2	ROW 3	ROW 4
NO. OF BARS	4	4	2	2
COVER	1.500	1.500	1.500	1.500

LOAD CASE	APPLIED FORCES AP	AMX	AMY	ULTIMATE CAPACITY UP	UMX	UMY	UP/AP
1	1330.	790.	0.	1626.	966.	0.	1.223
2	1330.	0.	394.	2216.	0.	655.	1.666
3	1330.	790.	394.	1388.	824.	411.	1.044

INTERACTION CONTROL POINTS REQUESTED

	PZ	PB	MB	MZ
X -AXIS	3062.9	983.0	1167.4	999.1
Y -AXIS	3062.9	983.0	1167.4	999.1
Z -AXIS	3062.9	910.2	949.7	947.4

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FIGURE 3.13-57

VALIDATION PROBLEM 3
DESIGN OF A TIED COLUMN
BIAXIAL BENDING

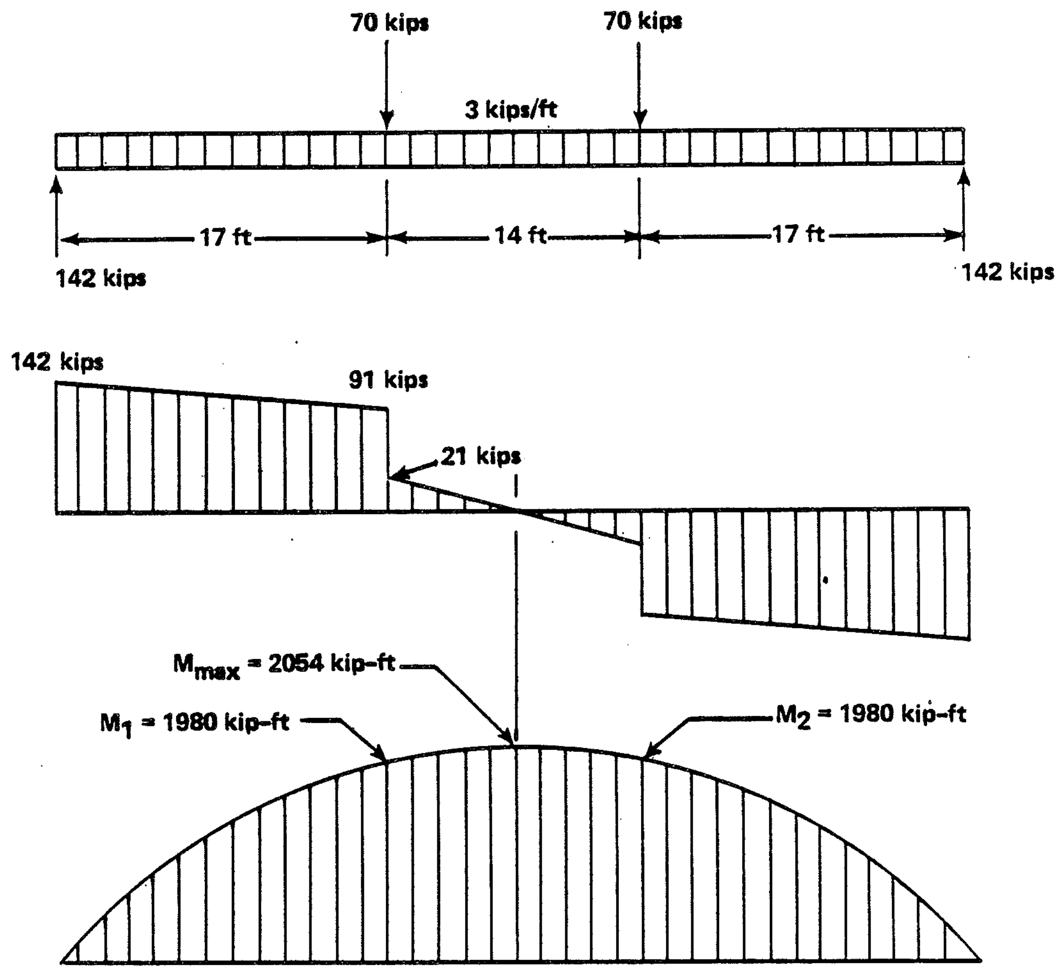

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FIGURE 3.13-58

SHEAR AND MOMENT DIAGRAMS

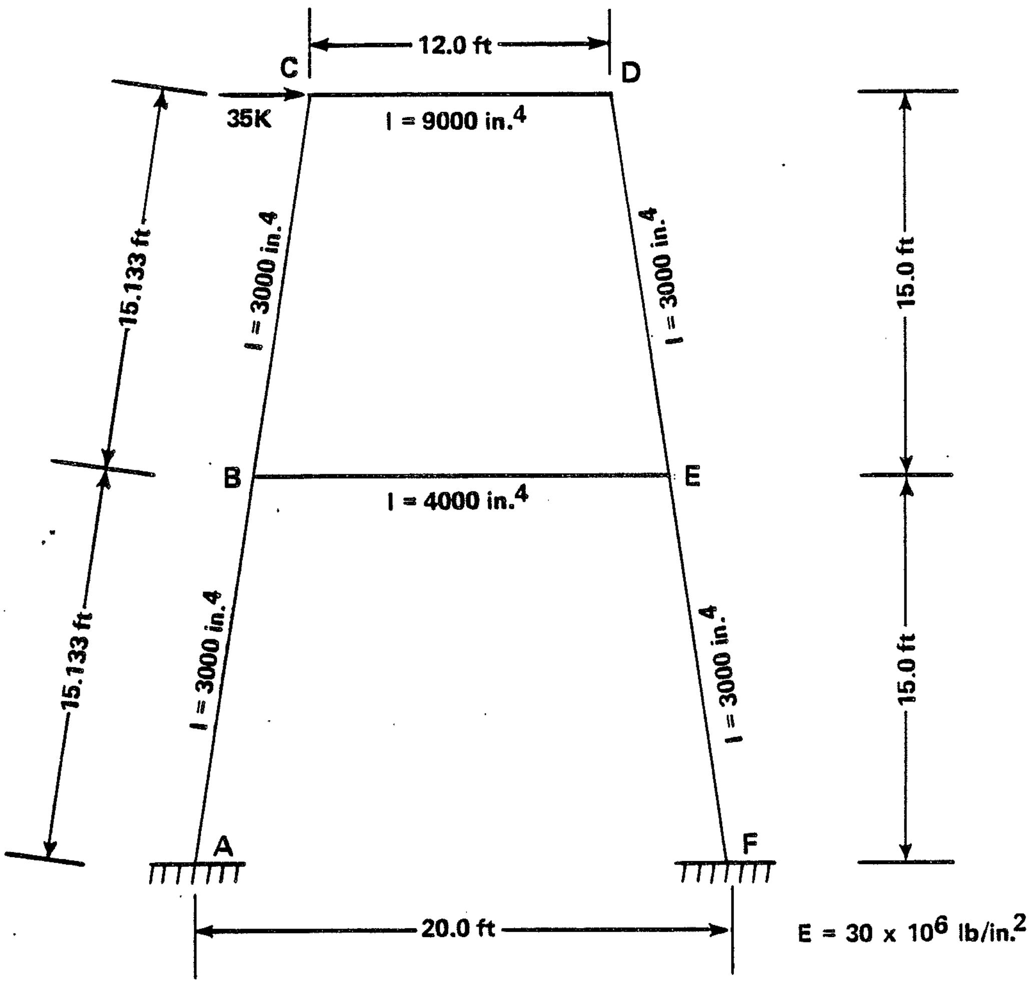

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FIGURE 3.13-59

EXAMPLE FOR STATIC ANALYSIS

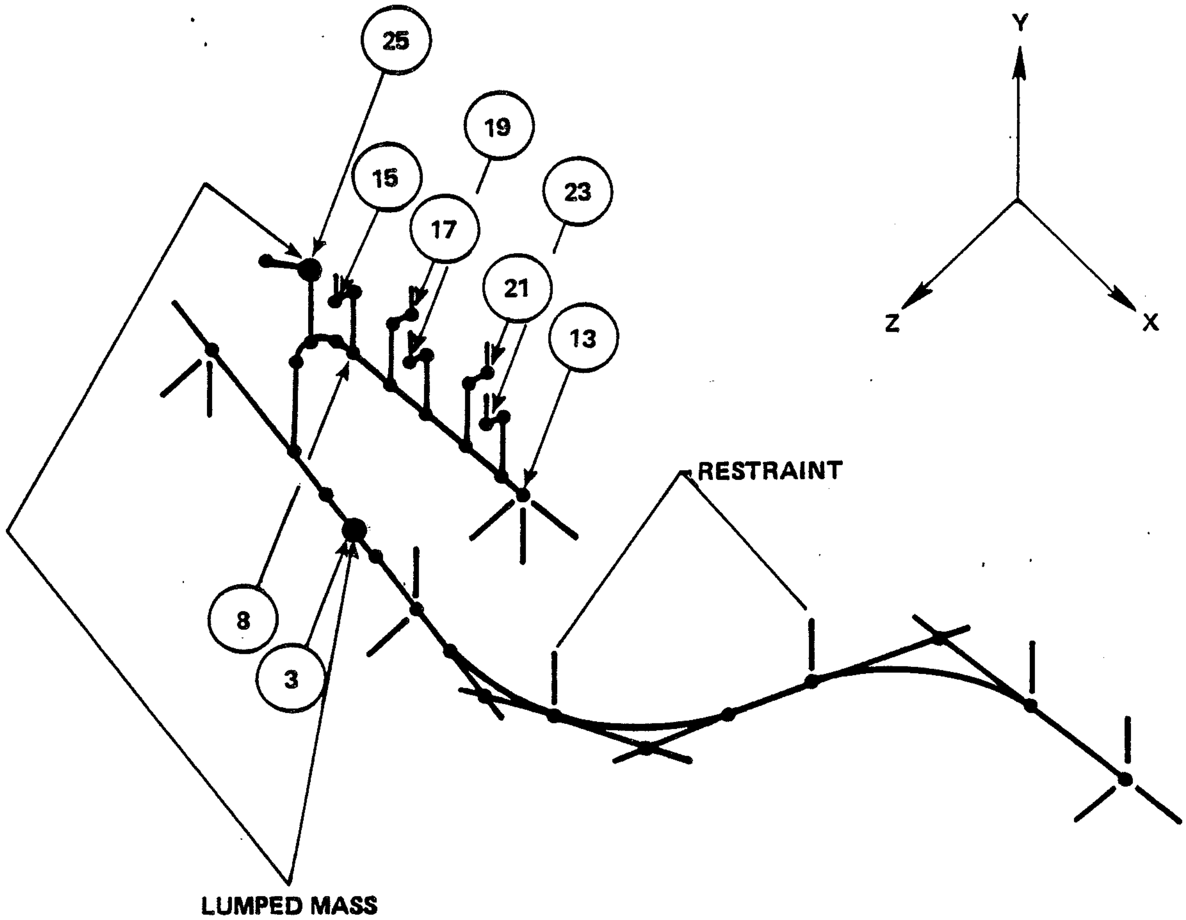

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FIGURE 3.13-60

STRUCTURAL MODEL OF PIPING SYSTEM

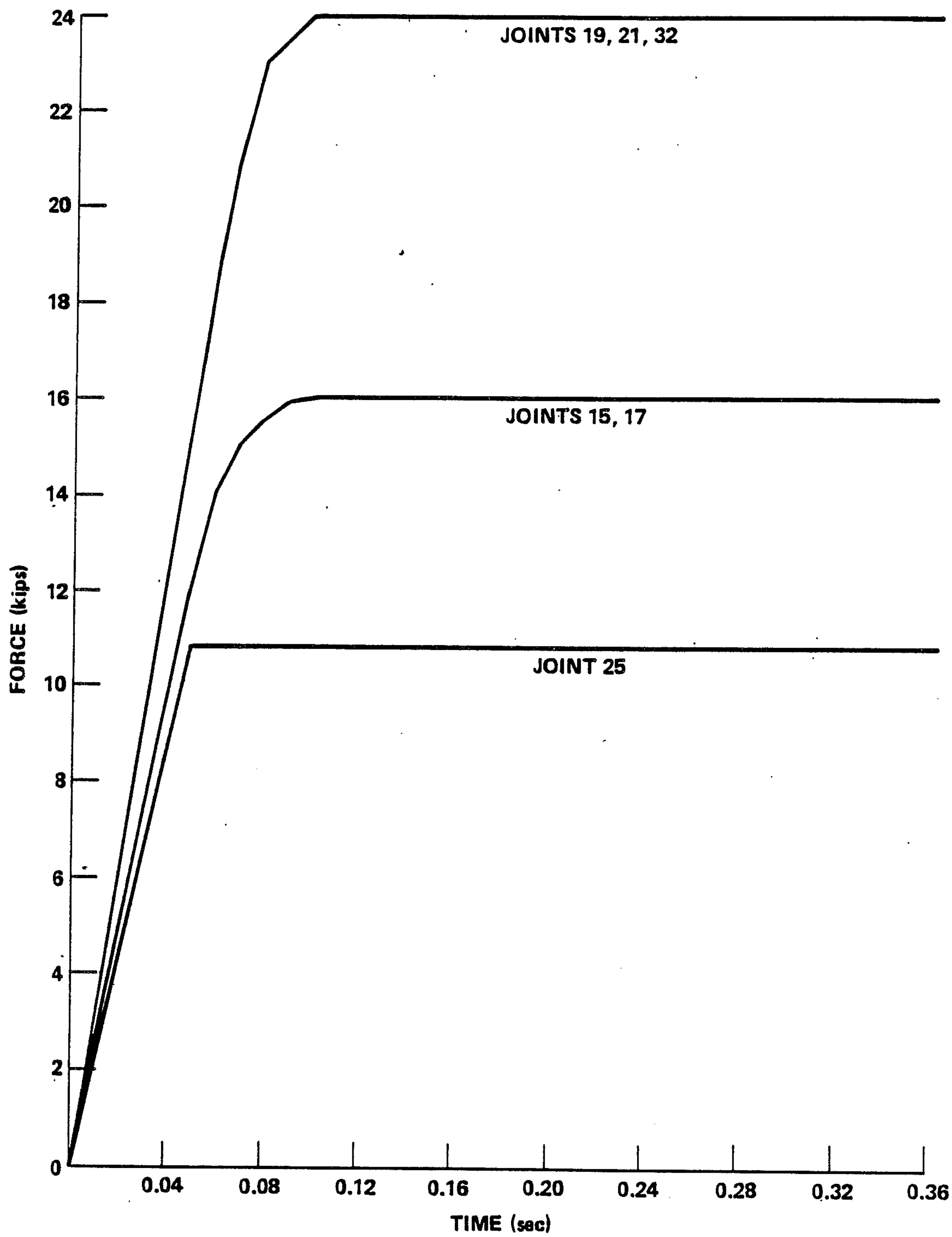

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FIGURE 3.13-61

LOAD TIME HISTORY

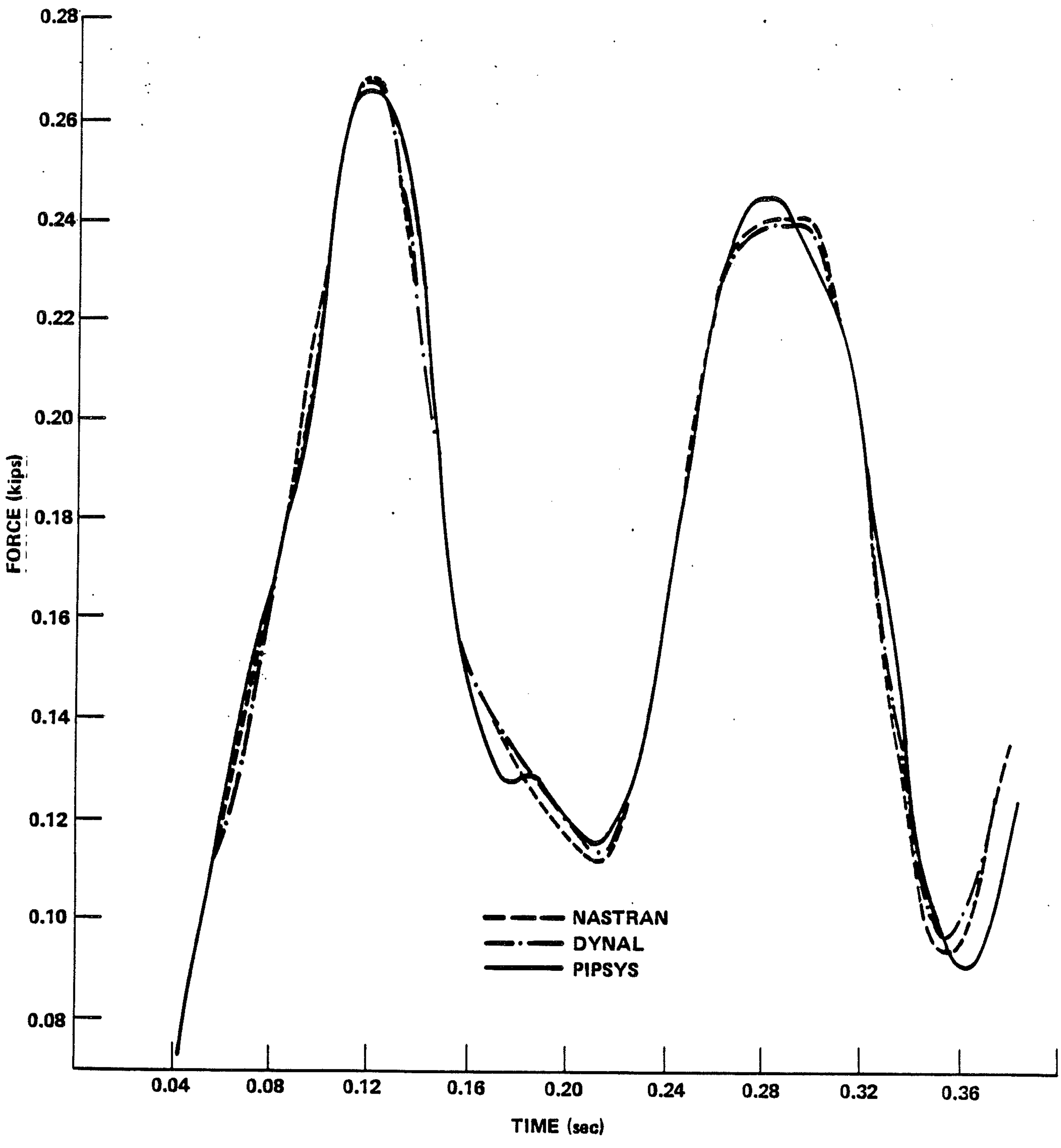

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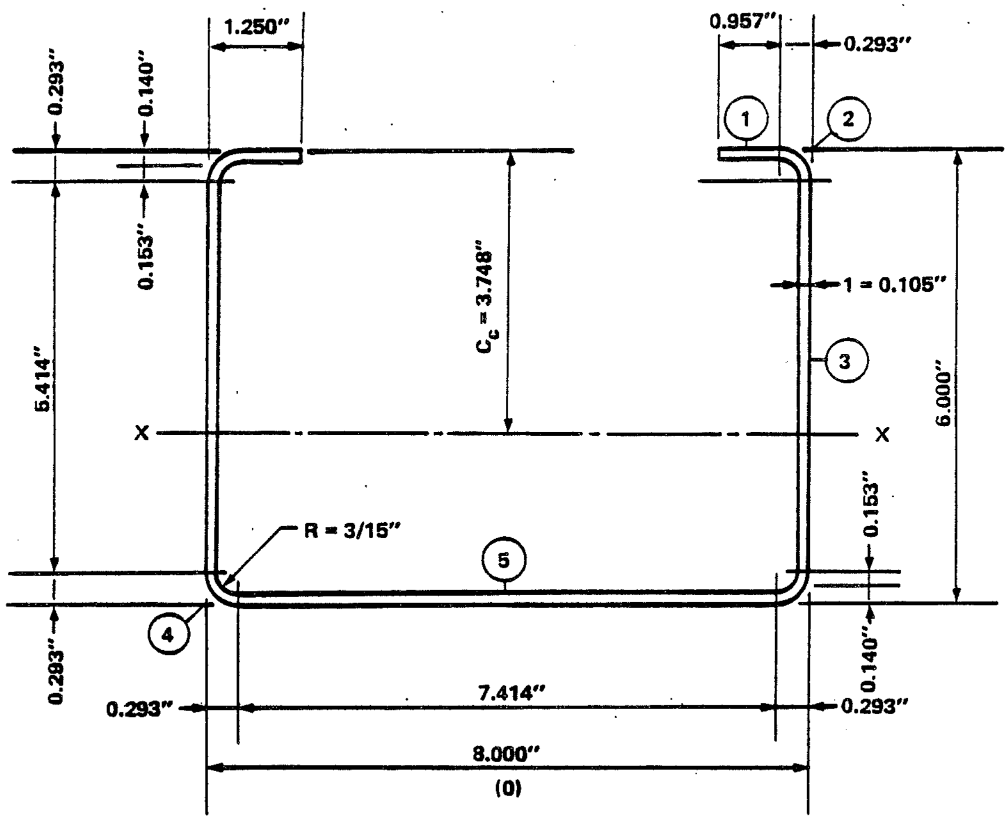
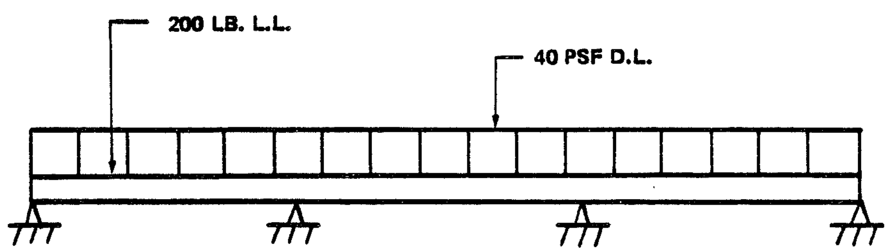
FIGURE 3.13-62

DISPLACEMENT VERSUS TIME
JOINT 8, Z DIRECTION





VERTICAL SEISMIC DESIGN LOAD = 1.5g
HORIZONTAL SEISMIC DESIGN LOAD = 4.5g

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FIGURE 3.13-63

CABLE TRAY MODEL FOR "SEISHANG" PROGRAM

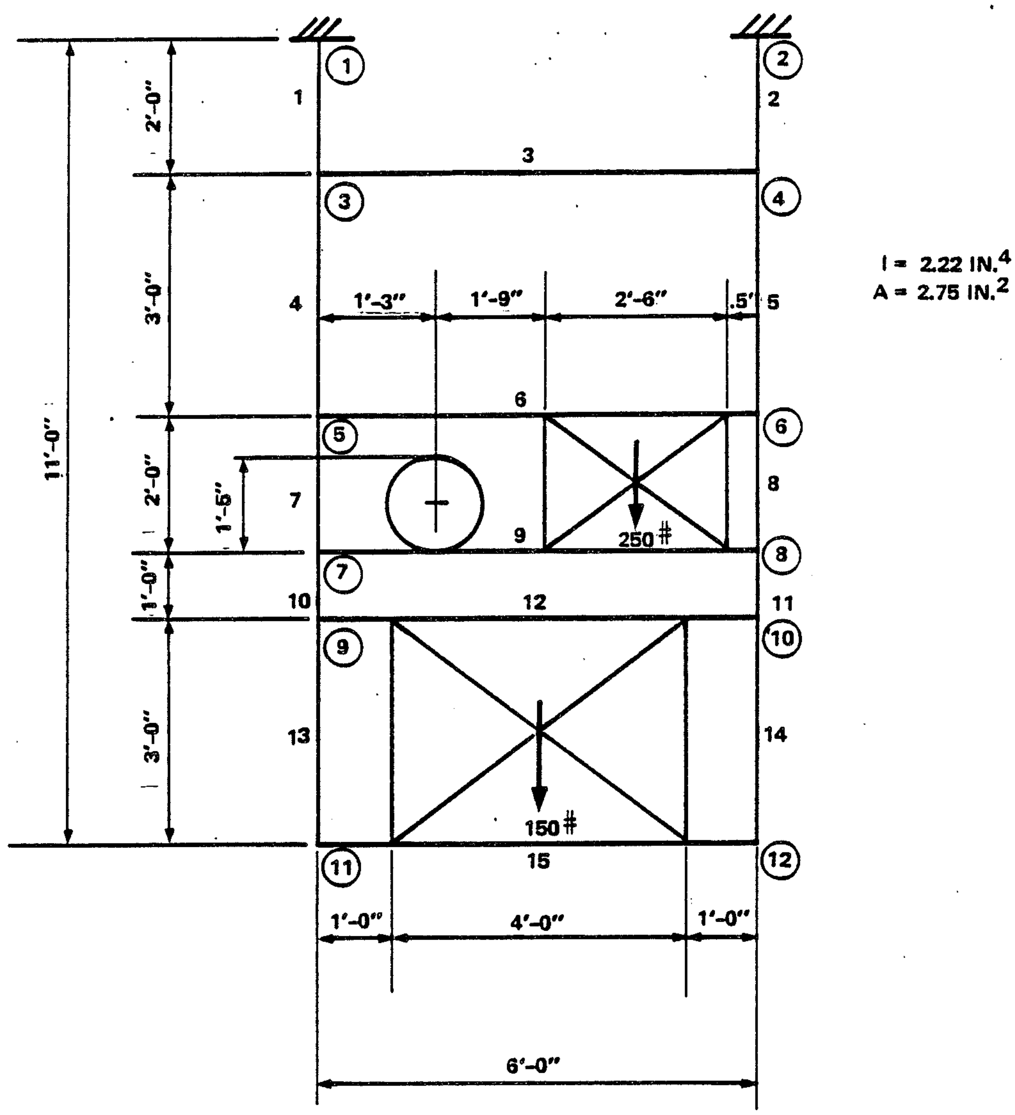

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FIGURE 3.13-64

CEILING MOUNTED SUPPORT MODEL FOR "SEISHANG" PROGRAM

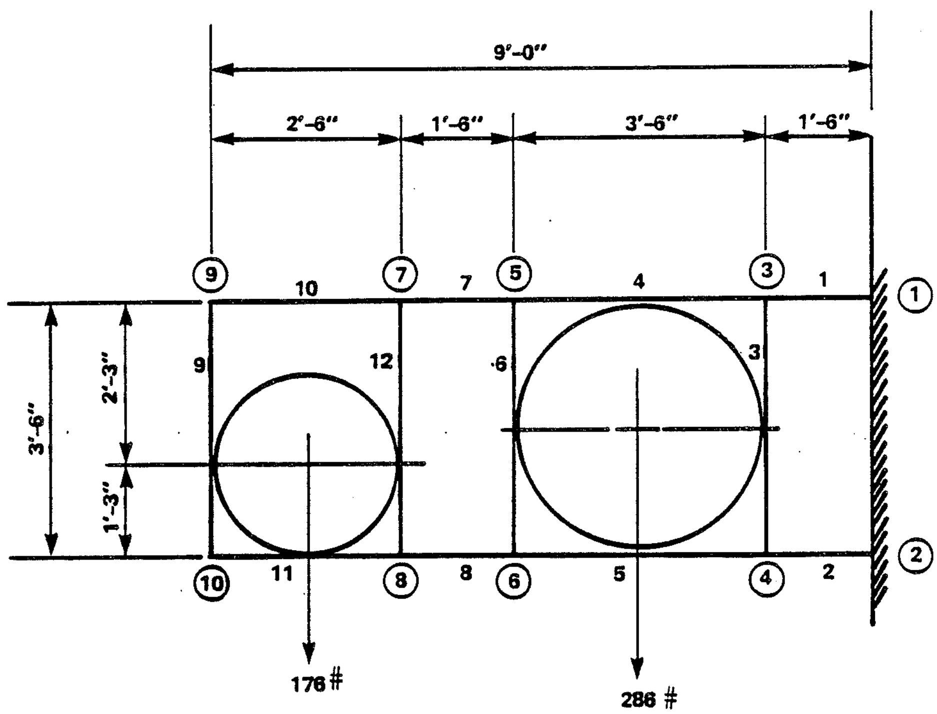

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FIGURE 3.13-65

WALL MOUNTED SUPPORT MODEL FOR "SEISHANG" PROGRAM

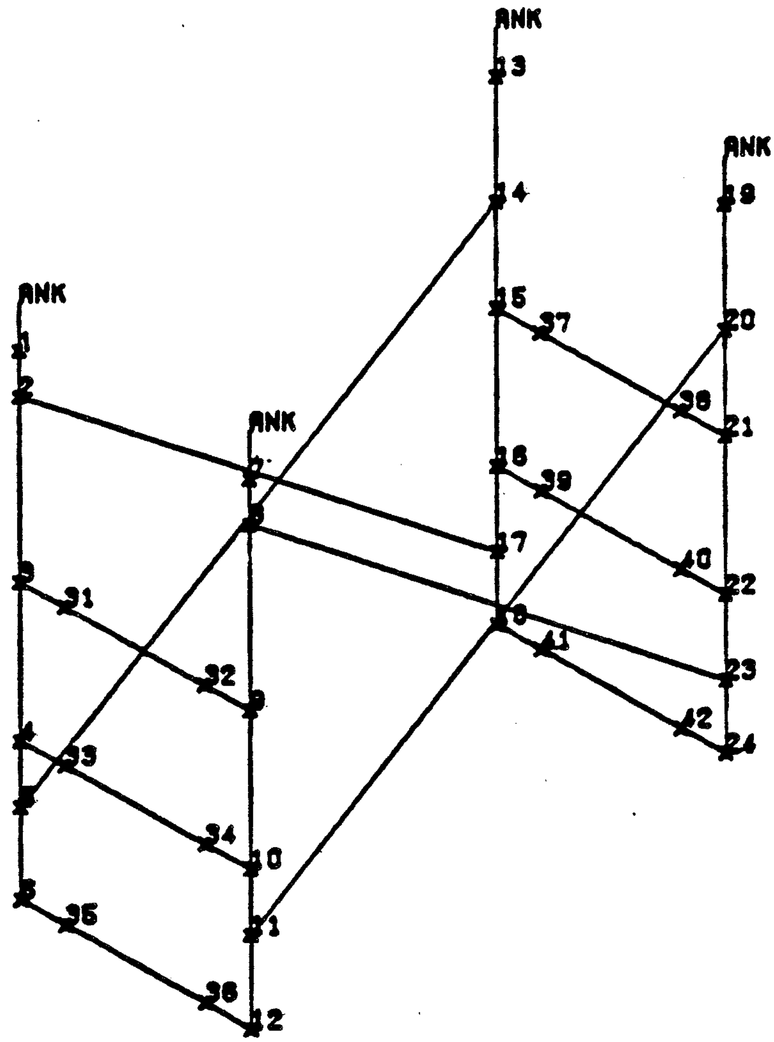

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FIGURE 3.13-66

CABLE TRAY SUPPORT

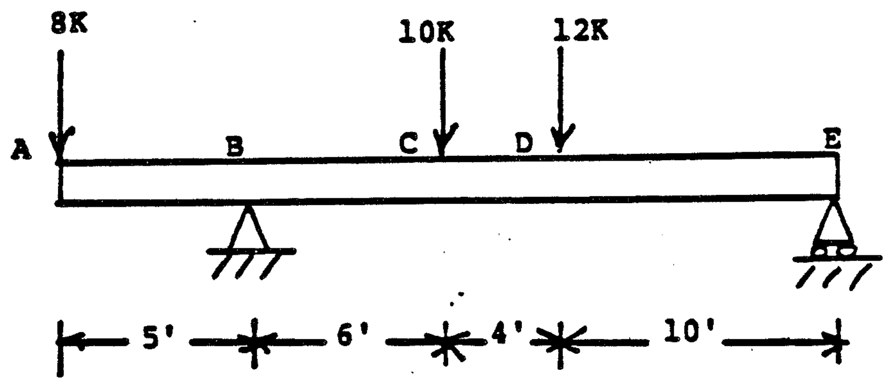

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FIGURE 3.13-67

CONTINUOUS BEAM PROBLEM
"PFRAME" VALIDATION

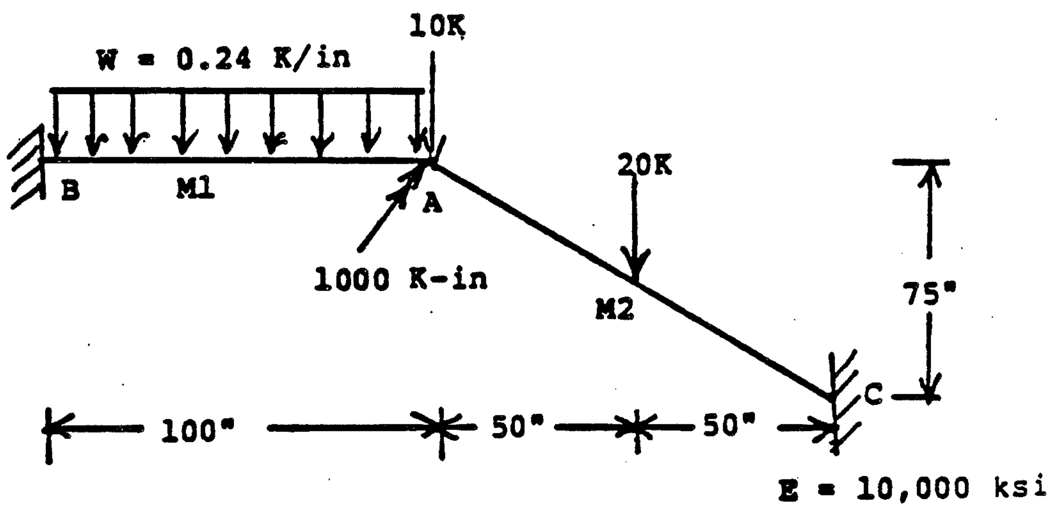

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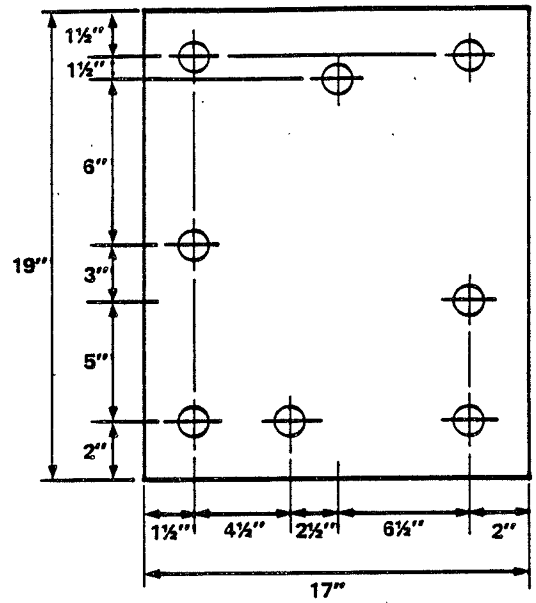
FIGURE 3.13-68

PLANE FRAME PROBLEM
"PFRAME" VALIDATION



I = 1.24 in^4

A = 1.44 in^2

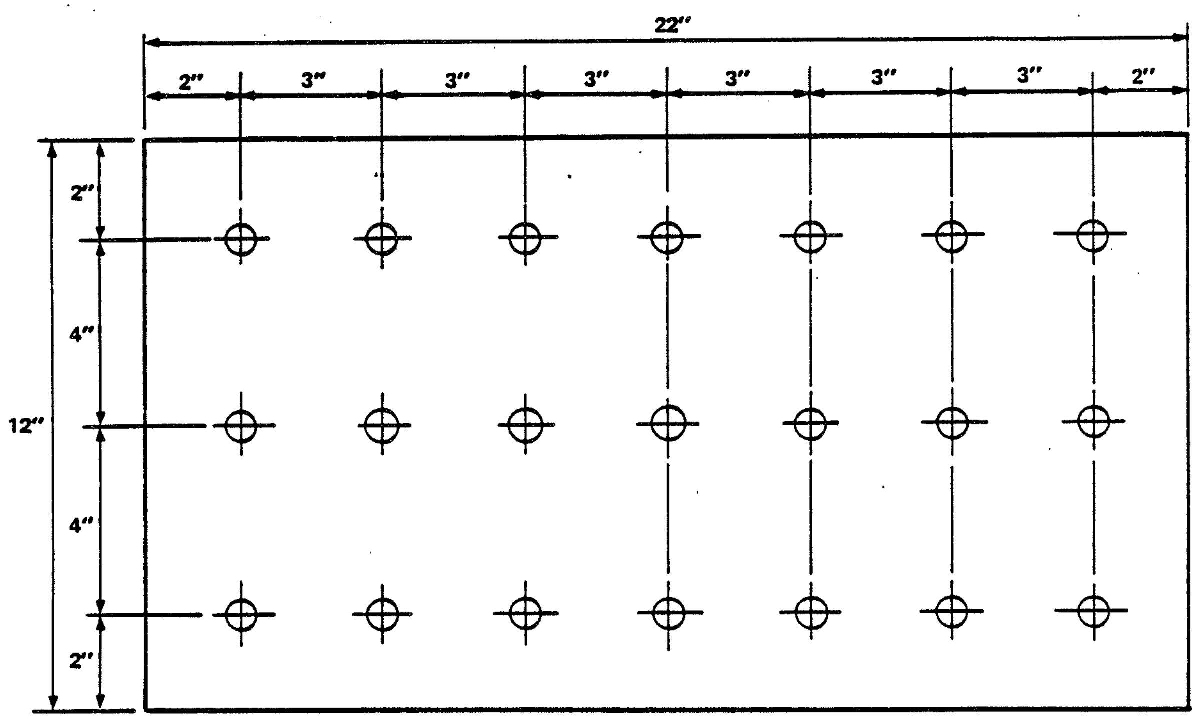


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FIGURE 3.13-69

BASE PLATE ANALYSIS

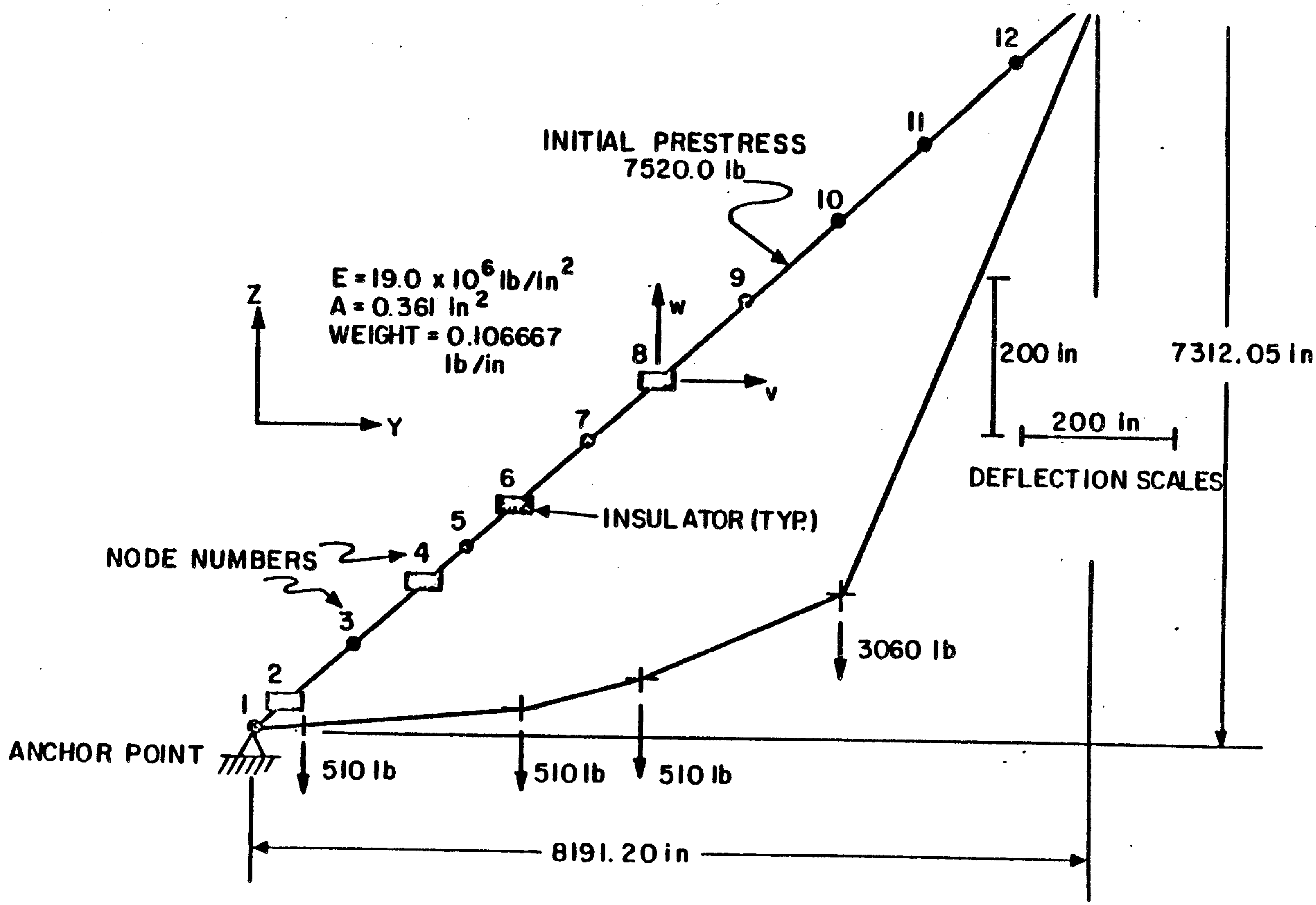

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FIGURE 3.13-70

STATIC CONFIGURATION OF TOWER CABLE
"ADINA" – VALIDATION PROBLEM 1

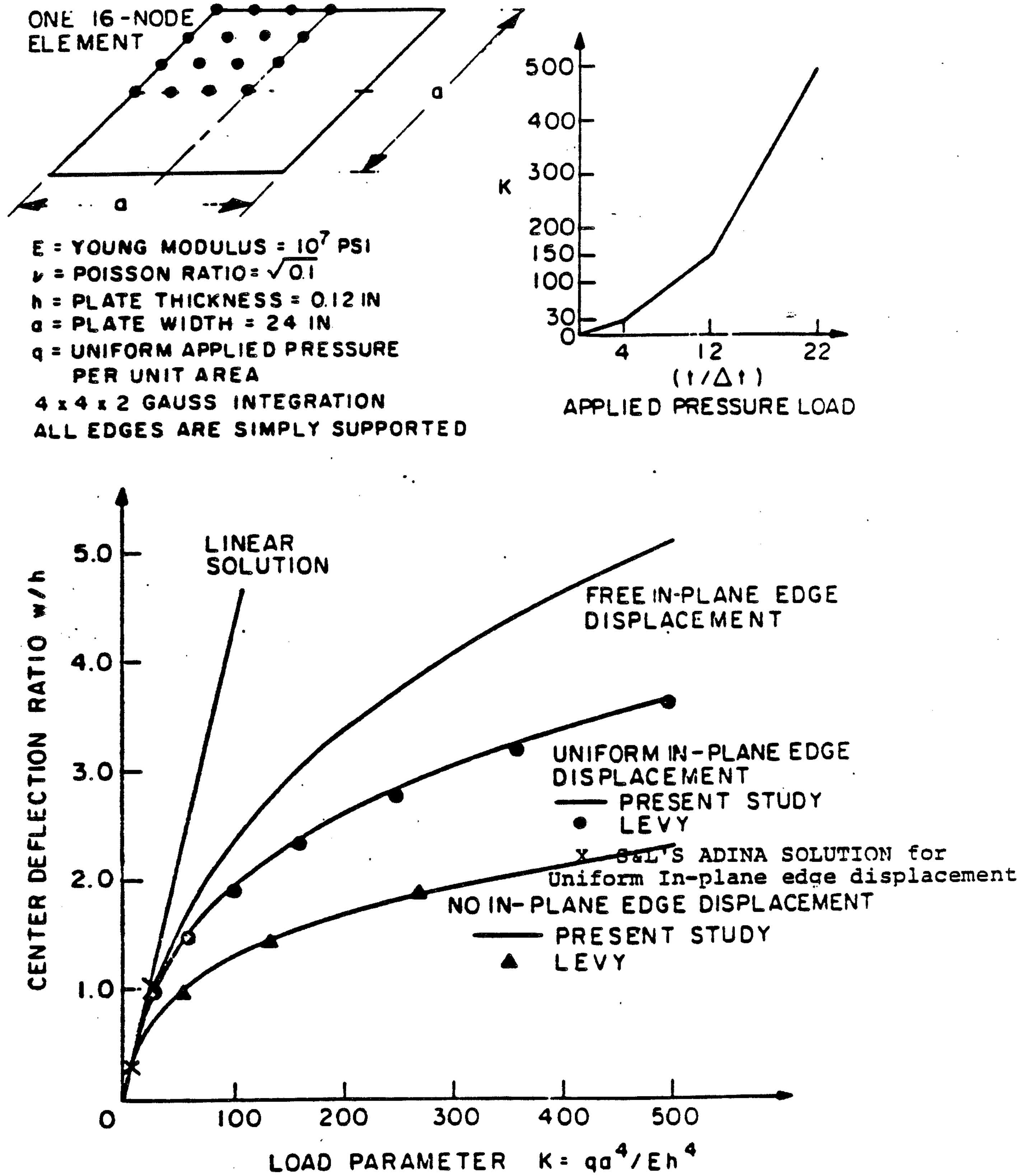

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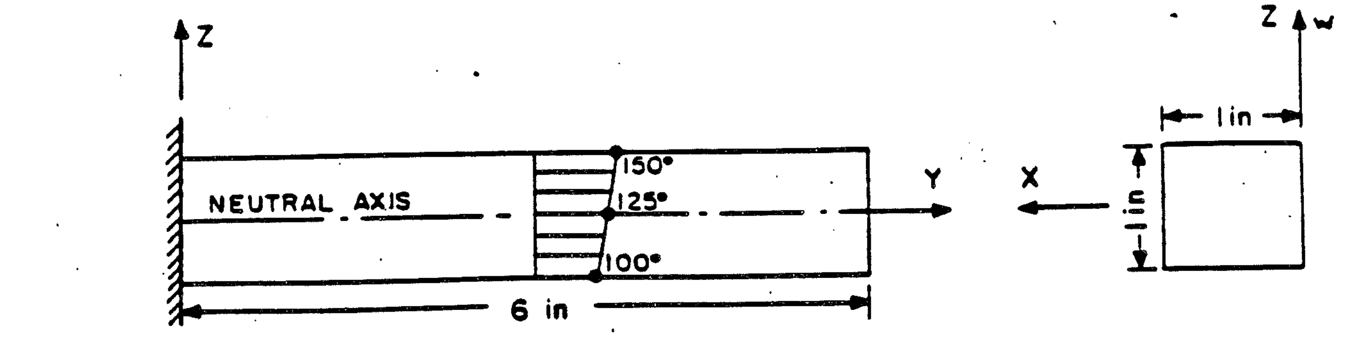
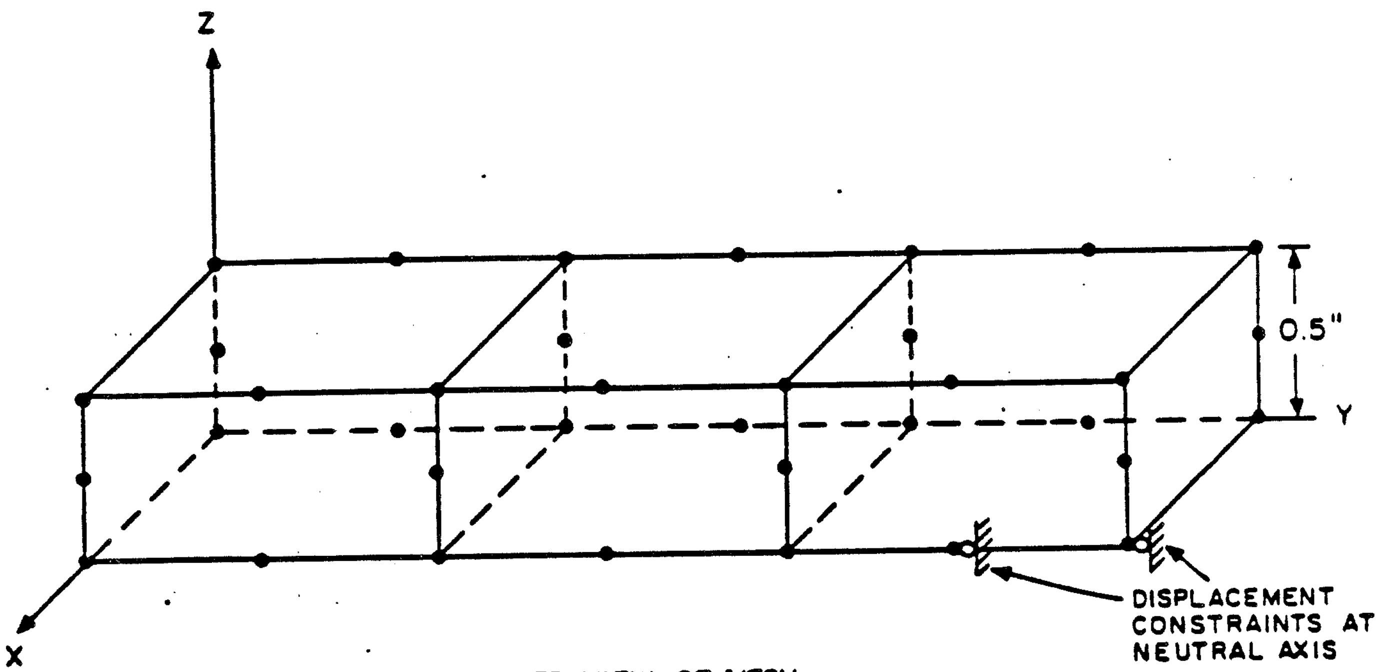
FIGURE 3.13-71

LARGE DEFLECTION ANALYSIS OF A SIMPLY SUPPORTED SQUARE PLATE SUBJECTED TO PRESSURE LOADING
"ADINA" – VALIDATION PROBLEM 2



SIDE AND END VIEWS



ENLARGED VIEW OF MESH

	70°F	200°F	
E	$30. \times 10^6$	$28. \times 10^6$	lb/in^2
υ	0.0	0.0	
α	5.5×10^{-6}	6.0×10^{-6}	in/in/°F

REFERENCE TEMPERATURE = 125° F

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FIGURE 3.13-72

FINITE ELEMENT MESH OF CANTILEVER BEAM "ADINA" – VALIDATION PROBLEM 3

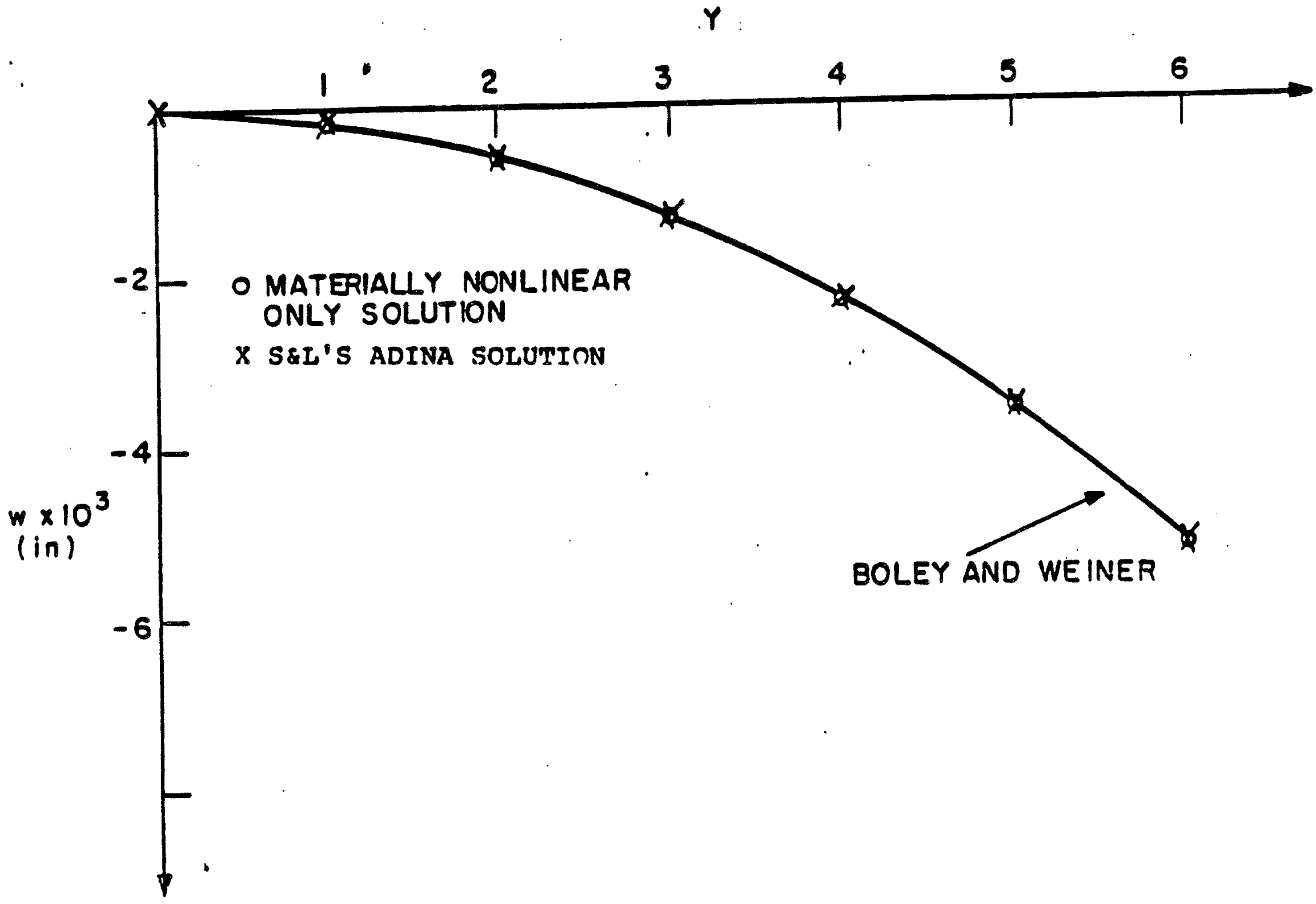

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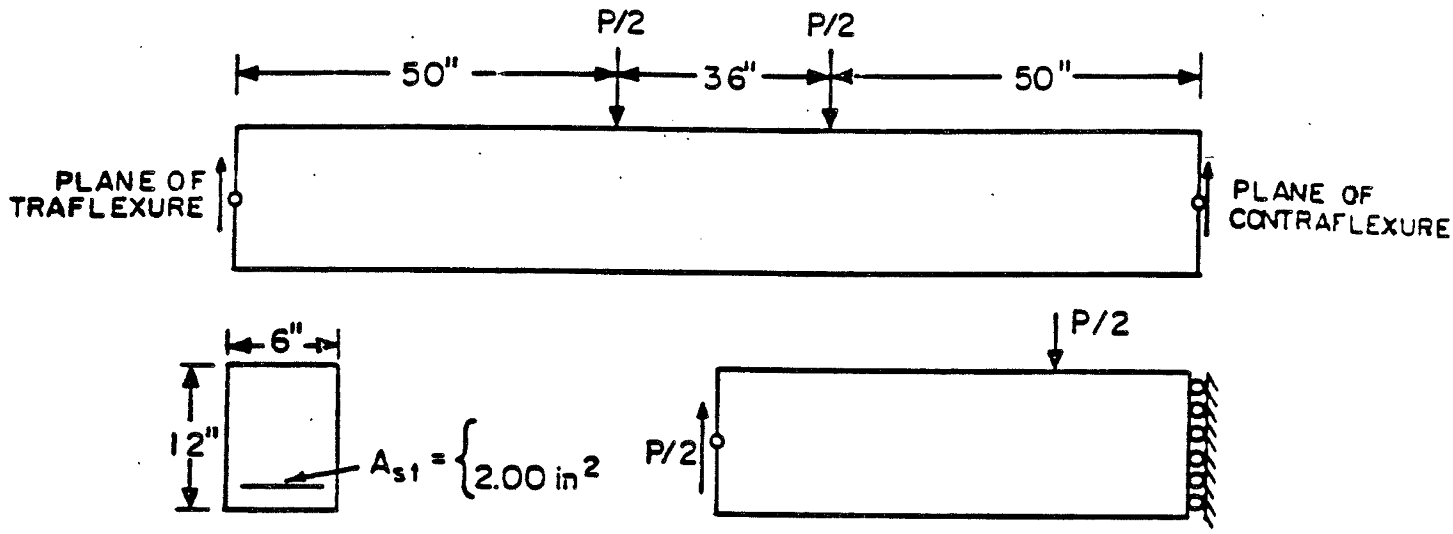
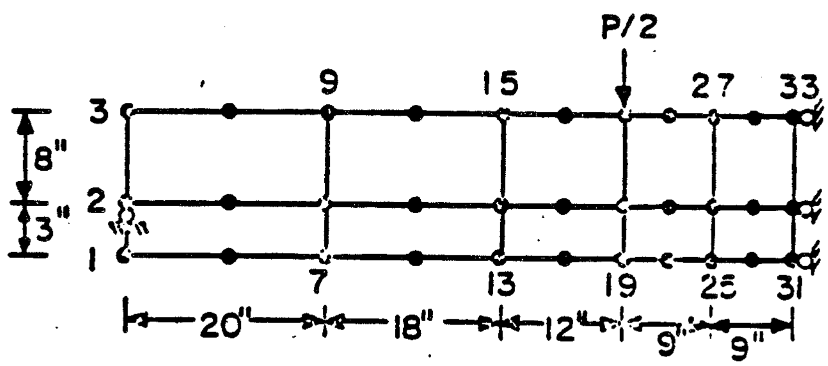
FIGURE 3.13-73

ELASTIC DISPLACEMENT RESPONSE OF CANTILEVER "ADINA" – VALIDATION PROBLEM 3



BEAM DIMENSIONS



FINITE ELEMENT IDEALIZATION

MATERIAL PROPERTIES:

$\tilde{\sigma}_c = -3740$ psi

$\tilde{\sigma}_t = 458$ psi

$\sigma_{y\,steel} = 44000$ psi

$\tilde{E}_{o_{concrete}} = 6100$ ksi

$\nu = 0.2$

$E_{steel} = 30000$ ksi

$E_{t_{steel}} = 300$ ksi

$\tilde{\sigma}_u = -3225$ psi

$\tilde{e}_u = -.003$ in/in

$\tilde{e}_c = -.002$ in/in

$\rho_{concrete} = 0.2172 \times 10^{-3}$ slugs/in^3

$\rho_{steel} = 0.7339 \times 10^{-3}$ slugs/in^3

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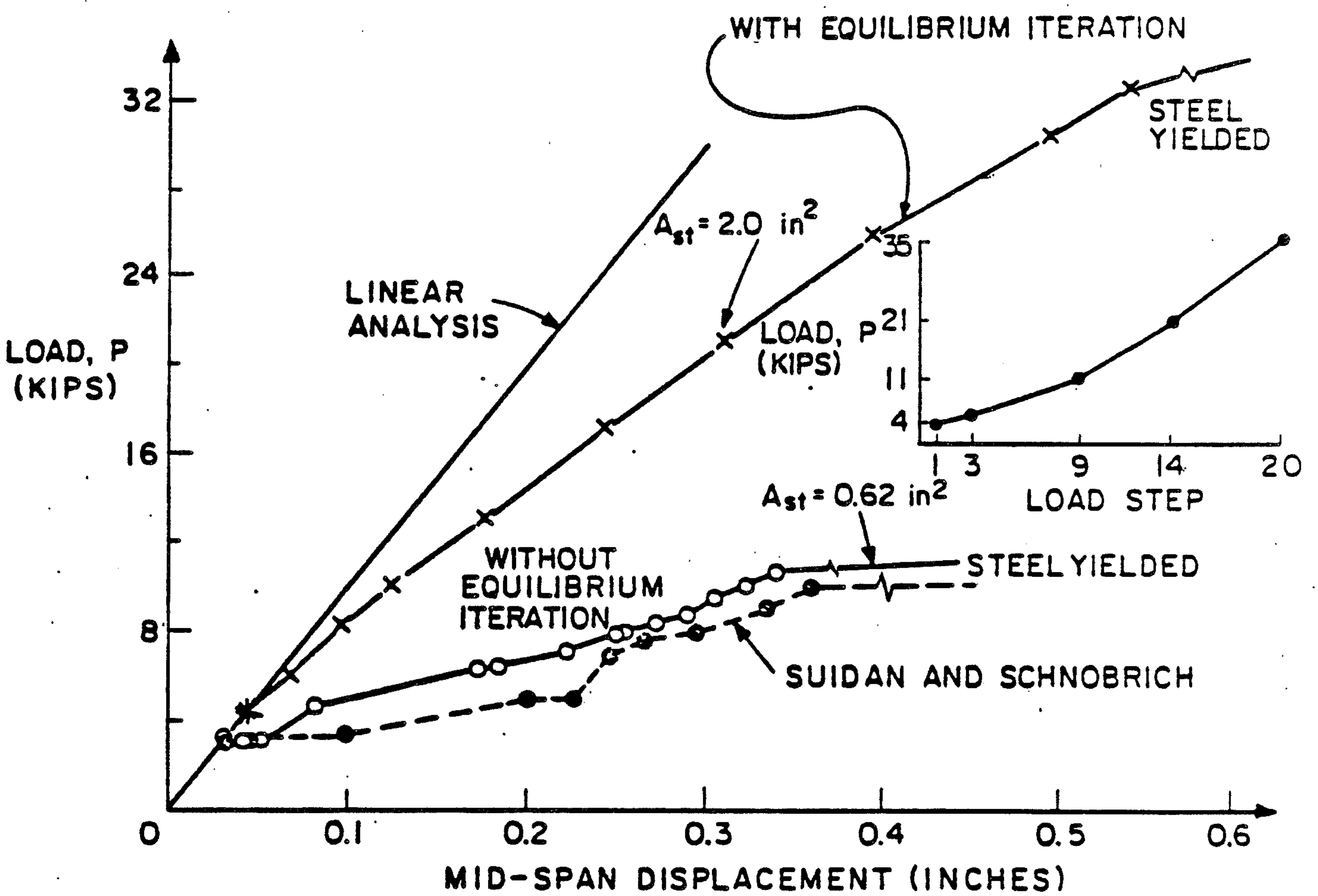
FIGURE 3.13-74

REINFORCED CONCRETE BEAM
"ADINA" – VALIDATION PROBLEM 4



*S&L'S Version for Nonlinear Static Response
Ast = 2.0

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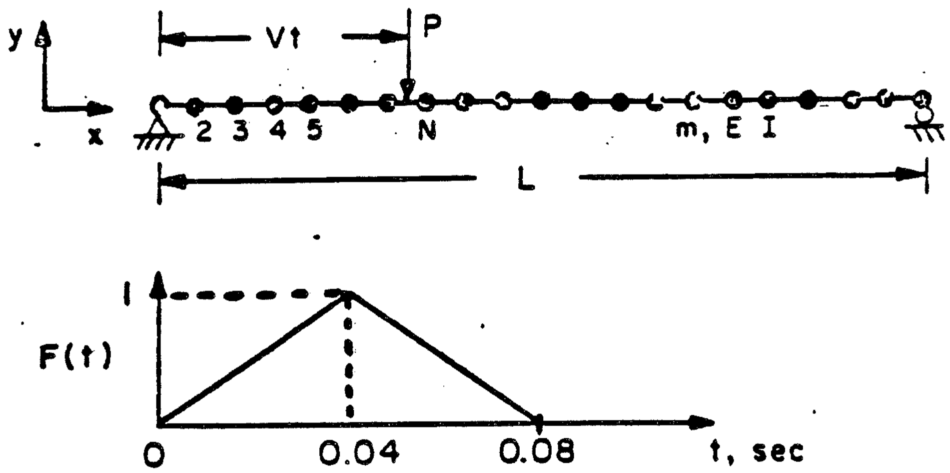
FIGURE 3.13-75

LOAD DISPLACEMENT CURVE FOR THE CONCRETE BEAM – "ADINA" – VALIDATION PROBLEM 4



TIME VARIATION OF LOAD

L = 40 ft
$m = 0.1\ \text{lb-sec}^2/\text{in}^2$
V = 50 ft/sec
$EI = 2 \times 10^{10}\ \text{lb-in}^2$
$T_f = 0.33$ sec
P = −8680.6 lbs
$$\frac{PL^3}{48EI} = -1$$

NOTE: ARRIVAL TIME OF LOAD AT N^{th} NODE = (N−2) x.04 SEC.
THE MAGNITUDE AND DURATION OF ACTION OF THE LOAD AT A NODE IS OBTAINED FROM THE ABOVE TIME FUNCTION, SHIFTED BY THE CORRESPONDING ARRIVAL TIME.

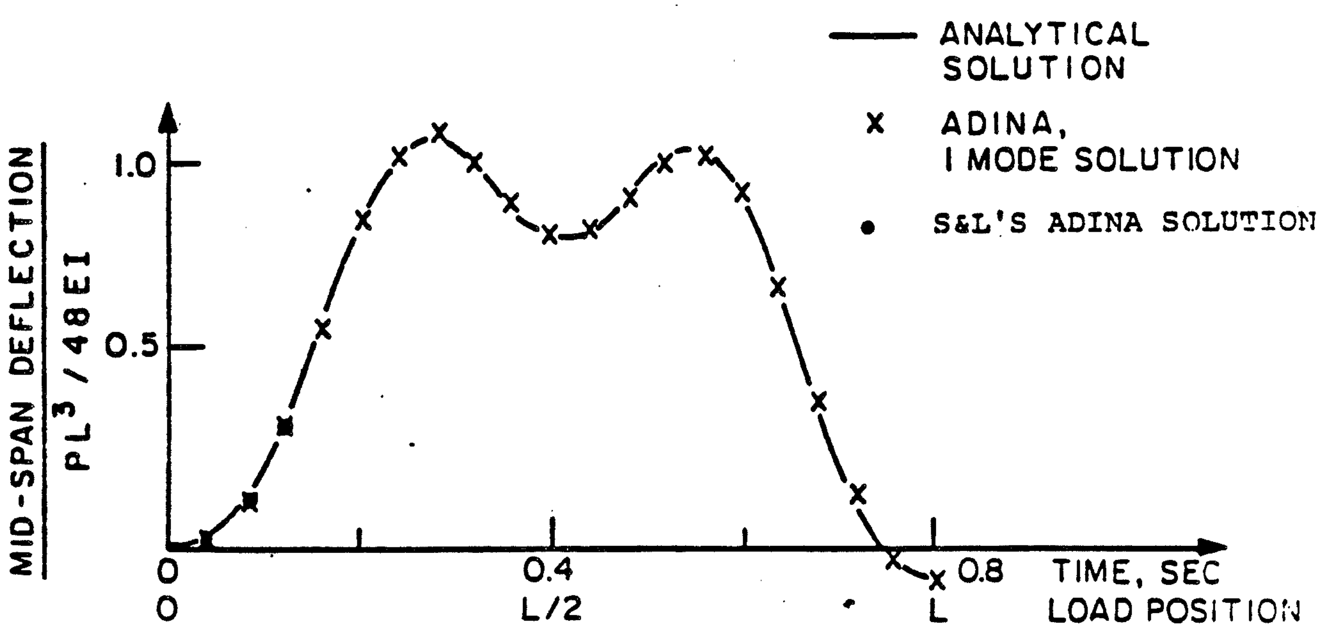


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FIGURE 3.13-76

ANALYSIS OF A BEAM SUBJECTED TO TRAVELLING LOAD "ADINA" – VALIDATION PROBLEM 5

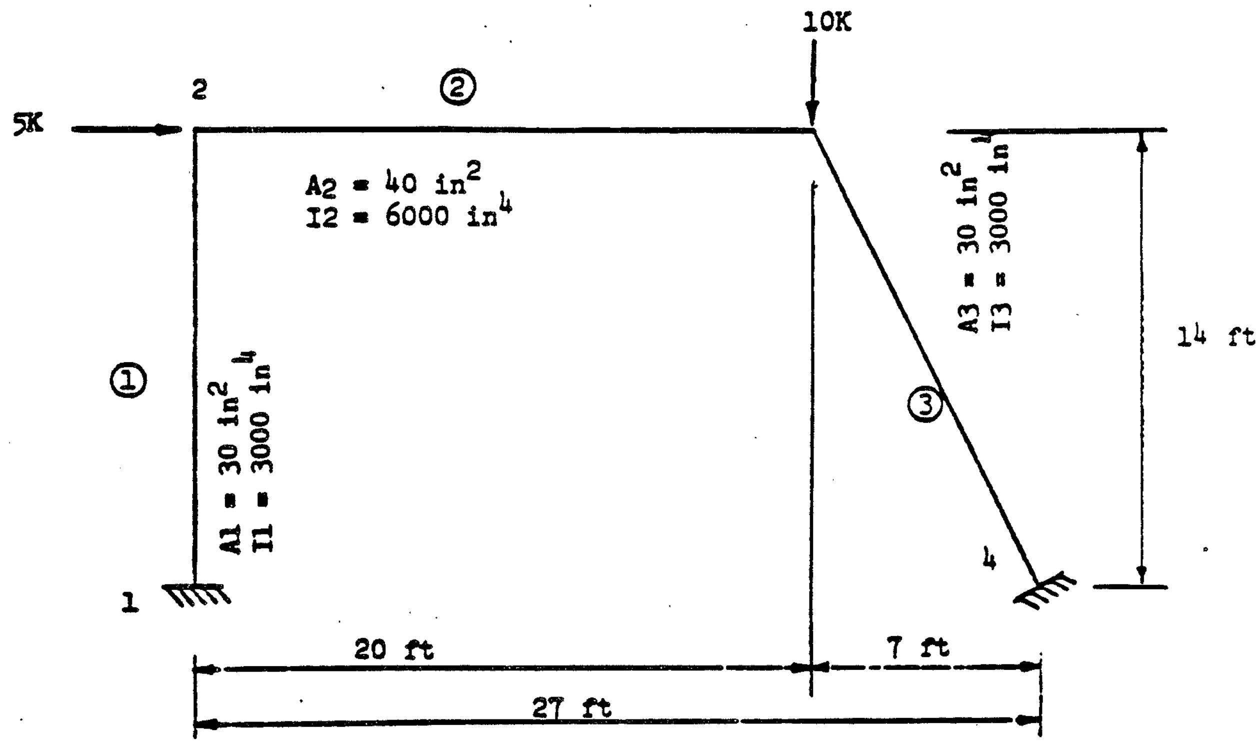

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FIGURE 3.13-77

FRAME USED TO VALIDATE STATIC ANALYSIS OF "FRAME"

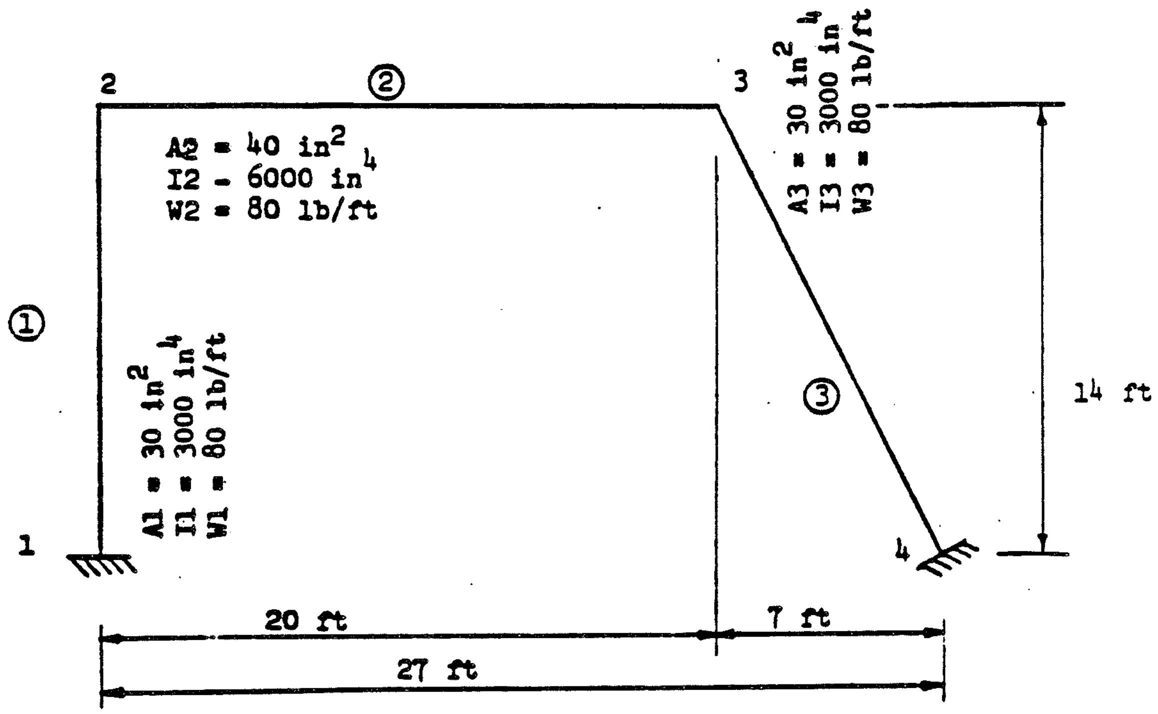

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FIGURE 3.13-78

FRAME USED TO VALIDATE DYNAMIC ANALYSIS OF "FRAME"

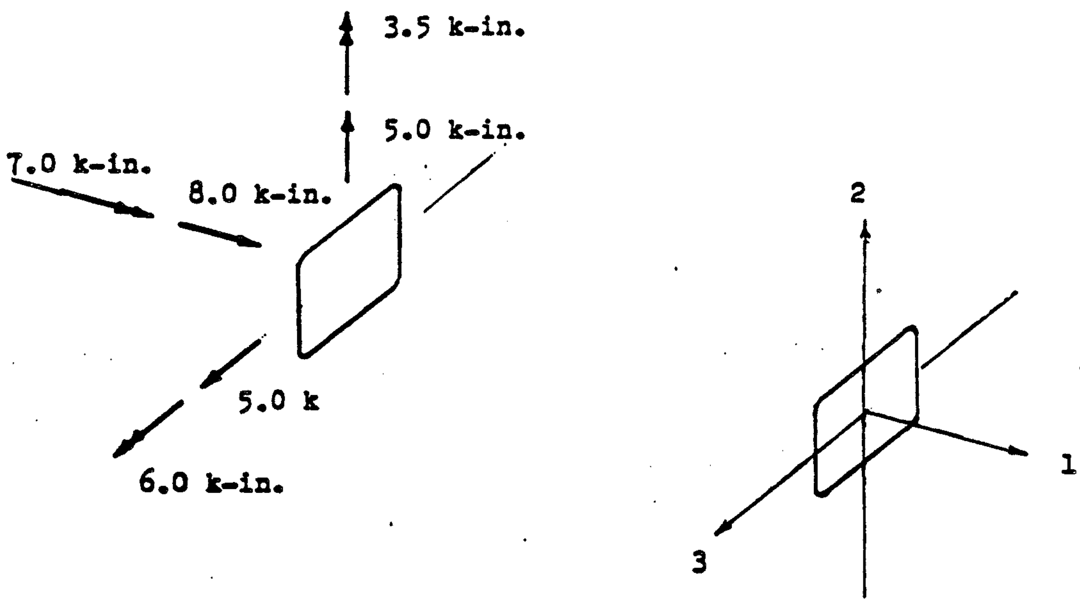

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FIGURE 3.13-79

LOADING FOR "FRAME" STRESS CHECK VALIDATION PROBLEM 1

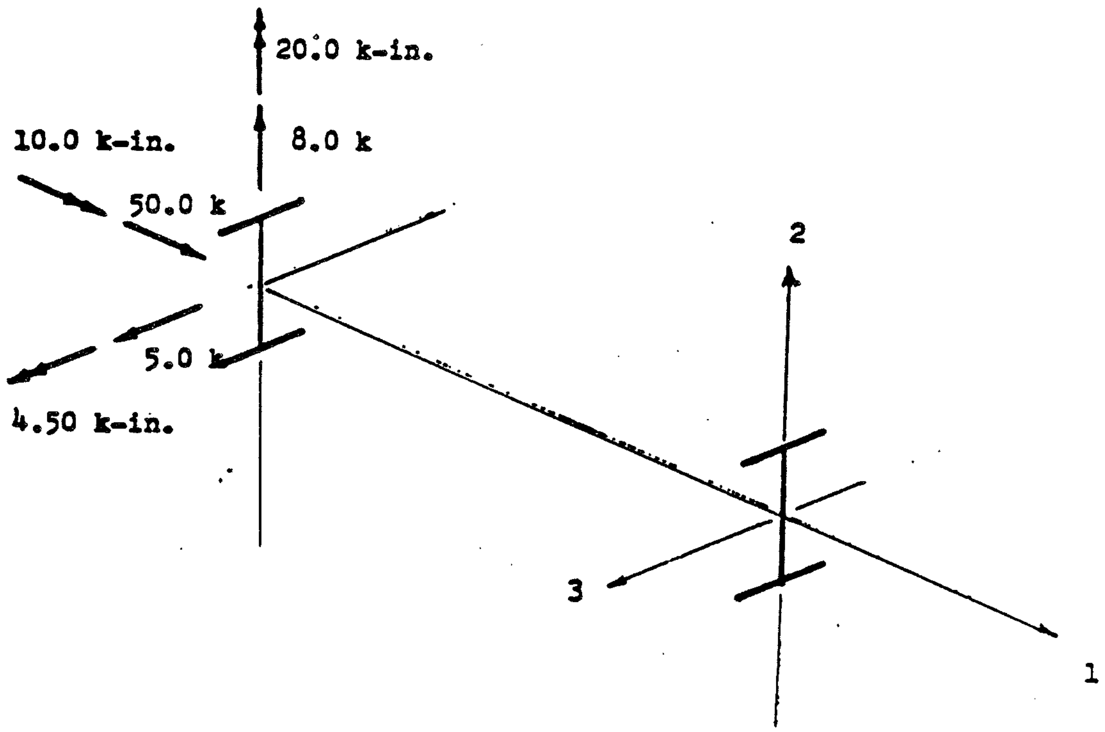

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FIGURE 3.13-80

LOADING FOR "FRAME" STRESS CHECK VALIDATION PROBLEM 2

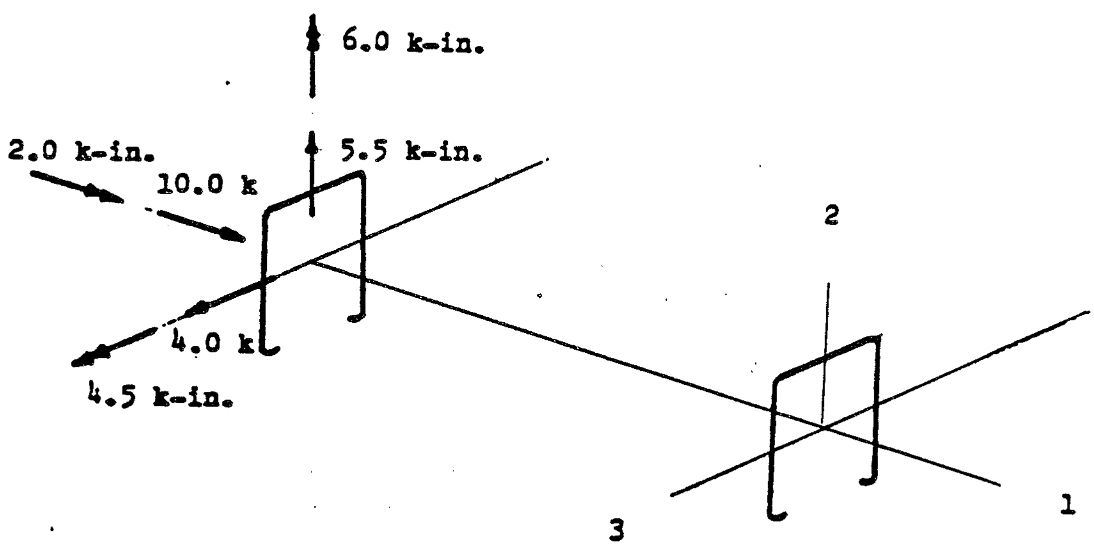

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FIGURE 3.13-81

LOADING FOR "FRAME" STRESS CHECK VALIDATION PROBLEM 3

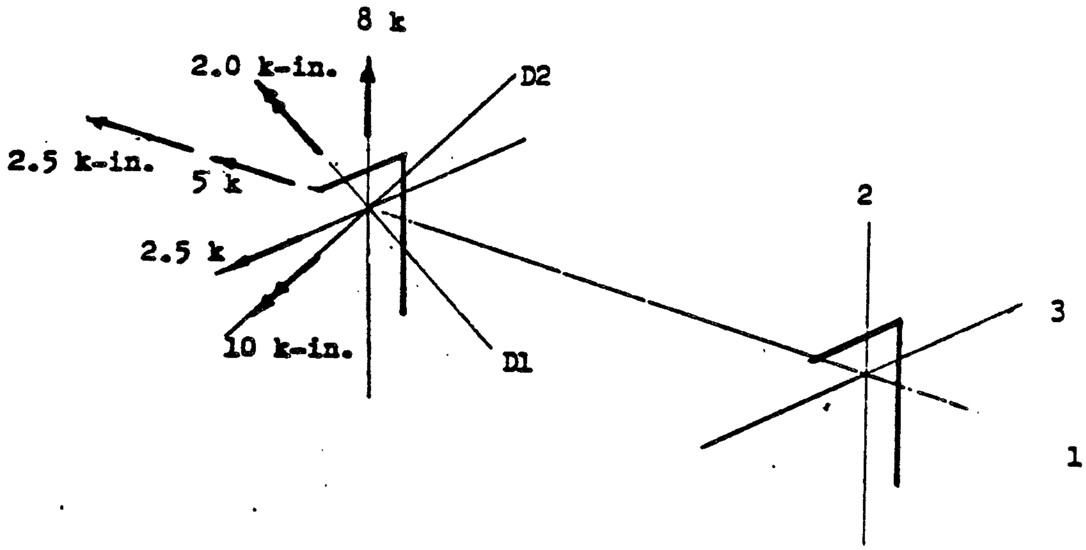

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FIGURE 3.13-82

LOADING FOR "FRAME" STRESS CHECK VALIDATION PROBLEM 4

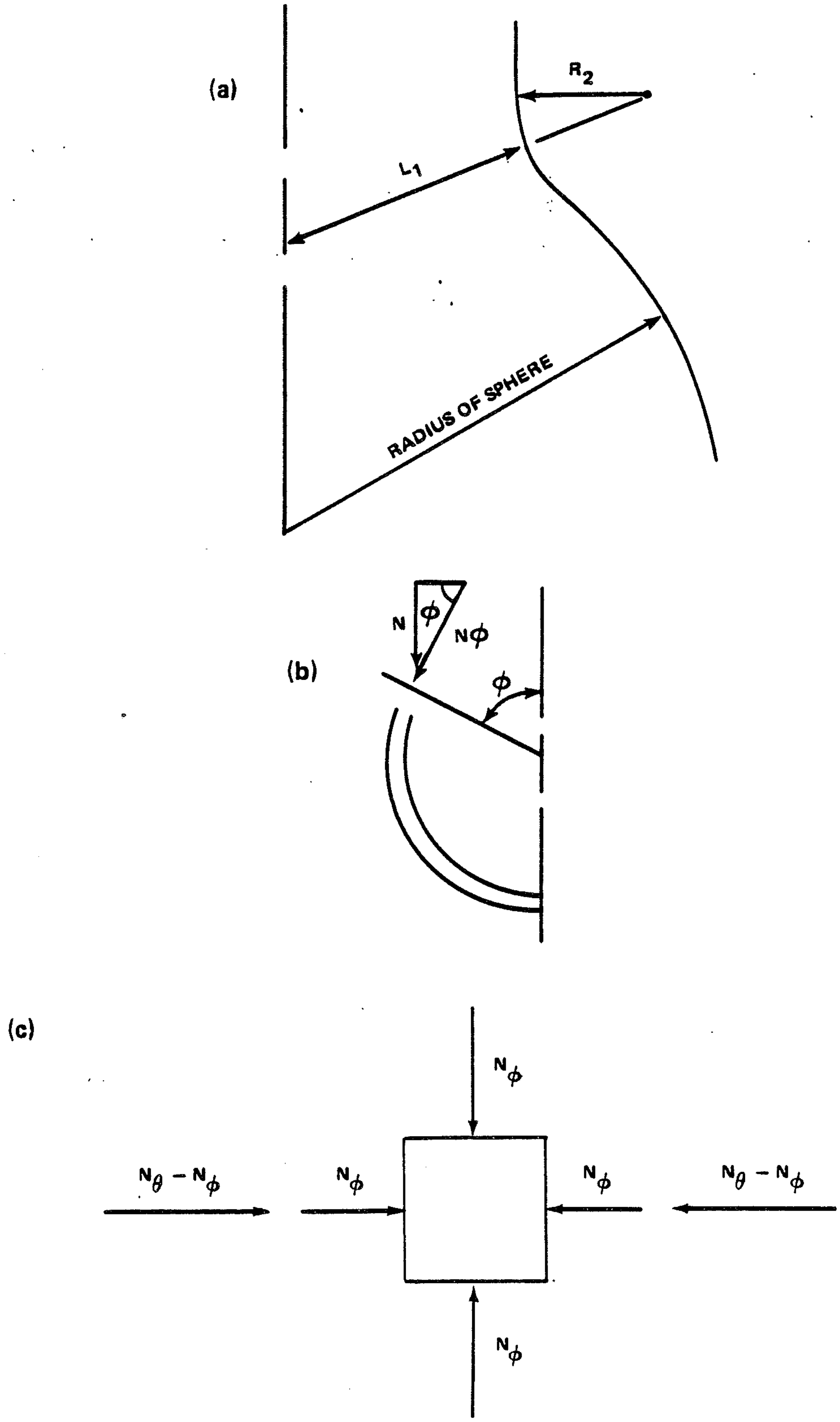

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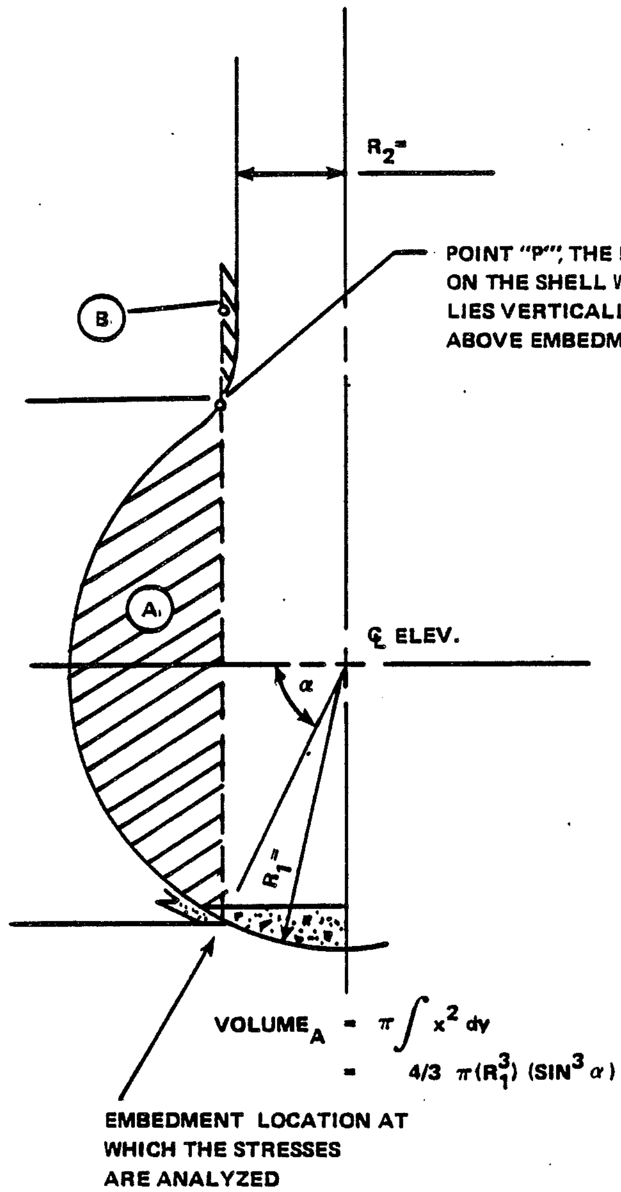
FIGURE 3.13-83

DRYWELL ANALYSIS



PROGRAM 7–78 (SUBSECTION 3.13.2.8)
DRYWELL PRIMARY MEMBRANE
STRESS ANALYSIS

CHICAGO BRIDGE & IRON COMPANY

Fermi 2
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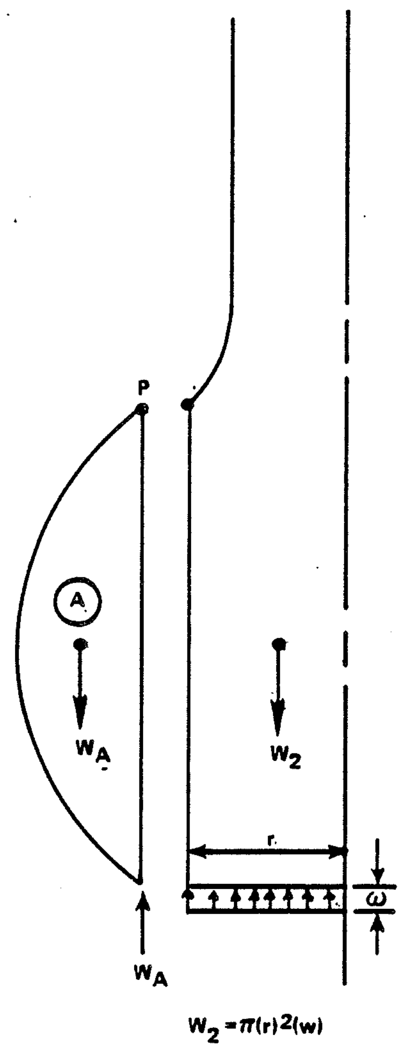
FIGURE 3.13-84

EMBEDMENT LOCATION AT WHICH THE STRESSES ARE ANALYZED



PROGRAM 7–78 (SUBSECTION 3.13.2.8)
DRYWELL PRIMARY MEMBRANE
STRESS ANALYSIS

CHICAGO BRIDGE & IRON COMPANY

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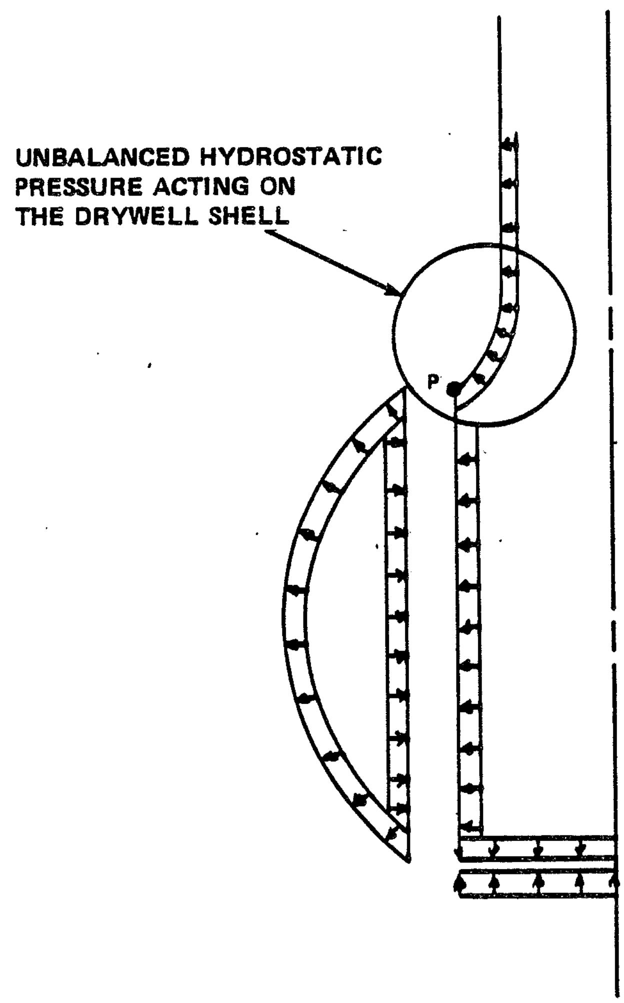
FIGURE 3.13-85

FREE-BODY DIAGRAM, WATER WEIGHT



PROGRAM 7–78 (SUBSECTION 3.13.2.8)
DRYWELL PRIMARY MEMBRANE
STRESS ANALYSIS

CHICAGO BRIDGE & IRON COMPANY

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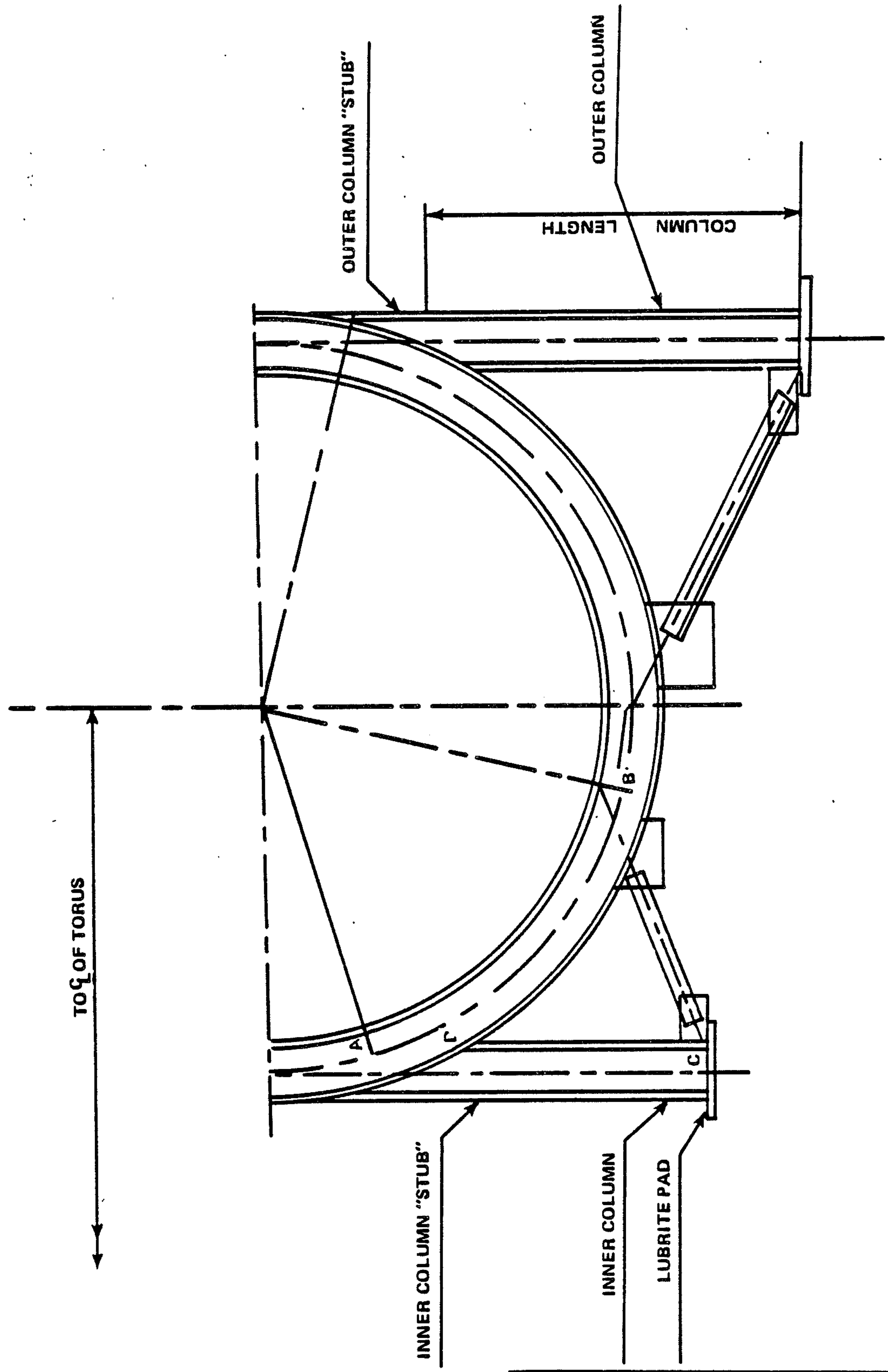
FIGURE 3.13-86

FREE-BODY DIAGRAM, WATER PRESSURE



PROGRAM 7–71 (SUBSECTION 3.13.2.9)
TORUS COLUMNS AND COLUMN
"STUBS" DESIGN

CHICAGO BRIDGE & IRON COMPANY

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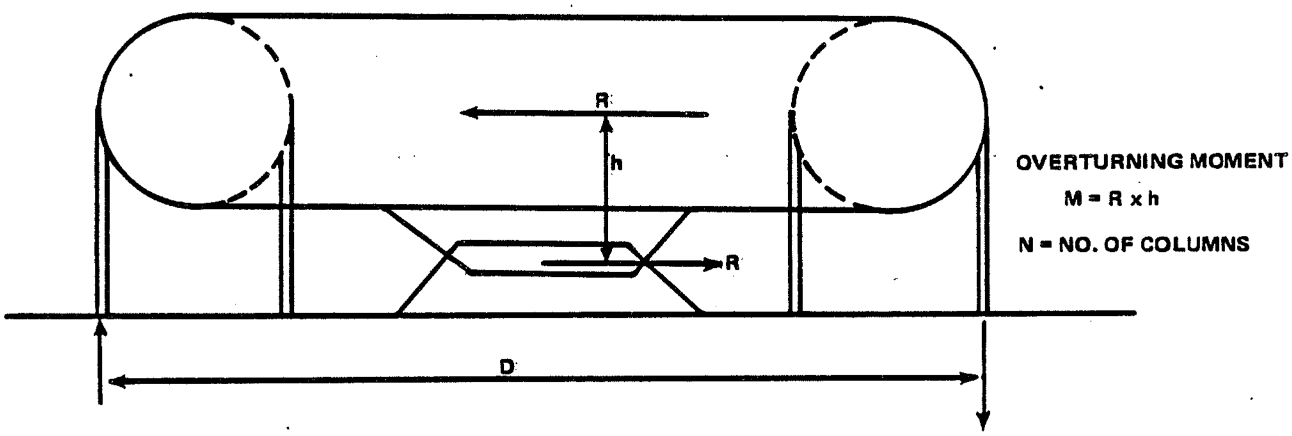
FIGURE 3.13-87

TORUS COLUMNS AND COLUMN "STUBS" DESIGN



COLUMN AXIAL LOAD DUE TO OVERTURNING

$$\text{MOMENT} = \frac{4M}{ND}$$

PROGRAM 7–71 (SUBSECTION 3.13.2.9)
TORUS COLUMNS AND COLUMN
"STUBS" DESIGN

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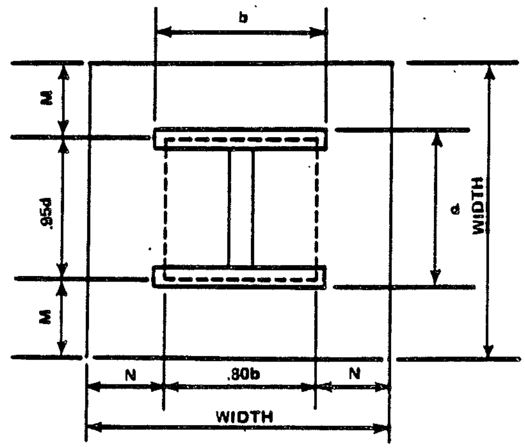
FIGURE 3.13-88

COLUMN AXIAL LOAD DUE TO OVERTURNING

(a)



(b)

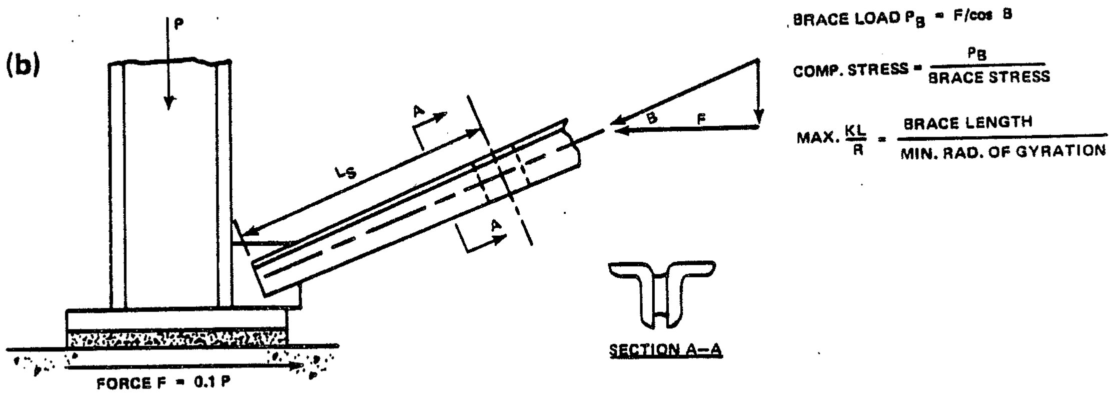


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FIGURE 3.13-89

SUPPRESSION POOL COLUMNS

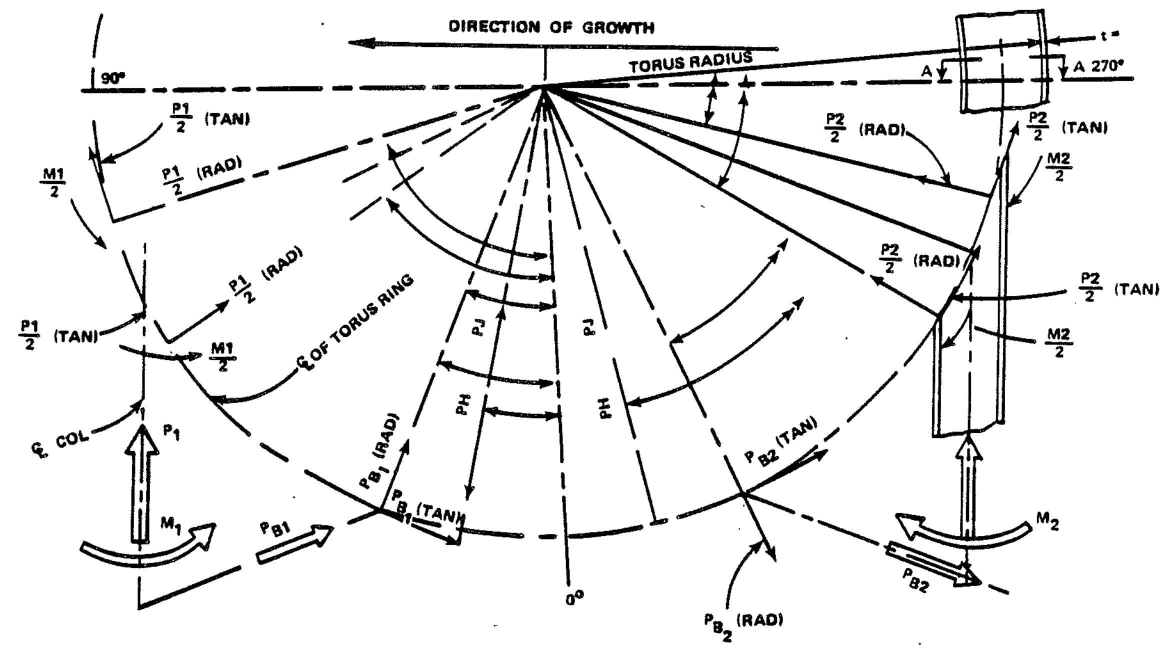

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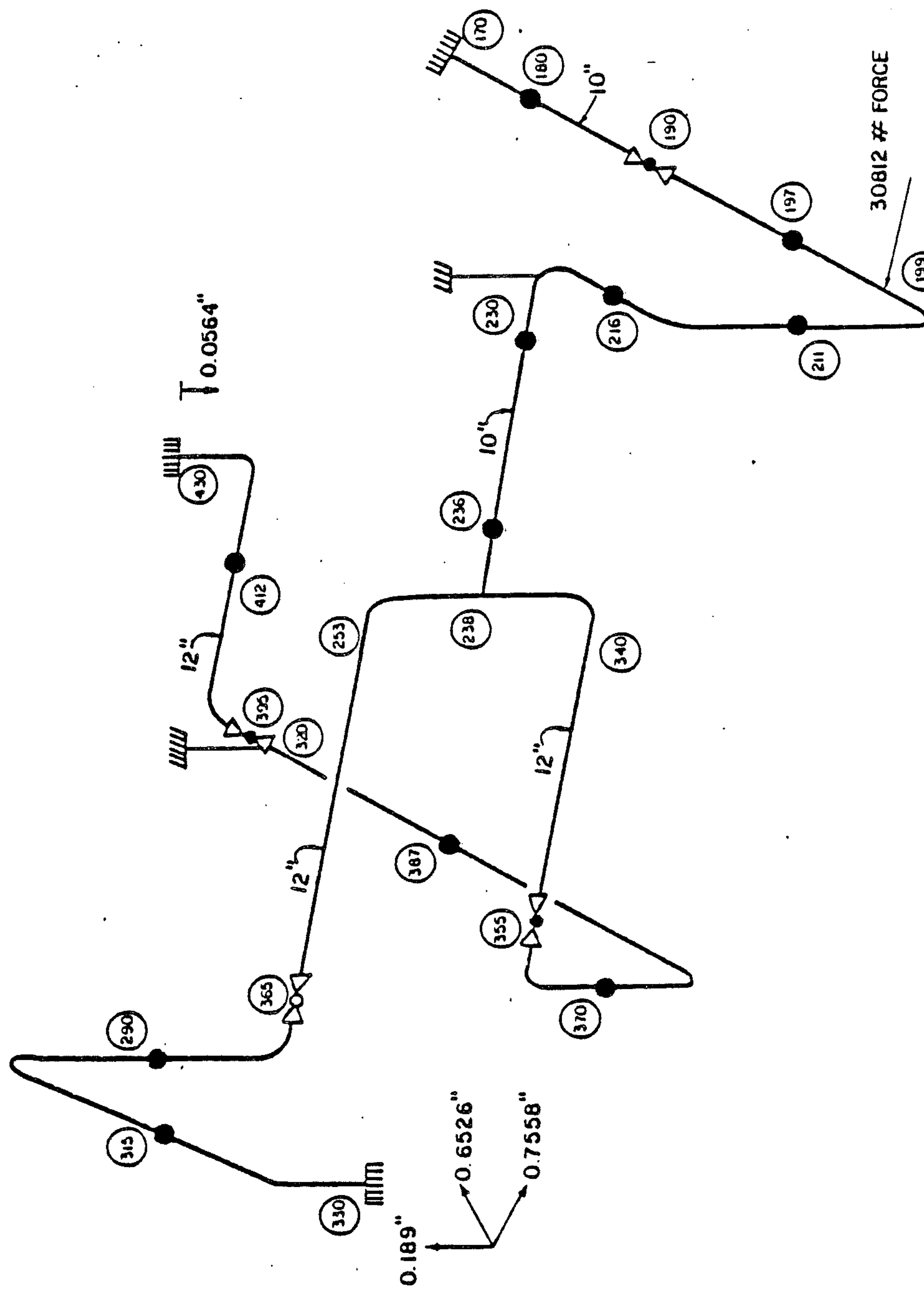
FIGURE 3.13-90

SUPPRESSION POOL LOADS



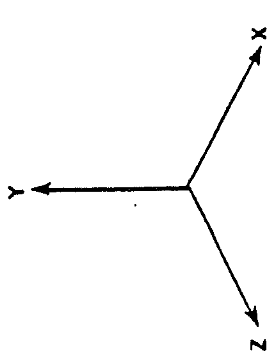


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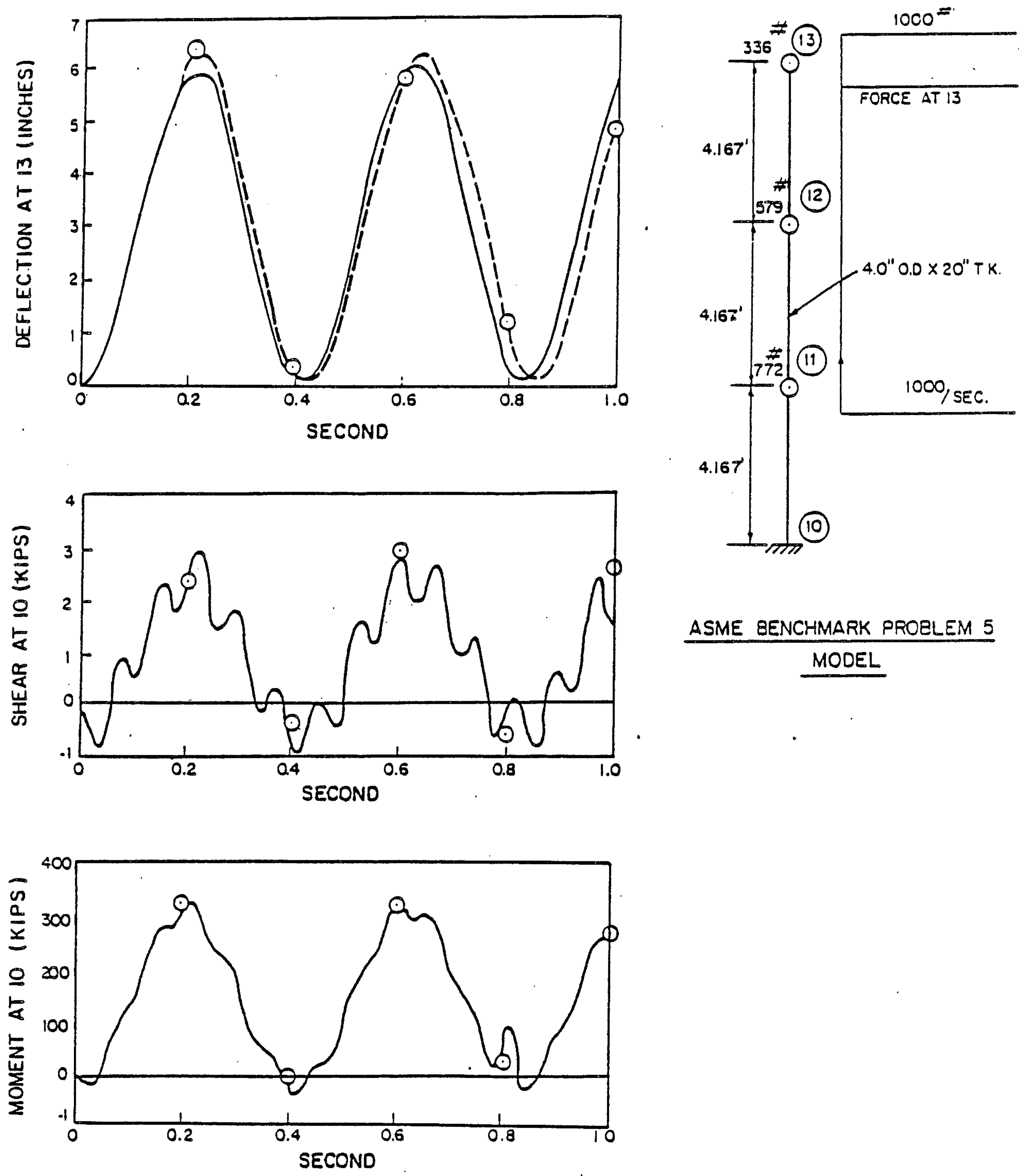
FIGURE 3.13-91

MATHEMATICAL MODEL FOR FLEXIBILITY ANALYSIS VERIFICATION



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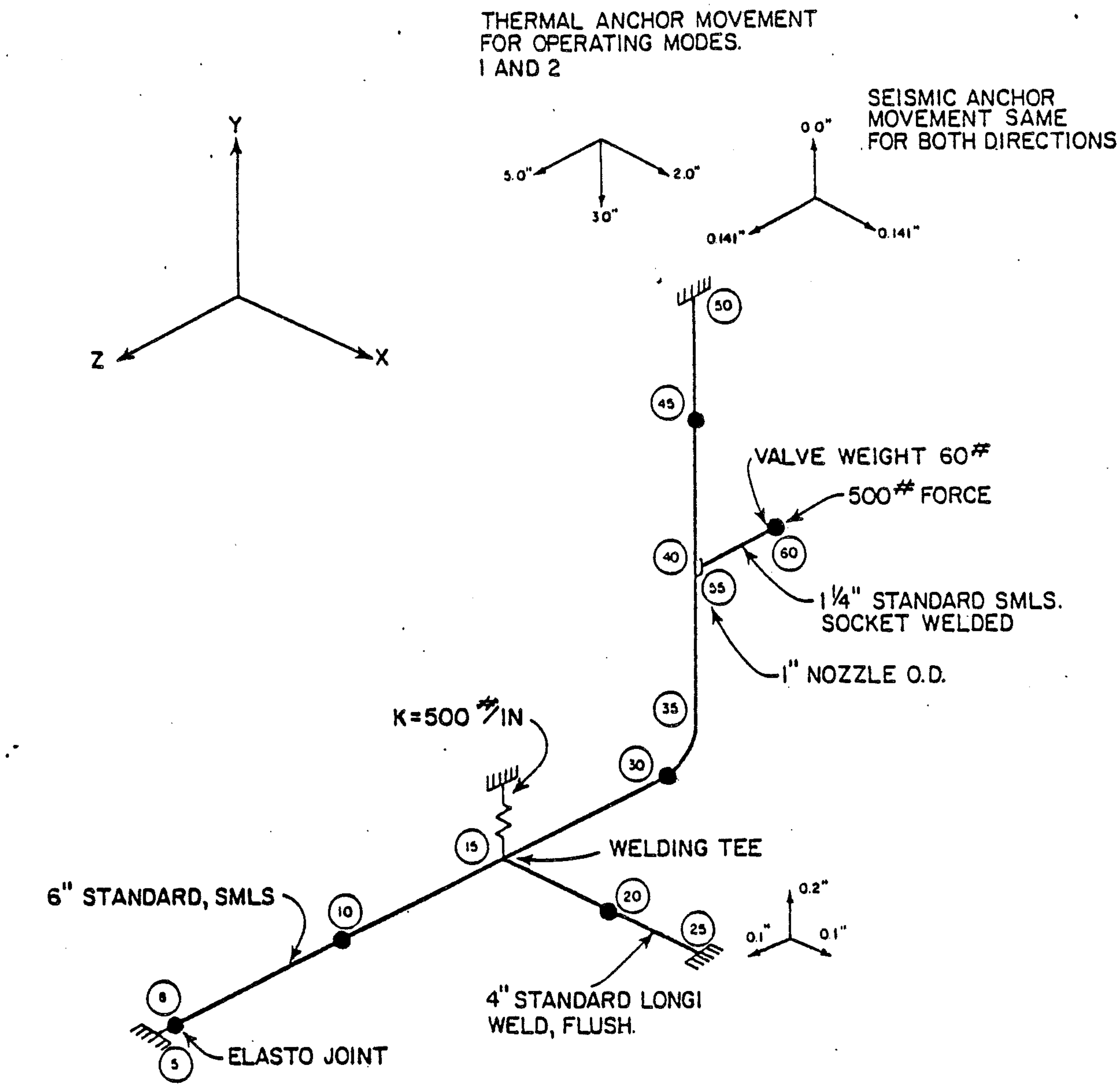
UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 3.13-92

NUPIPE PROGRAM FORCE TIME-HISTORY VERIFICATION



OPERATING CONDITIONS			
OPER MODE	PIPE	PRESSURE (PSI)	TEMPERATURE °F
1	6"	200	400
	4"	"	"
	1¼"	"	"
$E/\alpha_1 T_a - \alpha_b T_b / AT$ 15 = 440 PSI			
2	6"	200	700
	4"	0	70
	1¼"	200	700
$\alpha \Delta T_1 = 0.0002$ $\alpha \Delta T_2 = 0.0004$ IN/FT			
3	6"	700	70
	4"	700	70
	1¼"	700	70

Fermi 2

UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 3.13-93

MATHEMATICAL MODEL FOR CLASS 1 STRESS VERIFICATION

CHAPTER 4: REACTOR

This chapter was prepared using the latest approved version of the licensing topical report "General Electric Standard Application for Reactor Fuel" (GESTAR II) NEDE-24011-P-A including the "United States Supplement," NEDE-24011-P-A-US (Reference 1). Applicable sections of this report are referenced as noted in Sections 4.1 through 4.4. Reference is made to standardized information contained in the topical report, consistent with the NRC overall standardization philosophy. Additional cycle-specific reload information is in the cycle-specific supplemental reload licensing report.

4.1 REACTOR SUMMARY DESCRIPTION

The reactor assembly consists of the reactor pressure vessel (RPV) and its internal components, including the core, shroud, steam separator and dryer assemblies, and jet pumps. Also included in the reactor assembly are the control rods, control rod drive (CRD) housings, and the CRDs. The RPV cutaway, Figure 4.1-1, shows the arrangement of reactor assembly components. A summary of the important design and performance characteristics is given in Section 1.3. Loading conditions for reactor assembly components are specified in Table 3.9-14. Summary tables of the pertinent reactor data are presented at the end of Sections 4.2, 4.3, and 4.4.

4.1.1 Reactor Pressure Vessel

The RPV design and description are covered in Section 5.4.

4.1.2 Reactor Internal Components

The major reactor internal components are the core (fuel, channels, control rods, and instrumentation), the core support structure (including the core shroud, shroud head separators, top guide, and core support plate), the steam dryer assembly, and the jet pumps. Except for the zirconium alloys in the reactor core, these reactor internals are stainless steel or other corrosion- resistant alloys. All major internal components of the RPV can be removed except the jet pump diffusers, the core shroud, the core spray spargers, and the jet pump inlet piping. The removal of the steam dryers, shroud head separators, fuel assemblies, incore assemblies, control rods, and control rod guide tubes can be accomplished on a routine basis.

4.1.2.1 Reactor Core

4.1.2.1.1 General

The design of the Fermi 2 BWR core and fuel is based on the proper combination of many design variables and operating experience. These factors contribute to the achievement of high reliability.

A number of important features of the BWR core design are summarized in the following:

a. The BWR core mechanical design is based on conservative application of stress limits, operating experience, and experimental test results. The pressure levels (approximately 1000 psia) result in moderate cladding temperatures and stress levels.

b. The low coolant saturation temperature, high heat transfer coefficients, and neutral water chemistry of the BWR are significant, advantageous factors in minimizing zircaloy temperature and associated temperature-dependent corrosion and hydride buildup. The relatively uniform fuel cladding temperatures throughout the core minimize migration of the hydrides to cold cladding zones and reduce thermal stresses.

c. The basic thermal and mechanical criteria applied in the design have been proven by irradiation of statistically significant quantities of fuel. The design heat fluxes and linear heat generation rates are similar to values proven in fuel assembly irradiation.

d. The design power distribution used in sizing the core represents a worst-expected state of operation.

e. The GE thermal analysis basis, GETAB, is applied to ensure that more than 99.9 percent of the fuel rods in the core are expected to avoid boiling transition for the most severe abnormal operational transient described in Chapter 15 and the cycle-specific supplemental reload licensing report. The possibility of boiling transition occurring during normal reactor operation is insignificant.

f. Because of the large negative moderator density coefficient of reactivity, the BWR has a number of inherent advantages. These are the use of recirculation coolant flow for load following, the inherent self-flattening of the radial power distribution, the ease of control, the spatial xenon stability, and the ability to override xenon in order to follow load.

Boiling water reactors do not have instability problems due to xenon. This has been demonstrated by special tests which have been conducted on operating BWRs in an attempt to force the reactor into xenon instability, and by calculations. No xenon instabilities have ever been observed in the test results. All of these indicators have proven that xenon transients are highly damped in a BWR due to the large negative power coefficient of reactivity (Reference 1).

Important features of the reactor core arrangement are as follows:

a. The bottom-entry cruciform control rods consist of: (1) boron carbide (B_4C) in stainless steel tubes or (2) boron carbide (B_4C) in stainless steel tubes and hafnium metal. Duralife 140 control rods are surrounded by a stainless steel sheath. Marathon C, Ultra-MD, and Ultra-HD control rods have absorber tubes that are edge welded to form the cruciform shape.

b. The fixed in-core ion chambers provide continuous-power-range neutron flux monitoring. A probe tube in each in-core assembly provides for a traversing ion chamber for calibration and axial detail. Source range monitors (SRM) and intermediate range monitors (IRM) are located in-core and are axially retractable. The in-core location of the startup and IRM instruments provides coverage of the large reactor core and provides an acceptable signal-to-noise ratio and neutron-to-gamma ratio. All in-core instrument leads enter from the bottom and the instruments are in service during refueling. In-core instrumentation is further discussed in Chapter 7.

c. As shown by experience obtained at Dresden 1 and other plants, the operator, utilizing the in-core flux monitor system, can maintain the desired power distribution within a large core by proper control rod scheduling.

d. The zirconium alloy reusable channels provide a fixed flow path for the boiling coolant, serve as a guiding surface for the control rods, and protect the fuel during handling operations.

e. The mechanical reactivity control permits criticality checks during refueling. The core is designed to be subcritical at any time in its operating history with any one control rod fully withdrawn.

f. The selected control rod pitch represents a practical value of individual control rod reactivity worth and allows ample clearance below the RPV between CRD mechanisms for ease of maintenance and removal.

4.1.2.1.2 Core Configuration

The reactor core is arranged as an upright circular cylinder containing a large number of fuel cells and is located within the RPV. The coolant flows upward through the core. The core arrangement (plan view) and the lattice configuration are shown in Figure 4.1-2.

4.1.2.1.3 Fuel Assembly Description

As can be seen from Figure 4.1-2, the BWR core is essentially composed of only two components: fuel assemblies and control rods. The fuel assembly and control rod mechanical designs (See Subsection 4.5.2.2) are basically the same as those used in Dresden 1 and in all subsequent GE BWRs. A description of the fuel assembly including fuel rods, water rods, other fuel assembly components, and channels is given in Section 4.2. A brief description of the fuel rods and bundle is given below.

4.1.2.1.3.1 Fuel Rod

A fuel rod consists of uranium oxide (UO_2) pellets and a zircaloy cladding tube. Barrier fuel bundles consist of fuel rods with a thin, high purity zirconium liner, i.e. barrier, mechanically bonded to the cladding tube. A fuel rod is made by stacking pellets into a zircaloy cladding tube that is evacuated, backfilled with helium, and sealed by welding zircaloy end plugs in each end of the tube.

The BWR fuel rod is designed as a pressure vessel. The ASME Boiler and Pressure Vessel (B&PV) Code, Section III, is used as a guide in the mechanical design and stress analysis of the fuel rod.

The rod is designed to withstand the applied loads, both external and internal. The fuel pellet is sized to provide sufficient clearance within the fuel tube to accommodate axial and radial differential expansion between fuel and cladding. Overall fuel rod design is conservative in its accommodation of the mechanisms affecting fuel in a BWR environment. Fuel rod design bases are discussed in more detail in Subsection 4.2.1.

4.1.2.1.3.2 Fuel Bundle

Each fuel bundle contains fuel rods and water rods that are spaced and supported in a square array by spacers and a lower and upper tie plate. The fuel bundle has two important design features:

a. The bundle design places minimum external forces on a fuel rod; each fuel rod is free to expand in the axial direction.

b. The unique structural design permits the removal and replacement, if required, of individual fuel rods.

Before fuel is inserted into the reactor, a zirconium alloy fuel channel is placed around the fuel bundle, forming a fuel assembly.

The fuel assemblies of which the core is comprised are designed to meet all the criteria for core performance and to provide ease of handling. Selected fuel rods in each assembly differ from the others in uranium enrichment. This arrangement produces more uniform power production across the fuel assembly.

4.1.2.1.4 Assembly Support and Control Rod Location

A few peripheral fuel assemblies (24) and their individual fuel support pieces are supported by the core support plate. Otherwise, individual fuel assemblies in the core rest on fuel support pieces mounted on top of the control rod guide tubes. Each guide tube, with its fuel support piece, bears the weight of four assemblies and is supported by a control rod drive penetration nozzle in the bottom head of the RPV. The core support plate provides lateral support and guidance at the top of each control rod guide tube. For a discussion of fuel channel wear from flow-induced instrument tube vibrations caused by flow through the bypass holes in the core support plate, see Subsection 4.5.1.2.3.

The top guide, mounted inside the core shroud, provides lateral support and guidance for each fuel assembly. The reactivity of the core is controlled by cruciform control rods containing boron carbide or a combination of boron carbide and hafnium metal and by the associated mechanical hydraulic drive system. The control rods occupy alternate spaces between fuel assemblies. Each independent CRD enters the core from the bottom and can accurately position its associated control rod during normal operation and yet exert approximately 10 times the force of gravity to insert the control rod during the scram mode of operation. Bottom entry allows optimum power shaping in the core, ease of refueling, and convenient CRD maintenance.

4.1.2.2 Shroud

The shroud is a cylindrical, stainless steel structure that surrounds the core and provides a barrier to separate the upward flow through the core from the downward flow in the annulus. The shroud also provides a floodable volume in the unlikely event of an incident that tends to drain the RPV. A flange at the top of the shroud cylinder mates with a flange on the shroud head to form the core discharge plenum. The shroud support is welded to the RPV wall and is designed to support and locate the jet pumps and core support structure. The 20 jet pump discharge diffusers penetrate the shroud support below the core elevation to introduce the coolant to the lower inlet plenum.

Mounted inside the shroud in the space between the top of the core and the flange at the top of the shroud are the two core spray spargers with spray nozzles for injection of cooling water. The core spray spargers and nozzles do not interfere with the installation or removal of fuel from the core. A pipe for the injection of neutron absorber (sodium pentaborate) solution is mounted below the core to ensure mixing with the cooling water rising through the core.

4.1.2.3 Shroud Head and Separators

The shroud head and separators consist of a flange and dome onto which is welded an array of standpipes (225), with a steam separator located at the top of each standpipe. The shroud head mounts on the flange at the top of the shroud top cylinder and forms the cover (shroud head) of the core discharge plenum region. The joint between the shroud head and shroud top cylinder does not require a gasket or other replacement sealing techniques. The fixed axial flow-type steam separators have no moving parts and are made of stainless steel.

In each separator, the steam/water mixture rising from the standpipe impinges on vanes that give the mixture a spin to establish a vortex wherein the centrifugal forces separate the steam from the water. Steam leaves the separator at the top and passes into the wet steam plenum below the dryer. The separated water exits from the lower end of the separator and enters the pool that surrounds the standpipes to enter the downcomer annulus. An internal steam separator schematic is shown in Figure 4.1-3.

For ease of removal, the shroud head and separators are bolted to the top cylinder by long shroud head bolts that extend above the separators for easy access during refueling. The shroud head and separators are guided into position on the shroud and flange with guide rods and locating pins. The objective of the longbolt design is to provide direct access to the bolts during reactor refueling operations with minimum-depth underwater tool manipulation during the removal and installation of the assemblies.

4.1.2.4 Steam Dryer Assembly

The steam dryer assembly is mounted in the RPV above the shroud head and separators and forms the top and sides of the wet steam plenum. Vertical guide rods on the inside of the RPV provide alignment for the dryer assembly during installation. The dryer assembly is supported by pads extending from the RPV wall and is locked into position during operation by the RPV top head. Steam from the separators flows upward into the dryer assembly. The steam leaving the top of the dryer assembly flows into four RPV steam outlet nozzles that are located alongside the steam dryer assembly. Moisture is removed by the dryer vanes and flows first through a system of troughs and pipes to the pool surrounding the separators and then into the downcomer annulus between the shroud and RPV wall. A schematic of a typical steam dryer panel is shown in Figure 4.1-4.

4.1.3 Reactivity Control Systems

4.1.3.1 Operation

The control rods perform dual functions of power distribution shaping and reactivity control. Power distribution in the core is controlled during operation of the reactor by manipulation of selected patterns of rods. The rods, which enter from the bottom of the near-cylindrical reactor core, are positioned in a manner such as to counterbalance steam voids in the top of the core and effect significant power flattening.

The reactivity control function requires that all rods be available for both reactor scram and reactivity regulation. Because of this, the control elements are mechanically designed to withstand the dynamic forces resulting from a scram. They are connected to bottom-mounted, hydraulically actuated drive mechanisms that allow either axial positioning for reactivity regulation or rapid scram insertion. The design of the rod-to-drive connection permits each blade to be attached or detached from its CRD without disturbing the remainder of the control system. The bottom-mounted CRDs permit the entire control system to be left intact and operable for tests with the RPV open. See also Subsection 4.5.2.2.2.4.

4.1.3.2 Description of Rods

The cruciform-shaped control rods consist of (1) boron carbide (B_4C) in stainless steel tubes or (2) boron carbide (B_4C) in stainless steel tubes and hafnium metal. Duralife 140 control rods are surrounded by a stainless steel sheath. Marathon C, Ultra-MD, and Ultra-HD control rods have absorber tubes that are edge welded to form the cruciform shape. Hafnium metal (another neutron absorber) is used in the Duralife 140, Marathon C, and Ultra-HD control rod designs to extend service life. Refer to Subsection 4.5.2.1.2 for a description of the control rods.

Control rods are cooled by the core bypass flow that is made up of leakage through various flow paths of the fuel support and lower core plate structure.

4.1.3.3 Supplementary Reactivity Control

The control requirements of the initial core are considerably in excess of the equilibrium core requirements because all the fuel is fresh. The initial core control requirements are met by use of the combined effects of the movable control rods and a supplementary burnable poison. The supplementary burnable poison is gadolinia (Gd_2O_3) mixed with UO_2 in several fuel rods in each fuel bundle.

4.1.4 Analysis Techniques

4.1.4.1 Reactor Internal Components

Computer codes used for the analysis of the internal components are listed below:

a. MASS (Mechanical Analysis of Space Structure)

b. SNAP and MULTISHELL

c. GASP

d. NOHEAT

e. FINITE

f. SAMIS (Structural Analysis and Matrix Interpretive System)

g. GEMOP (General Matrix Manipulation Program)

h. SHELL 5 and SHELL 9

i. HEATER

j. FAP-71 (Fatigue Analysis Program)

k. DYSEA (Dynamic and Seismic Analysis).

Detailed descriptions of these programs are given in the subsections that follow.

4.1.4.1.1 MASS (Mechanical Analysis of Space Structure)

4.1.4.1.1.1 Program Description

The program, proprietary of GE, is an outgrowth of the plate and panel analysis program originally developed by L. Beitch in the early 1960s. The program is based on the principle of the finite element method. Governing matrix equations are formed in terms of joint displacements using a "stiffness-influence-coefficient" concept originally proposed by L. Beitch (Reference 1a). The program offers curved beam, plate, and shell elements. It can handle mechanical and thermal loads in a static analysis and predict natural frequencies and mode shapes in a dynamic analysis.

4.1.4.1.1.2 Program Version

The Nuclear Energy Division of GE is using a past revision of MASS. This revision is identified as revision "0" in the computer production library.

4.1.4.1.1.3 History of Use

Since its development in the early 1960s, the program has been successfully applied to a wide variety of jet-engine structural problems, many of which involve extremely complex geometries. The use of the program in the GE Nuclear Energy Division also started shortly after its development.

4.1.4.1.1.4 Extent of Application

In addition to the GE Jet Engine Division, the Nuclear Energy Division, and the Missile and Space Division, the Appliance Division and the Turbine Division have also applied the program to a wide range of engineering problems. The Nuclear Energy Division used it mainly for piping and reactor internals analysis.

4.1.4.1.2 SNAP (MULTISHELL)

4.1.4.1.2.1 Program Description

The SNAP program, which is also called MULTISHELL, is a code that determines the loads, deformations, and stresses of axisymmetric shells of revolution (cylinders, cones, disks, toroids, and rings) for axisymmetric thermal boundary and surface load conditions. Thin shell theory is inherent in the solution of E. Reissner's differential equations for each shell's influence coefficients. Surface loading capability includes pressure, average temperature, and linear through-wall gradients; the latter two may be linearly varied over the shell meridian. The theoretical limitations of this program are the same as those of classical theory.

4.1.4.1.2.2 Program Version

The current version maintained by the GE Jet Engine Division at Evandale, Ohio.

4.1.4.1.2.3 History of Use

The initial version of the Shell Analysis Program was completed by the Jet Engine Division in l96l. Since then, a considerable amount of modification and addition has been made to accommodate its broadening area of application. Its application in the Nuclear Energy Division had a history of over 10 years when used for the Fermi 2 analysis.

4.1.4.1.2.4 Extent of Application

The program has been used to analyze jet engine, space vehicle, and nuclear reactor components. Because of its efficiency and economy, in addition to reliability, it has been one of the main shell analysis programs in GE's Nuclear Energy Division.

4.1.4.1.2.5 Test Problems

The program has been used to analyze the pressure vessel specified in Article I-7 of ASME Section III. The program results are compared with those from other shell programs under three loadings: internal pressure, axial temperature gradient, and linear radial temperature gradient. It was found that the thin-shell theory programs (OMP, SOR, and MULTISHELL) were within 4 percent of thin-shell theoretical results for the pressure loading and within 1 percent of each other for the other two loadings. The thick-shell theory program (SEAL-SHELL-2) was within 7 percent of theory for the pressure loading and within 9 percent of the thin-shell codes on the other two loadings. Detailed results are presented in Figures 4.l-5 through 4.1-13.

4.1.4.1.3 GASP

4.1.4.1.3.1 Program Description

GASP is a finite element program for the stress analysis of axisymmetric or plane two-dimensional geometries. The element representations can be either quadrilateral or triangular. Axisymmetric or plane structural loads can be input at nodal points. Displacements, temperatures, pressure loads, and axial inertia can be accommodated. Effective plastic stress and strain distributions can be calculated using a bilinear stress-strain relationship by means of an iterative convergence procedure.

4.1.4.1.3.2 Program Version and Computer

The GE version, originally obtained from the developer, Professor E. L. Wilson, operates on the Honeywell 6000 computer.

4.1.4.1.3.3 History of Use

The program was developed by E. L. Wilson in l965 (Reference 2). The present version in GE's Nuclear Energy Division has been in operation since l967.

4.1.4.1.3.4 Extent of Application

The application of GASP in the GE Nuclear Energy Division is mainly for elastic analysis of axisymmetric and plane structures under thermal and pressure loads. The GE version has been extensively tested and used by engineers in the company.

4.1.4.1.3.5 Test Problems

The ASME computer-program-verification problem l9 (Reference 3) was solved using the triangular elements of GASP and ANSYS (Figure 4.1-14). The results of both solutions are very close to each other and they agree with a closed-form solution given in Reference 3 (Figure 4.1-15).

4.1.4.1.4 NOHEAT

4.1.4.1.4.1 Program Description

The NOHEAT program (Reference 4) is a two-dimensional and axisymmetric transient nonlinear temperature analysis program. An unconditionally stable numerical integration scheme is combined with iteration procedure to compute temperature distribution within the body subjected to arbitrary time- and temperature-dependent boundary conditions.

This program utilizes the finite element method. Included in the analysis are the three basic forms of heat transfer, conduction, radiation, and convection, as well as internal heat generation. In addition, cooling pipe boundary conditions are also treated. The output includes temperature of all the nodal points for the time instants required by the user. The program can handle multitransient temperature input.

4.1.4.1.4.2 Program Version

The current version of the program is an improvement of the program NOHEAT originally developed by I. Farhoomand and Professor E. L. Wilson of the University of California at Berkeley.

4.1.4.1.4.3 History of Use

The program was developed in l97l and installed in the Honeywell computer by one of its original developers, I. Farhoomand, in 1972. A number of heat transfer problems related to the reactor pedestal have been satisfactorily solved using the program.

4.1.4.1.4.4 Extent of Application

The program using finite element formulation is compatible with the finite element stress-analysis computer program GASP. Such compatibility simplified the connection of the two analyses and minimized human error.

4.1.4.1.4.5 Test Problems

Problem 1

Problem 1 involves one-dimensional temperature response of a plate with insulated back face after sudden change in external front surface temperature.

The prescribed heat-input boundary condition is useful in problems of aerodynamics, nuclear reactor power plants, and similar problems. The temperature response of a plate caused by a sudden change in external front surface temperature has been solved by direct integration technique (Reference 5). Figure 4.1-16 shows the response in a nondimensional form. The following variables are used in the description of the figure:

a. T_o = Initial temperature of figure

b. T_e = Boundary temperature

c. α = Thermal diffusivity of body material = $k/\rho c$

d. k = Conductance

e. ρ = Density

f. c = Specific heat

g. t = Time

h. L = Plate thickness

i. T = Temperature of the body at time t.

A linear finite element analysis was conducted using T = 0, T_e = 100, k = 0.0006, ρ = 0.3, c = 0.1, L = 100. The finite element mesh is shown in Figure 4.1-17. The result of the finite element analysis (dark circles in Figure 4.1-16) indicates excellent agreement with the result of the analytical solution.

Problem 2

Problem 2 involves temperature response of the front face of a plate with insulated back face after sudden exposure to constant-temperature radiation.

This example demonstrates the accuracy of the finite element as compared with an analytical solution of a radiation heat transfer problem. Consider a plate of thickness L, with finite conductivity k, specific heat c, and density ρ. The back face of the plate is insulated and the front face is subjected to a constant radiation heat flow with sink temperature, T_s = 0°R. The time variation of the temperature of the front surface was computed in a nondimensional form by the application of an approximate analytical technique (Reference 5). Figure 4.1-18 presents the temperature response for a particular value of parameter M. The variables used to construct Figure 4.l-18 are

a. σ = 17.3×10^{-10} Btu/hr ft^4/°R

b. F_e = Shape factor for plate surface

c. F_A = Shape factor for sink

d. T_o = Initial temperature of plate (°R)

e. T_e = Surface temperature of plate (°R).

Several finite element analyses with the same time increment but different numbers of iterations within each cycle were conducted. The finite element mesh layout is shown in Figure 4.1-19. In the analyses F_A = F_e = 1., T_o = 500, M = l, α = k/c = 0.02 and T_x = 0°R.

Comparison of the finite element solutions with the analytical solution indicates that the incremental approach without iteration does not converge to the "true" solution. However, if one iteration is made in each time increment, the finite element result becomes nearly identical to the analytical result.

4.1.4.1.5 FINITE

4.1.4.1.5.1 Program Description

FINITE is a general-purpose finite element computer program for elastic stress analyses of two-dimensional structural problems including plane stress, plane strain, and axisymmetric structures. It has provision for thermal, mechanical, and body force loads. The materials of the structure may be homogeneous or nonhomogeneous and isotropic or orthotropic. The development of the FINITE program is based on the GASP program, described in Subsection 4.1.4.1.3.

4.1.4.1.5.2 Program Version

The present version of the program at the GE Nuclear Energy Division was obtained from the developer, J. E. McConoclee of the GE Gas Turbine Department in 1969 (Reference 6).

4.1.4.1.5.3 History of Use

Since its completion in 1969, the program has been widely used in the GE Gas Turbine and Jet Engine Divisions for the analysis of turbine components.

4.1.4.1.5.4 Extent of Application

The program is used at GE's Nuclear Energy Division in the analysis of axisymmetric or nearly axisymmetric BWR internals.

4.1.4.1.5.5 Test Problems

Two simple examples are described herein with a comparison of the stresses calculated by FINITE with theoretical solutions.

The two cases considered are

a. A tube with internal pressure

b. A spinning disk of elliptical cross section.

The analytical models for these cases are shown in Figures 4.1-20 and 4.1-21, and comparisons of the calculated stresses with theoretical solutions are shown in Figures 4.1-22 and 4.1-23.

Figure 4.1-22 shows a comparison of the radial and tangential stresses at the midlength of the tube with those calculated using the Lamé solution.

Figure 4.1-23 shows a comparison of the radial and tangential stresses calculated by FINITE using the plane stress (with variable thickness) option with those obtained using the analysis of Goldberg and Sadowsky (Reference 7). This problem could have been done more exactly using the axisymmetric option which would have given the variation of the stresses through the thickness of the disk. However, the purpose in this case was explicitly to check out the use of the variable thickness plane stress case and a comparison of these results with an exact solution. Another purpose of this case was to check out the use of the skew boundary condition.

4.1.4.1.6 SAMIS (Structural Analysis and Matrix Interpretive System)

4.1.4.1.6.1 Program Description

The SAMIS program (References 8 through 10) is well designed to solve problems involving matrix algebra with particular emphasis on structural applications. The user has control over the flow of the calculations through the use of "pseudo instructions." Execution of the program is performed in two phases: the generation phase and the manipulative phase. Input data defining the idealization of a structure is read and stiffness, stress, and load coefficient matrices are generated for elements available to the user. The program has two fundamental and widely used finite elements incorporated. A triangular flat plate element, called a facet, is available for idealization of plate and shell structures, and a straight beam element is available for idealization of frames and trusses and plate/shell structure stiffener representation.

The element formulation and analyses are based on the finite element matrix displacement method. The triangular plate and beam elements are capable of resisting stretching, shearing, bending, and twisting stresses. In the second phase of execution, the generated or input matrices are manipulated according to the rules of matrix algebra as directed by the user.

The program is written in modular form, making it easy to add new modules without major reprogramming of subroutines. This facilitates adding to the structural element library other elements to extend idealization capability. Those structural problems consisting of elements that cannot be adequately idealized by triangular plate or beam elements may have their stiffness coefficients submitted directly as input matrices.

4.1.4.1.6.2 Program Version

The SAMIS version was obtained from the developer, Philco Corporation, Western Development Laboratory, via the Space Division. A considerable amount of modification was made on the input and output of the original version to suit the analysis need of this division of GE. Both spectrum and time-history analyses can be performed using the GE Nuclear Energy Division version.

4.1.4.1.6.3 History of Use

The SAMIS program was developed by the Philco Corporation, Western Development Laboratories, under contract to and in association with the Jet Propulsion Laboratory in 1966. The program was first used by GE in 1967 and in the Nuclear Energy Division of GE in 1970.

4.1.4.1.6.4 Extent of Application

The current GE version of SAMIS has been extensively used since 1970 in the analysis of reactor components' response to seismic loadings. Results of test problems were found to agree closely with theoretical results of the same problem.

4.1.4.1.6.5 Test Problem

The clamped square plate frequency study considers a square plate having all four of its edges clamped. Figure 4.1-24 shows a quarter panel of the plate.

The particular plate dimensions and material properties used in the analysis were as follows:

a. $a = 10$ in.

b. $t = 0.05$ in.

c. $E = 30 \times 10^6$ lb/in.^{2}

d. $\nu = 0.03$

e. $\rho = 7.26 \times 10^{-4}$ lb-sec^2/in.^{4}.

For all grids used in the study, the triangular elements in any one grid were all uniform size except as noted.

A total of four grid models were analyzed for the clamped plate, each based on selected value of a/c = a/d or c = d for the square plate models. Each case will be referred to by number. In the table below are listed four cases and the grid size function for each case.

Case No.	a/c, a/d
1	4
2	5
3	6
4	7

For each case, three sets of modes were computed: symmetric modes, antisymmetric modes, and mixed modes (symmetric about X and antisymmetric about Y). The fourth set of modes was not required since the plate is square and the remaining mixed mode set (symmetric about Y and antisymmetric about X) would only be duplicate frequencies of the first mixed mode set.

Table 4.1-1 is a list of computed frequencies for the clamped square plate models. The first six frequencies are listed for each case along with the percent variation from the theoretical frequencies. The table shows, as would be expected, successive improvement in computed frequencies as the grid is refined. The results for Case Number 4 show rather good agreement for all six frequency values, the largest difference being in the third and sixth frequency values which differ from the exact frequency by 12.6 percent and 13.3 percent, respectively. A number of other models could be analyzed using larger grid size functions; however, it is doubtful that the improvement in accuracy would be as marked as in the initial four models for the six frequencies.

4.1.4.1.7 GEMOP (General Matrix Manipulation Program)

4.1.4.1.7.1 Program Description

GEMOP is a general matrix manipulation program capable of performing the majority of standard matrix operations. There presently are 41 operation commands in the program. A maximum of nine full 60 by 60 matrices and six 60-element vectors may be stored in core at any one time. Also available for search and storage are up to a maximum of three tapes. This latest version of the program includes subroutines for calculating earthquake, or other forcing functions, and response of a lumped-mass structure, either by time-history or spectral response methods. The most used features are in the eigenvalue, eigenvector subroutine and response subroutine. The response is calculated for a system subjected to any piecewise linear forcing function.

4.1.4.1.7.2 Program Version

The current version of the program being used in GE was obtained from the originator, the Knolls Atomic Power Laboratory, in June 1969. It was converted from Control Data Corporation to GE computers.

4.1.4.1.7.3 History of Use

The program was originally written in the GE Knolls Atomic Power Laboratory for the solution of vibration problems.

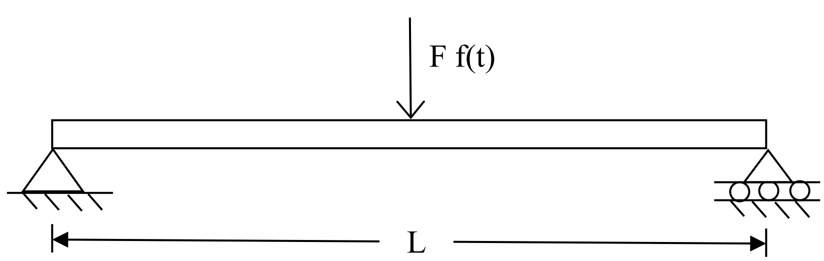
4.1.4.1.7.4 Extent of Application

Since its installation in the Nuclear Energy Division in 1969, the general matrix manipulation program has been constantly used to solve seismic problems involving small lumped-mass systems of less than 80 degrees of freedom. Because of its limitation on problem size, the program is being replaced by SAMIS.

4.1.4.1.7.5 Test Problems

To evaluate its capability, the computer program has been used to solve the following sample problem. The satisfactory agreement between the lumped-mass numerical solution and the continuous system theoretical solution indicates the reliability of the general matrix manipulation program.

Consider a simply supported beam with a suddenly applied load at its center as the problem.



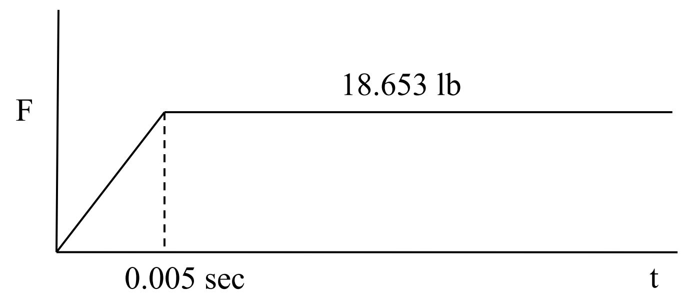
L = l00 in.

E = 30 x 10^6 psi

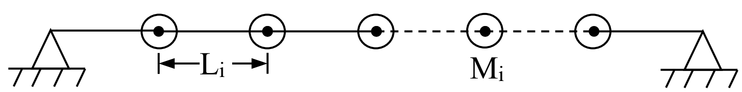
I = 2.5907 $in.^4$

A = 9.8696 $in.^2$

$\rho = 0.3 \text{ lb/in.}^3$



For this problem the beam is modeled as a five-lump mass system, or



all lengths are equal

$L_i \quad = \quad L/6$

all masses are equal

$$M_i = \frac{M}{5} = \frac{AL\rho}{5g} \qquad (4.1\text{-}1)$$

A comparison of the calculated natural frequencies of the lumped-mass system compared with the continuous system shows very good agreement.

Beam Natural Frequencies

Mode	GEMOP Lumped-Mass Frequency (Hz)	Continuous System Frequency (Hz)	GEMOP Error (percent)
1	5.00	5.00	0.0
2	19.98	20.00	0.1
3	44.66	45.00	0.8
4	77.33	80.00	3.3
5	110.59	125.00	11.5

The maximum displacement response of the beam is calculated considering zero damping and a cutoff frequency of 45 Hz. With this cutoff frequency, the calculated response included the effect of Modes 1, 2, and 3. The calculated maximum response for this second case was 0.997 in., compared with the theoretical value of 1.00 in. This indicates an error of only 0.32 percent.

4.1.4.1.8 SHELL 5 and SHELL 9

4.1.4.1.8.1 Program Description

SHELL 5 and SHELL 9 are two finite-shell element programs used to analyze smoothly curved thin-shell structures with any distribution of elastic material properties, boundary constraints, and mechanical thermal and displacement loading conditions. The basic element is triangular. Its membrane displacement fields are linear polynomial functions and its bending displacement field is a cubic polynomial function (Reference 11). Five degrees of freedom (three displacements and two bending rotations) are obtained at each nodal point. SHELL 9 is an improvement of SHELL 5. It includes a more accurate shell element with nine degrees of freedom at each node. Output displacements and stresses are in a local (tangent) surface coordinate system.

Due to the approximation of element membrane displacements by linear functions, the in-plane rotation about the surface normal is neglected. Therefore, the only rotations considered are those caused by bending of the shell cross section. Application of the method is not recommended for shell intersection (or discontinuous surface) problems where in-plane rotation can be significant.

4.1.4.1.8.2 Program Version

A copy of the source deck of SHELL 5 is maintained in the GE Nuclear Energy Division. SHELL 9 is a proprietary computer program of Gulf Atomic Incorporated.

4.1.4.1.8.3 History of Use

SHELL 5 and SHELL 9 are programs developed by Gulf General Atomic Incorporated (Reference 12) in 1969. The programs have been in production status at Gulf General Atomic and other major computer operating systems since 1970.

4.1.4.1.8.4 Extent of Application

SHELL 5 has been used at GE to analyze the reactor shroud support and torus.

4.1.4.1.8.5 Test Problems

Two examples showing comparisons of solutions obtained by the present method with a solution based on a simpler model, an exact solution, and experimental data are presented in Figures 4.1-25 through 4.1-29. Figure 4.1-26 shows the radial displacement for the line-loaded cylinder shown in Figure 4.1-25 compared with the exact solution (Reference 13) and a solution obtained for the element model of Reference 11 with linear membrane and cubic bending displacement approximations. Symmetry permitted the analysis of one slice. In order to show the dependence of the solution on the mesh density, the circumferential angle of the slice was varied, which is equivalent to varying the number of elements. It should be pointed out that this comparison does not constitute a complete study, and other examples may show different convergence behavior. The differences between the two models shown by this example warrant further study.

Figure 4.1-27 shows the finite element idealization of a nozzle-to-cylinder intersection problem that is under experimental investigation at the Oak Ridge National Laboratory.

Because of symmetry about the longitudinal plane, only half of the structure is analyzed for internal pressure. The idealization consisted of 640 modal points and 1168 elements. Comparisons of the analysis with the experimental data in the vicinity of the right-angle intersection for the longitudinal plane are shown in Figures 4.1-28 and 4.1-29. Figure 4.1-28 shows the axial and circumferential outside surface stresses for the cylinder. Figure 4.1-29 shows the axial and circumferential outside surface stresses for the nozzle. The analytical results compare favorably with the distribution and magnitude of experimental stresses (obtained from strain gage results).

4.1.4.1.9 HEATER

4.1.4.1.9.1 Program Description

HEATER is a computer program (Reference 14) used in the hydraulic design of feedwater spargers and their associated delivery heads and piping. The program utilizes test data obtained by GE using full-scale mockups of a feedwater sparger combined with a series of models that represent the complex mixing processes obtained in the upper plenum, downcomer, and lower plenum. Mass and energy balances throughout the nuclear steam supply system (NSSS) are modeled in detail.

4.1.4.1.9.2 Program Version

This program was developed at GE's Nuclear Energy Division.

4.1.4.1.9.3 History of Use

The program was developed by various individuals beginning in 1970. The present version of the program has been in operation since January 1972.

4.1.4.1.9.4 Extent of Application

The program is used in the hydraulic design of the feedwater spargers for each BWR plant in the evaluation of design modifications and the evaluation of unusual operational conditions.

4.1.4.1.9.5 Test Problems

Various critical parts of the program have been verified by hand calculation. The program has also been used to predict test results.

4.1.4.1.10 FAP-71 (Fatigue Analysis Program)

4.1.4.1.10.1 Program Description

The FAP-71 computer code, or Fatigue Analysis Program, is a stress-analysis tool used as an aid in performing ASME B&PV Code Section III structural design calculations. Specifically, FAP-71 is used in determining the primary plus secondary stress range and number of allowable fatigue cycles at points of interest. For structural locations at which the $3S_m$ (P+Q) ASME Code limit is exceeded, the program can perform either (or both) of two elastic-plastic fatigue life evaluations: (a) the method reported in ASME Paper 68-PVP-3; and (b) the present method documented in Paragraph NB-3228.3 of the 1971 Edition of the ASME B&PV Section III Code.

The program can accommodate up to 25 transient stress states of as many as 20 structural locations.

4.1.4.1.10.2 Program Version

The present version of FAP-71 was completed by L. Young of GE's Nuclear Energy Division in 1971 (Reference 15).

4.1.4.1.10.3 History of Use

Since its completion in 1971, the program has been applied to several design analyses of GE BWR vessels.

4.1.4.1.10.4 Extent of Application

The program is used in conjunction with several shell analysis programs in determining the fatigue life of BWR mechanical components subject to thermal transients.

4.1.4.1.10.5 Test Problems

The program has been verified using hand calculations.

4.1.4.1.11 DYSEA

4.1.4.1.11.1 Program Description

The DYSEA (Dynamic and Seismic Analysis) program is a GE proprietary program developed specifically for seismic and dynamic analyses of the reactor building coupled to the RPV and internals. It calculates the dynamic response of linear structural systems by either temporal modal superposition or response spectrum method. Fluid-structure interaction effect in the RPV is taken into account by way of hydrodynamic mass.

The DYSEA program was based on the SAP IV program with added capability to handle the hydrodynamic mass effect. Structural stiffness and mass matrices similar to SAP IV are formulated. Solution is obtained in time domain by calculating the dynamic response mode by mode. Time integration is performed by using Newmark's β-method. Response spectrum solution is also available as an option.

4.1.4.1.11.2 Program Version

The DYSEA version was developed at GE by modifying the SAP IV program. Capability was added to handle the hydrodynamic mass effect due to fluid-structure interaction in the reactor. It can handle three-dimensional dynamic problems with beams, trusses, and springs. Both acceleration time-histories and response spectra may be used as input.

4.1.4.1.11.3 History of Use

The DYSEA program was developed in the summer of 1976. It has been adopted as a standard production program since 1977 and has been used extensively in all dynamic and seismic analyses of the reactor building coupled to the RPV and internals.

4.1.4.1.11.4 Extent of Application

The current version of DYSEA has been used in all dynamic and seismic analyses since its development. Results from test problems were found to be in close agreement with those obtained from either verified programs or analytic solutions.

4.1.4.1.11.5 Test Problems

Problem 1

The first test problem involves finding the eigenvalues and eigenvectors from the following characteristic equation:

$$(\omega^2[M] - [K])\,\{\chi\} = 0$$

where ω is the circular frequency and χ is the eigenvector. The stiffness and the mass matrices are represented by [K] and [M], respectively, and are given by

$$[M] = \begin{bmatrix} 1-\frac{4}{\pi^2} & \frac{4}{\pi^2} & -\frac{4}{9\pi^2} \\ & 1-\frac{4}{9\pi^2} & \frac{4}{\pi^2} \\ Symmetric & & 1-\frac{4}{25\pi^2} \end{bmatrix}$$

$$[K] = \begin{bmatrix} 1+\frac{4}{\pi^2} & 3 & \frac{5}{9} \\ & 1+\frac{9\pi^2}{4} & 15 \\ Symmetric & & 1+\frac{25\pi^2}{4} \end{bmatrix}$$

The analytic solutions and the solutions from DYSEA are

Eigenvalues ω_i

i	DYSEA Solution	Analytic Solution
1	5.7835	5.7837
2	30.4889	30.4878
3	75.0493	75.0751

Eigenvector χ

DYSEA Solution	Analytic Solution
$\begin{bmatrix} 1.000 & 1.000 & 1.000 \\ -0.0319 & -1.5536 & -1.2105 \\ -0.0072 & -0.066 & 2.0271 \end{bmatrix}$	$\begin{bmatrix} 1.000 & 1.000 & 1.000 \\ -0.0319 & -1.554 & -1.211 \\ -0.0072 & 0.0666 & 2.027 \end{bmatrix}$

Problem 2

The second test problem compares the dynamic responses of the reactor building coupled to the RPV and internals when subjected to earthquake ground motion.

The mathematical model of the reactor building coupled to the RPV and internals is given in Figure 4.1-30. The input in the form of ground spectra is applied at the basemat level. Response spectrum analysis was used in the analysis.

Natural frequencies of the system and the maximum responses at key locations have been calculated by both DYSEA and SAMIS. Comparisons of results are given in Tables 4.1-2 and 4.1-3. The results calculated by DYSEA agree closely with those obtained by SAMIS.

4.1.4.2 Fuel Rod Thermal Analysis

Fuel thermal design analysis techniques are described in Subsection 4.2.3.

4.1.4.3 Reactor Systems Dynamics

The analysis techniques and computer codes used in reactor systems dynamics are described in Reference 16.

4.1.4.4 Nuclear Analysis

The analysis techniques and nuclear data used to determine the neutronic characteristics of the assembly and the core are generally similar to those used in the industry for light-water reactors. The methods are described fully in Subsection 4.3.3.

4.1.4.5 Neutron Fluence Calculations

The neutron fluence calculational technique is described in Subsection 4.3.2.8.

4.1.4.6 Thermal-Hydraulic Calculations

The thermal-hydraulic calculational techniques are described in Subsection 4.4.4.5.

4.1 REACTOR SUMMARY DESCRIPTION

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13. S. Timoshenko and S. Woinowsky-Krieger, Theory of Plates and Shells, McGraw-Hill Book Company, New York, 1959.

14. A. B. Burgess, User Guide and Engineering Description of HEATER Computer Program, March 1974.

4.1 REACTOR SUMMARY DESCRIPTION

REFERENCES

15. L. J. Young, FAP-71 (Fatigue Analysis Program) Computer Code, GE/NED, Design Analysis Unit, R. A. Report No. 409, January 1972.

16. L. A. Carmichael and G. J. Scatena, Stability and Dynamic Performance of the General Electric Boiling Water Reactor, APED-5652, April 1969.

TABLE 4.1-1 CLAMPED SQUARE PLATE THEORETICAL AND COMPUTED FREQUENCY COMPARISON

Case No:	f_1[a]	% Diff.	f_2	% Diff.	f_3	% Diff.	f_4	% Diff.	f_5	% Diff.	f_6	% Diff.
Theory	176.5		359.9		530.9		645.5		648.6		810.0	
1	205.6	16.5	438.0	21.7	817.4	54.0	727.7	12.7	769.3	18.6	1476.0	82.2
2	190.7	8.0	409.1	13.8	696.5	31.2	672.7	4.2	702.3	8.3	1076.1	32.9
3	183.8	4.1	391.2	8.7	600.2	13.5	705.1	9.2	719.2	10.9	999.0	23.3
4	183.3	3.8	380.7	5.8	597.9	12.6	657.3	1.8	670.4	3.4	917.4	13.3

[a] Frequency values f_1 to f_6 are in cps

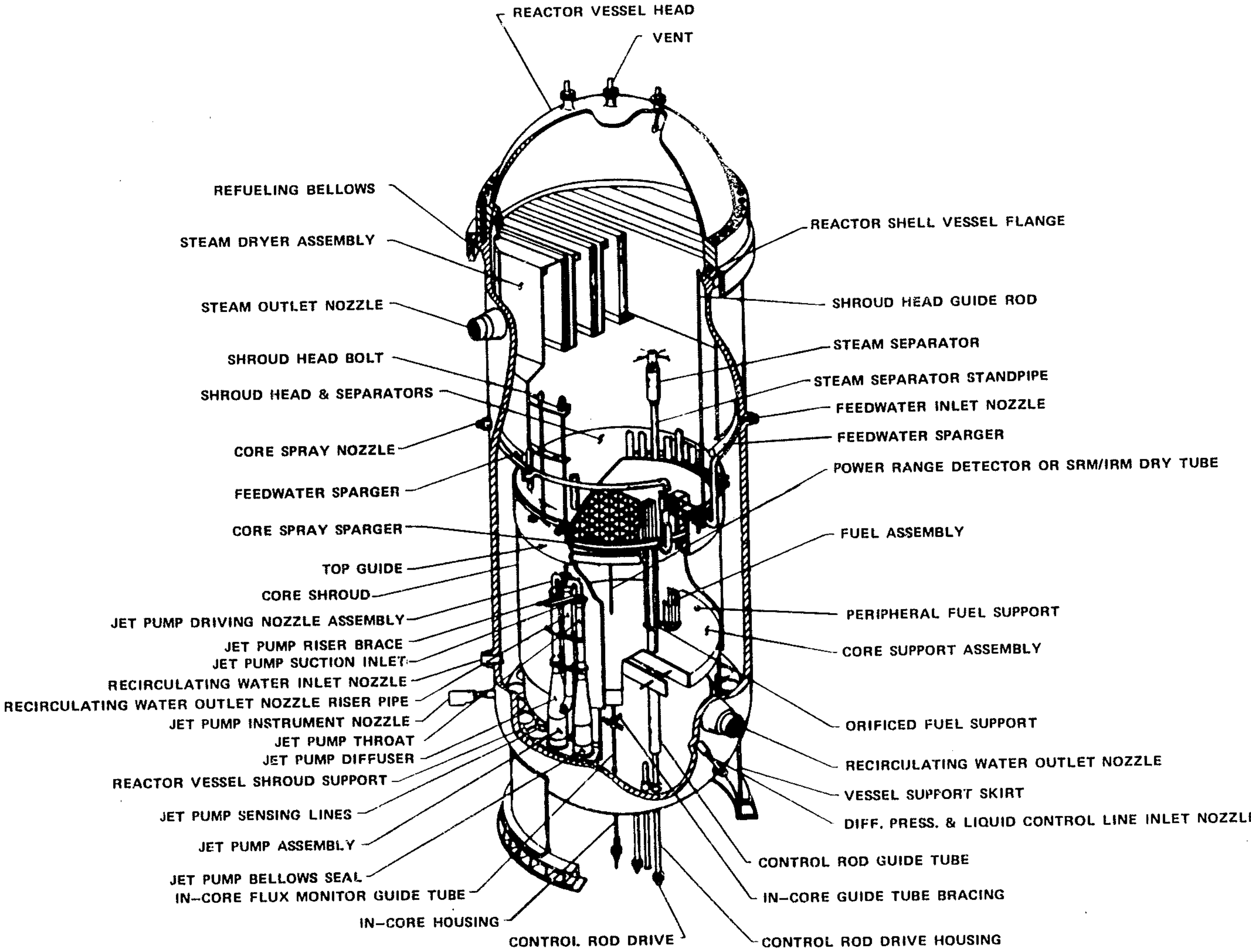
TABLE 4.1-2 COMPARISON OF NATURAL FREQUENCIES

	X-Direction Frequency		Y-Direction Frequency	
Mode	Old Analysis	DYSEA	Old Analysis	DYSEA
1	2.810	2.727	2.678	2.649
2	3.040	2.999	2.810	2.728
3	3.764	3.763	3.762	3.758
4	3.791	3.781	3.771	3.769
5	4.588	4.576	4.578	4.531
6	5.041	5.044	5.040	5.039
7	5.776	5.791	5.486	5.431
8	6.071	6.047	6.069	6.025
9	8.731	8.625	8.598	8.524
10	10.950	11.270	9.614	9.824
11	12.796	12.800	12.563	12.760

TABLE 4.1-3 COMPARISON OF MAXIMUM LOADS

Structural Component	DYSEA Solution	SAMIS Solution
I. RPV and internals		
Fuel moment	17.11 (in-K)[a]	18.64 (in-K)
Top guide shear	188 (K)	204 (K)
Shroud head shear	198 (K)	213 (K)
Shroud head moment	16,783 (in-K)	18,150 (in-K)
Shroud support shear	479.3 (K)	503.3 (K)
Shroud support moment	119,020 (in-K)	126,600 (in-K)
II. Building		
RPV pedestal		
- Shear	602 (K)	575.9 (K)
- Moment	94,200 (in-K)	91,500 (in-K)
Containment		
- Shear	2,902 (K)	2,908 (K)
- Moment	1,413,000 (in-K)	1,434,000 (in-K)
Shield building		
- Shear	34,037 (K)	38,060 (K)
- Moment	38,494,000 (in-K)	37,270,000 (in-K)

[a] K = kips, 1 kip = 100 lb.



GENERAL ELECTRIC CO. DRAWING

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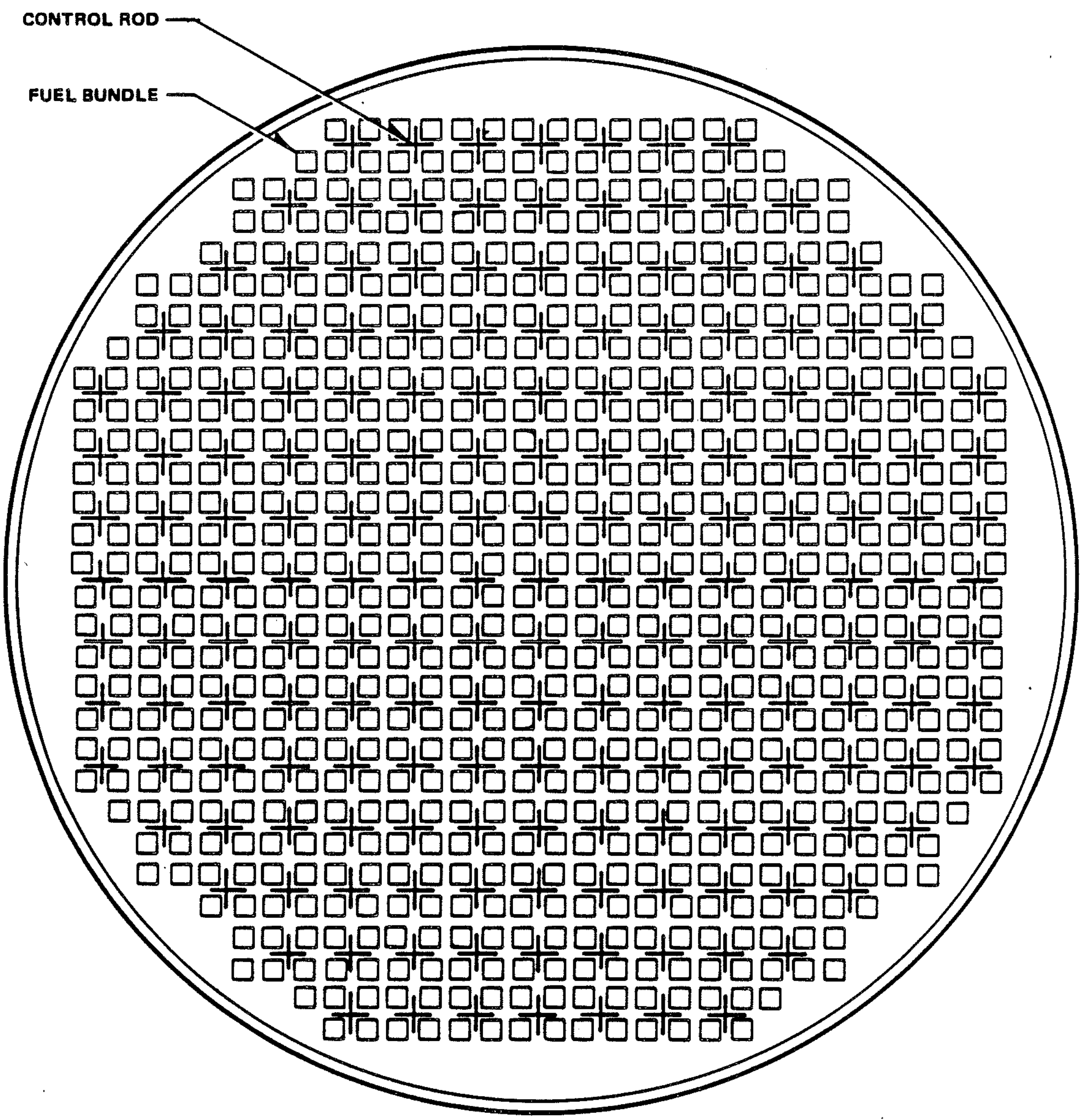
FIGURE 4.1-1

REACTOR VESSEL CUTAWAY



CORE LATTICE

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FIGURE 4.1-2

TYPICAL CORE ARRANGEMENT

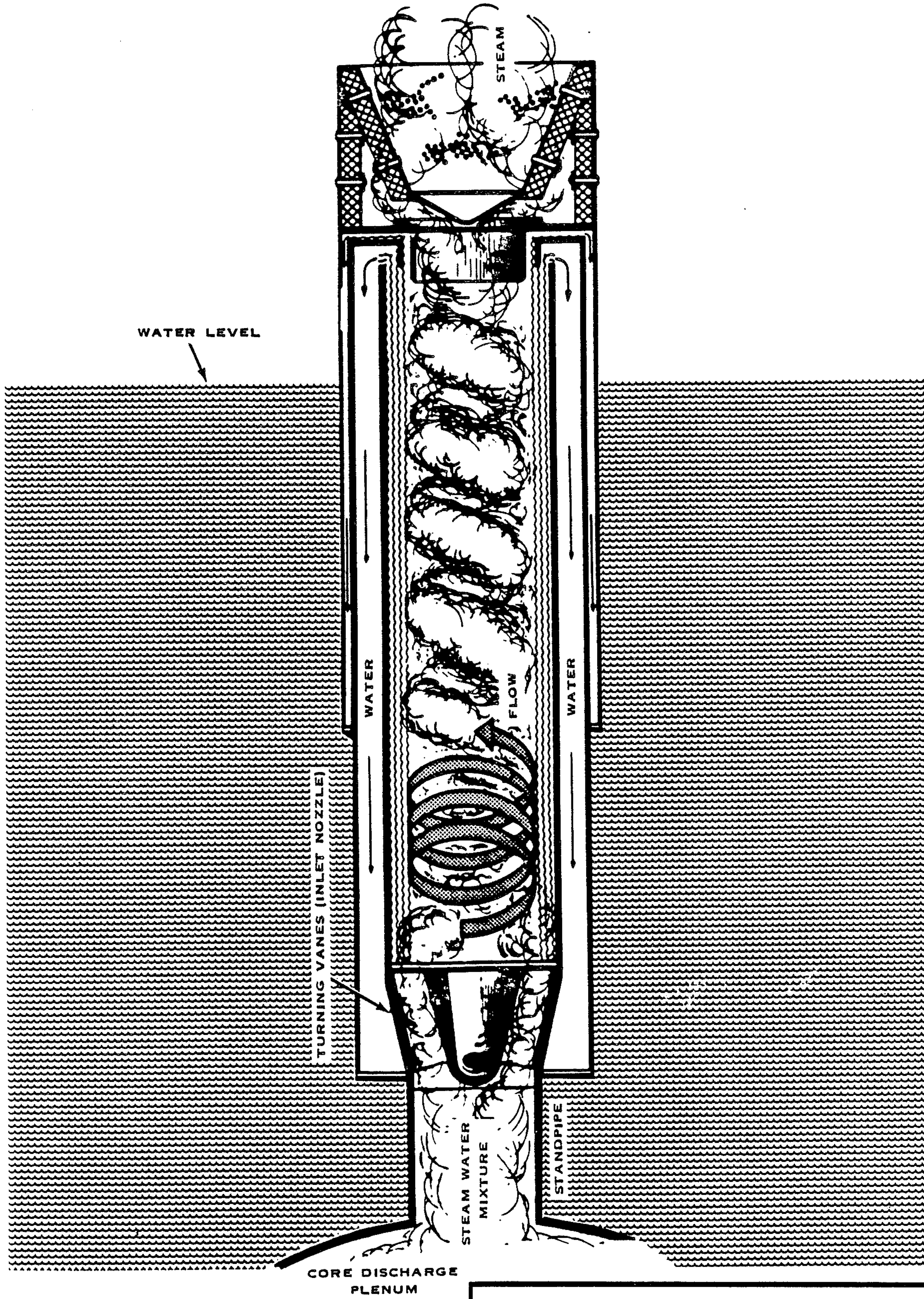

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FIGURE 4.1-3

STEAM SEPARATOR

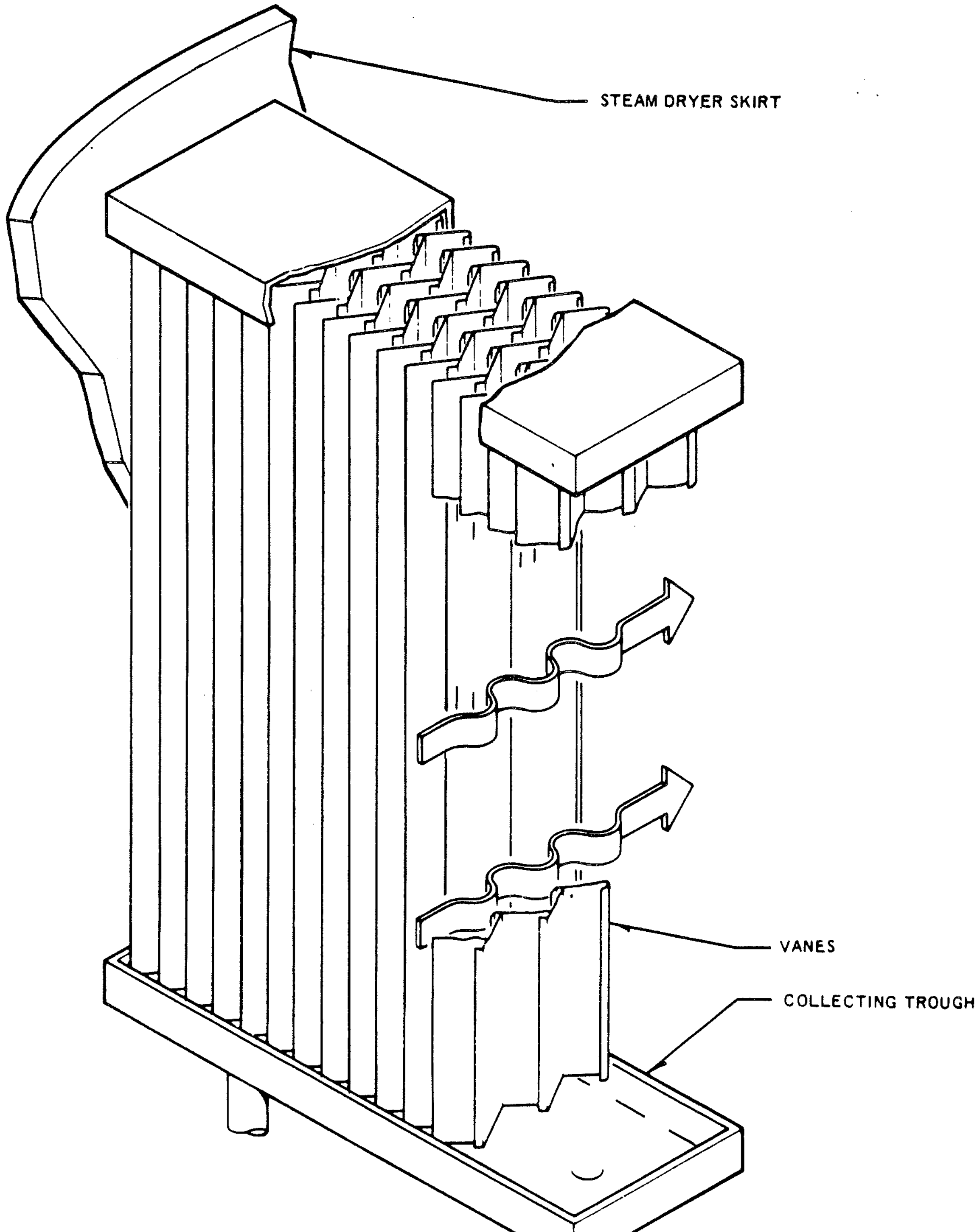

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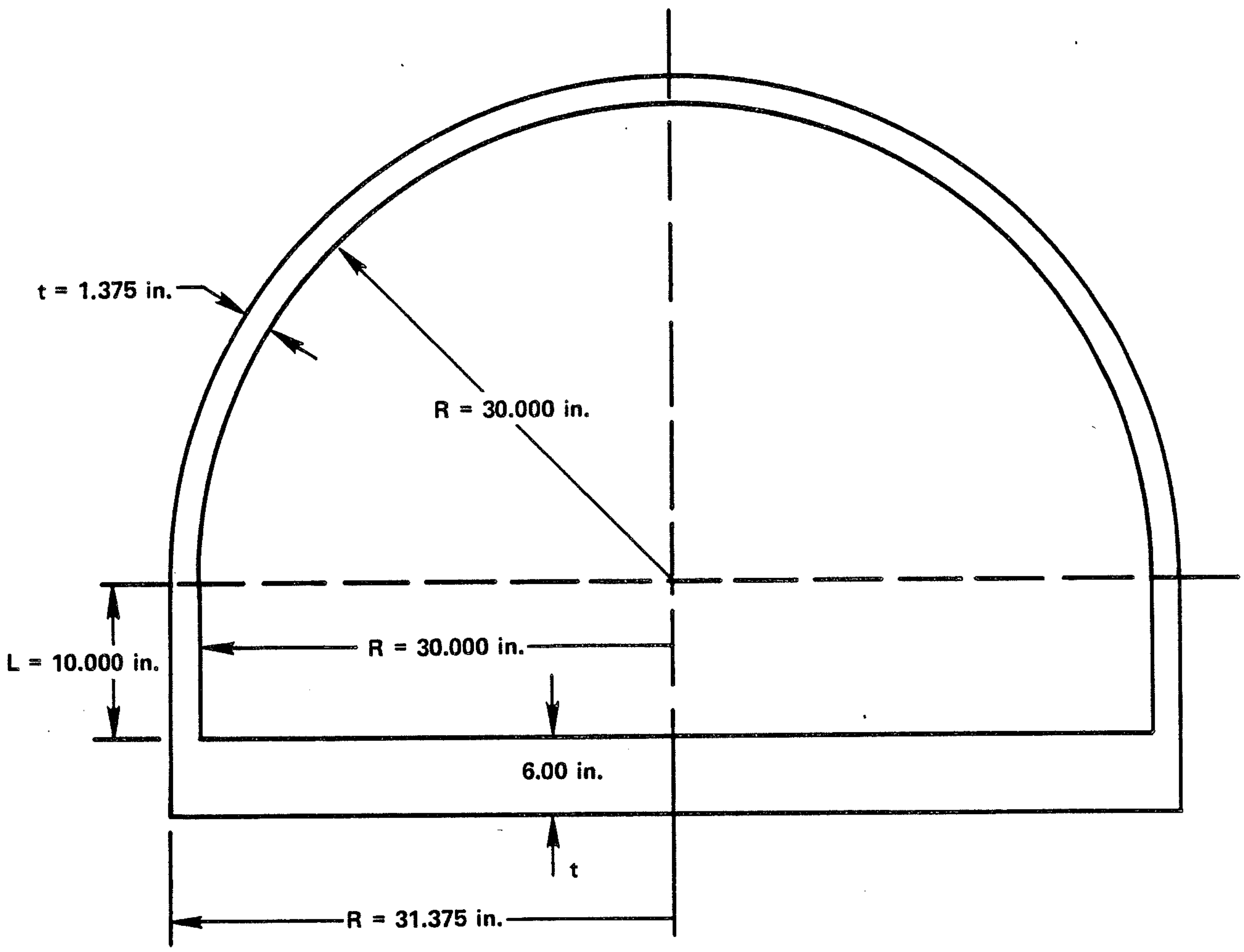
FIGURE 4.1-4

STEAM DRYER



MATERIAL	SA 533 Gr. B LOW ALLOY STEEL
YOUNG'S MODULUS	29 X 10^6 psi
POISSON'S RATIO	0.3
COEFFICIENT OF THERMAL EXPANSION	6.6 X 10^{-6} $(^oF)^{-1}$

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FIGURE 4.1-5

PRESSURE VESSEL ANALYSIS

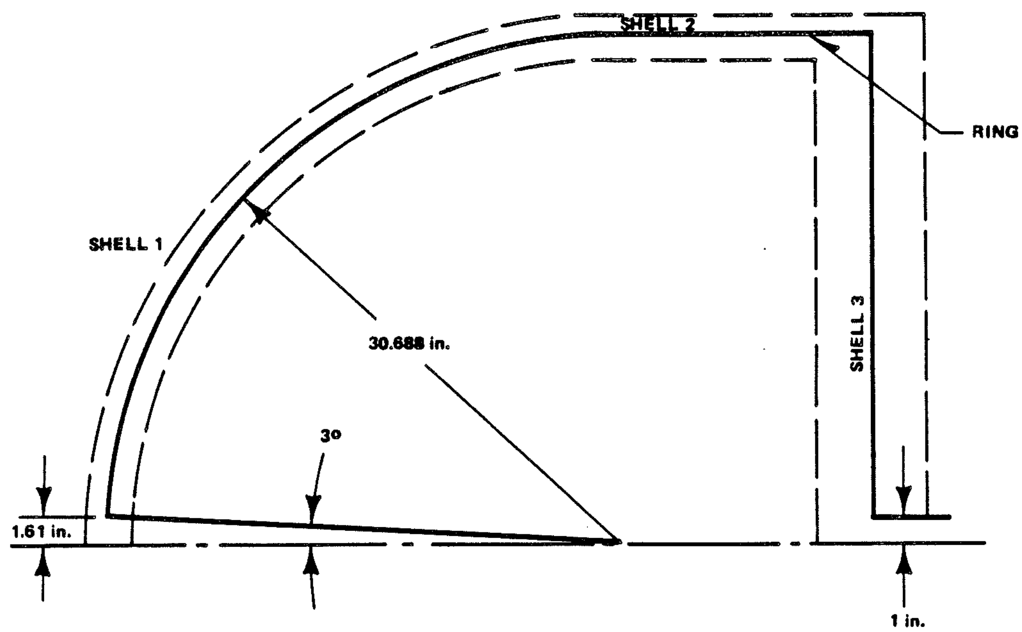

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FIGURE 4.1-6

MULTISHELL MODEL

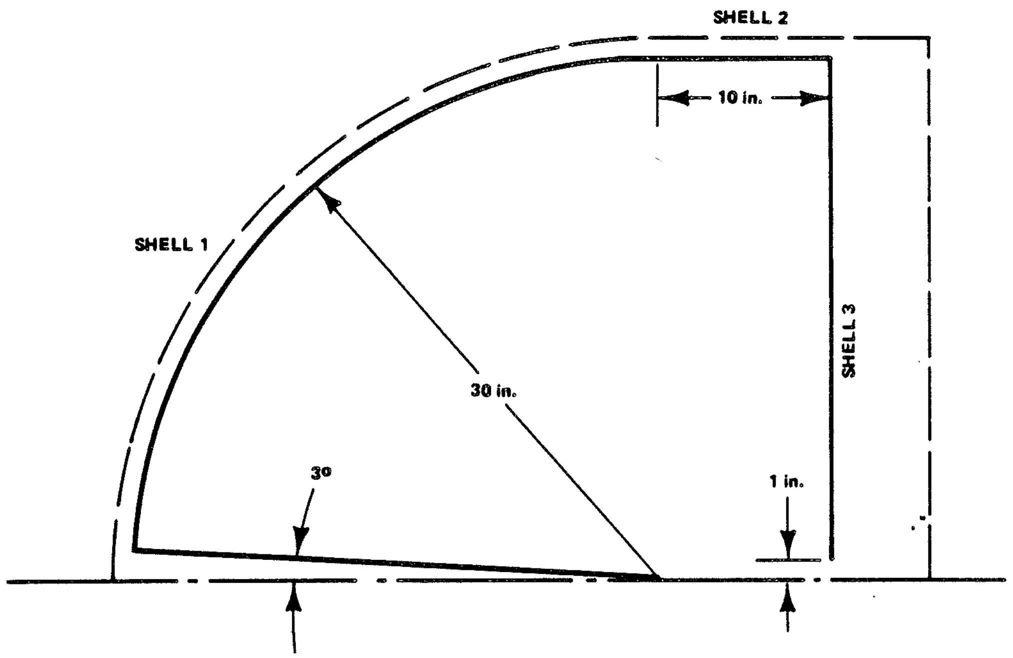

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FIGURE 4.1-7

OMP MODEL

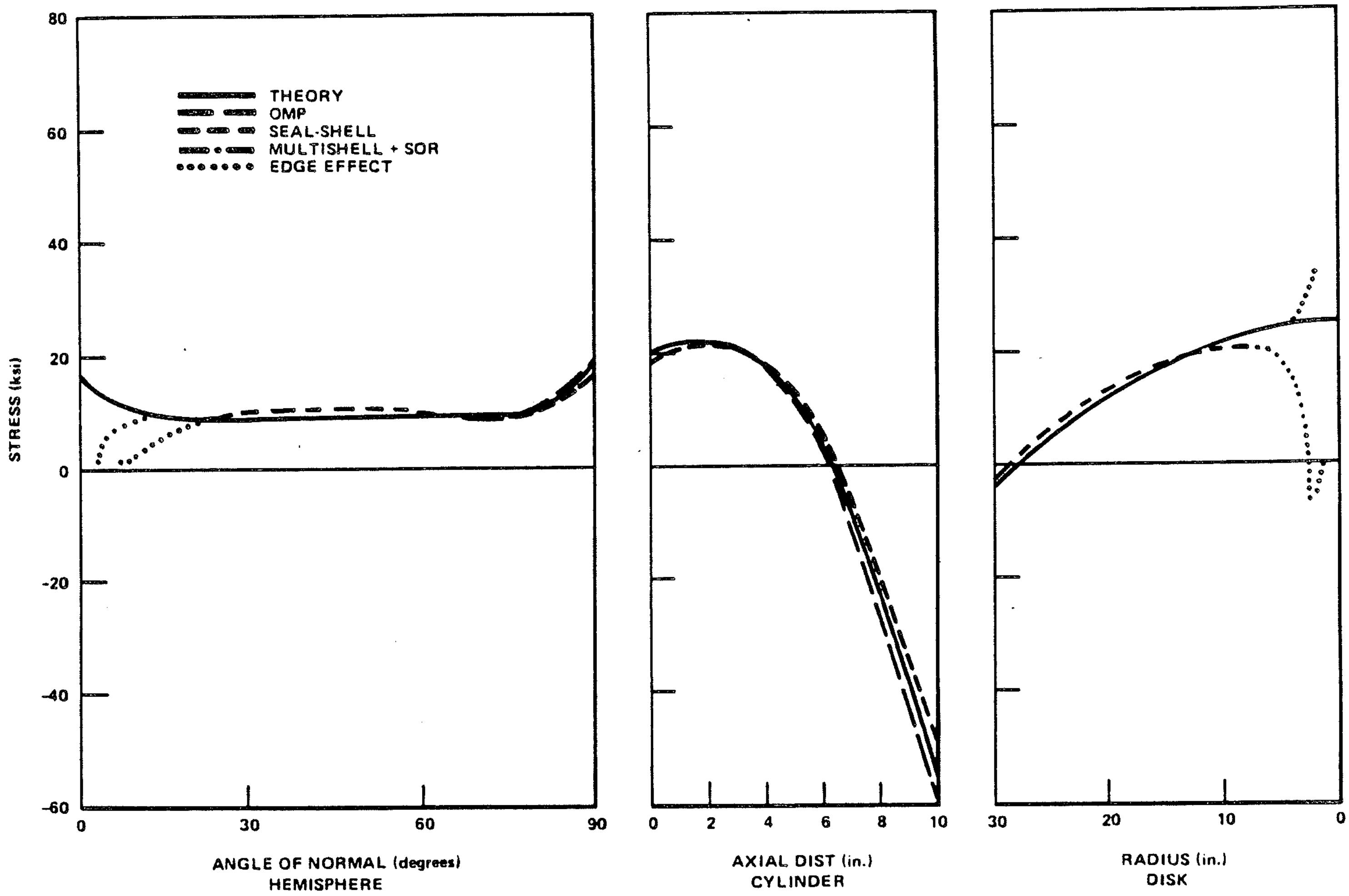

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FIGURE 4.1-8

950 PSI INTERNAL PRESSURE AXIAL STRESS
OUTER SURFACE

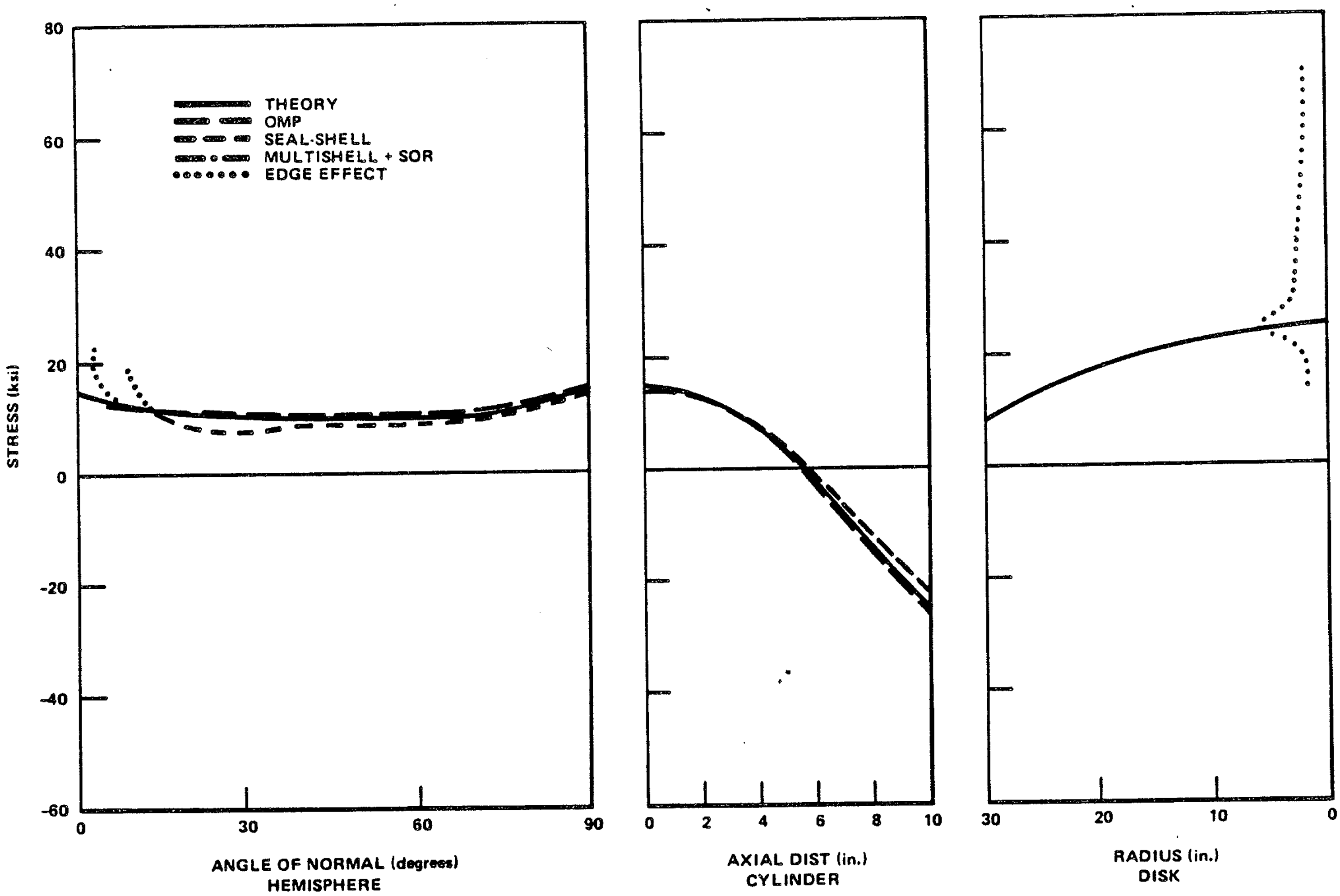

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FIGURE 4.1-9

950 PSI INTERNAL PRESSURE HOOP STRESS
OUTER SURFACE

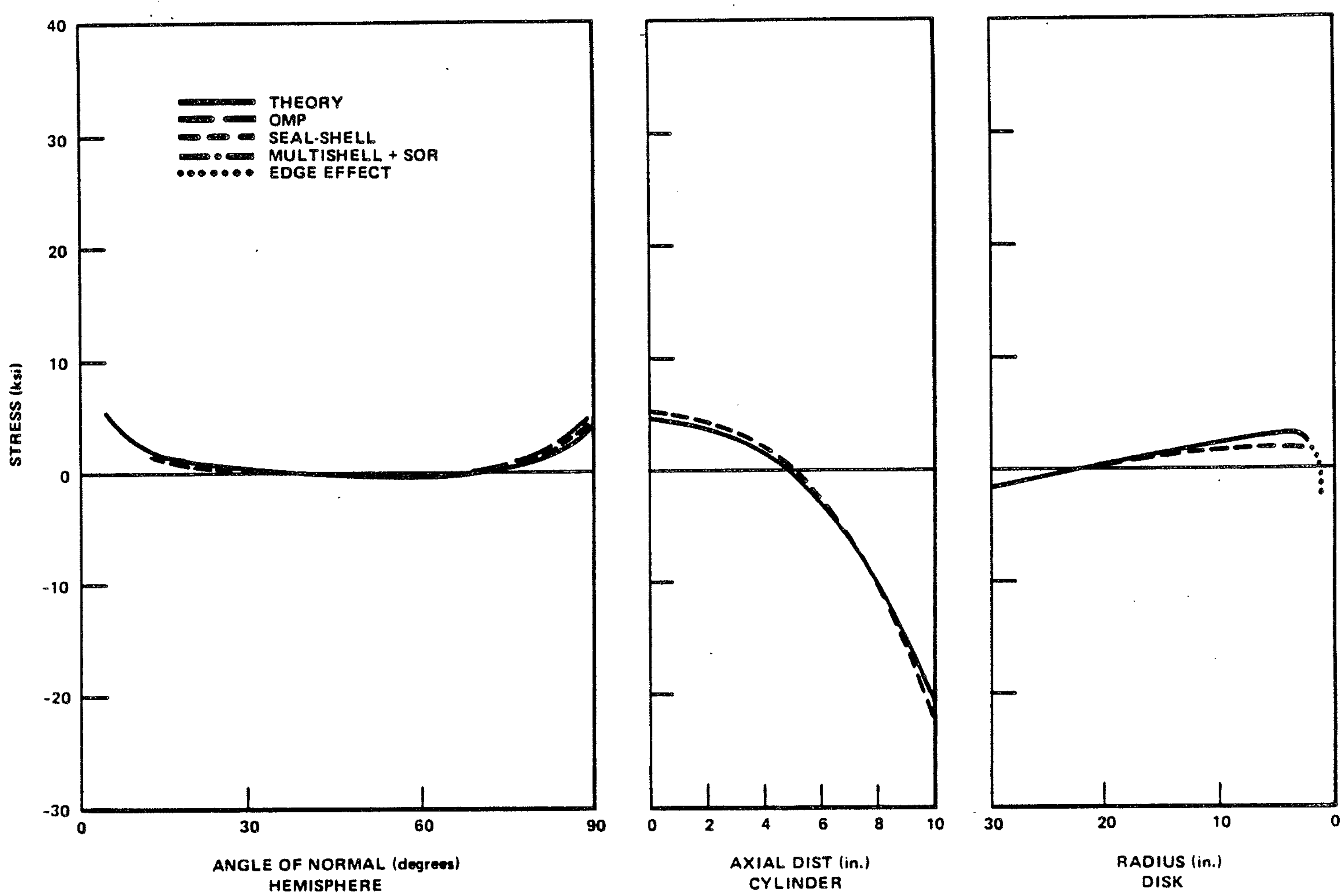

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FIGURE 4.1-10

AXIAL TEMPERATURE GRADIENT AXIAL STRESS OUTER SURFACE

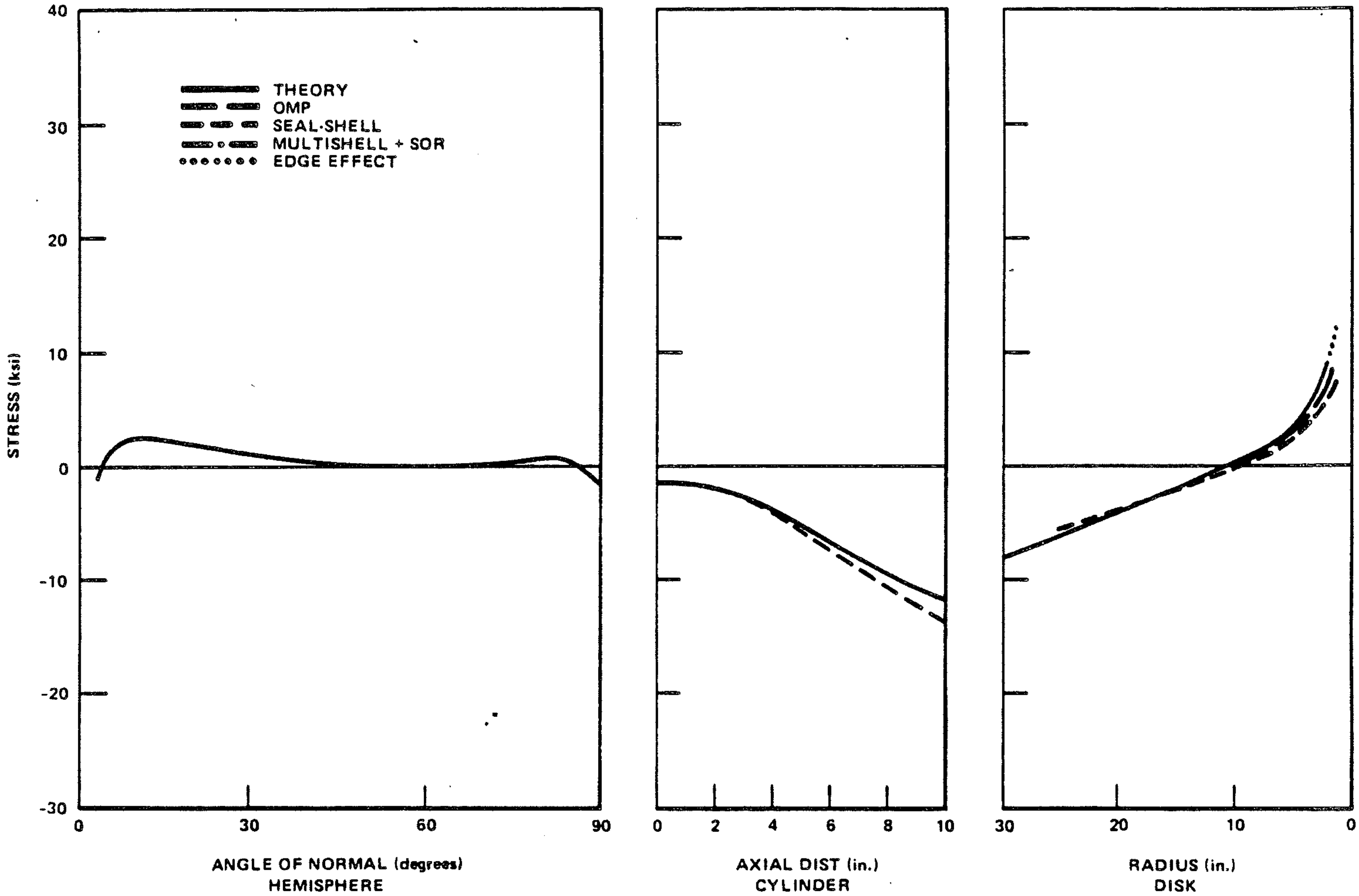

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FIGURE 4.1-11

AXIAL TEMPERATURE GRADIENT HOOP STRESS
OUTER SURFACE

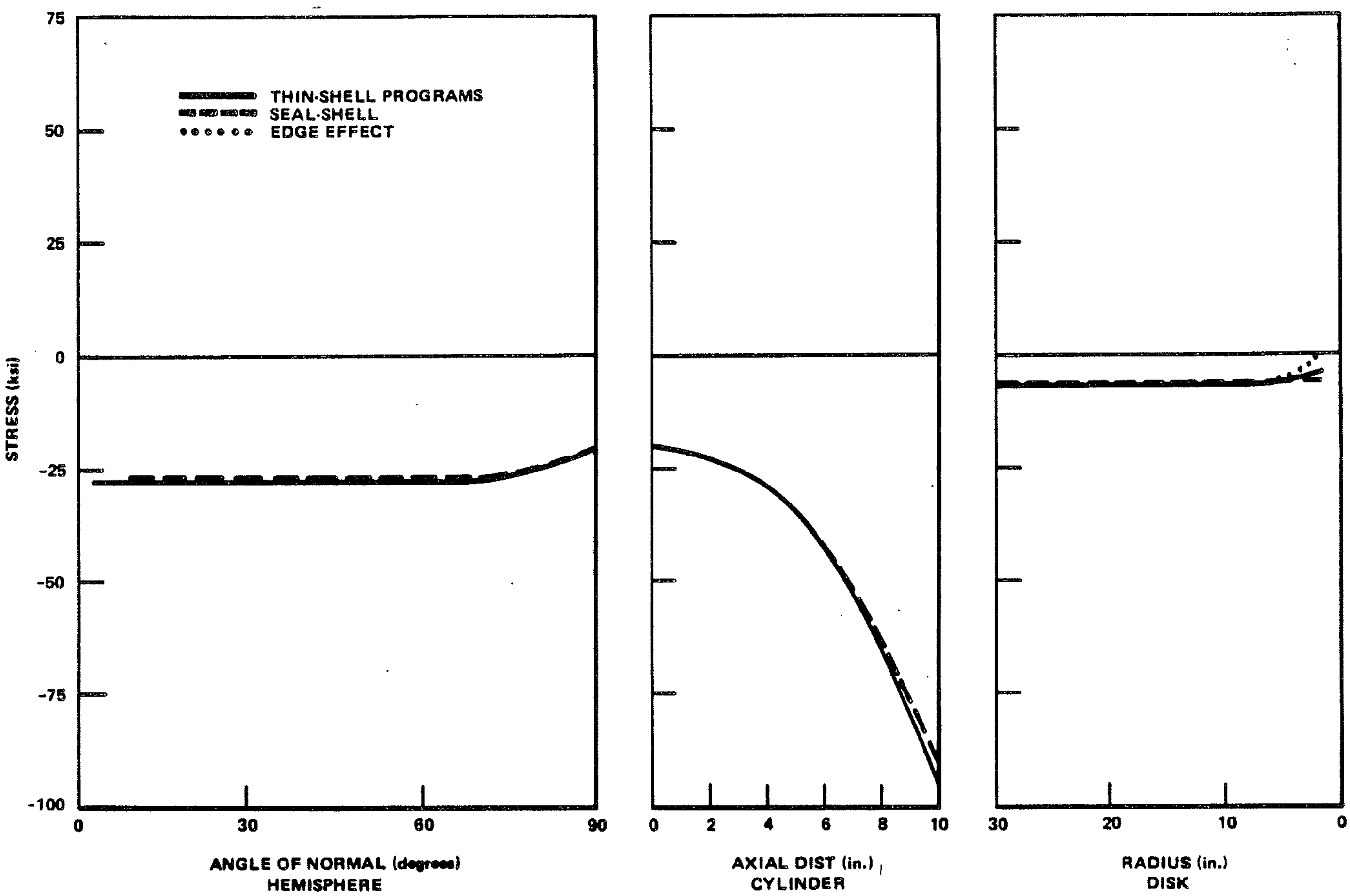

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FIGURE 4.1-12

LINEAR RADIAL TEMPERATURE GRADIENT
AXIAL STRESS – OUTER SURFACE

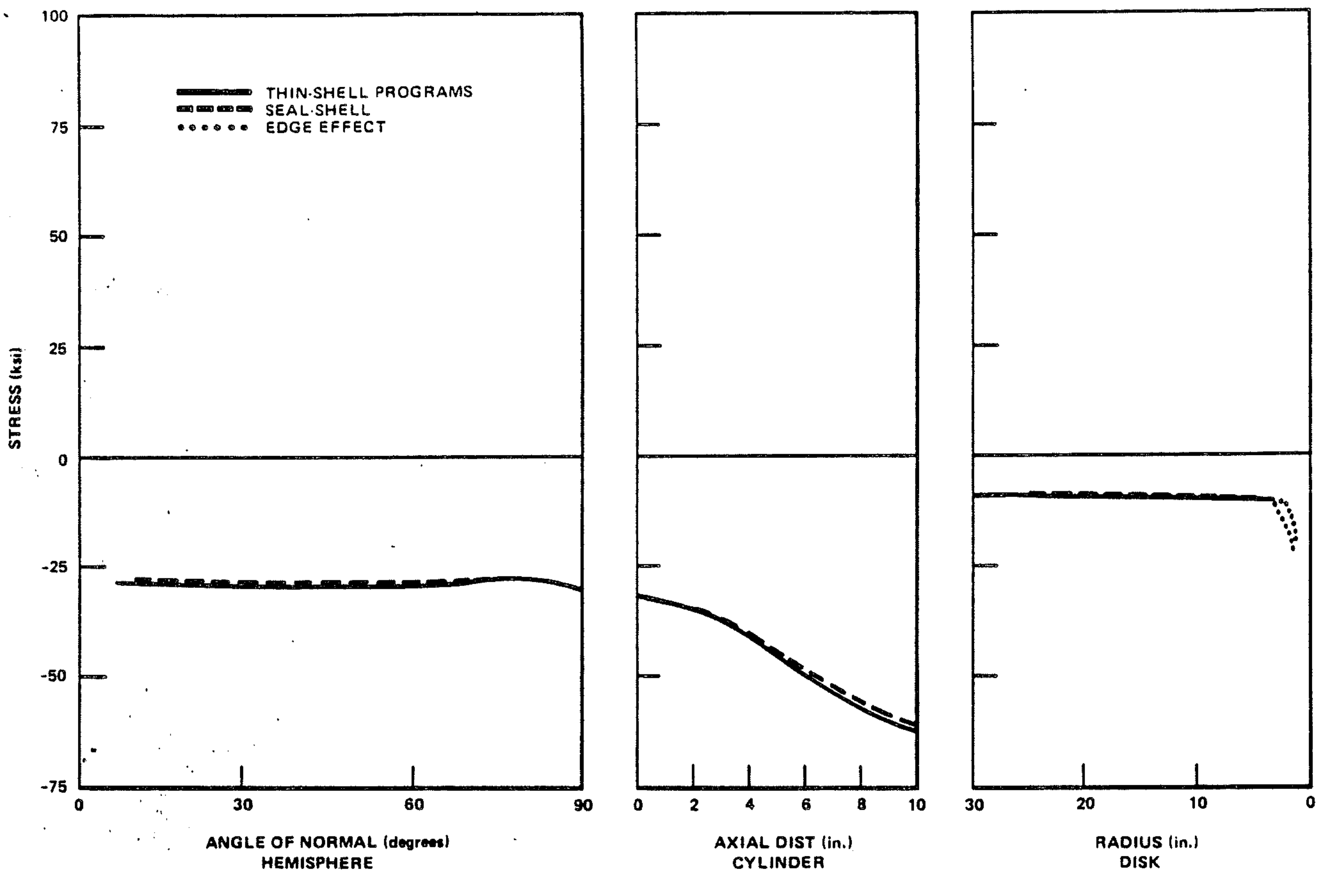

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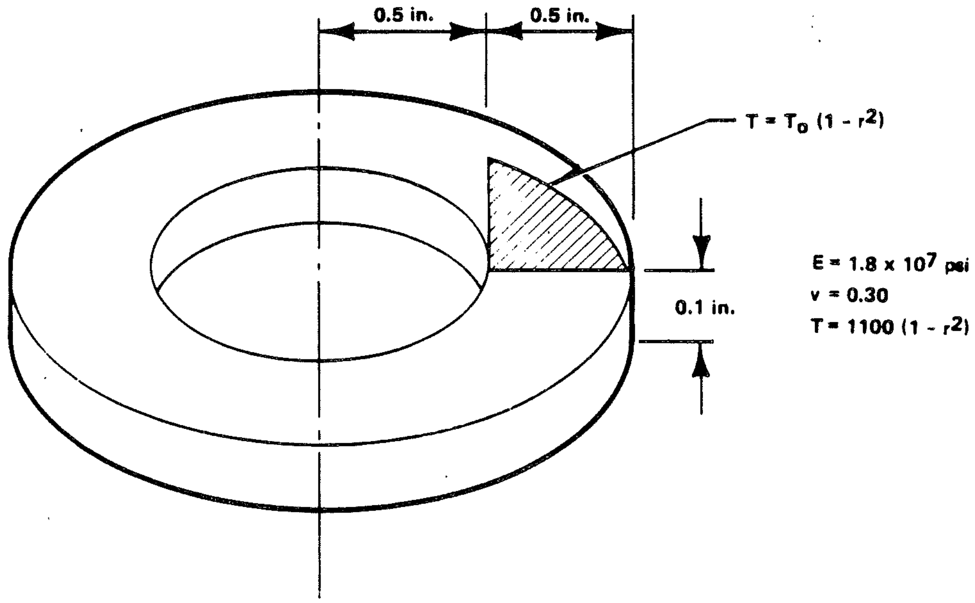
FIGURE 4.1-13

LINEAR RADIAL TEMPERATURE GRADIENT HOOP STRESS – OUTER SURFACE



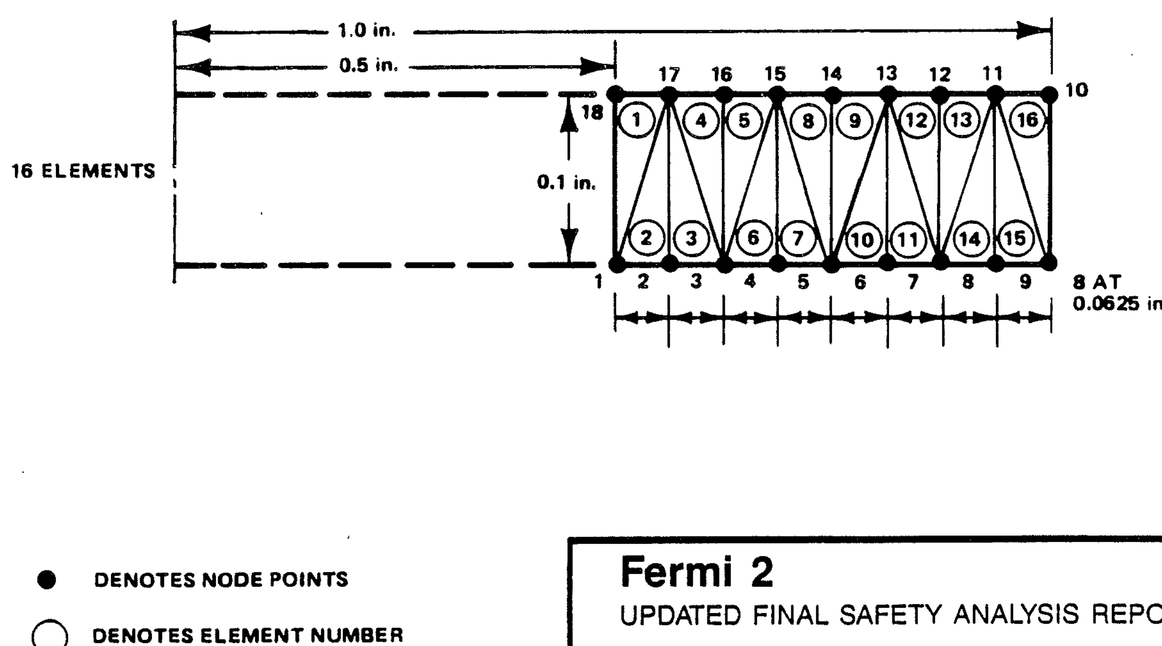


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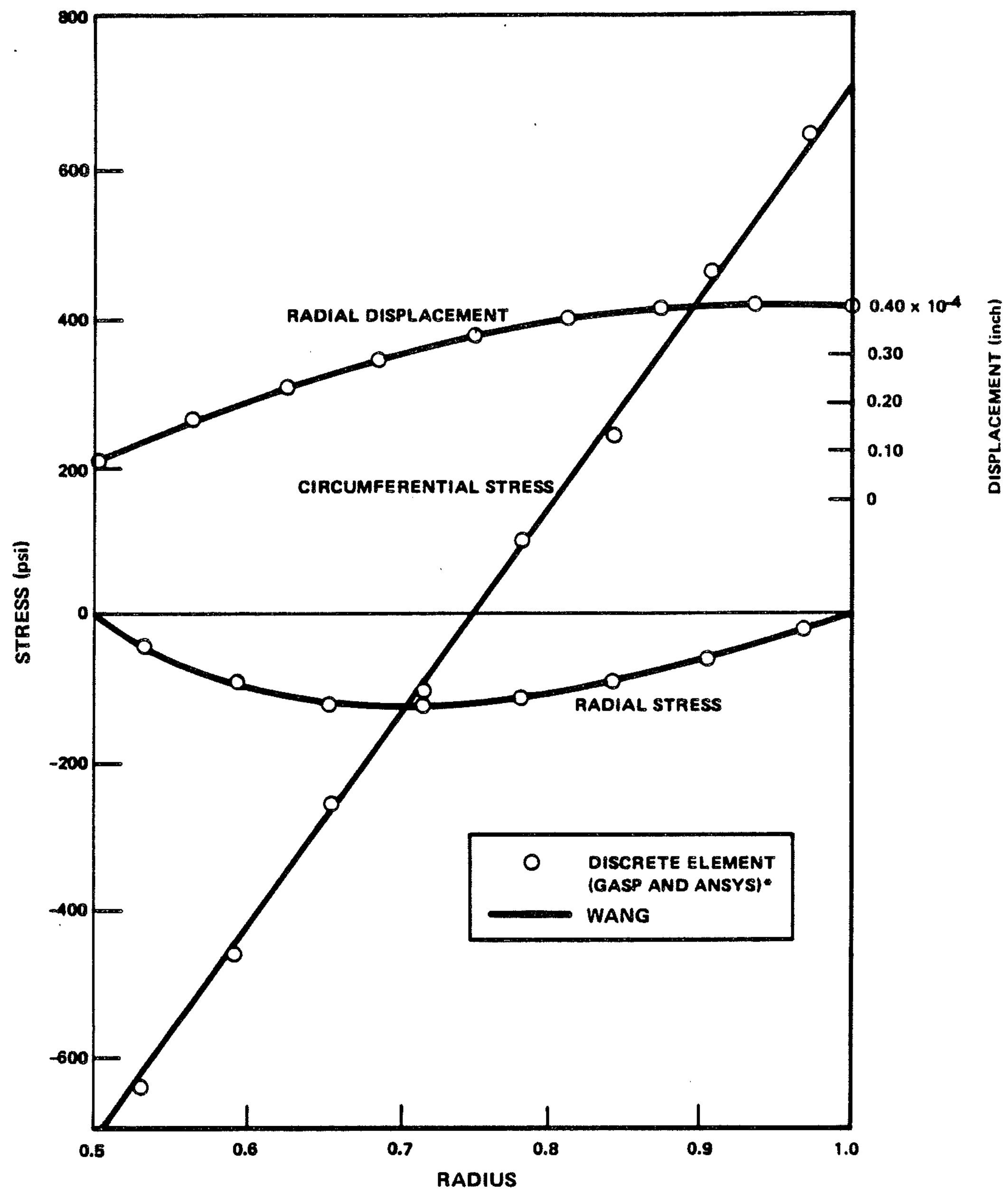
FIGURE 4.1-14

ASME COMPUTER PROGRAM VERIFICATION PROBLEM 19 AND FINITE ELEMENT MODEL



** ALL STRESS VALUES ARE AVERAGES OF STRESSES IN TWO NEIGHBORING TRIANGULAR ELEMENTS.

** CLOSED FORM SOLUTION FROM REFERENCE 3.

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FIGURE 4.1-15

COMPARISON OF ANALYTICAL RESULTS FOR PROBLEM 19

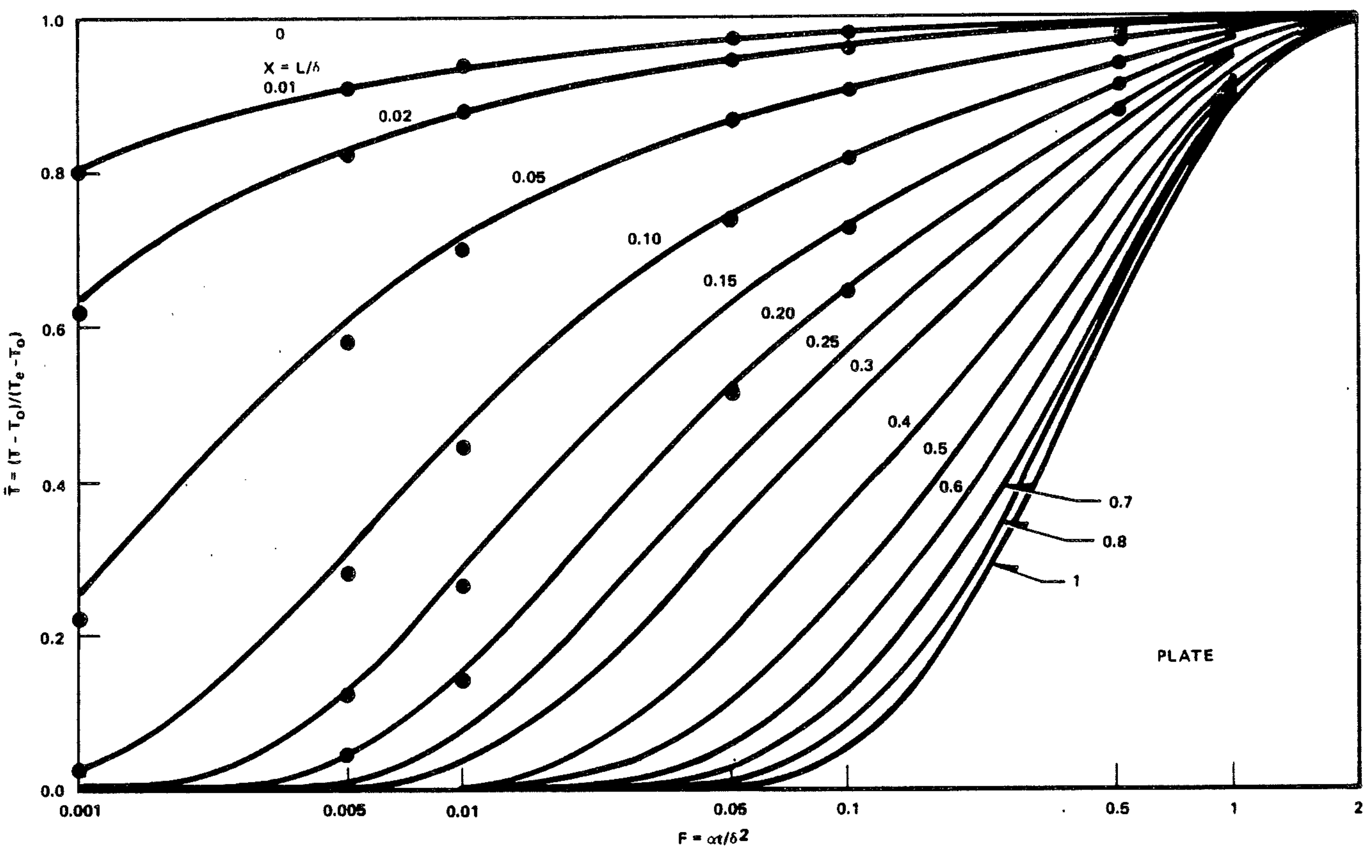

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FIGURE 4.1-16

TEMPERATURE RESPONSE OF PLATE THROUGH THICKNESS

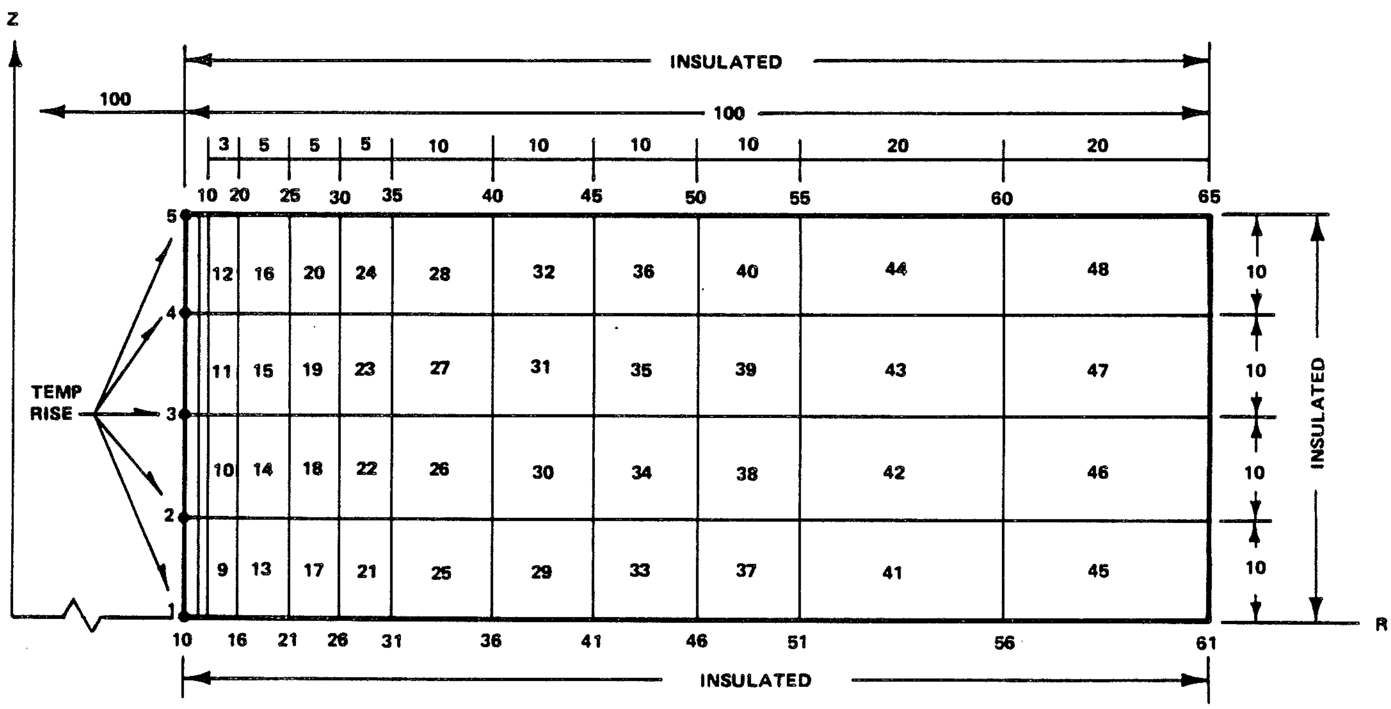

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FIGURE 4.1-17

FINITE ELEMENT MESH

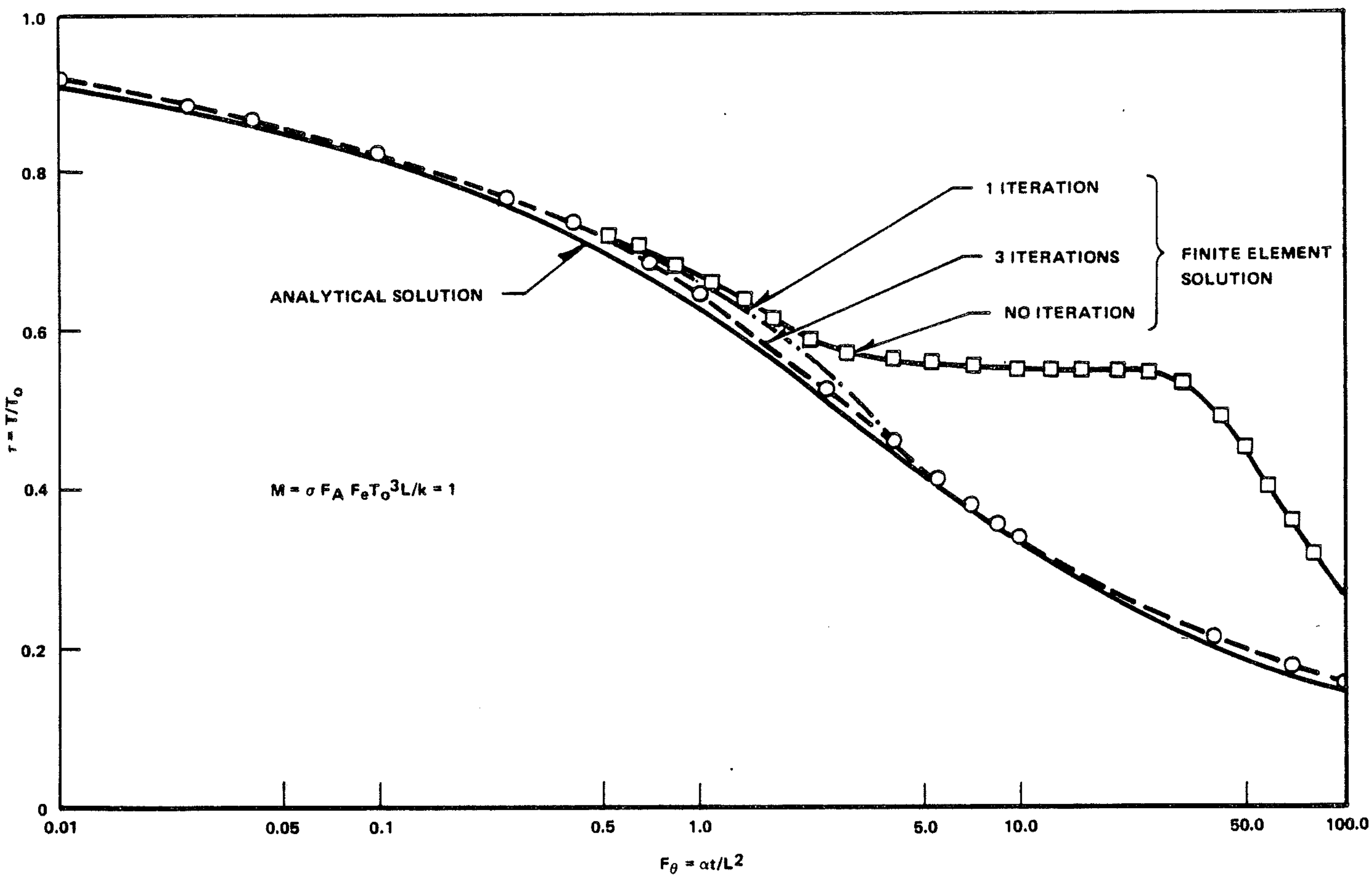

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FIGURE 4.1-18

TEMPERATURE RESPONSE OF A PLATE SUBJECTED TO RADIATION

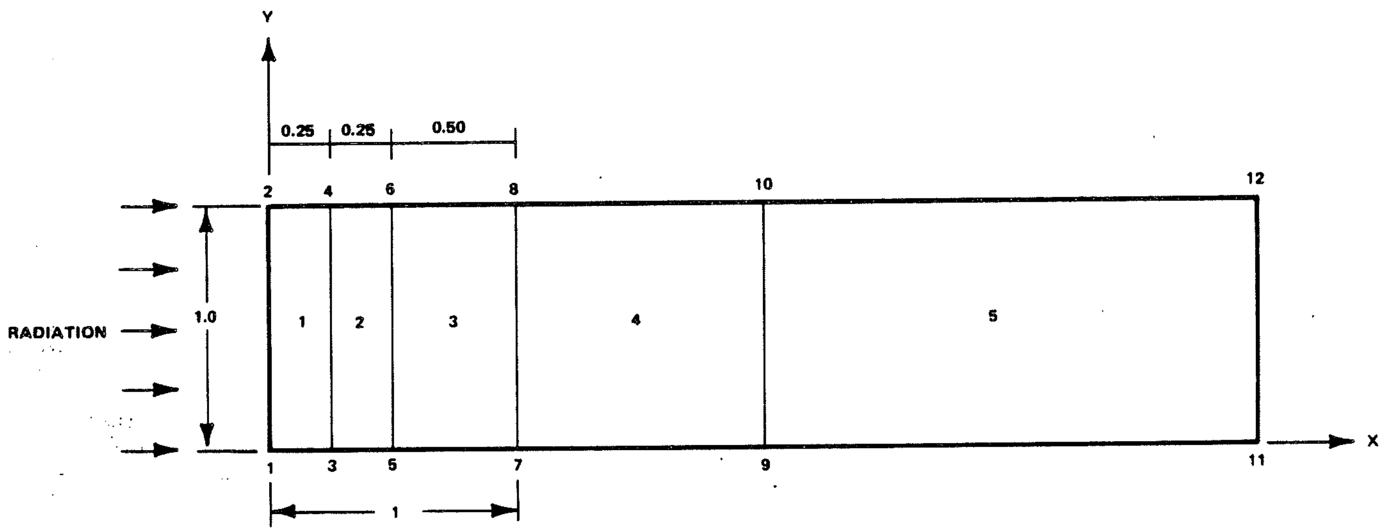

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FIGURE 4.1-19

FINITE ELEMENT MESH LAYOUT

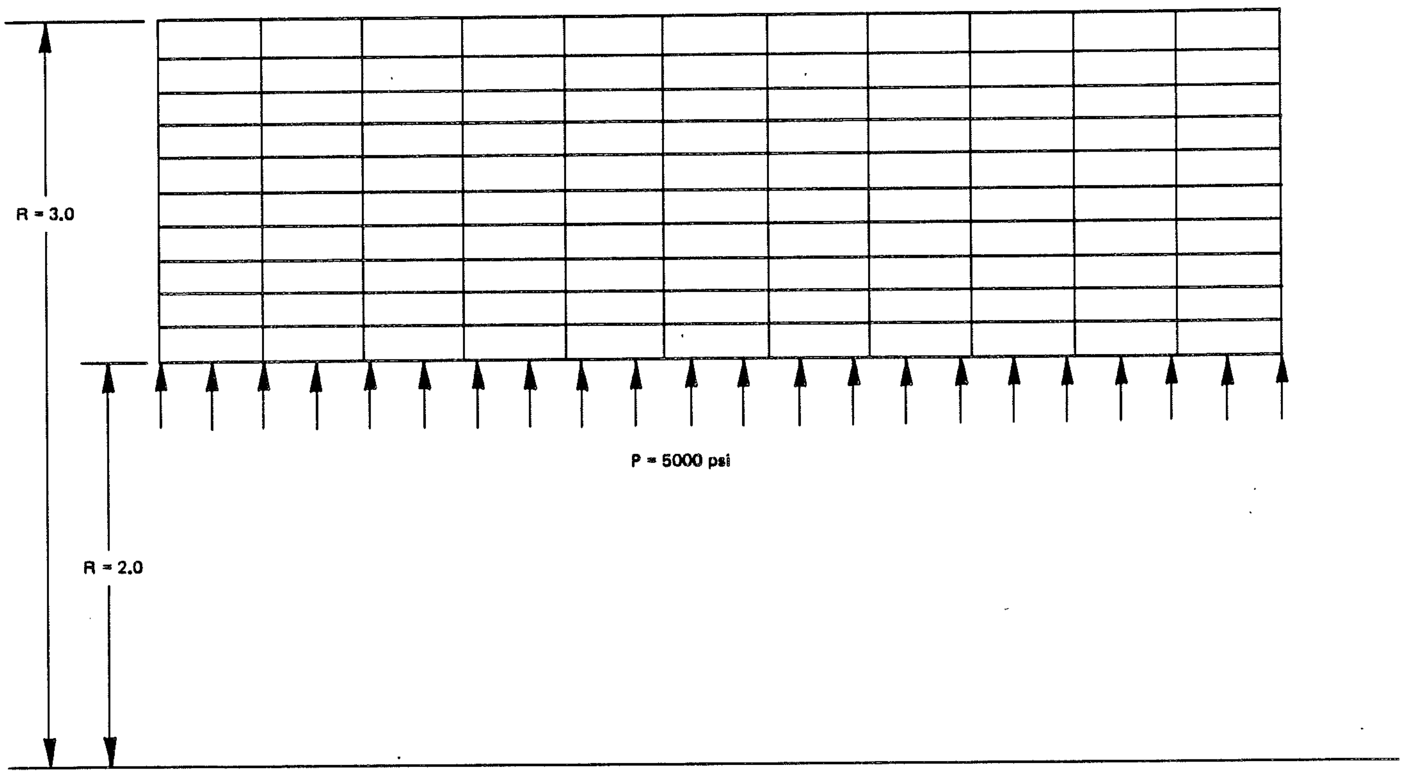

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FIGURE 4.1-20

ANALYTICAL MODEL – CASE A

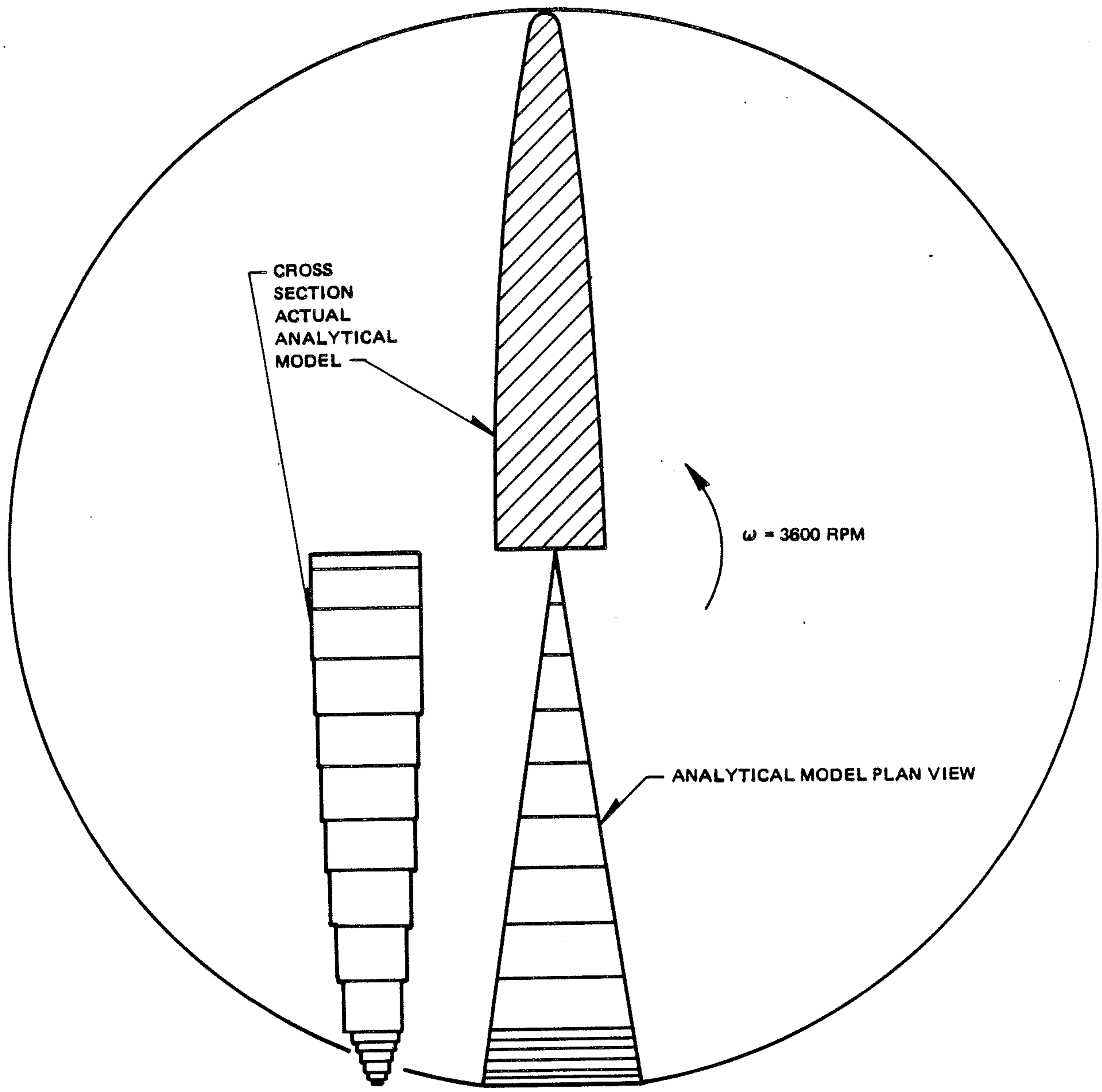

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FIGURE 4.1-21

ANALYTICAL MODEL – CASE B

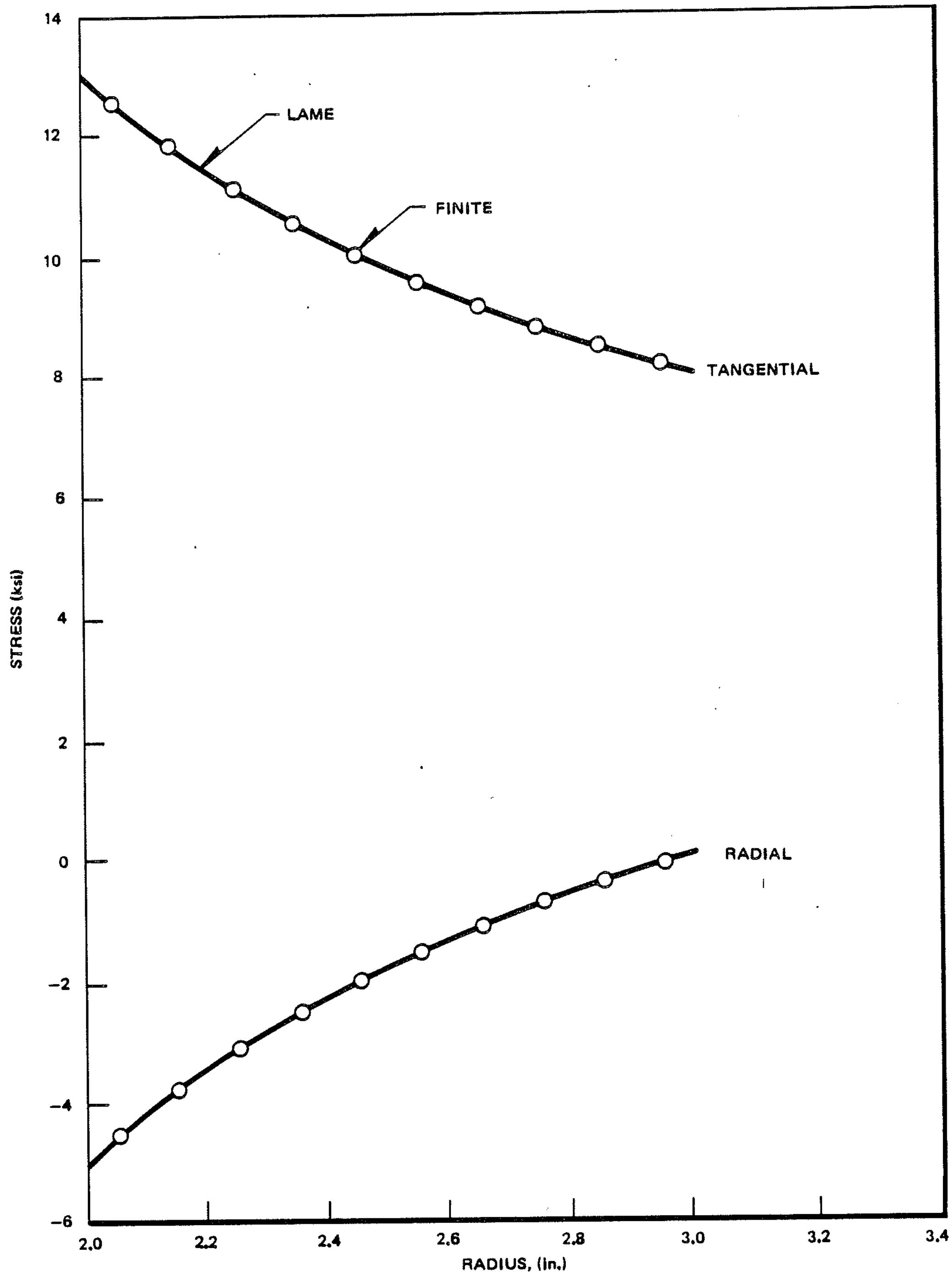

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FIGURE 4.1-22

COMPARISON OF STRESSES – CASE A

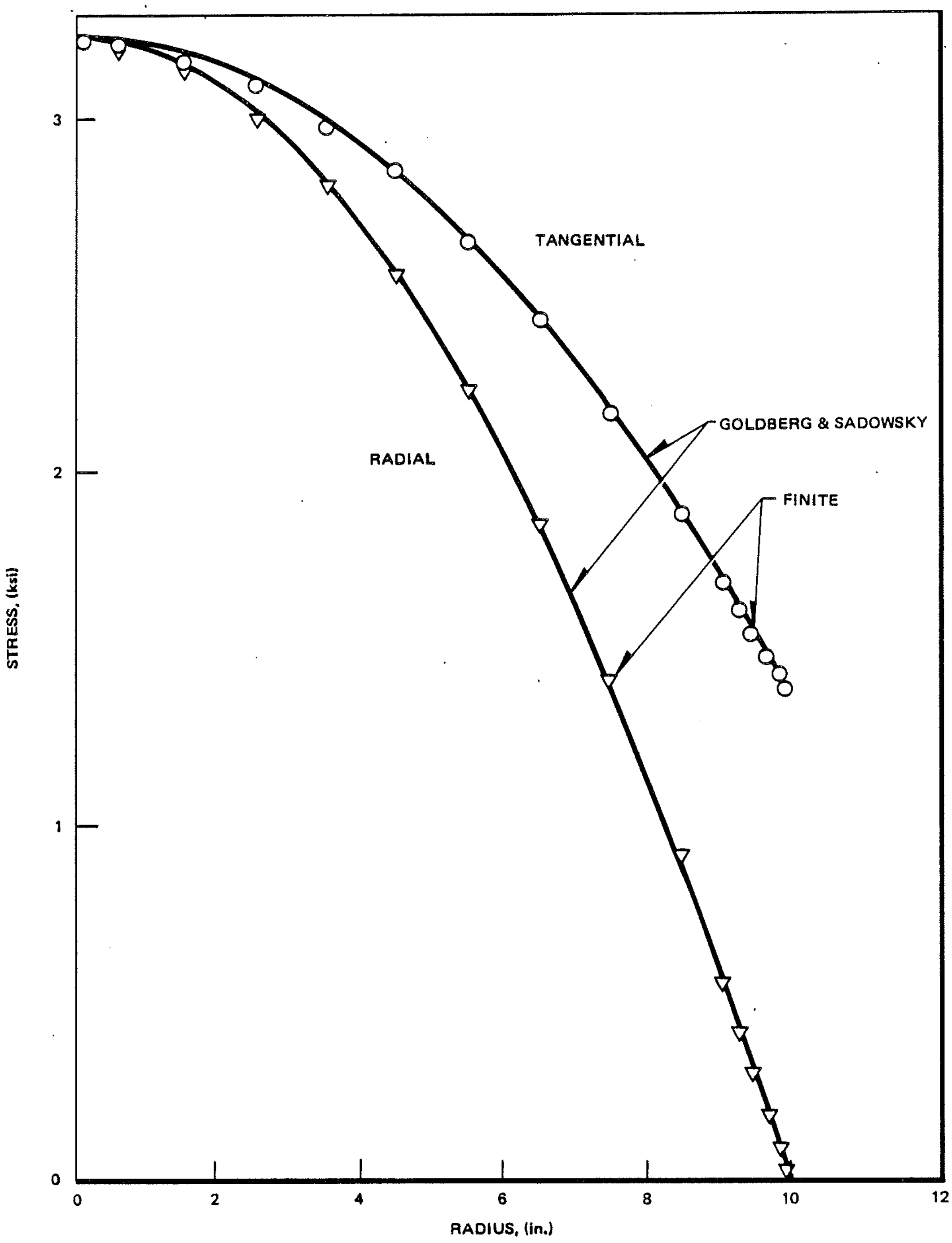

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FIGURE 4.1-23

COMPARISON OF STRESSES – CASE B

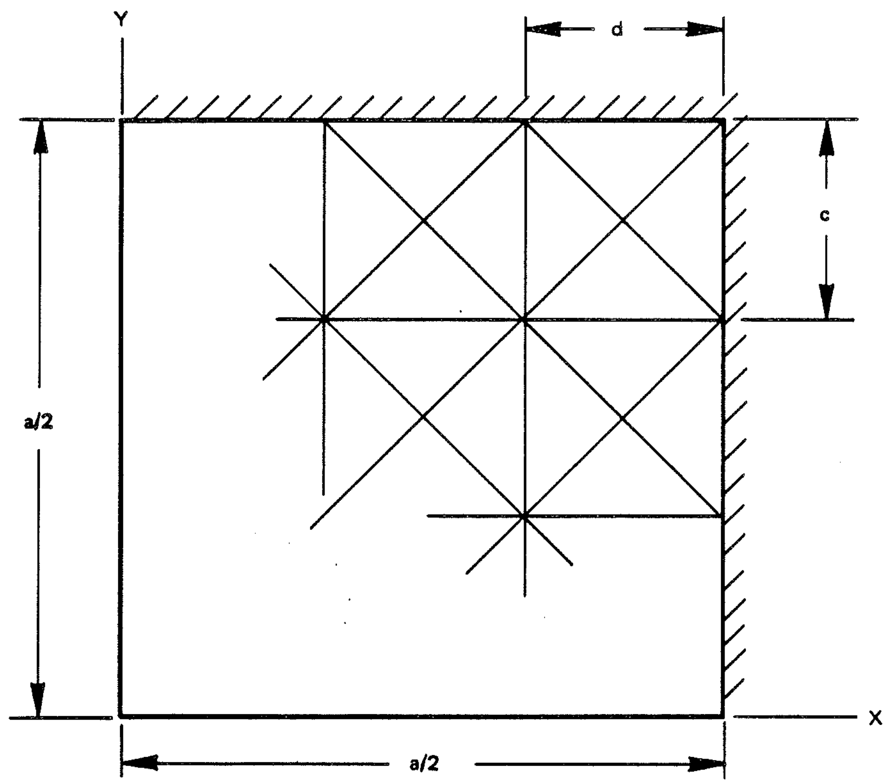

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FIGURE 4.1-24

CLAMPED SQUARE PLATE QUARTER PANEL

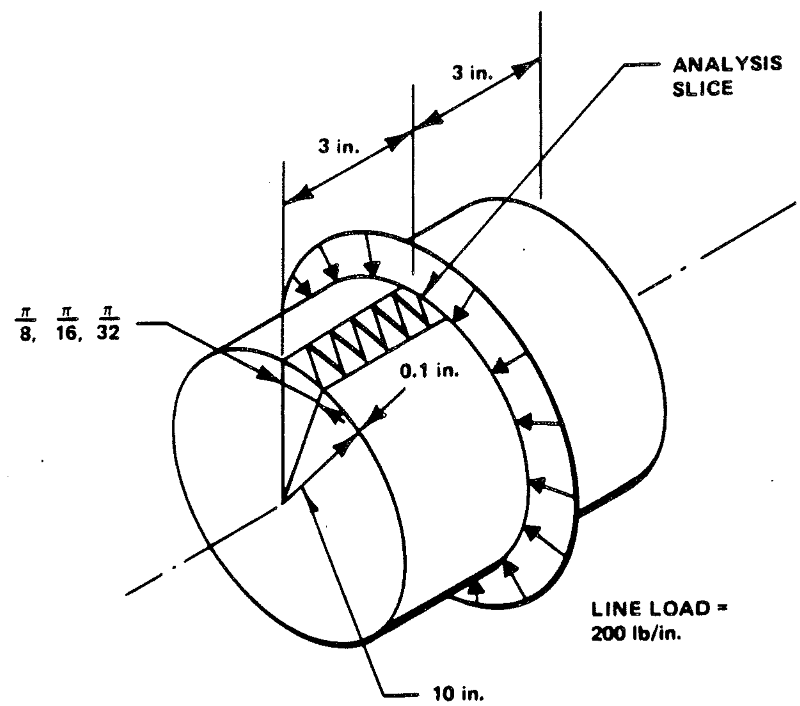

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FIGURE 4.1-25

LINE LOADED CYLINDER

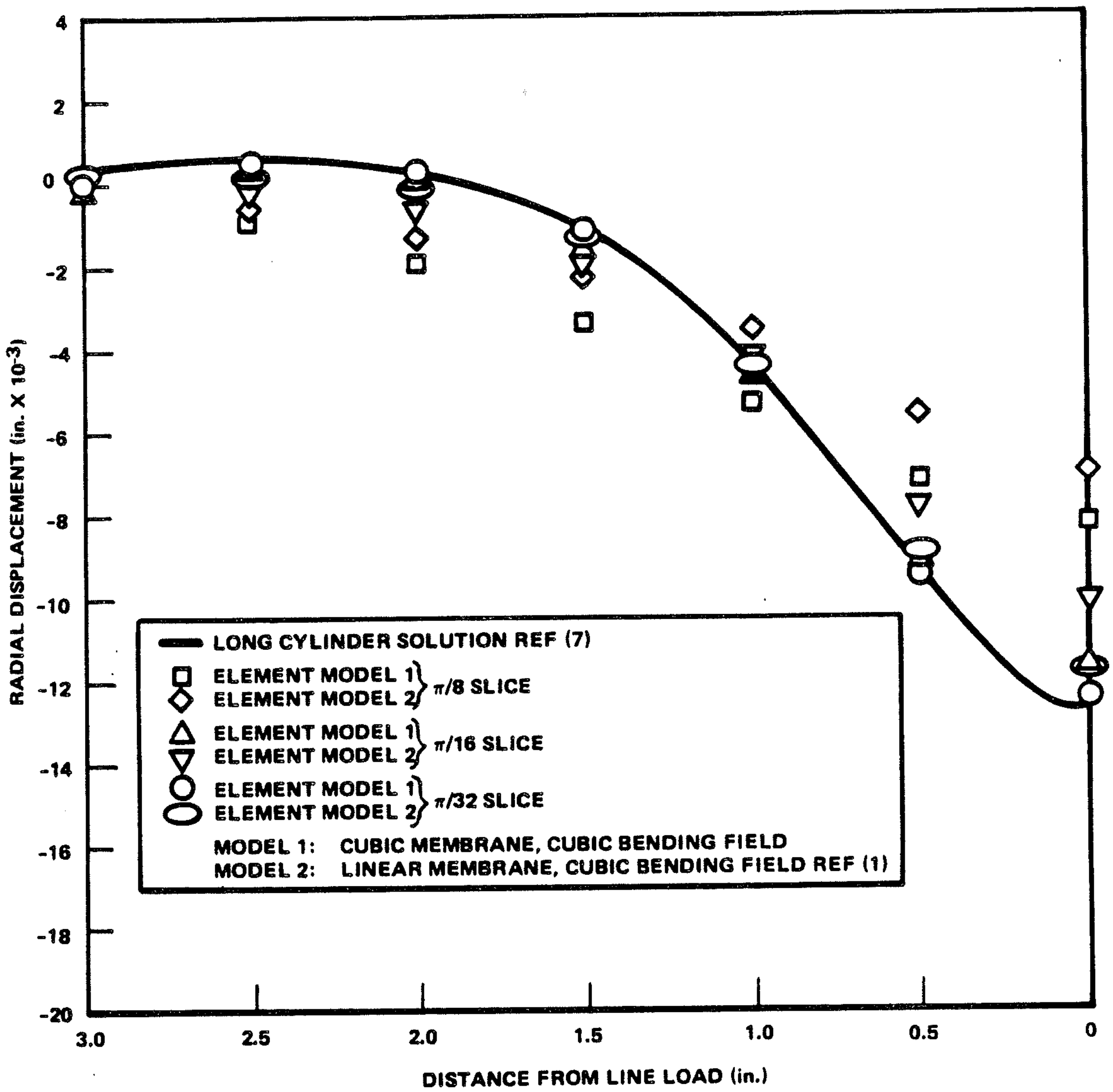

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FIGURE 4.1-26

RADIAL DISPLACEMENT FOR LINE LOADED CYLINDER

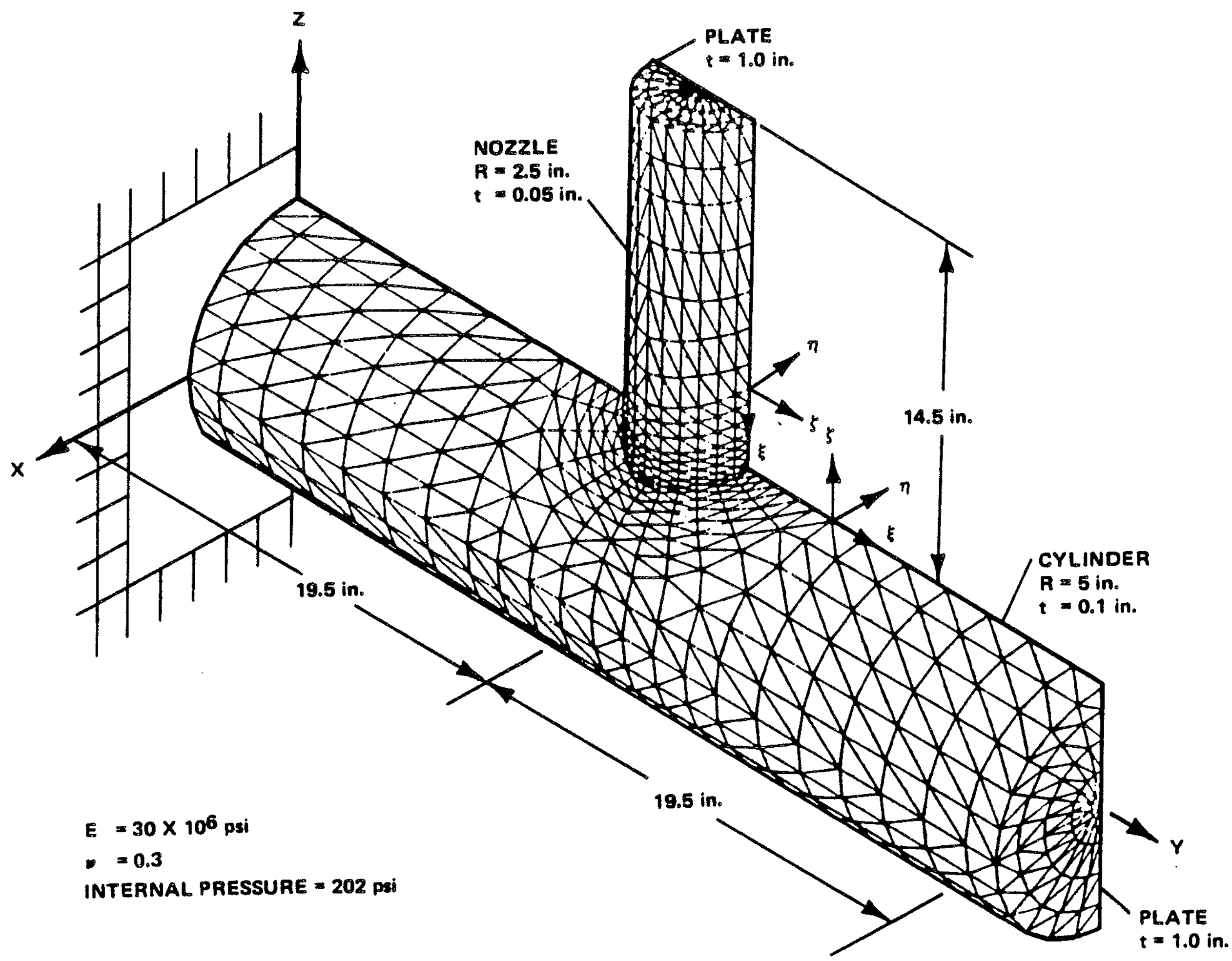

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FIGURE 4.1-27

NOZZLE TO CYLINDER INTERSECTION

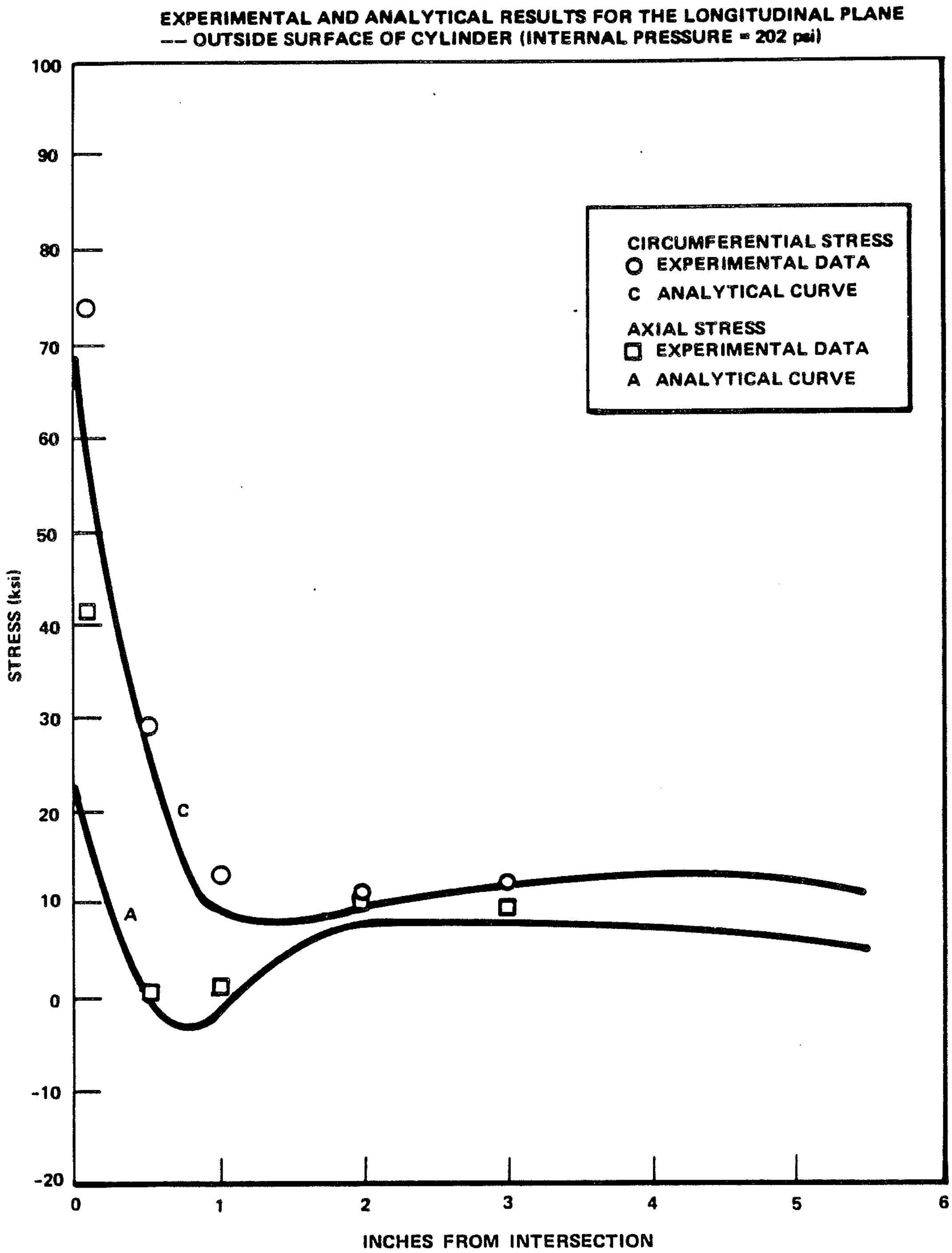

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FIGURE 4.1-28

CYLINDER STRESSES

EXPERIMENTAL AND ANALYTICAL RESULTS FOR THE LONGITUDINAL PLANE
— OUTSIDE SURFACE OF NOZZLE (INTERNAL PRESSURE = 202 psi)

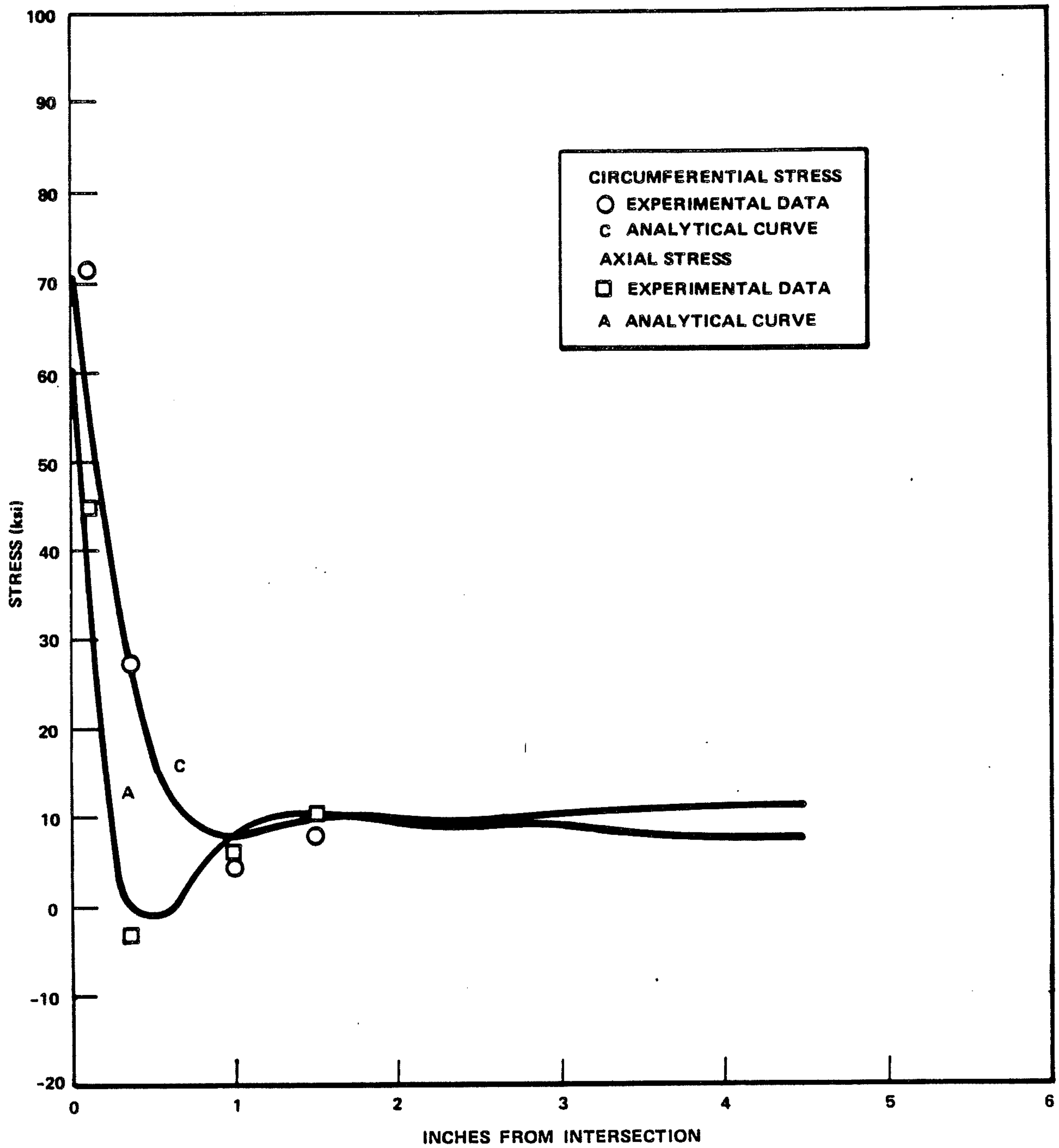

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FIGURE 4.1-29

NOZZLE STRESSES

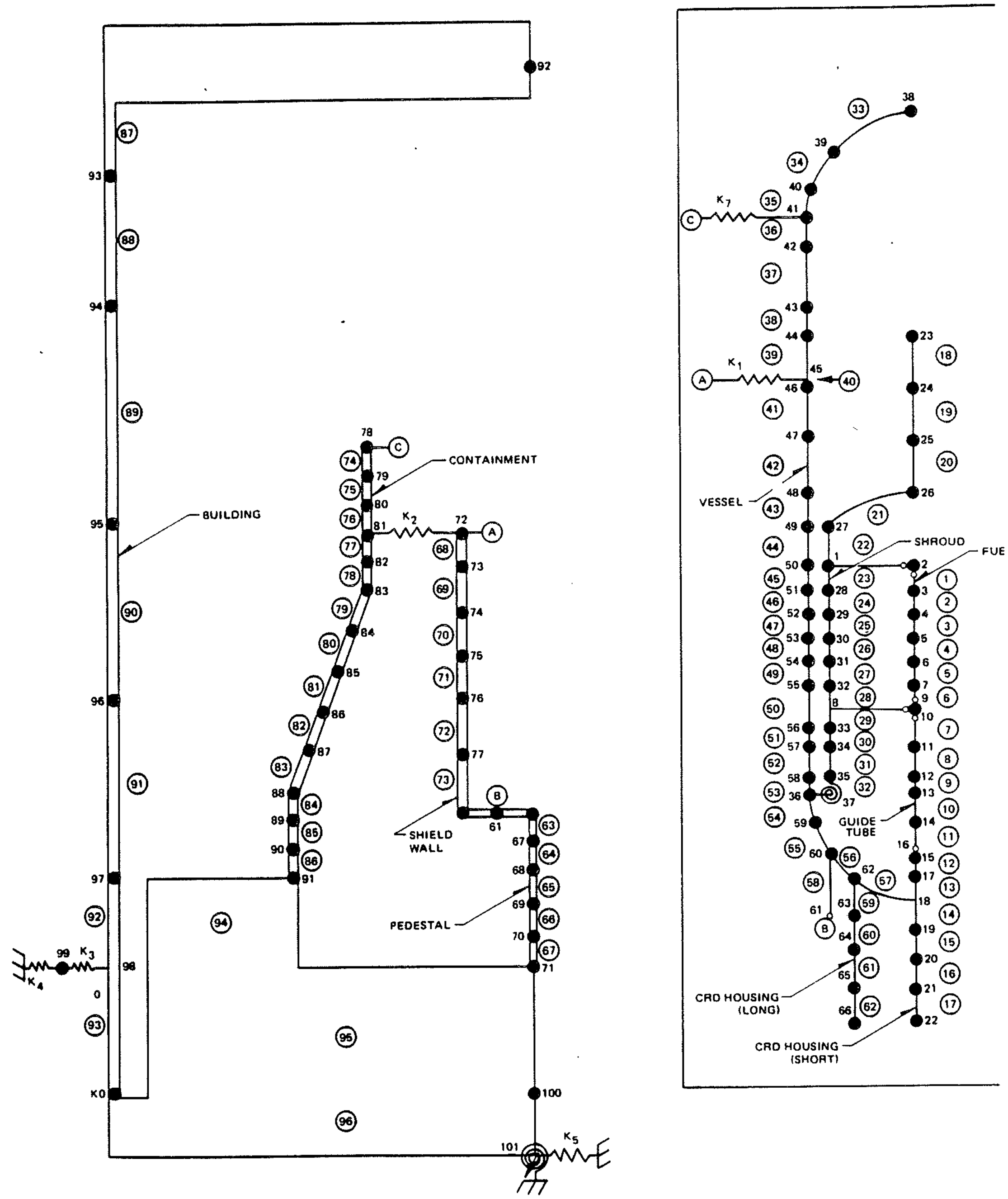

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FIGURE 4.1-30

LUMPED MASS MODEL

4.2 FUEL SYSTEM DESIGN

Fermi 2 is a BWR 4 with a 251 in. pressure vessel and 764 fuel assemblies loaded on a C lattice. The subsection numbers in Section 4.2 generally correspond to the subsection numbers of Appendix A of GESTAR II (Reference 1). Any additional information or differences are given for the applicable subsection.

4.2.1 Design Bases

Information in fuel system design bases is provided in Reference 1, Subsection A.4.2.1.

4.2.2 Description and Design Drawings

Information on fuel system design bases is provided in Reference 1, Subsection A.4.2.2, except for the reactivity control assembly description, which is described below.

4.2.2.1 Reactivity Control Assembly

4.2.2.1.1 Control Rods

The control rods perform the dual function of power shaping and reactivity control (See Figures 4.5-8 through 4.5-10). Power distribution in the core is controlled during operation of the reactor by manipulating selected patterns of control rods. Control rod displacement tends to counterbalance steam void effects at the top of the core and results in significant power flattening. See Subsection 4.5.2.1.2 for a description of the control rods.

4.2.3 Design Evaluations

Information on fuel system evaluation for compliance with the design bases is provided in Reference 1, Subsection A.4.2.3.

4.2.4 Testing, Inspection and Surveillance Plans

Information on testing, inspection and surveillance is provided in Reference 1, Subsection A.4.2.4. Fuel assembly surveillance plans are further described below.

Fermi 2 has a pre-established Fuel Reliability Action Plan for detection, analysis, reporting and taking corrective action whenever fuel failures occur. Detection is based primarily on sampling radioactivity in the off-gas system. At the end of a fuel cycle, fuel inspection and reconstitution using proven vendor techniques will be performed as needed to provide a basis for accomplishing the discharge of all failed fuel rods in accordance with a zero-defect goal. A zero-defect goal implies that no detected failed fuel rods will be re-inserted into the core after a refueling outage.

Proven inspection techniques used include the following:

a. Leak-detection tests such as sipping

b. Visual inspection with various aids such as binoculars, borescope, periscope, and/or underwater TV with a photographic record of observations

c. Nondestructive testing of selected fuel rods by ultrasonic test and/or eddy current test techniques

d. Dimensional measurements of selected fuel rods.

Such inspections may also be performed on fuel where there is no indication of fuel failure to obtain additional data on fuel performance. This fuel may either be from discharged bundles or from bundles scheduled for re-irradiation.

Unexpected conditions or abnormalities that may arise, such as distortions, cladding perforation, or surface disturbances, will be analyzed. Resolution of specific technical questions indicated by site examinations may require examination of selected fuel rods in radioactive material laboratory facilities.

Fermi 2 participated in a vendor's lead fuel test assembly program to obtain fuel performance data for an improved fuel design. This program took place with the insertion of full-length lead bundles during the second refueling outage. Performance inspection of this program is complete and only four lead fuel test assemblies were used. They are currently discharged. Additional lead fuel test programs may be instituted as the need requires.

4.2 FUEL SYSTEM DESIGN

REFERENCES

1. General Electric Co. "General Electric Standard Application for Reactor Fuel, GESTAR-II," NEDE-24011-P-A, (Latest Approved Revision as identified in the COLR).

4.3 NUCLEAR DESIGN

Most of the information in Section 4.3 is provided in the licensing topical report GESTAR II (Reference 1). The design bases and licensing requirements are independent of enrichment.

4.3.1 Design Bases

The design bases are those that are required for the plant to operate, meeting all safety requirements. Safety design bases fall into two categories: (1) the reactivity basis, which prevents an uncontrolled positive reactivity excursion, and (2) the overpower basis, which prevent the core from operating beyond the fuel integrity limits.

4.3.1.1 Reactivity Basis

The nuclear design shall meet the following basis: The core shall be capable of being made subcritical at any time or at any core condition with the highest worth control rod fully withdrawn.

4.3.1.2 Overpower Bases

The Technical Specification limits on minimum critical power ratio (MCPR), maximum linear heat generation rate (MLHGR), and the maximum average planar linear heat generation rate (MAPLHGR) are determined such that the fuel will not exceed required licensing limits during abnormal operational occurrences or accidents.

4.3.2 Description

The BWR core design consists of a light-water moderated reactor, fueled with slightly enriched uranium-dioxide. The use of water as a moderator produces a neutron energy spectrum in which fissions are caused principally by thermal neutrons. At normal operating conditions, the moderator boils, producing a spatially variable distribution of steam voids in the core. The BWR design provides a system for which reactivity is reduced by an increase in the steam void content in the moderator. This void feedback effect is one of the inherent safety features of the BWR system. Any system input which increases reactor power, either in a local or gross sense, produces additional steam voids which reduce reactivity and thereby reduce the power.

4.3.2.1 Nuclear Design Description

The initial fuel loading is composed of three distinct bundle types, each with a unique rod-by-rod enrichment distribution. The bottom and top of each fuel rod in two of these bundle types consists of 6 inches of natural uranium. The third bundle type contains only natural uranium fuel rods. The three unique bundle types are distributed in the initial core based on the principle of minimizing radial power peaking and maximizing core reactivity for the end-of-cycle state. This same strategy is carried into the reload core. A diagram of the cycle-specific reference pattern loading is shown in the cycle-specific supplemental reload licensing report.

The peripheral core zone of the initial core is composed of bundles containing only natural uranium fuel rods. The interior of the core is divided into two zones: an inner zone which comprises about 50 percent of the core area, and an outer zone, a ring, which comprises about 35 percent of the core area. The outer zone consists entirely of the high enrichment bundles. The inner zone is an array of high and medium enrichment bundles arranged in a checkerboard fashion.

Beginning with Cycle 2, the core is loaded with a Control Cell Core (CCC) configuration. The CCC uses a strategy in which control rod movement to offset reactivity changes during power operation is limited to a fixed group of control rods. Each of these rods and its four surrounding fuel bundles comprise a control cell. Low-reactivity bundles are placed in control cells so that control rod motion occurs adjacent to low power fuel. The control cells are located in octant symmetric positions in the core and are separated from each other by a four-bundle cell. All other control rods are normally completely withdrawn from the core while at power.

The reference loading pattern is the basis for all fuel licensing. It is designed with the intent that it will represent, as closely as possible, the actual core loading pattern; however, there will be occurrences where the number and/or types of bundles in the reference design and the actual core loading do not agree exactly.

Any differences between the reference loading pattern and the actual loading pattern are evaluated as described in Reference 1, Section 3.4.

4.3.2.2 Power Distribution

The core power distribution is a function of fuel bundle design, core loading, control rod pattern, core exposure distributions and core coolant flow rate. The thermal performance parameters, MAPLHGR, MLHGR, and MCPR, defined in Table 4.3-1, limit unacceptable core power distributions.

4.3.2.2.1 Power Distribution Calculations

Core power distributions are calculated based on the reference loading pattern shown in the cycle-specific Supplemental Reload Licensing Report. These calculations confirm that the limits established by the thermal performance parameters are not violated. Appropriate design allowances are included at the design stage to ensure that these limits are met. A full range of calculated power distributions along with the resultant exposure shapes and corresponding control rod patterns are also shown in Reference 2.

4.3.2.2.2 Power Distribution Measurements

The techniques for measurement of the power distribution within the reactor core, together with instrumentation correlations and operating limits, are discussed in Reference 3.

4.3.2.2.3 Power Distribution Accuracy

The accuracy of the calculated power distributions is discussed in References 4 and 5.

4.3.2.2.4 Power Distribution Anomalies

Stringent inspection procedures are utilized to ensure the correct arrangement of the core following fuel loading. A fuel loading error (a mislocated or a misoriented fuel bundle in the core) would be a very improbable event, but calculations have been performed to determine the effects of such events on CPR. The inherent design characteristics of the BWR are well suited to limit gross power tilting. The stabilizing nature of the large moderator void coefficient effectively reduces the effect of perturbations on the power distribution. In addition, the in-core instrumentation system, together with the on-line computer, provides the operator with prompt information on the power distribution so that he can readily use control rods or other means to limit the undesirable effects of power tilting. Because of these design characteristics, it is not necessary to allocate a specific margin in the peaking factor to account for power tilt. If, for some reason, the power distribution could not be maintained within normal limits using control rods and flow, then the total core power would have to be reduced.

4.3.2.3 Reactivity Coefficients

Reactivity coefficients, the differential changes in reactivity produced by differential changes in core conditions, are useful in calculating stability and evaluating the response of the core to external disturbances. The base initial condition of the system and the postulated initiating event determine which of the several defined coefficients are significant in evaluating the response of the reactor. The coefficients of interest, relative to BWR systems, are discussed here individually.

There are two primary reactivity coefficients that characterize the dynamic behavior of BWRs; these are the Doppler reactivity coefficient and the moderator void reactivity coefficient. Also associated with the BWR is a power reactivity coefficient and a temperature coefficient. The power coefficient is a combination of the Doppler and void reactivity coefficients in the power operating range, and the temperature coefficient is merely a combination of the Doppler and moderator temperature coefficients. Power and temperature coefficients are not specifically calculated for reload cores. The Doppler and void coefficients are unique for each core, however their values are not typically reported to the customer by the fuel vendor.

4.3.2.3.1 Doppler Reactivity Coefficient

The Doppler coefficient is of prime importance in reactor safety. The Doppler coefficient is a measure of the reactivity change associated with an increase in the absorption of resonance-energy neutrons caused by a change in the temperature of the material in question. The Doppler reactivity coefficient provides instantaneous negative reactivity feedback to any rise in fuel temperature, on either a gross or local basis. The magnitude of the Doppler coefficient is inherent in the fuel design and does not vary significantly among BWR designs. For most structural and moderator materials, resonance absorption is not significant, but in U-238 and Pu-240 an increase in temperature produces a comparatively large increase in the effective absorption cross-section. The resulting parasitic absorption of neutrons causes a significant loss in reactivity. In BWR fuel, in which approximately 96 percent of the uranium in UO_2 is U-238, the Doppler coefficient provides an immediate negative reactivity response that opposes increased fuel fission rate changes.

Although the reactivity change caused by the Doppler Effect is small compared to other power-related reactivity changes during normal operation, it becomes very important during postulated rapid power excursions in which large fuel temperature changes occur. The most severe power excursions are those associated with rod drop accidents. A local Doppler feedback associated with a 3000°F to 5000°F temperature rise is available for terminating the initial excursion. The Doppler coefficient is determined using the theory and methods described in Reference 6.

4.3.2.3.2 Moderator Void Coefficient

The moderator void coefficient should be large enough to prevent power oscillation due to spatial xenon changes yet small enough that pressurization transients do not unduly limit plant operation. In addition, the void coefficient in a BWR has the ability to flatten the radial power distribution and to provide ease of reactor control due to the void feedback mechanism. The overall void coefficient is always negative over the complete operating range since the BWR design is undermoderated.

A detailed discussion of the methods used to calculate void reactivity coefficients, their accuracy and their application to plant transient analyses is presented in Reference 6.

4.3.2.4 Control Requirements

The General Electric BWR control rod system is designed to provide adequate control of the maximum excess reactivity anticipated during the plant operation. The shutdown capability is evaluated at various temperatures and exposures in a xenon-free core.

4.3.2.4.1 Shutdown Reactivity

The core must be capable of being made subcritical, with margin, in the most reactive condition throughout the operating cycle with the most reactive control rod fully withdrawn and all other rods fully inserted. The shutdown margin is determined by using the BWR simulator code (Section 3.3 of Reference 1) to calculate the core multiplication at selected exposure points with the strongest rod fully withdrawn. The shutdown margin is calculated based on the carryover of the minimum expected exposure at the end of the previous cycle. The core is assumed to be at various temperatures and exposures in a xenon-free condition in order to ensure that the calculated values are conservative. Further discussion of the uncertainty of these calculations is given in References 7 and 8.

As exposure accumulates and burnable poison depletes in the lower exposure fuel bundles, an increase in core reactivity may occur. The nature of this increase depends on specifics of fuel loading and control state.

The cold k_{eff} is calculated with the strongest control rod out at various exposures through the cycle. A value R is defined as the difference between the strongest rod out k_{eff} at beginning of cycle (BOC) and the maximum calculated strongest rod out k_{eff} at any exposure point. The strongest rod out k_{eff} at any exposure point in the cycle is equal to or less than:

$$k_{eff} = k_{eff}\,(\text{Strongest rod withdrawn})_{BOC} + R$$

where

R is always greater than or equal to 0.

The cycle-specific calculated values of k_{eff} with the strongest rod withdrawn at BOC and R are reported in cycle-specific supplemental reload licensing report. For completeness, the uncontrolled k_{eff} and fully controlled k_{eff} values are also reported.

4.3.2.4.2 Reactivity Variations

The excess reactivity designed into the core is controlled by the control rod system supplemented by gadolinia-uranium fuel rods. Control rods are used during the cycle partly to compensate for burnup and partly to control the power distribution.

4.3.2.4.3 Standby Liquid Control System

The Standby Liquid Control System (SLCS) is designed to provide the capability of bringing the reactor, at any time in a cycle, from a full power and minimum control rod inventory (which is defined to be at the peak of the xenon transient) to a subcritical condition with the reactor in the most reactive xenon-free state. The requirements of this system are dependent primarily on the reactor power level and on the reactivity effects of voids and temperature between full power and cold, xenon-free condition. The cycle-specific shutdown capability of the SLCS is given in cycle-specific supplemental reload licensing report.

4.3.2.5 Control Rod Patterns and Reactivity Worths

Control rod patterns are chosen to achieve an exposure distribution approaching the target end-of-cycle exposure shape and a power distribution meeting the thermal limits. Control rod patterns will be altered as necessary to meet these criteria.

4.3.2.6 Criticality of Reactor During Refueling

The core is subcritical at all times.

4.3.2.7 Stability

4.3.2.7.1 Xenon Transients

Boiling water reactors do not have instability problems due to xenon. This has been demonstrated by (1) never having observed xenon instabilities in operating BWRs, (2) special tests which have been conducted on operating BWRs in an attempt to force the reactor into xenon instability, and (3) calculations. All of these indicators have proven that xenon transients are highly damped in a BWR due to the large negative power coefficient (Reference 9).

4.3.2.7.2 Thermal Hydraulic Stability

Information on thermal hydraulic stability is provided in Reference 1, Subsection A.4.3.2.7.2, and is also covered in Subsection 4.4.4.6. Cycle-specific thermal hydraulic stability is covered in cycle-specific supplemental reload licensing report.

4.3.2.8 Vessel Irradiations

4.3.2.8.1 Historical Information

Neutron vessel fluence calculations used for determining the lead factor (the ratio of the surveillance capsule flux to the peak vessel inside surface flux) were carried out using a two-dimensional, discrete ordinate, Sn transport code with general anisotropic scattering. This code was a widely used discrete ordinates code which solved a wide variety of radiation transport problems. Slab, cylinder, and spherical geometries are allowed with various boundary conditions. The fluence calculations incorporate, as an initial starting point, a distributed fission neutron source distribution prepared from core physics data. Anisotropic scattering is considered for all regions. The cross sections are represented by third order Legendre polynomial expansions.

4.3.2.8.2 Measurement Uncertainty Recapture/Thermal Power Optimization Uprate, 24-Month Cycle, and GNF3 New Fuel Introduction Analysis

An RPV fluence evaluation was performed by GE in support of a planned Fermi 2 shift to GNF3 fuel and 24-month operating cycles. Detailed flux calculations were performed for pre-MUR/TPO cycles at the Licensed Thermal Power (LTP) levels corresponding to the respective cycles and for an MUR/TPO core that is representative of future cycles at the target power level of 3486 MWt. The NRC approved GE fluence methodology was used for these flux calculations. In addition, fluence distributions at 52 Effective-Full-Power-Years (EFPY) were evaluated based on calculated LTP and anticipated MUR/TPO flux distributions, in conjunction with the cycle-dependent energy generation data.

The peak fluence for the RPV inner surface used for developing the P-T curves was 9.92×10^{17} n/cm^2. The peak fluence for the girth weld location was calculated based on its elevation between the lower and lower intermediate shell plates, and is also provided in Reference 12. This fluence value was applied to this girth weld and all plates and welds in the lower shell.

The N16 water level instrumentation (WLI) nozzle(s), which are within the beltline region, were also considered in this evaluation. Fluence was determined for the specific location of these nozzles. The peak fluence for the WLI nozzles used for determination of the P-T curves was 3.59×10^{17} n/cm^2.

The fluence determined for the WLI nozzles is based upon operation at 3293 MWt for 3.4 EFPY, 3430 MWt for 16.38 EFPY, and 3486 MWt for 32.22 EFPY.

All vessel components have been evaluated considering MUR/TPO. The basis for all fluence values is contained in Reference 12.

The current NRC approved GE methodology for neutron flux calculations is documented in Reference 13. GE's methodology adheres to the guidance contained in Regulatory Guide 1.190 for neutron flux evaluation.

4.3.3 Analytical Methods

Information on the analytical methods is provided in Section 3.3 of Reference 1, and in Reference 13.

4.3.4 Changes

Information on changes relative to the design is provided in Reference 1, Subsection A.4.3.4.

4.3 NUCLEAR DESIGN

Most of the information in Section 4.3 is provided in the licensing topical report GESTAR II (Reference 1). The design bases and licensing requirements are independent of enrichment.

4.3.1 Design Bases

The design bases are those that are required for the plant to operate, meeting all safety requirements. Safety design bases fall into two categories: (1) the reactivity basis, which prevents an uncontrolled positive reactivity excursion, and (2) the overpower basis, which prevent the core from operating beyond the fuel integrity limits.

4.3.1.1 Reactivity Basis

The nuclear design shall meet the following basis: The core shall be capable of being made subcritical at any time or at any core condition with the highest worth control rod fully withdrawn.

4.3.1.2 Overpower Bases

The Technical Specification limits on minimum critical power ratio (MCPR), maximum linear heat generation rate (MLHGR), and the maximum average planar linear heat generation rate (MAPLHGR) are determined such that the fuel will not exceed required licensing limits during abnormal operational occurrences or accidents.

4.3.2 Description

The BWR core design consists of a light-water moderated reactor, fueled with slightly enriched uranium-dioxide. The use of water as a moderator produces a neutron energy spectrum in which fissions are caused principally by thermal neutrons. At normal operating conditions, the moderator boils, producing a spatially variable distribution of steam voids in the core. The BWR design provides a system for which reactivity is reduced by an increase in the steam void content in the moderator. This void feedback effect is one of the inherent safety features of the BWR system. Any system input which increases reactor power, either in a local or gross sense, produces additional steam voids which reduce reactivity and thereby reduce the power.

4.3.2.1 Nuclear Design Description

The initial fuel loading is composed of three distinct bundle types, each with a unique rod-by-rod enrichment distribution. The bottom and top of each fuel rod in two of these bundle types consists of 6 inches of natural uranium. The third bundle type contains only natural uranium fuel rods. The three unique bundle types are distributed in the initial core based on the principle of minimizing radial power peaking and maximizing core reactivity for the end-of-cycle state. This same strategy is carried into the reload core. A diagram of the cycle-specific reference pattern loading is shown in the cycle-specific supplemental reload licensing report.

TABLE 4.3-1 DEFINITION OF FUEL DESIGN LIMITS

Maximum Linear Heat Generation Rate (MLHGR)

The MLHGR is the maximum linear heat generation rate expressed in kW/ft for the fuel rod with the highest surface heat flux at a given nodal plane in the bundle. The MLHGR operating limit is fuel rod type dependent. The MLHGR can be monitored to assure that all mechanical design requirements will be met.

Maximum Average Planar Linear Heat Generation Rate (MAPLHGR)

The MAPLHGR is the maximum average linear heat generation rate (expressed in kW/ft) in any plane of a fuel bundle allowed by the plant Technical Specifications for that fuel type. This parameter is obtained by averaging the linear heat generation rate over each fuel rod in the plane, and its limiting value is selected such that:

(a) the peak clad temperature during the design basis loss-of-coolant accident will not exceed 2200°F in the plane of interest, and

(b) all fuel design limits specified in Reference 1, Section 2 will be met if the MLHGR is not monitored for that purpose.

Minimum Critical Power Ratio (MCPR)

The critical power ratio is defined as the ratio of the critical power (bundle power at which some point within the assembly experiences onset of boiling transition) to the operating bundle power. The critical power is determined at the same mass flux, inlet temperature, and pressure that exists at the specified reactor condition. Thermal margin is stated in terms of the minimum value of the critical power ratio, MCPR, which corresponds to the most limiting fuel assembly in the core.

Operating Limit MCPR

The MCPR operating limit is the minimum CPR allowed by the plant Technical Specifications for a given bundle type. The minimum CPR is a function of several parameters, the most important of which are bundle power, bundle flow, and bundle R-factor. The R-factor is dependent upon the local power distribution and details of the bundle mechanical design. The limiting value of CPR is selected for each bundle type such that, during the most limiting event of moderate frequency, the calculated CPR in that bundle is not less than the safety limit CPR. The MCPR operating limit is attained when the bundle power, R-factor, flow and other relevant parameters combine to yield the Technical Specification value.

TABLE 4.3-2 FLUENCE DETERMINATION FOR THE PEAK LOCATION IN THE FERMI 2 VESSEL

HISTORICAL DATA (Reference 10)

Time at Power	
EOC1 - 2.92 years at 42.8% CF	1.25 EFPY
Design - 40 years at 80% CF	32 EFPY
Lead Factor	
Peak Location ID	0.90*
Dosimeter Flux	
Measured Value	4.9×10^{8} n/cm^{2}-sec
Upper Bound	6.1×10^{8} n/cm^{2}-sec
Dosimeter Fluence	
Measured Value	1.9×10^{16} n/cm^{2}
Upper Bound	2.4×10^{16} n/cm^{2}
Peak Vessel ID 32 EFPY Fluence	
Nominal Prediction	5.8×10^{17} n/cm^{2}
Upper Bound	7.3×10^{17} n/cm^{2}

* Value adjusted from 1.05 to 0.90 (Reference 12)

GNF3/24MC Fluence Analysis Data (Reference 12)

Calculated Peak Fast Flux at the RPV Inside Surface

Parameter	Elevation (Inches above BAF)	Azimuth (°)	Flux (n/cm^{2}-s)
RPV ID peak flux (>1.0 MeV) – 3486 MWt	127.0	64.0	4.81E8

Calculated Fast Flux and Lead Factor at Surveillance Capsule Location

Capsule No.*	Azimuth (°)	Flux (n/cm^{2}-s)	Lead Factor
1 and 2 – 3486 MWt	30 and 120	4.27E8	0.90

* Surveillance capsule 3 at 300° was withdrawn at 8.1 EFPY.

TABLE 4.3-2 FLUENCE DETERMINATION FOR THE PEAK LOCATION IN THE FERMI 2 VESSEL

Calculated Peak Flux at Shroud Inside Surface (Reference 12)

Parameter	Elevation (Inches above BAF)	Azimuth (°)	Flux (n/cm^2-s)
Shroud ID peak flux (>1.0 MeV) – 3486 MWt	97.0	66.0	1.16E12

Neutron Flux at Top Guide and Core Plate

Parameter	Flux (n/cm^2-s)
Top Guide bounding flux (>1.0 MeV) – 3486 MWt	2.57E13
Core Plate bounding Flux (>1.0Mev) – 3486 MWt	6.13E11

Calculated Neutron Fluence Values

Parameters	52-EFPY Fluence (n/cm^2)
RPV ID peak fluence(>1.0MeV)	1.03E18
Shroud ID peak fluence >1.0MeV)	2.53E21
Top guide bounding fluence (>1.0Mev)	3.71E22
Core plate bounding fluence (>1.0 MeV)	8.59E20
Girth weld (elevation 28.3125 inches above BAF) peak fluence (>1.0 MeV)	5.95E17
(N16) Water Level Instrumentation Nozzles Peak fluence (>1.0 MeV)	2.46E17

TABLE 4.3-2 FLUENCE DETERMINATION FOR THE PEAK LOCATION IN THE FERMI 2 VESSEL

Fermi 2 Beltline Fluence for 52 EFPY**

Parameter	52-EFPY Fluence (n/cm^2)
Lower-Intermediate Shell Plates, Axial Welds Thickness = 6.125 inches	Peak ID fluence = 9.92E17 Peak ¼T fluence = 6.87E17
Water Level Instrumentation Nozzle Thickness = 6.125 inches	Peak ID fluence = 3.59E17 Peak ¼T fluence = 2.49E17
Lower Shell Plates and Axial Welds and Lower to Lower-Intermediate Girth Weld Thickness = 7.125 inches	Peak ID fluence = 5.74E17 Peak ¼T fluence = 3.74E17
(N16) Water Level Instrumentation Nozzles	Peak fluence = 3.59E17

** Values documented in Reference 14

4.4. THERMAL-HYDRAULIC DESIGN

Most of the information in Section 4.4 is provided in the licensing topical report GESTAR II (Reference 1).

4.4.1. Design Basis

4.4.1.1. Safety Design Bases

Thermal-hydraulic design of the core shall establish the thermal-hydraulic safety limits for use in evaluating the safety margin relating the consequences of fuel cladding failure to public safety.

4.4.1.2. Requirements for Steady-State Conditions

For purposes of maintaining adequate fuel performance margin during normal steady-state operation, the MCPR must not be less than the required MCPR operating limit, the LHGR must be maintained below the required LHGR limit (MLHGR), and the APLHGR must be maintained below the required APLHGR limit (MAPLHGR). The steady-state MCPR, MLHGR, and MAPLHGR limits are determined by analysis of the most severe moderate frequency anticipated operational occurrences (AOOs) to accommodate uncertainties and provide reasonable assurance that no fuel damage results during moderate frequency AOOs at any time in life.

4.4.1.3. Requirements for Anticipated Operational Occurrences (AOOs)

The MCPR, MLHGR, and MAPLHGR limits are established such that no safety limit is expected to be exceeded during the most severe moderate frequency AOO event. The cycle-specific MCPR, MLHGR, and MAPLHGR limits are provided in the Core Operating Limits Report (COLR) and corresponding licensing basis in the cycle-specific supplemental reload licensing report.

4.4.1.4. Summary of Design Bases

In summary, the steady-state operating limits have been established to ensure that the design bases are satisfied for the most severe moderate frequency AOO. Demonstration that the steady-state MCPR, MLHGR, and MAPLHGR limits are not exceeded is sufficient to conclude that the design bases are satisfied.

4.4.2. Description of Thermal-Hydraulic Design of the Reactor Core

4.4.2.1. Summary Comparison

An evaluation of plant performance from a thermal and hydraulic standpoint is provided in Subsection 4.4.3.

A tabulation of thermal and hydraulic parameters of the core is given in Table 4.4-1 along with a comparison of Fermi 2 to others of similar design. Any changes for reload cores are provided in the cycle-specific supplemental reload licensing report.

4.4.2.2. Critical Power Ratio

A description of the critical power ratio and model used to calculate this ratio is provided in Subsection 4.4.4.1. Criteria used to calculate the critical power safety limit are given in Subsection 1.1.5 of Reference 1.

4.4.2.3. Average Planar Linear Heat Generation Rate (APLHGR)

Models used to calculate the APLHGR limit are given in Reference 1, Subsection 4.2.2, as pertaining to the fuel mechanical design limits and as pertaining to 10 CFR 50, Appendix K, limits provided in the Technical Specifications.

4.4.2.4. Void Fraction Distribution

The core average and maximum exit void fractions in the core at rated power conditions are calculated on a cycle-specific basis.

4.4.2.5. Core Coolant Flow Distribution and Orificing Pattern

The flow distribution to the fuel assemblies and bypass flow paths is calculated on the assumption that the pressure drop across all fuel assemblies and bypass flow paths is the same. This assumption has been confirmed by measuring the flow distribution in boiling water reactors (References 2 through 4). The components of bundle pressure drop considered are friction, local, elevation, and acceleration (Subsections 4.4.2.6.1 through 4.4.2.6.4, respectively). Pressure drop measurements made in operating reactors confirm that the total measured core pressure drop and calculated core pressure drop are in good agreement. There is reasonable assurance, therefore, that the calculated flow distribution throughout the core is in close agreement with the actual flow distribution of an operating reactor.

An iteration is performed on flow through each flow path (fuel assemblies and bypass flow paths), which equates the total differential pressure (plenum to plenum) across each path and matches the sum of the flows through each path to the total core flow. The total core flow less the control rod cooling flow enters the lower plenum. A fraction of this passes through various bypass flow paths. The remainder passes through the orifice in the fuel support plate (experiencing a pressure loss) where some of the flow exits through the fit-up between the fuel support and the lower tieplate and through the lower tieplate holes into the bypass flow region. All initial and reload core fuel bundles have lower tieplate holes. The majority of the flow continues through the lower tieplate (experiencing a pressure loss) where some flow exits through the flow path defined by the fuel channel and lower tieplate into the bypass region. This bypass flow is lower for those fuel assemblies with finger springs. The bypass flow paths considered in the analysis and typical values of the fraction of bypass flow through each flow path are given in Reference 5.

Within the fuel assembly, heat balances on the active coolant are performed nodally. Fluid properties are expressed as the bundle average at the particular node of interest and are based on 1967 International Standard Steam-Water Properties. In evaluating fluid properties a constant pressure model is used.

The relative radial and axial power distributions are used with the bundle flow to determine the axial coolant property distribution, which gives sufficient information to calculate the pressure drop components within each fuel assembly type. When the equal pressure drop criterion described above is satisfied, the flow distributions are established.

4.4.2.6. Core Pressure Drop and Hydraulic Loads

The components of bundle pressure drop considered are friction, local, elevation, and acceleration pressure drops. Pressure drop measurements made in operating reactors confirm that the total measured core pressure drop and calculated core pressure drop are in good agreement.

4.4.2.6.1. Friction Pressure Drop

Friction pressure drop is calculated with a basic model as follows:

$$\Delta P_f = \frac{w^2}{2g_c\rho_\ell}\frac{fL}{D_H A_{ch}^2}\phi_{TPF}^2 \qquad (4.4\text{-}1)$$

where

ΔP_f	=	friction pressure drop, psi
w	=	mass flow rate
g_c	=	acceleration of gravity
ρ_ℓ	=	average nodal liquid density
D_H	=	channel hydraulic diameter
A_{ch}	=	channel flow area
L	=	incremental length
f	=	friction factor
ϕ_{TPF}^2	=	two-phase friction multiplier

The formulation for the two-phase multiplier is similar to that presented in References 6 and 7 and is based on data that is taken from prototypical BWR fuel bundles.

4.4.2.6.2. Local Pressure Drop

The local pressure drop is defined as the irreversible pressure loss associated with an area change, such as the orifice, lower tieplate, and spacers of a fuel assembly.

The general local pressure drop model is similar to the friction pressure drop and is

$$\Delta P_L = \frac{w^2}{2g_c\rho_\ell}\frac{K}{A^2}\phi_{TPL}^2 \qquad (4.4\text{-}2)$$

where

ΔP_L = local pressure drop, psi

K = local pressure drop loss coefficient

A = reference area for local loss coefficient

ϕ^2_{TPL} = two-phase local multiplier

and w, g, and ρ_ℓ are defined in Equation 4.4-1. The formulation for the two-phase multiplier is similar to that reported in Reference 7. For advanced spacer designs, a quality modifier has been incorporated in the two-phase multiplier to better fit the data. Empirical constants were added to fit the results to data taken for the specific designs of the BWR fuel assembly. These data were obtained from tests performed in single-phase water to calibrate the orifice, the lower tieplate, and the holes in the lower tieplate, in both single- and two-phase flow to derive the best fit design values for the spacer and upper tieplate pressure drop. The range of test variables was specified to include the range of interest for BWRs. New test data are obtained whenever there is a significant design change to ensure the most applicable methods are used.

4.4.2.6.3. Elevation Pressure Drop

The elevation pressure drop is based on the relation:

$$\Delta P_E = \bar{\rho}\Delta L; \qquad (4.4\text{-}3)$$

$$\bar{\rho} = \rho_f(1-\alpha) + \rho_g\alpha$$

where

ΔP_E = elevation pressure drop, psi

ΔL = incremental length

$\bar{\rho}$ = average water density

α = nodal average void fraction

ρ_f, ρ_g = saturated water and vapor density, respectively

The void fraction model used is an extension of the Zuber-Findlay model (Reference 8), and uses an empirically fit constant to predict a large block of steam void fraction data. Checks against new data are made on a continuing basis to ensure the best models are used over the full range of interest of Boiling Water Reactors.

4.4.2.6.4. Acceleration Pressure Drop

A reversible pressure change occurs when an area change is encountered, and an irreversible loss occurs when the fluid is accelerated through the boiling process. The basic formulation for the reversible pressure change resulting from a flow area change in the case of single-phase flow is given by:

$$\Delta P_{ACC} = (1-\sigma_A^2)\frac{W^2}{2g_c\rho_\ell A_2^2} \qquad (4.4\text{-}4)$$

$$\sigma_A = \frac{A_2}{A_1} = \frac{\text{final flow area}}{\text{initial flow area}}$$

where

ΔP_{ACC} = acceleration pressure drop

A_2 = final flow area

A_1 = initial flow area

In the case of two-phase flow, the liquid density is replaced by a density ratio so that the reversible pressure change is given by:

$$\Delta P_{ACC} = (1 - \sigma_A^2)\frac{W^2 \rho_H}{2g_c \rho_{KE}^2 A_2^2} \quad (4.4\text{-}5)$$

where:

$$\frac{1}{\rho_H} = \frac{x}{\rho_g} + \frac{(1-x)}{\rho_\ell}$$, homogeneous density

$$\frac{1}{\rho_{KE}^2} = \frac{x^3}{\rho_g^2 \alpha^2} + \frac{(1-x)^3}{\rho_\ell^2 (1-\alpha)^2}$$, kinetic energy density

where:

α = void fraction at A_2

x = steam quality at A_2

and other terms are as previously defined. The basic formulation for the acceleration pressure change due to density change is:

$$\Delta P_{acc} = \frac{w^2}{gA_{ch}^2}\left[\left(\frac{1}{\rho_{M_{OUT}}}\right) - \left(\frac{1}{\rho_{M_{IN}}}\right)\right] \quad (4.4\text{-}6)$$

where

$$\frac{1}{\rho_{M_{OUT}}} = \frac{x_{OUT}^2}{\rho_g \alpha_{OUT}} + \frac{(1-x_{OUT})^2}{\rho_\ell (1-\alpha_{OUT})}$$

$$\frac{1}{\rho_{M_{IN}}} = \frac{x_{IN}^2}{\rho_g \alpha_{IN}} + \frac{(1-x_{IN})^2}{\rho_\ell (1-\alpha_{IN})}$$

and is evaluated at the inlet and outlet of each axial node. Other terms are as previously defined. The total acceleration pressure drop in Boiling Water Reactors is on the order of a few percent of the total pressure drop.

4.4.2.7. Correlation and Physical Data

General Electric Company has obtained substantial amounts of physical data in support of the pressure drop and thermal-hydraulic loads discussed in Subsection 4.4.2.6. Correlations have been developed to fit these data to the formulations discussed.

4.4.2.7.1. Pressure Drop Correlations

General Electric Company has taken significant amounts of friction pressure drop data in multi-rod geometries representative of BWR plant fuel bundles and correlated both the friction factor and two-phase multipliers on a best fit basis using the pressure drop formulations reported in Subsections 4.4.2.6.1 and 4.4.2.6.3. Tests are performed in single-phase water to calibrate the orifice and the lower tieplate, and in both single- and two-phase flow to arrive at best-fit design values for spacer and upper tieplate pressure drop. The range of test variables is specified to include the range of interest to BWRs. New data are taken whenever there is a significant design change to ensure the most applicable methods are in use at all times.

Applicability of the single-phase and two-phase hydraulic models discussed in Subsections 4.4.2.6.1 and 4.4.2.6.3 was confirmed by prototype flow tests. The typical range of the test data is summarized in Table 4.4-2.

4.4.2.7.2. Void Fraction Correlation

The void fraction correlation includes effects of pressure, flow direction, mass velocity, quality, and subcooled boiling.

4.4.2.7.3. Heat Transfer Correlation

The Jens-Lottes (Reference 9) heat transfer correlation is used in fuel design to determine the cladding-to-coolant heat transfer coefficients for nucleate boiling.

4.4.2.8. Thermal Effects of Anticipated Operational Occurrences

The evaluation of the core's capability to withstand the thermal effects resulting from anticipated operational occurrences (AOOs) is covered in Chapter 15 (Accident Analysis) and the cycle-specific reload analysis.

4.4.2.9. Uncertainties in Estimates

Uncertainties in thermal-hydraulic parameters are considered in the statistical analysis which is performed to establish the fuel cladding integrity safety limit documented in Subsection 4.4.4.1.1. The uncertainties considered and their input values for the analysis are shown in Table 4.4-3 and Reference 38.

4.4.2.10. Flux Tilt Considerations

For flux tilt considerations, refer to Subsection 4.3.2.2.

4.4.3. Description of the Thermal and Hydraulic Design of the Reactor Coolant System

4.4.3.1. Plant Configuration Data

4.4.3.1.1. Reactor Coolant System Configuration

The reactor coolant system is described in Section 5.1 and shown in isometric perspective in Figure 5.5-1. The piping sizes, fittings, and valves are listed in Table 5.5-1.

4.4.3.1.2. Reactor Coolant System Thermal-Hydraulic Data

The steady-state distribution of temperature, pressure, and flow rate for each flow path in the reactor coolant system is shown in Figure 5.1-1a and 5.1-1b.

4.4.3.1.3. Reactor Coolant System Geometric Data

Volumes of regions and components within the reactor vessel are shown in Figure 5.1-2.

Table 4.4-4 provides the flow path length, height, liquid level, minimum elevations, and minimum flow areas for each major flow path volume within the reactor vessel and for the recirculation loops of the reactor coolant systems.

Table 4.4-5 provides the lengths and sizes of all safety injection lines to the reactor coolant system.

4.4.3.2. Operating Restrictions on Pumps

Expected recirculation pump performance curves are shown in Figures 4.4-1 and 4.4-2. These curves are valid for all conditions with a normal operating range varying from approximately 20 percent to 115 percent of rated pump flow.

The pump characteristics, including considerations of net positive suction head (NPSH) requirements, are the same for the conditions of a two-pump and one-pump operation as described in Subsection 5.5.1. Subsection 4.4.3.3 gives the operating limits imposed on the recirculation pumps by cavitation, pump loads, bearing design flow starvation, and pump speed.

4.4.3.3. Power-Flow Operating Map

4.4.3.3.1. Limits for Normal Operation

A BWR must operate with certain restrictions because of pump NPSH, overall plant control characteristics, and core thermal power limits. A typical power-flow map for the power range of operation is shown in Figure 4.4-3. The nuclear system equipment, nuclear instrumentation, and the reactor protection system (RPS), in conjunction with operating procedures, maintain operations within the area of this map for normal operating conditions. The boundaries on this map are as follows:

a. Natural circulation line, A: The power-versus-flow operating state of the reactor moves along this line for the normal control rod withdrawal sequence in the absence of recirculation pump operation.

b. Recirculation pump minimum speed line, B: The minimum speed of the recirculation pumps is 20 percent as established by the mechanical stops.

Startup operations of the plant are normally carried out with the recirculation pumps operating at approximately 30 percent speed. The power-versus-flow operating state for the reactor follows the 30 percent speed line for the normal control rod withdrawal sequence.

c. APRM rod block line and APRM scram lines: The APRM rod block line represents a power level above which rod blocks will be encountered if the control rods are manipulated. This line is defined by the equation: Power = 0.62w + 57.4 percent, with a maximum of 110 percent, where w is the loop recirculation flow as a percentage of the loop recirculation flow which produces a rated core flow of 100 million lb/hr at 100 percent of rated thermal power. The APRM scram line represents a power level above which a reactor scram will occur. This line is defined by the equation: Power = 0.62w + 63.1 percent, with a maximum of 115.5 percent. The APRM rod block line is intentionally kept below the APRM scram line to prevent rod withdrawal before it causes a reactor scram.

d. Cavitation protection line: This line (minimum power line) results from the recirculation pump and jet pump NPSH requirements. The recirculation pumps are automatically switched to 30 percent speed when the feedwater flow drops below a preset value.

e. Maximum extended load line limit (MELLL) and increased core flow (ICF) lines: The MELLL line is above the 100 percent rod line and represents a region hereafter referred to as the MELLL region (References 9a, 9b, and 9c). The MELLL region allows rated power operation down to 83 percent of rated core flow. Below 83 percent of rated core flow, the boundary of the analyzed operating region is defined by an analytical approximation of the rod line which passes through the rated power and 83 percent core flow point.

   The ICF region allows rated power operation with core flows up to 105 percent of rated. Below 100% power, 105% core flow is held constant at 105% until power is 3430 MWth. Then the ICF boundary is expanded to allow for constant pump speed operation corresponding to 105 percent core flow at 3430 MWth. This expands the allowable operating map to 114 percent rated core flow at 36.0 percent rated power at which the expected recirculation pump cavitation region is encountered.

4.4.3.3.2. Performance Characteristics

Other performance characteristics shown on the power/flow operating map are

a. Recirculation pump constant speed line, C or D: These lines show the change in flow associated with power changes while maintaining constant recirculation pump speed

b. Constant rod lines: These lines show the change in power associated with flow changes while maintaining constant control rod position (for example, 50 percent rod density pattern line).

4.4.3.3.3. Regions of the Power/Flow Map

For normal operating conditions, the nuclear system equipment, nuclear instrumentation, and the RPS, in conjunction with operating procedures, maintain operation outside the exclusion areas of the power/flow map. The main regions of the power/flow map are discussed below to clarify operational capabilities.

a. Region I: This is the transition region between natural circulation operation and 20 percent pump speed operation. Steady-state conditions cannot exist in this area because the recirculation pumps cannot be operated below 20 percent speed. Normal startup is along the 30 percent pump speed line near this region

b. Region II: This region (including the increased core flow or ICF region) represents the normal operating zone of the power/flow map where power changes can be made, either by control rod movement or by core flow changes, achieved by changing recirculation pump drive speed. (The Technical Specifications contain limitations on operating in certain areas of Region II)

c. Region III: This is the low power area of the map where cavitation can be expected in the recirculation pumps and in the jet pumps. Operation within this region is precluded by system interlocks that set the recircula-tion pumps to 30 percent speed whenever feedwater flow is less than a preset value (typically 20 percent of rated flow).

4.4.3.4. Temperature-Power Operating Map (PWR)

Not applicable.

4.4.3.5. Load-Following Characteristics

The following simple description of BWR operation with recirculation flow control summarizes the principal modes of normal power range operation. Assuming the plant to be initially hot with the reactor critical, full power operation can be approached following the sequence shown as Points 1 to 6 in Figure 4.4-3. The first part of the sequence (1 to 3) is achieved with control rod withdrawal and manual, individual recirculation pump control. Individual pump startup procedures are provided that achieve 30 percent of full pump speed in each loop. Power, steam flow, and feedwater flow are increased as control rods are manually withdrawn until the feedwater flow has reached approximately 20 percent. An interlock prevents low-power/high-recirculation flow combinations that create recirculation pump and jet pump cavitation problems.

Reactor power increases as the operating state moves from Point 2 to Point 3 due to the inherent flow control characteristics of the BWR. Once the feedwater interlock is cleared, the operator can manually increase recirculation flow in each loop until the operating state reaches Point 3, the lower limit of the flow control range. At Point 3, the operator can switch to simultaneous recirculation pump control. Thermal output can then be increased by either control rod withdrawal or recirculation flow increase. For example, the operator can increase power in the ways indicated by Points 3a or 5c. With a slight rod withdrawal and an increase of recirculation flow to 90 percent rated flow, Point 3a can be achieved. If, however, it is desired to maintain the lowest recirculation flow, power can be increased by withdrawing control rods until Point 5c is reached. The recirculation system individual loop controllers are limited, and these limits established the operating state (refer to Section 7.7). The operating map is shown in Figure 4.4-3 with the designated flow control range expected.

The curve labeled "MELLL line" represents a typical steady-state power flow characteristic for a fixed rod pattern. It is slightly affected by xenon, core leakage flow assumptions, and reactor vessel pressure variations. However, for this example, these effects have been neglected.

Normal power range operation is along or below the MELLL and ICF line. If load-following response is desired in either direction, plant operation near 90 percent power provides most capability. If maximum load-pickup capability is desired, the nuclear system can be operated near Point 5c, with fast load response available all the way up to Point 6a, rated power.

The large negative operating reactivity and power coefficients that are inherent in the BWR provide important advantages as follows:

a. Good load following with well-damped behavior and little undershoot or overshoot in the heat transfer response

b. Load following with recirculation flow control

c. Strong damping of spatial power disturbances.

Design of the single-cycle BWR plant includes the ability to follow load demand over a reasonable range. This load-following capability is accomplished, under operator control, by variation of reactor recirculation flow. The reactor power level can be controlled by flow over approximately 35 percent power when on the 100% rod line.

To increase reactor power, it is necessary to increase the recirculation flow rate, which sweeps some of the voids from the moderator, causing an increase in core reactivity. As the reactor power increases, more steam is formed and the reactor stabilizes at a new power level with the transient excess reactivity balanced by the new void formation. No control rods are moved to accomplish this power level change. Conversely, when a power reduction is required, it is necessary only to reduce the recirculation flow rate. When this is done, more voids in the moderator automatically decrease the reactor power level to be commensurate with the new recirculation flow rate. Again, no control rods are moved to accomplish the power reduction.

Varying the recirculation flow rate (flow control) is more advantageous, relative to load following, than using control rod positioning. Flow variations perturb the reactor uniformly in the horizontal planes and ensure a flatter power distribution and reduced transient allowances. As flow is varied, the power and void distributions remain approximately constant at the steady-state end points for a wide range of flow variations. After adjusting the power distribution by positioning the control rods at a reduced power and flow, the operator can then bring the reactor to rated conditions by increasing flow, with the assurance that the power distribution will remain approximately constant. Section 7.7 describes how recirculation flow is varied.

4.4.3.6. Thermal and Hydraulic Characteristics Summary Table

The thermal-hydraulic characteristics are provided in Table 4.4-1 for the core and tables of Section 5.5 for other portions of the reactor coolant system.

4.4.4. Evaluation

The thermal-hydraulic design of the reactor core and reactor coolant system is based upon an objective of no fuel damage during normal operation or during anticipated operational occurrences. This design objective is demonstrated by analysis as described in the following sections.

4.4.4.1. Critical Power

The objective for normal operation and AOOs is to maintain nucleate boiling and thus avoid a transition to film boiling. Operating limits are specified to maintain adequate margin to the onset of the boiling transition. The figure of merit utilized for plant operation is the critical power ratio. This is defined as the ratio of the critical power (bundle power at which some point within the assembly experiences onset of boiling transition) to the operating bundle power. The critical power is determined at the same mass flux, inlet temperature, and pressure which exists at the specified reactor condition. Thermal margin is stated in terms of the minimum value of the critical power ratio, MCPR, which corresponds to the most limiting fuel assembly in the core. To ensure that adequate margin is maintained, a design requirement based on a statistical analysis was selected as follows:

> Moderate frequency AOOs caused by a single operator error or equipment malfunction shall be limited such that, considering uncertainties in manufacturing and monitoring the core operating state, more than 99.9 percent of the fuel rods would be expected to avoid boiling transition (Reference 10).

Both the transient (safety) and normal operating thermal limits in terms of MCPR are derived from this basis. A discussion of these limits follows.

4.4.4.1.1. Fuel Cladding Integrity Safety Limit

The generation of the Minimum Critical Power Ratio (MCPR) limit requires a statistical analysis of the core near the limiting MCPR condition. The statistical analysis is used to determine the MCPR corresponding to the transient design requirement given in Reference 1. The MCPR fuel cladding integrity safety limit applies not only for core wide AOOs, but is also applied to the localized rod withdrawal error AOO.

4.4.4.1.1.1. Statistical Model

The statistical analysis utilizes a model of the BWR core which simulates the plant process variables and the 3D-Monicore PANACEA core modeling function. This code produces a critical power ratio (CPR) map of the core based on inputs of power distribution, flow, and heat balance information. Details of the procedure are documented in Appendix IV of Reference 10 and Section 4 of Reference 38. Random Monte Carlo selections of all operating parameters based on the uncertainty ranges of manufacturing tolerances, uncertainties in measurement of core operating parameters, calculational uncertainties, and statistical uncertainty associated with the critical power correlations (References 11 through 13) are imposed upon the analytical representation of the core and the resulting bundle critical power ratios are calculated. Applications of critical power correlation uncertainties to critical power ratio calculations are presented in References 10, 14, 15, 38, 39 and 40.

The minimum allowable critical power ratio is set to correspond to the criterion that 99.9 percent of the rods are expected to avoid boiling transition by interpolation among the means of the distributions formed by all the trials.

4.4.4.1.1.2. Bounding BWR Statistical Analysis

Statistical analyses are performed for each operating cycle that provides the fuel cladding integrity safety limit MCPR. The analyses are performed for the specific core loading and the specific bundle design to be used in the given cycle. Core radial power distributions are selected to reasonably bound the number of bundles at or near thermal limits. The assumed local fuel pin power distribution is based on the specific bundle design. The analyses are performed for multiple exposure points throughout the cycle. Typically the most limiting value is applied over the entire cycle, but exposure-dependent values are technically correct and may be applied if necessary.

Uncertainties used in the analyses are listed in Table 4.4-3, including the uncertainty associated with the appropriate critical power correlation. The critical power correlation uncertainty used in the Safety Limit MCPR determination is that uncertainty associated with the operating regions that can be obtained during normal operation or during Anticipated Operational Occurrences (AOO).

The results of the analyses show that at least 99.9 percent of the fuel rods in the core are expected to avoid boiling transition if the MCPR is equal to or greater than the applicable value listed in the Core Operating Limits Report. Therefore, based on the results of the statistical analysis, the fuel cladding integrity safety limit is an MCPR equal to the values presented in the Core Operating Limits Report.

4.4.4.1.2. MCPR Operating Limit Calculational Procedure

A plant-unique MCPR operating limit is established to provide adequate assurance that the cycle specific fuel cladding integrity safety limit for that plant is not exceeded for any moderate frequency AOO. This operating requirement is obtained by addition of the maximum ΔCPR value for the most limiting AOO (including any imposed adjustment factors) from conditions postulated to occur at the plant to the cycle specific fuel cladding integrity safety limit.

4.4.4.1.2.1. Calculational Procedure for AOO Pressurization Events

Core-wide rapid pressurization events (turbine trip w/o bypass, load rejection w/o bypass, feedwater controller failure, and pressure regulator failure-closed with backup pressure regulator out of service) are analyzed using TRACG which has been approved for application to AOO transients. TRACG uses a multi-dimensional two-fluid model and a three-dimensional kinetics model consistent with the GEMINI method. The application of

TRACG is described in References 45 and 46. The set of methods used (GENESIS, GEMINI or TRACG) will be identified in the supplemental reload licensing report; however, application of a different approved method set may be used subsequently for the same cycle.

4.4.4.1.2.2. Calculational Procedure for AOO Slow Events

The slower core-wide anticipated operational occurrence, loss of feedwater heating, is analyzed using either the steady-state 3-D BWR Simulator Code (Reference 18 for GENESIS methods or Reference 21 for GEMINI methods), or the ODYN transient model as described in Reference 1. Inadvertent HPCI startup is not analyzed when its enthalpy is bounded by that of the loss of feedwater heating event (Reference 37). When necessary, it is analyzed using the ODYN transient model.

4.4.4.1.2.3. Rod Withdrawal Error Calculational Procedure

The reactor core behavior during the rod withdrawal error transient is calculated by doing a series of steady-state three-dimensional coupled nuclear-thermal-hydraulic calculations using the 3-D BWR Simulator (Reference 18 for GENESIS methods or Reference 21 for GEMINI methods).

4.4.4.1.2.4. Event Descriptions

Descriptions of the limiting AOO events are given in Chapter 15 for the cycle-specific reload analysis. The AOO descriptions given are used as a basis for the typical analyses performed. Some plant-unique analyses will differ in certain aspects from the typical calculational procedure. These differences arise because of utility-selected margin improvement options.

4.4.4.1.2.5. MCPR Operating Limit Calculation

The operating limit MCPR for rapid AOOs is calculated by using the GESAM computer program (Reference 45). Cycle-dependent plant initial conditions for the MCPR operating limit analysis and the resulting parameters are given in the cycle-specific supplemental reload licensing report.

4.4.4.1.2.6. MCPR Uncertainty Considerations

The deterministic ΔCPR value which results from ODYN/TASC or TRACG evaluations (for all rapid pressurization AOOs) must be adjusted such that a 95/95 ΔCPR/ICPR licensing basis is calculated (i.e., 95 percent probability with 95 percent confidence that the safety limit will not be violated). The NRC Safety Evaluation Report which describes these requirements and procedures is given in Reference 29.

Fermi 2 has the choice of operating under either Option A or Option B.

Option A Operating under Option A with the GENESIS set of methods, an NRC-imposed factor of 1.044 is applied to the MCPR for each event to account for code uncertainties. With the GEMINI set of methods, the MCPR for each event is determined using statistically evaluated scram times. Plants that do not demonstrate compliance with the statistically evaluated scram times must operate using a higher limit that does not take credit for these scram times. The higher limit will also be referred to as Option A. Details are provided in Reference 29.

Option B Under Option B, the ΔCPR/ICPR ratio for the pressurization events is evaluated on either a plant-unique or generic statistical basis per the methodology and procedures of References 29 and 30 for GENESIS, and Reference 31 for GEMINI. The generic basis utilizes adjustment factors which are dependent on plant and event type. Reference 29 summarizes these factors for the GENESIS set of methods. For the GEMINI set of methods, the adjustment factors and their application are described in Reference 31. Since both the GENESIS and GEMINI adjustment factors take credit for conservatism in the scram speed assumed for the transient analyses, each plant operating under Option B must demonstrate that its actual scram speeds are within the distribution assumed in the derivation of the adjustment factors. This conformance procedure is described in Reference 29.

The cycle-specific adjusted MCPR values for all rapid pressurization events are given in the cycle-specific supplemental reload licensing report.

If the ΔCPR is calculated by TRACG (References 45 and 46), the ΔCPR and the OLMCPR are calculated such that less than 0.1% of the fuel rods will be subject to boiling transition during the transient.

4.4.4.1.2.7. Low Flow and Low Power Effects on MCPR

The operating limit MCPR must be increased for low flow because, in the BWR, power increases as core flow increases, which results in a corresponding lower MCPR. If the MCPR at a reduced flow condition were at the 100 percent power and flow MCPR operating limit, a sufficiently large inadvertent flow increase could cause the MCPR to decrease below the fuel cladding integrity safety limit MCPR.

The plant is licensed for the average power range monitor (APRM), rod block monitor (RBM), Technical Specification improvement program (ARTS), and has both power and flow dependent limits imposed on the operating limit MCPR (OLMCPR) (References 9a and 9b). The flow dependent OLMCPR, $MCPR_f$, is defined as a function of the core flow rate. The plant specific $MCPR_f$ is shown in the Core Operating Limits Report (COLR). The power dependent OLMCPR, $MCPR_p$, is determined from the product of the OLMCPR at 100 percent power [OLMCPR (100)] with a power dependent term, k_p. For power between 25 percent rated and 29.5 percent rated (bypass for turbine stop valve and control valve fast closure scram signal) there are two values for $MCPR_p$, one for core flows > 50 percent rated and the other for core flows ≤ 50 percent rated, as shown in COLR. Once the power exceeds 29.5 percent, the $MCPR_p$ is determined from a single curve of k_p which must be multiplied by [OLMCPR (100)] to produce the reduced power OLMCPR, $MCPR_p$. The OLMCPR to be used is the most limiting value of either $MCPR_p$ or $MCPR_f$.

4.4.4.1.2.8. End-of-Cycle Coastdown Considerations

AOO analyses are performed at the full power, end-of-cycle (EOC), all-rods-out condition. Once an individual plant reaches this condition, it may shutdown for refueling or it may be placed in a coastdown mode of operation. In this type of operation the control rods are held in the all-rods-out position and the plant is allowed to coastdown to a lower percent of rated power while maintaining rated increased core flow. The power profile during this period is assumed to be a linear function with respect to exposure. It is expected that the actual profile will be a slow, exponential curve. An analysis to the linear approximation, however, will be conservative, since it overpredicts the power level for any given exposure.

In Reference 32, evaluations were made at 90 percent, 80 percent, and 70 percent power level points on the linear curve. The results show that the pressure and MCPR from the limiting pressurization AOO exhibit a larger margin for each of these points than the EOC full power, full flow case. MLHGR limits for the full power, rated increased core flow case are conservative for the coastdown period, since the power will be decreasing and rated increased core flow will be maintained. Therefore, it can be concluded that the coastdown operation beyond full power operation is conservatively bounded by the analysis at the EOC conditions. In Reference 33, this conclusion is confirmed for coastdown operation down to 40 percent power and is shown to hold for analyses performed with ODYN. In Reference 1, the conclusion of coastdown to 40 percent power also holds for analyses performed with TRACG.

4.4.4.2. Core Hydraulics

Core hydraulics models and correlations are discussed in Subsection 4.4.2.

4.4.4.3. Influence of Power Distributions

The influence of power distributions on the thermal-hydraulic design is discussed in Reference 10.

4.4.4.4. Core Thermal Response

The thermal response of the core for accidents and expected AOO conditions is given in Chapter 15 and cycle specific reload analysis.

4.4.4.5. Analytical Methods

The analytical methods, thermodynamic data, and hydrodynamic data used in determining the thermal and hydraulic characteristics of the core are documented in Subsection 4.4.4.1.2.

4.4.4.6. Thermal-Hydraulic Stability Analysis

4.4.4.6.1. Introduction

There are many definitions of stability, but for feedback processes and control systems it can be defined as follows: A system is stable if, following a disturbance, the transient settles to a steady, noncyclic state.

A system may also be acceptably safe even if it oscillates, provided that any limit cycle of the oscillations is less than a prescribed magnitude. Instability, then, is either a continual departure from a final steady-state value or a greater-than-prescribed limit cycle about the final steady-state value.

The mechanism for instability can be explained in terms of frequency response. Consider a sinusoidal input to a feedback control system which, for the moment, has the feedback disconnected. If there were no time lags or delays between input and output, the output would be in phase with the input. Connecting the output to subtract from the input (negative feedback or 180° out-of-phase connection) would result in stable closed-loop operation. However, natural laws can cause phase shift between output and input, and should the phase shift reach 180° the feedback signal would reinforce the input signal rather than subtract from it. If the feedback signal were equal to or larger than the input signal (loop gain equal to one or greater), the input signal could be disconnected and the system would continue to oscillate. If the feedback signal were less than the input signal (loop gains less than one), the oscillations would die out.

It is possible for an unstable process to be stabilized by adding a control system. In general, however, it is preferable that a process with inherent feedback be designed to be stable by itself before it is combined with other processes and control systems. The design of the BWR is based on the premise that individual system components are stable under expected operating conditions.

4.4.4.6.2. <u>Description</u>

Three types of stability considered in the design of BWRs are

a. Reactor core (reactivity) stability

b. Channel hydrodynamic stability

c. Total system stability.

Reactivity feedback instability of the reactor core could drive the reactor into power oscillations. Hydrodynamic channel instability could impede heat transfer to the moderator and drive the reactor into power oscillations. The total system stability considers control system dynamics combined with basic process dynamics. A stable system is analytically demonstrated if no inherent limit cycle or divergent oscillation develops within the system as a result of calculated step disturbances of any critical variable, such as steam flow, pressure, neutron flux, and recirculation flow.

The criteria to be considered are stated in terms of two compatible parameters. The first parameter is the decay ratio x_2/x_o, designated as the ratio of the magnitude of the second overshoot to the first overshoot resulting from a step perturbation. A plot of the decay ratio is a graphic representation of the physical responsiveness of the system which is readily evaluated in a time-domain analysis. The second parameter is the damping coefficient ζ_n, the definition of which corresponds to the pole pair closest to the j_ω axis in the s-plane for the system closed-loop transfer function. This parameter also applies to the frequency domain interpretation. The damping coefficient is related to the decay ratio as shown in Figure 4.4-4.

4.4.4.6.3. Stability Criteria

General Design Criterion 12 of 10 CFR 50, Appendix A, states that the reactor core and associated coolant, control, and protection systems shall be designed to assure power oscillations which can result in conditions exceeding specified acceptable fuel design limits are not possible or can be reliably and readily detected and suppressed.

The assurance that the total plant is stable, is demonstrated analytically when the decay ratio, x_2/x_o, is less than 1.0, or equivalently, when the damping coefficient, ζ_n, is greater than zero for each type of stability discussed. It is necessary to differentiate between stability related limit cycles and small, acceptable cyclic behavior that is always present, even in the most stable reactors. Acceptable cyclic behavior is caused by physical nonlinearities (deadband and striction) in real control systems and is not representative of inherent hydrodynamic or reactivity instabilities in the reactor. The ultimate performance limit criteria for the three types of dynamic performance are summarized below in terms of decay ratio and damping coefficient

a. Channel hydrodynamic stability: x_2/x_o less than 1, ζ_n greater than 0

b. Reactor core (reactivity) stability: x_2/x_o less than 1, ζ_n greater than 0

c. Total system stability: x_2/x_o less than 1, ζ_n greater than 0

To assure stable operation, these criteria should be satisfied for all attainable conditions of the reactor that may be encountered in the course of plant operation. For stability purposes, the most severe condition to which these criteria will be applied corresponds to the highest attainable rod-line intersection with natural circulation flow.

Under certain operating conditions, power oscillations induced by thermal-hydraulic instability have been observed in other BWR facilities. If power and flow oscillations become large enough, the MCPR Safety Limit could be challenged. Fermi 2 has implemented the BWROG Long Term Stability Solution Option III. An Oscillation Power Range Monitor (OPRM) Upscale Function is incorporated into each APRM channel to reliably and readily detect power oscillation which could result from thermal-hydraulic instability in the operating ranges where such instability has been determined to be credible. The OPRM Upscale Function generates a trip signal to RPS upon detection of power oscillations, which causes an automatic scram to suppress the oscillation while it is still small. This automatic detection and suppression methodology provides protection against violation of the MCPR Safety Limit for power oscillations. The OPRM Upscale Function is described in References 34 – 37.

4.4.4.6.4. Conclusion

Stability-based MCPR Operating Limits are calculated for each operating cycle. These calculated values validate the selected OPRM setpoints for a given core configuration. Thus, the core design, combined with hardware, software, and selected system setpoints for detection and suppression of thermal-hydraulic power oscillations conform to the requirements of General Design Criterion 12 of 10 CFR 20, Appendix A.

4.4.5. Testing and Verification

The testing and verification techniques used to ensure that the planned thermal and hydraulic design characteristics of the core have been provided, and will remain within required limits throughout core lifetime, are discussed in Chapter 14. A summary follows.

a. Preoperational testing: Tests are performed during the preoperational test program to confirm that construction is complete and that all process and safety equipment is operational. Baseline data are taken to assist in the evaluation of subsequent tests. Heat balance instrumentation, jet pump flow, and core temperature instrumentation are calibrated, and set-points are verified

b. Initial startup: Core performance (for example, peaking factors and LHGR) is evaluated periodically when the reactor is operating at greater than 25 percent power to verify the core expected and actual performance margins and to ensure that the reactor is operating within allowable limits.

4.4.6. Instrumentation Requirements

4.4.6.1. Operating Parameters

The reactor vessel instrumentation monitors the key reactor vessel operating parameters during planned operations. This ensures sufficient control of the parameters. The following reactor vessel sensors are discussed in Subsections 7.6.1.2 and 7.6.1.13:

a. Reactor vessel temperature

b. Reactor vessel water level

c. Reactor vessel coolant flow rates and differential pressures

d. Reactor vessel internal pressure

e. Neutron monitoring system.

4.4.6.2. Loose Parts Monitoring System

System has been abandoned.

4.4 THERMAL-HYDRAULIC DESIGN

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TABLE 4.4-1 THERMAL AND HYDRAULIC DESIGN CHARACTERISTICS OF THE INITIAL REACTOR CORE

General Operating Conditions	(201-444)	(218-560)	Fermi 2 (251-764)
Reference design thermal output, MWt	1931	2436	3293
Power level for engineered safety features, MWt	2028	2558	3430
Steam flow rate, at 420°F final feedwater temperature, millions lb/hr	8.303	10.5	14.159
Core coolant flow rate, millions lb/hr	61.5	77.0	100
Feedwater flow rate, millions lb/hr	8.284	10.4	14.127
System pressure, nominal in steam dome, psia	1020	1020	1020
System pressure, nominal core design, psia	1,035	1035	1035
Coolant saturation temperature at core design pressure, °F	549	548.8	549
Average power density, kW/liter	49.2	49.2	48.7
Maximum linear heat generation rate, kW/ft	13.4	13.4	13.4
Average linear heat generation rate, kW/ft	5.4	5.4	5.3
Core total heat transfer area, ft^2	43,511	54,879	74,871
Maximum heat flux, Btu/hr-ft^2	361,600	361,600	361,600
Average heat flux, Btu/hr-ft^2	145,000	145,060	143,700

TABLE 4.4-1 THERMAL AND HYDRAULIC DESIGN CHARACTERISTICS OF THE INITIAL REACTOR CORE

General Operating Conditions	(201-444)	(218-560)	Fermi 2 (251-764)
Design operating minimum critical power ratio	1.24	1.22	1.24
Core inlet enthalpy at 420°F FFWT[a], Btu/lb	527.1	526.9	526.1
Core inlet temperature, at 420°F FFWT[a], °F	532	532	532
Core maximum exit voids within assemblies, percent	76.2	76.0	77.1
Core average void fraction, active coolant	0.412	0.422	0.418
Maximum fuel temperature,°F	3435	3435	3435
Active coolant flow area per assembly, in.^{2} (BOL)	15.824	15.824	15.824
Core average inlet velocity, ft/sec	6.72	6.65	6.34
Maximum inlet velocity, ft/sec	8.28	7.1	7.78
Total core pressure drop, psi	23.71	23.89	21.25
Core support plate pressure drop, psi	19.28	19.46	16.83
Average orifice pressure drop			
Central region, psi	5.93	8.0	5.12
Peripheral region, psi	15.93	16.52	13.95
Maximum channel pressure loading, psi	12.39	12.86	10.88

[a] Final feedwater temperature.

TABLE 4.4-2 TYPICAL RANGE OF TEST DATA

Measured Parameter	Test Conditions
Adiabatic tests	
Spacer single-phase loss coefficient	Re[a] = 0.5×10^5 to 3.5×10^5
Lower tie plate and orifice single-phase loss coefficient	T = 100 to 500°F
Upper tie plate single-phase friction factor	
Spacer two-phase loss coefficient	P = 800 to 1400 psia
Two-phase friction multiplier	G = 0.5×10^6 to 1.5×10^6 lb/hr-ft^2 X = 0 to 40 percent
Diabatic tests	
Heated bundle pressure drop	P = 800 to 1400 psia G = 0.5×10^6 to 1.5×10^6 lb/hr-ft^2

[a] Reynolds Number.

TABLE 4.4-3 UNCERTAINTIES USED IN STATISTICAL ANALYSIS

Quality	Comment
Feedwater Flow	This is the largest component of total reactor power uncertainty.
Feedwater Temperature	These are the other significant parameters in core power determination.
Reactor Pressure	
Core Inlet Temperature	Affected quality annular flow length and boiling length.
Core Total Flow	Flow is not measured directly, but is calculated from jet pump ΔP[a].
Channel Flow Area	This accounts for manufacturing and service induced variations in the free flow area within the channel.
Friction Factor Multiplier	Accounts for uncertainty in the correlation representing two-phase pressure losses.
Channel Friction Factor Multiplier	Represents variation in the pressure loss characteristics of individual channels. Pressure loss variations affect the core flow distribution, influencing the mass flux.
TIP Readings Random Uncertainty	[b]
R Factor	This is a function of the uncertainty in local fuel rod power.

[a] This uncertainty is higher for single recirculation pump.
[b] For single recirculation pump, this uncertainty is higher.

Note:
Values for the uncertainties used in SLMCPR calculations are found in NEDC-32601P-A (Reference 38)

TABLE 4.4-4 REACTOR COOLANT SYSTEM GEOMETRIC DATA

	Flow Path Length (in.)	Height and Liquid Level (in.)	Elevation of Bottom of Each Volume[a] (in.)	Minimum Flow Area (ft.^{2})
A. Lower plenum	216.5	216.5 216.5	-161.5	92.5
B. Core	163.0	163.0 163.0	55.0	152.0
C. Upper plenum and separators	185.0	185.0 185.0	217.5	45.0
D Dome (above normal water level)	299.5	299.5 0	402.5	352.0
E. Downcomer area	311.0	311.0 311.0	-30.0	118.0
F. Recirculation loops and jet pumps (one loop)	97.0 ft	492.0 492.0	-472.5	0.538

[a] Reference point is recirculation outlet nozzle centerline.

TABLE 4.4-5 LINE LENGTHS AND SIZES OF SAFETY INJECTION LINES[a]

RHR Pumps

Pump A:
20-in. diameter/40-ft length joins
24-in. diameter/170-ft length
24-in. diameter/170-ft length joins
24-in. diameter/30-ft length
24-in. diameter/30-ft length joins
12-in. diameter/30-ft length

Pump B:
Same as Pump A

Pump C: 20-in. diameter/60-ft length joins
24-in. diameter/170-ft length
24-in. diameter/170-ft length joins
24-in. diameter/30-ft length
24-in. diameter/30-ft length joins
12-in. diameter/30-ft length

Pump D:
Same as Pump C

HPCI Pumps Discharge

10-in. pipe diameter increases to 14-in. pipe diameter
Length: 2 ft, 10 in.
Other: 14-in. pipe diameter/170-ft length
12-in. pipe diameter/32-ft length

LPCI Pump Discharge

Pumps A and B:
28-in. pipe diameter/40-ft length
22-in. pipe diameter/30-ft length
12-in. pipe diameter/15-ft length

Core Spray

Pumps A and C:
12-in pipe diameter/132-ft length
14-in. pipe diameter/150-ft length

Pumps B and D:
12-in pipe diameter/127-ft length
14-in pipe diameter/182-ft length

[a] These piping dimensions are for information only. The piping dimensions are shown on the applicable Piping Isometrics. The associated pressure drops are determined in the applicable Hydraulic Calculations.

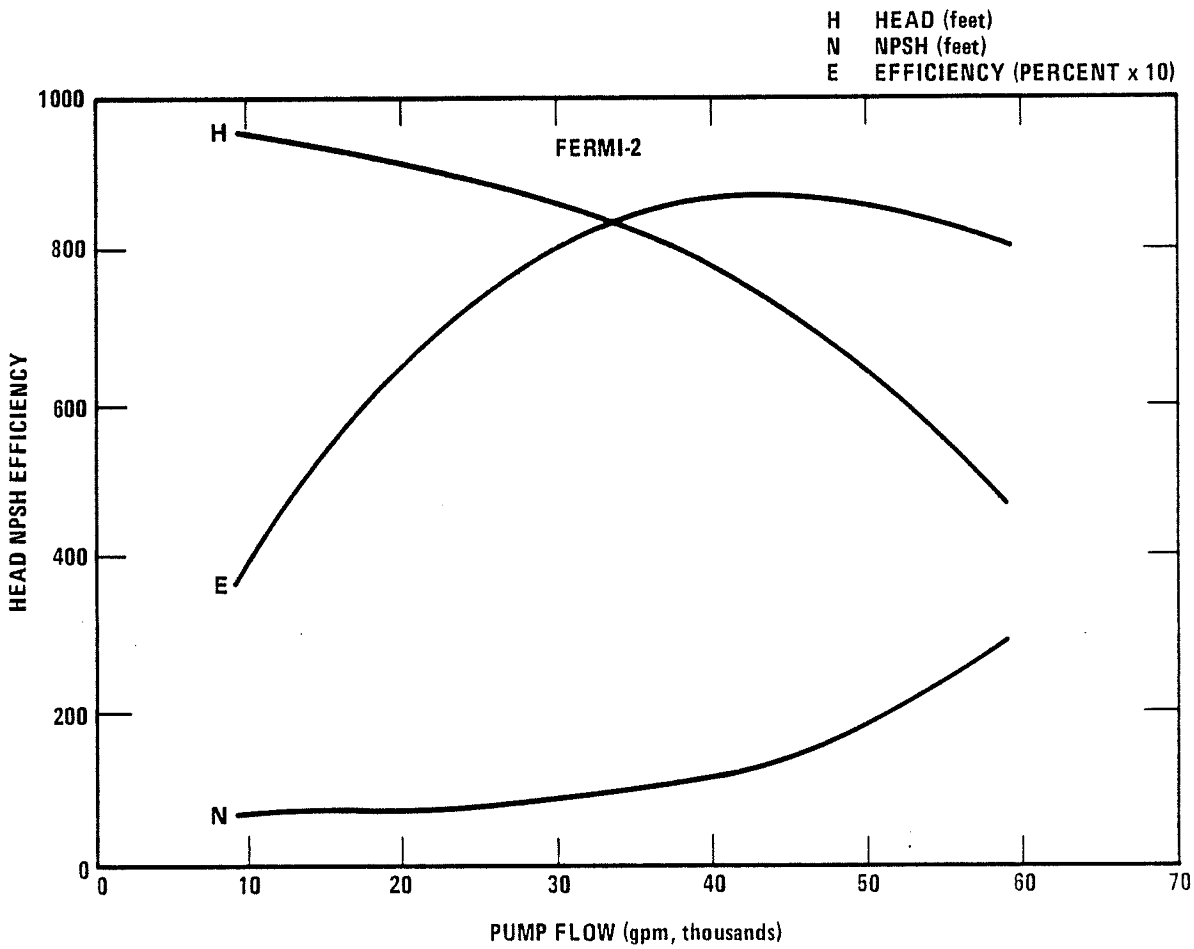

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FIGURE 4.4-1

VARIABLE SPEED PUMP PERFORMANCE (RECIRCULATION PUMP)

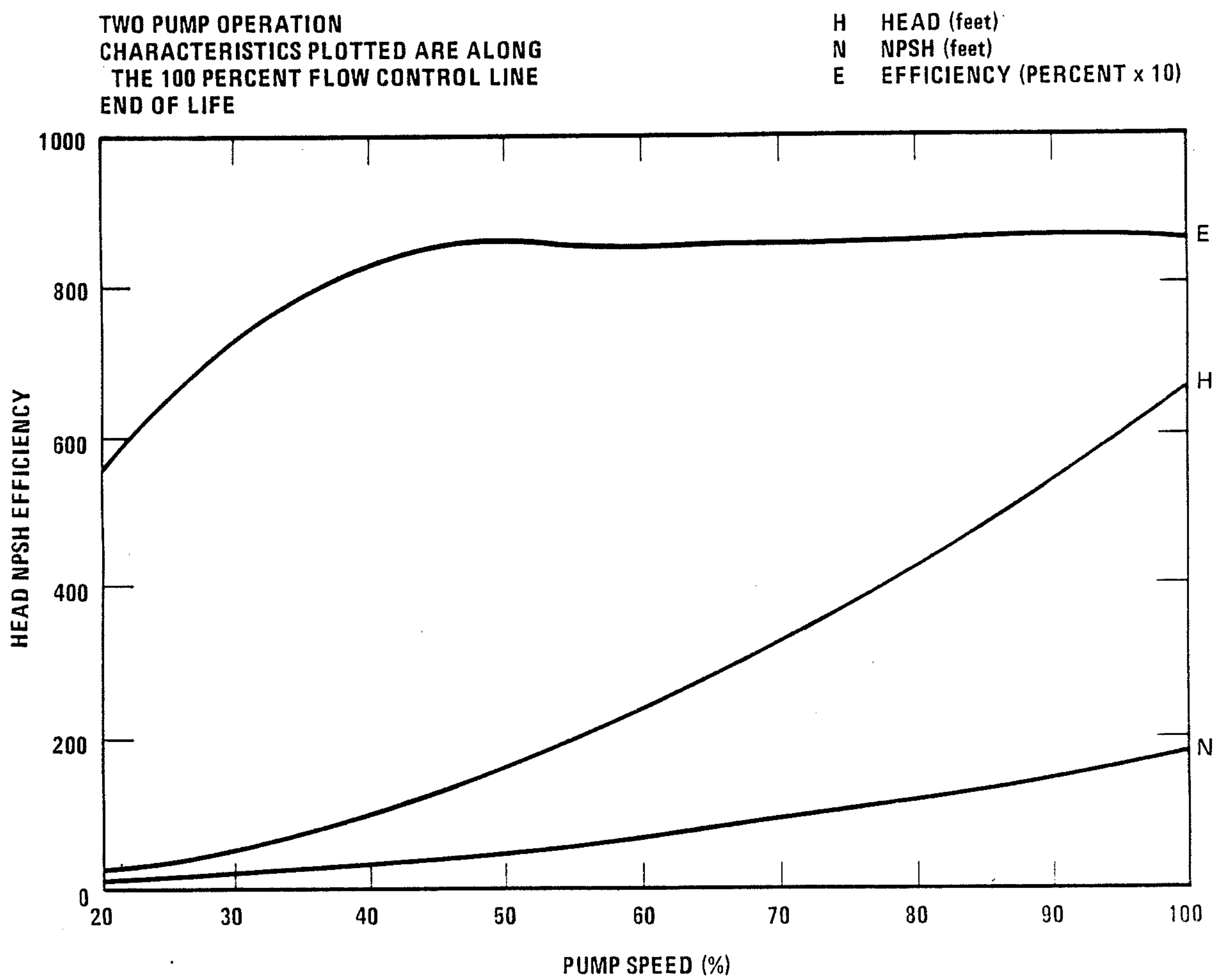

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FIGURE 4.4-2

EXPECTED PUMP PERFORMANCE (RECIRCULATION PUMP)

FERMI-2 POWER/FLOW MAP

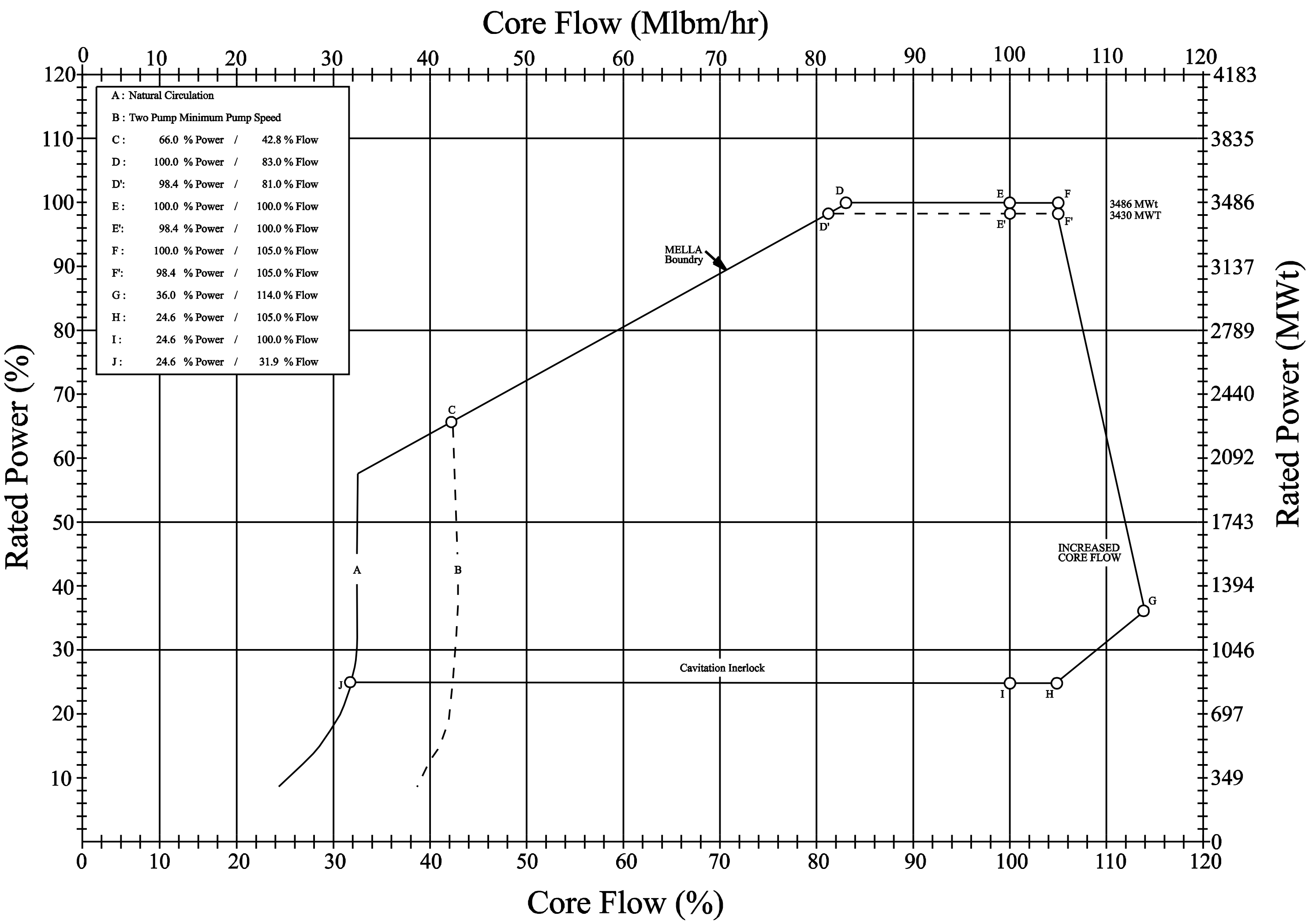

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FIGURE 4.4-3

TYPICAL POWER / FLOW OPERATING MAP

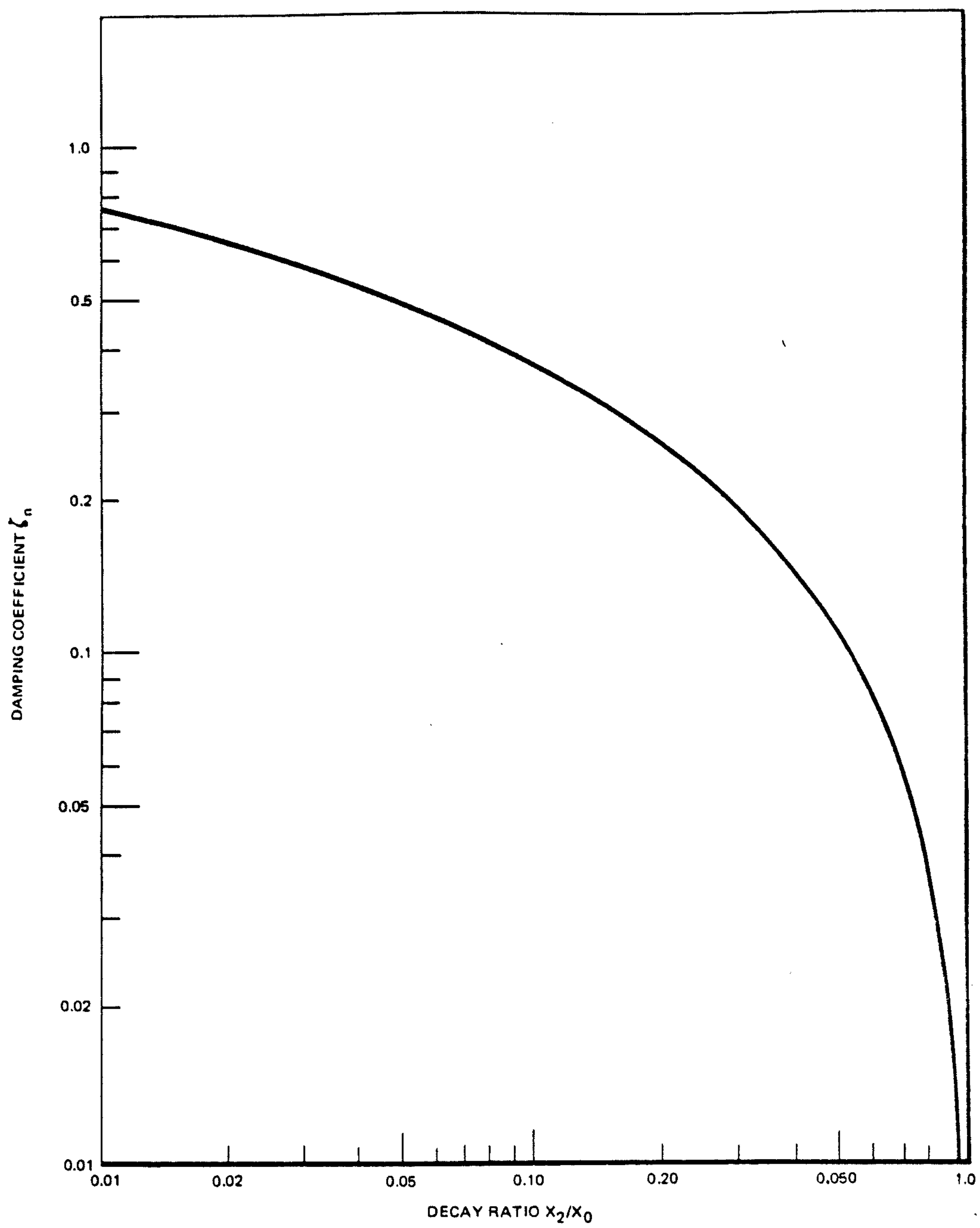

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FIGURE 4.4-4

DAMPING COEFFICIENT VERSUS DECAY RATIO (SECOND ORDER SYSTEMS)

4.5 REACTOR MECHANICAL DESIGN

4.5.1 Reactor Core Support Structures and Internals Mechanical Design

4.5.1.1 Design Bases

4.5.1.1.1 General Design Bases

4.5.1.1.1.1 Safety Design Bases

The reactor core support structures and internals meet the following safety design bases:

a. They are arranged to provide a floodable volume in which the core can be adequately cooled in the event of a breach in the nuclear system process barrier external to the reactor pressure vessel (RPV)

b. Deformation is limited to ensure that the control rods and core standby cooling systems can perform their safety functions

c. Mechanical design of applicable structures ensures that safety design bases items a. and b. are satisfied so that the safe shutdown of the plant and removal of decay heat are not impaired.

4.5.1.1.1.2 Power Generation Design Bases

The reactor core support structures and internals shall be designed in accordance with the following power generation design bases.

a. They provide the proper coolant distribution during all anticipated normal operating conditions to allow power operation of the core without fuel damage

b. They are arranged to facilitate refueling operations

c. They are designed to facilitate inspection.

4.5.1.1.2 Specific Design Characteristics

4.5.1.1.2.1 Design Loading Combinations

The design loading combinations of the RPV internals are covered in Subsection 4.5.1.3.1.1.

4.5.1.1.2.2 Stress, Deformation, and Fatigue Limits for Reactor Internals (Except Core Support Structures)

The stress, deformation, and fatigue criteria listed in Tables 4.5-1 through 4.5-4 are used or the criteria shall be based on the criteria established in applicable codes and standards for similar equipment, by manufacturers' standards, or by empirical methods based on field experience and testing. For the quantity SF_{min} (minimum safety factor) appearing in those tables, the following listed values shall be used.

Design Condition	SF_{min}
Normal	2.25
Upset	2.25
Emergency	1.5
Fault	1.125

4.5.1.1.2.3 Stress, Deformation, and Fatigue Limits for Core Support Structures

The stress, deformation, and fatigue criteria presented in Tables 4.5-5, 4.5-6, and 4.5-7 are used. These criteria are supplemented, where applicable, by the criteria for the reactor internals in the previous paragraph, but in no case shall the criteria presented in these tables be exceeded for core support structures.

4.5.1.1.2.4 Fuel Assembly Restraints

The fuel assembly structural design shall demonstrate sufficient dimensional stability and sufficient fuel rod support to maintain core geometry, thus avoiding fuel damage for both planned operation and abnormal operational transients.

4.5.1.1.2.5 Material Selection

The material used for fabricating most of the reactor core support and reactor internal structures is solution heat treated, unstabilized type 304 austenitic stainless steel conforming to ASTM specifications. Weld procedures and welders are qualified in accordance with the intent of Section IX of the ASME Boiler and Pressure Vessel (B&PV) Code. Further controls for stainless steel welding are covered in Subsection 5.2.5.

All the materials of construction exposed to the reactor coolant are resistant to stress corrosion in the BWR coolant. Conservative corrosion allowances are provided for all exposed surfaces of carbon or low-alloy steels.

Contaminants in the reactor coolant are controlled to very low limits by the reactor water-quality specifications. No detrimental effects occur on any of the materials from allowable contaminant levels in the high-purity reactor coolant. Radiolytic products in a BWR have no adverse effects on the construction materials.

4.5.1.1.2.6 Radiation Effects

Where feasible, the design is such that irradiation effects on the material properties are minimized. Where irradiation effects cannot be minimized, the design of the RPV internals either has provisions for replaceable components, or the design is shown to satisfy a set of stress and fatigue design limits that have been arrived at considering the effect of irradiation damage on the fracture toughness, ductility, and tensile properties of the materials.

4.5.1.1.2.7 Shock Loads

The components are designed so as to accommodate the loadings discussed in Section 3.9.

4.5.1.2 Description

The core support structures and RPV internals (excluding fuel, control rods, and in-core nuclear instrumentation) include the following components.

a. Core support structures

   1. Shroud
   2. Shroud support
   3. Core support and hold-down bolts
   4. Top guide (including wedges, bolts, and keepers)
   5. Fuel support pieces
   6. Control rod guide tubes.

b. Reactor pressure vessel internals

   1. Jet pump assemblies and instrumentation
   2. Shroud head and steam separator assembly (including shroud head bolts)
   3. Steam dryers
   4. Feedwater spargers
   5. Deleted
   6. Differential pressure and liquid control line
   7. In-core flux monitor guide tubes and stabilizers
   8. Surveillance sample holders
   9. Core spray lines and spargers.

The overall arrangement of the structures within the RPV is shown in Figure 4.1-l.

A general assembly drawing of the important reactor components is shown in Figure 4.5-1.

The floodable inner volume of the RPV can be seen in Figure 4.5-2. It is the volume inside the core shroud up to the level of the jet pump suction inlet.

The core support structure is used to form partitions within the RPV, to sustain pressure differentials across the partitions, to direct the flow of the coolant water, and to locate laterally and support the fuel assemblies, control rod guide tubes, and steam separators. Figure 4.5-2 shows the RPV internal flow paths.

4.5.1.2.1 Shroud

The core shroud is a stainless steel cylindrical assembly that provides a partition to separate the upward flow of coolant through the core from the downward recirculation flow. This partition separates the core region from the downcomer annulus, thus providing a floodable region following a recirculation line break.

The volume enclosed by the shroud is characterized by three regions. The upper shroud surrounds the core discharge plenum, which is bounded by the shroud head on top and the top guide below. The central portion of the shroud surrounds the active fuel and forms the longest section of the shroud. This section is bounded at the bottom by the core support. The lower shroud, surrounding part of the lower plenum, is welded to the RPV shroud support (Section 5.4).

4.5.1.2.2 Shroud Head and Steam Separator Assembly

The shroud head and steam separator assembly is bolted to the top of the upper shroud to form the top of the core discharge plenum. This plenum provides a mixing chamber for the steam/water mixture before it enters the steam separators. Individual stainless steel axial flow steam separators, shown in Figure 4.l-3, are attached to the top of standpipes that are welded into the shroud head. The steam separators have no moving parts. In each separator, the steam/water mixture rising through the standpipe passes vanes that impart a spin to establish a vortex separating the water from the steam. The separated water flows from the lower portion of the steam separator into the downcomer annulus.

4.5.1.2.3 Core Support Plate

The core support plate consists of a circular stainless steel plate with bored holes stiffened with a rim and beam structure. The plate provides lateral support and guidance for the control rod guide tubes, in-core flux monitor guide tubes, and peripheral fuel supports. The last item is also supported vertically by the core support plate.

The entire assembly is bolted to a support ledge between the central and lower portions of the core shroud. Alignment pins that engage slots and bear against the shroud are used to correctly position the assembly before it is secured.

The flow holes in the core support plate were plugged, and two holes for each fuel bundle were drilled in the lower tie plate. This modification reduces the channel box wear from flow-induced instrument tube vibrations caused by flow through the bypass holes in the lower core support plate. The above fixes are similar to that provided for Peach Bottom 2. A detailed discussion of the channel box wear problem and the solution is provided in Reference 1.

4.5.1.2.4 Top Guide

The top guide is formed by a series of stainless steel beams joined at right angles to form square openings, with the beams fastened to a peripheral rim. Each large opening provides lateral support and guidance for four fuel assemblies or, in the case of peripheral fuel, one or two fuel assemblies. Notches are provided in the bottom of the beam intersections to anchor the in-core flux monitors and startup neutron sources (all neutron sources were removed from the core during the first refueling outage).

4.5.1.2.5 Fuel Support

The fuel supports, shown in Figure 4.5-3, are of two basic types: namely, peripheral supports and four-lobed orificed fuel supports. The peripheral fuel support is located at the outer edge of the active core and is not adjacent to control rods. Each peripheral fuel support supports one fuel assembly and contains a single orifice assembly designed to ensure proper coolant flow to the fuel peripheral assembly. Each four-lobed orificed fuel support supports four fuel assemblies and is provided with orifice plates to ensure proper coolant flow distribution to each rod-controlled fuel assembly. The four-lobed orificed fuel supports rest in the top of the control rod guide tubes which are supported laterally by the core support. The control rods pass through slots in the center of the four-lobed orificed fuel support. A control rod and the four adjacent fuel assemblies represent a core cell (Subsection 4.1.2.1.4).

4.5.1.2.6 Control Rod Guide Tubes

The control rod guide tubes, located inside the RPV, extend from the top of the control rod drive (CRD) housing up through holes in the core support plate. Each tube is designed as the guide for a control rod and as the vertical support for a four-lobed orificed fuel support piece and the four fuel assemblies surrounding the control rod. The bottom of the guide tube is supported by the CRD housing (Section 5.4), which in turn transmits the weight of the guide tube, fuel support, and fuel assemblies to the RPV bottom head. A thermal sleeve is inserted into the CRD housing from below and is rotated to lock the control rod guide tube in place. A key is inserted into a locking slot in the bottom of the CRD housing to hold the thermal sleeve in position.

4.5.1.2.7 Jet Pump Assemblies

The jet pump assemblies are located in two semicircular groups in the downcomer annulus between the core shroud and the RPV wall. The design and performance of the jet pump are covered in detail in References 2 and 3. Each stainless steel jet pump consists of driving nozzles, suction inlet, throat or mixing section, and diffuser (Figure 4.5-4). The driving nozzle, suction inlet, and throat are joined together as a removable unit, and the diffuser is permanently installed. High-pressure water from the recirculation pumps (Subsection 5.5.l) is supplied to each pair of jet pumps through a riser pipe welded to the recirculation inlet nozzle thermal sleeve. A riser brace consists of cantilever beams extending from pads on the RPV wall.

The nozzle entry section is connected to the riser by a metal-to-metal, spherical-to-conical seal joint. Firm contact is maintained by a hold-down clamp. The throat section is supported laterally by a bracket attached to the riser. There is a slip-fit joint between the throat and diffuser. The diffuser is a gradual conical section changing to a straight cylindrical section at the lower end.

Evaluations performed by GE have shown that jet pump riser beam failures have resulted from intergranular stress corrosion cracking (IGSCC). Comparison of the failed BWR 3 beam with the BWR 4-6 beam structural design (i.e., the Fermi 2 design) has identified that the BWR 4-6 beam operates at a peak stress 14 percent lower than that of the BWR 3 design at the current joint preload. Because the time to crack initiation and subsequent failure increases with a decrease in stress, a reduction in preload was evaluated. The results of this evaluation, together with flow tests performed on prototypical components, have demonstrated the operational acceptability of a preload reduction to 25,000 lb. From relationships developed from field experience and laboratory stress corrosion tests, the minimum time to crack initiation for the Fermi 2 jet pump beam is estimated to increase by a factor of 4 with respect to the BWR 3 jet pump beam. In summary, Edison

a. Reduced the preload on all jet pump beams from 30,000 to 25,000 lb

b. Plans to inspect the jet pump beams during plant outages at a frequency to be determined from the surveillance of lead operating plants of this design.

By taking the above actions, the likelihood of beams developing cracks during the projected life of the plant is remote, and the likelihood of the cracks leading to beam failure before detection is extremely remote. However, if replacement beams that do not require periodic ultrasonic inspections are developed, Edison's position will be reevaluated.

In 1993, a jet pump hold-down beam failure occurred at a BWR-6. While previous failures occurred in the middle section of the beam, the recent failure occurred in the transition to the arms at the ends of the beam, with the cause of the failure identified as IGSCC. The most significant new findings resulting from this failure were that while the material and stress conditions were about the same at the beam middle and end sections, fracture mechanics evaluations indicated that crack growth to failure could occur in the beam ends in less than one 18-month operating cycle.

As a result of this failure, Edison elected to replace all jet pump hold down beams during the fourth refueling outage with replacement hold-down beam bolt assemblies. The new replacement beams received high temperature anneal (HTA) heat treatment during manufacturing and are less susceptible to IGSCC than the beams that were originally installed. Prior to and following installation in the RPV, the beam/bolt assemblies were inspected utilizing the latest inspection technology. The beams were preloaded to 25,000 lbs, consistent with the previous installation, and will be subjected to inservice inspection. The recommended inservice inspection interval provided in IE Bulletin 80-07 and NUREG/CR-3052 is once every 10 years. Subsequent UT and alternative inspections will be performed during future refueling outages based on industry experiences and the recommendations provided in NUREG/CR-3052.

If a crack is detected in a jet pump hold-down beam, that beam will be replaced by one of a suitable material and design before the return to power operation.

4.5.1.2.8 Steam Dryers

The steam dryers remove moisture from the wet steam leaving the steam separators. The extracted moisture flows down the dryer vanes to the collecting troughs, then flows through tubes into the downcomer annulus (Figure 4.1-4). A skirt extends from the bottom of the dryer vane housing to the steam separator standpipe, below the water level. This skirt forms a seal between the wet steam plenum and the dry steam flowing from the top of the dryers to the steam outlet nozzles.

4.5.1.2.9 Feedwater Spargers

The feedwater spargers are perforated stainless steel headers located in the mixing plenum above the downcomer annulus (Figure 4.1-1). A separate sparger is fitted to each feedwater nozzle and is shaped to conform to the curve of the RPV wall. Feedwater flow enters the center of the spargers and is discharged radially inward to mix the cooler feedwater with the downcomer flow from the steam separators before it contacts the RPV wall. The feedwater also serves to condense the steam in the region above the downcomer annulus and to subcool the water flowing to the jet pumps and recirculation pumps.

4.5.1.2.10 Core Spray Lines

The core spray lines are the means for directing flow to the core spray nozzles that distribute coolant so that peak fuel cladding temperatures of 2200°F are not exceeded during accident conditions.

Two core spray lines enter the RPV through the two core spray nozzles (Figure 4.1-1 and Section 6.3). The lines divide immediately inside the RPV. The two halves are routed to opposite sides of the RPV and are supported by clamps attached to the RPV wall. The lines are then routed downward into the downcomer annulus and pass through the upper shroud immediately below the flange. The flow divides again as it enters the center of the semicircular sparger, which is routed halfway around the inside of the upper shroud. The ends of the two spargers are supported by brackets designed to accommodate thermal expansion. The line routing and supports are designed to accommodate differential movement between the shroud and RPV. The other core spray line is identical except that it enters the opposite side of the RPV, and the spargers are at a slightly different elevation inside the shroud. The correct spray distribution pattern is provided by a combination of distribution nozzles pointed radially inward and downward from the spargers (Section 6.3).

4.5.1.2.11 Differential Pressure and Liquid Control Line

The differential pressure and liquid control line (Figure 4.l-l) serves a dual function within the RPV: to provide a path for the injection of the liquid control solution into the coolant stream (discussed in Subsection 4.5.2.4) and to sense the differential pressure across the core support plate (Section 5.4). This line enters the RPV at a point below the core shroud as two concentric pipes. In the lower plenum, the two pipes separate. The inner pipe terminates near the lower shroud with a perforated length below the core support plate. It is used to sense the pressure below the core support plate during normal operation and to inject liquid control solution if required. This location facilitates good mixing and dispersion. The inner pipe also reduces thermal shock to the RPV nozzle should the standby liquid control system (SLCS) be actuated. The outer pipe terminates immediately above the core support plate and senses the pressure in the region outside the fuel assemblies.

4.5.1.2.12 In-Core Flux Monitor Guide Tubes

The in-core flux monitor guide tubes provide a means of positioning fixed detectors in the core as well as providing a path for calibration monitors (traversing in-core probe or TIP system), and extend from the top of the in-core flux monitor housing (Section 5.4) in the lower plenum to the top of the core support plate. The power range detectors for the power range monitoring units and the dry tubes for the source range monitor and intermediate range monitor (SRM/IRM) detectors are inserted through the guide tubes. A latticework of clamps, tie bars, and spacers gives lateral support and rigidity to the guide tubes. The bolts and clamps are welded in place, after assembly, to prevent loosening during reactor operation.

4.5.1.2.13 Surveillance Sample Holders

The surveillance sample holders are welded baskets containing impact and tensile specimen capsules (Subsection 5.2.4.4). The baskets hang from the brackets that are attached to the inside wall of the RPV and extend to mid-height of the active core. The radial positions are chosen to expose the specimens to the same environment and maximum neutron fluxes experienced by the RPV itself while avoiding jet pump removal interference or damage.

4.5.1.2.14 Neutron Startup Source

The source assembly is comprised of two basic components: a source holder and a gamma source. The source holder is hollow, cylindrical, stainless steel sheathed, and spring loaded. It seals a beryllium tube from reactor water. The gamma source is a stainless-steel-sheathed assembly that houses neutron-irradiated antimony. In the neutron irradiation, some of the antimony is converted to ^{122}Sb, some to ^{124}Sb, and some remains unconverted. ^{122}Sb and ^{124}Sb emit gamma radiation.

Prior to startup, the gamma sources are inserted in the source holders. Neutrons are emitted from the beryllium as gamma radiation is absorbed. The gammas from the ^{124}Sb contribute almost all the generation of neutrons, as the half-life of ^{124}Sb is 60 days while the half-life of ^{122}Sb is 2.8 days. Most of the ^{122}Sb has decayed away during the postirradiation testing and shipment.

All sources assemblies were removed from the core during the first refueling outage.

4.5.1.3 Safety Evaluation

4.5.1.3.1 Evaluation Methods

To determine that the safety design bases are satisfied, responses of the RPV internals to loads imposed during normal, upset, emergency, and faulted conditions are examined. The effects on the ability to insert control rods, cool the core, and flood the inner volume of the RPV are determined.

4.5.1.3.1.1 Input for Safety Evaluation

The operating conditions that provide the basis for the design of the reactor internals to sustain normal, upset, emergency, and faulted conditions as well as combinations of design loadings that are accounted for in design of the core support structure are covered in Table 4.5-8.

In addition, each combination of operating loads is categorized with respect to either normal, upset, emergency, or faulted conditions as well as the associated design stress intensity or deformation limits.

The bases for the proposed design stress and deformation criteria are also specified in Chapter 3.

4.5.1.3.1.2 Events To Be Evaluated

Examination of the spectrum of conditions for which the safety design basis must be satisfied reveals three significant events.

a. Recirculation line break (LOCA) - The accident results in pressure differentials, within the RPV, that may exceed normal loads

b. Steam line break accident - This is a break in one main steam line between the RPV and the flow restrictor. The accident results in significant pressure differentials across some of the structures within the reactor

c. Earthquake - It subjects the core support structures and reactor internals to significant forces as a result of ground motion.

For other conditions existing during normal operation, abnormal operational transients, and accidents, the loads affecting the core support structures and reactor internals are less severe than these three postulated events.

4.5.1.3.2 Recirculation Line and Steam Line Break

4.5.1.3.2.1 Accident Definition

Both a recirculation line break (the largest liquid break) and an inside steam line break (the largest steam break) are considered in determining the design-basis accident (DBA) for the reactor internals. The recirculation line break is the same as the design-basis LOCA described in Section 6.3. A sudden, complete circumferential break is assumed to occur in one recirculation loop.

The analysis of the steam line break assumes a sudden, complete circumferential break of one main steam line between the RPV and the main steam line restrictor. This is not the same accident described in Section 15.6, which has greater potential radiological effects. A steam line break upstream of the flow restrictors produces a larger blowdown area and thus a faster depressurization rate than a break downstream of the restrictors. The larger blowdown area results in greater pressure differentials across the reactor assembly internal structures.

The steam line break accident produces higher pressure differentials across the reactor internal structures than does the recirculation line break. This results from the higher reactor depressurization rate associated with the steam line break. The depressurization rate is proportional to the mass flow rate and the excess of fluid escape enthalpy above saturated water enthalpy, h_f. Mass flow rate is inversely proportional to escape enthalpy, h_e, and therefore the depressurization rate is approximately proportional to $[1 - (h_f/h_e)]$. Consequently, depressurization rate decreases as $[1 - (h_f/h_e)]$ decreases; that is, the depressurization rate is less for mixture flow than for steam flow. Therefore, the steam line break is the DBA for internal pressure differentials.

4.5.1.3.2.2 Effects of Initial Reactor Power and Core Flow

For purposes of illustration, the maximum internal pressure loads can be considered to be composed of two parts: steady-state and transient pressure differentials. For a given plant, the core flow and power are the two major factors that influence the reactor internal pressure differentials. The core flow essentially affects only the steady-state part. For a fixed power, the greater the core flow, the larger the steady-state pressure differential. The core power affects both the steady-state and the transient parts. As the power is decreased there is less voiding in the core and consequently the steady-state core pressure differential is less. However, less voiding in the core also means that less steam is generated in the RPV and thus the depressurization rate and the transient part of the maximum pressure load are increased. Figure 4.4-3 is a power-flow map that defines the permissible operating conditions of the reactor (Subsection 4.4.3.3 discusses the boundaries on this map). From this range of operating conditions, it is necessary to determine the combination of core power and flow that results in the maximum internal pressure loads.

Consider the historical study where the power is 3430 MWt and the core flow is at 105 percent of rated conditions (the maximum point on the operating map). Since a decrease in power results in higher transient pressure differentials, a more severe initial condition might be the condition of 754.6 MWt, 116 percent flow. In going from 3430 MWt, 105 percent flow to 754.6 MWt, 116 percent flow condition, the steady-state pressure differential has a net decrease. There is an increase due to the slight increase in flow and a decrease due to the decrease in power (lower core pressure drop). The transient pressure differential increases due to the decrease in power. However, the maximum pressure load (steady-state plus transient) has a net increase for the low power condition. If the power is decreased below 754.6 MWt, the core flow must also be reduced. Analysis has shown that the decrease in flow and power reduces the steady-state part of the maximum pressure load more than the corresponding increase in the transient part. Hence, the maximum pressure loads (steady-state plus transient) are less if the core flow is reduced from its maximum value. Therefore, the maximum internal pressure loads occur following an inside steam line break from an initial condition in which the reactor is at the minimum power associated with the maximum core flow (754.6 MWt, 116 percent flow).

Table 4.5-9 lists the maximum pressure loads occurring across the reactor internals during the accident for two cases in the study. Case 1 is for an initial condition of (3694 MWt) and 105 percent core flow. Case 2 is for the maximum pressure loads that occur from the initial condition of (771 MWt), 116 percent flow. Comparison of Cases 1 and 2 illustrates the generalized statements made above concerning the relationship between the maximum internal pressure loads and core power and flow.

Realistically, if an inside steam line break were to occur, the maximum internal pressure loads would probably be closer to Case 1. This is because the plant will probably be operating at or near full power. Also, the Case 2 condition, although possible, is rather abnormal in that rated core flow is neither required nor desirable at such a reduced power condition.

4.5.1.3.2.3 <u>Break Size Spectrum Analysis</u>

It has been determined that the maximum internal pressure loads occur from an initial condition in which the reactor is at the minimum power associated with the maximum core flow. It has also been concluded that these maximum loads occur for an inside steam line break, the largest possible steam break. The initial reactor condition chosen for this break analysis is the worst case condition determined above (22 percent steam flow, 116 percent recirculation flow).

4.5.1.3.2.4 Conclusions

It is concluded from the above study, that the maximum pressure loads acting on the reactor internal components result from an inside steam line break occurring while the reactor is at 22 percent power associated with the 116 percent core flow (Table 4.5-9, Case 2).

It has also been pointed out that, although possible, it is not probable that the reactor would be operating at the rather abnormal condition of minimum power and maximum core flow. More realistically, the reactor would be at or near a full-power condition and thus the expected maximum pressure loads acting on the internal components would be as listed under Case 1 in Table 4.5-9.

4.5.1.3.2.5 Response of Structures Within the Reactor Pressure Vessel to Pressure Differences

The maximum differential pressures are used in combination with other structural loads to determine the total loading on the various structures within the reactor. The structures are then evaluated to assess the extent of deformation and buckling instability, if any. Of particular interest are the responses of the guide tubes and the metal channels around the fuel bundles, and the potential leakage around the jet pump joints.

Guide Tube

The guide tube is evaluated for buckling instability caused by externally applied pressure. Two primary modes of failure have been analyzed and are described in Subsection 4.5.2.1.3. For a guide tube with minimum wall thickness (t = 0.144 in.) and maximum allowed ovality, the pressure which causes yield stress is 93 psi compared to the design pressure of 37.5 psi. The design pressure is greater than the 21.1 psi maximum pressure differential the guide tube experiences, including accident conditions.

The stress the guide tube could experience has been calculated to be 6200 psi due to external pressure (30 psi - Reference 5), a 1.2g earthquake (include deadweight loading) and lateral loading due to coolant flow, while yield stress at 575°F is 17,450 psi. It is concluded that the guide tube does not fail under the assumed conditions. Additional guide tube analyses are given in References 6 and 7.

Fuel Channel

The fuel channel load resulting from an internally applied pressure is evaluated utilizing a fixed-beam analytical model under a uniform load. Tests to verify the applicability of the analytical model indicate that the model is conservative. A roller, at the top of some of the control rods, guides the blade as it is inserted. If the gap between channels is less than the diameter of the roller, the roller deflects the channel walls as it makes its way into the core. The friction force is a small percentage of the total force available to the CRDs for overcoming such friction, and it is concluded that the main steam line break accident does not impede the insertability of the control rod.

Marathon C (some), Ultra-MD, and Ultra-HD Control Rods without rollers have been designed to take reactor clearances into account. Evaluations of the roller-less control rods have concluded that there is no interference or fit issues related to this design.

Loads Assessment of Fuel Assembly Components

General Electric has prepared the licensing topical report NEDE-21175-3-P, "BWR Fuel Assembly Evaluation of Combined SSE and LOCA Loadings," dated July 1982, on behalf of the Licensing Review Group (LRG), to incorporate a detailed discussion of the fuel liftoff model and a bounding analysis applicable to Fermi 2 for combined faulted loads (safe-shutdown earthquake and LOCA annulus ρ) and transmitted this report to the NRC in a letter dated July 27, 1982, from J. F. Quirk of GE to Mr. Hal Bernard of the NRC. Subsection 3.9.1.5 provides additional information on the structural evaluation of Fermi 2 fuel assemblies under safe-shutdown earthquake (SSE) and LOCA loads. See Subsection 4.2.3 for further information.

Jet Pump Joints

Jet pump joints have been analyzed to evaluate the potential leakage from within the floodable inner volume of the RPV during the recirculation line break and subsequent low-pressure coolant injection (LPCI) reflooding. Because the jet pump diffuser is welded to the shroud support, the only remaining source of leakage from the lower plenum to the downcomer annulus is the jet pump throat-to-diffuser joint. These joints for all jet pumps leak no more than a total of 225 gpm.

The LPCI capacity is sized to accommodate 600 gpm leakage at these locations plus an additional 200 gpm to accommodate accepted internal flaws associated with the core baffle access hole cover and RS-1 jet pump riser. It is concluded that the RPV structures retain sufficient integrity during the recirculation line break accident to allow reflooding of the inner volume of the RPV and in sufficient time to prevent significant increases in cladding temperature.

4.5.1.3.3 Earthquake

The seismic loads acting on the structures within the RPV are based on a dynamic analysis of a model similar to that shown in Figure 4.5-7. Seismic analysis is performed by coupling this lumped mass model of the RPV and internals with the building model to determine the system natural frequencies and mode shapes. The relevant displacement, acceleration, and load response are then determined by the modal superposition time history method.

4.5.1.3.4 Conclusions

Response analyses of the reactor structures show that deformations are sufficiently limited to allow both adequate control rod insertion and proper operation of the emergency core cooling system (ECCS). Sufficient integrity of the structures is retained during accident conditions to allow successful reflooding of the RPV inner volume. The analyses considered various loading combinations, including loads imposed by external forces. Thus, safety design bases listed in Subsection 4.5.1.1.1.1 are satisfied.

4.5.1.4 Design Loading Categories

Refer to Table 4.5-8 and Section 3.9.

4.5.1.5 Design-Basis Criteria

The reactor core support structures and internals meet the safety requirements and power generation requirements in Subsection 4.5.1.1. This is accomplished without exceeding the design-basis conditions for normal, upset, emergency, and faulted conditions described in Table 4.5-8. The internals' and core support structures' design stress and deformation criteria are specified in Chapter 3.

4.5.2 Reactivity Control System

The reactivity control system consists of the control rods, the CRDs, the supplementary reactivity control, and the SLCS. Because of the nature of this material, each item is discussed in this subsection on a system basis.

4.5.2.1 Control Rods

4.5.2.1.1 Design Bases

4.5.2.1.1.1 General Design Bases

Safety Design Bases

The safety design bases are as follows.

a. The control rods shall have sufficient mechanical strength to prevent displacement of their reactivity control material

b. The control rods shall have sufficient strength and be designed to prevent deformation that could inhibit their motion

c. Each control rod shall have a device to limit its freefall velocity sufficiently to avoid damage to the nuclear system process barrier by the rapid reactivity increase resulting from a free-fall of one control rod from its fully inserted position to the position where the drive was withdrawn.

Power Generation Design Basis

The reactivity control mechanical design shall include reactivity control devices (control rods and gadolinia burnable poison) that contain and position the material that controls the excess reactivity in the core. Control rods should have the capability of being removed or replaced, as required.

4.5.2.1.1.2 Specific Design Characteristics

Control Rod Clearances

The basis of the mechanical design of the control rod blade clearances is that there will be no interference that restricts the passage of the control rod blade. A clearance study that generically applied to BWR 4 and BWR 5 C-lattice plants with 0.100 channels was issued in October 1975 (reference G.E. 767E667, Revision 0).

Mechanical Insertion Requirements

Mechanical insertion requirements during normal operation are selected to provide adequate operability and load-following capability, and to be able to control the reactivity addition resulting from burnout of peak shutdown xenon at 100 percent power.

Scram insertion requirements are chosen to provide sufficient shutdown margin to meet all safety criteria for plant operational transients described in Chapter 15.

Material Selection

The selection of materials for use in the control rod design is based on their in-reactor properties. The irradiated properties of type 304 austenitic stainless steel (which comprises the major portion of the assembly), type 304S "Rad Resist" stainless steel, boron carbide (B_4C) powder, hafnium metal, Inconel X750, and PH13-8Mo are well known and are taken into account in establishing the mechanical design of the control rod components.

Radiation Effects

The radiation effects on B_4C powder include the release of gaseous products, and the B_4C cladding is designed to sustain the resulting internal pressure buildup. The corrosion rate and the physical properties (density, modulus of elasticity, dimensional aspects) of austenitic stainless steel, Inconel-X, and hafnium are essentially unaffected by the irradiation experienced in the BWR reactor core. The effects on the mechanical properties, such as yield strength, ultimate tensile strength, elongation, and ductility on the high purity type 304S rad resist stainless steel cladding also are well known and are considered in mechanical design.

Positioning Requirements

Rod positioning increments (notch lengths) are selected to provide adequate power-shaping capability. The combination of rod speed and notch length must also meet the limiting reactivity addition rate criteria.

4.5.2.1.2 Description

The control rods perform the dual function of power shaping and reactivity control (see Figure 4.5-8). Power distribution in the core is controlled during operation of the reactor by manipulating selected patterns of control rods. Control rod displacement tends to counterbalance steam void effects at the top of the core and results in significant power flattening.

All the control rods consist of a cruciform array of stainless steel tubes filled with boron carbide powder or hafnium metal. Duralife 140 control rods are surrounded by a stainless steel sheath. Marathon C, Ultra-MD, and Ultra-HD control rods have absorber tubes that are edge welded to form the cruciform shape.

The control rod assemblies shall be full length. Control blade total span is nominally 9.81 inches. Control rods are separated uniformly throughout the core on a 12 inch pitch. Each control rod is surrounded by four fuel assemblies. The absorber material used in the original equipment control rods (the control rods originally supplied with the plant) is the boron carbide powder only. Some General Electric designs employ hafnium metal as an additional absorber to extend the service life of the control rods. The thicker sheath material used in the Duralife-140 model has allowed the removal of the stiffener rods in the original design without a loss of limiting mechanical load capability. The Duralife-140 model has an increased number of B_4C absorber tubes in each wing. In addition, the length of the B_4C absorber rods in the Duralife-140 has been reduced to accommodate a six inch hafnium plate (tip) at the top. The Marathon C model has replaced the absorber tubes and sheath arrangement with an array of square tubes. The Ultra-HD and Ultra-MD models replaced the Marathon C tube geometry with more cylindrical tubes that have increased wall thickness for improved strength.

For the Duralife 140 control rod model, the main structural member of a control rod is made of Type-304 stainless steel and consists of a top handle, a bottom casting with a velocity limiter and control rod drive coupling, a vertical cruciform center post, and four U-shaped absorber tube sheaths. The top handle, bottom casting, and center post are welded into a single skeletal structure. The U-shaped sheaths are fusion welded to the center post, handle, and castings on the newer designs to form a rigid housing to contain the absorber material. On the original equipment control rods resistance (spot) welding was employed. The fusion weld fabrication eliminates the overlap area between the sheath and the handle, tie rod and velocity limiter. By eliminating the overlap, the potential for crevice corrosion cracking in adverse water chemistry conditions is eliminated. Analyses and tests have shown that the fusion welded control rod is equal to or better than the spot welded control rod under all loading conditions. The bail handle on the newer control rods was extended (as an option) to minimize the use of blade guides during refueling outages. Rollers at the top and bottom of the control rod guide the control rod as it is inserted and withdrawn from the core. The control rods are cooled by the core bypass flow. The U-shaped sheaths are perforated to allow coolant to circulate freely about the absorber tubes. In addition, coolant grooves are included in the hafnium absorber plate at the top of the newer control rods. Operating experience has shown that control rods constructed as described above are not susceptible to dimensional distortions.

For the Duralife 140 control rod model, the boron carbide (B_4C) powder in the absorber tubes is compacted to about 70 percent of its theoretical density. The boron carbide contains a minimum of 76.5 percent by weight natural boron; the boron-10 (B-10) minimum content of the boron is 18 percent by weight. The absorber tubes in the originally supplied control rods were made of Type-304 stainless steel. The absorber tubes in the newer control rods are a high purity Type 304S "Rad Resist" stainless steel. The high purity stainless steel has an improved resistance to intergrannular stress corrosion cracking (IGSCC).

Each absorber tube of the Duralife 140 model is 0.188 inch in outside diameter. The Duralife 140 model has a 0.025-inch wall thickness. Absorber tubes are sealed by a plug welded into each end. The boron carbide is longitudinally separated into individual compartments by stainless steel balls at approximately 16 inch intervals. The steel balls are held in place by a slight crimp of the tube. Should boron carbide tend to compact further in service, the steel balls will distribute the resulting voids over the length of the absorber tube.

For Marathon C blades, each square absorber tube has an internal cylinder with 0.204 inside diameter with a nominal 0.021 inch wall thickness. These tubes are loaded with either B_4C powder or hafnium. B_4C powder is compacted to 70 percent of its theoretical density and is contained in capsules which are then loaded into the absorber tubes. The space between the capsules and the wall of the absorber tubes allows the B_4C to swell before contact is made with the absorber tubes, providing improved resistance to stress corrosion. These capsules are designed to securely contain the B_4C powder while allowing helium released from B_4C to migrate through the absorber tube. Empty capsules may be used in the absorber tubes to provide a plenum for helium released from other capsules within the absorber tubes. After the capsules are installed inside the absorber tubes the ends of the tube are seal welded. The square absorber tubes are welded lengthwise to form the four wings of the cruciform control rod blade.

Ultra-HD absorber tubes are loaded with either B_4C capsules or hafnium while the Ultra-MD absorber tubes are filled with B_4C only. B_4C capsules in Ultra-MD and Ultra-HD control rods are similar to B_4C capsules in the Marathon C control rods. However, the dimensions of the Ultra-MD and Ultra-HD B_4C capsule are sized such that clearance exists between the capsule and absorber tube, even at 100% local depletion. This, combined with a thicker capsule wall, results in slightly less B_4C powder mass in each capsule. The condition of clearance between capsule and absorber tube at 100% local depletion provides a significant structural advantage for the Ultra-MD and Ultra-HD designs over the Marathon C design, as no strain is induced in the absorber tube due to swelling of the B_4C capsule. Empty capsules may be used in the absorber tubes to provide a plenum for helium released from other capsules within the absorber tubes. After the capsules are installed inside the absorber tubes the ends of the tube are seal welded. The absorber tubes are welded lengthwise to form the four wings of the cruciform control rod blade.

The Duralife-140, Marathon C, Ultra-MD, and Ultra-HD are all Matched Reactivity Worth control rods. The Marathon C, Ultra-MD, and Ultra-HD models have a slight increase in cold reactivity worth due to the increased volume of boron carbide. The increase is small but in the conservative direction for increased shutdown margin. Because the increase is small, no changes in lattice physics calculation or 3D Monicore computer constants are required and no accident analyses are affected.

The nuclear operational lifetime of the control rods is determined by the burnup of ^{10}B from neutron absorption and local B_4C loss from B_4C swelling. The nuclear lifetime limit is reached when the quarter-segment depletion achieves a control rod cold reactivity worth (delta k/k) of 10% less than its zero-depletion cold reactivity worth. The mechanical lifetime limit for control rods due to B_4C swelling is bounded by the nuclear operational lifetime limit. The mechanical lifetime limit for GE-Hitachi BWR control rods is reached at 40 years of in-core residency time for all blade types.

The structural effect of helium gas buildup in the absorber rod, due to B-10 neutron absorption and radiolysis of small amounts of water vapor in the absorber rod, was evaluated by General Electric using a two-dimensional finite element computer model of the absorber tubing and end plug. The helium gas pressure was calculated using an empirical correlation for the helium release fraction from the B_4C matrix as a function of percent B-10 depletion, which varies from 4 percent to 30 percent.

The control rod velocity limiter (Figures 4.5-8 through 4.5-10) is an integral part of the bottom assembly of each control rod. This engineered safety feature (ESF) system protects against a high reactivity insertion rate by limiting the control rod velocity in the event of a control rod drop accident. It is a one-way device in that the control rod scram velocity is not significantly affected, but the control rod dropout velocity is reduced to a permissible limit.

Three different types of velocity limiters are employed. On the Duralife 140 model the velocity limiter is in the form of two nearly mated conical elements made from a single casting (Figure 4.5-9). The lower conical element is separated from the upper conical element by four radial spacers 90 degrees apart and is at a 15° angle relative to the upper conical element. The cast velocity limiter employs a single reversed jet. The velocity limiter on the Marathon C model has been redesigned to offset the weight of the hafnium absorber. This machined velocity limiter employs an optimized twin reversed jet (Figure 4.5-10). The velocity limiter on Ultra-HD and Ultra-MD control rods is a cast/fabricated hybrid called the FabriCast. The FabriCast velocity limiter uses a casting for the “vane” of the velocity limiter (Figure 4.5-10), which has identical geometry to the “vane” portion of the single piece cast velocity limiter. Because the geometry is the same, the FabriCast velocity limiter has the same drop speed and scram insertion performance as the original single piece cast velocity limiter design.

The hydraulic drag forces on a control rod are proportional to approximately the square of the rod velocity and are negligible at normal rod-withdrawal or rod-insertion speeds. However, during the scram stroke the rod reaches high velocity, and the drag forces must be overcome by the drive mechanism.

To limit control rod velocity during dropout but not during scram, the velocity limiter is provided with a streamlined profile in the scram (upward) direction. When a control rod with a cast velocity limiter is scrammed, water flows over the smooth surface of the upper conical element into the annulus between the guide tube and the limiter. For the redesigned velocity limiter, water flows over the conical element into the annulus between the element and the CRD coupling socket and the annulus between the guide tube and the limiter. In the dropout direction, however, for the cast velocity limiter, water is trapped by the lower conical element and discharged through the annulus between the two conical sections. For the machined velocity limiter, the trapped water is discharged in two directions. Because this water is jetted in a partially reversed direction into water flowing upward in the annulus, a severe turbulence is created, thereby slowing the descent of the control rod assembly to less than 5 ft/sec at 70°F (Appendix A of Reference 8).

4.5.2.1.3 Safety Evaluation

4.5.2.1.3.1 Materials Adequacy Throughout Design Lifetime

The adequacy of the materials throughout the design life was evaluated in the mechanical design of the control rods. The primary materials, B_4C powder, hafnium, and high purity Type 304S "Rad Resist" stainless steel, have been found suitable in meeting the demands of the BWR environment.

4.5.2.1.3.2 Dimensional and Tolerance Analysis

Layout studies are done to ensure that, given the worst combination of extreme detail part tolerance ranges at assembly, no interference exists that will restrict the passage of control rods. In addition, preoperational and operational verification is made on each control blade system to show that the acceptable levels of operational performance are met. See Subsections 4.5.2.1.4 and 4.5.2.2.4.

4.5.2.1.3.3 Thermal Analysis of the Tendency To Warp

The various parts of the control rod assembly remain at approximately the same temperature during reactor operation, negating the problem of distortion or warpage. What little differential thermal growth could exist is allowed for in the mechanical design. A minimum axial gap is maintained between absorber rod tubes and the control rod frame assembly for this purpose. In addition, dissimilar metals are avoided to further this end.

4.5.2.1.3.4 Forces for Expulsion

An analysis has been performed that evaluates the maximum pressure forces which could tend to eject a control rod from the core. The results of this analysis are given in Subsection 4.5.2.2.3.1. In summary if the collet were to remain open, which is unlikely, calculations indicate that the steady-state control rod withdrawal velocity would be 2 fps for a pressure-under line break, the limiting case for rod withdrawal.

4.5.2.1.3.5 Functional Failure of Critical Components

The consequences of a functional failure of critical components have been evaluated, and the results are covered in Subsection 4.5.2.2.3.1.

4.5.2.1.3.6 Precluding Excessive Rates of Reactivity Addition

In order to preclude excessive rates of reactivity addition, the design is based on analyses that have been performed both on the velocity limiter device and the effect of probable control rod failures (see Subsection 4.5.2.2.3.1).

4.5.2.1.3.7 Effect of Fuel Rod Failure on Control Rod Channel Clearances

The CRD mechanical design ensures a sufficiently rapid insertion of control rods to preclude the occurrence of fuel rod failures that could hinder reactor shutdown by causing significant distortions in channel clearances.

4.5.2.1.3.8 Mechanical Damage

Analysis has been performed for all areas of the control system showing that system mechanical damage does not affect the capability to continuously provide reactivity control.

In addition to the analysis performed on the CRD (Subsections 4.5.2.2.3.1 and 4.5.2.2.3.2), the following discussion summarizes the analysis performed on the control rod guide tube.

The guide tube can be subjected to any or all of the following loads:

a. Inward load due to pressure differential

b. Lateral loads due to flow across the guide tube

c. Dead weight

d. Seismic.

In all cases, analysis was performed considering both a recirculation line break and a steam line break, events that result in the largest hydraulic loadings on a control rod guide tube.

Two primary modes of failure were considered in the guide tube analysis: exceeding allowable stress and excessive elastic deformation. It was found that the allowable stress limit will not be exceeded and that the elastic deformations of the guide tube never are great enough to cause the free movement of the control rod to be jeopardized.

The first mode of failure is evaluated by the addition of all the stresses resulting from the maximum loads for the faulted condition. This results in the maximum theoretical stress value for that condition. Making a linear superposition of all calculated stresses and comparing this value to the allowable limit defined by the ASME B&PV Code yields a factor of safety of approximately three. Using the allowable limit for faulted conditions, the factor of safety is approximately 4.2.

Evaluation of the second mode of failure is based on clearance reduction between the guide tube and the control rod. The minimum allowable clearance is about 0.1 in. This assumes maximum ovality and minimum diameter of the guide tube and the maximum control rod dimension. The analysis showed that if the approximate 6000 psi for the faulted condition were entirely the result of differential pressure, the clearance between the control rod and the guide tube would reduce by a value of approximately 0.01 in. This gives a design margin of 10 between the theoretically calculated maximum displacement and the minimum allowable clearance.

Two types of instability were considered in the analysis of guide tube design. The first was the classic instability associated with vertically loaded columns. The second was the diametral collapse when a circular tube experiences external-to-internal differential pressure.

The limited axially applied load is approximately 77,500 lb resulting in a material compressive stress of 17,450 psi (code allowable stress). Comparing the actual load to the yield stress level gives a design margin greater than 20 to 1. From these values it is concluded that the guide tube is not an unstable column.

When a circular tube experiences external-to-internal differential pressure, two modes of failure are possible, depending on whether the tube is "long" or "short." In the analysis here the guide tube is taken to be an infinitely long tube with the maximum allowable ovality and minimum wall thickness. The conditions will result in the lowest critical pressure calculation for the guide tube (that is, if the tube were "short," the critical pressure calculation would give a higher number). The critical pressure is approximately 140 psi. However, if the maximum allowable stress is reached at a pressure lower than the critical pressure, then that pressure is limiting. This is the case for a BWR guide tube. The allowable stress of 17,450 psi will be reached at approximately 96 psi. Comparing the maximum possible pressure differential for a steam line break to the limiting pressure of 96 psi gives a design margin greater than 3 to 1. Therefore, the guide tube is not unstable with respect to differential pressure. References 6 and 7 provide a detailed discussion of analyses and design margins for the control rod guide tube.

4.5.2.1.3.9 Evaluation of Control Rod Velocity Limiter

The control rod velocity limiter limits the free-fall velocity of the control rod. This velocity is evaluated by the control rod drop accident analysis described in Subsection 15.4.9.

4.5.2.1.4 Testing and Inspection

The control rod absorber tube tests are examples of the quality control tests performed on the control rods. The absorber tube tests include the following:

a. The ^{10}B fraction of the boron content of each lot of boron carbide is verified

b. Weld integrity of the finished absorber tubes is verified by helium leak testing.

The Surveillance Test Program is described in Subsection 4.5.2.2.4.5 and in the Technical Specifications.

Fermi 2 procedures require replacement of control blades when a 10 percent reduction of rod worth occurs.

4.5.2.1.5 Instrumentation

The instrumentation for both the control rods and CRDs is defined by that given for the reactor manual control system (RMCS). The objective of the RMCS is to provide the operator with the means to make changes in nuclear reactivity so that reactor power level and power distribution can be controlled. The system allows the operator to manipulate control rods.

The design bases and further discussion are covered in Subsection 7.7.1.

4.5.2.2 Control Rod Drive System

4.5.2.2.1 Design Bases

4.5.2.2.1.1 Safety Design Bases

The CRD mechanical system shall meet the following safety design bases:

a. Design shall provide for a control rod insertion sufficiently rapid that no fuel damage results from any abnormal operating transient

b. Design shall include positioning devices, each of which individually supports and positions a control rod

c. Each positioning device shall

   1. Prevent its control rod from withdrawing as a result of a single malfunction

2. Be individually operated so that a failure in one positioning device does not affect the operation of any other positioning device

3. Be individually energized when rapid control rod insertion (scram) is signaled so that failure of power sources external to the positioning device does not prevent the positioning devices of other control rods from being inserted

4. Be locked to its control rod to prevent undesirable separation.

d. The CRD mechanisms and that part of the CRD hydraulic system necessary for scram shall be designed to Category I requirements.

4.5.2.2.1.2 Power Generation Design Basis

The CRD system design shall provide for positioning the control rods to control power generation in the core.

4.5.2.2.2 Description

The CRD system controls gross changes in core reactivity and neutron flux shape by incrementally positioning neutron-absorbing control rods within the reactor core in response to manual control signals. It is also required to shutdown the reactor by rapidly inserting withdrawn control rods into the core in response to a manual or automatic signal. The CRD system consists of locking piston, CRD mechanisms, and the CRD hydraulic system (including hydraulic control units, interconnecting piping, instrumentation, and electrical controls).

4.5.2.2.2.1 Control Rod Drive Mechanisms

The CRD mechanism (drive) used for positioning the control rod in the reactor core is a double-acting, mechanically latched, hydraulic cylinder using water as its operating fluid (Figures 4.5-11 through 4.5-14). The individual drives are mounted on the bottom head of the RPV. The drives do not interfere with refueling and are operative even when the head is removed from the RPV. The drives are also readily accessible for inspection and servicing. The bottom location makes maximum use of the water in the reactor as a neutron shield and gives the least possible neutron exposure to the drive components. Using water from the condensate treatment system or condensate storage tank as the operating fluid eliminates the need for special hydraulic fluid. Drives are able to use simple piston seals whose leakage does not contaminate the reactor water and does cool the drive mechanisms and their seals.

The drives are capable of inserting or withdrawing a control rod at a slow, controlled rate, as well as providing rapid insertion when required. A mechanism on the drive locks the control rod in 6-in. increments of stroke over the length of the core.

A coupling spud at the top end of the drive index tube (piston rod) engages and locks into a mating socket at the base of the control rod. The weight of the control rod is sufficient to engage and lock this coupling. Once locked, the drive and rod form an integral unit that must be manually unlocked by specific procedures before the components can be separated.

The drive holds its control rod in distinct latch positions until the hydraulic system actuates movement to a new position. Withdrawal of each rod is limited by the seating of the rod in its guide tube. Withdrawal beyond the full-out limit can be accomplished only if the rod and drive are uncoupled. Withdrawal past the full-out limit is annunciated by an over travel alarm.

The individual rod indicators, grouped in one control panel display, correspond to relative rod locations in the core. A separate, smaller display is located just below the large display on the vertical part of the benchboard. This smaller display presents the positions of the control rod selected for movement and its adjacent rods.

For display purposes, the control rods are considered in groups of four adjacent rods centered around a common core volume. Each group is monitored by four local power range monitor (LPRM) strings (Subsection 7.6.1). Rod groups at the periphery of the core may have less than four rods and less than 4 LPRM strings. The small rod display shows the positions, in digital form, of the rods in the group to which the selected rod belongs. A white light indicates which of the four rods is the one selected for movement.

4.5.2.2.2.2 Control Rod Drive Components

Figure 4.5-12 illustrates the operating principle of a CRD. Figures 4.5-13 and 4.5-14 illustrate the CRD in more detail. The main components of the CRD and their functions are described as follows.

The CRD piston is mounted at the lower end of the index tube. This tube functions as a piston rod. The CRD piston and index tube make up the main moving assembly in the CRD. The CRD piston operates between positive end stops, with a hydraulic cushion provided at the upper end only. The piston has both inside and outside seal rings and operates in an annular space between the fixed piston tube assembly and the drive inner cylinder tube. Because the type of inner seal used is effective in only one direction, the lower sets of seal rings are mounted with one set sealing in each direction.

A pair of nonmetallic bushings prevents metal-to-metal contact between the piston tube assembly and the inner cylinder surface. The outer piston rings are segmented step-cut seals with expander springs holding the segments against the cylinder wall. A pair of split bushings on the outside of the piston prevents piston contact with the inner cylinder wall. The effective piston area for downtravel, or withdrawal, is approximately 1.2 in.^{2} versus 4.1 in.^{2} for uptravel, or insertion. This difference in driving area tends to balance the control rod weight and ensures a higher force for insertion than for withdrawal.

The index tube is a long hollow shaft made of either nitrided type 304 or Grade XM-19 stainless steel. Circumferential locking grooves, spaced every 6 in. along the outer surface, transmit the weight of the control rod to the collet assembly.

The collet assembly serves as the index tube locking mechanism. It is located in the upper part of the drive unit. This assembly prevents the index tube from accidentally moving downward. The assembly consists of the collet fingers, a return spring, a guide cap, a collet housing (part of the cylinder, tube, and flange), and the collet piston.

The problem of IGSCC in the collet assembly is discussed in Subsection 4.5.2.2.4.5.

Locking is accomplished by fingers mounted on the collet piston at the top of the drive cylinder. In the locked or latched position, the fingers engage a locking groove in the index tube.

The collet piston is normally held in the latched position by a force of approximately 150 lb supplied by a spring. Metal piston rings are used to seal the collet piston from RPV pressure. The collet assembly will not unlatch until the collet fingers are unloaded by a short, automatically sequenced, drive-in signal. A pressure, approximately 180 psi above RPV pressure, must then be applied to the collet piston to overcome spring force, slide the collet up against the conical surface in the guide cap, and spread the fingers out so they do not engage a locking groove.

A guide cap is fixed in the upper end of the CRD assembly. This member provides the unlocking cam surface for the collet fingers and serves as the upper bushing for the index tube.

If reactor water is used during a scram to supplement accumulator pressure, it is drawn through a filter on the guide cap.

The piston tube is an inner cylinder, or column, extending upward inside the CRD piston and index tube. The piston tube is fixed to the bottom flange of the CRD and remains stationary. Water is brought to the upper side of the CRD piston through this tube. A series of progressively decreasing orifices at the top of the tube form the hydraulic buffer to cushion the CRD piston at the end of its scram stroke.

A stationary piston, called the stop piston, is mounted on the upper end of the piston tube. This piston provides the seal between RPV pressure and the space above the drive piston. It also functions as a positive end stop at the upper limit of control rod travel. A stack of spring washers just below the stop piston helps absorb the final mechanical shock at the end of control rod travel. The stop piston seal rings are similar to the drive piston outer seal rings. A bleed-off passage to the center of the piston tube is located between the two pairs of rings. This arrangement allows seal leakage from the RPV (during a scram) to be bled directly to the discharge line. The lower pair of seals is used only during the cushioning of the CRD piston at the upper end of the stroke.

The center tube of the CRD mechanism forms a well to contain the position indicator probe. This probe is an aluminum extrusion attached to an aluminum housing. Mounted on the extrusion are hermetically sealed, magnetically operated position indicator switches. Each switch is sheathed in a braided glass sleeve, and the entire probe assembly is protected by a thin-walled stainless steel tube. The switches are actuated by a ring magnet located at the bottom of the drive piston.

The drive piston, piston tube, and indicator tube are all of nonmagnetic stainless steel, allowing the individual switches to be operated by the magnet as the piston passes. One switch is located at each position corresponding to an index tube groove, thus allowing indication at each latching point. An additional switch is located at each midpoint between latching points to indicate the intermediate positions during drive motion. Thus, indication is provided for each 3 in. of travel. Duplicate switches are provided for the full-in and full-out positions. One additional switch (an overtravel switch) is located at a position below the normal full-out position. Because the limit of downtravel is normally provided by the control rod itself as it reaches the backseat position of the control rod guide tube, the CRD can pass this position and actuate the overtravel switch only if it is uncoupled from its control rod. A convenient means is thus provided to verify that the drive and control rod are coupled after installation of a drive or at any time during plant operation.

A flange and cylinder assembly is made up of a heavy flange welded to the CRD cylinder. A sealing surface on the upper face of this flange forms the seal to the drive housing flange. The seals contain reactor pressure and the two hydraulic control pressures. Teflon-coated, stainless steel rings are used for these seals. The CRD flange contains the integral ball, or two-way, check (ball-shuttle) valve. This valve directs either the RPV pressure or the CRD system driving pressure, whichever is higher, to the underside of the CRD piston. Reactor pressure vessel pressure is admitted to this valve from the annular space between the drive and drive housing through passages in the flange.

Water used to operate the collet piston passes between the outer tube and the cylinder tube. The inside of the cylinder tube is honed to provide the surface required for the drive piston seals.

Both the cylinder tube and outer tube are welded to the CRD flange. The upper ends of these tubes have a sliding fit to allow for differential expansion.

The upper end of the index tube is threaded to receive a coupling spud. The coupling (Figure 4.5-11) accommodates a small amount of angular misalignment between the CRD and the control rod. Six spring fingers allow the coupling spud to enter the mating socket on the control rod. A plug then enters the spud and prevents uncoupling.

Two means of uncoupling are provided. With the RPV head removed, the lock plug can be raised against the spring force of approximately 50 lb by a rod extending up through the center of the control rod to an unlocking handle located above the control rod velocity limiter. The control rod, with the lock plug raised, can then be lifted from the CRD.

The lock plug can also be pushed up from below, if it is desired to uncouple a drive without removing the RPV head for access. In this case, the central portion of the drive mechanism is pushed up against the uncoupling rod assembly, which raises the lock plug and allows the coupling spud to disengage the socket as the drive piston and index tube are driven down.

The control rod is heavy enough to force the spud fingers to enter its socket and push the lock plug up, allowing the spud to enter the socket completely and the plug to snap back into place. Therefore, the CRD can be coupled to the control rod using only the weight of the control rod. However, with the lock plug in place, a force in excess of 50,000 lb is required to pull the coupling apart.

<u>Materials of Construction</u>

Factors that determine the choice of construction materials are discussed in the following paragraphs.

The index tube must withstand the locking and unlocking action of the collet fingers. A compatible bearing combination must be provided that is able to withstand moderate misalignment forces. The reactor environment limits the choice of materials suitable for corrosion resistance. The column and tensile loads can be satisfied by either an annealed 300 series or Grade XM-19 stainless steel. The wear and bearing requirements are provided by hard facing the completed tube. To obtain suitable corrosion resistance, a carefully controlled process of surface preparation is employed.

The coupling spud is made of Inconel-750 that is aged for maximum physical strength and the required corrosion resistance. Because misalignment tends to cause chafing in the semispherical contact area, the part is protected by a thin chromium plating (electrolyzed). This plating also prevents galling of the threads attaching the coupling spud to the index tube.

Inconel-750 is used for the collet fingers, which must function as leaf springs when cammed open to the unlocked position. Colmonoy-6 hard facing provides a long-wearing surface, adequate for design life, to the area contacting the index tube and unlocking cam surface of the guide cap.

Graphitar-14 is selected for seals and bushings on the CRD piston and stop piston. The material is inert and has a low friction coefficient when water-lubricated. The Graphitar is relatively soft, which is advantageous when an occasional particle of foreign matter reaches a seal. The resulting scratches in the seal reduce sealing efficiency until worn smooth, but the CRD design can tolerate considerable water leakage past the seals into the RPV.

An alternate material approved for use in the seals and bushings in Graphitar-3030, due to its higher strength and superior wear resistance characteristics.

All CRD components exposed to RPV water are made of AISI 300 series stainless steel except the following.

a. Seals and bushings on the CRD piston and stop piston are either Graphitar-14 or Graphitar-3030

b. All springs and members requiring spring action (collet fingers, coupling spud, and spring washers) are made of Inconel-750

c. The ball check valve is a Haynes Stellite cobalt-base alloy

d. Elastomeric O-ring seals are ethylene propylene

e. Collet piston rings are Haynes-25 alloy

f. Certain wear surfaces are hard-faced with Colmonoy-6

g. Nitriding by a proprietary new hard facing process and chromium plating is used in certain areas where resistance to abrasion is necessary

h. The CRD piston head is made of ARMCO 17-4Ph.

i. An alternate material acceptable for the index and piston tube is nitrided Grade XM-19SS.

j. An equivalent piston tube assembly contains an anti-rotation pin made of nickel-chromium-iron wire per GE spec B14H19.

Pressure-containing portions of the CRDs are designed and fabricated in accordance with requirements of Section III of the ASME B&PV Code.

4.5.2.2.2.3 Control Rod Drive Hydraulic System

The CRD hydraulic system supplies and controls the pressure and flow to and from the drives through hydraulic control units (HCUs). The water discharged from the CRDs during a scram flows through the HCUs to the scram discharge volume (SDV). The water discharged from a CRD during a normal control rod positioning operation flows through the HCU and the exhaust header, and is dispersed into the RPV via the HCUs of other nonmoving drives.

The CRD hydraulic system also supplies water for the reactor vessel instrumentation reference leg backfill system.

The CRD hydraulic system design is shown in Figure 4.5-15. The hydraulic requirements, identified by the function they perform, are as follows:

a. Normal accumulator hydraulic charging pressure is required. Flow to the accumulators is required only during scram reset or system startup

b. Drive pressure of approximately 250 psi above RPV pressure is required. A flow rate of approximately 4 gpm to insert a control rod and 2 gpm to withdraw a control rod is required

c. Cooling water to the CRDs is required at approximately 6 to 30 psi above RPV pressure and at a flow rate of approximately 0.3 gpm times the number of drive units. Cooling water can be interrupted for short periods without damaging the drive

d. The SDV is sized to receive and contain all the water discharged by the CRDs during a scram. A minimum volume of 3.34 gal per CRD is required.

The CRD hydraulic systems provide the required functions with the pumps, filter, valves, instrumentation, and piping shown in Figure 4.5-15 (Sheets 1 and 2) and described in the following paragraphs.

Duplicate components are included, where necessary, to ensure continuous system operation if an inservice component requires maintenance.

One supply pump pressurizes the system with water from the condensate treatment system or condensate storage tank. One spare pump is provided for standby. A discharge check valve prevents backflow through the nonoperating pump. A portion of the pump discharge flow is diverted through a minimum flow bypass line to the condensate storage tank. This flow is controlled by an orifice and is sufficient to prevent immediate pump damage if the pump discharge is inadvertently closed.

The primary source of water for the CRD system is the condensate treatment system. There are two pump suction filters installed in parallel for each CRD pump. The CRD pump operation has been demonstrated for many years at this level of filtration. The drive water filters have cleanable elements. One drive water filter is operated at a time. There are Y-strainers downstream of the drive water filters that protect the CRD hydraulic system in the event of filter-element failure. A sampling of the CRD system water is continuously delivered to the reactor water-sampling station for monitoring. Necessary corrective actions would be taken if a significant change in CRD system water quality were to result from the failure of a drive water filter. The total pressure drop across the drive-water filters is continuously monitored with an alarm on high pressure differential.

The CRD pump provides water for the reactor vessel instrumentation reference leg backfill system. A small amount of water is injected into two reference legs to prevent the accumulation of noncondensable gases. The backfill lines are tapped to the CRD charging water header.

Provisions have been taken to keep the water in the CRD hydraulic system from freezing. The CRD system is completely contained within the reactor building. This building is well heated and ventilated; it also receives most of the heat loss from the reactor system. It is therefore incredible that the temperature would drop below freezing while the plant is operating. The CRD system water supply is normally taken from the condensate demineralizers via the torus water management system; no portion of this line is outside the building. Backup supply is provided by the condensate storage tank. Subsection 9.2.6 describes the procedure used to keep the tank from freezing. The valve pit from the tank is only partially above grade. Heat sources into this valve pit are sufficient to keep the temperature well above freezing. The lines from the pit to the turbine building are 42 in. or more below grade and, consequently, are not subject to freezing.

Accumulator charging pressure is established by the discharge pressure of the system supply pump. During scram the scram inlet (and outlet) valves open and permit the stored energy in the accumulators to discharge into the CRDs. The resulting pressure decrease in the water header allows the CRD supply pump to increase flow rate substantially into the CRDs via the charging water header. The flow sensing system upstream of the accumulator charging header detects high flow and closes the flow control valve. This action maintains increased flow through the charging water header.

Pressure in the charging header is monitored in the main control room with a pressure indicator and low-pressure alarm.

The failure of a CRD pump or the plugging of a drive water filter would result in a loss of pressure in the CRD charging water header, which directly feeds each hydraulic control unit accumulator. The effect that this can have on the ability to scram the rods is minimized for the following reasons:

a. At reactor pressures greater than 600 psig, the rods can scram with specified insertion times independent of the accumulator pressure

b. If header pressure were lost because of CRD pump failure, the operator could readily restore header pressure by bringing the second pump on line

c. If header pressure were lost because of filter plugging, the parallel filter could be brought into service

d. Accumulator depressurization is prevented by check valve No. 115 (see Figure 4.5-15) to retain accumulator scram capability, especially if reactor pressure is below 600 psig.

Each accumulator is monitored with a pressure switch that activates individual low pressure alarms that have setpoints which are above the limit established in the Technical Specifications. An alarm annunciates for any accumulator at or before the pressure reaches the setpoint value provided in the Technical Specifications. The setpoint value has been conservatively established by the design to assure a margin of accumulator operability sufficient to scram the associated control rod.

By design, control rod scram can be accomplished without the accumulator pressure when the reactor vessel pressure is at or above 600 psig. If the reactor were operating at a pressure of less than 600 psig, a manual scram would be required upon receipt of the first accumulator low pressure alarm that follows a loss of charging water header pressure. This design required manual scram is a very conservative action because the core is designed to be shut down from all operating conditions with the most reactive control rod fully withdrawn. The plant operating procedures call for a manual scram at a reactor pressure limit above the design 600 psig as required by the Technical Specifications in case of a loss of accumulator function. This additional conservatism of the Technical Specifications adds more margin to assure the scram function during plant power operation, startup or refueling when applicable.

The manual scram capability of the accumulators is periodically verified by a pressure drop surveillance to confirm that operators have at least 10 minutes of accumulator scram capability upon loss of control rod drive system hydraulic charging capability.

During normal operation, the flow control valve maintains a constant system flow rate. This flow is used for drive flow, drive cooling, and system stability.

Control rod drive water pressure required in the drive header is maintained by the drive pressure control valve, which is manually adjusted from the main control room. A flow rate of approximately 6 gpm (the sum of the flow rate required to insert and withdraw a control rod) normally passes from the CRD water pressure stage through two solenoid-operated stabilizing valves (arranged in parallel) and then goes into the cooling water line downstream from the drive/cooling-water pressure control valve. The flow through one stabilizing valve equals the drive insert flow; that of the other stabilizing valve equals the CRD withdrawal flow. When a CRD is operated, the required flow is diverted to that CRD while closing the appropriate stabilizing valve. Thus, flow through the CRD pressure control valve is always constant.

Flow indicators in the CRD water header and in the line downstream from the stabilizing valves allow the flow rate through the stabilizing valves to be adjusted when necessary. Differential pressure between the RPV and the CRD pressure stage is indicated in the main control room.

The cooling water header is located downstream from the drive/ cooling water pressure control valve. The cooling water pressure control valve is manually adjusted from the main control room to produce the required cooling water pressure. The flow through the flow control valve is virtually constant. Therefore, once adjusted, the drive/cooling water pressure control valve can maintain its required pressure independent of reactor pressure. Changes in setting of the pressure control valves are required only to adjust for changes in the cooling requirements of the CRDs, as their seal characteristics change with time.

Failure of the drive/cooling water pressure control valve in the full-open or full-closed position would cause some perturbation in CRD system operation, but it does not present a safety problem or affect the scram capability of the CRD system. If the pressure control valve (PCV) were to fail to a full-open position, the cooling water pressure would increase and the drive water pressure would decrease. The resulting cooling water pressure increase could cause control rods to drift inward. The existence of rod drifts would be alarmed to the control room operator for appropriate action. The resulting drop in drive water pressure would make normal control rod notch movements impossible, but would not affect the ability of the scram function. Conversely, if the PCV were to fail to a full-closed position, the cooling water pressure would decrease while the drive water pressure would increase. The reduction in cooling water pressure (and flow) would eventually lead to high CRD temperature being alarmed in the control room. In the limiting case, the resulting increase in drive water pressure would reach the shutoff pressure of the supply pump (1600 psig). The occurrence of this condition during withdrawal of a drive at zero reactor pressure will result in a drive pressure increase from 260 psig to no more than 1600 psig. Calculations indicated that the drive would accelerate from 3 in./sec to approximately 6 in./sec. The rod movement would stop as soon as the driving signal is removed. In both of the cases described above, the manually operated bypass PCV, in conjunction with isolation valves upstream and downstream of the primary PCV, would enable the operators to take corrective action.

A flow indicator in the main control room monitors cooling water flow. A differential pressure indicator in the main control room indicates the difference between RPV pressure and CRD cooling water pressure. The temperature of each CRD is recorded in the relay room, and excessive temperatures are annunciated by a control room alarm.

Exhaust water from a moving drive is dispersed to the RPV via the HCUs of nonmoving drives.

In order to eliminate the problem of cracking of the CRD return line (CRDRL), the CRDRL was removed and the CRDRL nozzles were capped. The modification meets the requirements of NRC (Reference 13), on the subject of CRDRL removal as follows:

a. Equalizing valves between the cooling water header and the normal drive movement exhaust water header have been incorporated

b. Exhaust water headers have been changed to stainless steel

c. The flow stabilizer loop is stainless steel and is routed directly to the cooling water header.

All modifications were constructed and inspected consistent with the applicable sections of the ASME B&PV Code.

Figure 4.5-15 shows the CRD hydraulic system with the return line eliminated. The reactor water makeup capability of the CRD system with this modification is 135 gpm at 1110 psig reactor vessel pressure (before the modification, the makeup capability was 170 gpm).

The SDV consists of header piping, which connects to each HCU and drains into an instrument volume. The header piping is sized to receive and contain all the water discharged by the CRDs during a scram, independent of the instrument volume. Each of the two sets of headers has a directly connected scram discharge instrument volume attached to the low point of the header piping. Thus, the large-diameter pipe of the instrument volume serves as a vertical extension of the SDV (although no credit is taken for it in determining scram discharge volume requirements).

During normal plant operation, the SDV is empty and vented to atmosphere through its open vent and drain valve. When a scram occurs, upon a signal from the safety circuit, these vent and drain valves are closed to conserve reactor water. Lights in the main control room indicate the position of these valves. Redundant vent and drain valves are provided to ensure against loss of reactor coolant from the SDV following a scram.

During a scram, the SDV partly fills with water discharged from above the drive pistons. While scrammed, the CRD seal leakage from the reactor continues to flow into the SDV until the discharge volume pressure equals the RPV pressure. A check valve in each HCU prevents reverse flow from the scram discharge header volume to the CRD. When the scram signals are cleared from the reactor protection system (RPS), the SDV signal is overridden with a keylock override switch, and the scram discharge volume is drained and returned to atmospheric pressure.

Remote manual switches in the pilot valve solenoid circuits allow the discharge volume vent and drain valves to be tested without disturbing the RPS. Closing the SDV valves allows the outlet scram valve seats to be leak tested by timing the accumulation of leakage inside the scram discharge volume.

Four liquid level switches and two level transmitters connected to each instrument volume monitor the volume for abnormal water level. They provide redundant and diverse inputs to the RPS scram function and provide inputs for control room annunciation and control rod withdrawal block functions (see Figure 4.5-15).

Each level transmitter provides input to actuate a trip unit. Three different level setpoints are used. At the lowest level, a level switch actuates to indicate that the volume is not completely empty during postscram draining or to indicate that the volume starts to fill through leakage accumulation at other times during reactor operation. At the second level, one level switch produces a rod withdrawal block to prevent further withdrawal of any control rod when leakage accumulates to approximately half the capacity of the instrument volume. The remaining two switches and two transmitter-actuated trip units are interconnected with the trip channels of the RPS and initiate a reactor scram should water accumulation fill the instrument volume.

Modifications of the SDV instrumentation and vent and drain valves were made to meet the criteria stated in the NRC's Generic Safety Evaluation Report BWR Scram Discharge System, dated December 1, 1980.

The design deficiencies in the SDV that were identified in the Safety Evaluation Report (SER) were

a. Inadequate hydraulic coupling between the SDV headers and the instrument volume

b. Complex vent and drain piping connections to the SDV

c. Failure mechanisms for the instrument volume level instrumentation

d. Failure of the control air system resulting in the potential inability to scram.

Items a. and d. were not applicable to Fermi 2 because adequate coupling is ensured by the integral coupling of the 12-in. instrument volume to the 8-in. SDV header.

Criteria of the BWR Owners subgroup were used in the design for items b. and c. The vent and drain valves are redundant and routed as dedicated lines. The instrumentation was upgraded on each instrument volume.

The instrumentation connections are made to the instrument volume and not to the drain line. Each instrument volume has one alarm, one rod block, and four scram level instruments. The two new scram level instruments are diverse.

Hydraulic Control Units

Each HCU furnishes pressurized water, on signal, to a CRD unit. The CRD then positions its control rod as required. Operation of the electrical system that supplies scram and normal control rod positioning signals to the HCU is described in Subsections 7.2.1 and 7.7.1.

The basic components in each HCU are manual, pneumatic, and electrical valves; an accumulator; related piping; electrical connections; filters; and instrumentation (Figures 4.5-15 and 4.5-16). The components and their functions are described in the following paragraphs.

The insert CRD valve is solenoid operated and opens on an insert signal. The valve supplies drive water to the bottom side of the main CRD piston.

The insert exhaust valve also opens by solenoid on an insert signal. The valve discharges water from above the CRD piston to the exhaust water header.

The withdraw CRD valve is solenoid operated and opens on a withdraw signal. The valve supplies drive water to the top of the drive piston.

The solenoid-operated withdraw exhaust valve opens on a withdraw signal and discharges water from below the main CRD piston to the exhaust header. The withdraw exhaust valve also serves as the settle valve. The valve opens following any normal CRD insert, the valve stays open a little longer on a withdrawal. This allows the control rod and its CRD to settle back into the nearest latch position.

The speed control valves regulate the control rod insertion and withdrawal rates during normal operation. They are manually adjustable flow-control valves used to regulate the water flow to and from the volume beneath the main drive piston. A correctly adjusted valve does not require readjustment except to compensate for changes in CRD seal leakage.

The scram pilot valves are operated from the RPS trip system. Two scram pilot valves control both the scram inlet valve and the scram exhaust valve by depressurizing the scram air header. The scram pilot valves are identical, three-way, solenoid-operated, normally energized valves. Upon a loss of electrical signal to the pilot valves, such as the loss of external ac power, the inlet ports close and the exhaust ports open on both pilot valves. The pilot valves (Figure 4.5-15) are arranged so that the trip system signal must be removed from both valves before air pressure can be discharged from the scram valve operators. This prevents the inadvertent scram of a single CRD in the event of a failure of one of the solenoid pilot valves.

The scram exhaust valve opens slightly before the scram inlet valve, exhausting water from above the CRD piston. The exhaust valve opens faster than the inlet valve because of a larger spring in the valve operator. Otherwise the valves are similar.

The scram inlet valve opens to supply pressurized water to the bottom of the CRD piston. This quick-opening globe valve is operated by an internal spring and system pressure. It is closed by air pressure applied to the top of its diaphragm operator. A position-indicator switch on this valve energizes a light in the main control room as soon as both of the valves start to open.

The scram accumulator stores sufficient energy to fully insert a control rod at lower RPV pressures. At higher RPV pressures, the accumulator pressure is assisted or replaced by RPV pressure.

The accumulator is a hydraulic cylinder with a free-floating piston. The piston separates the water on top from the nitrogen below. A check valve in the accumulator charging line prevents loss of water pressure in the event supply pressure is lost.

During normal plant operation, the accumulator piston is seated at the bottom of its cylinder. Loss of nitrogen decreases the nitrogen pressure, and this actuates a pressure switch that sounds an alarm in the main control room.

To ensure that the accumulator is always able to produce a scram, it is continuously monitored for water leakage. A float-type level switch actuates an alarm if water leaks past the piston barrier and collects in the accumulator instrumentation block.

4.5.2.2.2.4 Control Rod Drive System Operation

The CRD system performs rod insertion, rod withdrawal, and scram. These operational functions are described in the following paragraphs.

Rod insertion is initiated by a signal from the operator to the insert valve solenoids. This signal causes both insert valves to open. The insert CRD valve applies differential drive pressure of approximately 90 psi under the CRD piston. The insert exhaust valve allows water from above the CRD piston to discharge to the exhaust header.

As illustrated in Figure 4.5-12, the locking mechanism is a ratchet-type device and does not interfere with rod insertion. The speed at which the CRD moves is determined by the flow through the insert speed control valve, which is set for approximately 4 gpm for a shim speed (nonscram operation) of 3 in./sec. During normal insertion, the pressure is adjusted by the speed control valve to compensate for CRD pipe length losses.

Rod withdrawal is, by design, more involved than insertion. The collet finger (latch) must be raised to reach the unlocked position (see Figure 4.5-12). The notches in the index tube and the collet fingers are shaped so that the downward force on the index tube holds the collet fingers in place. The index tube must be lifted before the collet fingers can be released. This is done by opening the CRD insert valves (in the manner described in the preceding paragraph) for approximately 1 sec. The withdraw valves are then opened, applying driving pressure above the drive piston and opening the area below the piston to the exhaust header. As the piston rises, the collet fingers are cammed outward by the guide cap, away from the index tube.

The pressure required to release the latch is set and maintained at a level high enough to overcome the force of the latch return spring plus the force of reactor pressure opposing movement of the collet piston. When this occurs, the index tube is unlatched and free to move in the withdraw direction. Water displaced by the CRD piston flows out through the withdraw speed control valve, which is set to give the control rod a shim speed of 3 in./sec. The entire valving sequence is automatically controlled and is initiated by a single operation of the rod withdraw switch.

During a scram, the scram pilot valves and scram valves are operated as previously described. With the scram valves open, accumulator pressure is admitted under the CRD piston, and the area over the drive piston is vented to the SDV.

The large differential pressure (depending on charging water header pressure and RPV pressure) produces a large upward force on the index tube and control rod. This force gives the rod a high initial acceleration and provides a large margin of force to overcome any possible friction. After the initial acceleration is achieved, the CRD continues at a nearly constant velocity. This characteristic provides a high initial rod insertion rate. As the CRD piston nears the top of its stroke, the piston seals close off the flow passages (buffer orifices) in the piston tube, and the CRD slows.

Prior to a scram signal and assuming the accumulator is normally charged, the inlet scram valve opens and the full water-side pressure is available at the CRD acting on a 4.1-in.^{2} area. As CRD motion begins, this pressure drops to the gas-side pressure less line losses between the accumulator and the CRD. At low RPV pressures, the accumulator completely discharges with a resulting gas-side pressure of approximately 575 psig. At reactor operating pressure, the accumulator only partially discharges, with reactor pressure providing the necessary scram force when reactor pressure exceeds scram accumulator pressure.

The CRD accumulators are required to scram the control rod when the reactor pressure is low. When the reactor pressure is low, the accumulator retains sufficient stored energy to ensure the complete insertion of the control rod in the required time. The accumulator is not required in order to scram the control rod in time when the reactor is close to or at full operating pressure. In this instance, the reactor pressure alone scrams the control rod in the required time. However, the accumulator does provide an additional energy boost to the reactor pressure in providing scram action at RPV pressures less than accumulator pressures.

The CRD system, with accumulators, provides the following scram performances at full-power operation, in terms of elapsed time after deenergization of the scram pilot valve solenoids for the drives to attain the scram strokes listed in the table below. The scram insertion time is an analytical limit that assures the scram reactivity curve used in the transient analyses is met. Some control rods can be slower than the listed scram insertion times as long as others are faster so that the analytical scram reactivity curve is met. (Reference 12)

Position Inserted From Fully Withdrawn	Scram Insertion Time (sec)
46	0.457
36	1.084
26	1.841
6	3.361

The alternative rod insertion (ARI) feature provides an alternative means for initiating scram if there is a failure in the electrical portion of the RPS during an operational transient that normally requires a reactor scram. The ARI enables the insertion of reactor control rods by depressurizing the scram pilot valve air header through valves that are redundant and diverse from the RPS-initiated backup scram valves.

The redundant reactivity system signal to insert control rods results in energizing the eight ARI solenoid valves. Two ARI valves in series with the backup scram valves also have parallel functioning check valves to vent air from the air supply line in case an ARI valve fails. These two valves and four other ARI valves vent the A and B hydraulic control unit scram valve pilot air headers to the atmosphere in order to depressurize the headers and scram all rods. Two additional valves vent the portion of the scram air header that serves the scram discharge volume drain and vent lines, closing the vent and drain valves and isolating the SDV. (See also Subsection 7.6.1.18.)

4.5.2.2.3 Evaluation of Scram Time

The rod scram function of the CRD system provides the negative reactivity insertion required by the safety design basis (c.1) in Subsection 4.5.2.2.1.1. The scram time shown in the description is adequate as shown by the transient analyses of Section 15.1. Sufficient driving force is available to overcome the retarding force during a scram. The control rod weighs 154 lb in water and 183 lb in air. The index tube weighs 62 lb in water and 71 in air. Other moving parts weigh about 5 lb so the wet drive line weight is about 225 lb.

At the start of motion, assuming the accumulator is normally charged, the CRD pump will be supplying charging water at a pressure greater than RPV pressure at the inlet scram valve. This supplies a large differential to assist opening of the valve and exists until drive motion starts. Pressure at the CRD immediately drops to reactor pressure due to losses in the piping and valves, and reactor pressure is applied through the ball check valve in the CRD. This pressure is actually slightly less than reactor pressure caused by flow losses as the water comes down the annulus between the CRD and thermal sleeve. The pressure is applied to the 4.1-in.^{2} under piston area. The area above the piston, 1.25 in.^{2}, is vented to the SDV, and initially drops to atmospheric pressure. As soon as drive motion starts, line losses in the discharge line raise the pressure over the piston to about 180 psi. The balance of the over-piston area (4.1 minus 1.25 in.^{2}) is exposed to reactor pressure. Available force, assuming a stuck rod, reduces simply to 1.25 x 1000 or 1250 lb throughout the stroke after accumulator energy is expended. Since the available force is constant at 1250 lb from the beginning of motion to the end of the strokes, no plot of the force developed by the CRD mechanism versus stroke for a scram with the accumulator and RPV at nominal pressure is necessary.

4.5.2.2.3.1 Analysis of Malfunction Relating to Rod Withdrawal

There are no known single malfunctions that cause the unplanned withdrawal of even a single control rod. However, if multiple malfunctions are postulated, studies show that an unplanned rod withdrawal can occur at withdrawal speeds that vary with the combination of malfunctions postulated. In all cases the subsequent withdrawal speeds are less than that assumed in the control rod drop accident analysis as discussed in Subsection 15.4.9.

Therefore, the physical and radiological consequences of such rod withdrawals are less than those analyzed in the control rod drop accident.

Drive Housing Fails at Attachment Weld

The bottom head of the RPV has a penetration for each CRD location. A CRD housing is raised into position inside each penetration and fastened by welding. The CRD is raised into the CRD housing and bolted to a flange at the bottom of the housing. The housing material is seamless, type 304 stainless steel pipe with a minimum tensile strength of 75,000 psi. The basic failure considered here is a complete circumferential crack through the housing wall at an elevation just below the J-weld.

Static loads on the housing wall include the weight of the CRD and the control rod, the weight of the housing below the J-weld, and the reactor pressure acting on the 6-in.-diameter cross-sectional area of the housing and the CRD. Dynamic loading results from the reaction force during CRD operation.

If the housing were to fail as described, the following sequence of events is foreseen. The housing would separate from the RPV. The control rod, CRD, and housing would be blown downward against the support structure by reactor pressure acting on the cross-sectional area of the housing and the CRD. The downward motion of the CRD and associated parts would be determined by the gap between the bottom of the CRD and the support structure and by the deflection of the support structure under load. In the current design, maximum deflection is approximately 3 in. If the collet were to remain latched, no further control rod ejection would occur (Reference 9); the housing would not drop far enough to clear the RPV penetration. Reactor water would leak at a rate of approximately 180 gpm through the 0.03-in. diametral clearance between the housing and the RPV penetration.

If the basic housing failure were to occur while the control rod is being withdrawn (this is a small fraction of the total CRD operating time), and if the collet were to stay unlatched, the following sequence of events is foreseen: the housing would separate from the RPV and the drive and housing would be blown downward against the CRD housing support. Calculations indicate that the steady-state rod withdrawal velocity would be 0.3 fps. During withdrawal, pressure under the collet piston would be approximately 250 psi greater than the pressure over it. Therefore, the collet would be held in the unlatched position until driving pressure was removed from the pressure-over port.

Rupture of Hydraulic Line(s) to Control Rod Drive Housing Flange

There are three types of possible rupture of hydraulic lines to the CRD housing flange:

a. Pressure-under line break

b. Pressure-over line break

c. Coincident breakage of both of these lines.

For the case of a pressure-under line break, a partial or complete circumferential opening is postulated at or near the point where the line enters the housing flange. Failure is more likely to occur after another basic failure wherein the CRD housing or housing flange separates from the RPV. Failure of the housing, however, does not necessarily lead directly to failure of the hydraulic lines.

If the pressure-under line were to fail and if the collet were latched, no control rod withdrawal would occur. There would be no pressure differential across the collet piston and therefore no tendency to unlatch the collet. Consequently, the associated control rod could not be inserted or withdrawn.

The ball check valve is designed to seal off a broken pressure-under line by using reactor pressure to shift the check ball to its upper seat. If the ball check valve were prevented from seating, reactor water would leak to the atmosphere. Because of the broken line, cooling water could not be supplied to the CRD involved. Loss of cooling water would cause no immediate damage to the CRD. However, prolonged exposure of the CRD to temperatures at or near reactor temperature could lead to deterioration of material in the seals. High temperature would be indicated to the operator by the thermocouple in the position-indicator probe. A second indication would be high cooling water flow.

If the basic line failure were to occur while the control rod is being withdrawn, the hydraulic force would not be sufficient to hold the collet open, and spring force normally would cause the collet to latch and stop rod withdrawal. However, if the collet were to remain open, calculations indicate that the steady-state control rod withdrawal velocity would be 2 fps.

The case of the pressure-over line break considers the complete breakage of the line at or near the point where it enters the housing flange. If the line were to break, pressure over the CRD piston would drop from reactor pressure to atmospheric pressure. Any significant reactor pressure (approximately 600 psig or greater) would act on the bottom of the CRD piston and fully insert the CRD. Insertion would occur regardless of the operational mode at the time of the failure. After full insertion, reactor water would leak past the stop piston seals, the contracting seals on the drive piston, and the collet piston seals. This leakage would exhaust to the atmosphere through the broken pressure-over line. The leakage rate at 1000 psi reactor pressure is estimated to be 4 gpm nominal but not more than 80 gpm, based on experimental measurements. If the reactor were hot, drive temperature would increase. This situation would be indicated to the reactor operator by the drift alarm, by the fully inserted drive, by a high drive temperature (indicated and printed out on a recorder in the relay room), and by operation of the drywell sump pump.

For the simultaneous breakage of the pressure-over and pressure-under lines, pressures above and below the CRD piston would drop to zero, and the ball check valve would close the broken pressure-under line. Reactor water would flow from the annulus outside the CRD, through the RPV ports, and to the space below the drive piston. As in the case of pressure-over line breakage, the CRD would then insert (if the reactor were above 600 psi) at a speed dependent on reactor pressure. Full insertion would occur regardless of the operational mode at the time of failure. Reactor water would leak past the CRD seals and out the broken pressure-over line to the atmosphere, as described previously. Control rod drive temperature would increase. Indication in the main control room would include the drift alarm, the fully inserted CRD, the high CRD temperature printed out on a recorder in the relay room, and operation of the drywell sump pump.

For the evaluation of CRD hydraulic line failures outside the containment, see Subsection 3.6.2.2.6.

<u>All Control Rod Drive Flange Bolts Fail in Tension</u>

Each CRD is bolted to a flange at the bottom of a CRD housing. The flange is welded to the CRD housing. Bolts are made of AISI-4140 steel, with a minimum tensile strength of 125,000 psi. Each bolt has an allowable load capacity of approximately 15,700 lb. Capacity of the eight bolts is approximately 125,800 lb. As a result of the reactor design pressure of l250 psig, the major load on all eight bolts is approximately 45,000 lb.

If a progressive or simultaneous failure of all bolts were to occur, the CRD would separate from the housing. The control rod and the CRD would be blown downward against the support structure. Impact velocity and support structure loading would be slightly less than that for CRD housing failure, because reactor pressure would act on the CRD cross-sectional area only and the housing would remain attached to the RPV. The CRD would be isolated from the cooling-water supply. Reactor water would flow downward past the velocity limiter piston, through the large CRD filter, and into the annular space between the thermal sleeve and the CRD. For worst-case leakage calculations, the large filter is assumed to be deformed or swept out of the way so it would offer no significant flow restriction. At a point near the top of the annulus, where pressure would have dropped to 350 psi, the water would flash to steam and cause choke-flow conditions. Steam would flow down the annulus and out the space between the housing and the CRD flanges to the atmosphere. Steam formation would limit the leakage rate to approximately 840 gpm.

If the collet were latched, control rod ejection would be limited to the distance the CRD can drop before coming to rest on the support structure. There would be no tendency for the collet to unlatch, because pressure below the collet piston would drop to zero. Pressure forces, in fact, exert l435 lb to hold the collet in the latched position.

If the bolts failed during control rod withdrawal, pressure below the collet piston would drop to zero. The collet, with l650 lb return force, would latch and stop rod withdrawal.

<u>Weld Joining Flange to Housing Fails in Tension</u>

The failure considered is a crack in or near the weld that joins the flange to the housing. This crack extends through the wall and completely around the housing. The flange material is forged, type 304 stainless steel, with a minimum tensile strength of 75,000 psi. The housing material is seamless, type 304 stainless steel pipe, with a minimum tensile strength of 75,000 psi. The conventional, full-penetration weld of type 308 stainless steel has a minimum tensile strength approximately the same as that of the parent metal. The design pressure and temperature are l250 psig and 575°F. Reactor pressure acting on the cross-sectional area of the CRD; the weight of the control rod, CRD, and flange; and the dynamic reaction force during CRD operation result in a maximum tensile stress at the weld of approximately 6000 psi.

If the basic flange-to-housing joint failure occurred, the flange and the attached CRD would be blown downward against the support structure. The support structure loading would be slightly less than that for CRD housing failure, because reactor pressure would act only on the CRD cross-sectional area. Lack of differential pressure across the collet piston would cause the collet to remain latched and limit control rod motion to approximately 3 in. Downward CRD movement would be small; therefore, most of the CRD would remain inside the housing. The pressure-under and pressure-over lines are flexible enough to withstand the small displacement and remain attached to the flange. Reactor water would follow the same leakage path described above for the flange-bolt failure, except that exit to the atmosphere would be through the gap between the lower end of the housing and the top of the flange. Water would flash to steam in the annulus surrounding the CRD. The leakage rate would be approximately 840 gpm.

If the basic failure were to occur during control rod withdrawal (a small fraction of the total operating time) and if the collet were held unlatched, the flange would separate from the housing. The CRD and flange would be blown downward against the support structure. The calculated steady-state rod withdrawal velocity would be 0.13 fps. Because pressure-under and pressure-over lines remain intact, driving water pressure would continue to the CRD, and the normal exhaust line restriction would exist. The pressure below the velocity limiter piston would drop below normal as a result of leakage from the gap between the housing and the flange. This differential pressure across the velocity limiter piston would result in a net downward force of approximately 70 lb. Leakage out of the housing would greatly reduce the pressure in the annulus surrounding the CRD. Thus, the net downward force on the CRD piston would be less than normal. The overall effect of these events would be to reduce rod withdrawal to approximately one-half normal speed. With a 560-psi differential across the collet piston, the collet would remain unlatched; however, it should relatch as soon as the CRD signal is removed.

Housing Wall Ruptures

This failure is a vertical split in the CRD housing wall just below the bottom head of the RPV. The flow area of the hole is considered equivalent to the annular area between the CRD and the thermal sleeve. Thus, flow through this annular area, rather than flow through the hole in the housing, would govern leakage flow. The housing is made of type 304 stainless steel seamless pipe, with a minimum tensile strength of 75,000 psi. The maximum hoop stress of 5530 psi results primarily from the reactor design pressure (1250 psig) acting on the inside of the housing.

If such a rupture were to occur, reactor water would flash to steam and leak through the hole in the housing to the atmosphere at approximately 1030 gpm. Choke-flow conditions would exist, as described above for the flange-bolt failure. However, leakage flow would be greater because flow resistance would be less; that is, the leaking water and steam would not have to flow down the length of the housing to reach the atmosphere. A critical pressure of 350 psi causes the water to flash to steam.

No pressure differential across the collet piston would tend to unlatch the collet; but the CRD would insert as a result of loss of pressure in the CRD housing, causing a pressure drop in the space above the CRD piston.

If this failure occurred during control rod withdrawal, CRD withdrawal would stop, but the collet would remain unlatched. The CRD would be stopped by a reduction of the net downward force on the CRD line. The net force reduction would occur when the leakage flow of 1030 gpm reduces the pressure in the annulus outside the CRD to approximately 540 psig, thereby reducing the pressure acting on top of the CRD piston to the same value. A pressure differential of approximately 710 psi would exist across the collet piston and hold the collet unlatched as long as the operator held the withdraw signal.

Flange Plug Blows Out

To connect the RPV ports with the bottom of the ball check valve, a hole of 3/4-in. diameter is drilled in the CRD flange. The outer end of this hole is sealed with a plug of 0.812-in. diameter and 0.250-in. thickness. A full-penetration, type 308 stainless steel weld holds the plug in place. The postulated failure is a full circumferential crack in this weld and subsequent blowout of the plug.

If the weld was to fail, the plug was to blow out, and the collet remained latched, there would be no control rod motion. There would be no pressure differential across the collet piston acting to unlatch the collet. Reactor water would leak past the velocity limiter piston, down the annulus between the CRD and the thermal sleeve, through the RPV ports and drilled passage, and out the open plug hole to the atmosphere at approximately 320 gpm. Leakage calculations assume only liquid flows from the flange. Actually, hot reactor water would flash to steam, and choke-flow conditions would exist. Thus, the expected leakage rate would be lower than the calculated value. Control rod temperature would increase and initiate an alarm in the control room.

If this failure were to occur during control rod withdrawal and if the collet were to stay unlatched, calculations indicate that control rod withdrawal speed would be approximately 0.24 fps. Leakage from the open plug hole in the flange would cause reactor water to flow downward past the velocity limiter piston. A small differential pressure across the piston would result in an insignificant driving force of approximately 10 lb, tending to increase withdrawal velocity.

A pressure differential of 295 psi across the collet piston would hold the collet unlatched as long as the driving signal was maintained.

Flow resistance of the exhaust path from the CRD would be normal because the ball check valve would be seated at the lower end of its travel by pressure under the CRD piston.

<u>Ball Check Valve Plug Blows Out</u>

As a means of access for machining the ball check valve cavity, a 1.25-in.-diameter hole has been drilled in the flange forging. This hole is sealed with a plug of 1.31-in. diameter and 0.38-in. thickness. A full-penetration weld, utilizing type 308 stainless steel filler, holds the plug in place. The failure postulated is a circumferential crack in this weld leading to a blowout of the plug.

If the plug were to blow out while the drive was latched there would be no control rod motion. No pressure differential would exist across the collet piston to unlatch the collet. As in the previous failure, reactor water would flow past the velocity limiter, down the annulus between the drive and thermal sleeve, through the vessel ports and drilled passage, through the ball check valve cage, and out the open plug hole to the drywell. The leakage calculations indicate the flow rate would be 350 gpm. This calculation assumes liquid flow, but flashing of the hot reactor water to steam would reduce this rate to a lower value.

Drive temperature would rapidly increase and initiate an alarm in the control room.

If the plug failure were to occur during control rod withdrawal (it would not be possible to unlatch the drive <u>after</u> such a failure), the collet would relatch at the first locking groove. If the collet were to stick, calculations indicate the control rod withdrawal speed would be 11.8 fps. There would be a large retarding force exerted by the velocity limiter because of a 35-psi pressure differential across the velocity limiter piston.

Control Rod Drive Pressure Control Valve Closure (Reactor Pressure, 0 psig)

The pressure to move a CRD is controlled by adjustment of the drive/cooling water pressure control valve. This valve is motor-operated and adjusted to a fixed opening. The normal pressure drop across this valve is 230 psi.

If the flow through the CRD pressure control valve were to be stopped, as by a valve closure or flow blockage, the CRD pressure would increase to the shutoff pressure of the supply pump. The occurrence of this condition during withdrawal of a CRD at zero RPV pressure will result in a CRD pressure increase from 260 psig to no more than 1600 psig. Calculations indicate that the drive would accelerate from 3 in./sec to approximately 6 in./sec. A pressure differential of l670 psi across the collet piston would hold the collet unlatched. Flow would be upward, past the velocity limiter piston, but retarding force would be negligible. Rod movement would stop as soon as the driving signal was removed.

Ball Check Valve Fails To Close Passage to Reactor Pressure Vessel Ports

Should the ball check valve sealing the passage to the RPV ports be dislodged and prevented from reseating following the insert portion of a CRD withdrawal sequence, water below the CRD piston would return to the reactor through the RPV ports and the annulus between the CRD and the housing rather than through the speed control valve. Because the flow resistance of this return path would be lower than normal, the calculated withdrawal speed would be 2 fps. During withdrawal, differential pressure across the collet piston would be approximately 40 psi. Therefore, the collet would tend to latch and would have to stick open before continuous withdrawal at 2 fps could occur. Water would flow upward past the velocity limiter piston, generating a small retarding force of approximately 120 lb.

Hydraulic Control Unit Valve Failures

Various failures of the valves in the HCU can be postulated, but none could produce differential pressures approaching those described in the preceding paragraphs and none alone could produce a high velocity withdrawal. Leakage through either one or both of the scram valves produces a pressure that tends to insert the control rod rather than to withdraw it. If the pressure in the scram discharge volume should exceed reactor pressure following a scram, a check valve in the line to the scram discharge header prevents this pressure from operating the CRD mechanisms.

Collet Fingers Fail To Latch

The failure is presumed to occur when the drive withdraw signal is removed. If the collet fails to latch, the drive continues to withdraw at a fraction of the normal speed. This assumption is made because there is no known means for the collet fingers to become unlocked without some initiating signal. Because the collet fingers will not cam open under a load, accidental application of a down signal does not unlock them. (The drive must be given a short insert signal to unload the fingers and cam them open before the collet can be driven to the unlock position.) If the drive withdrawal valve fails to close following a rod withdrawal, the collet would remain open and the drive continue to move at a reduced speed.

Withdrawal Speed Control Valve Failure

Normal withdrawal speed is determined by differential pressures in the CRD and is set for a nominal value of 3 in./sec. Withdrawal speed is maintained by the pressure regulating system and is independent of RPV pressure. Tests have shown that accidental opening of the speed control valve to the full-open position produces a velocity of approximately 6 in./sec. The CRD system prevents rod withdrawal and it has been shown above that only multiple failures in a CRD unit and in its control unit could cause an unplanned rod withdrawal.

4.5.2.2.3.2 Scram Reliability

High scram reliability is the result of a number of features of the CRD system. For example

a. An individual accumulator is provided for each control rod drive with sufficient stored energy to scram at lower reactor pressures. The reactor vessel itself, at pressures above 600 psi, will supply the necessary force to insert a drive

b. Each drive mechanism has its own scram and pilot valves so only one drive can be affected if a scram valve fails to open. Two pilot valves are provided for each drive. Both pilot valves must be deenergized to initiate a scram

c. The RPS and the HCUs are designed so that the scram signal and mode of operation override all others

d. The collet assembly and index tube are designed so they will not restrain or prevent control rod insertion during scram

e. The SDV is monitored for accumulated water and will scram the reactor before the volume is reduced to a point that could interfere with a scram.

4.5.2.2.3.3 Control Rod Support and Operation

Each control rod is independently supported and controlled as required by safety design bases.

4.5.2.2.3.4 Common Mode Failures of Reactivity Control Systems

The CRD system and the standby liquid control system (SLCS), which is the backup reactivity control system, do not share any instrumentation or components. Thus, a common mode failure of the reactivity systems would be limited to an accident event that could damage essential equipment in the two independent systems.

A seismic event or the postulated accident environments are not considered potential common mode failures because the essential (scram) portions of the CRD system are designed to Category I standards and to operate as required under the environmental conditions of the postulated design-basis accident. The SLCS is tested and maintained as a safety-related system.

No common mode power failure is considered credible. The scram function of the CRD system is fail-safe on a loss of power and is designed to override any other function of the CRD system. The SLCS has two independent power supplies to its essential redundant pumps and valves. The power supplies to the SLCS are switched to the onsite standby diesels on a loss of normal power sources.

The design of the SDV incorporates separate instrument volumes for each division of CRDs. Each SDV 8-in. header is integrally coupled to its 12-in. instrument volume. This design is not susceptible to the common mode problem of earlier designs caused by a 2-in. line connecting the SDVs to a single instrument volume.

General Electric completed a reliability analysis of the BWR scram system in 1976. The overall probability of failure was assessed to be 5 x 10^{-6} per year. The major contributor to this failure probability value was a common mode failure in the electrical trip circuit. The analysis identified design modifications that were made and that reduced the failure probability value to less than 1 x 10^{-7} per year.

The most recent analysis of CRD system reliability, which takes into account the design changes directed at reducing the potential for common mode failure in the mechanical portion of the CRD system (i.e., changes in the SDV), reaffirms that the CRD unreliability value is still estimated to be less than 1 x 10^{-7} per year.

NOTE: General Electric defined failure to be noninsertion of the CRDs in the following manner: greater than 50 percent in a checkerboard pattern, greater than 31 percent in a random pattern, or more than 4 in a cluster.

4.5.2.2.4 Inspection and Testing

4.5.2.2.4.1 Development Tests

The development drive (one prototype) testing up to the submittal of the original FSAR included more than 5000 scrams and approximately 100,000 latching cycles. One prototype was exposed to simulated operating conditions for 5000 hr. These tests yielded the following results:

a. The drive easily withstands the forces, pressures, and temperatures imposed

b. Wear, abrasion, and corrosion of the nitrided type 304 stainless steel parts are negligible. Mechanical performance of the nitrided surface is superior to that of materials used in earlier operating reactors

c. The basic scram speed of the CRD has a satisfactory margin above minimum plant requirements at any RPV pressure

d. Usable seal lifetimes in excess of l000 scram cycles can be expected.

4.5.2.2.4.2 Factory Quality Control Tests

Quality control of welding, heat treatment, dimensional tolerances, material verification, and similar factors is maintained throughout the manufacturing process to ensure reliable performance of the mechanical reactivity control components. Some of the quality control tests performed on the CRD mechanisms and HCUs follow.

a. Control rod drive mechanism tests

    1. Pressure welds on the CRDs are hydrostatically tested in accordance with ASME codes

    2. Electrical components are checked for electrical continuity and resistance to ground

3. Control rod drive parts that cannot be visually inspected for dirt are flushed with filtered water at high velocity. No significant foreign material is permitted in effluent water
4. Seals are tested for leakage to demonstrate correct seal operation
5. Each CRD is tested for shim motion, latching, and control rod position indication
6. Each drive is subjected to cold scram tests at various reactor pressures to verify correct scram performance.

b. <u>Hydraulic-control unit tests</u>

1. Hydraulic systems are hydrostatically tested in accordance with the applicable code
2. Electrical components and systems are tested for electrical continuity and resistance to ground
3. Correct operation of the accumulator pressure and level switches is verified
4. The unit's ability to perform its part of a scram is demonstrated. Correct operation and adjustment of the insert and withdrawal valves are demonstrated.

4.5.2.2.4.3 <u>Operational Tests</u>

After installation, all rods and CRD mechanisms can be tested through their full stroke for operability.

During normal operation, each time a control rod is withdrawn a notch, the operator can observe the in-core monitor indications to verify that the control rod is following the CRD mechanism. All control rods that are partially withdrawn from the core can be tested for rod following by inserting or withdrawing the rod one notch and returning it to its original position, while the operator observes the in-core monitor indications.

To make a positive test of control rod to CRD coupling integrity, the operator can withdraw a control rod to the end of its travel and then attempt to withdraw the CRD to the overtravel position. Failure of the CRD to overtravel demonstrates rod-to-drive coupling integrity.

Hydraulic supply subsystem pressures can be observed from instrumentation in the main control room. Scram accumulator pressures can be observed on the nitrogen pressure gages.

4.5.2.2.4.4 <u>Acceptance Tests</u>

Criteria for acceptance of the individual CRD mechanisms and the associated control and protection systems were incorporated in specifications and test procedures covering three distinct phases: preinstallation, after installation prior to startup, and during startup testing.

The preinstallation specification defined criteria and acceptable ranges of such characteristics as seal leakage, friction, and scram performance under fixed test conditions, which must be met before the component can be shipped.

The after-installation, prestartup tests included normal and scram motion and were primarily intended to verify that piping, valves, electrical components, and instrumentation were properly installed. The test specifications included criteria and acceptable ranges for CRD speed, time settings, scram valve response times, and control pressures. These tests were intended more to document system condition than to test performance.

During initial preoperational testing, an observer who was in direct communication with the control room observed the operation of each individual control rod and verified that there was no binding or restriction to rod motion and listened for any scraping or binding noises that might signify rod misalignment. In addition, the friction of each CRD was measured as indicated by the differential pressure developed across the CRD piston during notch withdrawal. These differential pressure traces were compared against reference traces to ensure proper operation and the absence of abnormal friction.

As fuel was placed in the reactor, the startup test procedure was followed. The tests in this procedure are intended to determine that the initial operational characteristics meet the limits of the specifications over the range of primary coolant temperatures and pressures from ambient to operating. The initial testing program is described in Chapter 14.

4.5.2.2.4.5 Surveillance Tests

The surveillance requirements for the CRD system are included in the Technical Specifications.

To detect any increased friction of the control rods due to postulated bowing of the fuel channel boxes, Edison has committed to a surveillance program that includes guidelines for channel box rotation to minimize the potential for channel bowing. In addition, periodic channel box bow testing monitors for appropriate settle time and abnormal rod motion that can be attributable to bow. Settle time is assessed for every control rod movement from control rod position 46 to 00 during normal rod motion as well as during a test. Channel box friction measurements also monitor for channel bow. Analytical assessments are performed each cycle to keep track of high friction cells so mitigating actions can be employed to prevent control rod blade interference. Reference 15 details many of the acceptable channel box bow monitoring methods employed.

Fermi 2 has implemented a program that addresses a possible problem with IGSCC in the collet assembly of the CRD mechanism. The program is consistent with GE recommendations. It consists of the following three parts:

a. An augmented surveillance and inspection program

b. Modification of CRD operations to eliminate unnecessary thermal cycling

c. Modification of the CRD water supply to provide high-purity deaerated water to the CRD system during plant operation.

The Fermi 2 program consists of the following corresponding actions:

a. Each rod not fully inserted will be tested to confirm operability by inserting one or more notches in accordance with the frequency specified in the Technical Specifications.

   All CRDs removed from the reactor for maintenance or for access to inservice CRD housing inspections will have a dye penetrant examination made of the outer surface of the collet retainer tube. CRDMs which do not experience any performance problems and are removed for inspection undervessel, or to replace a flange o-ring, for example, will not require a dye penetrant examination. CRDMs that are rebuilt after seeing reactor service will receive a dye penetrant examination of the collet retainer tube. The criteria established by GE in Service Information Letter (SIL) 139 will be used to decide rejection. The term collet retainer tube refers to a portion of the outer tube, and replacement of a rejected collet retainer tube requires a new cylinder, tube, and flange subassembly

b. A CRD with a high-temperature alarm will not be cooled by giving it repeated drive signals.

c. The source of water for the CRD system has been changed to the condensate treatment system effluent with the condensate storage tank as backup. The water source is very pure and of very low oxygen content

   A flowing sample line downstream of the drivewater filter has been installed to provide for conductivity and oxygen grab sample measurement.

The use of high-purity deaerated water effects a significant increase in the time to crack formation. General Electric estimated that the time to crack initiation in current CRD collet retainer tubes may be increased by a factor of 100 with this reduction in dissolved oxygen content.

4.5.2.2.4.6 Instrumentation

The general functional requirements for the CRD are discussed in Subsection 4.5.2.1.5.

4.5.2.3 Supplementary Reactivity Control

4.5.2.3.1 Design Basis

The fuel rods containing supplementary reactivity control shall have sufficient mechanical strength to prevent displacement of their reactivity control material.

4.5.2.3.2 Description

The reactivity control requirements of the initial core load considerably exceed the equilibrium core requirements because all the fuel in the initial core loading is fresh. To meet the reactivity control requirements of the initial core load, or any core load with excess reactivity, gadolinia-urania fuel rods are placed in each enriched fuel assembly. Some assemblies contain more gadolinium than others to improve transverse power flattening.

Also, some assemblies contain axially distributed gadolinium to improve axial power flattening. For a detailed discussion of gadolinia fuels, refer to Subsection 4.3.2.

4.5.2.3.3 Safety Evaluation

The description shows that the gadolinia-urania fuel rods meet the design-basis requirements (Subsection 4.3.2).

4.5.2.3.4 Inspection and Testing

The same rigid quality control requirements observed for standard UO_2 fuel are employed in manufacturing gadolinia-urania fuel. Gadolinia-bearing UO_2 fuel pellets of a given enrichment and gadolinia concentration are maintained in separate groups throughout the manufacturing process. The percent enrichment and gadolinia concentration characterizing a pellet group are identified by a stamp on the pellet.

Fuel rods are individually numbered prior to loading of fuel pellets into the fuel rods for three reasons: to identify which pellet group is to be loaded in each fuel rod, to identify which position in the fuel assembly each fuel rod is to be loaded into, and to facilitate total material accountability for a given project. For the initial core, longer upper end plug shanks for gadolinia-bearing rods ensured their correct placement within the fuel assembly. For reload cores, a uniform end plug is used for all rods. Correct placement is ensured by an automated bundle assembly machine.

The following QC inspections are made.

a. Gadolinia concentration in the gadolinia-urania powder blend is verified

b. Sintered pellet UO_2-Gd_2O_3 solid-solution homogeneity across a fuel pellet is verified by examination of metallographic specimens

c. Gadolinia-urania pellet identification is verified

d. Gadolinia-urania fuel rod identification is checked.

All assemblies and rods of a given project are inspected to ensure overall accountability of fuel quantity and placement for the project.

4.5.2.4 Standby Liquid Control System

4.5.2.4.1 Design Bases

The standby liquid control system (SLCS) is a special-event plant capability system and is tested and maintained as a safety-related system. The system is designed with a high degree of reliability and with certain safety features; however, it is not required to meet the safety design-basis requirements of the safety systems. The SLCS process equipment, instrumentation and control essential for injection of the sodium pentaborate solution into the reactor are designed to withstand the safe shutdown earthquake.

The SLCS shall meet the following design bases:

a. Backup capability for reactivity control shall be provided, independent of normal reactivity control provisions in the nuclear reactor, to be able to shut down the reactor if the normal control ever becomes inoperative

b. The backup system shall have the capacity for controlling the reactivity difference between the steady-state rated operating condition of the reactor with voids and the cold shutdown condition, including shutdown margin, to ensure complete shutdown from the most reactive condition at any time in core life

c. The time required for actuation and effectiveness of the backup control shall be consistent with the nuclear reactivity rate of change predicted between rated operating and cold shutdown conditions. A fast scram of the reactor or operational control of fast reactivity transients is not specified to be accomplished by this system

d. Means shall be provided by which the functional performance capability of the backup control system components can be verified periodically under conditions approaching actual use requirements. A substitute solution, rather than the actual neutron absorber solution, can be injected into the reactor to test the operation of all components of the redundant control system

e. The neutron absorber shall be dispersed within the reactor core in sufficient quantity to provide a reasonable margin for leakage or imperfect mixing

f. The system shall be reliable to a degree consistent with its role as a control system; the possibility of unintentional or accidental shutdown of the reactor by this system shall be minimized

g. The system shall have the capability of controlling suppression pool pH following a LOCA in the event of fuel failure.

4.5.2.4.2 Description

The SLCS (Figure 4.5-17) is manually initiated from the main control room to pump a boron neutron absorber solution into the reactor if the operator believes the reactor cannot be shut down or kept shut down with the control rods. However, insertion of control rods is expected to ensure prompt shutdown of the reactor should it be required.

The SLCS is required to shut down the reactor and keep the reactor from going critical again as it cools. In addition, SLC is required to control suppression pool pH following a LOCA in the event of fuel failure.

The SLCS is needed in the improbable event that not enough control rods can be inserted in the reactor core to accomplish shutdown and cooldown in the normal manner.

The storage tank and active portion of the SLCS necessary for the injection of boron have been reclassified to identify that the SLCS was not originally intended, procured, designed, or classified as safety related, but is being maintained and tested as a safety-related system after completion of its preoperational tests.

The boron solution tank, the test water tank, the two positive-displacement pumps, the two explosive valves, and associated local valves and controls are mounted in the reactor building. The liquid is piped into the RPV and discharged near the bottom of the core shroud so it mixes with the cooling water rising through the core (Subsection 4.5.1.2 and Figure 4.5-2).

The boron absorbs thermal neutrons and thereby terminates the nuclear fission chain reaction in the uranium fuel.

The specified neutron absorber solution is enriched sodium pentaborate ($Na_2B_{10}O_{16} \cdot 10H_2O$) dissolved in demineralized water. An air sparger is provided in the tank for mixing. To prevent system plugging, the tank outlet is raised above the bottom of the tank.

Whenever it is possible to make the reactor critical, the SLCS shall be able to deliver enough sodium pentaborate solution into the reactor (Figure 4.5-18) to ensure reactor shutdown. This is accomplished by placing the required amount of sodium pentaborate in the standby liquid control tank and filling with demineralized water to at least the low-level alarm point.

The saturation temperature of the recommended solution is approximately 40°F. The SLC tank is installed in a room in which the air temperature is to be maintained within the range of 70°F to 100°F. High or low temperature, or high or low liquid level, causes an alarm in the main control room.

The lines and equipment from the storage tank to the explosive valves are insulated.

The SLCS is completely contained within the reactor building. This building is well heated and ventilated; it also receives most of the heat loss from the reactor system. It is therefore incredible for the water in the SLCS to freeze while the plant is operating.

Each positive displacement pump is sized to inject the solution into the reactor in 50 to 125 minutes, independent of the amount of solution in the tank. The pump and system design pressure between the explosive valves and the pump discharge is 1400 psig. The two relief valves are set slightly under 1400 psig. To prevent bypass flow from one pump in case of relief valve failure in the line from the other pump, a check valve is installed downstream of each relief valve line in the pump discharge pipe.

SLC is manually initiated upon indication of fuel failure following a LOCA to control suppression pool pH in order to prevent iodine re-evolution. The analysis shows that SLC injection and mixing within 6 hours of the beginning of the event will maintain suppression pool pH 7.0 or higher for the 30-day duration of the accident. The amount of sodium pentaborate solution that is required for reactivity control is sufficient for pH control.

The two explosive-actuated injection valves provide assurance of opening when needed and ensure that boron does not leak into the reactor even when the pumps are being tested.

Each explosive valve is closed by a plug in the inlet chamber. The plug is circumscribed with a deep groove so the end readily shears off when pushed with the valve plunger. This opens the inlet hole through the plug. The sheared end is pushed out of the way in the chamber; it is shaped so it does not block the ports after release.

The shearing plunger is actuated by an explosive charge with dual ignition primers inserted in the side chamber of the valve.

Ignition circuit continuity is monitored by a trickle current, and an alarm occurs in the main control room if either circuit opens. Indicator lights show which primary circuit opened.

The SLCS is actuated by a three-position keylocked switch on the main control room console. This ensures that switching from the "off" position is a deliberate act. Switching to either side starts an injection pump, actuates both of the explosive valves, and closes the reactor cleanup system outboard isolation valve to prevent loss or dilution of the boron. This action occurs only if the SLC system is lined up normally. If either SLC pump breaker is racked out, only one pump and explosive actuated injection valve will operate.

A green light in the main control room indicates that power is available to the pump motor contactor and that the contactor is open (pump not running). A red light indicates that the contactor is closed (pump running).

If the pump lights or explosive valve light indicate that the liquid may not be flowing, the operator can immediately turn the switch to the other side, which actuates the alternative pump.

Cross piping and check valves ensure a flow path through either pump and either explosive valve. Placing the local switch in its “off” position will not terminate pump operation if the switch in the main control room has been placed in the “run” position. This prevents the separation of the pump from the main control room. Pump discharge pressure is also indicated in the main control room.

Equipment drains and tank overflow are not piped to the radwaste system but to separate containers (such as 55-gal drums) that can be removed and disposed of independently to prevent any trace of boron from inadvertently reaching the reactor.

Instrumentation consisting of solution temperature indication, solution level, and heater system status is provided locally at the storage tank.

4.5.2.4.3 Safety Evaluation

The SLCS is a suppression pool pH control system and a redundant reactivity control system and is maintained in a standby operational status in the reactor modes 1 and 2. The system is not expected to be needed for safety reasons because of the large number of independent control rods available to shut down the reactor.

However, to ensure the availability of the SLCS, two sets of pumps and explosive valves are provided in parallel redundancy.

The system is designed to bring the reactor from rated power to a cold shutdown at any time in core life. The reactivity compensation provided reduces reactor power from rated to zero level and allows cooling the nuclear system to room temperature, with the control rods remaining withdrawn in the rated power pattern. It includes the reactivity gains that result from complete decay of the rated power xenon inventory. It also includes the positive reactivity effects from eliminating steam voids, changing water density from hot to cold, reducing Doppler effect in uranium, reducing neutron leakage from boiling to cold, and decreasing control rod worth as the moderator cools. The specified minimum final concentration of boron in the reactor core provides a margin of -0.033 Δk for calculational uncertainties and ensures subcriticality.

Fermi 2 meets the requirements of 10CFR50.62, ATWS Rule, by increasing the enrichment of boron-10 to a minimum of 65 atom percent. The current design of the SLC system is sufficient to handle the increased enrichment of sodium pentaborate solution because the enriched boron solution is chemically similar to the current solution. Using an enriched solution will not change any of the key SLC system process parameters, i.e., flow rate, discharge pressure, required NPSH, etc.

The specified minimum average concentration of natural boron in the reactor to provide the specified shutdown margin, after operation of the SLCS, is 720 ppm. This value is increased by 25 percent to 900 ppm to allow for imperfect mixing and leakage. Thus, calculation of the minimum quantity of sodium pentaborate to be injected into the reactor is based on 900 ppm average concentration in the reactor coolant, including recirculation loops and the RHR system in the shutdown cooling mode, at 70°F and reactor water Level 8.

Cooldown of the nuclear system requires a minimum of several hours to remove the thermal energy stored in the reactor cooling water and associated equipment. The controlled limit for the RPV cooldown is 100°F per hour, and normal operating temperature is approximately 550°F. Use of the main condenser and various shutdown cooling systems requires 10 to 24 hr to lower the RPV to room temperature (70°F). SLCS is designed to provide the capability of bringing the reactor, at any temperature and time in a cycle, to a subcritical condition with the reactor in the most reactive xenon-free state with all of the control rods in the full out condition.

The injection rate is limited to a range of 8 to 20 ppm/minute change in boron concentration in reactor water, based on the weight of water in the reactor and recirculation loops at normal water level and 70°F. The lower rate ensures that the boron is injected into the reactor in approximately 2 hr. This resulting reactivity insertion is considerably quicker than that covered by the cooldown. However, power cyclic oscillations from uneven mixing of boron in the core at high delivery rates is not a concern because of the steady boron concentration buildup observed in mixing tests, as documented in NEDC-30921.

The SLCS equipment essential for injection of neutron absorber solution into the reactor is designed to withstand the safe shutdown earthquake and is tested and maintained as safety-related equipment.

The SLCS is required to be operable in the event of a station power failure. Therefore, the pumps, valves, and controls are powered from the standby ac power supply. The pumps and valves are powered and controlled from separate buses and circuits.

The SLCS and pumps have sufficient pressure margin, up to the system relief valve setting of approximately 1400 psig, to ensure solution injection into the reactor above the normal pressure in the bottom of the reactor. The nuclear system relief and safety valves begin to relieve pressure above approximately 1100 psig. Therefore, the SLCS positive displacement pumps cannot overpressurize the nuclear system.

Only one of the two standby liquid control pumps and/or explosive actuated injection valves is needed for system operation. If one pump and/or injection valve is found to be inoperable, there is no immediate threat to shutdown capability, and reactor operation and/or rod movement can continue during repairs. The time during which one redundant component upstream of the explosive valves may be out of operation should be consistent with the following: the probability of failure of both the control rod shutdown capability and the alternative component in the SLCS; and the fact that nuclear system cooldown takes several hours while liquid control solution injection takes approximately 2 hr. Since this probability is small, considerable time is available for repairing and restoring the SLCS to an operable condition while reactor operation continues. Assurance that the system will still fulfill its function during repairs is obtained by maintaining the operable status of the redundant pump/valve combination.

Standard Review Plan (SRP) 4.6 states that the SLCS is reviewed by using SRP 9.3.5 to determine its adequacy to perform its function of reactivity control. The following summarizes the comparison of the Fermi 2 SLCS with the acceptance criteria listed in SRP 9.3.5:

a. The system is housed in the reactor building and therefore meets General Design Criterion (GDC) 2 for withstanding natural phenomena

b. The system is located in a missile-free area on the fourth floor of the reactor building. The system piping is studied for pipe whip and jet impingement effects both inside and outside primary containment. These studies show conformance with GDC 4

c. The SLCS meets the requirements for high functional reliability and inservice testability. However, the system design criteria do not specify a single-failure criterion for tanks and piping, but dual pumps and dual explosive valves are incorporated. The reliability criteria are further discussed elsewhere in this section and in Subsection 4.5.2.2.3.4

d. The SLCS is independent of other control systems and is capable of maintaining the core subcritical under cold conditions. Therefore, GDC 26 and GDC 27 are met

e. The classification of system components is given in Table 3.2-1.

f. The location of the SLCS renders it immune to the effects of flooding and tornado missiles. The system meets the criteria for breaks in piping systems outside the drywell.

A discussion in Subsection 4.5.2.2.3.4 addresses the vulnerability of the CRD system and SLCS to common mode failures. The two systems do not share any instrumentation or components. The probability of a common mode failure in the SLCS is dominated by the failure of an operator to actuate the system in a timely manner. The probability of this type of operator error is estimated to be in the range of 1×10^{-1} to 1×10^{-3} per demand, depending on the time required for system activation.

The amount of sodium pentaborate solution that is required for reactivity control is sufficient for pH control. SLC injection and mixing within 6 hours of the beginning of the event will maintain suppression pool pH 7.0 or higher for the 30-day duration of the accident.

4.5.2.4.4 Inspection and Testing

An operational test is performed on the SLCS on a once per fuel cycle frequency to:

a. Demonstrate that the pump relief valve setpoint is $\leq$ 1400 psig, and

b. Verify that the relief valve does not actuate during recirculation to the test tank.

Operational testing of the SLCS is performed in at least two parts to avoid inadvertently injecting boron into the reactor.

With the valves to and from the storage tank closed and the three valves to and from the test tank opened, demineralized water in the test tank can be recirculated by locally starting either pump.

The injection portion of the system can be functionally tested by valving the pump suction lines to the test tank and actuating the system from the main control room. Each pump loop and its injection valve are tested. System operation is indicated in the main control room.

After functional tests, the injection valve shear plugs and explosive charges must be replaced and all the valves returned to their normal positions as indicated.

After closing a local locked-open valve to the reactor, leakage through the injection valves can be determined by opening valves at a test connection in the line between the containment isolation check valves. Position indicator lights in the main control room indicate that the local valve is closed for tests or open and ready for operation. Leakage from the reactor through the first check valve can be detected by opening the same test connection when the reactor is pressurized.

The test tank contains demineralized water for approximately 3 minutes of pump operation. Demineralized water from the makeup system or the condensate storage system is available for refilling or flushing the system.

Should the boron solution ever be injected into the reactor, either intentionally or inadvertently, after it is made certain that the normal reactivity controls will keep the reactor subcritical, the boron is removed from the reactor coolant system by flushing for gross dilution followed by operating the reactor water cleanup (RWCU) system (Subsection 5.5.8). There is practically no effect on reactor operations when the boron concentration has been reduced below approximately 50 ppm.

The concentration of the sodium pentaborate in the solution tank is determined periodically by chemical analysis.

4.5.2.4.5 Instrumentation

The instrumentation and control system for the SLCS is designed to allow the injection of liquid poison into the reactor. The discussion of the SLCS instrumentation is included in Subsection 7.4.1.

4.5.3 Control Rod Drive Housing Supports

4.5.3.1 Safety Objective

The CRD housing supports prevent any significant nuclear transient in the event a drive housing breaks or separates from the bottom of the RPV.

4.5.3.2 Safety Design Bases

The CRD housing supports shall meet the following safety design bases:

a. Following a postulated CRD housing failure, control rod downward motion shall be limited so that any resulting nuclear transient could not be sufficient to cause fuel damage

b. The clearance between the CRD housings and the supports shall be sufficient to prevent vertical contact stresses caused by thermal expansion during plant operation.

4.5.3.3 Description

The CRD housing supports are shown in Figure 4.5-19. Horizontal beams are installed immediately below the bottom head of the RPV, between the rows of CRD housings. The beams are bolted to brackets welded to the steel form liner of the drive room in the reactor support pedestal.

Hanger rods, approximately 10 ft long and 1-3/4 in. in diameter, are supported from the beams on stacks of disk springs. These springs compress approximately 2 in. under the design load.

The support bars are bolted between the bottom ends of the hanger rods. The spring pivots at the top, and the beveled, loose-fitting ends on the support bars prevent substantial bending movement in the hanger rods if the support bars are overloaded.

Individual grids rest on the support bars between adjacent beams. Because a single-piece grid would be difficult to handle in the limited work space and because it is necessary that CRDs, position indicators, and in-core instrumentation components be accessible for inspection and maintenance, each grid is designed for in-place assembly or disassembly. Each grid assembly is made up of two grid plates, a clamp, and a bolt. The top part of the clamp guides the grid to its correct position directly below the respective CRD housing that it would support in the postulated accident.

When the support bars and grids are installed, a gap of approximately 1 in. at room temperature (approximately 70°F) is provided between the grid and the bottom contact surface of the CRD flange.

During system heatup, this gap is reduced by a net downward expansion of the housings with respect to the supports. In the hot operating condition, the gap is approximately 1/4 in.

In the postulated CRD housing failure, the CRD housing supports are loaded when the lower contact surface of the CRD flange contacts the grid. The resulting load is then carried by two grid plates, two support bars, four hanger rods, their disk springs, and two adjacent beams.

The American Institute of Steel Construction (AISC) Manual of Steel Construction, "Specification for the Design, Fabrication and Erection of Structural Steel for Buildings," was used as a guide in designing the CRD housing support system. However, to provide a structure that absorbs as much energy as practical without yielding, the allowable tension and bending stresses used were 90 percent of yield and the shear stress used was 60 percent of yield. These design stresses are 1.5 times the AISC allowable stresses (60 percent and 40 percent of yield, respectively).

For purposes of mechanical design, the postulated failure resulting in the highest forces is an instantaneous circumferential separation of the CRD housing from the RPV, with an internal pressure of 1250 psig (RPV design pressure) acting on the area of the separated housing. The weight of the separated housing, CRD, and blade, plus the pressure of 1250 psig acting on the area of the separated housing, gives a force of approximately 35,000 lb. This force is multiplied by a factor of three for impact, conservatively assuming that the housing travels through a 1-in. gap before it contacts the supports. The total force (105,000 lb) is then treated as a static load in design.

Selected CRD housing support hanger rods have TIP guide tube supports attached below the support bars.

All CRD housing support subassemblies are fabricated of ASTM-A-36 structural steel, except for the following items:

Item	Material
Grid	ASTM-A-441
Disk springs	Schnorr, Type BS-125-71-8
Hex bolts and nuts	ASTM-A-307
Structure tubing	ASTM-A-46

4.5.3.4 Safety Evaluation

For design purposes, the postulated failure resulting from an instantaneous circumferential separation of the CRD housing from the RPV, with an internal pressure of 1250 psig (RPV design pressure) acting on the area of the separated housing, is the governing design condition. The vertical force (dead load) of the separated housing, CRD, and blade plus the force of 1250 psig pressure acting on the area of the separated housing multiplied by an impact factor of three gives the design static load on the CRD housing support members. The effect of an earthquake on the design load is not considered in the design because the earthquake load is only 3 percent of the design load.

Downward travel of the CRD housing and its control rod following the postulated housing failure equals the sum of these distances:

a. The compression of the disk springs under dynamic loading

b. The initial gap between the grid and the bottom contact surface of the CRD flange. If the reactor were cold and pressurized, the downward motion of the control rod would be limited to the spring compression (approximately 2 in.) plus a gap of approximately 1 in. If the reactor were hot and pressurized, the gap would be approximately l/4 in. and the spring compression would be slightly less than in the cold condition. In either case, the control rod movement following a housing failure is substantially limited below one drive notch movement (6 in.). Sudden withdrawal of any control rod through a distance of one drive notch at any position in the core does not produce a transient sufficient to damage any radioactive material barrier.

The stress criterion (1.5 times the AISC allowable stresses) is considered desirable for this application and adequate for the "once in a lifetime" loading condition.

The CRD housing supports are in place during power operation and when the nuclear system is pressurized. If a control rod is ejected during shutdown, the reactor remains subcritical because it is designed to remain subcritical with any one control rod fully withdrawn at any time.

At plant operating temperature, a gap of approximately 1/4 in. exists between the CRD housing and the supports. At lower temperatures the gap is greater. Because the supports do not contact any of the CRD housing except during the postulated accident condition, vertical contact stresses are prevented.

4.5.3.5 Inspection and Testing

CRD housing supports are removed for inspection and maintenance of the CRDs. The supports for one control rod can be removed during reactor shutdown, even when the reactor is pressurized, because all control rods are then inserted. When the support structure is reinstalled, it is inspected for correct assembly with particular attention to maintaining the correct gap between the CRD flange lower contact surface and the grid.

4.5 REACTOR MECHANICAL DESIGN

REFERENCES

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5. Fermi Response to AEC, "Control Rod Guide Tube Collapse," General Electric Manual 383HA936, August 2, 1973.
6. Letter from C. M. Heidel, Detroit Edison, to A. Giambusso, AEC, EF2-16969, May 9, 1973.
7. Letter from C. M. Heidel Detroit Edison, to A. Giambusso, AEC, EF2-2l952, February 14, 1974.
8. R. G. Stirn et al., Rod Drop Accident Analysis for Large Boiling Water Reactors, NEDO-10527, March 1972.
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10. Detroit Edison Company, "Proposed License Amendment - Power Uprate, Power Uprate Safety Analysis," Fermi 2-91-150, September, 1991.
11. GE Nuclear Energy, "Maximum Extended Operating Domain Analysis for Detroit Edison Company, Enrico Fermi Energy Center," NEDC-31843P, July, 1990.
12. Safety Evaluation By The Office Of Nuclear Reactor Regulation Related To Amendment No. 134 To Facility Operating License No. NPF-43, Detroit Edison Company Fermi-2, Docket No. 50-341, October 7, 1999.
13. NRC letter from D. Eisenhut to R.Gridley, GE, January 28, 1980.
14. GE 14 Fuel Design Cycle – Independent Analysis for Fermi Unit 2, GE-NE-0000-0025-3282-00, Table 4-3, November 2004.
15. Letter from H. Tauber, Detroit Edison, to L. Kintner, NRC, EF2-60333, December 3, 1982.
16. TRVEND 24MCGNF3FTRT1104, "GE Hitachi, GNF3 Fuel Design Cycle Independent Analyses for Fermi 2 Power Plant," Revision 0, November 2019. GEH File Number 004N7423, Edison File # T19-158.

TABLE 4.5-1 DEFORMATION LIMIT

(For Reactor Internal Structures Only)

Either One of (Not Both)[a]	General Limit
a. $\frac{DP}{DL}$	$\leq \frac{0.9}{SF_{min}}$
b. $\frac{DP}{DE}$	$\leq \frac{1.0}{SF_{min}}$

where

DP = permissible deformation under stated conditions of normal, upset, emergency, or faulted

DL = analyzed deformation that could cause a system loss of function[b]

DE = experimentally determined deformation that could cause a system loss of function

SF_{min} = minimum safety factor

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[a] Equation b. is not used because equation a criteria are met. (Equation b. will not be used unless supporting data are provided to the NRC by GE.)

[b] "Loss of function" can only be defined quite generally until attention is focused on the component of interest. In cases of interest, where deformation limits can affect the function of equipment and components, they will be specifically delineated. From a practical viewpoint, it is convenient to interchange some deformation condition at which function is ensured with the loss of function condition if the required safety margins from the functioning conditions can be achieved. Therefore it is often unnecessary to determine the actual loss of function condition because this interchange procedure produces conservative and safe designs. Examples where deformation limits apply are control rod drive alignment and clearances for proper insertion and core support deformation causing fuel disarrangement or excess leakage of any component.

TABLE 4.5-2 PRIMARY STRESS LIMIT

(For Reactor Internal Structures Only)

Any One of (No More Than One Required)[a]		General Limit
a.	$\frac{PE}{PN}$	$\leq \frac{2.25}{SF_{min}}$
b.	$\frac{LP}{CL}$	$\leq \frac{1.5}{SF_{min}}$
c.	$\frac{PE}{US}$	$\leq \frac{0.75}{SF_{min}}$
d.	$\frac{EP}{US}$	$\leq \frac{0.9}{SF_{min}}$
e.	$\frac{LP}{PL}$	$\leq \frac{0.9}{SF_{min}}$
f.	$\frac{LP}{UF}$	$\leq \frac{0.9}{SF_{min}}$
g.	$\frac{LP}{LE}$	$\leq \frac{1.0}{SF_{min}}$

where

PE = primary stresses evaluated on an elastic basis. The effective membrane stresses are to be averaged through the load-carrying section of interest. The simplest average bending, shear, or torsion stress distribution that will support the external loading will be added to the membrane stresses at the section of interest

PN = permissible primary stress levels under normal or upset conditions under ASME Boiler and Pressure Vessel Code Section III

LP = permissible load under stated conditions of normal, upset, emergency, or faulted

CL = lower bound limit load with yield point equal to $1.5S_m$, where S_m is the tabulated value of allowable stress at temperature of the ASME III Code or its equivalent. The "lower bound limit load" is here defined as that produced from the analysis of an ideally plastic (nonstrain-hardening) material where deformations increase with no further increase in applied load. The lower bound load is one in which the material everywhere satisfies equilibrium and nowhere exceeds the defined material yield strength using either a shear theory or a strain energy of distortion theory to relate multiaxial yield to the uniaxial case

US = conventional ultimate strength at temperature or loading, which would cause a system malfunction, whichever is more limiting

EP = elastic-plastic evaluated nominal primary stress. Strain hardening of the material may be used for the actual monotonic stress-strain curve at the temperature of loading, or any approximation to the actual stress-strain curve that everywhere has a lower stress for the same strain than the actual monotonic curve may be used. Either the shear or strain energy of distortion flow rule may be used

PL = plastic instability load. The "plastic instability load" is defined here as the load at which any load-bearing section begins to diminish its cross-sectional area at a faster rate than the strain hardening can accommodate the loss in area. This type of analysis requires a true stress-true strain curve or a close approximation based on monotonic loading at the temperature of loading

UF = ultimate load from fracture analyses. For components which involve sharp discontinuities (local theoretical stress concentration < 3) the use of a "fracture mechanics" analysis where applicable, utilizing measurements of plane strain fracture toughness, may be applied to compute fracture loads. Correction for finite plastic zones and thickness effects as well as gross yielding may be necessary. The methods of linear elastic stress analysis may be used in the fracture analysis where its use is clearly conservative or supported by experimental evidence. Examples where "fracture mechanics" may be applied are for fillet welds or end-of-fatigue-life crack propagation

LE = ultimate load or loss of function load as determined from experiment. In using this method, account shall be taken of the dimensional tolerances that may exist between the actual part and the tested part or parts as well as differences that may exist in the ultimate tensile strength of the actual part and the tested parts. The guide to be used in each of these areas is that the experimentally determined load shall use adjusted values to account for material property and dimension variations, each of which has no greater probability than 0.1 of being exceeded in the actual part

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[a] Equations e., f., and g. are not used because criteria a., b., c., and d. are met. (Equations e., f., and g. will not be used unless supporting data are provided to the NRC by GE.)

TABLE 4.5-3 BUCKLING STABILITY LIMIT

(For Reactor Internal Structures Only)

Any One of (No More Than One Required)[a]	General Limit
a. $\frac{LP}{PN}$	$\leq \frac{2.25}{SF_{min}}$
b. $\frac{LP}{SL}$	$\leq \frac{0.9}{SF_{min}}$
c. $\frac{LP}{SE}$	$\leq \frac{1.0}{SF_{min}}$

where

LP = permissible load under stated conditions of normal, upset, emergency, or faulted

PN = applicable code normal event permissible load

SL = stability analysis load. The ideal buckling analysis is often sensitive to otherwise minor deviations from ideal geometry and boundary conditions. These effects shall be accounted for in the analysis of the buckling stability load. Examples of this are ovality in externally pressurized shells or eccentricity of column members

SE = ultimate buckling collapse load as determined from experiment. In using this method, account shall be taken of the dimensional tolerances that may exist between the actual part and the tested part. The guide to be used in each of these areas is that the experimentally determined load shall be adjusted to account for material property and dimension variations, each of which has no greater probability than 0.1 of being exceeded in the actual part

[a] Equation c. is not used because criteria a. and b. are met. (Equation c. will not be used unless supporting data are provided to the NRC by GE.)

TABLE 4.5-4 FATIGUE LIMIT

(For Reactor Internal Structures Only)

Summation of Fatigue Damage Usage with Design and Operation Loads Following Miner Hypotheses[a]

Any One of (No More Than One Required)	Limit for Normal and Upset Design Conditions
a. Mean fatigue[b,c] cycle usage from analyses	≤ 0.05
b. Mean fatigue[b,c] cycle usage from test	≤ 0.33
c. Design fatigue cycle usage from analysis using the method of Table 4.5-5	≤ 1.0

a. Miner, M. A., "Cumulative Damage in Fatigue," Journal of Applied Mechanics, Vol. 12, ASME, 67, pp. A159-A164, September 1945.

b. Fatigue failure is defined here as a 25 percent area reduction for a load-carrying member which is required to function, or excess leakage, whichever is more limiting.

c. Equations a. and b. are not used because criterion c. is met. (Equations a. and b. will not be used unless supporting data are provided to the NRC by GE.)

TABLE 4.5-5 CORE SUPPORT STRUCTURES: STRESS CATEGORIES AND LIMITS OF STRESS INTENSITY FOR NORMAL AND UPSET CONDITIONS

STRESS CATEGORY	PRIMARY STRESSES		SECONDARY STRESSES	PEAK STRESSES
	MEMBRANE, P_m (NOTES 4, 7 & 8)	BENDING, P_b (NOTES 4, 7 & 8)	MEMBRANE AND BENDING SECONDARY, Q (NOTES 2, 4 & 6)	PEAK, F (NOTES 2, 4 & 6)
NORMAL AND UPSET	P_m S_m ELASTIC ANALYSIS (NOTE 6) OR $.67L_L$ LIMIT ANALYSIS (NOTE 10) OR $.44L_u$ TEST (NOTE 11)	$P_m + P_b$ $1.5S_m$ ELASTIC ANALYSIS (NOTE 6) OR $.67L_L$ LIMIT ANALYSIS (NOTE 10) OR $.44L_u$ TEST (NOTE 11)	$P_m + P_b + Q$ $3S_m$ ELASTIC ANALYSIS (NOTE 1) OR S_L PLASTIC ANALYSIS (NOTE 5) OR FOR CYCLES LESS THAN 1000, USE PEAK (NOTE 12)	$P_m + P_b + Q + F$ ELASTIC FATIGUE (NOTES 3 & 9) S_a $P_m + P_b + Q + F$ S_a ELASTIC-PLASTIC FATIGUE (NOTES 3, 9 & 12)

Note 1: This limitation applies to the range of stress intensity. When the secondary stress is due to a temperature excursion at the point at which the stresses are being analyzed, the value of S_m shall be taken as the average of the S_m values tabulated in Tables I-1.1, I-1.2, and I-1.3 of the ASME Boiler and Pressure Vessel Code Section III (ASME III) for the highest and the lowest temperature of the metal during the transient. When part of the secondary stress is due to mechanical load, the value of S_m shall be taken as the S_m value for the highest temperature of the metal during the transient.

Note 2: The stresses in Category Q are those parts of the total stress that are produced by thermal gradients, structural discontinuities, etc., and do not include primary stresses that may also exist at the same point. It should be noted, however, that a detailed stress analysis frequently gives the combination of primary and secondary stresses directly, and, when appropriate, this calculated value represents the total of $P_m + P_b + Q$, and not Q alone. Similarly, if the stress in Category F is produced by a stress concentration, the quantity F is the additional stress produced by the notch, over and above the nominal stress. For example, if a plate has a nominal stress intensity, $P_m = S$, $P_b = 0$, $Q = 0$, and a notch with a stress concentration K is introduced, then $F = P_m (K - 1)$, and the peak stress intensity equals $P_m + P_m (K - 1) = KP_m$.

TABLE 4.5-5 CORE SUPPORT STRUCTURES: STRESS CATEGORIES AND LIMITS OF STRESS INTENSITY FOR NORMAL AND UPSET CONDITIONS

Note 3: The value of S_a is obtained from the fatigue curves (Figures I-9.1 and I-9.2 of ASME III). The allowable stress intensity for the full range of fluctuation is $2S_a$.

Note 4: The symbols P_m, P_b, Q, and F do not represent single quantities, but rather sets of six quantities representing the six stress components σ_t, σ_l, σ_r, τ_{t1}, τ_{1r}, and τ_{rt}.

Note 5: The quantity S_L denotes the structural action of shakedown load, as defined in Paragraph NB-3213.18 of ASME III, calculated on a plastic basis as applied to a specific location on the structure.

Note 6: The triaxial stresses represent the algebraic sum of the three primary principal stresses ($\sigma_1+\sigma_2+\sigma_3$) for the combination of stress components. Where uniform tension loading is present, triaxial stresses are limited to $4S_m$.

Note 7: For configurations in which compressive stresses occur, the stress limits shall be revised to take into account critical buckling stresses [see Paragraph NB-3211(c) of ASME III]. For external pressure, the permissible "equivalent static" external pressure shall be as specified by the rules of Paragraph NB-3133 of ASME III. Where dynamic pressures are involved, the permissible external pressure shall be limited to 25 percent of the dynamic instability pressure.

Note 8: When loads are transiently applied, consideration should be given to the use of dynamic load amplification and possible change in the modulus of elasticity.

Note 9: In the fatigue data curves, where the number of operating cycles is less than 10, the S_a value should be used for 10 cycles; where the number of operating cycles is more than 10^6, the S_a value should be used for 10^6 cycles.

Note 10: The quantity L_L is the lower bound limit load with yield point equal to $1.5S_m$, where S_m is the tabulated value of allowable stress at temperature as contained in ASME III. The "lower bound limit load" is here defined as that produced from the analysis of an ideally plastic (nonstrain-hardening) material where deformations increase with no further increase in applied load. The lower bound load is one in which the material everywhere satisfies equilibrium and nowhere exceeds the defined material yield strength, using either a shear theory or a strain energy of distortion theory to relate multiaxial yielding to the uniaxial case.

Note 11: For normal and upset conditions, the limits on primary membrane plus primary bending need not be satisfied in a component if it can be shown from the test of a proto-type or model that the specified loads (dynamic or static equivalent) do not exceed 44 percent of L_u, where L_u is the ultimate load or the maximum load or load combination used in the test. In using this method, account shall be taken of the size effect and dimensional tolerances that may exist between the actual part and the test part or parts as well as the differences that may exist in

TABLE 4.5-5 CORE SUPPORT STRUCTURES: STRESS CATEGORIES AND LIMITS OF STRESS INTENSITY FOR NORMAL AND UPSET CONDITIONS

the ultimate strength or other governing material properties of the actual part and the tested part to ensure that the loads obtained from the test are a conservative representation of the load-carrying capability of the actual component under the postulated loading for normal and upset conditions.

Note 12: The allowable value for the maximum range of this stress intensity is $3S_m$, except for cyclic events that occur less than 1000 times during the design life of the plant. For this exception, in lieu of meeting the $3S_m$ limit, an elastic-plastic fatigue analysis in accordance with ASME III may be performed to demonstrate that the cumulative fatigue usage attributable to the combination of these low events, plus all other cyclic events, does not exceed a fatigue usage value of 1.0.

TABLE 4.5-6 CORE SUPPORT STRUCTURES: STRESS CATEGORIES AND LIMITS OF STRESS INTENSITY FOR EMERGENCY CONDITIONS

STRESS CATEGORY	PRIMARY STRESSES		SECONDARY STRESSES	PEAK STRESSES
	MEMBRANE, P_m (NOTES 1, 2 & 10)	BENDING, P_b (NOTES 1, 2 &10)	MEMBRANE AND BENDING SECONDARY, Q	PEAK, F
EMERGENCY (NOTE 9)	P_m $1.5S_m$ ELASTIC ANALYSIS (NOTE 3) OR L_L LIMIT ANALYSIS (NOTE 4) OR $1.5S_m$ PLASTIC ANALYSIS (NOTE 6) OR $.6L_e$ TEST (NOTE 7) OR S_E STRESS RATIO ANALYSIS (NOTE 8)	$P_m + P_b$ $2.25S_m$ ELASTIC ANALYSIS (NOTE 3) OR L_L LIMIT ANALYSIS (NOTE 4) OR $2.25S_m$ PLASTIC ANALYSIS (NOTES 5 & 6) OR $.5S_u$ (NOTE 5) OR $.6L_e$ TEST (NOTE 7) OR KS_E STRESS RATIO ANALYSIS (NOTE 8)	EVALUATION NOT REQUIRED	EVALUATION NOT REQUIRED

Note 1: The symbols P_m, P_b, Q, and F do not represent single quantities, but rather sets of six quantities representing the six stress components σ_t, σ_l, σ_r, τ_{r1}, τ_{1r}, and τ_{rt}.

Note 2: For configurations in which compressive stresses occur, stress limits shall be revised to take into account critical buckling stresses. For external pressure, the permissible "equivalent static" external pressure shall be taken as 150 percent of that permitted by the rules of Paragraph NB-3133 of the ASME Boiler and Pressure Vessel Code, Section III (ASME III). Where dynamic pressures are involved, the permissible external pressure shall satisfy the preceding requirements or be limited to 50 percent of the dynamic instability pressure.

Note 3: The triaxial stresses represent the algebraic sum of the three primary principal stresses ($\sigma_1+\sigma_2+\sigma_3$) for the combination of stress components. Where uniform tension loading is present, triaxial stresses should be limited to $6S_m$.

Note 4: The quantity L_L is lower bound limit load with yield point equal to $1.5S_m$ (where S_m is the tabulated value of allowable stress at temperature as contained in ASME III). The "lower bound limit load" is here defined as that produced from the analysis of an ideally plastic (nonstrain-hardening) material where

TABLE 4.5-6 CORE SUPPORT STRUCTURES: STRESS CATEGORIES AND LIMITS OF STRESS INTENSITY FOR EMERGENCY CONDITIONS

deformations increase with no further increase in applied load. The lower bound load is one in which the material everywhere satisfies equilibrium and nowhere exceeds the defined material yield strength, using either a shear theory or a strain energy of distortion theory to relate multiaxial yielding to the uniaxial case.

Note 5: The quantity S_u is the ultimate strength at temperature. Multiaxial effects on ultimate strength shall be considered.

Note 6: This plastic analysis uses an elastic-plastic evaluated nominal primary stress. Strain hardening of the material may be used for the actual monotonic stress-strain curve at the temperature of loading, or any approximation to the actual stress-strain curve that everywhere has a lower stress for the same strain than the actual monotonic curve may be used. Either the shear or strain energy of distortion flow rule shall be used to account for multiaxial effects.

Note 7: For emergency conditions, the stress limits need not be satisfied if it can be shown from the test of a prototype or model that the specified loads (dynamic or static equivalent) do not exceed 60 percent of L_e, where L_e is the ultimate load or the maximum load or load combination used in the test. In using this method, account shall be taken of the size effect and dimensional tolerances that may exist between the actual part and the tested part or parts as well as the differences that may exist in the ultimate strength or other governing material properties of the actual part and the tested parts to ensure that the loads obtained from the test are a conservative representation of the load-carrying capability of the actual component under postulated loading for emergency conditions.

Note 8: Stress ratio is a method of plastic analysis that uses the stress ratio combinations (combination of stresses that consider the ratio of the actual stress to the allowable plastic or elastic stress) to compute the maximum load and strain-hardening that the material can carry. The term K is defined as the section factor; $S_e \leq 2S_m$ for primary membrane loading.

Note 9: Where deformation is of concern in a component, the deformation shall be limited to two-thirds of the value given for emergency conditions in the design specification.

Note 10: When loads are transiently applied, consideration should be given to the use of dynamic load amplification and possible change in the modulus of elasticity.

TABLE 4.5-7 CORE SUPPORT STRUCTURES: STRESS CATEGORIES AND LIMITS OF STRESS INTENSITY FOR FAULTED CONDITIONS

STRESS CATEGORIES	PRIMARY STRESSES		SECONDARY STRESSES	PEAK STRESSES
	MEMBRANE, P_m (NOTES 1, 2 & 3)	BENDING, P_b (NOTES 1, 2 & 3)	MEMBRANE AND BENDING SECONDARY, Q	PEAK, F
FAULT (NOTE 7)	P_m $2.4S_m$ ELASTIC ANALYSIS OR $.75S_u$ (NOTE 5) OR $1.33L_L$ LIMIT ANALYSIS (NOTE 4) OR $.67S_u$ PLASTIC ANALYSIS (NOTES 5 & 6) OR $.8L_F$ TEST (NOTE 9) OR S_F STRESS-RATIO ANALYSIS (NOTE 8)	$P_m + P_b$ $3.0S_m$ ELASTIC ANALYSIS OR $1.33L_L$ LIMIT ANALYSIS (NOTE 4) OR $.75S_u$ PLASTIC ANALYSIS (NOTES 5 & 6) OR $.8L_F$ TEST (NOTE 7) OR KS_F STRESS-RATIO ANALYSIS (NOTE 8)	EVALUATION NOT REQUIRED	EVALUATION NOT REQUIRED

Note 1: The symbols P_m, P_b, Q, and F do not represent quantities but rather sets of six quantities representing the six stress components, σ_t, σ_l, σ_r τ_{tl},τ_{lr}, and τ_{rt}.

Note 2: When loads are transiently applied, consideration should be given to the use of dynamic load amplification and possible changes in the modulus of elasticity.

Note 3: For configurations where compressive stresses occur, stress limits take into account critical buckling stresses. For external pressure, the permissible "equivalent static" external pressure shall be taken as 2.5 times that given by rules of paragraph NB-3133 of the ASME Boiler and Pressure Vessel Code Section III (ASME III). Where dynamic pressures are involved, the permissible external pressure shall satisfy the preceding requirements or shall be limited to 75 percent of the dynamic instability pressure.

Note 4: The quantity L_L is the lower bound limit load with yield point equal to $1.5S_m$ (where S_m is the tabulated value of allowable stress at temperature as contained in ASME III). The "lower bound limit load" is here defined as that produced from the analysis of an ideally plastic (nonstrain-hardening) material where deformations increase with no further increase in applied load. The lower

TABLE 4.5-7 CORE SUPPORT STRUCTURES: STRESS CATEGORIES AND LIMITS OF STRESS INTENSITY FOR FAULTED CONDITIONS

bound load is one in which the material everywhere satisfies equilibrium and nowhere exceeds the defined material yield strength, using either a shear theory or a strain energy of distortion theory to relate multiaxial yielding to the uniaxial case.

Note 5: The quantity S_u is the ultimate strength at temperature. Multiaxial effects on ultimate strength shall be considered.

Note 6: This plastic analysis uses an elastic-plastic evaluated nominal primary stress. Strain hardening of the material may be used for the actual monotonic stress-strain curve at the temperature of loading, or any approximation to the actual stress-strain curve that everywhere has a lower stress for the same strain as the actual curve may be used; either the maximum shear stress or the strain energy of distortion flow rule shall be used to account for multiaxial effects.

Note 7: For faulted conditions, the stress limits need not be satisfied if it can be shown from the test of a prototype or model that the specified loads (dynamic or static equivalent) do not exceed 80 percent of L_F, where L_F is the ultimate load or load combination used in the test.

In using this method, account shall be taken of the size effect and dimensional tolerances as well as differences that may exist in the ultimate strength or other governing material properties of the actual part and the tested parts to ensure that the loads obtained from the test are a conservative representation of the load-carrying capability of the actual component under the postulated loading for faulted condition.

Note 8: Stress ratio is a method of plastic analysis that uses the stress ratio combinations (combination of stresses that consider the ratio of the actual stress to the allowable plastic or elastic stress) to compute the maximum load and strain-hardening that the material can carry. The term K is defined as the section factor; S_F is the lesser of $2.4S_m$ or $0.75S_u$ for primary membrane loading.

Note 9: Where deformation is of concern in a component, the deformation shall be limited to 80 percent of the value for faulted conditions in the design specifications.

TABLE 4.5-8 DESIGN LOADING CONDITIONS AND COMBINATIONS

Operating Condition and Stress Limits[a]	Design Loading Conditions and Combinations
Normal and upset	N and A_D or N and U
Emergency	N and R or other conditions which have a 40-year encounter probability from 10^{-1} to 10^{-3}
Faulted	N and A_m and $\overline{R}$ or other conditions which have a 40-year encounter probability from 10^{-3} to 10^{-6}

where

N = normal loads

U = upset loads excluding earthquake

A_D = operating-basis earthquake (OBE), including any associated transients

A_m = safe-shutdown earthquake (SSE), including any associated transients

R = any auxiliary pipe rupture loading, including any associated transients; pipe rupture loadings are not directly considered on piping itself because this is handled by a failure mode analysis

$\overline{R}$ = primary loadings which result from rupture of a main steam line or a recirculation line

[a] The design stress, deformation, and fatigue limits are for RPV and appurtenances - ASME Code Section III.

For core support structures - Refer to Tables 4.5-5, 4.5-6, and 4.5-7.

For reactor internal structures - Refer to Tables 4.5-1 through 4.5-4.

TABLE 4.5-9 PRESSURE DIFFERENTIALS ACROSS REACTOR PRESSURE VESSEL INTERNALS

Reactor Component	Pressure Difference Maximum Occurring During a Steam Line Break (psid) Case 1 (a)	 Case 2 (b)
Core plate and guide tube	22.5	25.5
Shroud support ring and lower shroud	45.0	45.0
Upper shroud and shroud head	26.0	26.0
Average channel wall (bottom)	14.0	10.6
Top guide	1.1	1.9

NOTE: For Faulted Conditions using GE14 Fuel see Reference 14. GNF3 results are bounded by GE14 results (Reference 16).

Case 1 – Reactor initially at 1078 psia, 3694 MWt, 105 x 10^6 lb/hr core flow

Case 2 – Reactor initially at 1020 psia, 771 MWt, 116 x 10^6 lb/hr core flow

a-Data from Power Uprate Analysis (Reference 10)

b-Data from MEOD Analysis (Reference 11)

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Refer to Plant Drawing 197R603

FIGURE 4.5-1

GENERAL REACTOR ASSEMBLY DRAWING

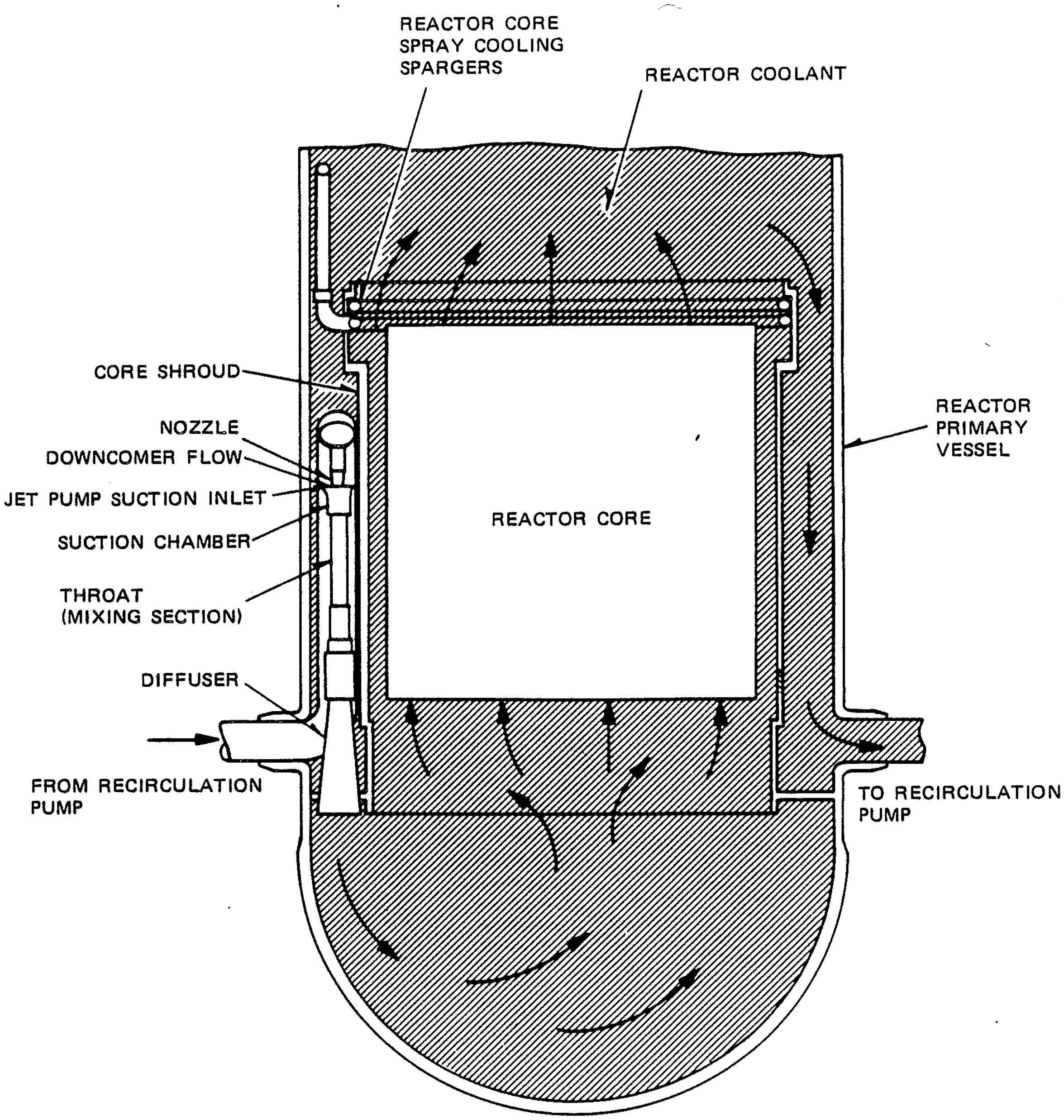

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FIGURE 4.5-2

REACTOR INTERNALS FLOW PATHS

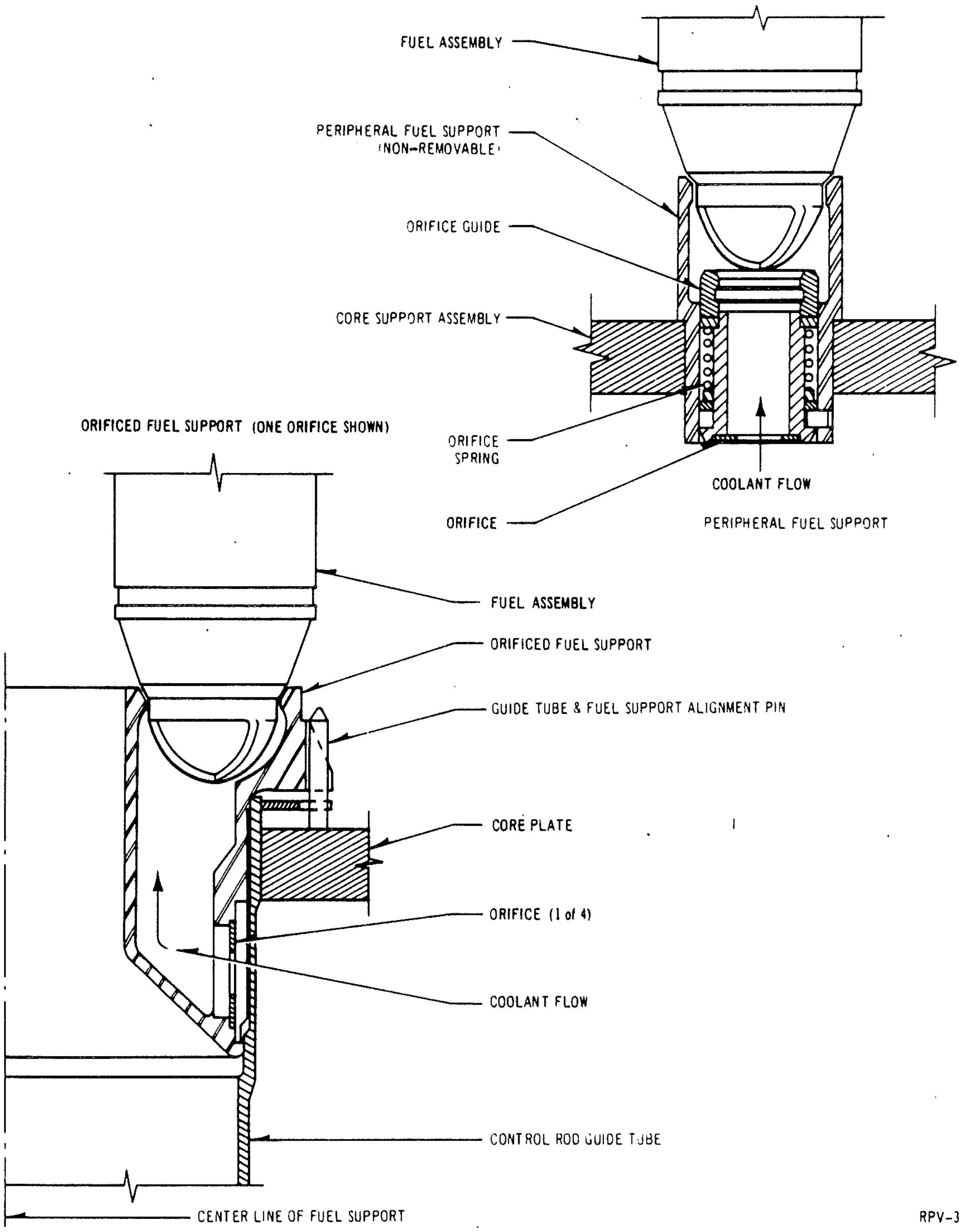

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FIGURE 4.5-3

FUEL SUPPORT PIECES

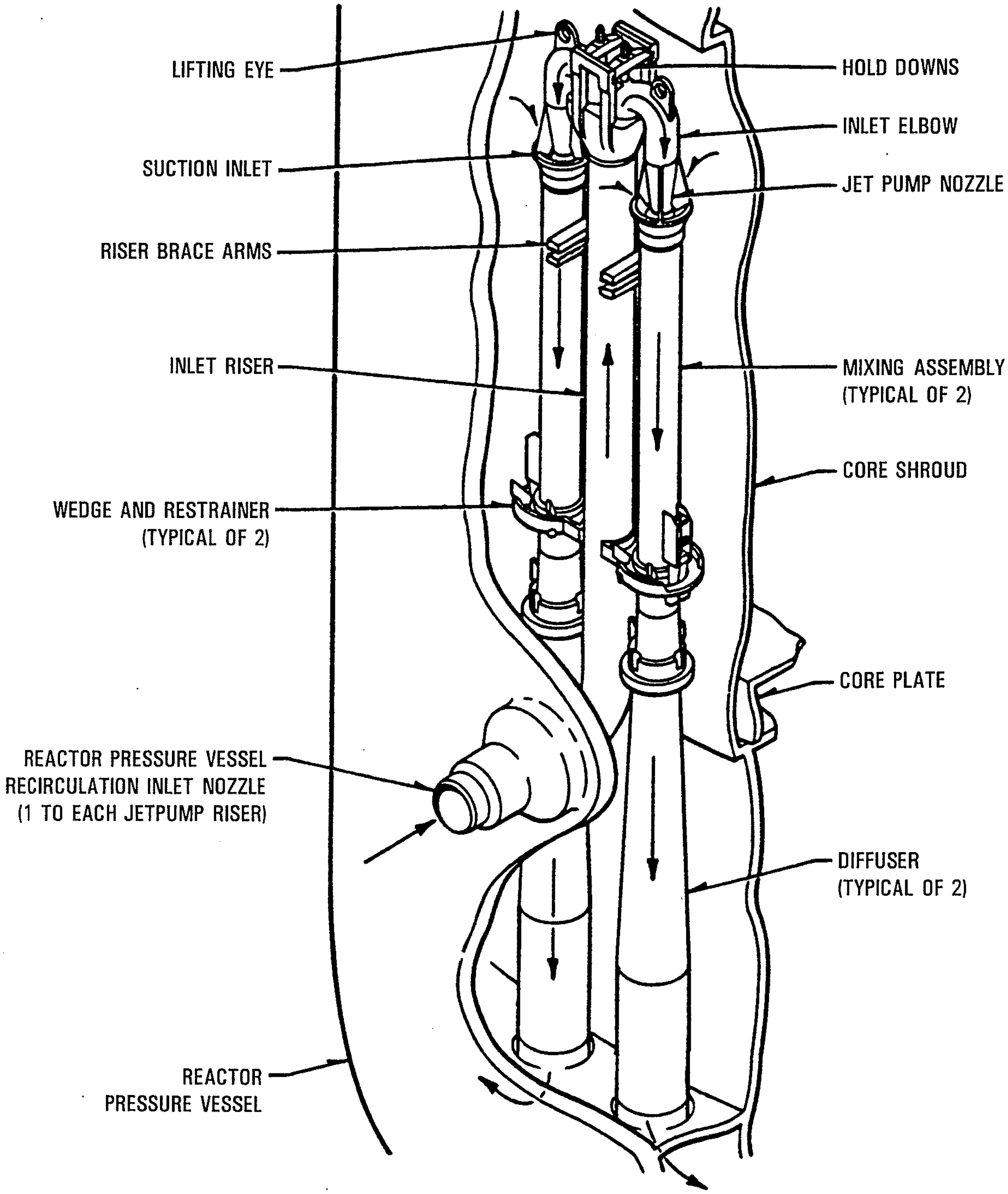

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FIGURE 4.5-4

JET PUMP ISOMETRIC

FIGURE 4.5-5 IS INTENTIONALLY DELETED

FIGURE 4.5-6 IS INTENTIONALLY DELETED

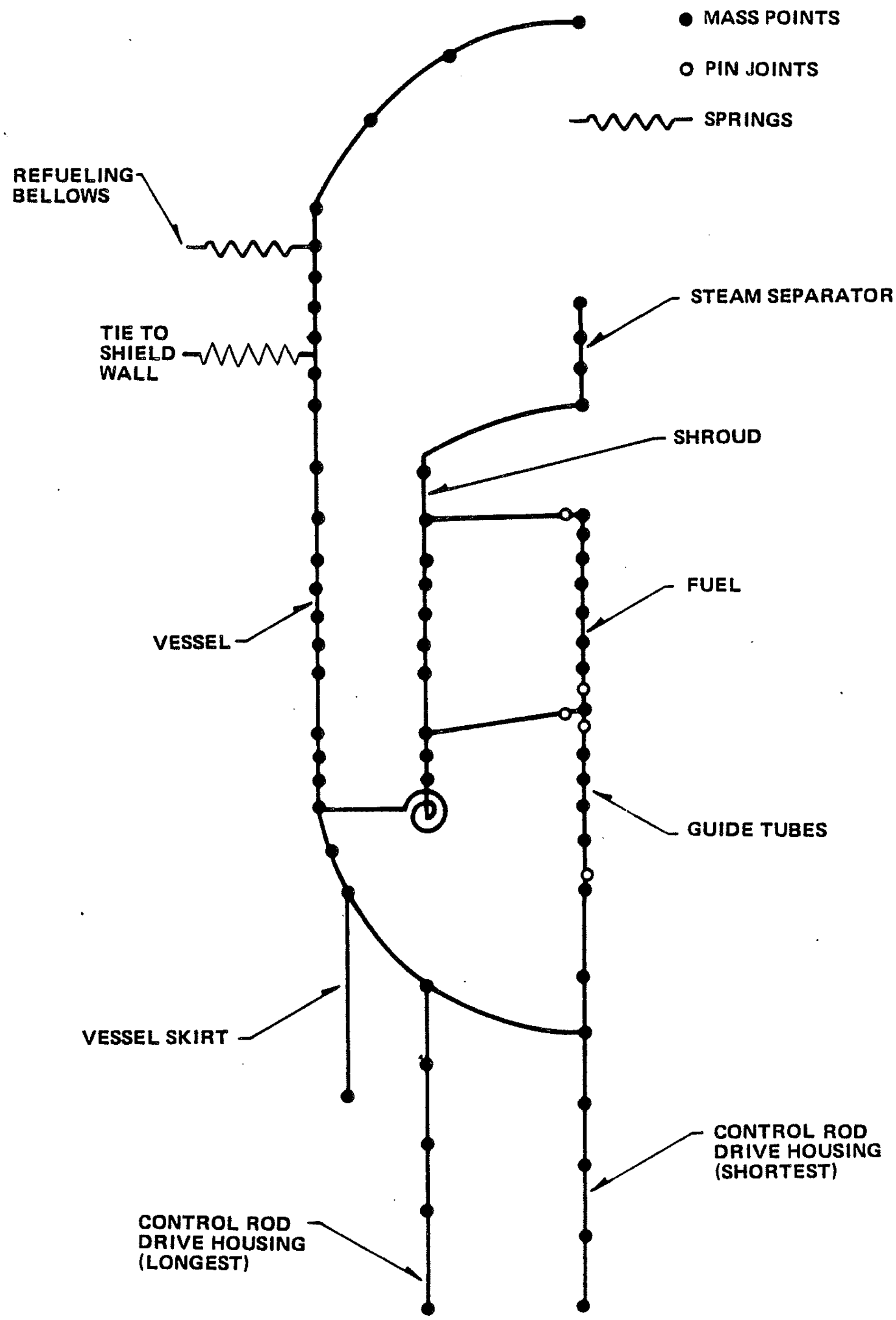

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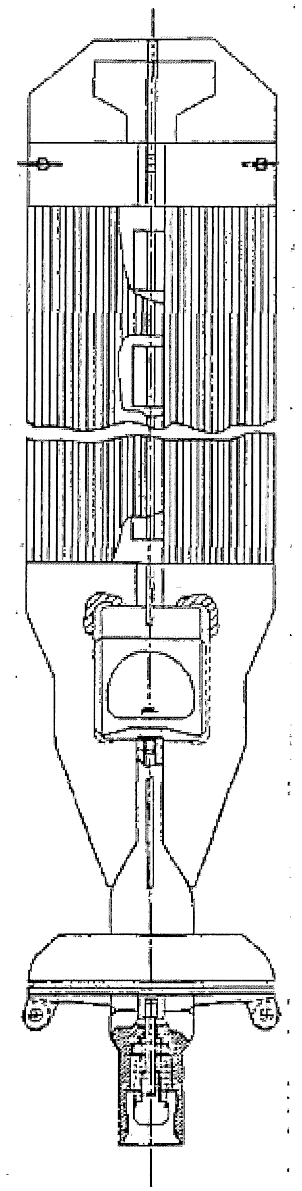
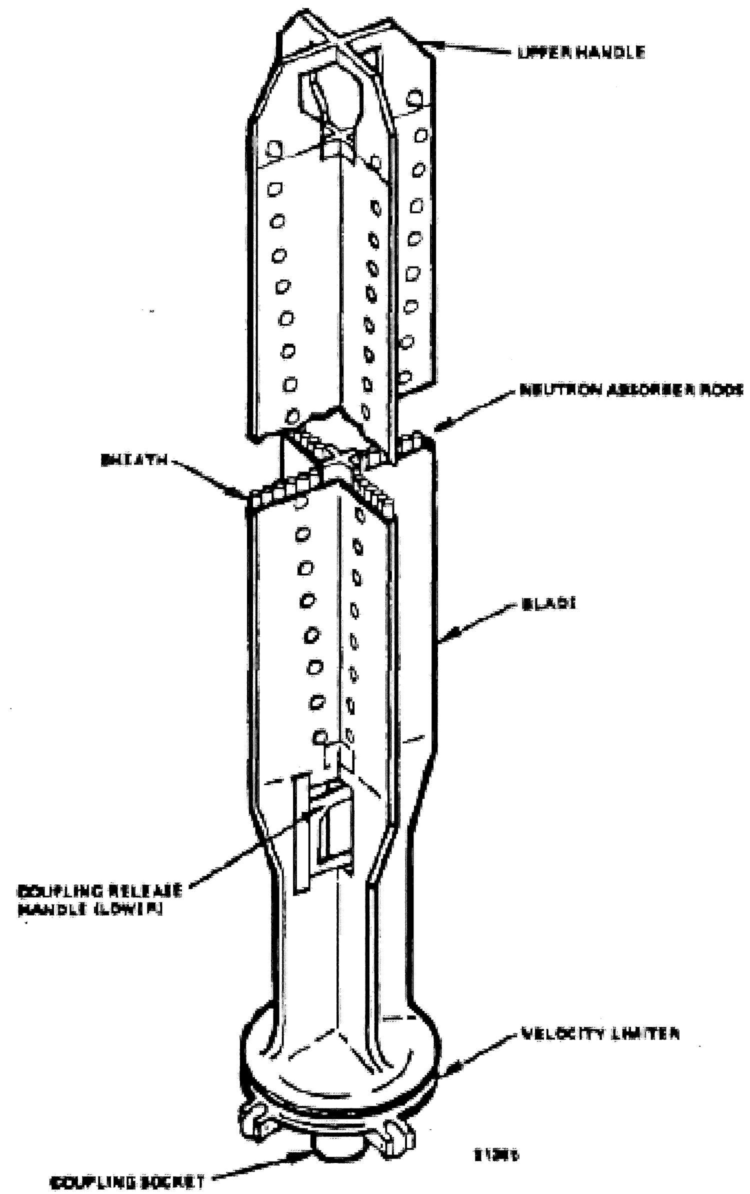
FIGURE 4.5-7

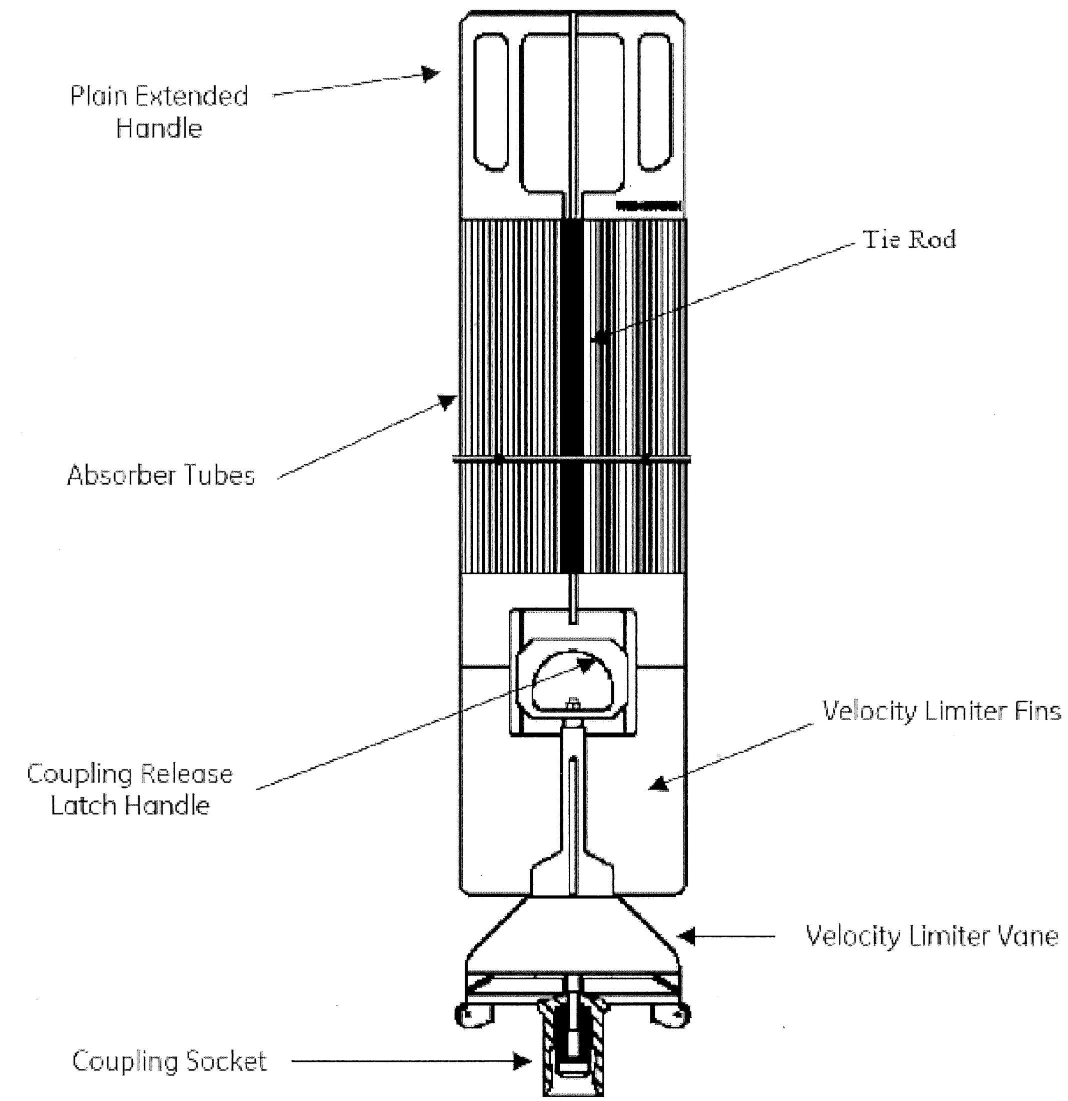
SEISMIC MATHEMATICAL MODEL OF THE REACTOR PRESSURE VESSEL



Typical Marathon C Control Rod Blade



Typical Duralife 140 Control Rod Blade



Typical Ultra-HD and Ultra-MD Control Rod Blade

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FIGURE 4.5-8

TYPICAL CONTROL ROD ASSEMBLIES

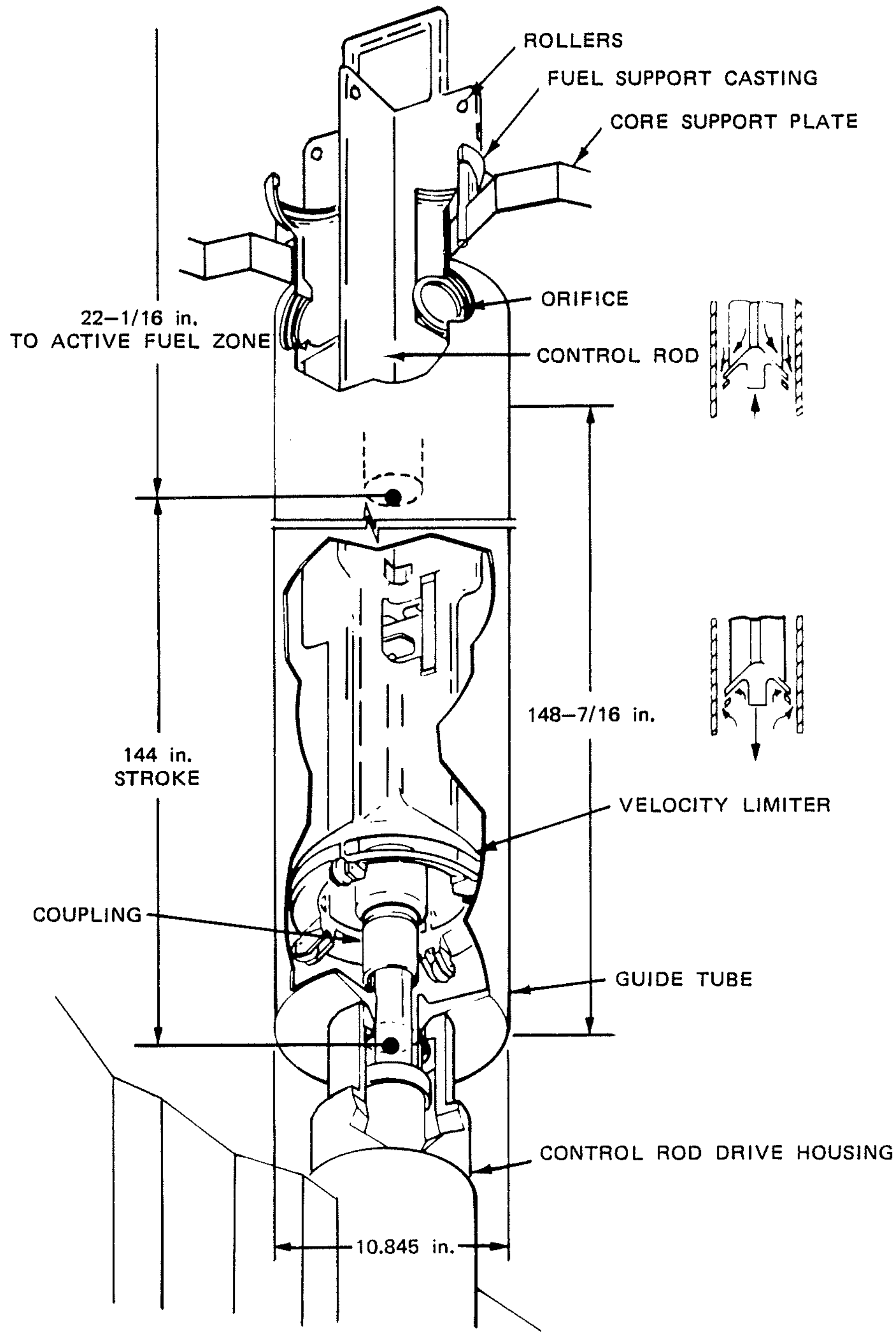

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FIGURE 4.5-9

CONTROL ROD VELOCITY LIMITER
DURALIFE 140

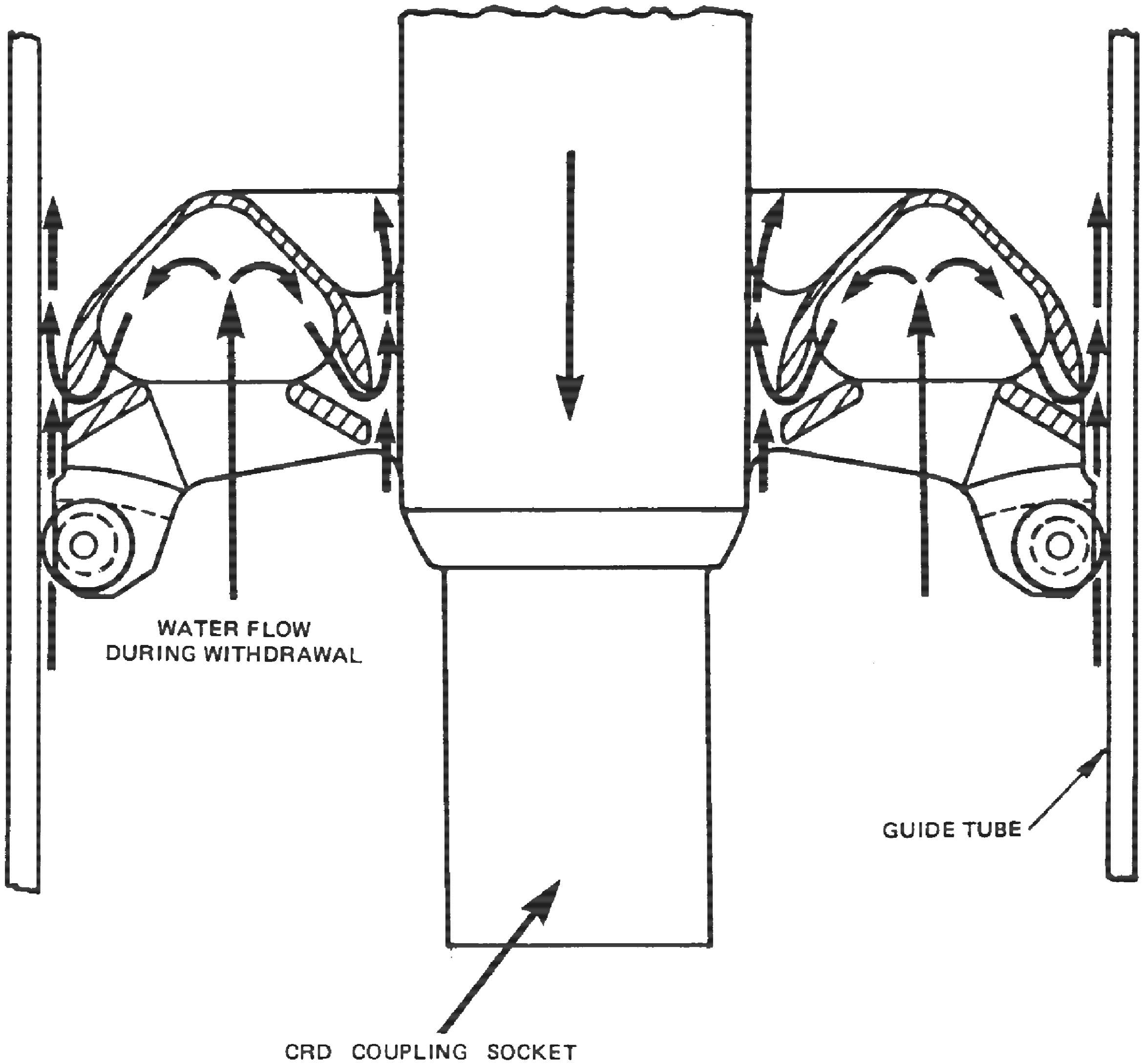

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FIGURE 4.5-10

TYPICAL CONTROL ROD
VELOCITY LIMITER OPERATION

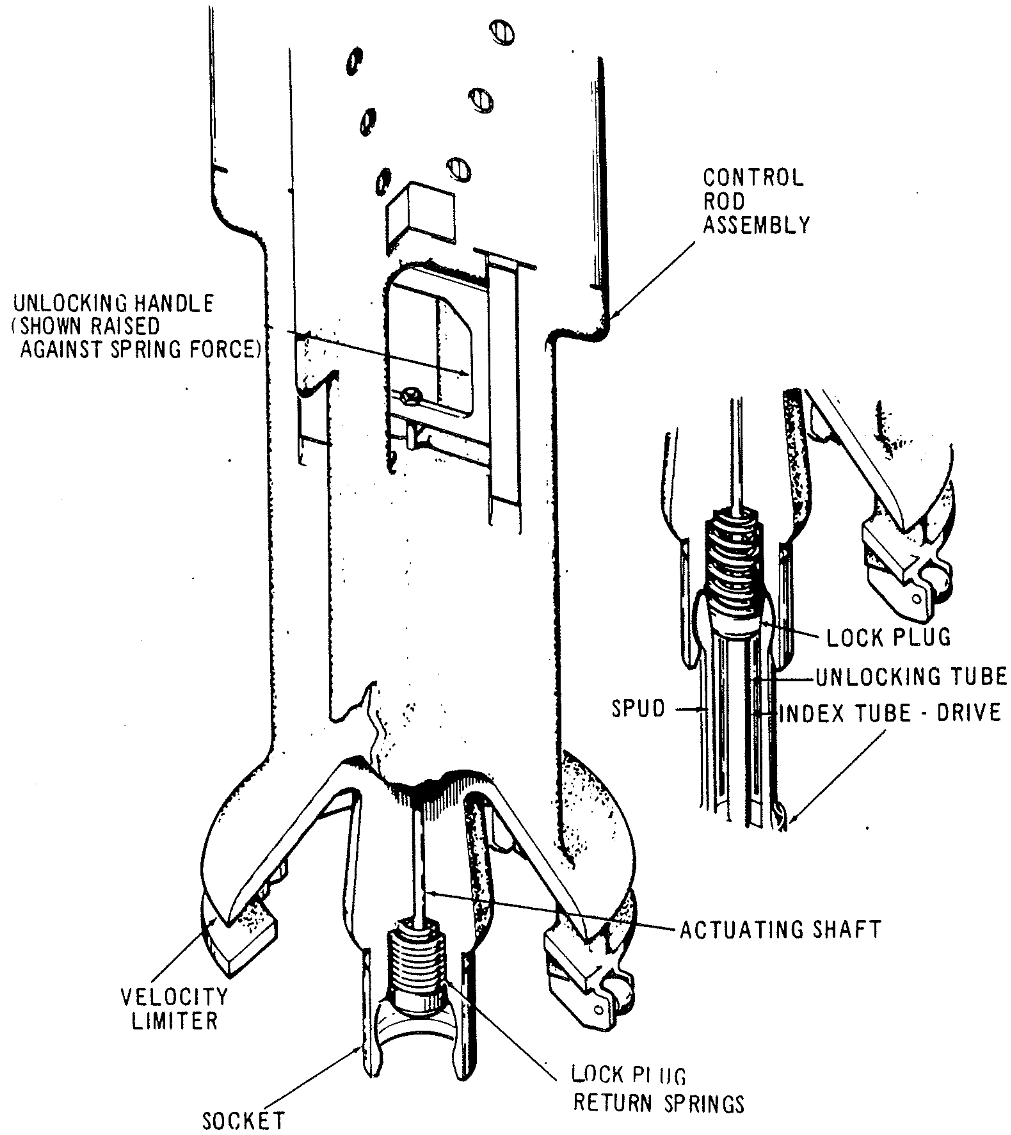

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FIGURE 4.5-11

CONTROL ROD AND CONTROL ROD DRIVE COUPLING

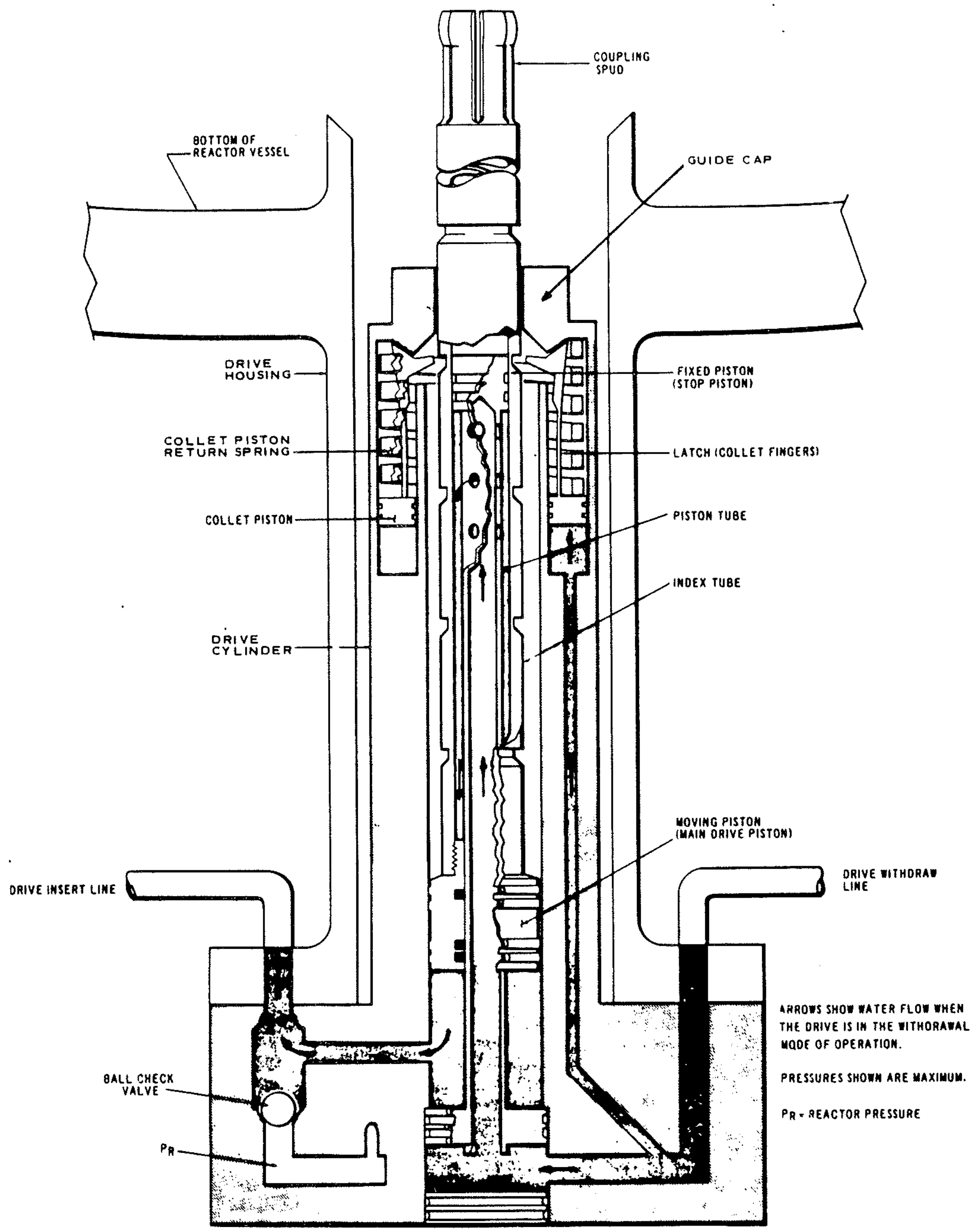

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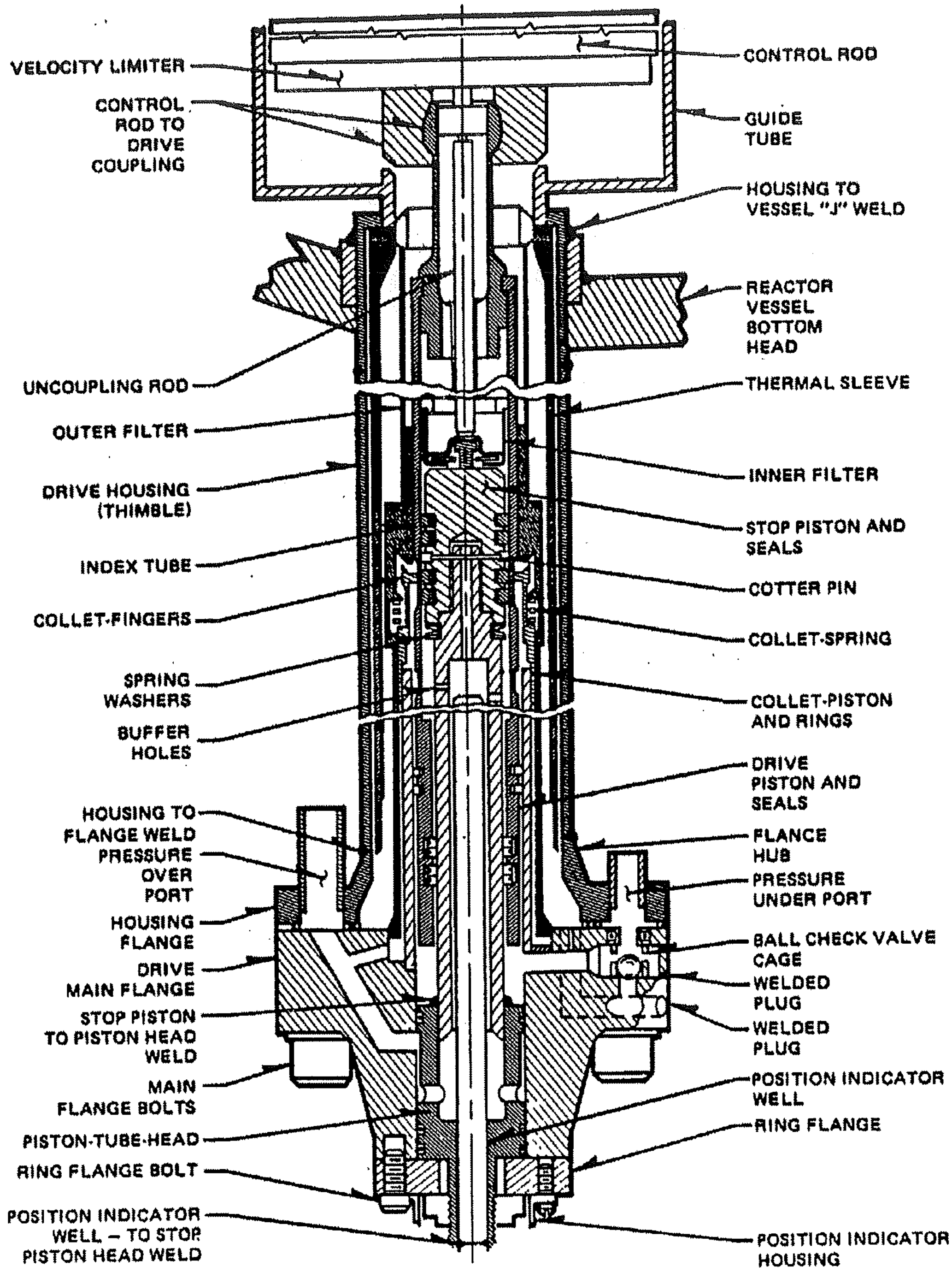
FIGURE 4.5-12

CONTROL ROD DRIVE UNIT



NOTES:

1. THERE ARE EQUIVALENT PISTON TUBE CONFIGURATIONS. EITHER MAYBE INSTALLED. SHOWN IS TYPICAL OF THE ORIGINAL DESIGN
2. WELD LOCATIONS ARE TYPICAL OF THE ORIGINAL PISTON TUBE DESIGN

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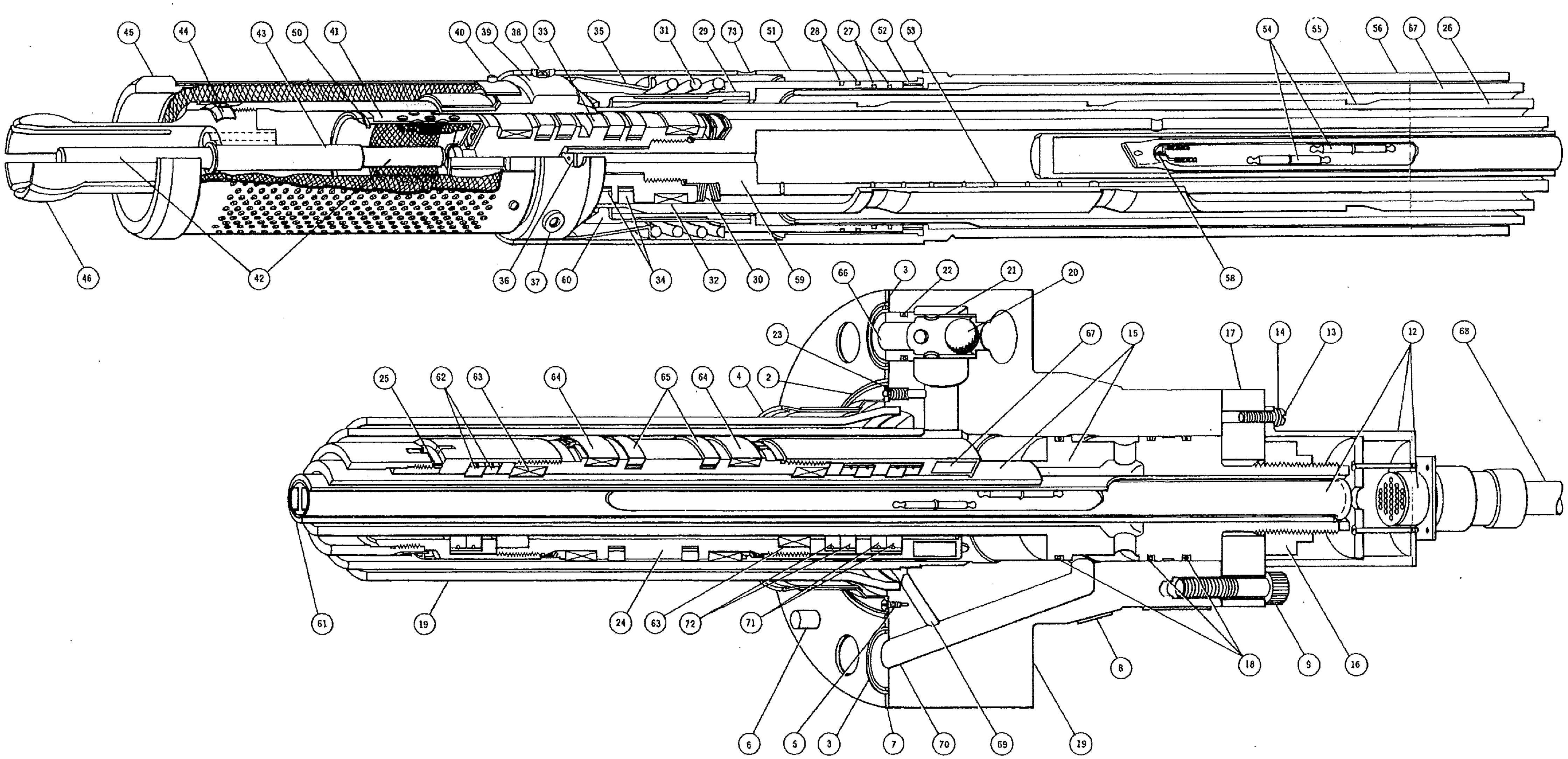
FIGURE 4.5-13

CONTROL ROD DRIVE UNIT SCHEMATIC



2 – O-RING (CRD FLANGE FACE)
3 – O-RING (INSERT AND WITHDRAW PORTS)
4 – STRAINER
5 – FLAT HEAD SCREW (STRAINER–MOUNTING)
6 – DOWEL ALIGNMENT PIN
7 – O-RING SPACER
8 – NAMEPLATE
9 – SOCKET–HEAD CAP SCREW (RING FLANGE MOUNTING)
12 – POSITION INDICATOR PROBE
13 – FILLISTER–HEAD SCREW (POSITION INDICATOR PROBE MOUNTING)
14 – LOCKWASHER (FOR PART 13)
15 – PISTON TUBE
16 – NUT (PISTON TUBE)
17 – RING FLANGE
18 – O-RING (PISTON TUBE)
19 – CYLINDER, TUBE, AND FLANGE
20 – BALL (CHECK VALVE)
21 – BALL RETAINER
22 – O-RING (BALL RETAINER)
23 – SET SCREW PLUG (COOLING WATER ORIFICE)
24 – DRIVE PISTON
25 – BAND
26 – INDEX TUBE
27 – SEAL RING (COLLET PISTON – INTERNAL)
28 – SEAL RING (COLLET PISTON – EXTERNAL)
29 – COLLET AND PISTON
30 – SPRING WASHERS
31 – COLLET SPRING
32 – SPLIT BUSHING (STOP PISTON)
33 – STOP PISTON
34 – SEAL RING (STOP PISTON)
35 – BARREL
36 – COTTER PIN (STOP PISTON)
37 – PLUG (GUIDE CAP)
38 – FILLISTER–HEAD SCREW (GUIDE CAP PLUG MOUNTING)
39 – GUIDE CAP
40 – DRILLED FILLISTER–HEAD SCREW (OUTER FILTER MOUNTING)
41 – INNER FILTER
42 – ROD
43 – TUBE
44 – BAND
45 – FILTER (OUTER)
46 – SPUD
50 – SEAL RING (INNER FILTER)
51 – COLLET HOUSING (PORTION OF OUTER TUBE)
52 – SPACER (PART OF CYLINDER, TUBE, AND FLANGE)
53 – BUFFER ORIFICES IN PISTON TUBE (TYPICAL)
54 – POSITION INDICATOR SWITCHES
55 – INDEX TUBE NOTCH
56 – OUTER TUBE (PART OF CYLINDER, TUBE, AND FLANGE)
57 – INNER CYLINDER (PART OF CYLINDER, TUBE, AND FLANGE)
58 – THERMOCOUPLE (PART OF POSITION INDICATOR PROBE)
59 – STUD (PORTION OF PISTON TUBE)
60 – COLLET FINGER (PART OF COLLET AND PISTON)
61 – INDICATOR TUBE (PART OF PISTON TUBE)
62 – INNER SEALS (DRIVE PISTON–BUFFER SEALS)
63 – INTERNAL BUSHING (DRIVE PISTON)
64 – EXTERNAL BUSHING (DRIVE PISTON)
65 – OUTER SEALS (DRIVE PISTON)
66 – INSERT PORT (INSERT AND SCRAM INLET/ WITHDRAW OUTLET)
67 – RING MAGNET (PART OF DRIVE PISTON)
68 – CABLE (POSITION INDICATOR)
69 – PORT TO COLLET PISTON (WITHDRAW PRESSURE TO COLLET PISTON)
70 – WITHDRAW PORT (WITHDRAW INLET/ INSERT OUTLET AND SCRAM DISCHARGE)
71 – INNER SEALS (DRIVE PISTON – DRIVE–DOWN SEALS)
72 – INNER SEALS (DRIVE PISTON – DRIVE–UP SEALS)
73 – WATER PORTS IN COLLET HOUSING

NOTES

1. THERE ARE EQUIVALENT PISTON TUBE CONFIGURATIONS. EITHER MAY BE INSTALLED. SHOWN IS THE TYPICAL OF THE ORIGINAL DESIGN.
2. INDICATOR TUBE CONFIGURATION IS TYPICAL OF THE ORIGINAL PISTON TUBE DESIGN.

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FIGURE 4.5-14

CONTROL ROD DRIVE UNIT CUTAWAY

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Refer to Plant Drawing M-2081

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FIGURE 4.5-15, SHEET 1

CONTROL ROD DRIVE HYDRAULIC SYSTEM
REACTOR BUILDING

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Refer to Plant Drawing M-5449

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FIGURE 4.5-15, SHEET 2

CONTROL ROD DRIVE HYDRAULIC SYSTEM
REACTOR BUILDING

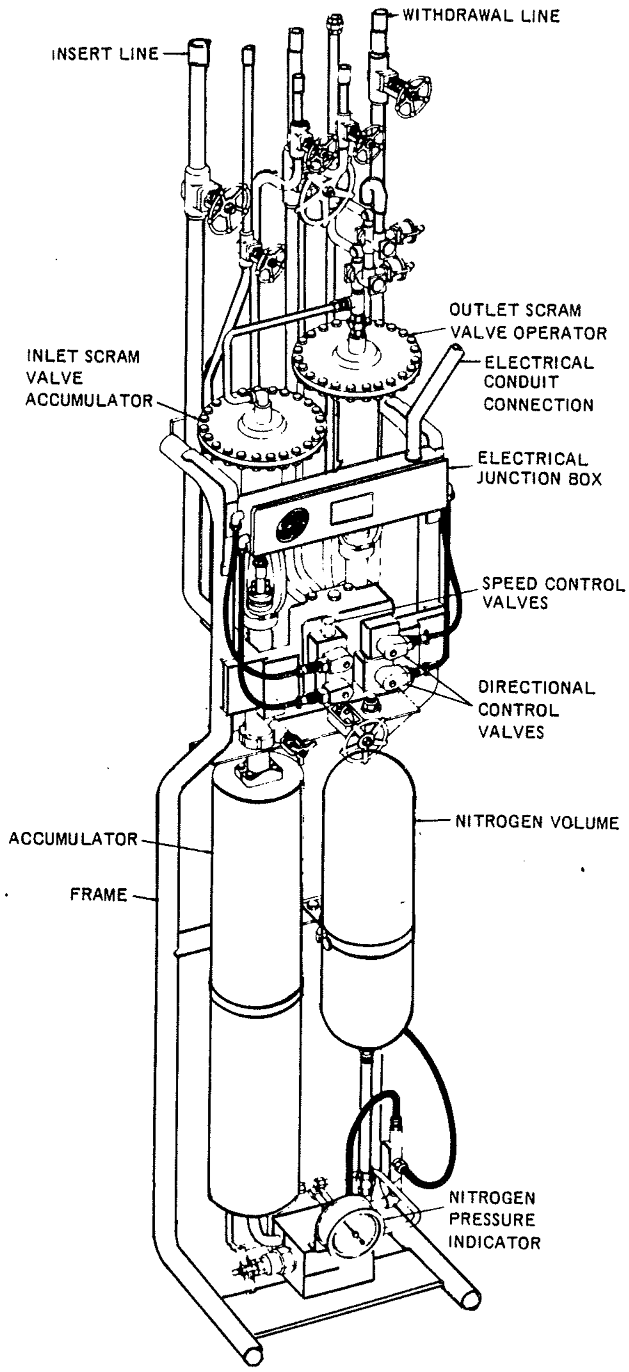

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FIGURE 4.5-16

CONTROL ROD DRIVE HYDRAULIC CONTROL UNIT

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Refer to Plant Drawing M-2082

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FIGURE 4.5-17

STANDBY LIQUID CONTROL SYSTEM P&ID

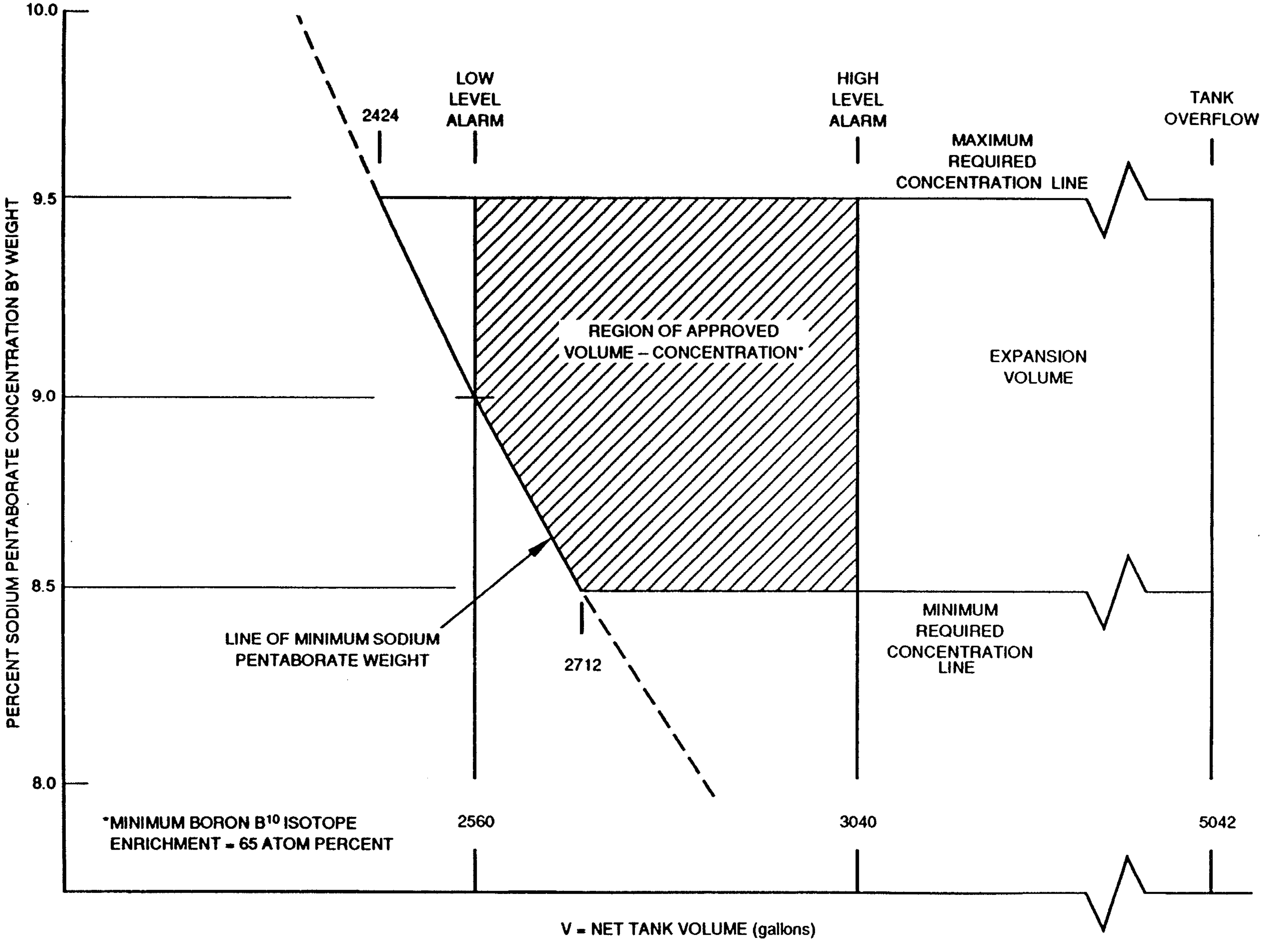

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FIGURE 4.5-18

SODIUM PENTABORATE SOLUTION VOLUME
CONCENTRATION REQUIREMENTS

REV 6 3/93

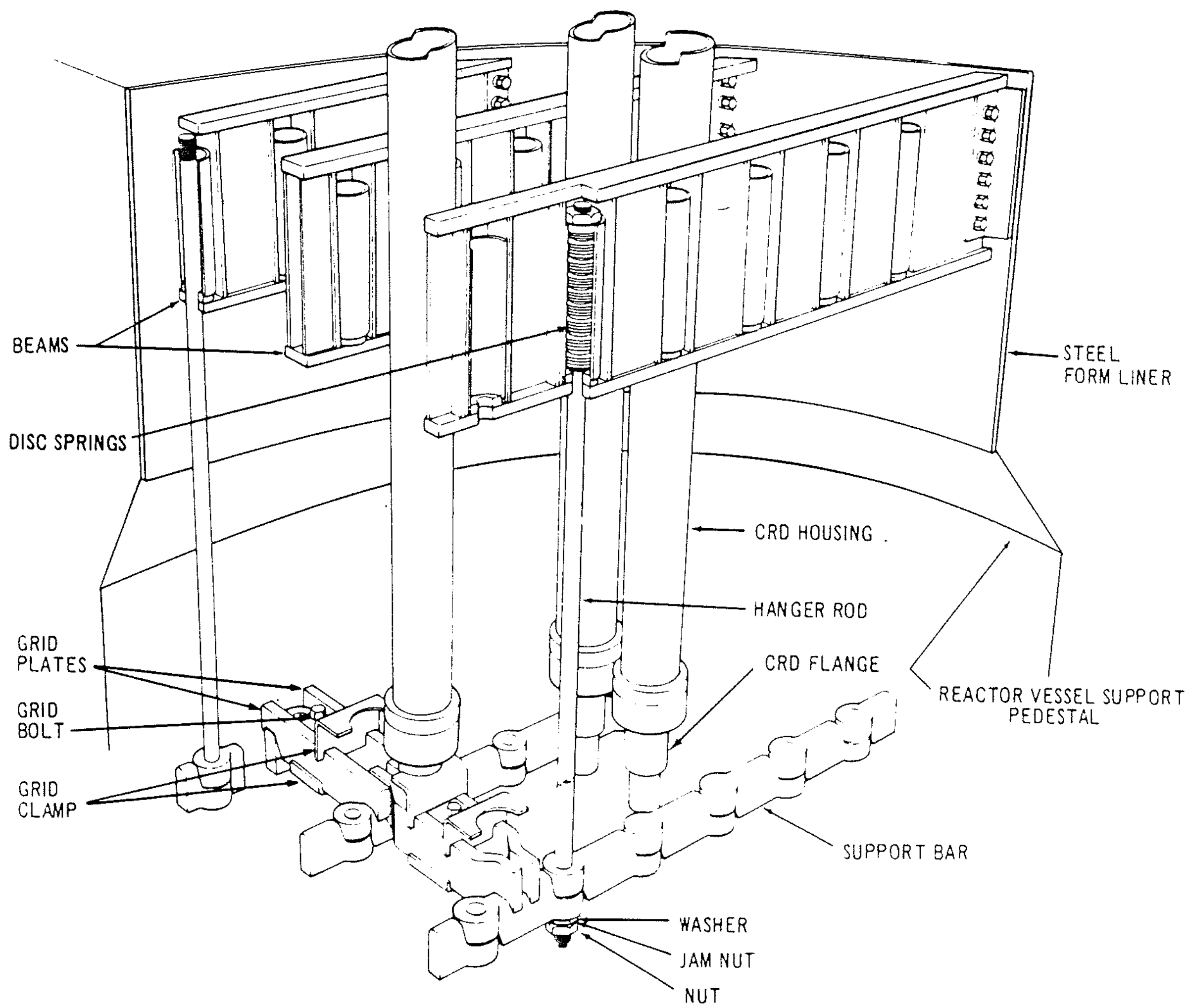

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FIGURE 4.5-19

CONTROL ROD DRIVE HOUSING SUPPORT

CHAPTER 5: REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

5.1 SUMMARY DESCRIPTION

The reactor coolant system includes those systems and components that contain or transport fluids to or from the reactor core. These systems form a major portion of the nuclear system process barrier. This chapter provides information regarding the reactor coolant system and pressure-containing appendages out to and including isolation valving. This group of components is defined as the reactor coolant pressure boundary (RCPB), in Section 50.2(v) of 10 CFR 50 as follows:

Reactor coolant pressure boundary means all those pressure- containing components of boiling and pressurized water- cooled nuclear power reactors, such as pressure vessels, piping, pumps, and valves, which are

a. Part of the reactor coolant system

b. Connected to the reactor coolant system, up to and including all of the following:

   1. The outermost containment isolation valve in system piping which penetrates primary reactor containment

   2. The second of the two valves normally closed during normal reactor operation in system piping which does not penetrate primary reactor containment

   3. The reactor coolant system safety/relief valves.

Section 5.5 of this chapter also deals with various subsystems of the RCPB that are closely allied to it. These are briefly reviewed below.

The nuclear pressure relief system (NPRS) protects the RCPB from damage due to overpressure. To protect against overpressure, pressure-operated safety/relief valves are provided to discharge steam from the nuclear steam supply system (NSSS) to the suppression pool. The NPRS also acts to automatically depressurize the NSSS in the event of a LOCA in which the high pressure coolant injection (HPCI) system fails to maintain reactor pressure vessel (RPV) water level. Depressurization of the NSSS allows the low- pressure core cooling systems to supply enough cooling water to cool the fuel adequately.

The RCPB leak detection system, described in Subsection 5.2.7, detects system leakage inside the primary containment so that appropriate action can be taken before the integrity of the nuclear system process barrier is impaired.

The RPV and appurtenances are described in Section 5.4. The major safety functions of the RPV are to maintain water over the core and to act as a radioactive material barrier. The RPV meets the requirements of applicable codes and criteria. The possibility of brittle fracture is considered, and suitable design and operational limits are established that avoid conditions where brittle fracture is possible.

The reactor recirculation system (RRS) provides coolant flow through the core. Adjustment of the core coolant flow rate changes reactor power output, thus providing a means of following plant load demand without adjusting control rods. The arrangement of the RRS routing is such that a piping failure cannot compromise the integrity of the floodable inner volume of the RPV, thereby ensuring adequate core cooling following a LOCA.

The main steam line flow restrictors are venturi-type flow devices. One restrictor is installed in each main steam line inside the primary containment. The restrictors are designed to limit the loss of coolant resulting from a main steam line break outside the primary containment. The coolant loss is limited so that RPV water level remains above the top of the core during the time required for the main steam line isolation valves (MSIVs) to close. This action maintains the integrity of the fuel cladding (fuel barrier).

The MSIVs automatically isolate the nuclear system process barrier in the event a pipe break occurs, thereby limiting the loss of coolant and the release of radioactive materials from the NSSS. Two MSIVs are installed on each main steam line, one inside and the other outside the primary containment. Closure of either of the two MSIVs acts to seal the primary containment in the event that a main steam line break occurs there. A third stop valve (third MSIV) is in each steam line downstream of the outboard MSIVs.

The reactor core isolation cooling (RCIC) system provides makeup water to the core during a reactor shutdown in which feedwater flow is not available. The system is started either automatically upon receipt of a low reactor water level signal or manually by the operator. Water is pumped to the core by a turbine pump driven by reactor steam.

The residual heat removal (RHR) system includes a number of pumps and heat exchangers that can be used to cool the NSSS under a variety of situations. During normal shutdown and reactor servicing, the RHR system removes residual and decay heat. The RHR system allows decay heat to be removed whenever the main heat sink (main condenser) is not available. Another operational mode of the RHR system is low pressure coolant injection (LPCI). Low pressure coolant injection operation is an engineered safety feature (ESF) system for use during a LOCA. This operation is described in Subsection 6.3.2.2.4.

The reactor water cleanup (RWCU) system functions to maintain the required purity of reactor coolant by circulating coolant through a system of filter-demineralizers.

5.1.1 Schematic Flow Diagram

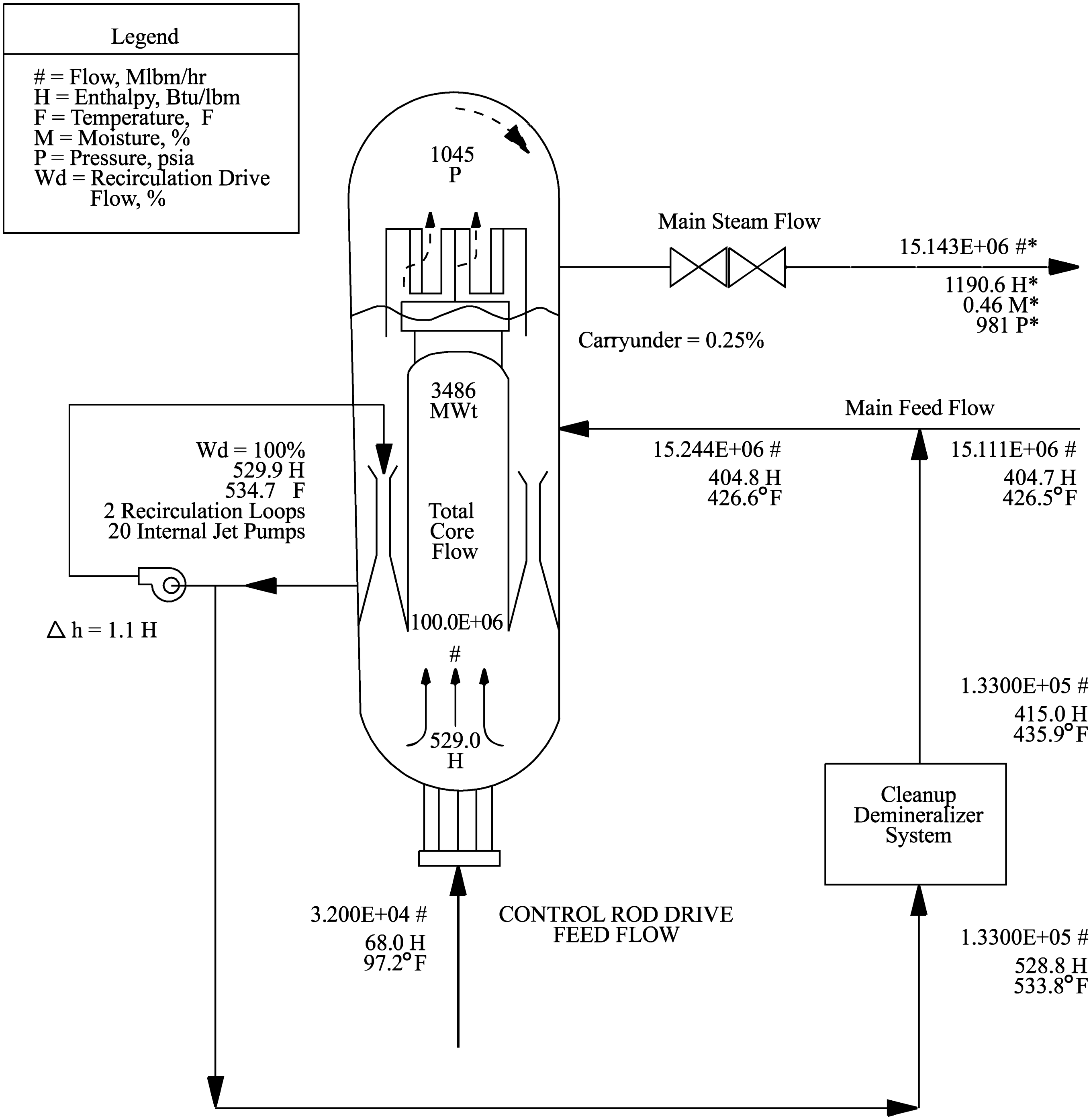
A schematic flow diagram of the reactor coolant system denoting all major components, principal pressures, temperatures, flow rates, and coolant volumes under normal steady-state full-power operating conditions is presented in Figures 5.1-1 and 5.1-2.

5.1.2 Piping and Instrumentation Diagram

A piping and instrumentation diagram for the NSSS is presented in Figure 5.1-3.

5.1.3 Elevation Drawing

Elevation drawings showing the containment system perspective and the principal dimensions of the reactor coolant system in relation to the containment are shown in Figures 5.1-4 and 5.1-5.



*Conditions at upstream side of TSV

Core Thermal Power	3486.0
Pump Heating	10.6
Cleanup Losses	-4.4
Other System Losses	-1.2
Turbine Cycle Use	3491.0 MWt

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FIGURE 5.1-1A

REACTOR COOLANT SYSTEM FLOW DIAGRAM-
100% POWER / 100% CORE FLOW

		VOLUME OF FLUID (ft^3)
A	LOWER PLENUM	3918
B	CORE	2054
C	UPPER PLENUM & SEPARATORS	1320
D	DOME (ABOVE NORMAL WATER LEVEL)	7553
E	DOWNCOMER REGION	5795
F	RECIRC LOOPS & JET PUMPS	1394

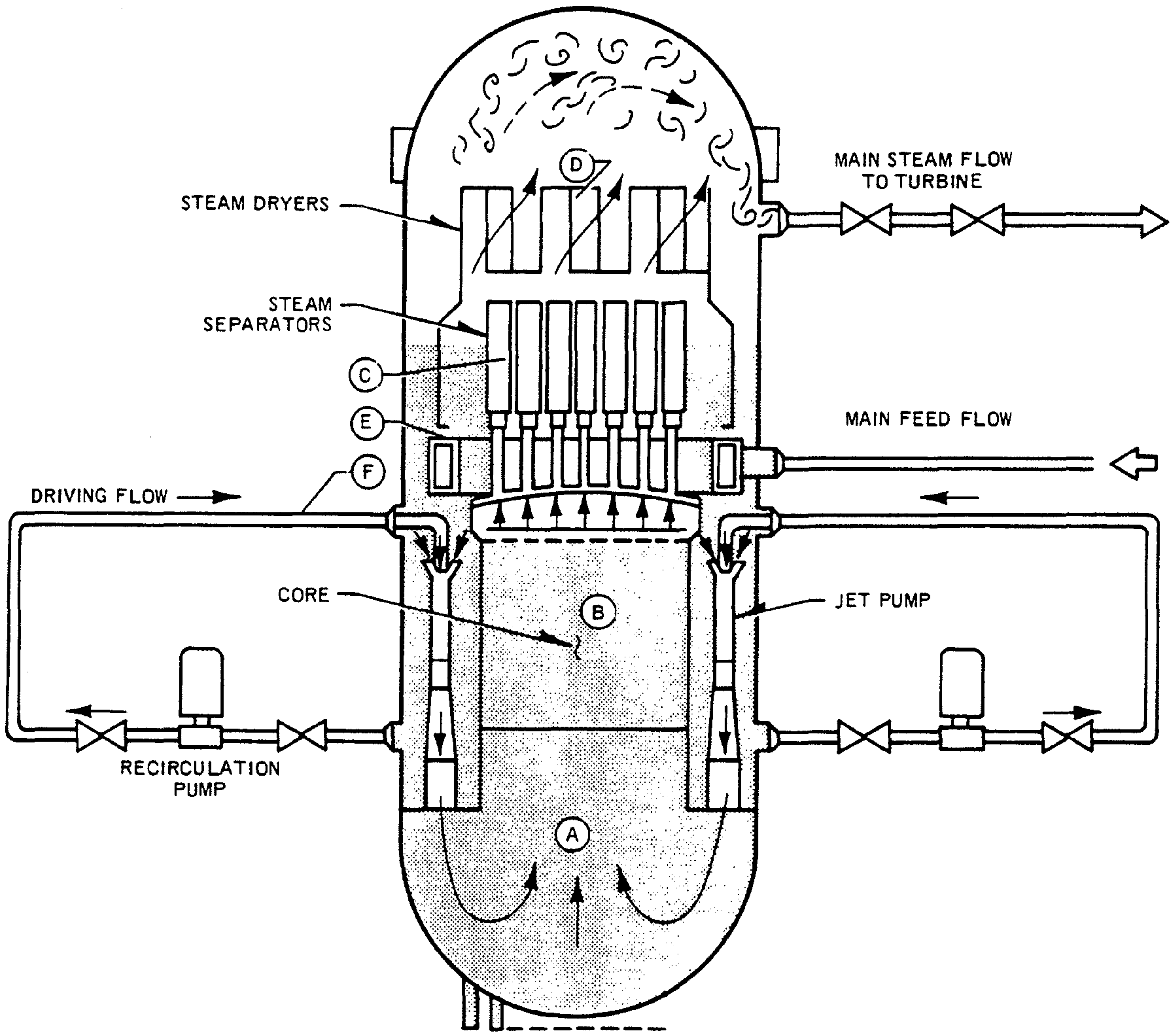

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FIGURE 5.1-2

COOLANT VOLUMES

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Refer to Plant Drawing M-2089

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FIGURE 5.1-3, SHEET 1

NUCLEAR STEAM SUPPLY SYSTEM
P&ID

Figure Intentionally Removed
Refer to Plant Drawing M-2090

FIGURE 5.1-3 SHEET 2
NUCLEAR STEAM SUPPLY SYSTEM P&ID

Figure Intentionally Removed
Refer to Plant Drawing M-5538

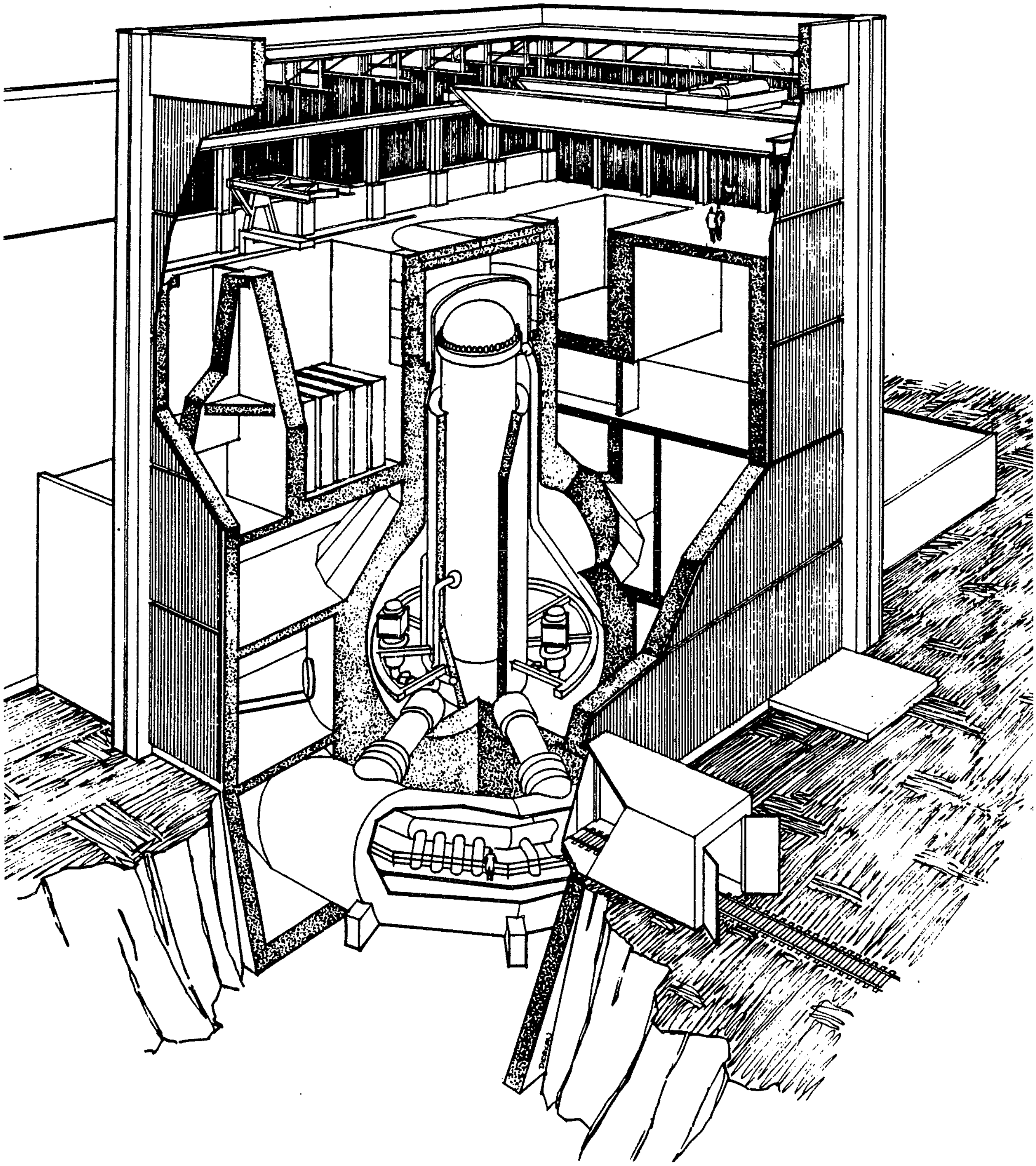

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FIGURE 5.1-4

CONTAINMENT SYSTEM PERSPECTIVE

Figure Intentionally Removed Refer to
Plant Drawing GENERAL PC SKETCH

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FIGURE 5.1-5

GENERAL ARRANGEMENT, PRIMARY CONTAINMENT SECTION

5.2 INTEGRITY OF REACTOR COOLANT PRESSURE BOUNDARY

5.2.1 Design of Reactor Coolant Pressure Boundary Components

5.2.1.1 Performance Objectives

5.2.1.1.1 Reactor Pressure Vessel and Appurtenances

The function of the reactor pressure vessel (RPV) design is to provide a volume in which the core can be submerged in coolant, thereby allowing power operation of the reactor. Design of the RPV and appurtenances provides the means for attaching pipelines to the RPV and for installing RPV internal components. All or portions of each of the following support systems interface with the RPV and form part of the reactor coolant pressure boundary.

5.2.1.1.2 Reactor Pressure Vessel Vent

The function of the RPV vent is to remove noncondensibles from the top dome of the reactor during power operation and to provide a vent path for floodup of the vessel prior to vessel head removal during refueling outages.

5.2.1.1.3 Nuclear Pressure Relief System

The function of the nuclear pressure relief system (NPRS) is to limit any overpressure that occurs during abnormal operational transients.

5.2.1.1.4 Main Steam Line Flow Restrictors

The function of the main steam line flow restrictors is to protect the fuel barrier by not allowing the core to be uncovered. The restrictors limit the loss of coolant from the RPV to a value that will ensure the core will remain covered with water before the main steam isolation valve closure, should rupture occur in a main steam line outside the primary containment. Additionally, the restrictors limit the depressurization rate of the reactor to a value which ensures that the steam dryer and other reactor internal structures will remain in place. This is to prevent fragments from the dryer to be blown down the steam lines that may prevent tight closure of the main steam isolation valves.

5.2.1.1.5 Main Steam Line Isolation Valves

The function of the MSIVs, one of which is on the drywell side while the other is just outside the primary containment, is to prevent damage to the fuel barrier by limiting loss of reactor coolant for a major steam piping leak outside the primary containment. Main steam isolation valves also limit radioactive releases to the plant environs.

5.2.1.1.6 Deleted

5.2.1.1.7 Feedwater System

The function of the feedwater system is to provide normal feed flow to the reactor pressure vessel during plant power operation. The feedwater inboard isolation valves also serve as the first isolation valve for return lines from the HPCI, RCIC and RWCU systems described below.

5.2.1.1.8 Reactor Recirculation System

The function of the reactor recirculation system (RRS) is to provide a variable moderator (coolant) flow to the reactor core for adjusting reactor power level.

5.2.1.1.9 Standby Liquid Control System

The function of the standby liquid control system (SLCS) is to provide backup reactivity control in the event the control rods do not completely shutdown the core following a scram initiation.

An additional function of the SLCS is to provide suppression pool pH control in the event of a loss-of-coolant accident in order to prevent iodine re-evolution.

5.2.1.1.10 Residual Heat Removal System

The function of the residual heat removal (RHR) system is as follows.

a. To remove decay heat and residual heat from the nuclear steam supply system (NSSS) so that refueling and NSSS servicing can be performed

b. To supplement the fuel pool cooling and cleanup system (FPCCS) capacity, when necessary, with additional cooling capacity

c. To provide containment (suppression pool) cooling and containment spray

d. To provide low-pressure coolant injection (LPCI) flow for RPV reflood and core cooling in the event of a DBA-LOCA

5.2.1.1.11 Core Spray System

The function of the core spray (CS) system is to provide low pressure coolant flow directly to the core fuel elements in the event of a loss-of-coolant accident.

5.2.1.1.12 High Pressure Coolant Injection System

The function of the high pressure coolant injection (HPCI) system is to provide high-pressure makeup to the RPV in the event of a small-break loss-of-coolant-accident.

5.2.1.1.13 Reactor Core Isolation Cooling System

The function of the reactor core isolation cooling (RCIC) system is to provide makeup water to the RPV during shutdown and isolation to ensure adequate core cooling.

5.2.1.1.14 Reactor Water Cleanup System

The function of the reactor water cleanup (RWCU) system is to maintain high reactor water purity to limit chemical and corrosive action, thereby limiting fouling and deposition on heat-transfer surfaces. It also removes excess reactor coolant during shutdown, startup, and hot standby conditions.

5.2.1.1.15 Nuclear System Leak Detection System

The function of the NSSS leak detection system (LDS) is to detect leakage from the nuclear system process barrier before predetermined limits are exceeded.

5.2.1.2 Design Parameters

Table 5.2-1 lists design temperature, pressure, and maximum test pressure for the reactor coolant pressure boundary (RCPB) structures and components. The specified operating transients used for the design of components within the RCPB are given in Table 5.2-2. A discussion of the input criteria for seismic design is contained in Subsection 3.7.1.

The design requirements established to protect the principal components of the reactor coolant system against environmental effects are discussed in Subsection 3.11.2.

5.2.1.3 Compliance With 10 CFR 50, Section 50.55a

Compliance with the guidelines of 10 CFR 50, Section 50.55a, "Code and Standards," is included in Tables 3.2-1 and 3.2-3 and in Section 3.2.

5.2.1.4 Applicable Code Cases

The RPV is designed in accordance with the 1968 ASME Boiler and Pressure Vessel (B&PV) Code Section III, Class A, with addenda through summer 1969. The steam and recirculation piping is designed in accordance with the 1969 ANSI B31.7 Nuclear Power Piping Code, Class I, including addenda ANSI B31.7b-1971. The recirculation system, motor-operated valves and pumps, and MSIVs are designed in accordance with the 1968 Draft ASME Code for Pumps and Valves for Nuclear Power, Class I. Main steam safety/relief valves comply with 1968 ASME B&PV Code, Secton III, 1969 Summer Addenda, Paragraph N911.4 for pilot-activated valves. Applicable code cases used in various aspects of the design are given in Table 5.2-3.

5.2.1.5 Design Transients

5.2.1.5.1 Loading and Stress Criteria for Reactor Coolant Pressure Boundary Components Designed by Rational Stress Analysis

The loading conditions may be divided into four categories: normal, upset, emergency, and faulted conditions. These categories are generically described in the ASME B&PV Code Section III, 1968 Edition, N-412. Representative loading combinations, design procedures, and acceptability criteria are listed in Tables 3.9-17 and 3.9-18. These tables apply only to the pressure-containing components of the RCPB. The seismic criteria for the RCPB are discussed in Subsection 3.7.2.

5.2.1.5.2 Components Designed Primarily by Empirical Methods

There are some structural and electrical nonpressure-containing parts of equipment that are not normally designed or sized directly by stress analysis techniques.

Simple stress analyses are sometimes used to augment the design of these components, but the primary design work does not depend on detailed stress analysis. These components are usually designed from tests and empirical experience. Field experience and testing are used to support the design. Where the structural or mechanical integrity of components is essential to safety, the components referred to in these criteria have been designed to accommodate the events of the safe-shutdown earthquake (SSE), a design-basis pipe rupture, or a combination of these events where appropriate. The reliability requirements of such components cannot be quantitatively described in a general criterion because of the varied nature of each component and its specific function in the system.

5.2.1.5.3 Detailed Analyses of Reactor Coolant Pressure Boundary Pressure Parts of the Reactor Pressure Vessel

The RPV is designed in accordance with the ASME B&PV Code (1968) Section III, its interpretations and applicable requirements for Class A vessels as defined therein, as of the summer 1969 addenda.

Both elastic and inelastic stress analysis techniques were used in the design of the RPV core support and reactor internal structures to show that stress limits were not exceeded, as described in Subsection 3.9.1.6.

Stress analysis requirements and load combinations for the RPV are evaluated as described in Tables 3.9-13 through 3.9-15. The RPV was designed for an operational life of 40 years. (Refer to Appendix B for evaluation of 60 years.)

5.2.1.6 Identification of Active Pumps and Valves

5.2.1.6.1 Classification of Pumps and Valves

Pumps and valves (NPS > 1-1/4 in.) within the RCPB are listed in Table 5.2-4. These components may be classified as either active or inactive.

Active components are those whose operability (e.g., valve opening or closure, pump operation or trip) is relied on to perform a safety function and/or reactor-shutdown function during or following the transient or event under consideration. Inactive components are those whose operability is not relied on to perform safety or shutdown functions during or following the transient or event under consideration.

There are no active pumps within the RCPB. The RCPB valves are generally assumed to be active during normal operating and seismic events and system functional evaluations performed only for accident conditions.

Leaktightness capability requirements for all RCPB valves are included in the applicable valve specifications. Valve parts forming the RCPB were pressure tested in accordance with the requirements of Nuclear Pump and Valve Code or ASME B&PV Code Section III. The maximum allowable leakage past valve seats is 2 cm^3/hr/in. of seat diameter for gate and globe type valves and 10 cm^3/hr/in. of seat diameter for check valves under the system design pressure during manufacturer's shop test.

5.2.1.6.2 Design Methods and Procedures for Pipe Rupture

The design objectives used to ensure that active RCPB components function as designed in the event of a pipe rupture are described in Section 3.6.

5.2.1.7 Design of Active Pumps and Valves

To ensure the functional performance of active valves of the RCPB, stringent design requirements were applied. Operability is ensured in the following manner.

All active valves were qualified for operability assurance by first being subjected to the following tests:

a. Shop tests, which include hydrostatic tests and seal leakage tests, were performed as specified in the applicable code

b. The valves are required to open and close within specified time limits when subjected to design or environmental conditions as required by applicable codes and regulatory guides. These valves were also subjected to cold hydrostatic tests and functional tests as part of the Preoperational Test Program.

Valves are designed to withstand the accelerations and/or loads predicted by the piping stress analysis. Assurance is therefore provided that the components will function as required when subjected to design loadings.

Finally, active valves are also required to be operated periodically, as required in the Technical Specifications. This repeated operability requirement throughout the life of the specified valve further provides assurance of reliable valve operation.

The representative combination of loads and analysis to ensure valve operability are summarized in Tables 3.9-17 and 3.9-18.

5.2.1.8 Inadvertent Operation of Valves

A discussion of the design-basis events and appropriate limits for this plant is given in Subsections 15.1.4, 15.2.2, 15.2.4, and 15.2.7. The events in Chapter 15 have been selected to envelop the most severe change in critical parameters from events that have been postulated to occur during planned operation.

5.2.1.9 Stress and Pressure Limits

Paragraphs NB-3655 and NB-3656 of ASME B&PV Code Section III are not directly applicable to pumps and valves. On the basis of the method of establishing design pressure, however, it can be stated that the requirements of Paragraph NB-3655.1 and NB-3656.1 of the above code are met for these components.

The allowable stress limits and design loads for NSSS components are summarized in Tables 3.9-8, 3.9-14, 3.9-17 through 3.9-26, 3.9-28 through 3.9-39, and 3.9-43.

5.2.1.10 Stress Analysis for Structural Adequacy

Stress analysis is used to determine structural adequacy of pressure components of the RCPB under various operating conditions and earthquakes. Significant discontinuities such as nozzles and flanges are considered. In addition to the design calculations required by the ASME Codes, stress analysis is performed by methods outlined in the code appendixes or by other methods applicable to the design condition through reference to analogous codes or other published literature.

Results of areas with potentially significant stress concerns are given for major components in Tables 3.9.17 through 3.9-26.

5.2.1.11 Analysis Method for Faulted Condition

Elastic stress analysis methods in conjunction with elastic system analysis were generally used for RCPB components. In the event that an inelastic stress analysis was performed, the analysis methods conform to the requirements of ASME B&PV Code Section III, Appendix F.

5.2.1.12 Protection Against Environmental Factors

The protection of the principal components of the reactor coolant system against environmental effects is discussed in Section 3.11. Missile protection is discussed in Section 3.5, and fire protection is discussed in Subsection 9.5.1.

5.2.1.13 Compliance With Code Requirements

For components that were constructed in accordance with Section III of the ASME B&PV Code Subsection NB, the analytical calculations or experimental testing was performed to demonstrate compliance with the code. Brief descriptions of the mathematical or test models and the methods of calculation or testing, including any simplifying assumptions with summary of results, are provided in Subsection 3.9.1 and in Table 3.9-13 and in Tables 3.9-18 through 3.9-24.

5.2.1.14 Stress Analysis for Emergency- and Faulted-Condition Loadings

The types of stress analysis that were used for the emergency and faulted conditions are given in tables in Section 3.9.

5.2.1.15 Stress Levels in Category I Systems

A representative list of Category I RCPB systems and associated stress levels is provided in Tables 3.9-13 through 3.9-24. Piping isometrics for the major systems are shown in Figures 3.9-6 through 3.9-15.

5.2.1.16 Analytical Methods for Stresses in Pumps and Valves

The methods and criteria for analysis of stresses and deformations in the pressure boundary portions of Class 1 pumps are as described in the ASME B&PV Code Section III and the Nuclear Pump and Valve Code.

The methods and criteria for design and acceptability of stresses and deformations, as determined for the pressure boundary portions of Class 1 line valves and safety/relief valves (SRVs), are those described in the applicable portions of the ASME B&PV Code Section III, and the Nuclear Pump and Valve Code.

Pumps, line valves, and safety/relief valves purchased for this project were constructed and designed in accordance with the categories explicitly addressed by the ASME Nuclear Pump and Valve Code and ANSI B-31.7 Nuclear Power Piping Code. In the event that components supplied with geometries or design conditions for which code limits had not been developed, a complete description of the analytical methods and criteria used for evaluation of stresses and deformations was submitted by the manufacturer.

The summary of the detailed analyses for selected RCPB components (analytical models, method of calculation, and a summary of results) is shown in Tables 3.9-17 and 3.9-18.

5.2.1.17 Analytical Methods for Evaluation of Pump Speed and Bearing Integrity

The Rayleigh's approximation method is used to calculate the combined pump and motor shaft critical speed. This procedure, which equates the inertial forces of the rotating masses to the elastic restoring forces in the shafts, yields the lowest possible frequency of resonant shaft excitation. The lowest vibration frequency thus calculated must be at least 130 percent of the maximum expected pump speed. The hydrodynamic bearings in the motor or pump are designed using "A Solution for Finite Journal Bearings and Its Application to Analysis and Design," by A. A. Raimondi and J. Boyd, ASME Transactions, Volume I, No. 1, April 1958 or by an equivalent method. If the pump has a hydrostatic bearing, the motor bearings are analyzed as above while the pump bearing is analyzed by use of a computer code which is the proprietary information of one of our pump vendors.

5.2.1.18 Operation of Active Valves Under Transient Loadings

The qualification test program to verify that active valves within the RCPB whose operability is relied upon to perform a safety function or to shut down the reactor operate under the transient loadings experienced during service life is described in the following subsections.

5.2.1.18.1 Motor-Operated Gate Valve

A motor operator built to the same design as the RRS gate valves has been tested to demonstrate its performance capability under expected operating conditions, including the containment environment after the LOCA. Performance was tested under maximum moisture, pressure, and temperature conditions after exposure to lifetime radiation dose and under design-basis seismic conditions.

5.2.1.18.2 Main Steam Line Isolation Valves

Components of the MSIVs that are required to operate during transient conditions and whose functional capabilities are sensitive to the abnormal ambient pressure and temperature associated with the transient were subjected to a test sequence that simulates the abnormal ambient conditions. Functional requirements were verified throughout the test sequence. Components prototypical of Fermi 2 valve components were tested.

5.2.1.18.3 Safety/Relief Valves

The SRVs were subjected to tests described in Subsection 5.2.2.6 that simulate conditions similar to those experienced during service life.

5.2.1.19 Field-Run Piping

All piping 2 in. in diameter and smaller was designed by Edison but was fabricated and installed in the field by the piping erection subcontractor. This includes all small process piping, instrument piping, and branches from large piping (2-1/2 in. and larger). Small piping exists in all Category I piping systems.

Design, materials procurement, fabrication, erection, and testing of field-run piping are done in accordance with documented process control procedures. Review and approval, particularly for Category I pipe routings, location, and identification of all shop and field welds, are required by these procedures.

Small RCPB piping is generally analyzed using the computerized elastic stress analysis techniques described in Section 3.9.

Hydrostatic testing, prior to erection, is required for any pipe spool that is embedded in concrete or installed in an inaccessible location.

5.2.1.20 Feedwater Sparger and Thermal Sleeve

Several distinct problems have been experienced with the feedwater nozzle and spargers of the design originally planned for Fermi 2. These problems resulted in sparger arm cracks, flow hole cracks, thermal sleeve cracks, and cracks in the feedwater nozzle itself. The causes for these problems were identified, solutions were investigated, and a new design for the feedwater thermal sleeve and sparger was developed.

General Electric prepared a detailed report on the problems, description of solutions, verification of solutions, and safety considerations. This report, "Boiling Water Reactor

Feedwater Nozzle/Sparger," NEDE-21821, March 1978, was submitted to the NRC. The report gives a considerable body of data to show the acceptability of the GE design.

Fermi 2 incorporates all elements of the new design.

The new sparger/thermal sleeve design meets the following objectives:

a. Protects the feedwater nozzle against the high-frequency thermal cycles that initiate nozzle cracks

b. Is immune to the vibration that causes sparger arm cracks

c. Eliminates low-flow stratification

d. Eliminates the nozzle flow separation that causes flow hole cracks.

In the spargers, top-mounted elbows, each with a converging discharge nozzle, replace the front discharge holes. These features solve two problems. The top-mounted elbows ensure that the sparger/thermal sleeve remains full of cold feedwater during low-flow conditions, thereby eliminating low-flow stratifica-tion. The converging discharge orifices eliminate the flow separation that was the cause of flow hole cracking.

The junction between the thermal sleeve and sparger arms uses a forged tee, which improves resistance to vibration-induced cracking.

The thermal sleeve configuration is drastically different from previous designs. The inner thermal sleeve is the feed pipe for the sparger and is sealed against the safe-end with a piston ring. The inner thermal sleeve is welded to the forged tee.

Since leakage will eventually occur past the primary seal, a means must be provided to protect the nozzle against this leakage. To provide the required protection, a second seal is provided downstream of the primary seal. This secondary seal is attached to an intermediate thermal sleeve, which is open to the reactor at its downstream end. The annulus between the inter-mediate and inner thermal sleeves has a low hydraulic resistance and serves to channel leakage to the reactor without impinging on the feedwater nozzle. As a further impediment to leakage and to provide damping against vibration, an interference fit is provided between the ring, which contains the secondary seal, and the nozzle safe end.

The two seal members are joined by a slotted member. This slotted member provides a structural tie between the two seal members, which allows radial thermal expansion while providing rigidity against the translational motion of vibration. The slots also provide a flow path for the primary leakage flow to enter the inner annulus.

Since the second seal is exposed to a very small pressure differential, its tendency to leak is very small.

Primary leakage flowing between the inner and intermediate sleeves would cool the intermediate sleeve and thereby produce a cold boundary layer on the outside of the intermediate sleeve. This boundary layer might then shed and produce nozzle thermal cycles. To preclude this, an outer sleeve is provided to isolate the nozzle against such shedding.

Thermal cycling is the cause for blend radii cracking. The presence of cladding increases thermal stresses by approximately a factor of 2. Most plants have elected to machine off the cladding in this region. The design and fabrication of the Fermi 2 vessel did not clad the feedwater nozzle and blend radii. Therefore, incorporation of the new design will not involve the task of removing cladding. Calculations and test program results show the potential for crack initiation is essentially zero for extended high-frequency, low differential-temperature thermal cycling, expected with the new design and unclad nozzles.

Preservice ultrasonic (UT) examinations of the blend radii were conducted by SWRI, and magnetic-particle examination was conducted by the RPV manufacturer. No recordable indications were found by either technique. The Fermi 2 feedwater sparger and thermal sleeve design is in conformance with NUREG-0619.

The Fermi 2 ISI NDE program requires performance of periodic feedwater nozzle inner radius examination as required by ASME Section XI and NUREG-0619, or other NRC approved alternative program, to detect service induced degradation (cracking).

In-service penetration (PT) examination of the nozzle blend radii area will not be performed because of very limited access and the possibility of damage to the thermal sleeve and sparger assemblies in preparing the surface for PT examination.

5.2.2 Overpressurization Protection

5.2.2.1 Location of Pressure-Relief Devices

Figure 5.1-3 shows the schematic location of all pressure-relieving devices for

a. The reactor coolant system

b. The primary side of the auxiliary or emergency systems interconnected with the primary containment system

c. All blowdown or heat dissipation systems connected to the discharge side of the pressure-relieving devices.

5.2.2.2 Mounting of Pressure-Relief Devices

5.2.2.2.1 Safety Design Bases

The NPRS is designed

a. To prevent overpressurization of the NSSS that could lead to the failure of the nuclear system process barrier

b. To provide automatic depressurization for small breaks in the NSSS so that the LPCI and the core spray systems can operate to protect the fuel barrier

c. To permit verification of its operability

d. To withstand adverse combinations of loadings and forces resulting from operation during abnormal, accident, or special-event conditions.

5.2.2.2.2 Power Generation Design Bases

The NPRS SRVs have been designed

a. To maintain reactor pressure below the ASME B&PV Code Section III allowable maximum pressure during abnormal operational transients

b. To provide automatic depressurization for small breaks in the NSSS occurring with maloperation of high pressure coolant injection (HPCI) so that the low pressure coolant systems (LPCI and core spray) can operate to protect the fuel barrier

c. To discharge to the primary containment suppression pool

d. To correctly reclose following operation so that maximum operational continuity can be obtained.

5.2.2.2.3 Description

The NPRS consists of SRVs located on the main steam lines between the RPV and the first isolation valve within the drywell. These valves protect against overpressurization of the NSSS.

The SRVs provide four main protection functions:

a. Overpressure-relief operation - The valves open by application of external power to limit a pressure rise. In the relief valve mode, any of these valves can be operated by manual action from the control room. No particular setpoint applies to this method of operation, as the operator may open a valve at his discretion for blowdown or test over a wide pressure range

b. Overpressure-safety operation - The valves function as safety valves and open to prevent NSSS overpressurization. These valves are self-actuated at their spring setpoint if not already opened for relief operation

c. Depressurization operation - Five valves are opened by indirectly operated devices (pneumatic) as part of the emergency core cooling system (ECCS) for events involving small breaks in the nuclear system process barrier. These valves, which are selected for automatic depressurization, are activated automatically

d. Post fire depressurization operation – Selected valves are manually operated from the control room using their pneumatic controls to enable use of low pressure makeup for certain post fire shutdowns.

Figure 5.1-3 shows the schematic location of the valves and piping. The SRVs are constructed and marked with data in accordance with the 1968 Draft of the ASME Nuclear Pump and Valve Code and addenda through March 1970. The popping-point tolerance, the pressure at which valves open by high steam pressure, conforms with the ASME B&PV Code Section III.

The majority of events that lead to actuation of the primary system SRVs are those that initially or eventually produce a NSSS pressure increase. These pressure-increase events result from sudden reductions of steam flow while the reactor is operating at power.

Table 5.2-5 shows the set pressures of the safety/relief valves. Once any SRV opens, subsequent actuations are controlled by two SRVs that are armed with the low-low set relief logic. The duration of each relief discharge should in most cases be less than 15 sec.

The SRVs are designed to operate in the accident environments stated in Table 3.11-1.

These conditions envelop the predicted pressure and temperature response of the containment following the design-basis LOCA (Subsection 6.2.1).

Each SRV discharges steam through a discharge line to a quencher device located below the minimum water level in the primary containment suppression pool. The SRV discharge piping is designed to limit valve outlet pressure to 40 percent of maximum valve inlet pressure with the valve wide open. Water in the line more than a few feet above suppression pool water level would cause excessive pressure at the valve discharge when the valve is again opened. For this reason, a vacuum relief valve is provided on each SRV discharge line to prevent drawing an excessive amount of water up into the line as a result of steam condensation following termination of relief operation. In addition, the safety/relief blowdown control system ensures that subsequent SRV discharges will not occur during periods of elevated water legs in the discharge piping (see Fig. 7.3-12, Sheet 1).

The selection of size of safety/relief line vacuum breakers for Fermi 2 was based on the following parameters:

a. Instant condensation of steam is assumed following SRV closure

b. The vacuum created must be equalized in 2 sec

c. The volume to be relieved is based upon the longest safety/relief line

d. The drywell pressure was its minimum value, 14.2 psia

e. Conservative L/Ds and C_v's were selected for the valve.

The Fermi 2 study selected 8-in. vacuum relief valves. The capacity, C_v, set pressure, and pressure drop at rated flow for these valves used in the study calculation were supplied by the vendor based on extrapolation of experimental data taken from smaller but similar valves. The calculations in the study showed that under the parameters selected above, the vacuum will be relieved in 1.5 sec (versus the recommended 2 sec), and that the water leg inside the line would rise less than 4.3 ft past the submerged end of the line in this time.

The SRVs are located on the main steam line piping, rather than on the RPV top head, primarily to simplify the discharge piping to the pool and to avoid the necessity of having to remove sections of this piping when the reactor head is removed for refueling. In addition, valves located on the steam lines are more accessible to correct possible valve malfunctions during a shutdown.

Each of the five SRVs provided for automatic depressurization system (ADS) is equipped with an accumulator and check valve arrangement. Each accumulator receives pneumatic pressure from the safety-grade Division I primary containment pneumatic supply lines, which also supplies pressure to the air operators of two non-ADS SRVs. Division I primary containment pneumatic supply is normally fed from the nitrogen supply system, with Division I noninterruptible control air (NIAS) available by operator action to be manually cross connected as a backup supply for the normal pneumatic supply. There is also a qualified connection located outside the secondary containment to permit bottled nitrogen to be supplied as an additional backup source for the Division I pneumatics. The sizing for the ADS accumulators allows about 17 hours for the recovery of a backup pneumatic supply under the most limiting postulated event conditions requiring ADS. Leakage from the accumulator assembly and the SRV air operator subassembly were considered in evaluating the accumulator sizing. Each accumulator has adequate storage capacity to allow five actuations of an SRV at the long-term drywell pressure of the design SBLOCA analysis (see Figure 6.2-15) without the recovery of backup pneumatic supply pressure. This provides adequate pneumatic storage to cover interruptions if the pneumatic supplies are switched from the normal to the emergency backup sources. There are also eight non-ADS SRVs supplied by Division II of the primary containment pneumatic supply system, which is a separate, fully qualified pneumatic subsystem, but does not include NIAS as a backup supply. Backup nitrogen is provided bottles located inside the secondary containment to allow the use of Division II SRVs for certain Appendix R post-fire shutdowns from the control room accompanied by a loss of offsite power. An additional separate qualified connection located outside the secondary containment is provided to permit bottled nitrogen to be supplied for a backup source of the Division II pneumatics. The backup pneumatic supplies of both divisions of primary containment pneumatic supply system, although no credit is taken for, would allow the ten non-ADS SRVs to be operated as a backup for reactor pressure relief. The ten non-ADS SRVs include two SRVs, one associated with each pneumatic division, which have accumulators for the Low-Low Set function (see Section 5.2.2.5.3). Refer to Figure 5.2-1 for a diagram of the primary containment pneumatic supply system. The drywell nitrogen pneumatic system is described in Section 9.3.6.

The NPRS automatically depressurizes the NSSS sufficiently to permit the LPCI and core spray systems to operate. Depressurization occurs when five of the SRVs are opened automatically (ADS).

Descriptions of the operation and features of the automatic depressurization system are found in Subsections 6.3.2 and 7.3.1.

The NSSS can be depressurized manually if the main condenser is not available as a heat sink after reactor shutdown. The SRVs are operated by remote manual controls from the main control room. Controls for two of the relief valves are located on the remote control panel, and can thus be operated outside the main control room.

5.2.2.3 Overpressure Protection Analysis

The vessel overpressure protection system is designed to satisfy the requirements of Section III, Nuclear Vessels, of the ASME Boiler and Pressure Vessel Code 1968. The general requirements for protection against overpressure, as given in Article 9 of Section III, recognize that reactor vessel overpressure protection is one function of the reactor protection system and allows the integration of pressure relief devices with the protection system of the nuclear reactor. Hence, credit is taken for the reactor protection system as a complementary pressure protection device. However, the vessel overprotection analysis for Fermi 2 takes credit only for reactor protection system signals which are indirectly derived.

Included in this subsection are the design bases for sizing of the SRVs, the overpressure protection analysis, and the effects on the vessel pressure transients of valve capacity. The overpressure protection analysis used the actual Fermi 2 scram characteristics (e.g., for BWR/4 scram and control rod drive (CRD) systems).

The head spray piping (Class 2 pipe in the drywell) is no longer connected with the RPV. Therefore, it is no longer protected by the RPV overpressure protection system. However, a blank flange is installed in the line, preventing any pressurization of the head spray pipe.

5.2.2.3.1 Design Basis

5.2.2.3.1.1 Safety/Relief Valve Sizing

The safety/relief valve capacity of the Fermi 2 plant is sized to limit the primary system pressure, including transients, to the requirements of the ASME Boiler and Pressure Vessel Code, Section III, 1968, Nuclear Vessels. The essential ASME requirements, which are all met by this analysis, are stated below.

It is recognized that the protection of vessels in a nuclear power plant is dependent upon many protective systems to relieve or terminate pressure transients. Installation of pressure relieving devices may not independently provide complete protection.

The safety/relief valve sizing evaluation assumes credit for operation of the reactor protection system. A scram may be initiated by any one of three sources; i.e., steam system isolation (i.e., direct), neutron flux, or reactor vessel pressure signal. The system isolation scram signal is derived from position switches mounted on the main steamline isolation valves or the turbine stop valves or from pressure switches mounted on the dump valve of the turbine control valve hydraulic actuation system. The position switches are actuated when the respective valves are closing and following 10 percent travel of full stroke. The pressure switches are actuated when a fast closure of the control valves is initiated. However, according to General Electric methodology, the safety/relief valve sizing evaluation does not assume credit for direct scram, only for the indirect flux scram. Further, no credit is allowed for power operated pressure relieving devices. Credit is taken only for the dual purpose safety/relief valves in their ASME Code qualified mode of safety operation.

The above considerations in the vessel overpressure analysis methodology require multiple equipment failures to occur. The probability of this many multiple failures (loss of direct scram and no automatic power operated relief valve actuation) is sufficiently low that the event should be considered, as a minimum, an “emergency” condition. However, the analysis applies the more conservative “upset” code requirements rather than the “emergency” limits such that the rated capacity of the pressure relieving devices is required to be sufficient to prevent a rise in pressure within the protected vessel of more than 110 percent of the design pressure (1.10 x 1250 = 1375 psig). All combination safety/relief valves discharge into the suppression pool through a discharge pipe from each valve which is designed to achieve sonic flow conditions through the valve, thus providing flow independence to discharge piping losses.

The ASME Boiler and Pressure Vessel Code requires the nominal pressure setting of at least one safety/relief valve connected to any vessel or system to not be greater than a pressure at the safety/relief valves corresponding to the design pressure (1250 psig) anywhere in the protected vessel. Valves which are additional to the one(s) set at or below design pressure, may be set higher, but in no case are any of these settings to exceed a pressure at the safety/relief valves corresponding to 105 percent of the design pressure anywhere in the vessel.

5.2.2.3.2 Method of Analysis

To design the pressure protection for the nuclear boiler system, a detailed analytical model representing all essential dynamic characteristics of the system is simulated on a computer. This model includes the hydrodynamics of the flow loop, the reactor kinetics, the thermal characteristics of the fuel and its transfer of heat to the coolant; and all the principal controller features, such as feedwater flow, recirculation flow, reactor water level, pressure, and load demand. These characteristics are represented with all their principal nonlinear features in a model that has evolved through extensive experience and favorable comparison of the analysis results with actual BWR test data. A detailed description of the model is documented in a General Electric licensing topical report.*

Typical capacity characteristics, as modeled, are represented in Figure 5.2-1(a) for the safety/relief valves. The associated bypass, turbine control valve, and main steam isolation valve (MSIV) characteristics are, of course, also represented fully in the model.

NOTE: * Report reference above is: General Electric Company, Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors, NEDO-24154, October 1978. (ODYN)

5.2.2.3.3 System Design

A parametric study was conducted to determine the required steam flow capacity of the safety/relief valves which satisfies the ASME Code requirements. The parameters used in the study have been updated to evaluate the impact of the 105% steam flow power uprate.

5.2.2.3.3.1 Analytic Conditions

Parameter	Value
Power level, MWt	3499 (102% of 3430)
Steam flow, lb/hr	15,200,000
Core flow, lb/hr	105×10^6
Vessel dome pressure, psig	1048
Doppler coefficient	(a)
Average fuel temperature, °F	1330
Dynamic void reactivity coefficient	(a)
Void fraction	(a)
Control rod scram speed	See Figure 5.2-1(b)
Scram reactivity curve	(a)
High neutron flux (APM) scram percent of initial power (3430 MWt)	124.4 (b)

High vessel dome scram pressure, psig	1126 [(b)]
High vessel dome pressure recirculation pump trip set point, psig	1135

(a) This input is calculated by ODYN analysis.
(b) Maximum safety limit.

The ATWS recirculation pump has been simulated in the overpressure analysis performed with ODYN.

5.2.2.3.3.2 Transients

The overpressure protection system must accommodate the most severe pressurization transient. Both the closure of all main steam isolation valves and a turbine trip with bypass failure produce severe transients. The evaluation of transient behavior with final plant configuration has shown that the isolation valve closure is slightly more severe when credit is taken only for indirect derived scrams, therefore, it is used as the overpressure protection basis event.

5.2.2.3.3.3 Scram

a. Direct reactor scram - Not credited (failure assumed)

b. Scram reactivity curve - This input is calculated by ODYN analysis

c. Control rod drive scram motion - See Figure 5.2-1(b)

5.2.2.3.3.4 Safety/Relief Valve Characteristics

Type	Target Rock
Number	15[a]
SRV capacity, steam flow	$87x10^4$ lb/hr at 1090 psig[b]
First safety relief analytical setpoint, psig	1169
Number of safety relief groups simulated	3
Increment in SRV setpoint between groups, psi	10
Valve response characteristics	See Figure 5.2-1(a)

a 11 SRVs were used in the overpressure protection analyses for power uprate.
b See Table 5.2-5 for SRV capacities and setpoints.

5.2.2.3.3.5 Safety/Relief Valve Sizing

The safety/relief valve capacity required for overpressure protection is determined from the minimum capacity that will provide an adequate margin between the peak vessel pressure and the vessel code limit (1375 psig) in response to the MSIV closure-flux SCRAM event. The number of safety/relief valves which provide a total capacity equal to or greater than the minimum required capacity constitutes the minimum safety valve requirement for overpressure protection.

The MSIV closure-pressure SCRAM event is evaluated as confirmation of the safety/relief valve capacity determined from the safety/relief valve sizing criteria and to demonstrate the overpressure protection capability of the safety/relief valve system at the highest level of indirect SCRAM.

5.2.2.3.4 Evaluation of Results

5.2.2.3.4.1 Safety/Relief Valve Capacity

The required SRV capacity is determined by analyzing the pressure rise from an MSIV closure with a flux scram transient. The plant is assumed to be operating at turbine-generator design conditions at a maximum vessel dome pressure of 1048 psig. The analysis hypothetically assumes the failure of the direct isolation valve position scram. The reactor is shut down by the backup, indirect, high-neutron flux scram. For the analysis, relief setpoints of the SRVs are assumed to be in the range of approximately 1169 to 1190 psig.

Under the general requirements for protection against overpressure as given in Section III of the ASME Code, credit can be allowed for a scram from the reactor protection system. As discussed in Section 5.2.2.3.1.1, the backup reactor high-neutron-flux scram is conservatively applied as a design basis for determining the required capacity of the pressure-relieving dual-purpose SRVs. The direct position scrams are not used in the design basis but could be since they qualify as acceptable pressure protection devices when determining the required SRV capacity of nuclear vessels under the provisions of the ASME Code.

The cycle specific overpressure protection analysis is included with the supplemental reload licensing report and Figure 5.2-1(c) shows the analytical results from TRACG, with only 11 of the 15 SRVs operating. Beginning with Cycle 16, the cycle specific overpressure analysis is performed with TRACG (References 23 and 24). The sequence of events assumed in this analysis was investigated to ensure that the ASME Code requirements were met and to evaluate the pressure relief system exclusively. The peak vessel (bottom) pressure for the MSIV transient with high-flux scram is less than the 1375 psig allowed by the ASME Code.

5.2.2.3.5 Safety/Relief Valve Characteristics

5.2.2.3.5.1 Schematic Arrangement

The schematic arrangements of the safety/relief valves are shown in Figures 5.2-1(d) and 5.2-1(e).

5.2.2.3.5.2 Pressure Drop in Inlet and Discharge

Pressure drop on the piping from the reactor vessel to the valves is taken into account in calculating the maximum vessel pressure reported above.

Pressure drop in the discharge piping to the suppression pool is limited by proper discharge line sizing to prevent back pressure on each safety/relief valve from exceeding 40 percent of the valve inlet pressure, thus assuring choked flow in the valve orifice and no reduction of valve capacity due to the discharge piping. Each safety/relief valve has its own separate discharge line.

5.2.2.3.5.3 Safety/Relief Valve Description

These valves were manufactured by Target Rock Corporation to ASME Section III, 1968 with 1970 Summer Addenda. They comply with ASME Section III, 1969 Summer Addenda, Paragraph N911.4 for pilot activated valves.

Valve quantities and Technical Specification set pressures are as follows: Note: These values are based on actual vendor test data, not analytical values.

Quantity	Set Pressure (psig)	ASME Rated Capacity at 103 Percent of Set Pressure (lb/hr minimum)
5	1135	904,400
5	1145	912,200
5	1155	920,100

5.2.2.3.6 Conclusions

Safety requirements have long demanded very high reliability in the reactor scram functions. Recognition of this reliability as being completely adequate justification for these functions to contribute to vessel pressure protection is reflected in the ASME Section III Code provisions. As discussed in subsection 5.2.2.3.1.1, actual General Electric design practice very conservatively applies the code provisions through use of margins even beyond those necessary to satisfy code limits. This further enhances the reliability of vessel pressure protection.

This design basis for sizing safety valves with indirect scram credit is technically sound and a most realistic approach. It is allowed under Section III of the ASME Boiler and Pressure Vessel Code, and has been adopted by the General Electric Company in the design of the Fermi 2 boiling-water reactor.

5.2.2.4 Main Steam Safety/Relief Valves

The Fermi 2 valves are the Target Rock Corporation Model 7567F, two-stage, pilot-operated SRVs. The pilot stage is designed for stable setpoint performance and high tolerance of pilot seat leakage.

5.2.2.4.1 Description

Figure 5.2-2 shows the top works for the two-stage valve. Reactor pressure is communicated through port (5) around the stabilizer disk (7) to the pilot disk (6). With the pilot disk (6) seated, pressure is supplied through the connecting port (10) to volume (3) against the main piston (4) which holds the main disk closed. When the reactor pressure reaches the pilot setpoint, the pilot lifts and the stabilizer disk seats. The stabilizer holds the pilot disk open as long as the stabilizer is against its own seat. The open pilot valve forms part of the path that releases the steam in volume (3) through ports (8), (9), and (10) The pressure in (3) drops quickly, and differential pressure across the main piston (4) opens the main stage valve.

SRV actuation is indicated by tailpipe pressure switches. The operations are displayed and recorded in the control room.

The principal features of the Target Rock two-stage design, and how they relate to improved performance, are described below:

a. The pilot valve is connected directly to the main piston chamber (3). If there is leakage past the pilot disk (6), it comes from the inlet pressure port (5) and through leakage passages around the main piston that maintain the pressure in chamber (3); leakage goes to the valve discharge line through port (9). Tests have shown that, even with leakage at 200 lb/hr, there is no appreciable effect on setpoint performance, and leakage will not cause the valve to open and blow down the reactor. Calculations show that the pilot leakage could reach a level greater than 1000 lb/hr without pilot lift or main-stage operation.

b. The 2-stage design has a direct-acting pilot with no pressure-sensing bellows and no need for a pressure switch. This feature resolves three problems that have occurred in earlier designs which used a leakage containing pilot bellows.

    1. Bellows leak

    2. Switch failures

    3. Short circuits in switch wiring.

c. The air actuator (11) is an integral part of the bonnet and has improved diaphragm-sealing characteristics. This change eliminates the need for grease or gaskets to effect an adequate seal. Tests and operational experience have shown delamination failures of the diaphragm in earlier designs. Tests under the same environmental conditions showed that the 2-stage pilot air operator diaphragm does not delaminate.

5.2.2.4.2 Materials

The topworks body is made of ASME-SA-105 as a forging. This combination of material and fabrication is code acceptable for this service.

5.2.2.5 Safety Evaluation

5.2.2.5.1 Introduction

The ASME B&PV Code requires that each RPV designed to meet Section III be protected from overpressure. The code allows a peak allowable pressure of 110 percent of RPV design pressure. The SRVs are set to open as a safety function in the range of 1135 to 1155 psig.

There are two major transients that represent the most severe abnormal operational transients resulting in an NSSS pressure rise. They are the closure of all MSIVs, and a turbine trip with coincident loss of condenser vacuum.

The transient produced by the closure of all MSIVs and the failure of direct scram represents the most severe operational pressure rise. The required relief valve capacity is determined by analyzing the pressure rise from such a transient. The plant is assumed to be operating at the turbine-generator design conditions at a maximum vessel dome pressure of 1048 psig. The analysis hypothetically assumes the failure of the direct isolation valve position scram. The reactor is shut down by the backup, indirect, high neutron flux scram. For the analysis, the self-actuated setpoints (safety function) of the SRVs are assumed to be in the range of approximately 1169 to 1190 psig. The analysis indicates that the design valve capacity is capable of maintaining adequate margin (at least 50 psi at the bottom of the RPV) below the peak ASME B&PV Code allowable pressure in the NSSS (1375 psig). The sequence of events assumed in this analysis was investigated to confirm conformance to code requirements and to evaluate the adequacy of the NPRS.

Under the general requirements for protection against overpressure as given in Paragraph NB-7000 of the ASME B&PV Code Section III, credit can be allowed for a scram from the reactor protection system (RPS). When determining the required SRV capacity, credit is also taken for the protection signals, which are indirectly derived. The backup reactor high neutron flux scram is conservatively applied as a design basis in determining the required capacity of the pressure-relieving dual-purpose SRVs.

Studies have been made on the loadings that the SRVs impose on the main steam line. The loadings considered include

a. Thermal expansion effects of the SRVs discharge piping

b. Dynamic effects of the SRVs and discharge piping due to earthquakes

c. The dynamic and jet force exerted on the SRVs during the first millisecond after the valve is opened and prior to the time that steady-state flow has been established. With steady-state flow, the dynamic flow reaction forces are self-equilibrated by the valve discharge piping. For the analysis and forcing function, refer to Subsection 3.9.2.5

d. Deleted

Thermal expansion analyses were made for several cases including the relief valve piping, both cold and hot, and jet forces.

The critical effect is the stress at the branch connection below the valve. In no case does the stress at this point exceed code specifications.

The analysis that forms the basis for the evaluation of the pressure relief function of the NPRS appears in Subsections 15.2.2, 15.2.3, and 15.2.4.

The setpoints of the relief valves are adjusted to operate in the range from 1135 to 1155, by self-actuation (i.e., overpressure relief function). The reactor is shut down by the normal trip scram (turbine stop valve closure scram).

System malfunctions that pose threats to the radioactive material containment barriers are presented in Chapter 15.

5.2.2.5.2 Two-Stage Target Rock Safety/Relief Valves

The special test programs have shown that the 2-stage pilot operated Target Rock SRV design has potential for improved reactor safety, plant availability, and capacity factor as compared to an earlier Target Rock design from the following considerations:

a. The probability of spontaneous valve opening because of pilot valve leakage has been made essentially zero. This problem has had a significant effect on availability and capacity factor

b. The possibility of setpoint changes because of bellows leakage has been eliminated completely. Actual setpoint changes caused by bellows leakage have been rare; however, leakage past bellows seals, switch failures, and related problems have reduced availability and capacity factors. (Note that the function of the seal bellows on the stem of the air operator of the two-stage valve is in no way related to the function of the pilot bellows of the three-stage valve).

c. The probability of air operator diaphragm failures has been reduced. This item has been of lesser concern than the first two, but it is a significant improvement

d. The integral air actuator has improved the pressure boundary, and reduced the probability of bending and/or sticking of the actuator shaft.

5.2.2.5.3 Reducing Stuck-Open Relief Valve Events

In response to NUREG-0737, Item II.K.3.16, GE, on behalf of the BWR Owners Group, has performed a study of the feasibility contraindications of reducing challenges to the SRVs by various methods. This study reviews the potential methods of reducing the likelihood of stuck-open relief-valve (SORV) events in BWRs and estimates the reduction in such events that can be achieved by implementing these methods. The results of this study have been provided to the NRC.

Although the NUREG-0737 position deals primarily with the reduction of challenges to SRVs, its clear intent is to reduce the incidence of SORV events. Reducing challenges is only one of three approaches to reducing SORV events. The other two are reducing the causes of spurious blowdowns and reducing the probability of SRVs to stick open when challenged. All three of these approaches present feasible and effective opportunities for reducing the incidence of uncontrolled blowdowns via SRV.

The following proposed modifications by the BWR Owners Group exist at Fermi 2:

a. Two-Stage Target Rock Valves

   The use of two-stage Target Rock valves at Fermi 2, as compared to the plants with 3-stage Target Rock valves, reduces the spurious blowdown events by 40 to 60 percent

b. Low-Low Set Relief

   Fermi 2 is equipped with a "low-low set" design feature that changes the setpoints of selected SRVs following the initial opening of a number of SRVs.

This ensures that following the initial pressurization, the pressure will be relieved by the low-low set valve alone, and the remaining SRVs will not experience any subsequent actuations. The purpose of low-low set at Fermi is to mitigate postulated loads caused by a second (after initial) opening of an SRV. However, the low-low set will also serve to reduce the frequency of SORV events.

According to the BWR Owners Group evaluation, these existing modifications at Fermi 2 are equivalent to a reduction in SRV challenges by a factor of almost 10 (Table 5.1, Reference 14).

In addition to these proposed modifications, Edison further reduced the SORV frequency by lowering the RPV water level isolation setpoint for MSIV closure from Level 2 to Level 1 and lowering the pressure setpoint for MSIV closure. This results in reduced SRV challenges by eliminating isolation cycling of the SRVs resulting from transients such as feedwater controller failure, trip of both recirculation pumps, and loss of feedwater flow.

The two-stage Target Rock valves and low-low set relief feature plus lowering the RPV water level isolation setpoint for MSIV closure from Level 2 to Level 1 and lowering the pressure setpoint for MSIV closure reduce the SORV frequency by a factor of more than 10 and meet the requirement of NUREG-0737, Item II.K.3.16.

5.2.2.6 Qualification Tests

5.2.2.6.1 Inspection and Testing

In November and December of 1976, GE performed a qualification/ life-cycle test program on one valve of the 2-stage pilot operated design. The program consisted of 300 valve cycles (150 manual and 150 pressure-induced operations). The objective of the life-cycle test was to verify the ability of the design to meet the requirements for (1) set pressure, (2) opening and closing response time, (3) blowdown, (4) seat tightness, and (5) achievement of flow-rated capacity lift (ASME). These tests were performed at reactor conditions, using a test facility that had the capability of providing full steam flow through the SRV when it opened. During the course of the test program, it was noted that the delay time on opening was erratic, and the pressure difference between the setpoint and reclosure was not large enough. All other performance parameters were acceptable, even at the extremes of low and high pressurization rates and the extremes of ambient temperatures. The same valve was operated another 150 cycles to identify the causes of the observed anomalies.

Minor design improvements were made to the 2-stage pilot operated valve design as a result of these tests, although the valve was functionally acceptable.

Because there had been design changes, a new qualification test program was begun in late 1977 by Target Rock Corporation. The program consisted of 300 cycles on one valve, and 60 cycles on each of three additional valves. These tests were completed satisfactorily. The tests showed that the valves produced consistently repeatable setpoint pressure operation, consistent delay times of less than, or equal to, 400 msec, and consistent reclosure ΔP's for a given back pressure.

Additional tests were performed to provide the data necessary for final selection of the seal bellows area. Note that these tests and the final selection comprise a "fine-tuning" improvement of a thoroughly tested and qualified valve.

The electric-pneumatic actuator assembly was subjected to a qualification aging test that consisted of (1) a reference frame test to determine leakage, response time, and solenoid electrical characteristics for subsequent comparison; (2) radiation aging to a cumulative radiation dose of 19.6 x 10^6 rads; (3) a reference frame test for the postradiation condition; (4) mechanical aging of 8000 cycles under normal ambient conditions of 150°F at 100 percent relative humidity; (5) thermal aging to 285°F at 100 percent relative humidity for 480 hr in air; (6) a reference frame test for the post-aging condition; (7) a simulated LOCA environment; (8) a reference frame test for the post-LOCA condition; (9) an accident radiation exposure of 13 x 10^6 rads; and (10) a final reference frame test. The qualification aging test established that the actuator assembly was compatible with the service environments.

In parallel with the latter part of the above testing, a seismic qualification test was performed consisting of a valve mounted on a shake table subjected to biaxial vibration, with statically applied moment loads at the valve flanges. The test program consisted of (1) resonant frequency determination, (2) nozzle loading, (3) a simulated operating-basis earthquake (OBE), (4) an SSE, and (5) reference frame tests. The valve was operated under reactor conditions using a restricted steam flow arrangement.

The qualification test results: (1) verified that the SRV design will be operable and is structurally sound under the various normal and abnormal environmental and dynamic conditions to which the valve may be subjected in service; (2) established the basis for confirming the installed and qualified life of the valve; and (3) provided information necessary to enhance the established quality assurance program to ensure that new valves are equivalent to the qualified design.

The vessel overpressure protection analysis in Subsection 5.2.2.3 shows that the peak vessel (bottom) pressure for the limiting MSIV transient with high-flux scram and position trip scram is less than the 1375 psig allowed by the ASME code. The cycle-specific results of the vessel overpressure protection analysis are reported in the cycle-specific Supplemental Reload Licensing Report. The deviation of setpoints by a common-mode failure after installation is highly unlikely because of the qualification and the established quality assurance program previously discussed. However, even considering the possibility of setpoint drift, the peak pressure for the limiting operational transient will still be less than the ASME Code limit.

In addition, in response to comments from the NRC on operation of relief valves during abnormal transients, Edison, together with the BWR Owners Group, undertook a special SRV testing program reported in Reference 1. The results of the BWR Owners Group evaluation indicated that there is one event and single-failure combination that would lead to the discharge of liquid from the SRVs. This event and single-failure combination leads to the alternative shutdown mode of operation that uses the SRVs as a return flow path for low-pressure liquid to the suppression pool. The evaluation demonstrated that all other events postulated to produce liquid or two-phase SRV flow, including events under high-pressure conditions, are either of sufficiently low probability or that consequences are concluded to be acceptable. As such, no testing is needed for these events.

The BWR Owners Group testing program included the testing of typical SRVs for BWR/2 through BWR/6 plants to demonstrate the ability to perform satisfactorily under the condition in which low-pressure (i.e., up to 250 ± 20 psig) water passes through the valve instead of saturated steam. This corresponds to conditions expected during the alternate shutdown cooling mode; that is, the mode in which low-pressure pumps are injecting cold water into the reactor vessel and this water is vented through the SRVs back to the suppression pool. A plant-specific evaluation (Reference 2) of the test data correlated the generic program test conditions to the alternate shutdown cooling mode conditions for Fermi 2.

For Fermi 2, the alternate shutdown cooling mode of passing water through the SRVs to the suppression pool is not an anticipated operating condition. The Fermi 2 design includes a parallel flow path (see section 5.5.7.3) inside containment for shutdown cooling employing a normally closed, remote manual isolation valve powered from the alternate division emergency power supply. In any case, the test results demonstrated that the Fermi 2 SRVs would be available and can accommodate adequate water passage for shutdown cooling in the extremely unlikely event that the normal shutdown cooling path and its backup are unavailable.

Also, Edison participates in a utility-sponsored performance evaluation program for SRVs.

5.2.2.6.2 <u>Inservice Inspection and Testing</u>

The following inservice test program is applied.

a. Fifty percent of the valves are to be removed from service and tested at least once per fuel cycle.

b. The remaining 50 percent are to be tested at least once per two fuel cycles.

The program for the in-place monitoring of valve performance is conducted by monitoring the discharge pipe thermocouples. Thermocouples, with continuous readouts, provide the signals that establish the leaktightness of the valve. In addition, a position monitoring system has been provided that meets the requirements of NUREG-0578.

The SRV inspection and overhaul program is developed from the manufacturer's recommendations to ensure the operability of these valves. The frequency of visual inspection and overhaul is in accordance with applicable ASME operating and maintenance standards for SRVs.

This testing and inspection will provide added confidence that the valves will operate reliably, and that there are no deficiencies that could cause them to function, in service, in an unsafe manner.

The SRVs are tested in accordance with Quality Control (QC) procedures to detect defects and to prove operability prior to installation. The following tests are conducted:

a. Hydrostatic test at ANSI-specified test conditions

b. Pneumatic seat leakage test at 90 percent of set pressure, with maximum permitted leakage of 30 bubbles per minute emitting from a 0.250-in.-diameter tube submerged 0.5 in. below a water surface, or an equivalent test using an approved test medium

c. Set pressure test with valve pressurized with saturated steam, or other approved test medium with the pressure rising to the valve set pressure

d. Response time test with each SRV tested to demonstrate acceptable response time.

The valves are installed as received from the factory. The setpoints are adjusted, verified, and indicated on the valves by the vendor. Specified manual and automatic actuation relief mode of each SRV pilot is verified during the Preoperational Test Program.

It is not feasible to test the SRV setpoints while the valves are in place or during normal plant operation. The valves are mounted on 6-in.-diameter, 1500-lb primary service rating flanges. They are removed for maintenance or bench checks and reinstalled during inspection periods.

The external surface and seating surface of all SRVs are 100 percent visually inspected when the valves are removed for maintenance or bench checks.

The SRV inspection and overhaul program is developed from the manufacturer's recommendations to ensure the operability of these valves. The frequency of visual inspection and overhaul will be in accordance with applicable ASME operating and maintenance standards for SRVs.

The improbable failure of the relief mode function of this valve will not cause failure of the safety mode function of the valve, and vice versa.

The automatic depressurization capability of the ADS is evaluated in Subsections 6.3.2 and 7.3.1.

5.2.2.7 Routing of Nuclear Pressure Relief System Valves to Torus

The NPRS valves could discharge to the drywell without exceeding drywell design conditions. However, such a discharge would cause undesirable high temperature and high moisture transients on drywell equipment. Consequently, all valves are routed to the torus with discharge below the water.

A separate discharge line is provided for each of the 15 valves. The isometric of one typical line is shown in Figure 5.2-3. The lines do not penetrate containment; they are routed to the torus through the drywell-to-torus vent lines. Inside the torus, they penetrate the vent line and terminate in a T-quencher. Details of a typical line inside the torus are shown in Figures 5.2-4 through 5.2-7.

The portions of the lines inside the drywell and the torus are designed and classified as Quality Group B,* Category I, QA Level I. The discharge lines are made of Schedule 80, seamless carbon steel pipe; joints are butt welded with a backing ring. Each line is equipped with an 8-in. vacuum breaker. The T-quenchers are designed and classified as Quality Group C, Category I, QA Level I.

The lines have been sized to be nonlimiting on flow; i.e., the back pressure at the relief valve is well below that which restricts the capacity of the valve. The lines are l0-in. nominal size in the drywell, 12-in. in the vents and torus. The discharge line supports are designed to handle the maximum reaction load. In addition, the supports in the torus are designed to accommodate the hydrodynamic loading conditions that occur during accident events. The evaluation is documented in Reference 2.

NOTE: * The portions of the lines in the vent line were originally installed as Quality Group D. These portions of the lines have been upgraded to include the requirements of Quality Group B components and are classified as Quality Group D+, Category I, QA Level I.

5.2.2.8 Pressure Isolation Valves

There are several safety systems connected to the RCPB that have design pressures below the rated reactor coolant system (RCS) pressure. There are also some systems which are rated at full reactor pressure on the discharge side of pumps but have pump suctions below RCS pressure. To protect these systems from RCS pressure, two or more isolation valves are placed in series to form the interface between the high-pressure RCS and the low-pressure systems. The leaktight integrity of these valves must be ensured by periodic leak testing to prevent exceeding the design pressure of the low-pressure systems, thus causing an inter-system LOCA.

5.2.3 General Material Considerations

5.2.3.1 Material Specifications

The principal pressure-retaining materials and the appropriate material specifications for the RCPB components are listed in Table 5.2-6.

5.2.3.2 Compatibility With Reactor Coolant

The construction materials exposed to the reactor coolant are

a. Solution-annealed austenitic stainless steels (both wrought and cast) types 304, 304L, 316, and 316L

b. Nickel base alloys, Inconel 600 and Inconel X750

c. Carbon steel and low alloy pressure vessel steel

d. Some 400 series martensitic stainless steel, all tempered at a minimum of 1100°F

e. Colmonoy and Stellite hardfacing materials.

f. Precipitation hardenable stainless steel material, XM-13.

All of these construction materials are resistant to stress corrosion in the BWR coolant. General corrosion on all materials except carbon and low alloy steel is negligible. Conservative corrosion allowances are provided for all exposed surfaces of carbon or low alloy steels.

Contaminants in the reactor coolant are controlled to very low limits by the reactor water quality specifications. No detrimental effects will occur on any of the materials from allowable contaminant levels in the high purity reactor coolant.

5.2.3.2.1 Steps To Minimize Stress Corrosion Cracking

In September 1974, cracking was experienced in the stainless steel piping at Dresden Nuclear Power Station Unit 2. This was the first of a series of incidents of intergranular stress corrosion cracking (IGSCC) that occurred in BWRs. The cracking occurred in weld heat-affected zones in type 304 stainless steel recirculation bypass piping systems and core spray lines.

In May 1984, during a recirculation piping system replacement at the Pilgrim Station, IGSCC was discovered and confirmed in the Inconel 182 butter welds for recirculation piping RPV nozzles. This was the first of several instances documenting IGSCC in Inconel buttering which was not directly attributed to resin intrusions or other causes. With the issuance of NUREG 0313, Revision 2, and NRC Generic Letter 88-01, Inconel 182 has been removed from the list of materials which were considered resistant to IGSCC (NUREG 0313, Revision 2. par. 2.1.1). Since most reactor pressure vessel (RPV) nozzles were "buttered" with Inconel 182 prior to welding the "safe-ends" to the nozzles and the nozzles to safe-end welds were made using Inconel 182 filler metal, these welds were reclassified as "susceptible" to IGSCC.

As a result of these incidents, studies were undertaken by the NRC, GE, and Electric Power Research Institute (EPRI). These studies have shown that such cracking is caused by a combination of the presence of significant amounts of oxygen in the coolant, high stresses, and some sensitization of metal adjacent to welds. Such cracks are not expected to occur outside the heat-affected zones adjacent to welds, provided that the pipe material is annealed properly.

Pipe runs containing stagnant or low-velocity fluids have been observed to be more susceptible during plant operation to stress corrosion cracking than pipes containing a continuously flowing fluid. Historically, these cracks have been identified either by volumetric examination, by leak detection systems, or by visual inspection. Because of the inherent high material toughness of austenitic stainless steel piping, stress corrosion cracking is unlikely to cause a rapidly propagating failure resulting in a design-basis LOCA.

Although the probability is extremely low that these stress corrosion cracks will propagate far enough to create a significant safety hazard to the public, the presence of such cracks is undesirable. Steps have been taken to minimize stress corrosion cracking in Fermi 2 piping systems, to eliminate this condition, and to improve overall plant reliability. The various mitigating programs used at Fermi 2 to minimize the potential for IGSCC fall into three major categories: (a) induction heating stress improvement (IHSI), (b) solution annealing, and (c) Mechanical Stress Improvement Process (MSIP).

The countermeasures using solution annealing are expected to remain effective for the life of the plant, since no sensitized material will be exposed to reactor water at these welds.

The IHSI treatment is also expected to remain effective for the life of the plant, since it was implemented prior to operation. Plants in Japan have been operating for approximately 5 years after having performed IHSI. Edison will monitor the applicable performance of these plants and will make adjustments accordingly.

The MSIP treatment results in the stress reversal at the weld root and is a permanent "life-of-plant" mitigation method.

The specific actions taken to minimize the potential for IGSCC are addressed in Subsections 5.2.3.2.1.1 through 5.2.3.2.1.5.

5.2.3.2.1.1 Piping Modifications

Operating experience has shown that the line most susceptible to IGSCC is the recirculation pump discharge valve bypass line. General Electric has developed operating procedures that do not require the use of this line, thereby enabling the line to be removed from the system. The 4-in. sweepolets in the 28-in. recirculation pipe are closed with caps clad with type 308L stainless steel. The design and installation of the caps include incorporation of geometries necessary for inservice UT examinations.

The other line susceptible to IGSCC cracking is the reactor core spray line. The initial design of this line for Fermi 2 specified carbon steel with a short stainless steel transition piece connected to the RPV stainless steel safe-end. This transition piece has been changed to carbon steel; the safe-end has been changed to Inconel with a carbon steel extension piece. Much of the IGSCC research done by GE concerned the recirculation system. This system is exposed to reactor coolant and is fabricated of type 304 stainless steel. Much of this system is 28-in. and 22-in. pipe. On the basis of GE studies, residual stress levels in welds in this pipe were thought to be below the threshold to develop IGSCC. To further reduce residual stress levels at field welds, special welding procedures were adopted that reduced the weld heat input to 50,000 joules per inch and which prohibited weld bead straightening. In addition, special restrictions were placed on internal grinding. To minimize susceptibility of the weld metal to IGSCC, the weld metal should contain at least 8 percent ferrite.

The GE studies show welds in 12-in. pipe in the recirculation system risers to be much closer to the IGSCC threshold. To minimize IGSCC susceptibility of these pieces, they were returned to the shop for solution annealing and for application of a nonsusceptible inlay to the ends. The inlay extends beyond the heat-affected zone from field welds. Thus, no sensitized 12-in. pipe is exposed to reactor coolant.

5.2.3.2.1.2 Recirculation Inlet Nozzles

The recirculation inlet nozzle configuration for Fermi 2 is shown in Figure 5.2-8. The thermal sleeve is type 304 stainless steel; the weld buildup pad on the nozzle is type 308.

This configuration is different from the ones which have developed IGSCC.

a. The thickness of the pressure retaining boundary at the attachment is 4.751 in. on Fermi 2 versus 0.5 in.; therefore, stresses are very much lower

b. The pad material on Fermi 2 is type 308 stainless steel versus Inconel. Type 308 is basically not susceptible to IGSCC.

Compared to the configuration that developed IGSCC, the lower stress and decreased vulnerability of the Fermi 2 configuration will greatly increase the time to IGSCC initiation (if any occurs at all) and slow the rate of growth if IGSCC is initiated.

The configuration of Fermi 2 recirculation line vessel nozzles is essentially the same as that on five other operating plants: Millstone, Pilgrim, Cooper, FitzPatrick, and Hatch 1.

The safe-end welds are scheduled to be examined as part of the ASME Section XI Inservice Inspection Program. In addition, welds selected in accordance with the rules of Section XI will receive an increased frequency of examination commensurate with the requirements of NUREG-0313 (Revision 2) and Generic Letter 88-01, or other NRC approved alternative program.

5.2.3.2.1.3 Induction Heating Stress Improvement

Operating experience has shown that many BWR plants have had problems with IGSCC in large-diameter recirculation system piping. To minimize the likelihood of IGSCC in portions of the recirculation system piping that had not received IGSCC remedies, IHSI was performed during July 1983. Induction heating stress improvement is recommended by both GE and EPRI as an effective IGSCC countermeasure, especially for plants under construction.

On completion of IHSI, only four welds in the recirculation system piping did not receive some IGSCC countermeasure. These welds have been included in the inservice inspection program and will be inspected on the inspection cycle detailed in NUREG-0313, Revision 2, and Generic Letter 88-01, or other NRC approved alternative program.

5.2.3.2.1.4 Mechanical Stress Improvement Process

During the first refueling outage, the Mechanical Stress Improvement Process (MSIP) was applied to twenty-one (21) reclassified RPV nozzle and safe-end welds, four (4) welds not treated by IHSI, and two (2) bi-metallic welds in the reactor water clean-up system, which, due to changes in the NUREG 0313, Revision 2, susceptibility criteria, were re-evaluated as IGSCC susceptible. On completion of the MSIP treatment of these twenty-seven welds, all ASME Section III welds which were evaluated as IGSCC susceptible have had an IGSCC mitigation method applied. All of the IGSCC susceptible welds have been included in the inservice inspection program and will be inspected on the inspection cycle detailed in NUREG 0313, Revision 2, and Generic Letter 88-01, or other NRC approved alternative program.

5.2.3.2.1.5 Control Rod Drive System Modifications

Some BWR plants have experienced IGSCC in the collet retainer tube in their CRDs. General Electric has attributed this cracking to thermal cycles during hot scrams, followed by exposure to oxygenated CRD cooling water that is aggressive to sensitized material.

The program adopted by Fermi 2 is consistent with GE recommendations. It consists of the following three parts:

a. An augmented surveillance and inspection program

b. Modification of CRD operations to eliminate unnecessary thermal cycling

c. Modification of the CRD water supply to provide high-purity deaerated water to the CRD system during plant operation.

Specifically, the Fermi 2 program consists of the following actions:

a. Each rod not fully inserted will be tested to confirm operability by inserting one or more notches in accordance with the frequency specified in the Technical Specifications.

b. All CRDs removed for maintenance will have a dye penetrant examination of the outer surface of the collet retainer tube. The criteria established by GE in Service Information Letter (SIL) 139 will be used to decide rejection. The term collet retainer tube refers to a portion of the outer tube, and replacement of a rejected collet retainer tube requires a new cylinder, tube, and flange subassembly

c. A CRD with a high-temperature alarm will not be cooled by giving it repeated drive signals

d. The source of water for the CRD system has been changed to the condensate treatment system effluent with the condensate storage tank as backup. The new water source is very pure and of very low oxygen content. (See torus water management system, Subsection 9.2.8.)

e. A flowing sample line downstream of the drivewater filter has been installed to provide for conductivity and oxygen grab sample measurement.

The use of high-purity deaerated water affects a significant increase in the time to crack formation. General Electric believes the time to crack initiation in current CRD collet retainer tubes may be increased by a factor of 100 with this reduction in dissolved oxygen content.

5.2.3.2.1.6 Inservice Inspection and Leak Detection

NUREG-0313, Revision 2, and Generic Letter 88-01, January 1988, present the technical bases for the NRC staff positions on materials, processes, and primary coolant chemistry to minimize and control IGSCC problems. Inspection schedules are comparable to those specified in Section XI of the ASME Boiler and Pressure Vessel Code in cases where the piping material is IGSCC resistant.

The modifications discussed in the previous subsections significantly reduce susceptibility to IGSCC. As detailed in Generic Letter 88-01, inspection schedules and inspection sample sizes are based on the susceptibility of weldments to initiation and propagation of IGSCC. Varying amounts of augmented inspections are specified for piping, with a greater susceptibility to cracking.

All applicable welds at Fermi 2 have been evaluated and classified according to the requirements of NUREG 0313, Revision 2, and Generic Letter 88-01. As required selected welds are included in the ASME Section XI Inservice Inspection Program.

The leak detection capability on Fermi 2 discussed in Subsection 5.2.7.3 is consistent with the 5 gpm rate discussed in NUREG-0313, Revision 2. As stated in Subsection 5.2.7.3, the unidentified leakage rate limit is established to allow time for corrective action before the nuclear system process barrier can be significantly compromised.

5.2.3.2.2 Steps To Maintain Occupational Exposure As Low As Reasonably Achievable

Steps taken in the selection of material to minimize and control the buildup, transport, and deposition of activated corrosion products in the reactor coolant and auxiliary systems follow:

The primary coolant system consists primarily of carbon steel (very low nickel and cobalt content), except for the use of austenitic stainless steel (in the recirculation loops) and low alloy steel. The nickel content of these materials is low and is controlled in accordance with the applicable ASME material specifications. Because the cobalt in steel usually appears as a small-percentage component of the nickel (usually, 2 percent of the nickel), the amount of cobalt in the primary system components is also very low.

A small amount of nickel base material (Inconel 600) is used in the RPV internals. Inconel 600 is required where components are attached to the reactor vessel shell, and the coefficient of expansion must match the thermal expansion characteristics of the low alloy vessel steel. Inconel 600 was selected because it provides the proper thermal expansion characteristics and adequate corrosion resistance, and can be fabricated and welded readily.

Hardfaced and wear-resistant materials having a high percentage of cobalt were restricted to applications in which no satisfactory alternative materials were available at the time of construction.

5.2.3.3 Compatibility With External Insulation and Environmental Atmosphere

The RCPB is insulated with an all-metal (stainless steel and aluminum) reflective-type insulation in compliance with Regulatory Guide l.36. This type of insulation does not contain any silica, fluorides, or chlorides. It does not contribute to surface contamination, and it has no effect on the stainless steel components of the RCPB. The insulation is designed to perform its intended function throughout the expected life of Fermi 2.

5.2.3.4 Chemistry of Reactor Coolant

The coolant chemistry requirements discussed in this subsection are consistent with the requirements of Regulatory Guide 1.56.

Reactor water chemistry limits are established to provide an environment favorable to materials in contact with the water. Limits are placed on conductivity and chloride concentrations. Conductivity is limited because it can be continuously and reliably measured by an in-line conductivity cell and gives an indication of abnormal conditions and the presence of potentially detrimental constituents in the coolant. Chloride limits are specified to minimize the potential of stress corrosion cracking of stainless steel. The accuracy of the conductivity cell is verified once per week by radiation chemistry personnel.

Several investigations have shown that in neutral solutions some oxygen is required to cause stress corrosion cracking of stainless steel, while in the absence of oxygen no cracking occurs. One of these is the chloride-oxygen relationship of Williams (Reference 3), where it is shown that at high chloride concentration little oxygen is required to cause stress corrosion cracking of stainless steel and at high oxygen concentration little chloride is required to cause cracking. These measurements were determined in a wetting and drying situation using alkaline-phosphate-treated boiler water and, therefore, are of limited significance to BWR conditions. They are, however, a qualitative indication of trends.

The water quality requirements are further supported by GE stress corrosion test data, summarized as follows:

a. Type 304 stainless steel specimens were exposed in a flowing loop operating at 537°F. The water contained 1.5 ppm chloride and 1.2 ppm oxygen at pH 7. Test specimens were bent beam strips stressed over their yield strength. After 2100 hr exposure, no cracking or failures occurred

b. Welded type 304 stainless steel specimens were exposed in a refreshed autoclave operating at 550°F. The water contained 0.5 ppm chloride and 1.5 ppm oxygen at pH 7. Uniaxial tensile test specimens were stressed at 125 percent of their 550°F yield strength. No cracking or failures occurred at 15,000 hr exposure.

Zirconium alloys and Inconel alloys are highly resistant to chloride stress corrosion cracking failure.

When conductivity is in its normal range, pH, chloride and other impurities affecting conductivity will also be within their normal range. When conductivity becomes abnormal, chloride measurements are made to determine whether or not they are also out of their normal operating values. This would not necessarily be the case. Conductivity could be high due to the presence of a neutral salt which would not have an effect on pH or chloride. In such a case, high conductivity alone is not a cause for shutdown. In some types of water-cooled reactors, conductivities are high because of the purposeful use of additives. In BWRs, however, where few additives are used and where near-neutral pH is maintained, conductivity provides a good and prompt measure of the quality of the reactor water. Significant changes in conductivity provide the operator with a warning mechanism so he can investigate and remedy the condition before reactor water limits are reached. Methods available to the operator for correcting the off-standard condition include operation of the reactor cleanup system in the blowdown mode, reducing the input of impurities, and placing the reactor in the cold-shutdown condition. The major benefit of cold shutdown is to reduce the temperature-dependent corrosion rates and to provide time for the RWCS to reestablish the purity of the reactor coolant.

Zinc is added to the reactor water, via the feedwater system, to control radiation buildup on out-of-core primary coolant piping. The amount of zinc that will be added to the reactor water will increase the conductivity of the reactor water. This will not impact the use of conductivity as a good and prompt measure of the quality of the reactor water. The increases above the new equilibrium conductivity value can still be used as an indicator of impurities entering the reactor. The zinc added can be accounted for in overall conductivity of the reactor water.

The conductivity and dissolved oxygen levels of the reactor coolant are continuously monitored. The samples of the coolant which are taken periodically serve as a reference for calibration of these monitors and are considered adequate to ensure accurate readings of the monitors. If conductivity is within its normal range, chlorides and other impurities will also be within their normal ranges.

The relationship of chloride concentration to specific conductance measured at 25°C for chloride compounds such as sodium chloride and hydrochloric acid can be calculated (Reference 4). Values for these compounds essentially bracket values of other common chloride salts or mixtures at the same chloride concentration. Surveillance requirements are based on these relationships. The sampling frequency when reactor water has a low specific conductance is adequate for calibration and routine audit purposes. When specific conductance increases, and higher chloride concentrations are possible, or when continuous conductivity monitoring is unavailable, increased sampling is provided.

Chloride analysis of the reactor coolant is performed as required or at least daily on grab samples. Approved radiation chemistry section procedures, using methods such as specific ion electrode or titration, are used to determine the chloride concentration.

The reactor water quality for plant design and operational control when operating at rated power is:

a. Conductivity - ≤1.0 μmho/cm at 25°C

b. Chlorides (as Cl^-) - ≤200 ppb

c. pH - 5.6 to 8.6 at 25°C.

Reactor water quality in excess of the limits specified above is limited to 72 hrs for any instance. Exceeding the maximum limits specified below shall be cause for shutdown and cool down to ambient temperatures until the water is within the quality limits specified above:

a. Conductivity - 10 μmho/cm at 25°C

b. Chlorides (as Cl^-) - 0.5 ppm

Reactor water quality is also limited based on time in excess of operational limits on conductivity and chlorides.

a. Time above 1 umho/cm - 2 weeks per 12-month period

b. Time above 200 ppb (Cl^-) - 2 weeks per 12-month period

The addition of zinc will add to the dissolved metals, total metals, and conductivity in the reactor water. The zinc will provide the beneficial outcome of controlling radiation build-up on out-of-core surfaces; however, overall metals concentration will still be maintained within the fuel warranty limits to ensure no impact on fuel performance. The amount of conductivity of the added zinc is much less than the 1 μS/Cm operating conductivity limits.

See Subsection 10.4.6 for further details.

5.2.4 Fracture Toughness

5.2.4.1 Compliance With Code Requirements

The ferritic pressure boundary material of the RPVs was qualified by impact testing in accordance with the 1968 edition of Section III of the ASME Code, with addenda to and including summer 1969 addenda. From an operational standpoint, the minimum temperature limits for pressurization are used as the basis for compliance with the 1968 Edition of the ASME Code Section III. (The minimum temperature limits for pressurization are defined by the summer 1972 addenda, Appendix G, Protection Against Nonductile Failure.)

5.2.4.2 Compliance With 10 CFR 50, Appendix G

5.2.4.2.1 Introduction

Versions of 10 CFR 50, Appendix G, prior to the 1983 edition had specific requirements for the preparation and testing of all reactor coolant pressure boundary materials. In lieu of these specific requirements, the present version of Appendix G requires that for a reactor vessel which was constructed in conformance with an ASME Code Section III earlier than the summer 1972 addenda of the 1971 edition, the fracture toughness data and data analyses must be supplemented in a manner approved by the Director, Office of Nuclear Reactor Regulation, to demonstrate equivalence with the present fracture requirements of Appendix G. The Fermi 2 reactor vessel was constructed in compliance with an ASME Code earlier than the summer 1972 addenda of the 1971 edition. The NRC has stated in Supplement 1 to NUREG 0798, the Fermi 2 Safety Evaluation Report, that the alternative methods proposed by Fermi 2 to demonstrate compliance with Appendix G has been reviewed, evaluated, and found to provide the safety margin required by Appendix G. Accordingly, Fermi 2 has supplied sufficient information to demonstrate equivalency with the fracture toughness requirements of the present version of 10 CFR 50, Appendix G, (1983 as amended November 1986 and October 1988).

A major condition necessary for full compliance with 10 CFR 50, Appendix G prior to the 1983 edition is satisfying the requirements of the summer 1972 addenda to Section III of the ASME Code. This is not possible with components that were purchased in accordance with earlier Code requirements.

Ferritic material complying with 10 CFR 50, Appendix G, must have both drop-weight tests and Charpy V-Notch (CVN) tests with the CVN specimens oriented transversely to the maximum material working direction to establish the RT_{NDT}. The CVN tests must be evaluated against both absorbed-energy and lateral-expansion criteria. The maximum acceptable RT_{NDT} must be determined in accordance with the analytical procedures of ASME Code Section III, Appendix G. Appendix G of 10 CFR 50 requires a minimum of 75-ft-lb upper shelf CVN energy for beltline material. It also requires at least 45-ft-lb CVN energy and 25 mils lateral expansion for bolting material at either the preload or lowest service temperature, whichever is lower.

By comparison, material for the Fermi 2 reactor vessel was qualified by either drop-weight tests or longitudinally oriented CVN tests (both not required), confirming that the material nil-ductility transition temperature (NDTT) is at least 60°F below the lowest service temperature. When the CVN test was applied, a 30-ft-lb energy level was used in defining the NDTT. There was no upper shelf CVN energy requirement of the Fermi unit beltline material. The bolting material was qualified to a 30 ft-lb CVN energy requirement at 60°F below the minimum preload temperature.

From the previous comparison, it can be seen that the fracture toughness testing performed on the reactor vessel material cannot be shown to comply with 10 CFR 50, Appendix G; however, to determine operating limits in accordance with 10 CFR 50, Appendix G, estimates of the beltline material RT_{NDT} and the highest RT_{NDT} of all other material were made, as explained in Subsection 5.2.4.2.3. The method for developing these operating limits is also described therein.

5.2.4.2.2 Method of Compliance

A detailed description of compliance with 10 CFR 50 Appendix G is included in General Electric Report 004N8586, Reference 21. The 1998 Edition of the ASME Boiler and Pressure Vessel code, including 2000 Addenda, was used in this evaluation. The P-T curve methodology includes the following: 1) the use of K_{IC} from Figure A-4200-1 of Appendix A to determine T-RT_{NDT}, and 2) the use of the M_m calculation in the ASME Code paragraph G-2214.1 for a postulated defect normal to the direction of maximum stress. NRC approved methodology was utilized as detailed in NEDC-33178P-A, Reference 26.

The pressure-temperature (P-T) curves are established to the requirements of 10 CFR 50, Appendix G to assure that brittle fracture of the reactor vessel is prevented. Part of the analysis involved in developing the P-T curves is to account for irradiation embrittlement effects in the core region, or beltline. The method used to account for irradiation embrittlement is described in Regulatory Guide 1.99, Rev. 2.

The beltline region in the Fermi Unit 2 vessel includes a thickness discontinuity between the lower and lower-intermediate shells. In addition to beltline considerations, there are non-beltline discontinuity limits such as nozzles, penetrations, and flanges that influence the construction of P-T curves. The non-beltline limits are based on generic analyses that are adjusted to the maximum reference temperature of nil ductility transition (RT_{NDT}) or the applicable Fermi 2 vessel components.

5.2.4.2.3 Method of Obtaining Operating Limits Based on Fracture Toughness

Operating limits that define minimum reactor-vessel metal temperatures versus reactor pressure during normal heatup, cooldown, inservice hydrostatic testing, and anticipated operational occurrences were initially established using the methods of Appendix G of Section III of the ASME B&PV Code, 1971 Edition.

Updated Operating limits that define minimum reactor-vessel metal temperatures versus reactor pressure during normal heatup, cooldown, inservice hydrostatic testing, and anticipated operational occurrences were established using the methods of Appendix G of Section III of the ASME B&PV Code, 1998 Edition (including 2000 Addenda). This later edition of the Code is discussed in section 5.2.4.2.2.

Weld material toughness test coupons were made with the exact same weld filler metal and procedure as for the actual vessel weld. However, these weld deposits were not necessarily made on the exact same heat of baseplate as in the vessel. Baseplate of the same specification was used for this purpose. This small difference in baseplate would not affect the testing of the weld metal since the Charpy specimen would be in the weld metal. Toughness testing of the exact baseplates in the vessel was done separately. As part of the BWRVIP Integrated Surveillance Program (ISP), materials irradiated in other vessels were utilized to provide verification of material properties as detailed in section 5.2.4.4. This information was utilized in the development of the pressure temperature curves per General Electric Report 004N8586 (Reference 21), and as shown in figures for 52 EFPY contained in the Pressure and Temperature Limits Report (PTLR) (Reference 25).

5.2.4.2.4 <u>Temperature Limits for Inservice Inspection Hydrostatic or Leak Pressure Tests</u>

The fracture toughness analysis for system pressure tests resulted in the curve labeled A shown in the figures contained in the PTLR (Reference 25). The beltline materials are less limiting even at end-of-service fluence levels, based on evaluation according to Regulatory Guide 1.99, Revision 2, where the predicted shift in the RT_{NDT} (based on the neutron fluence at 1/4 of the vessel wall thickness) has been added to the beltline curve to account for the effect of neutron embrittlement as detailed in Reference 21.

5.2.4.2.5 <u>Temperature Limits for Boltup</u>

The flanges and adjacent shell are required to be warmed to minimum temperatures of 72°F before they are stressed by the full intended bolt preload as shown on the figures contained in the PTLR (Reference 25).

5.2.4.3 <u>Operating Limits During Heatup, Cooldown, and Core Operation</u>

The fracture toughness analysis was done for the normal heatup or cooldown rate of 100°F/hr. The temperature gradients and thermal stress effects corresponding to this rate were included. The results of the analyses are a set of operating limits for non-nuclear heatup or cooldown shown as Curves labelled B in the PTLR (Reference 25). Curves labelled C in the PTLR (Reference 25), apply whenever the core is critical. The basis for curves labelled C is described in 10 CFR 50, Appendix G, January 1990 Edition, Paragraph IV.A.3.

5.2.4.4 <u>Surveillance Programs for the Reactor Pressure Vessel</u>

A surveillance program will be carried out to monitor the neutron radiation effects on the RPV base metal, the weld HAZ metal, and the weld metal from a steel joint that simulates a welded joint in the RPV beltline. Versions of 10 CFR 50, Appendix H, prior to the 1983 edition required that the surveillance program conducted prior to the first capsule withdrawal comply with the 1973 edition of ASTM E185. The present version of Appendix H requires that the surveillance program conducted prior to the first capsule withdrawal comply with the requirements of the edition of ASTM E185 that was current with respect to the ASME Code to which the reactor vessel was purchased.

The Fermi 2 surveillance program was shown to comply with the revised requirements of 10 CFR 50, Appendix H (1983 as amended November 1986 and October 1988).

Subsequent to development of the Fermi plant specific surveillance program, the BWR Vessel and Internals Project (BWRVIP) developed an integrated surveillance program to comply with the requirements of 10 CFR 50 Appendix H, Paragraph III.C. "Requirements for an Integrated Surveillance Program." No capsules from the Fermi 2 vessel are currently required to be withdrawn or tested as part of the BWRVIP Integrated Surveillance Program (ISP). Capsules from other plants have been removed, and specimens were tested in accordance with the ISP implementation plan. The results from these tests have provided the necessary data to monitor embrittlement of the Fermi 2 vessel as documented in Reference 21. A description of the BWRVIP ISP and its application to Fermi is contained in Section 5.2.4.4.3.

5.2.4.4.1 Original Program Content

The original Fermi program consisted of three baskets, each containing tensile and CVN specimens hermetically sealed in an inert gas environment in thin-wall austenitic stainless steel capsules. The capsules are not buoyant and thus present no handling problems. The three baskets have been placed near core midplane adjacent to the RPV wall where the neutron flux and temperature will simulate that of the RPV wall. The three baskets contain test specimens made from the original RPV beltline material in accordance with the requirements of ASTM E185-73. In total, the program consists of 108 impact and 22 tensile specimens. In addition, there are 51 impact and 18 tensile baseline and spare specimens. The specimens include the following.

a. Base metal impact, transverse and longitudinal

b. Weld metal impact

c. HAZ impact

d. Base metal tensile

e. Weld metal tensile

f. HAZ tensile.

The following general statements apply to these specimens:

a. Base metal impact and tensile specimens are taken from the 1/4 T planes of the specimen plate

b. HAZ impact and tensile specimens are all oriented parallel to the rolling direction

c. Weld metal impact specimens are all transverse to the axis of the weld; tensile specimens are parallel. The fracture areas consist of all weld metal.

Details of the manufacture of these specimens are given in Reference 7.

The specimens were taken from two plates trimmed from the lower intermediate shell section of the reactor vessel. The plate sections for the base material specimens were given a simulated stress relief for 40 hr at 1150°F to ensure that they represent the metallurgical condition of the lower intermediate shell plates of the reactor vessel after final fabrication. The plate sections for the weld and HAZ specimens were joined with a continuous central weld identical to the reactor vessel longitudinal weld. The welded plate was then given a simulated stress relief for 40 hr at 1150°F, similar to the base material plate. The weld was X-rayed to ensure quality; no repair to the weld was allowed by the specifications.

The surveillance specimens were not taken from alongside the ASME NB-2300 specimens. This was not considered critical, since they are just as representative of the material in the vessel as the NB-2300 specimens. The actual specimens in each capsule and capsule locations are the following.

	Tensile	Charpy V-Notch
Capsule 3 (azimuth 300°)	2 BM, long. 2 WM 2 HAZ	12 BM, longitude 12 WM 12 HAZ
Capsule 2 (azimuth 120°)	3 BM, long. 3 WM 2 HAZ	12 BM, longitude 12 WM 12 HAZ
Capsule 1 (azimuth 30°)	3 BM, long. 2 WM 3 HAZ	12 BM, transverse 12 WM 12 HAZ

Each capsule includes an iron, nickel, and copper flux wire. A separate neutron dosimeter was attached at azimuth 30° and contains three copper and three iron flux wires at the Capsule 1 location. The separate capsule was removed from the reactor during the first refueling outage and tested in 1990.

Capsule 3 was removed from the vessel at 8.1 Effective Full Power Years. Testing of this capsule was deferred due to the ongoing development of the BWRVIP Integrated Surveillance Program.

The attachment method of the capsules is in accordance with GE drawing 922D218. The assembly is attached to mounting brackets (upper and lower), and a bolt at approximately the center of the assembly can be adjusted to secure the holder firmly against the top and bottom brackets.

The lead factor is the relationship between the measured flux/ fluence at the surveillance sample and the peak flux/fluence at the inside surface of the vessel wall. This relationship has two variations. One variation is the axial variation from the elevation of the surveillance sample to the elevation peak flux.

The second variation is the variation of the flux as a function of angle from a position adjacent to the surveillance sample to the position of the peak flux.

The lead factor for the capsule calculated with respect to the inside surface location is the ratio of the flux greater than 1 MeV at the surveillance sample, divided by the flux greater than 1 MeV at the point of greatest flux in the vessel. For Fermi 2 this value is 0.90 as detailed in Table 4.3-2.

The peak fluence at one-quarter thickness was calculated from the peak inside surface fluence using the methods of Regulatory Guide 1.99, Revision 2. The peak inside surface fluence was predicted by an 'absolute' fluence calculation compliant with Regulatory Guide 1.190.

5.2.4.4.2 Withdrawal Schedule

The withdrawal schedule of the three sets of specimens in the reactor is planned as follows.

a. The first set was withdrawn at 8.1 EFPY which was approximately 25 percent of the original licensed reactor service life (i.e., 40 years) and remains onsite untested.

b. The second set will be a standby.

c. The third set will be a standby.

5.2.4.4.3 Description of BWRVIP Integrated Surveillance Program

A 1997 NRC review of a surveillance capsule report identified that a licensee lacked adequate unirradiated baseline Charpy V-notch (CVN) data for materials in their RPV surveillance program. This lack of baseline data could inhibit the ability to effectively monitor changes in the RPV fracture toughness properties as required per 10 CFR 50 Appendix G. Subsequent discussions between the NRC and the BWRVIP identified several plants (including Fermi 2) that potentially lacked adequate unirradiated baseline CVN data for materials in their plant specific RPV surveillance programs.

Subsequent to this concern, the BWRVIP developed a BWR RPV Integrated Surveillance Program (ISP) to meet the requirements of 10 CFR 50 Appendix H Paragraph III.C. This effort resulted in development of reports BWRVIP-78 and BWRVIP-86 (as amended by responses to NRC RAIs), that were submitted to the NRC for review and approval (References 15 through 18). The NRC approved these reports by issuing NRC Safety Evaluation as an attachment to NRC letter to Carl Terry dated February 1, 2002 (Reference 19).

BWRVIP-78 describes the technical basis related to material selection and testing for the ISP. The report defines the methodology utilized to identify existing plant specific surveillance capsules and surveillance capsules from the Supplemental Surveillance Program (SSP) required for the ISP. Required surveillance materials are those that best represent the actual limiting plate and weld materials from which BWR RPVs are fabricated. BWRVIP-78 establishes the connection between the required surveillance materials and the specific BWR RPV plate or weld materials which they represent and provide a test matrix for the ISP.

BWRVIP-86 establishes specific guidelines for ISP implementation. It addresses surveillance capsule withdrawal and testing dates, information dealing with ISP project administration, information on neutron fluence determination, information on data utilization and sharing, and information on licensing aspects of ISP implementation. The BWRVIP issued BWRVIP-86-A (Reference 20) to incorporate NRC Requests for Additional Information (RAI), industry responses to RAIs and to include a copy of the NRC Safety Evaluation accepting the ISP Program.

BWRVIP Report BWRVIP-135, Reference 22 provides a detailed discussion of the analysis performed by the BWRVIP (ISP) of irradiated material samples representative of the Fermi 2 reactor pressure vessel assembly. This information was utilized in the development of the new pressure-temperature curves that are detailed in Section 5.2.4.

The NRC has approved use of the BWRVIP ISP as an acceptable alternative to a plant specific RPV surveillance program; with two conditions. First, that licensees submit a license amendment requesting NRC approval of their participation in the ISP. Second, that BWRs commit to utilizing an acceptable neutron fluence calculation methodology. Section 4.3.2.8 provides information dealing with Fermi 2 neutron fluence calculation methodology. The NRC has approved the Fermi 2 participation in the ISP per License Amendment No. 152.

5.2.4.5 Reactor Vessel Annealing

In-place annealing of the reactor vessel because of radiation embrittlement should not become necessary because the predicted EOL value of adjusted reference temperature will not exceed 200°F and the EOL upper shelf energy should remain above 50 ft-lb.

5.2.5 Austenitic Stainless Steel

5.2.5.1 Cleaning and Contamination Protection Procedures

During fabrication, the stainless steel surfaces were cleaned by mechanical methods (grinding, brushing with stainless steel brushes, machining), solvent cleaners, or chemical cleaning agents. Caustic cleaners and other solvents and cleaners containing halogens, sulfides, or other harmful constituents were not used for cleaning parts that contain crevices or entrapment areas.

Stainless steel materials were not pickled unless they were in the solution heat-treated condition. Stainless steel components were suitably packaged and protected during shipment, storage, and construction, to prevent contamination from potentially corrosive agents.

Immediately prior to hydrostatic testing of the reactor vessel, all interior surfaces that would contact water during the hydrostatic test, all nozzle fixtures, all piping to be used to fill the vessel, and all external surfaces of stainless and nickel-chrome-iron components were cleaned of all halogen-bearing soils, grease, oil, penetrant materials, inks, chalk or crayon marks, and all dirt and debris. Testing and operation of components and systems were performed using either inhibited water or high-purity demineralized water to avoid exposure to detrimental contaminants.

All loose dirt and other foreign materials were removed by sweeping or vacuuming. Deposits of grease and oil were removed with an approved solvent. Tightly adhering soils were removed with the aid of stainless steel brushes or by grinding. The vessel interior was then cleaned with high-pressure water containing corrosion inhibiting additives. The vessel and water temperatures were less than 180°F during the cleaning step. The water pressure was a minimum of 6000 psi. Water was potable, containing less than 25 ppm chlorides, 10 ppm fluorides, and l ppm sulfides.

The cleanliness of the vessel was checked visually and with the aid of an ultraviolet light to ensure that the vessel is clean. The ultraviolet examination was conducted under darkened conditions with a lamp providing a minimum intensity of 100 foot candles. All fluorescent materials were removed from the surface.

All plumbing, welding, or testing work was performed prior to cleaning. During any entry of personnel into the vessel after cleaning was completed, shoe covers were worn and clean conditions were maintained in the reactor vessel.

5.2.5.2 Solution Heat Treatment Requirements

Solution heat treatment of austenitic stainless steel consisted of heating the material to 1950 +/- 50ºF, holding for 1/2 hr per inch of thickness (minimum 1/2 hr), and quenching in water to below 800°F. Stainless steel castings may have been heated to 2050°F maximum prior to quenching. Nickel-chrome-iron alloys that may have been subjected to temperatures in excess of 1700°F exclusive of welding were rechecked for grain size for information and specified mechanical properties for acceptance and reported to the buyer.

5.2.5.3 Material Inspection Program

The raw material inspection program used to verify that the unstabilized austenitic stainless steels were properly solution heat-treated and not susceptible to intergranular attack is as follows.

a. No testing was required if valid documentation was furnished proving that the stainless steel had been given a suitable water quench from a temperature above l800°F, and that no subsequent heating had been employed

b. If documentation to verify adequate water quenching was not available, the material was required to be tested in accordance with ASTM A-262 Practice E.

5.2.5.4 Unstabilized Austenitic Stainless Steels

The nonstabilized grades of austenitic stainless steels with a carbon content greater than 0.03 percent used for RCPBs are types 304 and 316.

5.2.5.5 Avoidance of Sensitization

5.2.5.5.1 Base Metal

Wrought and cast austenitic stainless steels used for the RPV system (except for RPV cladding) were supplied in the solution heat-treated condition and thereafter were not subjected to any heating above 800°F except for welding, IHSI, or re-solution heat treatment.

Sensitization of wrought austenitic stainless steel was avoided for piping and RCPB pumps and valves. Austenitic stainless steel was considered to be furnace-sensitized if it had been heated by means other than welding within the range of 800°F to 1800°F, regardless of subsequent cooling rate. Such stainless steel was required to either pass the requirements of ASTM A-262 Practice E or be re-solution heat-treated. When heated above 1800°F, the austenitic stainless steel was required to be rapidly cooled through the range 1800°F to below 800°F by agitated water quench to produce an acceptable grain structure. Since severe sensitization of austenitic stainless steel was to be avoided, AISI type 304 and type 316 (0.08 percent maximum carbon) materials were used. Where severe sensitization could not be avoided, such as for parts that were required to be hard surfaced, low carbon AISI type 304 cast material was used.

5.2.5.5.2 Welding Controls

During stainless steel welding, the interpass temperature is controlled to a maximum of 350°F. Weld layers are built up uniformly along the joint and across the width of the joint. Block welding is not permitted and weld stops and starts are staggered. Welds are cleaned free of slag, flux, and other foreign material prior to depositing subsequent beads.

Austenitic weld materials are selected and controlled to produce welds that contain a minimum of 3 percent ferrite. Ferrite content is determined by one of the following methods.

a. Actual chemical analysis compared to the Schaeffler and Schoefer

b. Magne-gage

c. Metallography

d. Severn-gage.

The stainless steel components and systems for which stainless steel welding was controlled by GE or Dravo, Inc., include the following.

a. RRS

b. CRD hydraulic return

c. CRD housing to flange

d. RCIC system (suction from condensate storage).

The GE equipment was ordered, fabricated, and, in most cases, delivered prior to the issuance of Regulatory Guide 1.31. Therefore, there was no test program specifically directed toward the inspection of welds for delta ferrite. However, the welds were made by long-established procedures that included control of ferrite content of filler materials and had proved adequate for consistently producing satisfactory welds without evidence of fissuring. General Electric BWR 4/5/6 Standard Safety Analysis Report, Subsection 5.2.3.4.2.1, as amended in May 1978, provides an acceptable testing program for control of ferrite. The indicated testing program of welds on five BWRs was produced under the same procedures as the Fermi 2 equipment and fully demonstrated the presence of a minimum of 3 percent delta ferrite in the welds.

Similarly, stainless steel welds fabricated by Dravo were made with weld material having 5 to 15 percent delta ferrite. Inspection of welds made since the Fermi 2 piping was fabricated, but using the same procedures, has also consistently demonstrated the presence of a minimum of 3 percent delta ferrite.

The field pipe erection contractors were required to incorporate the requirements of Regulatory Guide 1.31 into their stainless steel weld procedures, including procedures for inspection of fabricated welds. See Subsection A.1.31 for conformance by Edison's and piping contractor's welding procedures with Regulatory Guide 1.31.

5.2.5.6 Retesting Unstabilized Austenitic Stainless Steels Exposed to Sensitizing Temperatures

Welding procedures require control of heat input to avoid severe sensitization and susceptibility to intergranular attack. No retesting of "as-welded" unstabilized austenitic stainless steel is required or planned.

Unstabilized austenitic stainless steel subjected to heat in the range of 800°F to 1500°F by any means other than welding or IHSI is required to be retested in accordance with ASTM A-262, Practice E.

5.2.5.7 Control of Delta Ferrite

The procedures and requirements that are used for the control of delta ferrite in austenitic stainless steel welds are discussed in Subsection 5.2.5.5.1. Additional information on delta ferrite in austenitic stainless steel weldments may be found in Subsections 5.2.3.2.1.1, 5.2.5.5.1, and A.1.31.

5.2.6 Pump Flywheels

Pumps with flywheels are not used in Fermi 2.

5.2.7 Reactor Coolant Pressure Boundary Leak Detection System

5.2.7.1 Leak Detection Methods

5.2.7.1.1 General

The RCPB leak detection system consists of temperature, pressure, flow, and fission product sensors with associated instrumentation and alarms. This system detects and annunciates abnormal leakage in the following systems:

a. Main steam lines

b. RWCU system

c. RHR system

d. RCIC system

e. Reactor feedwater system

f. HPCI system

g. Reactor recirculation system.

A summary of isolation and/or alarm of affected systems and the methods used appear in Table 5.2-11.

Small leaks are generally detected by temperature and pressure changes, fillup rate of drain sumps, and fission product concentration inside the primary containment. Large leaks are also detected by changes in reactor water level and changes in flow rates in process lines.

Leakage into systems that are directly or indirectly connected to the RCPB is detected by the leak detection system (LDS). The RHR system service water, general service water, and reactor building closed cooling water (RBCCW) have been provided with process radiation monitors for the detection of intersystem leaks.

Leakage into systems that are normally connected to the RCPB through closed isolation valves is detected by pressure and temperature indications. The core spray, RCIC, and HPCI systems are in this category. Leakage into the RWCU system is detected by differential flow and temperature devices. The standby liquid control system (SLCS) is monitored for intersystem leakage by the system pressure and tank level indicators provided.

5.2.7.1.2 Detection of Abnormal Leakage Within the Primary Containment

Leaks within the primary containment are detected by monitoring for

a. Abnormally high pressure and temperature within the primary containment
b. Sump pump frequency of operation on floor and equipment drains
c. A decrease in the RPV water level
d. Hydrogen and oxygen concentration
e. High flow rate in process lines
f. High gaseous radiation levels in the primary containment atmosphere
g. Floor drain sump level rate of change.

Temperatures within the primary containment are monitored at various elevations. Excessive temperature in the primary containment, increased drain sump flow, and increased fission product radiation level are annunciated by alarms in the main control room. Low RPV water level and high drywell pressure are annunciated by alarm in the main control room and cause automatic isolation of the containment. In addition, low RPV water level isolates the main steam lines.

The systems within the drywell share a common area; therefore, their LDSs are common. Each LDS inside the drywell is designed with a capability of detecting leakage less than established leakage rate limits.

5.2.7.1.3 Leak Detection

5.2.7.1.3.1 General

The drywell floor drain sump measurement system monitors the normal design leakage collected in the floor drain sump consisting of leakage from the CRDs, valve flange leakage, closed cooling water, air cooler drains, and any leakage not connected to the equipment drain sump.

The design includes a supplementary drywell floor drain level monitor to enhance the leak detection capability of the drywell floor drain sump system. A continuous analog level measurement of the drywell floor drain level is provided to meet the sensitivity requirement of Regulatory Guide 1.45. This sump level monitor provides a rate-of-change measurement, which is qualified seismically and has the sensitivity to detect a 1-gpm leak integrated over a 1-hr interval.

The drywell equipment drain sump level monitors identify leakage collected in the equipment drain sump. The sump receives condensate drainage from pump seal leakoff. Collection in excess of background leakage would indicate reactor coolant leakage. The equipment drain sump temperature is also monitored. High temperature would indicate leakage of high temperature water.

Four basic leak detection methods are used to determine sump collection rates. As the water in each of the floor or equipment drain sumps is pumped out, the flow is metered by a flow integrator. Level switches are used to set fill time and pump-out time periods using adjustable reset timing devices. If the nominal pumping out or filling time for the particular sump is exceeded, an alarm is generated in the control room. In addition, if both pumps are started to handle the flow into the sump, an alarm is generated. The drywell sump sensitivity is 21 gal/in. of level. The sumps are located at the lowest elevation of the drywell area, and there are no areas that can act as a temporary reservoir.

The level switches can be functionally checked during plant operation by manually controlling the pumps. The operators use careful monitoring of the flow integrators and the actual pumping times to verify the operating condition of the level switches.

The primary containment is maintained at a slightly positive pressure during reactor operation. The pressure fluctuates slightly as a result of barometric pressure changes and outleakage. A pressure rise above the normally indicated values indicates the presence of a leak within the drywell.

The primary containment cooling system recirculates the primary containment atmosphere through heat exchangers (air coolers) to maintain the primary containment at its average operating temperature as given in the Technical Specifications. The RBCCW system provides cooling water to the air coolers. An increase in primary containment atmosphere temperature would increase the temperature rise in the cooling water passing through the coils of the air coolers. Thus, the RBCCW temperature difference increase between inlet and outlet to the air coolers indicates the presence of a reactor coolant or steam leakage. Also, a drywell ambient temperature rise above normal indicates the presence of reactor coolant or steam leakage.

The drywell cooler units have been provided to maintain the ambient drywell temperature at a relatively low value, and steam leaks will be condensed by contact with the relatively cold surfaces in the drywell. If the steam finds its way to the cooler units, condensation will definitely occur. The drains from the coolers are collected in the drywell sumps and can then be detected via the leak detection scheme. It is expected that the normal operating humidity will be at or near saturation, which will promote rapid condensation and subsequent detection. In addition, the airborne gaseous sampling system monitors the airspace and detects leaks in a very timely manner.

Radiation monitoring of the primary containment is provided as required by Criterion 30 of 10 CFR 50, Appendix A, and Regulatory Guide 1.45. The primary containment radiation monitoring system is part of the redundant LDS. The primary containment radiation monitoring system information is used in conjunction with the drywell floor drain sump level indicating system. It is provided to improve the total drywell LDS diversity and sensitivity.

However, since the supplementary drywell floor drain level monitor is seismically qualified, and meets the sensitivity requirement of Regulatory Guide 1.45, the particulate channel of the containment radiation monitor is not required as a leak detection system and has been removed from the leak detection system, but the gaseous monitor was retained to meet diversity requirements.

The design basis for the primary containment radiation monitoring system, and the associated instrumentation are presented in Subsections 7.1.2.1.22 and 7.6.1.12.1.

Additional components monitored are discussed below.

5.2.7.1.3.2 Reactor Pressure Vessel Head Seal

Leakage past the first of two RPV head closure seals is detected by monitoring the drain line connected to the region between the seals. Leakage is collected in a small-volume, normally closed system that can be drained to the equipment drain sump. When the pressure in this volume increases, an alarm in the main control room is actuated.

5.2.7.1.3.3 Reactor Recirculation System Pump Seal

Reactor recirculation system pump seal leaks are detected by monitoring the drain line. Leakage is indicated by high-flow alarms in the main control room. Leakage is piped to the equipment drain sump, as shown in Figure 5.5-2.

5.2.7.1.3.4 Safety/Relief Valves

Safety/relief valve leakage is detected by monitoring the discharge path. High temperature is alarmed in the main control room.

5.2.7.1.4 Detection of Abnormal Leakage Outside the Primary Containment

Outside the primary containment, the piping within each system monitored for leakage is in compartments or rooms, separate from other systems where feasible, so that leakage may be detected by area temperature indications. Each LDS discussed below is designed to detect leak rates that are less than the established leakage limits. The method used to monitor for leakage for each RCPB component is shown in Table 5.2-11.

5.2.7.1.4.1 Room Ventilation or Standby Cooler Temperature

A differential temperature-sensing system is installed in each area containing equipment that is part of the nuclear system process barrier. These areas are the RCIC, HPCI, RHR, and RWCU systems equipment rooms, as well as the suppression chamber room and main steam line tunnel.

Temperature sensors are placed in the inlet and outlet ventilation ducts or ventilation air flow paths. Other sensors are installed in the equipment areas to monitor ambient temperature. A differential temperature switch between each set of sensors and/or ambient temperature switch initiates an alarm in the main control room when the temperature reaches a preset value. Remote readouts from temperature sensors are indicated in the relay room.

Due to the design characteristics of the reactor building ventilation design, the differential temperature isolation provides an alarm function only on the RCIC and HPCI areas. Similarly, the temperature sensors for the torus subbasement area provide an alarm function only and do not trip either the RCIC or HPCI systems. The HPCI and RCIC trip function is provided by the (redundant) HPCI and RCIC area ambient sensors.

5.2.7.1.4.2 Reactor Building Sump Flow Measurement

Monitors indicate the amount of leakage into the reactor building floor drainage system. The normal design leakage collected in the system consists of leakage from the RWCU, FPCCS, RCIC, HPCI, core spray, CRD, RHR, feedwater, and main steam systems and from other miscellaneous vents and drains.

5.2.7.1.4.3 Visual and Audible Inspection

Accessible areas are inspected periodically. The temperature and flow indicators discussed above are monitored regularly. Any instrument indication of abnormal leakage is investigated.

5.2.7.1.4.4 Differential Flow Measurement for Reactor Water Cleanup System Only

Because of the RWCU system arrangement, differential flow measurement provides an accurate leak detection method. The flow from the RPV is compared with the flow back to the RPV. An alarm in the main control room and an isolation signal are initiated when higher flow out of the RPV indicates that a leak greater than the established leak rate limit may exist.

5.2.7.2 Indication in Main Control Room

Details of the LDS indications are included in Subsection 7.6.1.8.

5.2.7.3 Limits for Reactor Coolant Leakage

5.2.7.3.1 Total Leakage Rate

The total leakage rate consists of all leakage, identified and unidentified, that flows to the drywell floor drain and equipment drain sumps. The total leakage rate limit is well within the makeup capability of the RCIC system. The total leakage rate limit is established at 25 gpm.

The total leakage rate limit is also set low enough to prevent overflow of the drywell sumps. The equipment drain sump and the floor drain sump, which collect all leakage, are each drained by two 50-gpm pumps. The total leakage rate limit for each sump of 25 gpm is set below the removal capacity of one pump in each sump because of the possibility that most of the total leakage could flow into one sump.

5.2.7.3.2 Identified Leakage

The pump packing glands, valve stems, and other seals in systems that are part of the nuclear system process barrier and from which a normal design leakage of 20 gpm is expected are provided with drains or auxiliary sealing systems. Nuclear steam supply system valves and pumps inside the drywell are equipped with double seals and packings.

Leakage from the primary RRS pump seals is piped to the equipment drain sump. Leakage from the main steam line SRVs is identified by temperature sensors that transmit to the main control room. Any temperature increase above the drywell ambient temperature detected by these sensors indicates valve leakage. Leakage from the RPV head flange gasket is detected by a pressure switch, as described in Subsection 5.2.7.1.3.2.

Thus, the leakage rates from pumps and valve seals are measurable during plant operation. These leakage rates, plus any other leakage rates measured while the drywell is open, are defined as identified leakage rates.

5.2.7.4 Unidentified Leakage

5.2.7.4.1 Unidentified-Leakage Rate

The unidentified-leakage rate is the portion of the total leak-age rate received in the drywell sumps that is not identified as previously described. A threat of significant compromise to the nuclear system process barrier exists if the barrier contains a crack that is large enough to propagate rapidly. The unidentified-leakage rate limit must be low because the unidentified leakage might be emitted from a single crack in the nuclear system process barrier.

An allowance is made for normal plant operation leakage that does not compromise barrier integrity and is not identifiable. The unidentified-leakage rate limit is established at a 5-gpm rate to allow time for corrective action before the nuclear system process barrier could be significantly compromised. This proposed limit is based on a calculated flow from a critical crack in a primary containment system pipe.

5.2.7.4.2 Sensitivity and Response Times

Sensitivity, including sensitivity tests and response time of the LDS, is presented in Subsection 7.6.1.8.

5.2.7.4.3 Length of Through-Wall Flaw

Experiments conducted by GE and Battelle Memorial Institute (BMI) permit an analysis of critical crack size and crack opening displacement. This analysis relates to axially oriented through-wall cracks.

5.2.7.4.3.1 Critical Crack Length

Both the GE and the BMI test results indicate that theoretical fracture mechanics formulas do not predict critical crack length. However, satisfactory empirical expressions may be developed to fit test results. A simple equation that fits the data in the range of normal design stresses for carbon steel pipe is:

$$\ell_C = \frac{15000D}{\sigma h} \qquad (5.2\text{-}1)$$

where

ℓ_C = critical crack length (inches)

D = mean pipe diameter (inches)

σh = nominal hoop stress (psi)

Data correlation for Equation 5.2-1 is shown in Figure 5.2-11.

5.2.7.4.3.2 Crack Opening Displacement

The elasticity theory predicts a crack opening displacement of

$$W = \frac{2\ell\sigma}{E} \qquad (5.2\text{-}2)$$

where

ℓ = crack length

σ = applied nominal stress

E = Young's modulus

Measurements of crack opening displacement made by BMI show that local yielding greatly increases the crack opening displacement as the applied stress approaches the failure stress σ_f. A suitable correction factor for elasticity effects is:

$$C = \frac{\pi}{2}\frac{\sigma}{\sigma_f} \qquad (5.2\text{-}3)$$

The crack opening area is given by

$$A = C\frac{\pi}{4}W = \frac{\pi}{2}\frac{\sigma}{\sigma_f}\frac{\pi\ell\sigma}{2E} \qquad (5.2\text{-}4)$$

For a given crack length ℓ, $\sigma_f = 15{,}000\,{}^{D}/_{\ell}$

5.2.7.4.3.3 Leakage Flow Rate

The maximum flow rate for blowdown of saturated water at 1000 psi is 55 lb/sec/in.^{2}, and for saturated steam the rate is l4.6 lb/sec/in.^{2}. Friction in the flow passage reduces this rate, but for cracks leaking at 5 gpm (0.7 lb/sec), the effect of friction is small. The required leak size for a 5-gpm flow is:

a. A = 0.0126 in.^{2} (saturated water)

b. A = 0.0475 in.^{2} (saturated steam).

From this mathematical model, the critical crack length and the 5-gpm crack length have been calculated for representative BWR pipe sizes (Schedule 80) and pressure (1050 psi). Results are tabulated as follows.

Normal Pipe Size (Sch. 80) (in.)	Average Wall Thickness (in.)	Steam Line Crack Length ℓ (in.)	Water Line Crack Length ℓ (in.)
4	0.337	7.2	4.9
12	0.687	8.5	4.8
24	1.218	8.6	4.6

The ratios of crack length (ℓ) to the critical crack length (ℓ_c) as a function of nominal pipe size are

Nominal Pipe Size (Sch. 80) (in.)	Ratio ℓ/ℓC	
	Steam Line	Water Line
4	0.745	0.510
12	0.432	0.243
24	0.247	0.132

It is important to recognize that the failure of ductile piping with a long through-wall crack is characterized by large crack opening displacements that precede unstable rupture. Judging from observed crack behavior in the GE and BMI experimental programs involving both circumferential and axial cracks, it is estimated that leak rates of hundreds of gallons per minute will precede crack instability. Measured crack opening displacements for the BMI experiments were in the range of 0.1 to 0.2 in. at the time of incipient rupture, corresponding to leaks of the order of 1 in.^{2} in size for plain carbon steel piping. For austenitic stainless steel piping, even larger leaks are expected to precede crack instability, although there are insufficient data to permit quantitative prediction.

The results given are for a longitudinally oriented flaw at normal operating hoop stress. A circumferentially oriented flaw could be subjected to stress as high as the 550°F yield stress, assuming high thermal expansion stresses exist. A good mathematical model that is supported by test data is not available for the circumferential crack. Therefore, it is assumed that the longitudinal crack, subject to a stress as high as 30,000 psi, approaches "worst case" with regard to leak rate versus critical size relationships. Given the same stress level, differences between the circumferential and longitudinal orientations are not expected to be significant in this comparison.

Figure 5.2-12 shows general relationships among crack length, leak rate, stress, and line size, using the mathematical model described above. The asterisks denote conditions at which the crack opening displacement is 0.1 in., at which time instability is imminent. This provides a realistic estimate of the leak rate to be expected from a crack of critical size. In every case, the leak rate from a crack of critical size is greater than the 5-gpm criterion.

5.2.7.4.4 Margins of Safety

The margins of safety for a detectable flow to assume critical size are presented in Subsection 5.2.7.4.3. Figure 5.2-12 shows general relationships among crack length, leak rate, stress, and line size obtained using the mathematical model.

5.2.7.4.5 Criteria To Evaluate the Adequacy and Margin of the Leak Detection System

For process lines that are normally open, there are at least two different methods of detecting abnormal leakage from each system within the nuclear system process barrier located in the primary containment and reactor building (Table 5.2-11). The instrumentation can be set to provide alarms at established leakage rate limits and isolate an affected system when necessary. The alarm points are determined analytically or, where appropriate, are based on measurements of appropriate parameters made during startup and preoperational tests.

The unidentified leakage rate limit is based, with an adequate margin for contingencies, on the crack size large enough to propagate rapidly. The established limit is sufficiently low so that, even if the entire unidentified leakage rate were coming from a single crack in the nuclear system process barrier, corrective action could be taken before the integrity of the barrier would be threatened.

The LDS is able to satisfactorily detect unidentified leakage of 5 gpm.

Sensitivity, including sensitivity tests and response time of the LDS, is included in Subsection 7.6.1.8. Subsection 7.1.2 presents the criteria for shutdown when the leakage limits are exceeded.

5.2.7.5 Maximum Allowable Total Leakage

The total leakage rate is presented in Subsection 5.2.7.3.1.

5.2.7.6 Differentiation Between Identified and Unidentified Leaks

Subsection 5.2.7.1 describes the systems that are monitored by the LDS. The ability of the LDS to differentiate between identified and unidentified leakage is discussed in Subsection 7.6.1.8 and Subsections 5.2.7.1 through 5.2.7.4.

5.2.7.7 Sensitivity and Operability Tests

Testability of the LDS is discussed in Subsection 7.6.1.8.

5.2.7.8 Leakage Reduction Program

Edison has developed a leakage reduction program to reduce and maintain leakage to as-low-as-practical levels from systems outside the primary containment that could or would contain highly radioactive fluids during and after a serious transient or accident. In addition, the program is designed to reduce potential paths due to design and/or operation deficiencies. This program is based on Requirement 2.1.6a of NUREG-0578 (Reference 8) and the requirements of Item III.D.1.1 of NUREG-0660, NUREG-0694, and NUREG-0737, "Primary Coolant Sources Outside Containment" (References 9, 10, and 11, respectively).

Table 5.2-12 identifies systems included in the leakage reduction program. Table 5.2-13 lists systems to which the leakage reduction program is not applicable and further provides the justification for their exclusion. Only the systems listed in Table 5.2-12 are included in the program.

5.2.7.8.1 Program Description

The Edison leakage reduction program includes the following features.

a. A combination of periodic visual inspections of accessible portions of the systems and detailed system walkdowns to identify leakage into the secondary containment out of components such as valve stems, pump seals, fittings, relief valve discharge lines, drains, vents, and instrument loops. When possible, these inspections are performed with the systems at approximately operating pressure in a normal or test condition

b. An aggressive maintenance program to correct identified leakage problems and assign a high priority to leakage-related work requests for systems in this program. Essentially all leakage of concerned (i.e., those identified in Table 5.2-12) systems will be addressed. These preventive and corrective maintenance measures ensure minimum leakage on a continuing basis

c. Periodic leak-rate testing of systems listed in Table 5.2-12 and system components such as valves at intervals not to exceed each refueling outage. The general test methods used to determine leakage from systems within the scope of this leakage reduction program are provided in Subsection 5.2.7.8.2

d. Maintenance of records on inspections and tests to identify chronic or generic leakage problems to implement modifications and/or corrective maintenance measures. A summary report on program effectiveness will be provided to plant management within 90 days of the conclusion of each reactor refueling.

In addition to the testing program, system leakage tests will be performed on many of these systems as part of the 10 CFR 50, Appendix J, leakage testing program. The systems and components subject to this testing and that form part of the containment boundary are identified in Table 6.2-2. This leakage reduction program will be completed by the time Fermi 2 reaches full-power operation.

Prior to the start of the second fuel cycle, Edison will revise the general criteria to the extent necessary according to the experience gained during the first operating cycle of Fermi 2. These revised criteria will be used as the basis for the long-term leakage reduction/monitoring program for Fermi 2.

5.2.7.8.2 Test Methods

The following methods are used to test systems identified in Table 5.2-12 for leakage:

a. Liquid systems - Systems or portions of systems that could contain radioactive liquids during or after an accident are periodically placed into normal operation or a testing mode. During these test conditions, the systems are visually inspected for leakage with all results being recorded. All leakage detected during the periodic visual inspections, or the less frequent integrated leak-rate test, will be measured where possible and recorded. Techniques used for leakage measurement will include collection into a graduated container and estimation by equating drops per unit of time to a standard volume

b. Gaseous systems - For systems or portions of systems that may contain radioactive gases during or after an accident, a pressure drop or makeup gas rate test is used. Clean air or nitrogen is used for these tests. When leakage is indicated by a pressure drop or excessive makeup, visual inspection techniques are applied to components during pressurization.

   Gaseous systems are tested by pressurizing the system with air or nitrogen to a specified pressure (usually accident pressure of 56.5 psig or the system relief valve set pressure) and measuring to within 20 standard cm^3 per minute the flow required to maintain test pressure using a local leak-rate test panel. The makeup flow is equivalent to the system leakage rate. This method of leak testing is similar to that required by 10 CFR 50, Appendix J, for leak-rate testing of the primary containment. If flow is detected, each system component will be tested with a soapy liquid in accordance with the procedure to identify sources of leakage. Corrective action will be taken as warranted to reduce the leakage from each source, and the system will be retested to yield a quantitative indication of the leakage reduction achieved. This measuring methodology, leakage source identification procedure, and corrective action will ensure that leakage is reduced to the lowest practical level, as dictated by system hardware limitations. The application of the helium leak detection method of inspection may be considered for some gaseous systems.

5.2.7.8.3 Test Procedures

Each system identified in Table 5.2-12 has surveillance testing procedures. These test procedures contain the following elements as applicable:

a. A description of system and plant operating conditions necessary to conduct each leak test. Test boundaries are identified and include only those portions of the system that could contain radioactive fluids during or after an accident. For example, the core spray suction piping from the condensate storage tank would not be inspected as this suction line is used for test purposes only and would not contain radioactive fluid during or after an accident

b. Elaboration of special test methods necessary to supplement general test methods

c. Data sheets listing the specific areas to be inspected. The data sheets will identify isometric drawing numbers and provide spaces to record inspection results.

5.2.8 Inservice Inspection Program

5.2.8.1 Inservice Inspection Program for Class 1, 2, and 3 Components

The inservice inspection (ISI) program for Class 1, 2, and 3 components complies to the extent practicable with the requirements of the ASME Code Section XI. The program for the initial inspection interval complies with the requirements of the 1980 edition of the Code including the winter 1981 addenda except that the extent of examination for Class 2 piping welds will be determined by the 1974 edition, summer 1975 addenda. The initial 10-year inspection interval commenced with the start of commercial operation. When compliance with ASME Code Section XI was impracticable, relief was requested from the NRC in compliance with 10 CFR 50.55a(g)(5)(iii). The Fermi 2 inservice inspection program plan for the initial 10-year inspection interval was submitted to the NRC for review and was found to be acceptable and in compliance with the provisions of 10 CFR 50.55a(g)(4). The first ten year interval was completed February 16, 2000. Upon completion of the first inspection interval, the inservice inspection program was updated to include later Editions and Addenda of ASME Section XI as required by 10 CFR 50.55.a. Successive ten year updates will be similarly processed.

5.2.8.2 Provisions for Access to Reactor Coolant Pressure Boundary

Fermi 2 uses reflective metal insulation typical of that used by GE for this series of RCPB. The RCPB design has been reviewed in detail to ensure adequate access for inspection according to ASME B&PV Code Section XI, Articles IS 141 and 142. The insulation design has considered access for inservice inspection.

5.2.8.2.1 Reactor Pressure Vessel Access Provisions

In the region of the sacrificial shield, there is a nominal 12-in. annulus between the insulation and the outside surface of the RPV. Access to this annulus can be gained from the bottom at locations adjacent to the support skirt to the lower head weld, and from two 3 x 3-1/2-ft openings, 8 ft from the top of the shield, at azimuths 180° and 351°. Inservice inspection of longitudinal and circumferential welds in the RPV will be performed using mechanized equipment.

Vessel nozzles are accessible for inservice examination through openings in the sacrificial shield. Automatic scanning devices enable complete inspection while minimizing personnel exposure.

The bottom head contains the penetrations for the CRD system and in-core flux monitoring system. The spacing between these penetrations makes volumetric inspection impractical. These nozzles are partial-penetration welds, and, typically, have not been included in normal ISI schedules as they meet exception criteria under a postulated CRD ejection accident.

5.2.8.2.2 Piping Access Provisions

Insulation on Class 1 piping inside the primary containment is of the removable reflective-metal type. Removable nonmetallic insulation is used on the portion of Class 1 lines outside the primary containment. Welds requiring an ISI inspection have identification tags attached to the insulation covering each weld.

The preservice baseline examination of the ASME Class 1 piping has been performed in accordance with the ASME Code Section XI, 1974 edition, through summer 1975 addenda to the extent possible. The scope and extent of examination of Class 1 piping is in accordance with Table 5.2-14. The preservice inspection program identified all welds that have access limitations for examination. For all welds that cannot be examined ultrasonically, alternate means of examination were used (such as radiography, liquid penetrant or magnetic particle, supplemented by visual examination during hydrostatic testing). The preservice inspection program exempted from volumetric and surface examination certain portions of Class 1 piping in accordance with the provisions of IWB-1220(b)(1) and (2), "Component Connections, Piping and Associated Valves (and their supports) One Inch Nominal Pipe Size and Smaller." The exempt components were examined in accordance with IWA-5000 during the system hydrostatic pressure test required by IWB-5000.

In addition, limited space between the process and guard pipes in the primary containment penetrations makes it impractical to perform an ultrasonic examination of the process pipe-to-flued head weld.

The ASME Code incorporated inservice inspection requirements for Class 2 and 3 systems after most of the design and manufacture of these systems had been completed. In September 1976, Edison engaged SWRI to analyze the extent to which Fermi 2 could comply with these new sections of the ASME Code. The study was based on the latest edition of the ASME Code available which was the 1974 Edition, including addenda through summer 1976 and reported in Reference 12.

Reference 12 shows that the layout of these systems and the design of the system supports are such that welds and components requiring examination by the ASME Code are accessible with, basically, no exceptions. The examination of some welds is limited partially by the close proximity of fittings or lugs; a few welds have limited accessibility and can be inspected from only one side. All limitations were identified in the preservice inspection report.

5.2.8.3 Equipment for Inservice Inspection

All equipment used for inservice inspection of the RPV and piping has been proven reliable on other preservice and inservice inspections. Included in this equipment are mechanized and manual inspection devices.

Pipe butt welds will be inspected using conventional ultrasonic inspection equipment. Basically, this is a light-weight, portable UT flaw detection equipment package with manually held search units.

5.2.8.4 Mechanized Inspection Equipment

In general, the RPV will be ultrasonically examined by automated equipment. Typically, the data acquisition system contains a multichannel recorder, cathode ray tube (CRT) displays, a TV video camera, and a minicomputer.

The computer is the primary data recording/comparison system, and the other systems are intended for backup to be used when required.

Computer programs have been written to allow comparison of the data obtained on the subsequent inservice examinations.

5.2.8.5 Reactor Pressure Vessel Acceptance Standards

The acceptance standards that were used to establish acceptability of the RPV for service during preservice mapping of the RPV by ultrasonic examination were those standards required by the ASME B&PV Code.

5.2.8.6 Coordination of Inspection Equipment With Access Provisions

The access provisions are designed to accommodate currently available examination equipment. This equipment has been used successfully on other preservice and inservice inspections.

5.2.8.7 Inservice Testing Program for Pumps and Valves

The testing program for pumps and valves complies to the extent practicable with the requirements of the Code and Addenda identified in 10 CFR 50.55a at the time the program is updated to the next 10 year interval. The scope of the program encompasses those pumps and valves necessary to safely shut down the plant or mitigate the consequences of an accident. The scope also includes those valves that perform an isolation function between high-pressure and low-pressure portions of systems connected to the reactor coolant system.

When compliance with Code requirements is impractical, relief is requested from the NRC in compliance with 10 CFR 50.55a.

Table 5.2-15 lists the valves that perform an isolation function between high-pressure and low-pressure portions of systems connected to the RCS. These pressure isolation valves are categorized as A or AC and are tested in compliance with Technical Specifications and the ASME Inservice Testing Code and Addenda applicable to the current ten year interval. The testing program for the valves, which is referenced in the Technical Specifications, consists of the following methods.

a. Exercise the valve and verify the position in accordance with the IST Program.

b. Exercise the valve (full stroke) and measure stroke time (as applicable) in accordance with the IST Program.

c. Leak test the valve seat before reaching power operation during refueling and after valve maintenance before the return to service, in accordance with the IST Program.

These valves shall not be routinely exercised every 3 months during plant operation (except E4100F005 and E5100F014, which are exercised during quarterly surveillance and then verified closed) as required by ASME Code because of the following:

a. Such tests remove one of the two barriers protecting the low-pressure portion of the emergency core cooling system (ECCS)

b. The operators on testable check valves cannot overcome the force on the valve with reactor pressure on one side.

Instead, the valves will be exercised during cold-shutdown periods as time permits (but not more frequently than once every 3 months).

A routine surveillance test every 3 months to exercise the valve presupposes that the test can be done with the plant operating at full power (and pressure). The purpose of dual barriers is to provide pressure isolation and protection even if one of the barriers should be faulty. Should one of the barriers be faulty by being inoperable, the core cooling systems have sufficient redundancy to perform their function. In addition, an inoperable barrier would be found during the proposed tests made at cold shutdown.

However, should one of the barriers be faulty by having excessive leakage, the core cooling system connected to that barrier could be severely damaged. Therefore, the test could cause a significant loss of primary coolant. On the other hand, had the test not been performed for this latter case, the core cooling system would have performed its function normally.

The full closure of these valves, except for the HPCI and RCIC check valves, is verified in the control room by direct monitoring position indicators. In addition, these lines are equipped with overpressure detection and protection devices should pressure isolation valves leak; these are summarized in Table 5.2-16, which shows that every line is protected by a relief valve and has pressure monitoring.

For the HPCI and RCIC system, pressure isolation is provided by normally closed gate valves, E4150F006 and E5150F013, and check valves E4100F005 and E5100F014, which are leak tested. E4150F007 and E5150F012 are normally open and not credited for pressure isolation.

If there is excessive leakage through the normally closed gate and check valves, the operator will be alerted by the high pump suction pressure alarm indicated in Table 5.2-16. The operator will then be directed to close the normally open gate valve per the Alarm Response Procedure.

The inservice testing program (IST) for pumps and valves for Fermi 2 commenced March 20, 1985. The first 10-year interval commenced following the initial start of Fermi 2 commercial operation in accordance with ASME Section XI, Paragraph IWA-2420, 1980 Edition including winter 1980 Addenda. The second and subsequent ten-year intervals will be updated to include later editions of the Code as required by 10 CFR 50.55a.

5.2.8.8 Preservice Inspection Program

A preservice inspection program was performed on all Class 1 components (except the RPV) and other components noted in Table 5.2-14 in accordance with the requirements of the 1974 Edition of ASME Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components," with addenda through the summer of 1975 (74/S75). The preservice inspection program for some Class 1 components was performed in accordance with the requirements of ASME Section XI, 1980 Edition, winter 1981 addenda, for compatibility with the ISI program. These components are identified in the remarks column of Table 5.2-14. Preservice inspection of the reactor vessel was performed in accordance with the 1971 Edition of Section XI (reference Subsection 5.4.2).

Southwest Research Institute was engaged by Edison to be the inspection agent to perform preservice examinations of welds. Southwest Research Institute supplied inspectors, equipment, and procedures. The Hartford Steam Boiler Inspection and Insurance Company was engaged by Edison to be the Authorized Inspector.

In general, Table 5.2-14 outlines the preservice examination requirements for Class 1 components in accordance with Tables IWB-2500 and IWB-2600 of Section XI (IS-251 through IS-261 for the RPV).

Class 2 systems within the scope of the Section XI preservice inspection program are the following:

a. Residual heat removal, Division I and Division II
   1. ECC function in LPCI mode
   2. RHR function in RHR mode
   3. RHR function in containment spray mode
b. Core spray, ECC function
c. HPCI, ECC function
d. SLCS, up to the Class 1 boundary valve
e. Main steam system between the second and third isolation valves.

In accordance with 10 CFR 50.55(a), the 1974 Edition of ASME Section XI through the summer 1975 addenda was used for determining the extent of examination (the number of welds required to be examined) for Class 2 pipe welds in RHR systems, ECCSs, and containment heat removal systems. For all other Class 2 systems, either the 1974 Edition of Section XI through the summer 1975 addenda or the latest NRC-approved edition may be used. For consistency, the 1974 Edition through the summer 1975 addenda was used for determining the extent of the examination for the preservice inspection program for these other systems. This includes the head spray system and SLCS added to the Class 2 preservice inspection program.

The selection of the individual welds to be examined on each Class 2 system was based on the inspection philosophy identified in the 1980 Edition, winter 1981 addenda, of Section XI. The selection philosophy contained in the 1975 summer addenda is based on a random selection of welds and results in examining a particular weld only once in the plant's 40-year operational life. No trending of data is possible under the 1975 summer rules. The 1981 winter addenda identifies a selection philosophy that concentrates the examinations on those welds that historically have a greater probability of failure: namely, high-stress welds, welds at terminal ends, and dissimilar metal welds. In addition, the 1981 winter addenda requires examinations of the same welds in each 10-year interval so that meaningful data trending can be accomplished. There is general agreement in the industry that the 1981 winter addenda philosophy is superior to the random-selection approach identified in the 1975 summer addenda.

The criteria used for the selection of specific welds to be examined for the preservice inspection program were based on the following.

a. All high-stress welds defined as loading stresses greater than $0.8(1.2S_h + S_a)$ as per the 1981 winter addenda

b. All moderately stressed welds defined as loading stresses greater than $0.7(1.2S_h + S_a)$ and less than or equal to $0.8(1.2S_h + S_a)$. Inclusion of these moderately stressed welds in the Fermi 2, Class 2, preservice inspection program, is an added conservatism that exceeds the requirements of the ASME Section XI, 1980 Edition, winter 1981 addenda

c. All dissimilar metal welds

d. One terminal end of each type of terminal end within a system. (Note: This is a modified version of the ASME Section XI, 1980 Edition, winter 1981 addenda, Table IWC-2500-1, Category C-F, Footnote [1][b].) Edison has taken this approach to prevent skewing the weld examination sample to this particular type of weld. For example, the core spray system has four pumps, each with a terminal end at the suction and discharge attachment welds. To examine all eight terminal ends would be redundant. Therefore, to enable a more representative sample to be taken, only one pump suction terminal end weld and one pump discharge terminal end weld would be selected for examination

e. Additional random selections such that the total number of welds examined meets the number required by paragraph IWC-2411 of ASME Section XI, 1974 Edition, summer 1975 addenda.

Based on the above, Edison requested relief from two of the 1975 summer requirements for all the Class 2 system welds included in the preservice and inservice inspection programs. The first request for relief is to allow Edison to select those types of welds that historically have a higher probability of failure in lieu of the random-selection approach required by the 1975 summer addenda. The second request for relief was to allow repeated examination of the same welds in subsequent 10-year intervals in lieu of the requirements that different welds be inspected in each 10-year interval. This second relief request is applicable to the ISI-NDE program only.

The preservice inspection program delineated all required examinations, methods, code allowable exemptions, and relief requests. The preservice inspection program has been completed and is available for review by the NRC staff.

5.2.8.9 Snubber Program

The examination and testing program for snubbers complies to the extent practicable with the requirements of the Code and Addenda identified in 10 CFR 50.55a at the time the program is updated to the next 10 year interval. When compliance with Code requirements is impractical, relief is requested from the NRC in compliance with 10 CFR 50.55a. The examination and testing program for snubbers is described in the Snubber Program Plan, as required by Technical Requirements Manual (TRM) Section 5.1.1.

5.2 INTEGRITY OF REACTOR COOLANT PRESSURE BOUNDARY

REFERENCES

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5.2 INTEGRITY OF REACTOR COOLANT PRESSURE BOUNDARY

REFERENCES

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TABLE 5.2-1 DESIGN TEMPERATURE AND PRESSURE AND MAXIMUM TEST PRESSURE FOR REACTOR COOLANT PRESSURE BOUNDARY COMPONENTS

Component	Design Temperature (°F)	Design Pressure (psig)	Maximum Test Pressure[a] (psig)
Reactor pressure vessel	575	1250	1563[a]
Reactor Recirculation System			
Pump discharge piping	575	1500	b
Pump suction piping	575	1250	b
Discharge valves	575	1525	f
Suction valves	575	1250	f
Pump[e]	562	1525	c
RPV vent line	575	1250	b
Main steam line	575	1250	b
Main steam line isolation valves	575	1250	f
Residual heat removal system			
Shutdown suction			
RRS header to second isolation valve			
Piping	575	1250	b
Valves	575	1250	c
Pump Discharge			
RHR return from RRS header to second isolation valve			
Piping	575	1500	b
Valves	575	1500	c
Core spray system			
Pump discharge			
RPV to second isolation valve			
Piping	575	1250	b
Valves	575	1250	c
Standby liquid control system			
Pump discharge to RPV			
RPV to second isolation valve			
Piping	575	1250	b
Valves	575	1250	c

TABLE 5.2-1 DESIGN TEMPERATURE AND PRESSURE AND MAXIMUM TEST PRESSURE FOR REACTOR COOLANT PRESSURE BOUNDARY COMPONENTS

Component	Design Temperature (°F)	Design Pressure (psig)	Maximum Test Pressure[a] (psig)
Reactor water cleanup system			
Pump suction			
RRS piping to isolation valve outside drywell			
Piping	575	1250	b
Valves	575	1250	c
Pump discharge to feedwater inlet			
Piping	575	1300	b
Valves	575	1300	c
RPV drain line	575	1250	b
Reactor feedwater system			
RPV to outer most isolation valve			
Piping	450	1275	b
Valves	450	1275	c
Reactor core isolation cooling system			
Steam to RCIC pump turbine			
MS line to second isolation valve			
Piping	575	1250	b
Valves	575	1250	c
Pump discharge to reactor via feedwater			
Piping	450	1275	b
Valves	450	1275	c
High Pressure coolant injection system			
Pump discharge to reactor via feedwater			
Piping	450	1275	b
Valves	450	1275	c
Steam to HPCI pump turbine MS line to second isolation valve			
Piping	575	1250	b

TABLE 5.2-1 DESIGN TEMPERATURE AND PRESSURE AND MAXIMUM TEST PRESSURE FOR REACTOR COOLANT PRESSURE BOUNDARY COMPONENTS

Component	Design Temperature (°F)	Design Pressure (psig)	Maximum Test Pressure[a] (psig)
Valves	575	1250	c
Main steam drains system			
MS lines to second isolation valve			
Piping	575	1250	b
Valves	575	1250	c
Instrument lines			
Piping	d	d	d
Valves	d	d	d

[a] Excluding shell test for valves according to Sections NB-3531-8 and NB-3531-9 of ASME B&PV Code Section III. The stress intensity ratio is interpreted from Section NB-6221 of the Code to be the ratio of the allowable stress; Sm, at test temperature to the allowable stress; Sm, at design temperature.

[b] Test pressure is 1.25 x design pressure x lowest stress intensity ratio.

[c] Test pressure is 1.50 x design pressure x lowest stress intensity ratio.

[d] Design and test conditions for the RCPB instrument lines are consistent with the conditions for the main pipeline they emanate from.

[e] The reactor recirculation system pump design pressure and temperature conditions envelop the system discharge piping design requirements.

[f] The reactor recirculation loop suction and discharge valves and the main steam isolation valves are tested per the 1968 ASME Pump and Valve Code, Article 7.

TABLE 5.2-2 REACTOR COOLANT PRESSURE BOUNDARY OPERATING THERMAL CYCLES

Normal, Upset and Testing Conditions

Event Description	Number of Cycles[a]	Analyzed Cycles for 60 Years[b]
Boltup	39	58
Design Hydrostatic Leak Test	55	75
Startup	183	246
Turbine Roll	152	201
Weekly Reduction to 50% Power	208	317
Loss of FW Heaters – Turbine Trip with 100% Bypass	7	10
Loss of FW Heaters – Partial FW Heater Bypass	15	19
SCRAM – Turbine Generator Trip	9	12
SCRAM – All Others	30	33
Control Rod Drive Isolation	32	47
Single Control Rod Drive Scram	32	47
Reduction to 0% Power	149	197
Hot Standby (Injections)	880	1307
SBFW Injection (Cold Injection into Hot Piping)	36	46
SBFW Injection (Cold Injection into Cold Piping)	11	18
RCIC Injection (Cold Injection into Hot Piping)	17	24
RCIC Injection (Cold Injection into Cold Piping)	779	1172
HPCI Injection (Cold Injection into Hot Piping)	23	29
HPCI Injection (Cold Injection into Cold Piping)	6	9
FW Injection (Cold Injection into Hot Piping)	5	10
FW Injection (Cold Injection into Cold Piping)	5	10
Shutdown	183	246
Hydrostatic Test (1563 psig)	1	2
Unbolt	39	58
Pre-Op Blowdown	2	3
SCRAM – Loss of FW Pumps	10	13
Loss of RWCU Flow	207	270
Core Spray Injection	3	4
Multiple SRV Actuation	7	9
Individual SRV Actuation (Sum)	1232	1851
RRS Pump Seal Injection On-Off-On	29	37[c]
RRS Single Loop Operation (SLO)	10	10/loop[d]
OBE (Operating Basis Earthquake)	1	2

TABLE 5.2-2 REACTOR COOLANT PRESSURE BOUNDARY OPERATING THERMAL CYCLES

Emergency Conditions

Event Description	Number of Cycles[a]
SCRAM – Single Safety/Relief Valve Blowdown	8
Reactor Overpressure with Delayed Scram, Feedwater Stays On, Isolation Valves Stay Open	1
Automatic Blowdown	1
Improper Start of Cold RRS loop	1
Sudden Start of Pump in Cold RRS loop	1
Improper Startup with Recirculation System Pumps Off and Drain Shut Off Followed by Turbine Roll and Increase to Rated Power	1
Natural Circulation Startup	3
Loss of AC Power, Natural Circulation Restart	5

Faulted Conditions

Event Description	Number of Cycles[a]
Pipe Rupture and Blowdown	1

Other Events with a Cyclic Limit

Event Description	Expected Duty[a]	Analyzed for 60 Years[b]
RRS Pump A Hot Standby (hours in SLO, idle with backflow)	464	697
RRS Pump B Hot Standby (hours in SLO, idle with backflow)	337	507
Main Steam Bypass Line – Time of Operation at 30-45% Valve Open Position (days)	72	100

[a] Expected number of cycles for a 40 year plant design life based on conservative projections of Fermi 2 operating history

[b] Analyzed number of cycles for License Renewal

[c] The Recirculation pump coolers were replaced in 1998. Through December 2012, 3 cycles had been experienced. The analysis input value for the coolers was 12 cycles.

[d] Per NEDC-32313P (Subsection 6.3, Reference 14), the 10 cycles are per loop. This analysis was not updated for License Renewal. This analysis applies to an isolated loop.

TABLE 5.2-3 CODE CASE INTERPRETATIONS

1.	1141	Foreign Produced Steel
2.	1332	Requirements for Steel Forgings
3.	1334	Requirements for Corrosion Resisting Steel Bars and Shaping
4.	1335	Requirements for Bolting Materials, Section III
5.	1336	Requirements for Nickel-Chrom-Inn Alloy
6.	1337	Requirements for Special Type 403 Modified Forgings and Bars
7.	1344	Requirements for Nickel-Chromium, Age-Hardenable Alloys, Section III
8.	1359	Ultrasonic Examination of Forgings, Section III
9.	1384	Requirements for Precipitation Hardening Alloy Bars and Forgings, Section III
10.	1388	Requirements for Stainless Steel Precipitation Hardening, Section III
11.	1390	Requirements for Nickel-Chromium Age-Hardenable Alloy for Bolting, Section III
12.	1401	Welding Repairs to Cladding of Class I Section III Components After Heat Treating
13.	1420	SB-167 Nickel-Chromium-Iron Alloy Pipe or Tube
14.	1423	Wrought Type 304 and 316 Nitrogen Added
15.	1433	Normalized and Tempered 2-1/4 and 3A Low Alloy Forgings
16.	1434	Postweld Heat Treatment of SA-487 Class 8N Castings
17.	1441	Waiving of 3.0 S_m Limit for Section III Construction
18.	1456	Substitution of U.T. Examination for Progressive PT or MT of Partial Penetration and Oblique Nozzle Attachment
19.	1459	Welding Repairs to Base Metal of Class I Section III Components After Final PWHT
20.	1487	Evaluation of Nuclear Piping for Faulted Conditions
21.	1492	Postweld Heat Treatment, Sections I, III, and VIII, Div. 1 and 2
22.	1495	Stress Indices in Table NB-3683.2-1
23.	1501	Use of SA-453 Bolts in Service Below 800°F Without Stress Rupture Tests, Section III
24.	1504	Electrical and Mechanical Penetration Assemblies, Section III, Classes 1, 2, and 3 Components
25.	1516-1	Welding of Seats in Valves for Section III Application
26.	N-32-4	Hydrostatic Testing of Embedded Piping, Class 2 and 3 Piping

TABLE 5.2-3 CODE CASE INTERPRETATIONS

27.	N-237-2	Hydrostatic Testing of Internal Piping, Class 2 and 3
28.	N-240	Hydrostatic Testing of Open-Ended Piping
29.	N-252	Low Energy Capacitive Discharge Welding Method for Temporary or Permanent Attachments to Components and Supports
30.	N-315	Repair of Bellows, Class 2, 3, and MC
31.	N-316	Alternative Rules for Fillet Weld Dimensions for Socket Welded Fittings, Class 1, 2, and 3
32.	N-274	Alternate Rules for Examination of Weld Repairs for Section III, Division 1 Construction
33.	N-275	Repair of Welds, Section III, Division 1
34.	N-236	Repair and Replacement of Class MC Vessels
35.	N-192-2	Use of Braided Flexible Connectors
36.	N-362-1	Pressure Testing of Containment Items
37.	N-411-1	Alternate Damping Values for Spectral Analysis of Piping Sections

TABLE 5.2-4 VALVE AND PUMP DESCRIPTION

Part A - Valve description

System/Location		Valve Identification	Valve Type
NUCLEAR BOILER/RPV Vent		B2100F001	manual globe
		B2100F002	manual globe
		B2100F005	manual globe
		B21F403	De-Energized & Abandoned in Place
		B21F404	De-Energized & Abandoned in Place
Main Steam Safety/Relief (Nuclear Pressure Relief)		B2104F013A	dual-function, 2-stage relief
		B2104F013B	
		B2104F013C	
		B2104F013D	
		B2104F013E	
		B2104F013F	
		B2104F013G	
		B2104F013H	
		B2104F013J	
		B2104F013K	
		B2104F013L	
		B2104F013M	
		B2104F013N	
		B2104F013P	
		B2104F013R	
Main Steam Drains		B2103F016	motor-operated gate
		B2103F019	motor-operated gate
Main Steam Isolation		B2103F022A	air-operated, Y-pattern globe
	(Inboard)	B2103F022B	
		B2103F022C	
		B2103F022D	
	(Outboard)	B2103F028A	
		B2103F028B	
		B2103F028C	
		B2103F028D	
Feedwater	(Inboard)	B2100F010A	swing check
		B2100F010B	swing check
		B2100F011A	manual gate
		B2100F011B	manual gate
Feedwater	(Outboard)	B2100F032A	testable swing check
		B2100F032B	testable swing check
		B2100F076A	spring-to-close swing check
		B2100F076B	spring-to-close swing check
REACTOR RECIRCULATION			
Suction		B3105F023A	motor-operated gate
		B3105F023B	motor-operated gate

TABLE 5.2-4 VALVE AND PUMP DESCRIPTION

Part A - Valve description

System/Location	Valve Identification	Valve Type
Discharge	B3105F031A	motor-operated gate
	B3105F031B	motor-operated gate
Drain/sample line	B3100F029	manual globe
	B3100F030	manual globe
STANDBY LIQUID CONTROL	C4100F006	swing check
	C4100F007	swing check
	C4100F008	manual globe
RESIDUAL HEAT REMOVAL		
RHR Return (LPCI)	E1150F015A	motor-operated gate
	E1150F015B	motor-operated gate
	E1100F050A	testable swing check
	E1100F050B	testable swing check
	E1100F060A	manual gate
	E1100F060B	manual gate
RHR Supply (SDC)	E1150F008	motor-operated gate
	E1150F009	motor-operated gate
	E1150F608	motor-operated gate
	E1100F067	manual gate
CORE SPRAY	E2150F005A	motor-operated gate
	E2150F005B	motor-operated gate
	E2100F006A	testable swing check
	E2100F006B	testable swing check
	E2100F007A	manual gate
	E2100F007B	manual gate
HIGH PRESSURE COOLANT INJECTION (HPCI) SYSTEM		
Steam to HPCI turbine	E4150F002	motor-operated gate
	E4150F003	motor-operated gate
	E4150F600	motor-operated globe bypass
Return through feedwater	E4150F006	motor-operated gate
REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM		
Steam to RCIC turbine	E5150F007	motor-operated gate
	E5150F008	motor-operated gate
Return through feedwater	E5150F013	motor-operated gate
REACTOR WATER CLEANUP		
Supply to RWCU	G3352F001	motor-operated gate
	G3352F004	motor-operated gate

TABLE 5.2-4 VALVE AND PUMP DESCRIPTION

Part A - Valve description

System/Location	Valve Identification	Valve Type
	G3352F100	motor-operated gate
	G3352F101	motor-operated gate
	G3352F106	motor-operated gate
	G3352F119	motor-operated gate
	G3352F102	motor-operated Y-globe throttle
Return through feedwater	G3300F120	swingcheck
	G3300F121	swingcheck
	G3352F220	motor-operated gate

Part B – Pump Description

REACTOR RECIRCULATION System Pumps	B3101C001A&B	28 X 28 X 35 DVSS

TABLE 5.2-5 NUCLEAR STEAM SUPPLY SYSTEM SAFETY/RELIEF VALVES

Types of Valves	No. of Valves	Set Pressure (psig)	ASME Rated Capacity at 103 Percent Set Pressure (lb/hr each)[b]
Safety/relief	5	1135	904,400
Safety/relief	5	1145	912,200
Safety/relief	5[a]	1155	920,100

[a] Indicates the number of safety/relief valves actuated to provide automatic depressurization. This provides sufficient flow capacity to satisfy automatic depressurization requirements, assuming that one valve fails to open.

[b] Flow capacity = W = 51.5 x K x 0.9 x A x P

where

K = 0.8 (friction coefficient)

A = $\pi/4 \times 5.125^2$ (flow area)

P = set pressure with 103 percent accumulation

This information is obtained from the Safety and Safety Relief Valve Relieving Capacity Certification - Target Rock Corporation, the National Board of Boiler and Pressure Vessel Inspectors, June 6, 1975.

TABLE 5.2-6 REACTOR COOLANT PRESSURE BOUNDARY MATERIALS

Component	Form	Material	Specification (ASTM/ASME)
Reactor pressure vessel heads, shells	Rolled plate or forgings	Low alloy steel	SA-533 Grade B, Class 1
	Welds	Low alloy steel	SFA-5.5
Closure flange	Forged ring	Low alloy steel	SA-508 Class 2
	Welds	Low alloy steel	SFA-5.5
Nozzles	Forged shapes	Low alloy steel	SA-508 Class 2
	Welds	Low alloy steel	SFA-5.5
Cladding	Weld overlay	Austenitic stainless steel	SFA-5.9 and SFA-5.4 TP 308, 309 and 312 carbon content of final surface limited to 0.8 percent maximum
Control rod drive stub tubes	Pipe	Incone1	SB-167
	Welds	Incone1	SFA-5.11 TP ENiCrFe-3
Control rod drive housing	Pipe	Austenitic stainless steel	SA-312 TP 304
	Welds	Stainless steel	SFA-5.9 TP 308
In-core housing	Pipe	Austenitic stainless steel	SA-213 TP 304
	Welds	Stainless steel	SFA-5.9 TP 308

Additional RCPB component materials and specifications used are specified below.

Depending on whether impact tests are required and depending on the lowest service metal temperature when impact tests are required, the following ferritic materials and specifications were used:

TABLE 5.2-6 REACTOR COOLANT PRESSURE BOUNDARY MATERIALS

Pipe	SA-106 Grade B; SA-333 Grade 6 and SA-155 Grade KCF-70
Valves	SA-105 Grade II; SA-350 Grade LF1 and SA-216 Grade WCB
Fittings	SA-105 Grade II; SA-350 Grade LF1; SA-234 Grade B; and SA-420 Grade WPL1 or WPL6
Bolting	SA-193 Grade B7; SA-194 Grades 7 and 2H; and SA-540 Grade B22, B23 and B24
Welding material	SFA-5.1 (E-7015, E-7016, E-7018) SFA-5.5 (E-7010A1, E-7015, E-7016, E-7018) SFA-5.17, SFA-5.18
Other material	SA-516, Grade 70

For those systems or portions of systems, such as the reactor recirculation system, which require austenitic stainless steel, the following materials and specifications were used:

Pipe	SA-376 Type 304; SA-312 Type 304; SA-358 Type 304
Valves	SA-182 Grade F-304; SA-351 Grades CF-8 and CF-8M
Pump	SA-182 Grade F-304; SA-351 Grades CF-8 and CF-8M
Flanges	SA-182 Grade F-316
Bolting	SA-193 Grade B7; SA-194 Grades 7 and 2H; SA-540 Grades B22, B23 and B24
Welding material	SFA-5.4 (E308-15, E308L-15, E316-15); SFA-5.9 (ER-308, ER-308L, ER-316)

TABLE 5.2-7 REACTOR VESSEL TOUGHNESS CHARPY V-NOTCH CHEMISTRY

RPV Location	Pc. No. (a)	Material Type	Drop Wt TNDT °F	Charpy V-Notch 50 ft-lb °F	Charpy V-Notch 35 MILS LE °F	Charpy V-Notch USE ft-1b	RT_{NDT} °F	Chemistry Cu %	Chemistry P %	Chemistry S %	Chemistry Ni(g) %
Closure Head-Lower Torus	319-03	SA-533-65 Grade B Class 1	-10	-40	-40	140	-10	0.13	0.012	0.019	
Closure Head Flange	319-02	A-508 Class 2	(b)	-40	-40	186	0	0.03	0.007	0.012	
Upper Shell	306-1	SA-533-65 Grade B Class 1	-10	35	30	125	-10	NA	0.012	0.018	
Vessel Flange	308-2	A-508 Class 2	(b)	-40	-40	145	10	0.15	0.003	0.019	
Lower Intermediate Shell	305-01E	SA-533-65(c) Grade B Class 1	-20	-10	-10	130	-20	0.12	0.010	0.015	0.61
	305-03		-30	40	10	119	-12	0.12	0.012	0.016	0.61
Lower Shell	305-04	SA-533-65(c) Grade B Class 1	-10	-10	-20	130	-10	0.12	0.011	0.017	0.56
Lower Intermediate to Lower Shell (d)		Weld I-313	NA	< 10	NA	>105	-50	0.23	0.016	0.010	1.0(h)
Lower Intermediate Long Seams (e)(c)		Weld 15-308A-D	NA	< 10	NA	>90	-50	0.32	0.016	0.011	0.5(h)
Lower Shell Long Seams (f)		Weld 2.307A-C	NA	< 10	NA	>57	-44	0.26(i)	0.013	NA	0.87(i)

(a) The values listed are for the piece having the highest T_{NDT} at the indicated location.
(b) RT_{NDT} assumed to be 10°F
(c) Values included for both plates from lower intermediate shell and the weld used for materials surveillance program
(d) Weld Charpy V-Notch Impact Tests at 10°F-101, 108, 107 ft-lb.
(e) Weld Charpy V-Notch Impact Tests at 10°F-83, 94, 97 ft-lb.
(f) Weld Charpy V-Notch Impact Tests at 10°F-62, 47, 62 ft-lb.
(g) Listed for plates and welds in the beltline region only
(h) Assumed, based on maximum allowables of filler metal specification, see report referenced in (i) below
(i) Calculated values from General Electric Report SASR 90-73, DRF 137-0010, Revision 1, January 1991
NA Not Available

TABLE 5.2-8 HAS BEEN INTENTIONALLY DELETED

TABLE 5.2-9 HAS BEEN INTENTIONALLY DELETED

TABLE 5.2-10 HAS BEEN INTENTIONALLY DELETED

TABLE 5.2-11 SUMMARY OF ISOLATION/ALARM OF SYSTEM MONITORED AND THE LEAK DETECTION METHODS USED

Function		A[a]	A	A	A	A/I[b]	A	A/I	A	A	A/I	A/I	A/I	A/I	A	A	A/I
Source of Leakage	Location	High PC[c] Temperature	PC Sump High Flow Rate	High PC Air Cooler CCW[d] ΔT	Equipment Area High T & ΔT	Low Steam Line Pressure	RB Sump High Flow Rate	Equipment Area High T Time Delay	Suppression Pool Area High T & ΔT Time Delay	PC Pressure (High)	High Flow Rate[e]	High Turbine Exhaust Pressure (RCIC)	CU[f] Δ Flow (High)	Reactor Low Water Level	Radiation Level	High Flow in Drain Line	High Radiation Level
Main steam line	PC	X	X	X						X	X			X	X		X
	RB[g]				X		X				X						
RHR	PC	X	X	X						X					X		
	RB				X		X										
RCIC steam	PC	X	X	X		X				X	X				X		
	RB					X	X	X[h]	X		X	X					
RCIC Water	PC																
	RB						X										
HPCI steam	PC	X	X	X		X				X	X				X		
	RB					X	X	X[h]	X		X	X					
HPCI water							X										
Cleanup Water	PC	X	X	X						X			X	X	X		
	RB	Hot			X		X	X[h]					X	X			
	RB	Cold			X		X						X	X			
Feedwater	PC	X	X	X						X					X		
	RB						X										
ECCS suction line	RB		X														
Recirculation System	PC															X	

[a] A – Alarm.
[b] A/I – Alarm/isolation.
[c] PC – Primary containment.
[d] CCW – Closed cooling Water.
[e] Break downstream of flow element isolates the steam line.
[f] CU – Cleanup.
[g] RB – Reactor building.
[h] No time delay.

TABLE 5.2-12 SYSTEMS OUTSIDE PRIMARY CONTAINMENT THAT COULD CONTAIN HIGHLY RADIOACTIVE FLUIDS

- Reactor core isolation cooling
- Residual heat removal
  - Containment spray
  - Suppression pool cooling
  - Low-pressure coolant injection
  - Shutdown cooling
- Core spray
- Reactor water sample
- Reactor water cleanup
- High-pressure coolant injection
- Standby gas treatment
- Control rod drive discharge headers
- Containment sampling system

TABLE 5.2-13 SYSTEMS OUTSIDE PRIMARY CONTAINMENT THAT WOULD NOT CONTAIN HIGHLY RADIOACTIVE FLUIDS

System	Comment
RHR fuel pool cooling	Not directly affected by accident.
Standby liquid control	Injects fluid and does not circulate reactor coolant.
General service water / emergency equipment service water	Do not circulate reactor coolant and could become contaminated only due to system leaks.
Reactor building closed cooling water / emergency equipment cooling water	Do not circulate reactor coolant and could become contaminated only due to system leaks.
Condensate storage	Could become contaminated only due to isolation valve leakage.
Demineralized water makeup	Could become contaminated only due to isolation valve leakage.
Torus water management	Isolated during LOCA and not required for accident mitigation.
Control air/station air	Would require system or interface required for accident mitigation.
Fuel-pool cooling and cleanup	Not directly affected by accident.
Main steam lines	Would require failure of MSIVs.
Feedwater lines	Would require failure of isolation valves.
Drywell cooling system	Uses RBCCW of EECW and is not needed for safe shutdown of plant.
Reactor building floor/equipment drains	Not required for accident mitigation. Minimizing leakage from systems in Table 5.2-12 minimizes input to the system.
Radwaste	Not required for accident mitigation.
Supplemental cooling chilled water	Does not circulate reactor coolant and could become contaminated only due to system leaks.
Combustible gas control system	Could become contaminated only due to isolation valve leakage.

TABLE 5.2-14 CLASS 1 PRESERVICE EXAMINATION REQUIREMENTS

Examination Category		Component or Part To Be Examined	Required Exam Method	Remarks
		Pump Pressure Boundary (IWB – 2500)		
B-G-1	Pressure-retaining bolting greater than 2 in. in diameter	Recirculation pumps	Volumetric and visual	Preservice inspection performed to ASME Section XI, 1980 Edition, winter 1980 addenda, for compatibility with ISI program.
B-K-1	Integrally welded supports		Volumetric or surface	Preservice inspection performed to ASME Section XI, 1980 Edition, winter 1980 addenda, for compatibility with ISI program.
B-L-1	Pump casing welds		Volumetric	
B-L-1	Pump casings		Visual	
		Valve Pressure Boundary (IWB – 2500)		
B-G-1	Pressure-retaining bolting greater than 2 in. in diameter	Class 1 valves	Volumetric and visual	Preservice inspection performed to ASME Section XI, 1980 Edition, winter 1980 addenda, for compatibility with ISI program.
B-G-2	Pressure-retaining bolting smaller than 2 in. in diameter		Visual	Preservice inspection performed to ASME Section XI, 1980 Edition, winter 1980 addenda, for compatibility with ISI program.
B-K-1	Integrally welded supports		Volumetric or surface	Preservice inspection performed to ASME Section XI, 1980 Edition, winter 1980 addenda, for compatibility with ISI program.
B-M-X	Valve body welds		Volumetric	
B-M-2	Valve bodies		Visual	
B-P	Except components		Visual	
		Piping Pressure Boundary (IWB – 2500)		

TABLE 5.2-14 CLASS 1 PRESERVICE EXAMINATION REQUIREMENTS

Examination Category		Component or Part To Be Examined	Required Exam Method	Remarks
B-F	Dissimilar metal safe-end to piping welds and safe-end to branch piping	Safe-end welds	Volumetric and surface	
B-G-2	Pressure-retaining bolting smaller than 2 in. in diameter	Bolting less than 2 in. in diameter	Visual	Preservice inspection performed to ASME Section XI, 1980 Edition, winter 1980 addenda, for compatibility with ISI program.
B-J	Circumferential and longitudinal pipe welds	Piping welds	Volumetric	
	Branch pipe connection welds exceeding 6 in. in diameter	Piping welds	Volumetric	
	Branch pipe welds 6 in. in diameter and smaller	Piping welds	Surface	
	Socket welds	Socket welds	Surface	
B-K-1	Integrally welded supports	Piping lugs	Surface	Preservice inspection performed to ASME Section XI, 1980 Edition, winter 1980 addenda, for compatibility with ISI program.
B-P	Exempted components	Exempted components	Visual	
		Reactor Pressure Vessel (IS – 251)		
A	Pressure-retaining welds in reactor bolting region	RPV longitudinal and circumferential weld in core region	UT	A manual UT examination was performed on the RPV longitudinal and circumferential welds in the combustion engineering fabrication shop.
B	Pressure-retaining welds in vessels	RPV closure head and meridional welds and bottom head meridional and circumferential welds	UT	See category A.

TABLE 5.2-14 CLASS 1 PRESERVICE EXAMINATION REQUIREMENTS

Examination Category		Component or Part To Be Examined	Required Exam Method	Remarks
		RPV longitudinal and circumferential welds above and below core region	UT	See category A.
C	Pressure-retaining welds: vessel-to-flange and head-to-flange	RPV closure head-to-flange weld RPV shell-to-flange weld	UT	Vessel-to-flange examined manually from the seal surface.
D	Primary nozzle-to-vessel welds and nozzle inside radius section	Nozzle-to-shell welds and inner radius section on the following nozzles: Recirculation inlet Recirculation outlet Main steam Feedwater Jet pump instrumentation Core spray Head spray and instrumentation spare CRD hydraulic system return RPV vent line	UT	Nozzle-to-shell welds examined manually in the fabrication shop. Inner radius examinations performed.
E-1	Pressure-containing welds in vessel penetration	CRD penetration	Visual	UT not possible; visual examination for leakage substituted.
G-1	Pressure-retaining bolting 2 in. and larger in diameter	RPV closure studs and nuts, washers, ligaments and bushings	UM/MT	
H	Vessel external skirts	RPV support skirt-to-vessel weld	UT	Examination completed.
I-1	Interior clad surfaces of reactor vessels	RPV cladding	Visual	
N	Interior surfaces and interior components of reactor vessel	RPV internals	Visual	

TABLE 5.2-15 PRESSURE ISOLATION VALVES

System	P&ID	Valve Numbers	Type	Size (in.)	Function
RHR	6M721-2083	E1150-F015A, B	Gate	24	Discharge to recirculation system
	6M721-2084	E1100-F050A, B	Check	24	Discharge to recirculation system
		E1150-F008	Gate	20	Suction from recirculation system
		E1150-F009	Gate	20	Suction from recirculation system
		E1150-F608	Gate	20	Suction from recirculation system
Core spray	6M721-2034	E2150-F005A, B	Gate	12	Discharge to core spray sparger
		E2100-F006A, B	Check	12	Discharge to core spray sparger
HPCI	6M721-2035	E4150-F006	Gate	14	Discharge to feedwater line
		E4100-F005	Check	14	Discharge to feedwater line
RCIC	6M721-2044	E5150-F013	Gate	6	Discharge to feedwater line
		E5100-F014	Check	6	Discharge to feedwater line

TABLE 5.2-16 PRESSURE ISOLATION PROTECTION AND MONITORING

System/Line Needing Protection	Relief Valve Overpressure Protection	Control Room Alarm	Control Room Indicator	Local Indicator
RHR discharge	E1100F025A, B, 1-1/2 in.	E11-N022A, B at 435 psig		E11-R003A, B, C, D, 0-600 psig
RHR suction	E1100F030A, B, C, D, E1100F029, 1in.	--		E11-R002A, B, C, D. 30 in. Hg, 150 psig
Core spray discharge	E2100F012A (V22-2016), E2100F012B (V22-2017), E2100F011B (V22-2119), E2100F011A (V22-2120), 2 in.	E21-N007A, B at 440 psig	E21-R600A, B, 0-600 psig	--
HPCI Booster Inlet	E4100-F020 (V22-2044), 1-1/2 in.	E41-N031 at 70 psig	E41 R609 30 in. Hg, 785 psig	E41-R004, 30 in. Hg to 100 psig
RCIC suction	E5100-F017 (V22-2002), 1 in.	E51-N030 at 70 psig	E51 R609 30 in. Hg, 85 psig	E51-R002, 30 in. Hg, 100 psig

Figure Intentionally Removed
Refer to Plant Drawing M-5007

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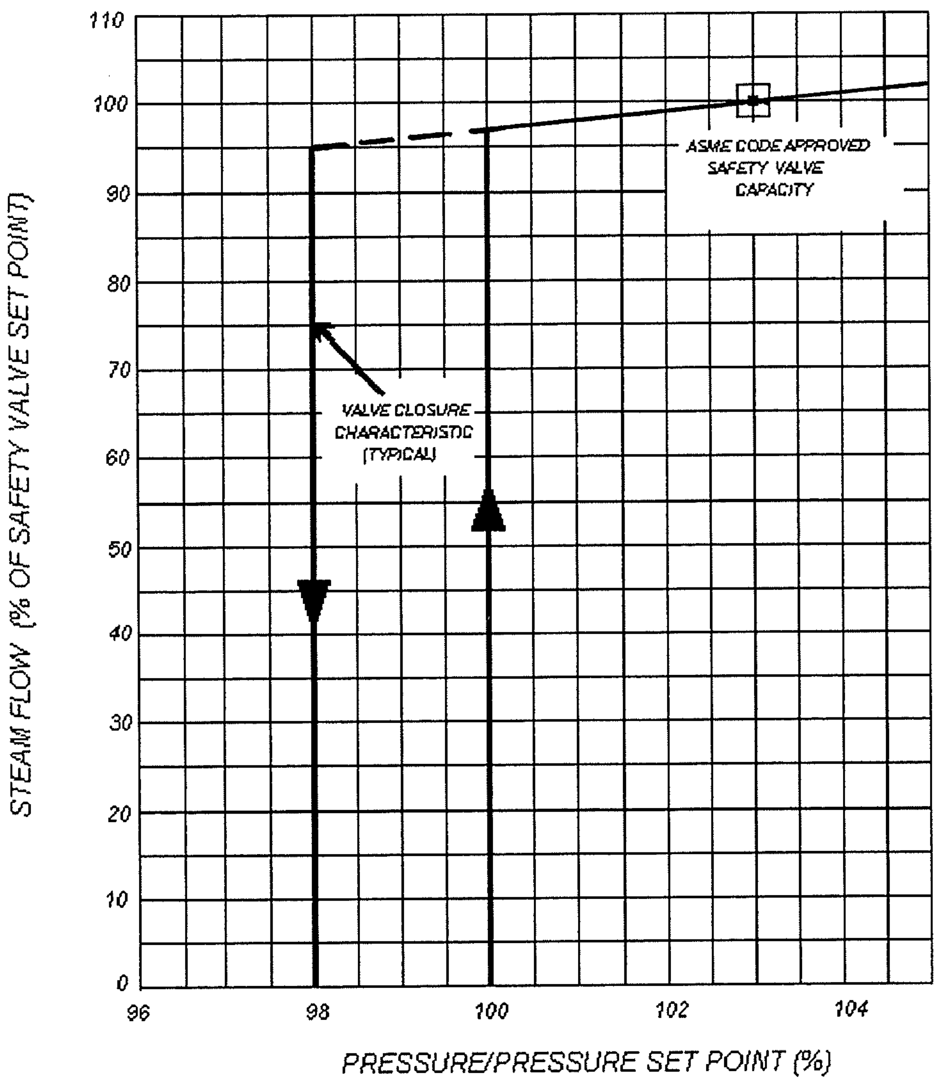
FIGURE 5.2-1
PRIMARY CONTAINMENT PNEUMATIC SUPPLY



SOURCE REFERENCE: GENERAL ELECTRIC DOCUMENT NO. 22A4070

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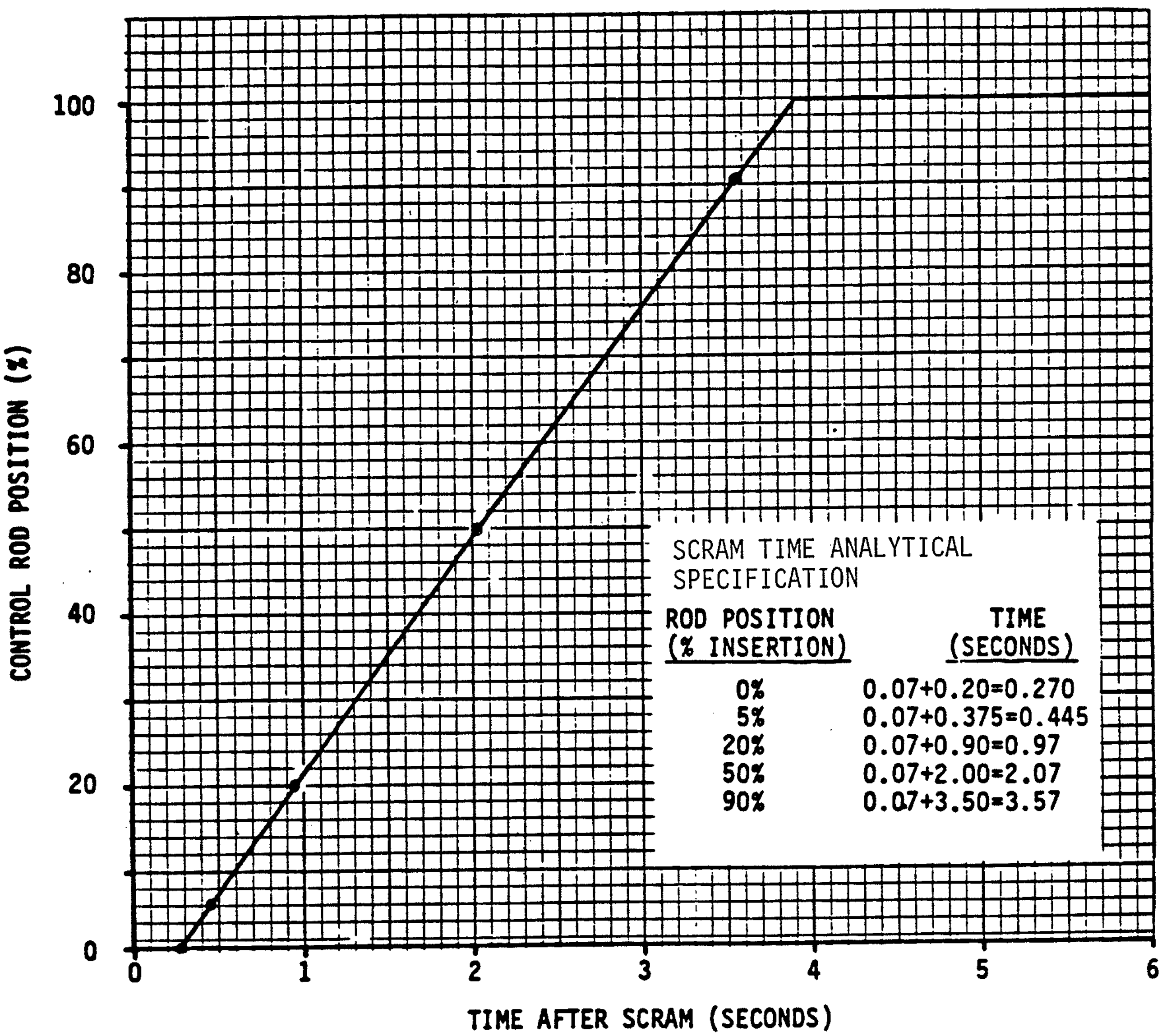
FIGURE 5.2-1a

TYPICAL DUAL SAFETY/RELIEF VALVE CAPACITY CHARACTERISTICS



REFERENCE: GENERAL ELECTRIC
DOCUMENT 384 HA259, SH. 24, REV. 3

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FIGURE 5.2-1b

CONTROL ROD DRIVE VERSUS TIME

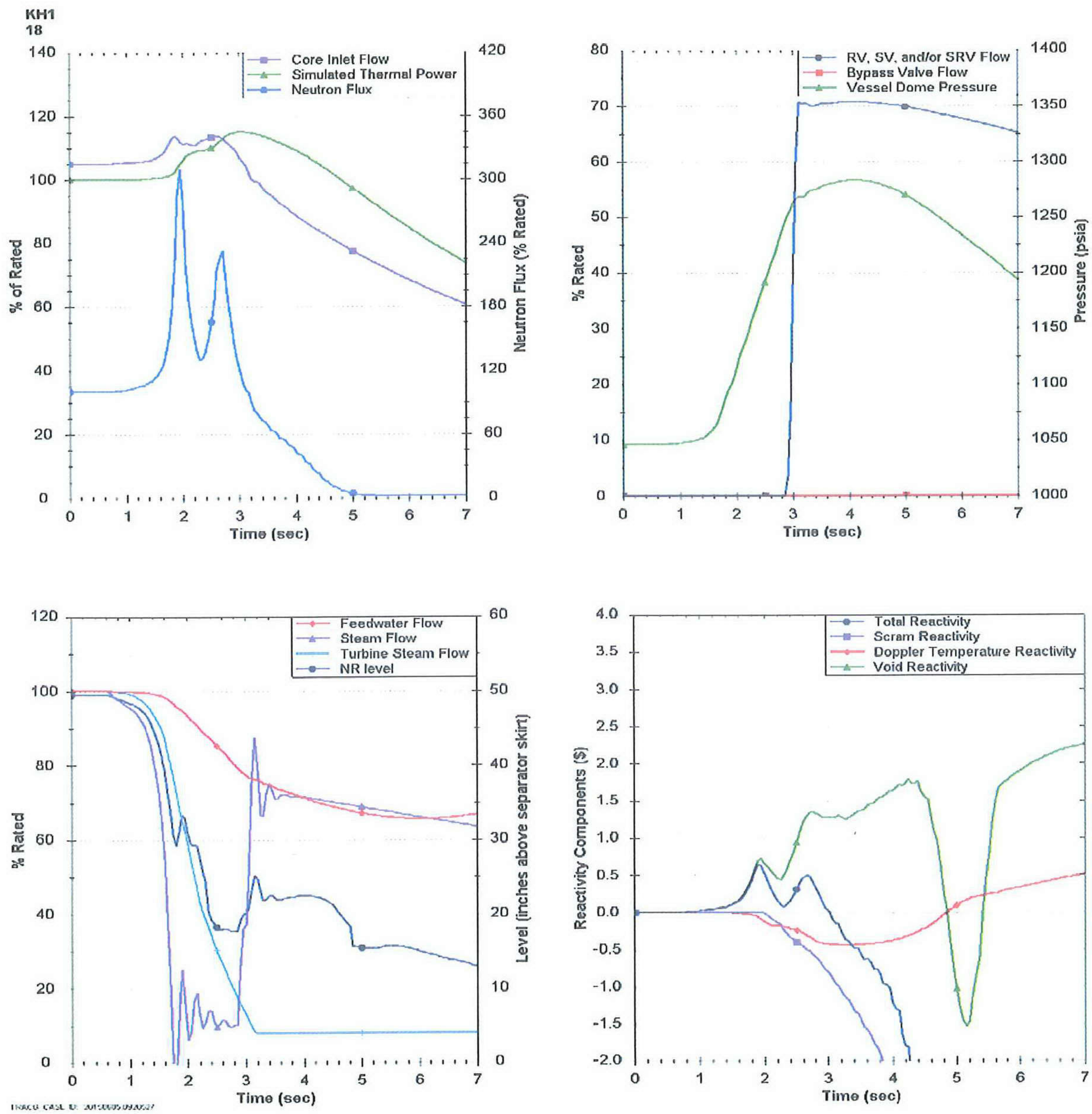

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FIGURE 5.2-1c

RESPONSE TO MSIV CLOSURE WITH FLUX SCRAM

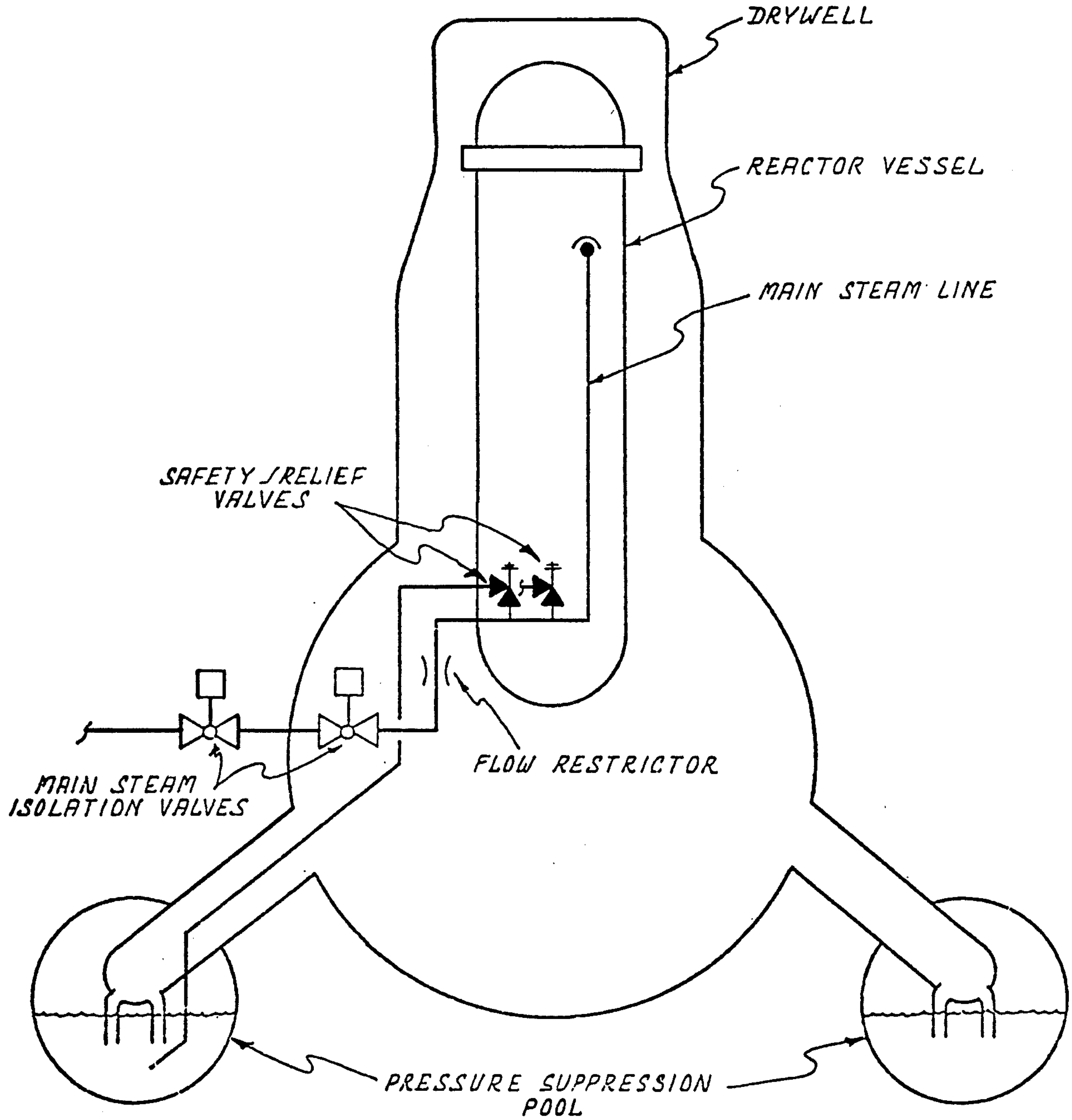

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FIGURE 5.2-1d

SAFETY RELIEF VALVE SCHEMATIC ELEVATION

SOURCE REFERENCE: GENERAL ELECTRIC DOCUMENT NO. 22A4070

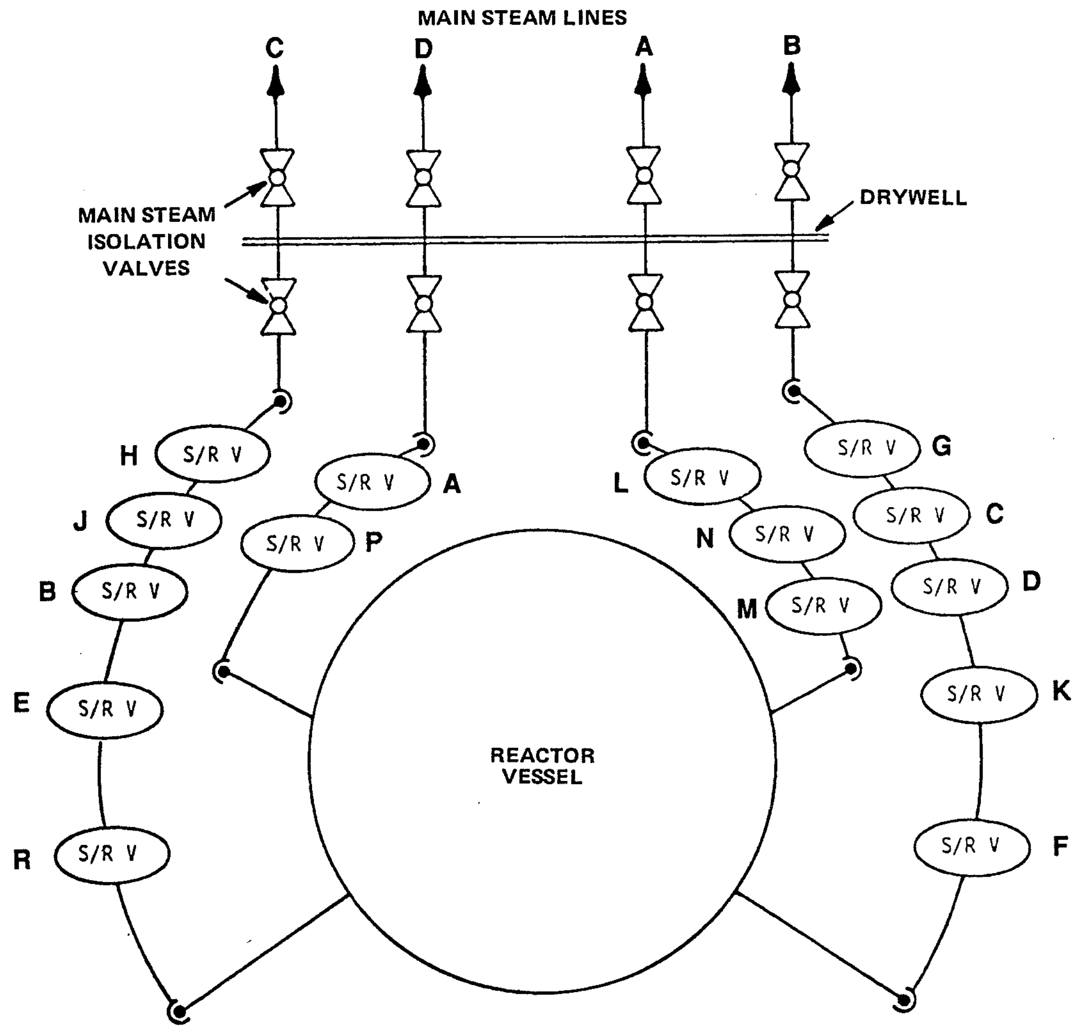

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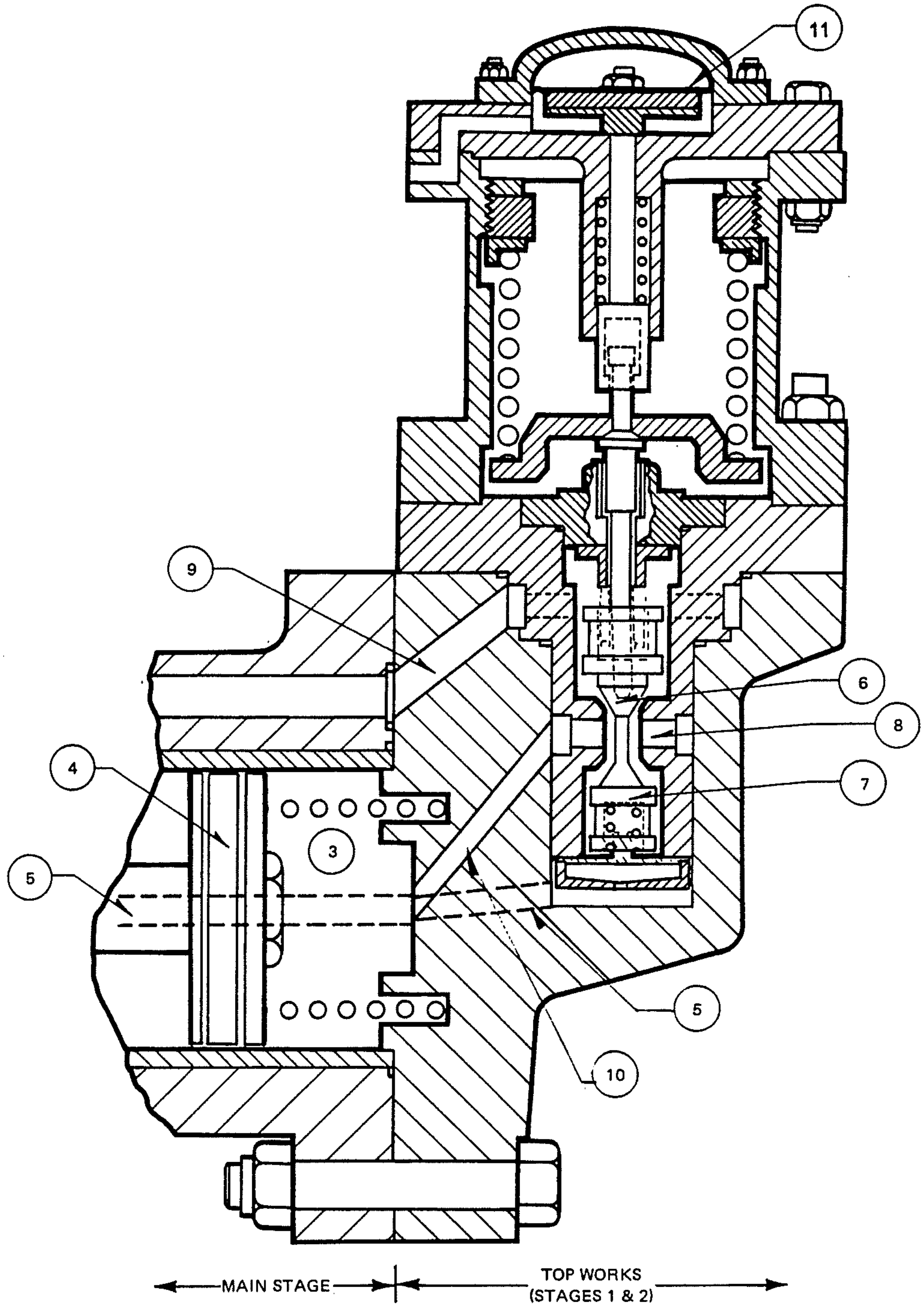
FIGURE 5.2-1e

SAFETY/RELIEF VALVE SCHEMATIC PLAN



NOTE: SUBSECTION 5.2.2.4.1 DESCRIBES THE NUMBERED PORTIONS OF THE VALVE.

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FIGURE 5.2-2

TARGET ROCK TWO-STAGE SAFETY/RELIEF VALVE

Figure Intentionally Removed
Refer to Plant Drawing M-4096-1

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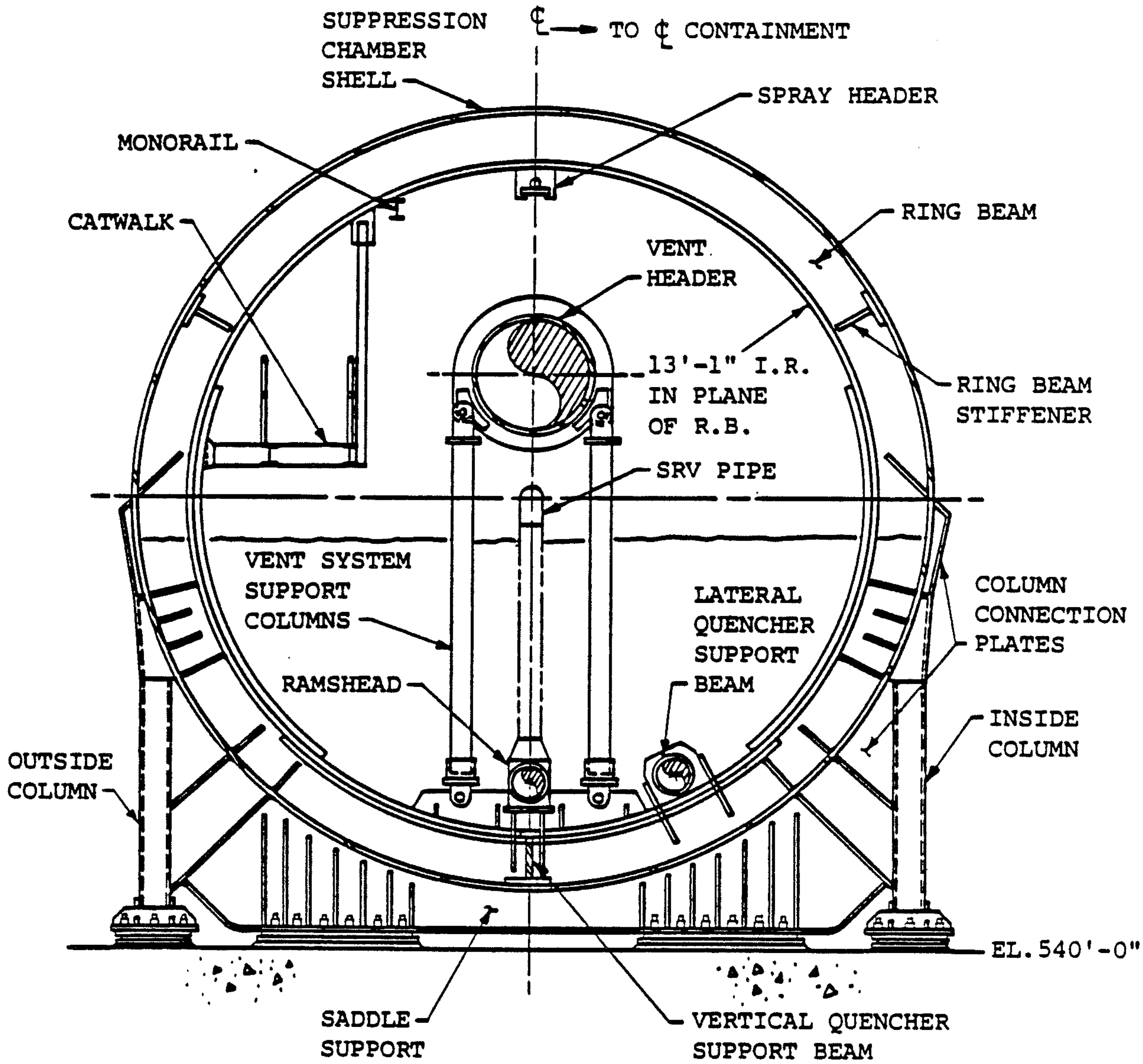
FIGURE 5.2-3

ISOMETRIC OF NUCLEAR PRESSURE RELIEF SYSTEM VALVE DISCHARGE PIPING TO TORUS TYPICAL



NUTECH DRAWING NO. DET-04-028-1, REV. 0
PUAR FIGURE 1-2.1-4

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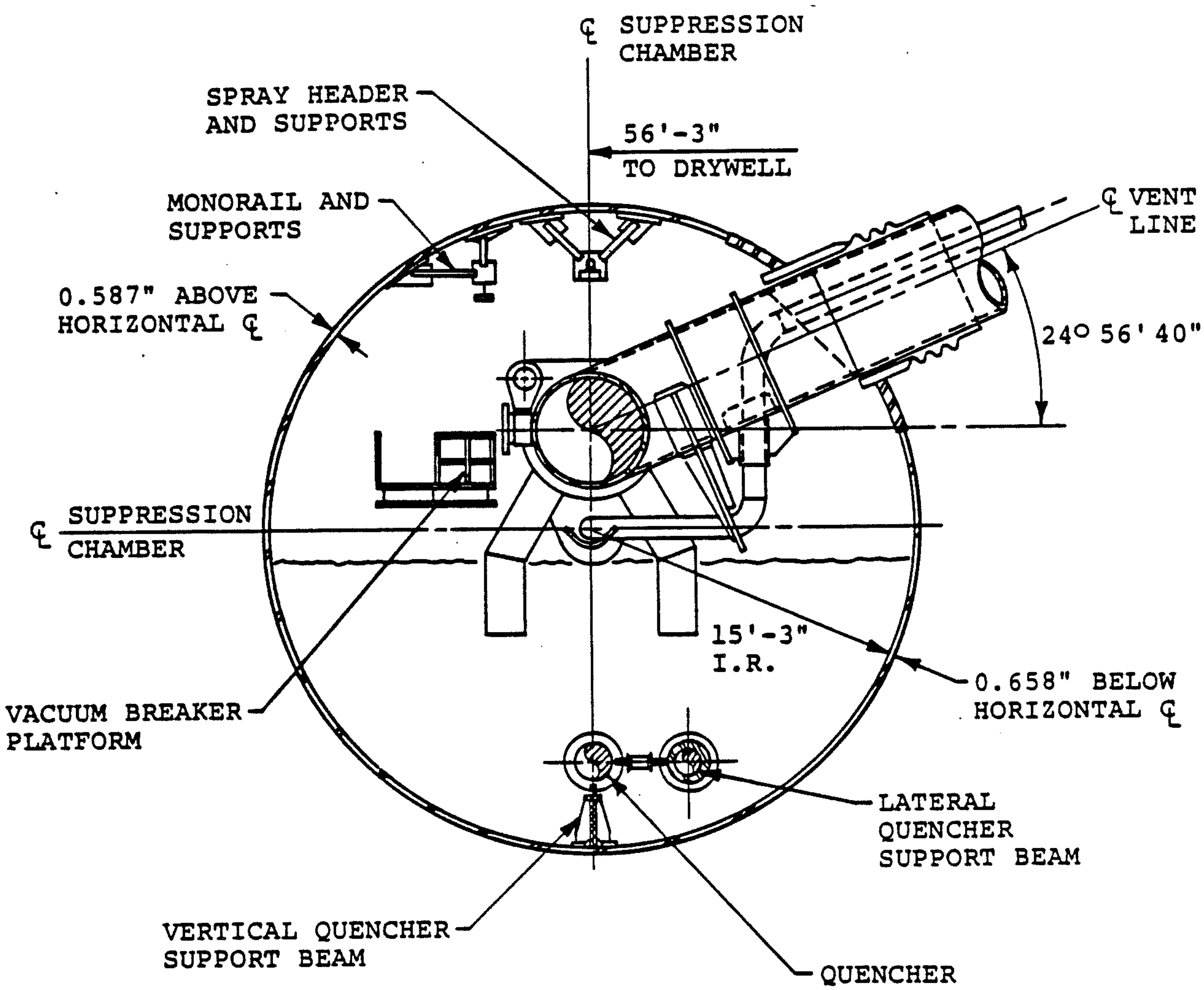
FIGURE 5.2-4

SUPPRESSION CHAMBER CROSS SECTION



NUTECH DRAWING NO. DET-04-028-1, REV. 0
PUAR FIGURE 1-2.1-3

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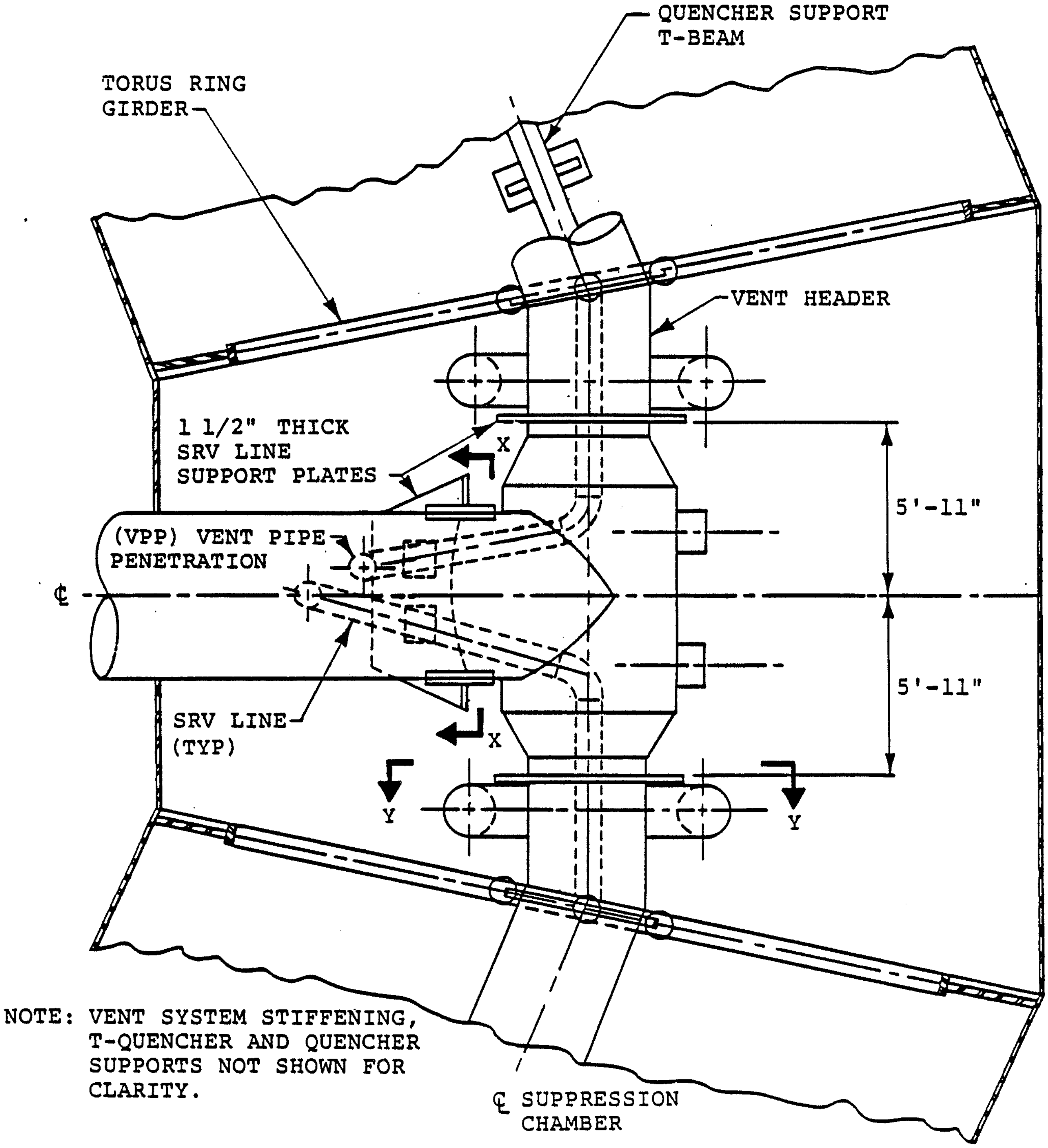
FIGURE 5.2-5

SUPPRESSION CHAMBER SECTION
MIDBAY VENT LINE BAY



NOTE: VENT SYSTEM STIFFENING, T-QUENCHER AND QUENCHER SUPPORTS NOT SHOWN FOR CLARITY.

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FIGURE 5.2-6

WETWELL SAFETY/RELIEF VALVE LINE ROUTING

NUTECH DRAWING NO. DET-20-015-5, REV. 0
PUAR FIGURE 5-2.1-5

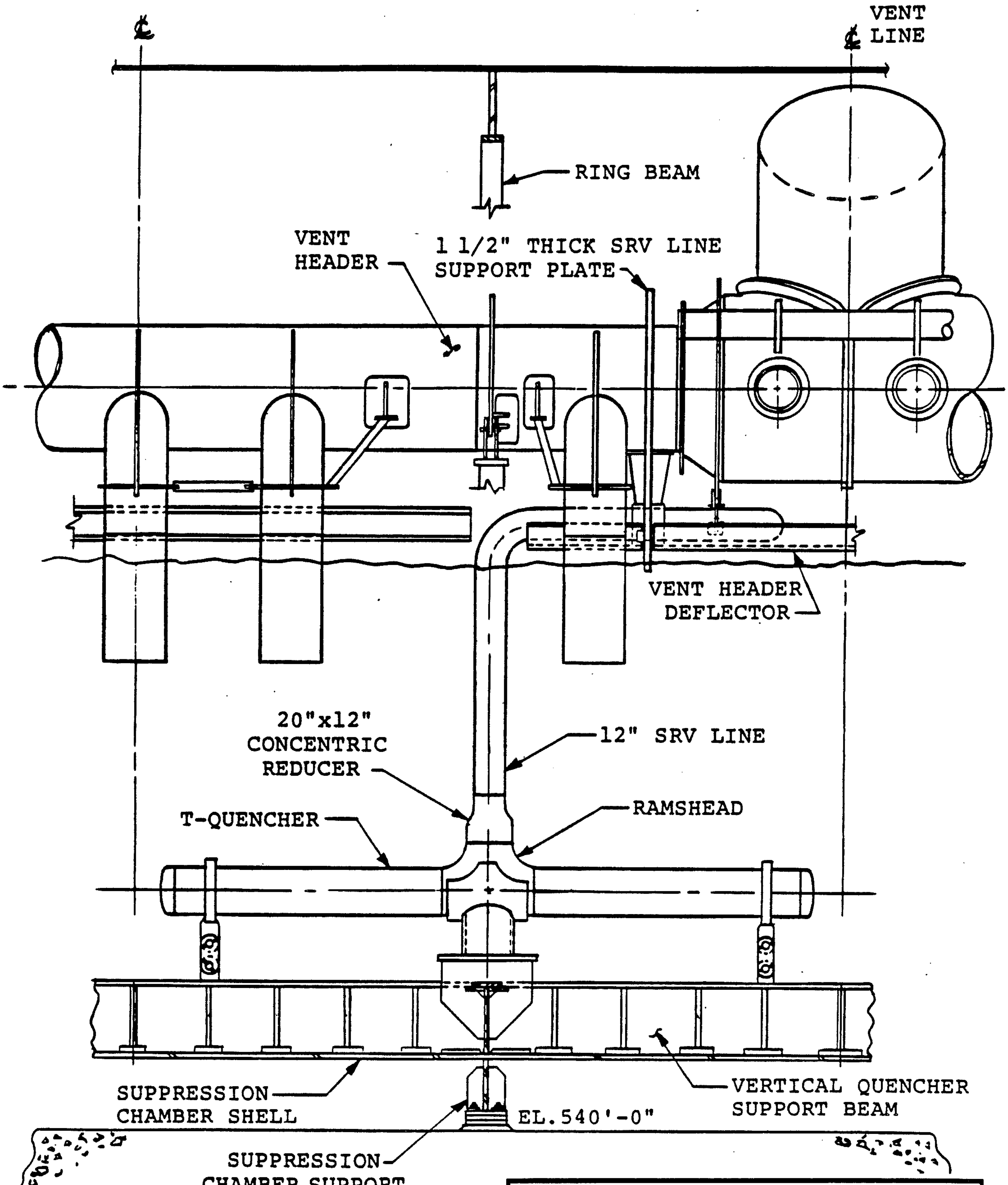

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FIGURE 5.2-7

SAFETY/RELIEF VALVE LINE IN THE SUPPRESSION CHAMBER

NUTECH DRAWING NO. DET-20-015-5, REV. 0
PUAR FIGURE 5-2.1-6

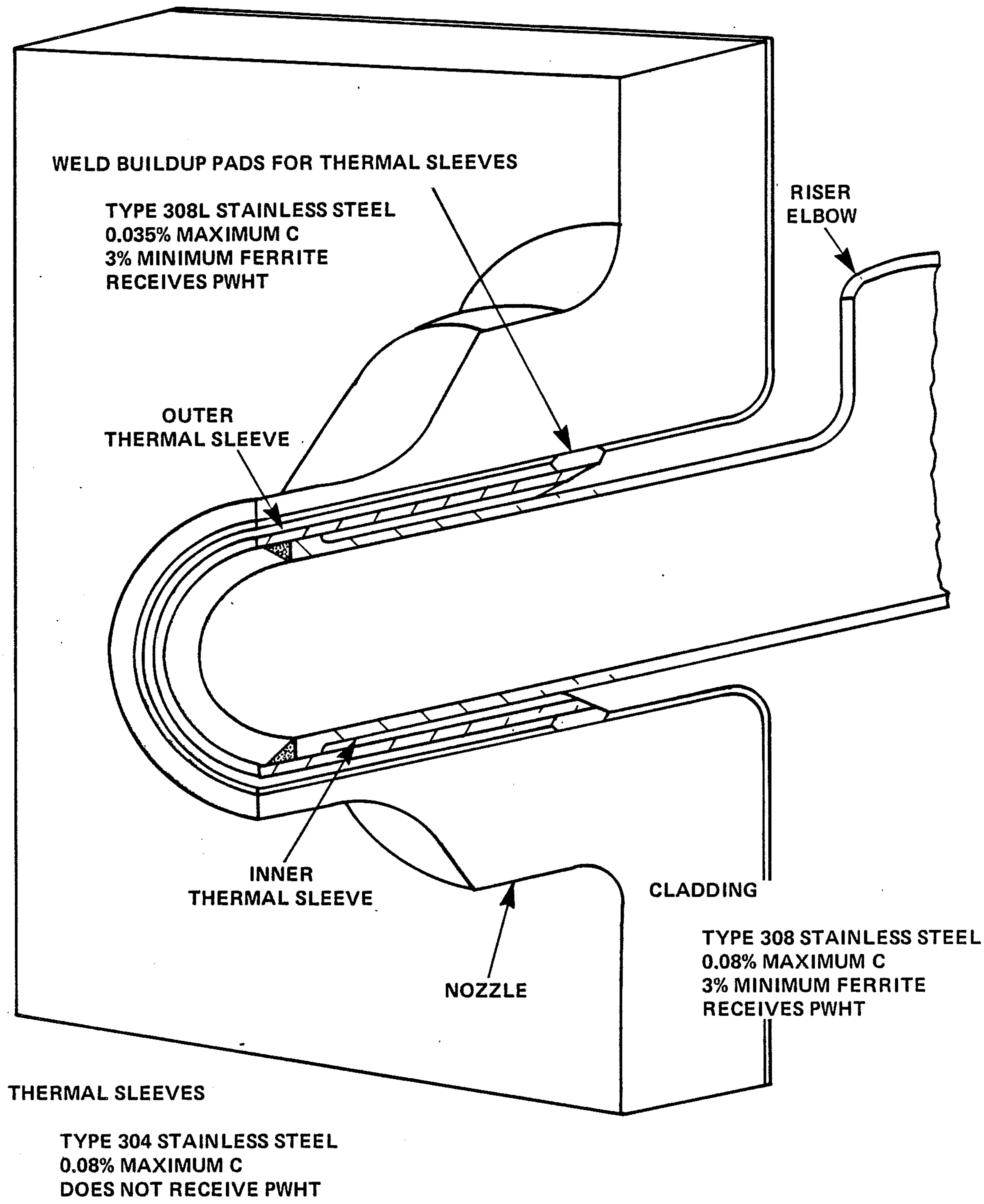

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FIGURE 5.2-8

RECIRCULATION INLET NOZZLE

FIGURE 5.2-9 HAS BEEN DELETED

FIGURE 5.2-10 HAS BEEN DELETED

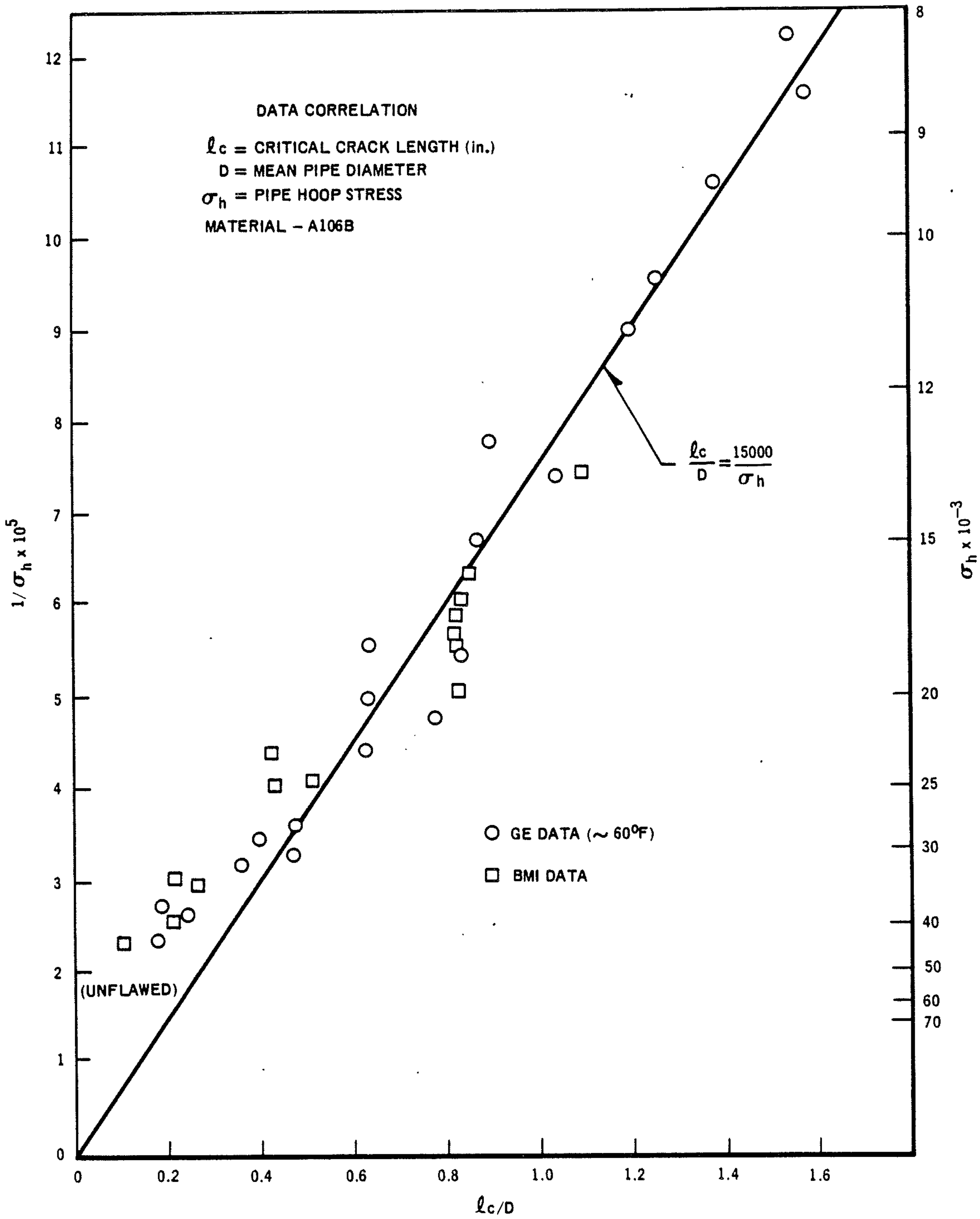

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FIGURE 5.2-11

AXIAL THROUGH-WALL CRACK

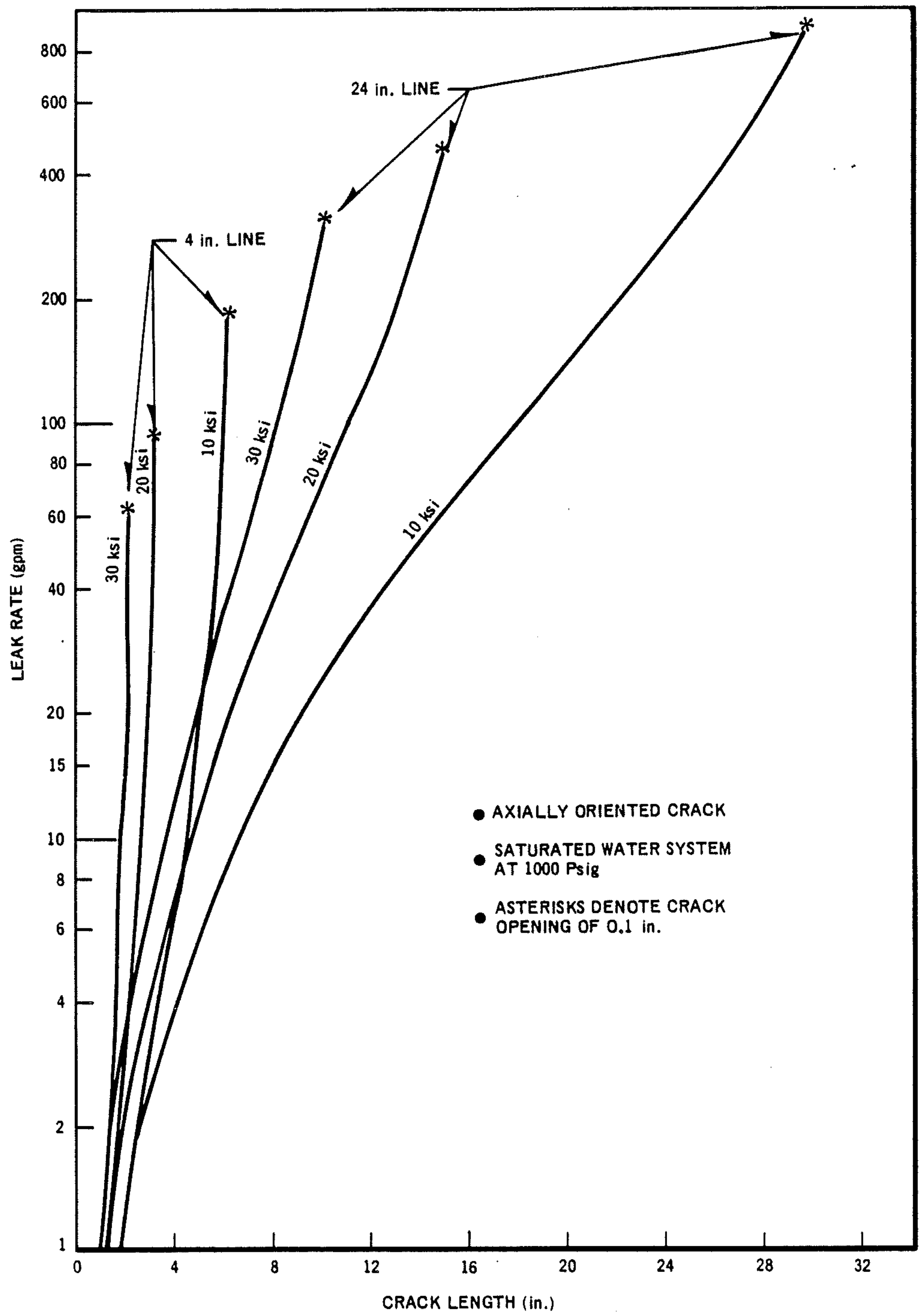

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FIGURE 5.2-12

CALCULATED LEAK RATE AS A FUNCTION OF CRACK LENGTH AND APPLIED HOOP STRESS

5.3 THERMAL HYDRAULIC SYSTEM DESIGN

5.3.1 Analytical Methods and Data

The analytical methods and thermodynamic and hydrodynamic data used to determine the thermal and hydraulic characteristics of the reactor coolant system are presented in Section 4.4.

5.3.2 Operating Restrictions on Pumps

The operating restrictions imposed on the coolant pumps to meet net positive suction head (NPSH) requirements are contained in Subsection 4.4.3.

5.3.3 Power-Flow Operating Map

A power-flow operating map that indicates the permissible operating range is contained in Subsection 4.4.3.

5.3.4 Load-Following Characteristics

The load-following characteristics are described in Subsection 4.4.3.

5.3.5 Transient Effects

The transient effects are presented in Chapter 15.

5.3.6 Thermal and Hydraulic Characteristics Summary Table

Thermal and hydraulic characteristics are summarized and compared in Table 4.4-1.

5.4 REACTOR PRESSURE VESSEL AND APPURTENANCES

5.4.1 Protection of Closure Studs

The Fermi 2 design and inspection procedures are in conformance with the requirements of Regulatory Guide 1.65 except those in regulatory positions 2b, 2e, and 3.

Studs were examined in accordance with the requirements of ASME Boiler and Pressure Vessel (B&PV) Code Section III, N-325 (1968 edition including Summer 1969 Addenda in effect at time of contract). Bored blank nuts were ultrasonically examined by both the longitudinal and shear wave methods. Shear wave examination on the nuts was performed in both the axial and circumferential directions.

Regulatory position 3 recommends provision for adequate corrosion protection during venting and filling of the vessel, and while the head is removed. General Electric supplies thread protectors that prevent stud damage, but stud holes are not plugged, and neither stud nor flange threads are protected from exposure to water. In practice this has been found to be adequate for studs complying with Regulatory Guide 1.65 Regulatory Position 1 & 2, as exposure to applied loads and operating and servicing environments has not required the replacement of any BWR studs (which were in compliance as stated above) or flange threads. No corrosion protection for studs is proposed.

5.4.2 Special Processes for Fabrication and Inspection

The product forms of the materials used to fabricate the reactor pressure vessel (RPV) are as follows.

Vessel Part	Product Form
Cylindrical shell	Rolled plate
Heads	Rolled plate
Main closure flanges	Forged rings
Closure bolting	High-strength bolting
Nozzles	Forgings
Nozzle safe ends	Forgings (stainless steel)
Nozzle safe ends	Forgings (carbon steel)

The rolled plate for vessel shells and head section was hot- formed, quenched, and tempered. These sections were welded into four rings for the vessel shell, and sections were welded to make up the top and bottom head. For a typical shell ring, the sequence of assembly is to weld the longitudinal seams, clad the inside diameter, and finally weld in the nozzles. The methods of fabrication used on the Fermi 2 reactor vessel are all allowed by the ASME B&PV Code and are not considered special or unusual.

From the standpoint of vessel inspection, normal radiographic techniques were used for the inspection of welds during fabrication. In addition, a preservice volumetric inspection using ultrasonic techniques was conducted in the fabrication shop.

This inspection was carried out in accordance with Section XI of the ASME Code, 1970 edition including winter 1971 addenda.

5.4.3 Features for Improved Reliability

No special features are incorporated in Fermi 2 that were not used before.

5.4.4 Quality Assurance Surveillance

The RPV was fabricated for GE by Combustion Engineering and was subject to Edison's QA audit.

Quality Assurance surveillance procedures were used to ensure that purchased material, equipment, and services associated with the RPV and appurtenances conformed to the requirements of the purchase documents. These procedures included provisions for source evaluation and selection, objective evidence of quality, inspection at the vendor source, and examination of the RPV upon delivery at the construction site.

5.4.5 Materials and Inspections

The materials that were used in the RPV are shown in Table 5.2-6.

The RPV was subject to the inspection requirements in accordance with the ASME B&PV Code Section III, 1968 edition with addenda through summer 1969, and the UT inspection discussed in Subsection 5.4.2.

The ASME Code Section XI baseline (preservice) inspection of the reactor vessel has been completed. One hundred percent of all RPV welds are included in the baseline. The Authorized Inspector has certified this inspection. The examination was conducted in the manufacturer's shop. It was completed on May 25, 1974.

At the site, during the preservice examination of piping, a new baseline was obtained on certain vessel welds because the inservice inspection program requires them to be examined from a surface different than the shop examination. These are

a. Top girth seam weld of head flange to reactor shell

b. Nozzle inter-radius areas.

At the time of fit and function of the mechanical equipment for the inservice inspection work, several typical areas were compared with the baseline data for assurance of baseline validity and reproducibility.

5.4.6 Reactor Pressure Vessel Design

5.4.6.1 Safety Design Bases

Design of the RPV appurtenances meets the following safety design bases.

a. The RPV and appurtenances shall withstand adverse combinations of loading and forces resulting from operation under abnormal and accident conditions

b. To minimize the possibility of brittle fracture of the nuclear system process barrier, the following is required.

   1. Maximum impact properties at temperatures related to RPV operation shall be specified for materials used in the RPV

   2. Expected shifts in nil ductility transition temperature (NDTT) during design life as a result of environmental conditions, such as neutron flux, shall be considered in the design. Operational limitations ensure that NDTT shifts are accounted for in reactor operation

   3. Operational margins to be observed with regard to the NDTT shall be specified for each mode of operation.

5.4.6.2 Power Generation Design Basis

Design of the RPV and appurtenances meets the following power generation design basis:

a. The RPV shall be designed for an operational life of 40 years (Refer to Appendix B for evaluations of 60 years)

b. External and internal supports that are integral parts of the RPV shall be located and designed so that stresses in the RPV and supports that result from reactions at these supports are within ASME Code limits

c. Design of the RPV and appurtenances shall allow for a suitable program of inspection and surveillance.

5.4.6.3 Description

5.4.6.3.1 Reactor Pressure Vessel

The RPV, shown in Figure 5.4-1, is a vertical, cylindrical pressure vessel with hemispherical heads of welded construction. The vessel design data are listed in Table 5.4-1. The RPV operating thermal cycles are listed in Table 5.2-2. The RPV is designed, fabricated, tested, inspected, and stamped in accordance with the ASME B&PV Code Section III, 1968, Class 1, up to and including summer 1969 addenda. Design of the RPV and its support system meets Category I equipment requirements.

The cylindrical shell and bottom head of the RPV are fabricated of low-alloy steel, the interior of which is clad with stainless- steel weld overlay. Internal surfaces of nozzles that connect to stainless-steel pipe are also clad.

Inplace annealing of the RPV because of radiation embrittlement is unnecessary, as described in Subsection 5.2.4.5.

Quality Assurance methods used during the fabrication and assembly of the RPV and appurtenances ensure that design specifications are met.

The RPV top head is secured to the RPV by studs and nuts. These nuts are tightened with a stud tensioner. The RPV flanges are sealed with two concentric metal seal rings. To detect seal failure, a vent tap is located between the two seal rings. A monitor line is attached to the tap to provide an indication of leakage from the inner seal ring.

Thermocouples are located on the exterior of the RPV. In some cases, thermocouples are attached to the RPV by magnets. At other thermocouple locations, two pads are provided. One is an end pad to hold the end of a 3/16-in. diameter thermocouple, and the other is a clamp pad equipped with a set screw to secure the thermocouple. These thermocouple locations provide a means of observing RPV temperature in response to changes in RPV coolant flow rate. Because RPV metal thickness and the thermal time constant cause the temperature of the RPV surface to lag the coolant temperature, measurements of surface temperature do not afford an effective means of monitoring thermal stresses in the RPV.

Procedural controls on plant operation are necessary to hold these thermal stresses within acceptable ranges. These restrictions on coolant temperature are

a. The average rate of change of reactor coolant temperature during normal heatup and cooldown shall not exceed 100°F during any 1-hr period

b. The RRS pumps shall not be operated unless the coolant temperatures in the upper and lower regions of the RPV are within 145°F of each other

c. The pump in an idle reactor recirculation system (RRS) loop shall not be started unless the coolant temperature in that loop is within 50°F of reactor coolant temperature.

The limit regarding the normal rate of heatup and cooldown described in Item a. ensures that the RPV closure, closure studs, RPV support skirt, control rod drive (CRD) housing, and stub tube stresses and usage remain within acceptable limits. The RPV temperature limit on RRS pump operation restriction described in Item b. augments the Item a. limit in further detail by ensuring that the RPV bottom head region will not be warmed at an excessive rate caused by rapid sweepout of cold coolant in the RPV lower head region by RRS pump operation. Cold coolant can accumulate as a result of CRD inleakage and/or low recirculation flow rate during startup or hot standby. The Item c. limit further restricts operation of the RRS pumps to avoid high thermal stress effects in pumps and piping, while also minimizing thermal stresses on the vessel nozzles.

5.4.6.3.2 Shroud Support

The shroud support is a circular plate welded to the RPV wall. This support is designed to carry the weight of the shroud, shroud head, core support plate, top guide, steam separators, and jet pump system, and to laterally support the fuel assemblies. Design of the shroud support also accounts for pressure differentials across the shroud support plate, for the restraining effect of components attached to the support, and for earthquake loadings. The shroud support design is specified to meet appropriate ASME Code stress limits.

5.4.6.3.3 Reactor Pressure Vessel Supports

5.4.6.3.3.1 Vessel Support Assembly

The RPV support assembly consists of a ring girder, sole plates, and the various bolts, shims, and set screws necessary to position and secure the assembly between the RPV support skirt and the support pedestal. The concrete and steel support pedestal is constructed integrally with the building foundation. Steel anchor bolts are set in the concrete with the threads extending above the surface. The sole plates are bolted to the underside of the RPV ring girder. The sole plate-ring girder assembly is set, leveled, and grouted to the top of the RPV pedestal.

The anchor bolts extend through both the sole plates and the ring girder bottom flange. High-strength bolts are used to bolt the flange of the RPV support skirt to the top flange of the ring girder. The ring girder is ASTM A-36 and the sole plates ASTM A-588 structural steel, both fabricated according to appropriate AISC Specifications.

The top of the pedestal is haunched slightly on the inside to accommodate the anchor bolts. The haunch size has been kept to a minimum to reduce stress concentrations. Reinforcing steel has been provided completely encircling the anchorage area of the bolts to transfer the bolt loads into the main part of the pedestal. The reinforcing details for the haunch have been reviewed and approved by the AEC (Reference 1).

5.4.6.3.3.2 Reactor Pressure Vessel Stabilizers

The RPV stabilizers are designed to permit radial and axial vessel expansion, to limit horizontal vibration, and to resist seismic and jet reaction forces. The stabilizers are connected between the RPV and the top of the shield wall surrounding the RPV to provide lateral stability for the upper part of the RPV. Eight stabilizer brackets are attached by full-penetration welds to the RPV at evenly spaced locations around the RPV below the flange. Each RPV stabilizer consists of a stabilizer rod threaded at the ends, springs, washers, a nut, a plate, and a bumper bracket with tapered shims. The stabilizers are attached to each bracket and apply tension in opposite directions. The stabilizers are evenly preloaded with tensioners to the values of the residual loads.

5.4.6.3.4 Control Rod Drive Housings

The CRD housings are inserted through the CRD penetrations in the RPV bottom head and are welded to stub tubes extending into the RPV. Each housing transmits a number of loads to the bottom head of the reactor. These loads include the weights of a control rod, a CRD, a control rod guide tube, a four-lobed fuel support piece, and the four fuel assemblies that rest on the fuel support piece. These loads are taken into account in designing the bottom head of the reactor. The housings are fabricated of type 304 austenitic stainless steel.

5.4.6.3.5 In-Core Neutron Flux Monitor Housings

Each in-core neutron flux monitor housing is inserted through the in-core penetrations in the bottom head of the RPV and is welded to the inner surface of the bottom head.

An in-core flux monitor guide tube is welded to the top of each housing, as described in Subsection 4.2.2. Either a source range monitor/intermediate range monitor (SRM/IRM) drive unit or a local power range monitor (LPRM) is bolted to the seal- ring flange at the bottom of the housing, as described in Subsection 4.2.2.

5.4.6.3.6 Refueling Bellows

The refueling bellows forms a seal between the RPV and the surrounding primary containment drywell to permit flooding of the space (reactor well) above the RPV during refueling operations. The refueling bellows assembly consists of a type 304 stainless steel bellows, a backing plate, a spring seal, and a removable guard ring. The backing plate surrounds the outer circumference of the bellows to protect it and is equipped with a tap for testing and for monitoring leakage. The self energizing spring seal is located in the area between the bellows and the backing plate. This seal is designed to limit water loss in the event of a bellows rupture by yielding to make a tight fit to the backing plate. This seal is designed to limit water loss in the event of a bellows rupture by yielding to make a tight fit to the backing plate when subjected to full hydrostatic pressure. The guard ring attaches to the assembly and protects the inner circumference of the bellows. The guard ring can be removed from above to inspect the bellows. The assembly is welded to the reactor bellows support skirt and the reactor well seal bulkhead plate. The reactor bellows support skirt is welded to the RPV shell flange. The reactor well seal bulkhead plate bridges the distance to the primary containment drywell wall. This plate contains eight 12-in. holes for air circulation and two 30-in. holes for manways. Each hole is equipped with a watertight cover. For normal operation, the covers on the eight 12-in. holes are opened and removable air supply ducts are inserted into four of them. For refueling operations, all holes are covered.

IE Bulletin 84-03, Refueling Cavity Water Seal, was reviewed by Edison and deemed not to be applicable, since the design of the bellows described above differed markedly from the seal that failed and was reported in IE Bulletin 84-03.

5.4.6.3.7 Reactor Pressure Vessel Insulation

The RPV insulation has an average maximum heat transfer rate of approximately 0.2-Btu/hr/ft^2/°F at the operating conditions of 550°F for the RPV and 134°F for the drywell air. The insulation panels for the cylindrical shell of the RPV are held in place by the sacrificial shield. The insulation is designed to be removable where inspection is required for inservice inspection. Shell course welds will be inspected remotely.

5.4.6.3.8 Reactor Pressure Vessel Nozzles

All piping connected to the RPV nozzles, including instrument piping, has been designed so as not to exceed the allowable loads on any nozzle.

The RPV nozzles are low-alloy steel forgings made in accordance with the ASME Code SA-508, Class 2. Nozzles of nominal size larger than 2 in. are full-penetration welded to the vessel. Nozzles of 2 in. nominal size and under may be partial-penetration welded, as permitted by ASME B&PV Code Section III. Nozzles that are partial-penetration welded are low-alloy steel or carbon steel forgings made in accordance with ASME Code SA-508, SA-105, or SA-106.

The RPV top head nozzles are provided with flanges with small groove facing. The drain nozzle is of the full-penetration weld design and extends below the bottom outside surface of the RPV. The RRS inlet nozzles (Figure 5.4-1), the feedwater inlet nozzles, and the core spray inlet nozzles all have thermal sleeves. For more information on the feedwater sparger and thermal sleeve design, see Subsection 5.2.1.20.

Nozzles connected to stainless piping have safe ends made of stainless steel. These safe ends are normally welded to the nozzles after the RPV has been heat treated to avoid furnace sensitization of the stainless steel. The material used is compatible with the material of the mating pipe. For more information on the safe ends, see Subsection 5.2.3.2.

The nozzle for the core differential pressure and liquid control pipe is designed with a transition so that the stainless-steel outer pipe of the differential pressure and liquid control line can be socket welded to the inner end of the nozzle and so that the inner pipe passes through the nozzle. This design provides an annular region between the nozzle and the inner liquid control line to minimize thermal shock effects on the RPV in the event that use of the standby liquid control system (SLCS) is required.

5.4.6.4 Safety Evaluation

The RPV design pressure of 1250 psig is based on an analysis of margins. The margins include additional allowances to accommodate transients above the operating pressure without initiating safety valve action. The RPV design temperature of 575°F is based on the saturation temperature of water that corresponds to the design pressure.

To withstand external and internal loadings while maintaining a high degree of corrosion resistance, a high-strength, low-alloy steel is used as the base metal, and an internal cladding of stainless steel is applied using weld overlay. Use of ASME B&PV Code Section III, Category I, RPV design criteria ensures that a vessel designed, built, and operated within its design limits has an extremely low probability of failure as a result of any known failure mechanism.

Stress analysis and load combinations for the RPV were evaluated for the cycles listed in Table 5.2-2, with the conclusion that ASME Code limits are satisfied.

5.4.7 Reactor Pressure Vessel Schematic

The RPV schematic is contained in Figure 5.4-2. The relation of the RPV to the biological shield is shown in Figure 5.1-4. Normal water level and high and low levels for alarm and trip are shown in Figure 7.3-12.

5.4 REACTOR PRESSURE VESSEL AND APPURTENANCES

REFERENCES

1 Letter from V. M. Moore, AEC, to C. M. Heidel, Edison, Subject: Review of Design of Biological Shield (Fermi 2 Post Construction Permit Open Item No. 12), dated October 29, 1973.

TABLE 5.4-1 REACTOR PRESSURE VESSEL DESIGN DATA

Reactor pressure vessel	
Inside diameter, in. (minimum)	251
Inside length (including closure head), ft.	72
Design pressure and temperature, psig @°F	1250 @ 575
Reactor pressure vessel support	
Design mechanical loads shear, kips	1300
Design mechanical loads moment, in.-kips	576,000
Vessel nozzles	Number/Size (in.)
Recirculation outlet	2/28
Steam outlet	4/26
Recirculation inlet	10/12
Feedwater inlet	6/12
Core spray inlet	2/10
Instrument (spare)	2/6
Control rod drive	185/6
Jet pump instrumentation	2/4
Vent	1/4
Instrumentation	6/2

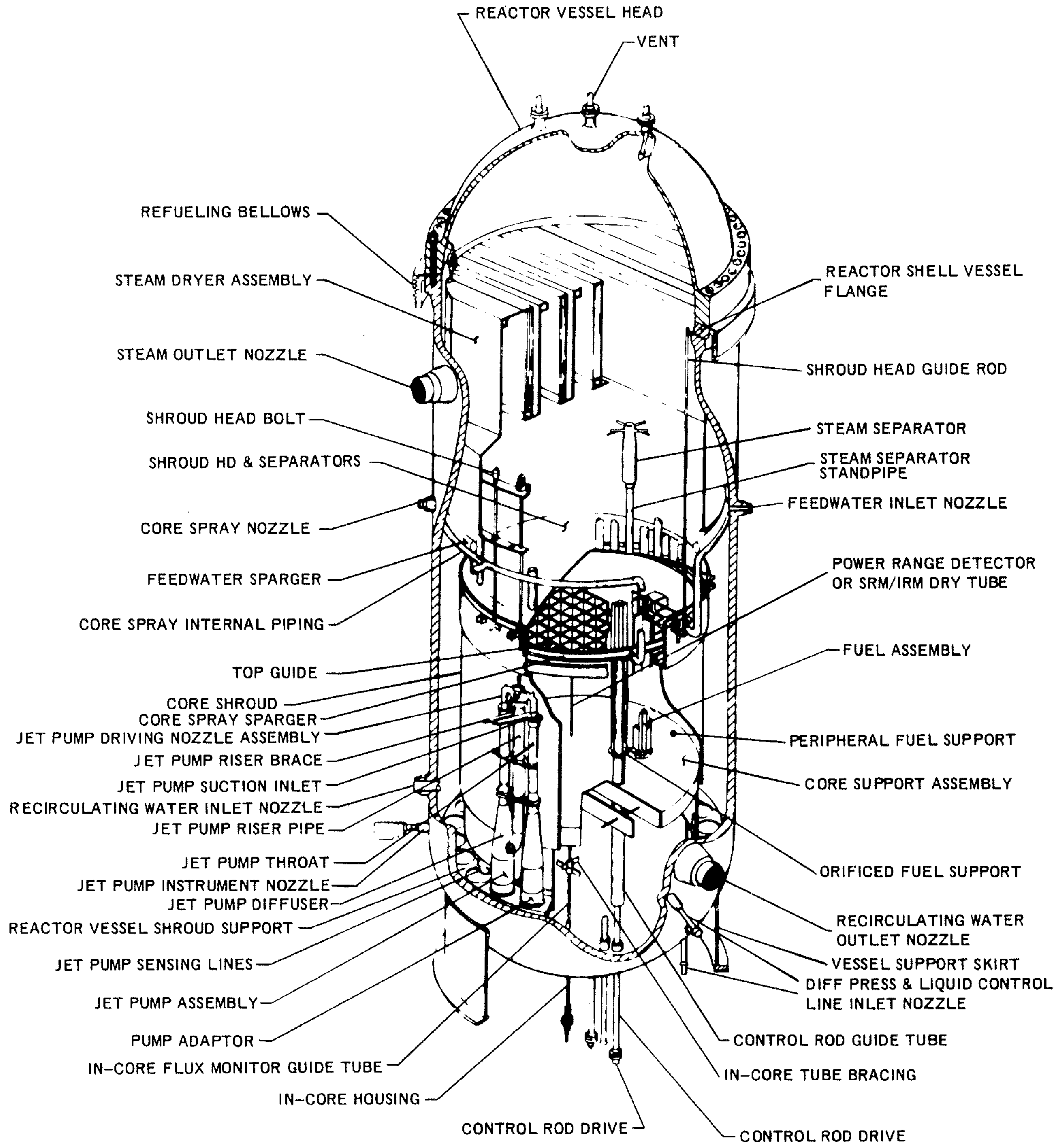

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FIGURE 5.4-1

REACTOR VESSEL CUTAWAY

GENERAL ELECTRIC CO. DRAWING

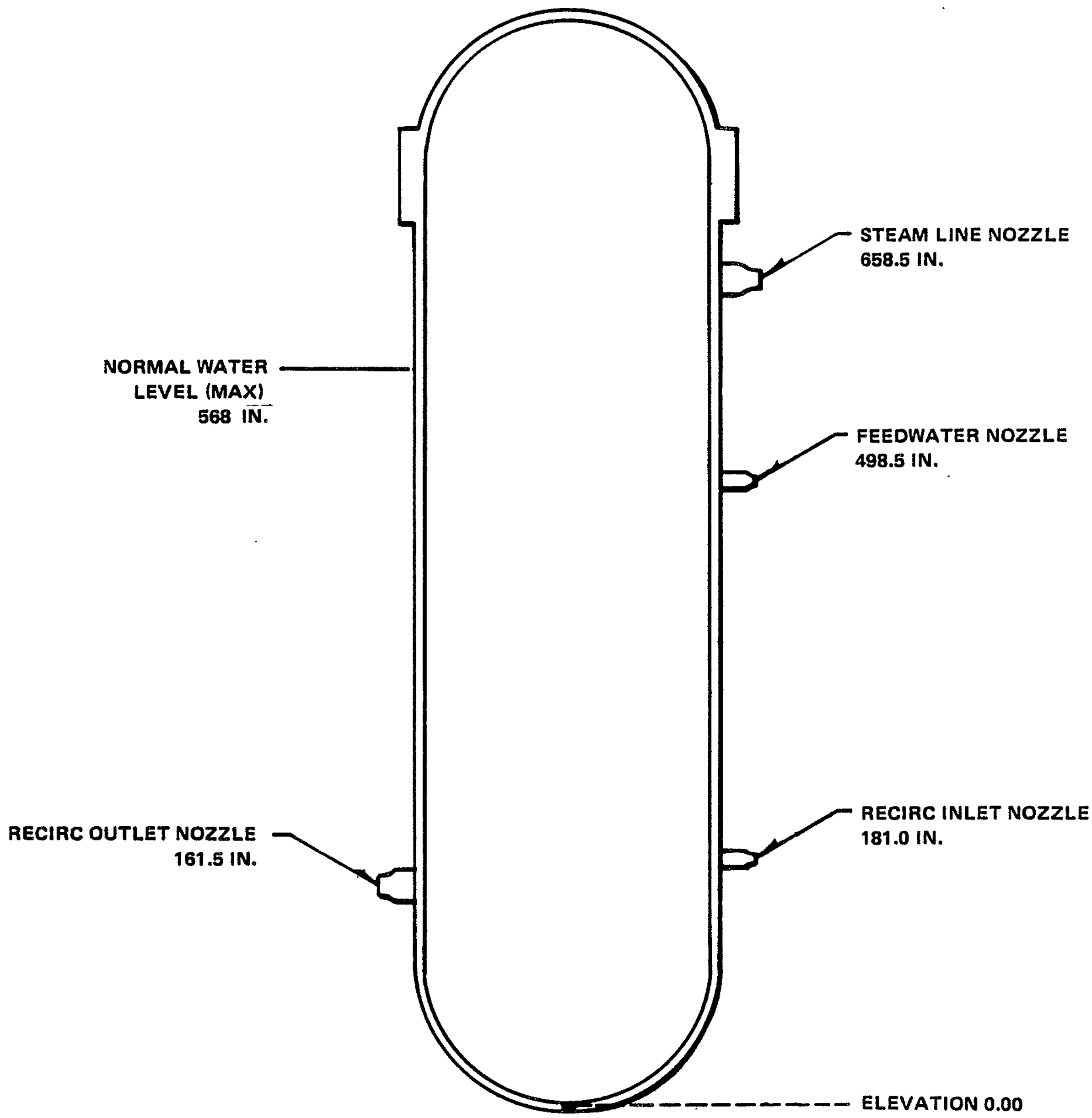

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FIGURE 5.4-2

REACTOR PRESSURE VESSEL SCHEMATIC

5.5 COMPONENT AND SUBSYSTEM DESIGN

This section presents discussions of the performance requirements and design features to ensure overall safety of the various components within the reactor coolant pressure boundary (RCPB) and those subsystems closely allied with the reactor coolant system but not a portion of the RCPB. The subsystems and components discussed in this section are the reactor core isolation cooling (RCIC) system; residual heat removal (RHR) system; reactor water cleanup (RWCU) system; main steam lines, feedwater piping, and drains, valves, and component supports. The portions of these subsystems which are within the RCPB are discussed in Subsections 5.5.1 through 5.5.4.

5.5.1 Reactor Recirculation System and Pumps

5.5.1.1 Safety Design Bases

The reactor recirculation system (RRS) is designed to meet the following safety design bases.

a. An adequate fuel barrier thermal margin shall be ensured during postulated transients

b. A failure of piping integrity shall not compromise the ability of the reactor pressure vessel (RPV) internals to provide a refloodable volume

c. The RRS shall maintain pressure integrity during adverse combinations of loadings and forces occurring during abnormal, accident, and special event conditions.

5.5.1.2 Power Generation Design Bases

The RRS meets the following power generation design bases:

a. The RRS shall provide sufficient flow to remove heat from the fuel

b. System design shall minimize maintenance situations that would require core disassembly and fuel removal.

5.5.1.3 Description

The RRS consists of the two RRS pump loops external to the RPV. These loops provide the piping path for the driving flow of water to the RPV jet pumps, as shown in Figures 5.5-1 and 5.5-2. Each external loop contains one variable-speed motor-driven RRS pump, two motor-operated gate valves, and a motor-generator set to control RRS pump speed. Each pump discharge line contains a venturi-type flow meter nozzle.

The RRS loops are part of the nuclear system process barrier and are located inside the primary containment structure. The jet pumps are RPV internals. Their location and mechanical design are discussed in Subsection 4.5.1.2.7. However, certain operational characteristics of the jet pumps are discussed in this subsection. Table 5.5-1 summarizes the design characteristics of the RRS.

The recirculated coolant consists of saturated water from the steam separators and dryers that has been subcooled by incoming feedwater. This water passes down the annulus between the RPV wall and the core shroud. A portion of the coolant flows from the RPV, through the two external RRS loops, and becomes the driving flow for the jet pumps. Each of the two external RRS loops discharges high pressure flow into an external manifold from which individual recirculation inlet lines are routed to the jet pump risers within the RPV. The remaining portion of the coolant mixture in the annulus becomes the driven flow for the jet pumps. This flow enters the jet pump at suction inlets and is accelerated by the driving flow. The flows, both driving and driven, are mixed in the jet pump throat section and result in partial pressure recovery. The balance of recovery is obtained in the jet pump diffusing section shown in Figure 5.5-3. The adequacy of the total flow to the core is discussed in Subsection 4.4.3. Documented tests show that the jet pump design is sound and that jet pump operation is stable and predictable.

The original design for Fermi 2 included a 4-in. bypass line around each pump discharge valve. The line was to be used during the startup of a loop to equalize the pressure across the discharge valve, to preheat the piping loop by reverse flow, and to prevent the pump from overheating prior to opening the discharge valve. Operating plants have found this line to be very susceptible to intergranular stress corrosion cracking. General Electric has developed a circuit for controlling the opening of the discharge valve that eliminates the need for the bypass line. Employment of this circuit enables the removal of the bypass line.

Based on this experience at other plants, the decision was made not to install the 4-in. bypass lines on Fermi 2 and to incorporate the controlled opening (jogging) circuit. Caps are welded onto the bypass line tees.

There is a very low probability that a RRS loop that has been allowed to cool would need to be placed in service again when the nuclear system is hot. The only valid reason for closing both the pump discharge valve and the suction valve is to prevent leakage out of that portion of the RRS loop between the valves; e.g., excessive leakage through the pump mechanical seal. A leak of this nature cannot be repaired without shutting the plant down to permit access to the drywell. The nuclear system would, in all probability, be cooled prior to repairing the leak.

Since the removal of RRS valve internals without alternate isolation capability requires unloading of the nuclear fuel, the valves are provided with high-quality back seats and a trim to facilitate stem-packing renewal and to provide adequate leaktightness. Alternative RRS loop isolation devices (plugs) have been approved for use only during Mode 5 to support maintenance activities without unloading the nuclear fuel.

The feedwater flowing into the RPV annulus during operation provides subcooling for the fluid passing to the RRS pumps, thus determining the additional net positive suction head (NPSH) available beyond that provided by the pump location below the RPV water level. If feedwater flow is below the minimum value that provides adequate NPSH for full speed RRS pump operation, the pump speed is automatically limited. This limit is chosen to prohibit pump cavitation. Operation with the suction pressure available only from the RPV provides adequate NPSH.

The RRS pumps can be operated during nuclear steam supply system (NSSS) heatup for hydrostatic tests. At this time, they act in conjunction with any contribution from reactor core decay heat to raise NSSS temperature above the limit imposed on the RPV by nil ductility transition temperature (NDTT) considerations so that the hydrostatic test can be conducted.

Each RRS pump is a single-stage, variable-speed, vertical, centrifugal pump equipped with mechanical shaft seal assemblies. In order to preclude shaft cracking due to thermal stress, the pumps have been upgraded to the 4^{th} generation design.

The pump is capable of stable and satisfactory performance while operating continuously at any speed corresponding to a power supply frequency range from 11.5 to 57.5 Hz. For loop startup, each pump operates at a speed corresponding to a power supply frequency of 11.5 Hz.

Each RRS pump motor is a standard ac induction motor which is operated as a variable-speed pump driver by using a variable frequency power supply. The power supply is provided by a motor-generator set with a fluid coupler which allows continuous generator speed adjustment so that the output power frequency may be varied from 11.5 to 57.5 Hz. The pump motor design is capable of operating at any speed within the power supply frequency range corresponding to a pump speed control range from 20 percent to 102 percent rated pump speed. The electrical equipment is designed, constructed, and tested in accordance with the applicable sections of the NEMA Standards.

The variable-frequency ac motor-generator sets for both RRS pumps are located outside the drywell. The pump motors are electrically connected to the generators. Pump start begins when the generator excitation field breaker of the motor-generator set is closed.

The RRS pump shaft seal assembly consists of two individual seals built into a cartridge or cartridges, which can be readily replaced without removing the motor from the pump. The seal assembly is designed to require minimum maintenance over a long period of time, regardless of whether the pump is stopped or is operating at various speeds, with water at various pressures and temperatures. Each individual seal in the cartridge is capable of sealing against pump design pressure so that any one seal can adequately limit leakage in the event that the other seal should fail. Reduced clearances in the pump casing reduce leakage in the event of a gross failure of both shaft seals. Leakage due to massive seal failure will remain insignificant as compared to the available makeup supply. Provision is made for monitoring the pressure drop across each individual seal as well as the cavity temperature of each seal. Provision is also made for piping the seal leakage to a flow measuring device.

The effective inertias of the RRS pump and motor, motor-generator set, and variable speed coupling are specified in the following form, which takes into account the torque and speed conditions on each rotating shaft.

$$\sum_{\substack{\text{ALL}\\\text{SHAFTS}}} \frac{\text{Inertia } (\text{lb}-\text{ft}^2) \text{x Speed (radian/sec)}}{\text{g} \left(\frac{\text{ft}}{\text{sec}^2}\right) \text{xTorque (ft}-\text{lb)}}$$

The design objective for the RRS pump is to provide a unit that will not require removal from the system for rework or overhaul at intervals of less than one operating cycle. Pump casing overhaul and valve bodies are designed for a 40-year operational life. The pump drive motor, impeller, and wear rings are designed for as long a life as is practical. Pump mechanical seal parts are expected to have a life exceeding one operating cycle to afford convenient replacement during refueling outages.

The RRS piping is of all-welded construction and is designed and constructed to meet the requirements of the ANSI B31.7 Nuclear Power Piping Code-1969, Class 1.

The RRS is designed as Category I. The pump is assumed to be filled with water for the analysis. Vibration snubbers located at the top of the motor and at the bottom of the pump casing are designed to resist the horizontal reactions.

The RRS piping, valves, and pumps are supported by hangers to avoid the use of piping expansion loops that would be required if the pumps were anchored. In addition, the RRS loops are provided with a system of restraints designed so that reaction forces associated with any split or circumferential break do not jeopardize containment integrity. This restraint system provides adequate clearance for normal thermal expansion movement of the loop. Because possible pipe movement is limited to slightly more than the clearance required for thermal expansion movement, no impact loading on limit stops is considered.

The RRS piping, valves, and pump casings are covered with thermal insulation having a total average heat transfer rate of 65 Btu/hr/ft^2 with the system at rated operating conditions.

The insulation is the all-metal reflective type and is prefabricated into components for field installation. Removable insulation is provided at various locations to permit periodic inspection of equipment and inservice inspection access to components (Subsection 5.2.3.3).

5.5.1.4 Safety Evaluation

RRS malfunctions that pose threats of damage to the fuel barrier are described and evaluated in Subsections 15.3.1 and 15.3.3. It is shown in Subsections 15.3.1 and 15.3.3 that none of the malfunctions, including pump trip or pump seizure, result in fuel damage.

The core flooding capability of the RRS and the core flooding capability of a jet pump design plant are discussed in detail in Reference 1.

Piping and pump design pressures for the RRS are based on peak steam pressure in the reactor dome, appropriate pump head allowances, and the elevation head above the lowest point in the RRS loop. Piping and related equipment pressure parts are chosen in accordance with applicable codes. Use of the applicable code design criteria listed in Tables 3.9-17, 3.9-18, 3.9-43, and 3.9-44 ensures that a system designed, built, and operated within design limits has an extremely low probability of failure caused by any known failure mechanism.

GE purchase specifications require that reactor coolant pressure boundary (RCPB) integrity of the pump case be maintained through all conditions. In addition, dynamic loads are transmitted by piping suspension system components attached to the motor. The parts of the pump and motor that withstand seismic loads as part of the piping suspension system are the pump lugs, pump case, bolting between the pump case and the motor stand, motor stand, bolts attaching the motor stand to the motor, motor frame and motor seismic lugs.

Analyses performed to determine if the RRS pump can become a missile indicate that, for the postulated full double-ended pipe break LOCA in the RRS pump suction line, destructive pump and motor overspeed could occur (Reference 2). In the event of motor failure, the motor stator and frame structure would prevent the release of any missiles. Given the postulated accident, RRS pump impeller destructive overspeed could occur. However, impeller missiles will not penetrate the pump case (Reference 3). Missiles could be ejected from the open end of the broken pipe. Analyses of the effects of missiles ejected from the broken pipe are contained in Reference 4. Additional piping restraints were added to prevent the potential missile exit points in the pipe from developing.

A comparison of break locations using the Fermi 2 recirculation piping stress report has confirmed that no unacceptable damage consequences can occur as a result of potential recirculation pump missiles.

The consequences of the loss-of-component cooling water to both the recirculation pumps have been evaluated. The cooling water is supplied from the reactor building closed cooling water (RBCCW) system during normal plant operation in all modes. Cooling water to the recirculation pump motors and seals is supplied through the divisional emergency equipment cooling water (EECW) system piping which is routed into the drywell from external supply and return flow tie-ins with RBCCW. Each pump is supplied through a different EECW piping division so that both pumps cannot simultaneously lose component cooling, except by closure of both divisions of the EECW supply line outboard isolation valves on an ECCS high drywell pressure signal. High drywell pressure would also cause a reactor protection system signal to initiate a reactor trip and to close the RRS pump seal purge supply flow drywell isolation valves.

If there were a gradual loss of cooling water to the pump motor, the following sequence of alarms would come into the control room.

a. Motor bearing oil cooling water discharge

b. Motor thrust bearing lower face

c. Motor thrust bearing upper face

d. Upper guide bearing

e. Motor windings

f. Lower guide bearing

A loss of RBCCW/EECW flow for pump seal cooling will also cause a low flow alarm to annunciate in the control room. Alarms would also come into the control room through the recirculation pump motor temperature recorder. As these alarms start to come in, the operator would respond by dropping the power level and changing the flow rates to minimize the transient in case it were to become necessary to trip the overheated pump. If the operator were to receive confirmation that the pump motor bearings or the pump seals were overheating, he would trip the pump.

On a sudden loss of cooling water to the pump motor, as could occur on high drywell pressure isolation of the EECW supply line, the motor bearings would begin to incur damage after 90 seconds of full speed operation. As the bearings fail, the pump motor trip would occur from an overcurrent protective relay opening when the loss of rotor stability causes the rotor to contact the stator. This would occur within 2 to 3 minutes from the loss of cooling.

The high drywell pressure isolation would also cause the secondary cooling supply to the pump shaft seals by the seal purge flow to be cut off. During the continued operation of the pump motor, the seals would be protected by the residual cooling capacity of the cooler. The bearing failure will not result in damage to the pump shaft seals due to the structural support of the motor and pump. Following the pump trip, seal cavity circulation would be lost and the seal cavity will gradually heat up. If cooling is restored within 10 to 15 minutes, the shaft seals will not be significantly damaged. However, the exposure to higher temperatures will shorten the operable life of the elastomereic components of the seals. If cooling cannot be restored, the resulting seal leakage rate would be 18 gpm loss of reactor coolant. This coolant loss rate is within the capacity of the normal operating and isolation mode plant makeup systems. The fuel thermal limits would not be exceeded and the seal leakage does not lead to further degradation of the RCPB barrier.

5.5.1.5 Inspection and Testing

Quality control (QC) methods are used during fabrication and assembly of the RRS to ensure that design specifications are met. The reactor coolant system is thoroughly cleaned and flushed before fuel is loaded initially.

Prior to the Preoperational Test Program, the RRS was given a hydrostatic test at 125 percent of RPV design pressure. Preoperational tests on the RRS were performed as described in Chapter 14.

During the Startup Test Program, horizontal and vertical motions of the RRS piping and equipment are observed, and supports are adjusted, as necessary, to ensure that components are free to move as designed. The NSSS responses to RRS pump trips at rated temperatures and pressure are evaluated during the startup tests, and plant power response to recirculation flow control is determined.

Inservice inspection, in accordance with ASME Boiler and Pressure Vessel (B&PV) Code Section XI, 1971 edition including winter 1971 addenda was considered in the design of the RRS to ensure adequate working space and access for inspection of selected components. The criteria for selecting the components and locations to be inspected are based on the probability of a defect occurring or enlarging at a given location, including areas of known stress concentrations and locations where cyclic strain or thermal stress might occur. The RRS pump casings, valve bodies, and piping connection welds are visually inspected and given other nondestructive inspections from at least one side on a periodic basis. The inservice inspection program is described in Section 5.2.8.

5.5.2 Steam Generators

The steam generators are not applicable to the BWR.

5.5.3 Reactor Coolant Piping

The RRS loops are shown in Figures 5.5-1 and 5.5-2. The design characteristics are presented in Table 5.5-1.

5.5.4 Main Steam Line Flow Restrictors

5.5.4.1 Safety Design Bases

The main steam line flow restrictors are designed

a. To limit the loss of coolant from the RPV following a steam line rupture outside the primary containment to the extent that the RPV water level does not fall below the top of the core within the time required to close the main steam isolation valves (MSIVs)

b. To withstand the maximum pressure difference expected across the restrictor, following complete severance of a main steam line.

5.5.4.2 Description

A main steam line flow restrictor is provided for each of the four main steam lines, as shown in Figure 5.5-4. The restrictor is a complete assembly welded into the main steam line. It is located between the RPV and the first MSIVs and is downstream of the main steam line safety/relief valves. The restrictor limits the coolant blowdown rate from the RPV in the event a main steam line break occurs outside the primary containment to the maximum (choke) flow specified. The restrictor assembly consists of a venturi-type nozzle insert welded, in accordance with applicable code requirements, into the main steam line. The restrictor assembly is self-draining in that it contains low point pockets which are drained internally to the main steam line. The flow restrictor is designed and fabricated to ANSI B31.7.

The flow restrictor has no moving parts. Its mechanical structure can withstand the velocities and forces associated with a main steam line break. The maximum differential pressure is ASME Code limit pressure. The rated capacity of the RPV pressure relieving devices shall be sufficient to prevent a rise in pressure within the protected vessel of more than 110 percent of the design pressure (1.10 x 1250 = 1375 psig).

The ratio of venturi throat diameter to steam line diameter, approximately 0.55, results in a maximum pressure differential of 10 psi at rated flow. This design limits the steam flow in a severed line to approximately 200 percent rated flow, yet it results in a negligible increase in steam moisture content during normal operation. The restrictor is also used to measure steam flow and to initiate closure of the MSIVs when the steam flow exceeds preselected operational limits.

5.5.4.3 Safety Evaluation

In the event a main steam line should break outside the primary containment, the critical flow phenomenon would restrict the steam flow rate in the venturi throat to 200 percent of the rated value. Prior to isolation valve closure, the total coolant losses from the RPV are not sufficient to cause core uncovering. Thus, the core is adequately cooled at all times. Analysis of the steam line rupture accident shows that the core remains covered with water and that the amount of radioactive materials released to the environs through the main steam line break does not exceed the guideline values of 10 CFR 100. This accident analysis is described in Chapter 15.

Tests on a scale model determined final design and performance characteristics of the flow restrictor. The characteristics include maximum flow rate of the restrictor corresponding to the accident conditions, irreversible losses under normal plant operating conditions, and discharge moisture level. The tests showed that flow restriction at critical throat velocities is stable and predictable.

If moisture forms in the nozzle throat due to a momentary large static pressure reduction, the droplets of wet steam would have to be at saturation temperature corresponding to throat static pressure. When proceeding to the downstream region where vapor temperatures are higher, the droplets of wet steam vaporize somewhat and reach equilibrium with vapor at a lower pressure. The moisture is reduced and actually is negligible. It has negligible corrosion effect on the highly corrosion-resistant material (A-351 stainless steel) used for the inlet and throat sections. High velocity steam also has negligible erosion effect on this material.

The steam flow restrictor is exposed to steam of 1/10 to 2/10 percent moisture flowing at velocities of 150 ft/sec (steam piping inside diameter) to 600 ft/sec (steam restrictor throat). ASTM-A351 (type 304) cast stainless steel was selected for the steam flow restrictor material because it has excellent resistance to erosion-corrosion in this environment.

5.5.4.4 Inspection and Testing

Because the flow restrictor forms a permanent part of the main steam line piping and has no moving components, no testing program is planned. Only very slow erosion will occur with time, and such a slight enlargement will have no safety significance. Stainless steel resistance to corrosion has been substantiated by turbine inspections at the Dresden Unit 1 facility, which have shown no noticeable effects from erosion on the stainless-steel nozzle partitions.

Calculations show that even if the erosion rates are as high as 0.004 in. per year, after 40 years of operation the increase in restrictor-choked flow rate will be no more than five percent (Refer to Appendix B for evaluation of 60 years). A five percent increase in the radiological dose calculated for the postulated main steam line break accident is not significant (Subsection 15.6.4).

5.5.5 Main Steam Line Isolation Valves

5.5.5.1 Safety Design Bases

The MSIVs, individually or collectively, meet the following safety design bases.

a. The MSIVs shall close the main steam lines within the time established by design-basis accident analysis to limit the release of reactor coolant

b. The MSIVs shall close the main steam lines slowly enough that simultaneous (inadvertent) closure of all steam lines will not exceed the NSSS design limits

c. The MSIVs shall close the main steam line when required, despite single failure in either valve or in the associated controls, to provide a high level of reliability for the safety function

d. The MSIVs shall use separate energy sources as the motive force to independently close the redundant isolation valves in the individual steam lines

e. The MSIVs shall use local stored energy (compressed air and springs) to close at least one isolation valve in each steam pipeline without relying on the continuity of any variety of electrical power to furnish the motive force to achieve closure

f. The MSIVs shall be able to close the steam lines, either during or after seismic loadings, to ensure isolation if the nuclear primary system is breached

g. The MSIVs shall have the capability for being tested, during normal operating conditions, to demonstrate that the valves will function.

5.5.5.2 Description

Two isolation valves are welded in a horizontal run of each of the four main steam pipes. One valve is as close as possible to the primary containment barrier and inside it, and the other is just outside the barrier. When closed, the valves form part of the nuclear system process barrier for openings outside the containment and part of the pressure barrier for nuclear system breaks inside the containment.

Figure 5.5-5 shows a typical MSIV, which does not necessarily reflect the actual detailed valve configuration utilized at Fermi 2. Each is a 26-in., Y-pattern, globe valve. Design steam flow rate through each valve is 3.72×10^6 lb/hr. The main disk or poppet is attached to the lower end of the stem. Normal steam flow tends to close the valve, and higher inlet pressure tends to hold the valve closed.

The bottom end of the valve stem closes a small pressure- balancing hole in the poppet. When the hole is open, it acts as a pilot valve to relieve differential pressure forces on the poppet. Valve stem travel is sufficient to give flow areas past the wide open poppet approximately equal to the seat port area. The poppet travels approximately 90 percent of the valve stem travel; approximately the last 10 percent of travel closes the pilot hole. The air cylinder can open the poppet with a maximum differential pressure of 200 psi across the isolation valve in a direction that tends to hold the valve closed.

A 45° angle permits the inlet and outlet passages to be stream-lined. This minimizes pressure drop during normal steam flow and helps prevent debris blockage. The pressure drop at rated flow is approximately 7 psi. The valve stem penetrates the valve bonnet through a stuffing box utilizing a live-loading configuration and graphite packing to help prevent leakage through the stem packing. The live-loading configuration consists of Belleville disc springs installed on the packing gland studs and the packing gland plate. This creates additional elasticity to the loading of the stuffing box packing. When the gland stud nuts are tightened to load the packing, the disc springs are compressed. As the packing consolidates inservice, the springs expand to maintain a relatively constant load on the packing providing a continual inservice adjustment.

Attached to the upper end of the stem is an air cylinder that opens and closes the valve and a hydraulic dashpot that controls its speed. The speed is adjusted by a valve in the hydraulic return line bypassing the dashpot piston. Valve closing time is adjustable to between 3 and 10 sec.

The air cylinder is supported on the valve bonnet by actuator support and spring guide shafts. Helical springs around the spring guide shafts with air pressure from either normal or accumulator sources are required together to close the valve.

The motion of the spring seat member actuates switches at fully open, 90 percent open and fully closed valve positions.

The valve is operated by pneumatic pressure and by the action of compressed springs. The control unit is attached to the air cylinder. This unit contains three types of control valves: pneumatic, ac, and dc. These control valves open and close the main valve and exercise it at slow and fast speed. Remote manual switches in the main control room enable the operator to operate the valves.

Operating air is supplied to the outboard valves from the plant interruptible control air system via accumulators protected by check valves. The accumulator tank between the control valve and the check valve provides a pneumatic reserve for the closing of each valve. Each valve is designed to accommodate saturated steam at 1250 psig and 575°F, with a moisture content of approximately 0.23 percent, an oxygen content of 30 ppm, and a hydrogen content of four ppm.

In the "worst case" condition of the main steam line rupturing downstream of the valve, steam flow would quickly increase to 200 percent of rated flow. Further increase is prevented by the venturi flow restrictor upstream of the valves.

During approximately the first 75 percent of closing, the valve has little effect on flow reduction because the flow is choked by the venturi restrictor upstream of the valves. After the valve is approximately 75 percent closed, flow is reduced as a function of the valve area versus travel characteristic.

The design objective for the valves is a minimum of 40 years of service at the specified operating conditions. Operating cycles are estimated to be 120 startup cycles, 120 shutdown cycles, and 180 scram cycles in the expected 40-year plant life. The valves shall be capable of actuating a minimum of 50 full cycles per year. The result of an updated evaluation for 60 years of projected cycles is contained in Reference 11.

In addition to minimum wall thickness required by applicable codes, a corrosion allowance of 0.120-in. minimum is added to provide for 40 years of service.

Design specification ambient conditions for normal plant operation are 135°F normal temperature, 150°F maximum temperature, 100 percent humidity, in a radiation field of 15 rads per hour due to radiation gamma and 25 rads per hour due to neutron plus gamma radiation, continuous for design life. The inside valves are not continuously exposed to maximum conditions, particularly during reactor shutdown, and valves outside the primary containment and shielding are in ambient conditions that are considerably less severe.

In addition, they are designed to close and remain closed under the post accident environment conditions listed in Table 3.11-1.

To sufficiently resist the response motion from the safe-shutdown earthquake (SSE), the MSIV installations are designed as Category I equipment. The valve assembly is manufactured to withstand the design-basis forces applied at the mass center, assuming the cylinder/spring operator is cantilevered from the valve body and the valve is located in a horizontal run of pipe. The stresses caused by horizontal and vertical forces are assumed to act simultaneously and are added directly. The stresses in the actuator supports caused by loads are combined with the stresses caused by other live and dead loads, including the operating loads. The allowable stress for this combination of loads is based on the ordinary allowable stress set forth in applicable codes. The parts of the MSIVs that constitute a process fluid pressure boundary are designed, fabricated, inspected, and tested as required by the ASME Nuclear Pump and Valve Code.

5.5.5.3 Safety Evaluation

In a direct cycle nuclear power plant, the reactor steam goes to the turbine and to other equipment outside the reactor containments. Radioactive materials in the steam are released to the environs through process openings in the steam system or they escape from accidental openings. A large break in the steam system can drain the water from the reactor core faster than it is replaced by feedwater.

The analysis of a complete, sudden steam line break outside the primary containment is described in Subsection 15.6.4. The analysis shows that the fuel barrier is protected against loss of cooling if MSIV closure takes 10.5 sec or less. This 10.5 sec limitation includes as much as 0.5 sec for the instrumentation to initiate valve closure after the break. The calculated radiological time effects of the radioactive material assumed to be released with the steam are shown to be well within the guideline values for such an accident.

The shortest closing time, approximately 3 sec, of the MSIVs is also shown in Subsection 15.2.4 to be satisfactory. The switches on the valves initiate reactor scram when several valves are more than 10 percent closed. The pressure rise in the system from stored and decay heat may cause the NSSS relief valves to open briefly, but the rise in fuel cladding temperature will be insignificant. No fuel damage results.

The ability of this 45°, Y-design globe valve to close in a few seconds after a steam line break, under conditions of high pressure differentials and fluid flows with fluid mixtures ranging from mostly steam to mostly water, has been demonstrated in a series of tests in dynamic test facilities. Dynamic tests with a 1-in. valve show that the analytical method is valid. A fullsize, 20-in. valve was tested in a range of steam-water blowdown conditions simulating postulated accident conditions (Reference 5).

The following specified hydrostatic, leakage, and stroking tests, as a minimum, are performed by the valve manufacturer in shop tests:

a. To verify its capability to close between 3 and 10 sec, each valve is tested at pressure (1000 psig) and no flow. The valve is stroked several times, and the closing time is recorded. The valve test logic closes the valve by spring only then the combination of air cylinder and springs. Usually the closing time is slightly greater when closure is by springs only

b. Leakage is measured with the valve seated. The specified maximum seat leakage, using cold water at design pressure, is 2 cm^3/hr/in. of nominal valve size. In addition, an air seat leakage test is conducted using 50 psi pressure upstream. Maximum permissible leakage is 0.1 scfh per inch of nominal valve size. The valve stem is operated a minimum of three times from the closed position to the open position, and the packing leakage must still be zero by visual examination

c. Each valve is hydrostatically tested in accordance with the requirements of the ASME Nuclear Pump and Valve Code. During valve fabrication, extensive nondestructive tests and examinations are conducted. Tests include radiographic, liquid penetrant, or magnetic particle examinations of casting, forgings, welds, hardfacings, and bolts

d. The spring guides, the guiding of the spring seat member on the support shafts, and rigid attachment of the seat member ensure correct alignment of the actuating components. Binding of the valve poppet in the internal guides is prevented by making the poppet in the form of a cylinder longer than its diameter and by applying stem force near the bottom of the poppet.

After the valves are installed in the NSSS, each valve is tested several times in accordance with the Preoperational and Startup Test procedures. Two isolation valves provide redundancy in each steam line so that either can perform the isolation function, and either can be tested for leakage after the other is closed. The inside valve, the outside valve, and their respective control systems are separated physically.

The isolation valves and their installation are designed as Category I equipment. The design of the isolation valve has been analyzed for earthquake loading. These loads are small compared with the pressure and operating loads that the valve components are designed to withstand. The cantilevered support of the air cylinder, hydraulic cylinder, springs, and controls is the key area. The increase in loading caused by the specified earthquake loading is negligible at the joints between the support shafts and the valve bonnet.

Electrical equipment that is associated with the isolation valves and operates in an accident environment is limited to the wiring, solenoid valves, and position switches on the isolation valves. The expected containment pressure and temperature transient following an accident is discussed in Section 6.2.

5.5.5.4 Inspection and Testing

Inspection and testing of the MSIVs will be conducted periodically in accordance with the Technical Specifications. Additional information on MSIV testing is contained in Subsection 6.2.6.4.

5.5.6 Reactor Core Isolation Cooling System

5.5.6.1 Safety Design Bases

The RCIC system meets the following safety design bases.

a. The system shall ensure that adequate core cooling takes place to prevent the reactor fuel from overheating in the event the reactor isolation is accompanied by loss of flow from the reactor feedwater system

b. The system shall operate automatically in time to maintain sufficient coolant in the RPV so that the integrity of the radioactive material barrier is not compromised

c. Piping and equipment, including support structures, shall be designed to withstand the effects of an earthquake without a failure that could lead to a release of radioactivity in excess of the guideline values in published regulations.

5.5.6.2 Power Generation Design Bases

The RCIC system meets the following power generation design bases.

a. The system shall operate automatically in time to maintain sufficient coolant in the RPV so that the low-pressure core standby cooling systems (low-pressure coolant injection [LPCI] and core spray systems) are not actuated

b. Design shall provide for remote-manual operation of the system by an operator

c. To provide a high degree of assurance that the system shall operate when necessary

   1. The power supply for the system shall be from immediately available energy sources of high reliability

   2. Design shall provide for periodic testing during plant operation.

5.5.6.2.1 Equipment and Component Description-Design Conditions

Operating parameters for the components of the RCIC system are shown in Figure 5.5-6. The RCIC components are the following.

a. One 100 percent-capacity turbine and accessories

b. One 100 percent-capacity pump assembly and accessories

c. Piping, valves, and instrumentation for

   1. Steam supply to the turbine

   2. Turbine exhaust to the suppression pool

   3. Makeup supply from the condensate storage tank to the pump suction

   4. Makeup supply from the suppression pool to the pump suction

   5. Pump discharge to the feedwater line, including a test line to the condensate storage tank, a minimum flow bypass line to the suppression pool, and a coolant water supply to accessory equipment.

The design conditions are from the ASME Section III, Nuclear Power Plant Components.

5.5.6.2.2 Design Parameters

Design parameters for the RCIC system components are listed below. See Figure 5.5-7 for cross-reference of component numbers.

1. <u>RCIC Pump Operation (C001)</u>

Flow rate	Injection flow, 600 gpm Cooling water flow, 16 gpm Total pump discharge, 616 gpm
Water temperature range	40°F to 140°F
NPSH	20 ft minimum
Developed head pressure	2915 ft at 1184-psia reactor pressure 525 ft at 165-psia reactor pressure
BHP, not to exceed	700 HP at 2915-ft developed head 100 HP at 525-ft developed head
Design pressure	1515 psia
Design ambient	148°F, maximum (Actual conditions to which this equipment is environmentally qualified under the Fermi 2 EQ program are documented in EQ0-EF2-018.)

2. <u>RCIC Turbine Operation (C002)</u>

	High-Pressure Condition	Low-Pressure Condition
Reactor pressure (saturated temperature)	1184 psia	165 psia
Steam inlet pressure	1169 psia, minimum	150 psia, minimum
Turbine exhaust pressure	25 psia, maximum	25 psia, maximum
Design inlet pressure	1250 psig at saturated temperature	
Design exhaust pressure	165 psig at saturation temperature	

3. <u>RCIC Orifice Sizing</u>

Coolant loop orifice (D009)	Sized with piping arrangement to ensure maximum pressure of 75 psia at the lube-oil cooler inlet and a minimum pressure of 45 psia at the spray nozzles at the barometric condenser.
Minimum flow orifice	Sized with piping arrangement to ensure minimum flow of 75 gpm with MO-F019 fully open.
Test return orifice (D006)	Sized with piping arrangement and drag valve E41-F011 to simulate pump discharge pressure required when the RCIC system is injecting design flow with the reactor vessel pressure at 165 psia.

Leak-off orifices (D008 and D010)	Sized for 1/8-in. diameter minimum; 3/16-in. diameter maximum.
Warm-up bypass orifice (D011)	Sized at 5/16-in. to insure sufficient steam supply to spin the turbine.

4. Valve Operation Requirements

Steam warm-up bypass valve (F095)	Open and/or close against 1169 psid pressure within 10 sec.
Steam supply valve (F045)	Open and/or close against maximum expected differential pressure within 45 sec.
Pump discharge valve (F013)	Open and/or close against maximum expected differential pressure within 30 sec.
Pump minimum flow bypass valve (F019)	Open and/or close against 1296 psid pressure within 25 sec.
Steam supply isolation valves (F007 and F008)	Close against maximum expected differential pressure within 15 sec.
Cooling water relief valve (F018)	Sized to prevent over-pressurizing piping, valves, and equipmentin the coolant loop in the event of failure of pressure control valve F015.
Pump discharge out-board isolation valve (F012)	Open against 1000 psid pressure within 15 sec (valve normally open and deenergized).
Pump test return valve (F022)	Capable of open and/or close against 1000 psi differential pressure.
Relief valve barometric condenser (F033)	Relief valve is capable of retiaing 10 in. of mercury vacuum at 140°F ambient, with a set pressure of 5 to 7 psig and flow of 20 gpm at 25 percent accumulation.
Turbine Exhaust isolation valve (F001)	Opens and/or closes against 50 psi differential pressure at a temperature of 267°F. Physically located as close to the containment as practical.
Vacuum pump discharge isolation (F002)	Opens and/or closes against 50 psi differential pressure at a temperature of 267°F. Physically located as close to the containment as practical.
Check valve turbine exhaust (F040)	Located at a high point in the line on a horizontal run, with adjacent piping arranged to provide a continuous downward slope, form the upstream side of the check valve to the turbine exhaust drain pot.

Vacuum breaker isolation valves (F062 and F084)	Open and/or close against a differential pressure of 50 psi.
Vacuum breaker check valves (F063 and F064)	Open with a minmum pressure drop (less than or equal to 0.5 psi) across the valve seat.

5. Rupture Disk Assemblies (D001 and D002)

Used for turbine casing protection; includes a mated vacuum support to prevent rupture disk reversing under vacuum conditions.

Rupture pressure	150 psig ± 10 psig
Flow capacity	60,000 lb/hr at 165 psig

6. Condensate Storage Requirements

150,000 gap (Total reserve storage for both HPCI and RCIC systems, see Section 6.3.2.6.)

7. Piping RCIC Water Temperature

The maximum water temperature range for continuous system operation does not exceed 140°F. However, due to potential short-term operation at higher temperatures, piping expansion calculations were based on 170°F.

8. Turbine Exhaust Vertical Reaction Force

Unbalanced pressure due to discharge under the suppression pool water level is described in Reference 6.

9. Ambient Condition

	Temperature	Relative Humidity
Normal plant operation	60° to 100°F	95 percent
Isolation conditions	148°F	100 percent

5.5.6.3 Description

5.5.6.3.1 General

The RCIC system consists of a steam-driven turbine-pump unit and associated valves and piping capable of delivering makeup water to the RPV. A schematic diagram is shown in Figure 5.5-7 and Figure 5.5-8. Logic diagrams are provided in Figure 7.4-1, Sheets 1 through 6.

The pump discharges either to the feedwater line or to a full flow test return line to the condensate storage tank. The discharge lines are full of water and remain flooded because they are connected to the feedwater line. The lines upstream of the normally closed HPCI and RCIC injection valves are kept full due to the static head provided by the condensate storage tank. The elevation of the injection valves is lower than the low level of the condensate storage tank, providing the static head. A minimum flow bypass line to the suppression pool is provided to protect the pump during startup and shutdown. The makeup water is delivered into the RPV through the feedwater line. Cooling water for the RCIC turbine lube-oil cooler and barometric condenser is supplied from the discharge of the pump, as shown in Figure 5.5-7.

Following any reactor shutdown, steam generation continues because of heat produced by the radioactive decay of fission products. Initially, the rate of steam generation can be as much as approximately 6 percent of rated flow and is augmented during the first few seconds by delayed neutrons and some of the residual energy stored in the fuel. Steam normally flows to the main condenser through the turbine bypass or, if the condenser is isolated, to the suppression pool. The fluid removed from the RPV is normally made up by the feedwater pumps supplemented by cooling water flow from the CRD system. If makeup water is required to supplement these primary sources of water, the RCIC turbine-pump unit starts automatically on receipt of a RPV low water level (L2) signal (Figure 7.4-1) or is started by the operator from the main control room. The RCIC delivers its design flow within 50 sec after actuation.

The RCIC makeup capacity is sufficient to avoid the need for the ECCS. Pump suction is usually lined up to the condensate storage tank but is automatically switched to the suppression pool on low condensate storage tank level. See Subsection 5.5.6.3.3.

Based upon normal condensate storage tank level of greater than 11’-0”, the volume of water stored for the RCIC (140,000 gal) is sufficient to allow operation for 8 hr after shutdown, assuming that none of the steam generated in the RPV is returned to the RPV as condensate. Other systems that use the condensate storage tank and could jeopardize the availability of this quantity of water can be isolated. However, manual actions are not required to protect the condensate storage tank inventory since, upon low level, RCIC suction is automatically transferred to the safety-related water source which is the suppression pool.

The RCIC system is sized to prevent actuation of the low level signal (L1) for RPV isolation incidents. Prevention of this signal ensures core cooling and prevents ADS actuation, thus preventing inadvertent blowdown of the RPV for this situation.

Quantitative information on steam and delivery water conditions is provided in Figure 5.5-6 for all operating modes of the RCIC system.

The backup supply of cooling water for the RCIC is the suppression pool. The turbine pump assembly is located below the level of the condensate storage tank and below the minimum water level in the suppression pool to ensure positive suction head to the pump.

All components required for initiating the RCIC are completely independent of auxiliary ac power, plant service air, and external cooling water systems. These components require only power derived from the station battery to operate the valves and logic. The power source for the turbine-pump unit is the steam generated in the RPV by the decay heat in the core. The steam is piped directly to the turbine, and the turbine exhaust is piped to the suppression pool.

Throughout the period of RCIC operation, the exhaust from the RCIC turbine is condensed in the suppression pool, which results in a slow temperature rise of approximately 3°F per hour in the pool. One RHR heat exchanger can be used to cool the suppression pool, if necessary. If for any reason the RCIC is unable to supply sufficient flow for core cooling, the emergency core cooling system (ECCS) provides the required boundary protection. A further discussion of this is found in Section 6.3.

The RCIC turbine-pump unit is located in a shielded area to ensure that personnel access areas are not restricted during RCIC operation. The turbine controls provide for automatic shutdown of the RCIC turbine on receipt of the following signals

a. RPV high water level - indicates that core cooling requirements are satisfied

b. Turbine overspeed - prevents damage to the turbine and turbine casing

c. Pump low suction pressure - prevents damage to the turbine pump unit that results from loss of cooling water

d. Turbine high exhaust pressure - indicates turbine or turbine control malfunction

e. System isolation signal - indicates need to shut down equipment.

Because the steam supply line to the RCIC turbine is a pressure containment boundary, certain signals automatically isolate this line and cause shutdown of the RCIC turbine.

The RCIC turbine has a speed governor that is positioned by the demand signal from the flow controller. Maximum output from the controller corresponds to maximum turbine speed.

The RCIC system may provide the ability to mitigate the consequences of small pipe breaks, but it is not provided primarily for such purpose. The ECCS provides redundant protection for the entire spectrum of pipe breaks. For small breaks this protection would be provided by HPCI and automatic depressurization.

Both the RCIC and HPCI systems provide decay heat removal capability when the main condenser is unavailable (i.e., isolated from the nuclear system) for heat sink purposes. The HPCI is a subsystem of the ECCS; however, the RCIC is not a subsystem of the ECCS.

Long-term heat removal capability may be provided by the RCIC or HPCI during the following operational events: scram, pressure relief, core cooling, RPV isolation, and restoration of ac power. The RHR system may be used for long-term heat removal during any long-term isolation. These events are all situations in which the RPV is isolated from the main condenser. None of these events are pipe break (loss of coolant) situations requiring immediate reactor water level restoration.

To ensure HPCI or RCIC system availability for the operational events noted previously, certain design considerations are used in the design of both systems.

5.5.6.3.2 Reactor Core Isolation Cooling Following Main Condenser Isolation (See Figure 5.5-9)

A reactor shutdown is accompanied by the isolation of the main condenser from the reactor vessel; the fission product decay heat results in an increase in the reactor vessel pressure. The pressure increase is limited by or manual operation of the relief valves, which serve to dump steam to the suppression pool. In the event the feedwater pumps and control rod drive leakage cannot provide sufficient water to make up for that lost by the steam dumping, the RCIC begins to operate by either a low reactor water signal or a manual start. For normal operation, the RCIC turbine-driven pump takes water from the condensate storage tank and injects it into the feedwater line. The steam supply for the RCIC turbine is from a main steam line using decay-heat-generated steam; exhaust is to the suppression pool. During RCIC operation, the desired reactor vessel pressure is maintained by manual control of the relief valves.

When RCIC is initiated, automatic actions will take place as described in Subsections 5.5.6.3.6 and 5.5.6.7. Also for RCIC operation, the turbine control system must function properly and there can be no turbine trip signals present. The RCIC can deliver its design flow within 50 sec of the initiation signal. Based on normal condensate storage tank level of greater than 11’-0”, the volume of water stored in the condensate storage tank for the RCIC (135,000 gal) is sufficient to allow operation of the RCIC for 8 hr after a shutdown. After this time, the system is sufficiently depressurized to allow the shutdown cooling mode of the RHR system to operate. The flow rate of water from the RCIC pump to the reactor vessel is 600 gpm, which is approximately equal to the reactor water boiloff rate 15 minutes after shutdown. This flow rate is sufficient to prevent the reactor vessel water level from dropping down to the top of the core.

5.5.6.3.3 Reactor Core Isolation Cooling Backup Mode (See Figure 5.5-10)

The RCIC can also take water from the suppression pool if the condensate storage tank level becomes too low. Transfer of the pump suction to the suppression pool is an automatic operation which follows the receipt of a low level signal from the condensate storage tank. The transfer requires the opening of normally closed valves (E51) F029 and (E51) F031 located in the pump suction line to the suppression pool. The opening of these valves causes the automatic closure of (E51) F010 located in the pump suction line leading to the condensate storage tank. Panel status information is provided for the operator in the form of valve position indication and an alarm if the operator closes either suppression pool suction valve while the condensate storage tank level is low.

5.5.6.3.4 Reactor Core Isolation Cooling Test Flow Mode (See Figure 5.5-11)

The RCIC system is designed commensurate with the safety importance of the system and its equipment. Each component is individually tested to confirm compliance with system requirements. The system as a whole is tested during both the startup and preoperational phases of the plant to set a base mark for system reliability. To confirm that the system maintains this mark, functional and operability testing is performed at predetermined intervals throughout the life of the reactor plant.

A design flow functional test of the RCIC system may be performed during normal plant operation by drawing suction from the condensate storage tank and discharging through a full flow test return line to the condensate storage tank. The discharge valve to the feedwater line remains closed during the test, and reactor operation remains undisturbed. All components of the RCIC system are capable of individual functional testing during normal plant operation. System control provides automatic return from test to operating mode if system initiation is required. There are three exceptions:

a. Auto/manual initiation on the flow controller. This feature is required for operator flexibility during system operation

b. Steam inboard/outboard isolation valves. The closing of either or both of these valves requires operator action to properly sequence their opening. An alarm sounds when the controls for either of these valves is operated to direct the valves to close

c. Other parts of the system that have been bypassed or deliberately rendered inoperable. These shall be indicated in the control room at the system level.

5.5.6.3.5 Reactor Core Isolation Cooling Minimum Flow Mode (See Figure 5.5-12)

A minimum flow bypass line is provided for protection of the RCIC pump. A flowmeter in the pump discharge line provides a signal for initiating the minimum flow mode for low flow and stopping its operation for a sufficient flow. Pump discharge pressure also must be sensed by PS N020 to allow minimum flow bypass valve F019 to open.

5.5.6.3.6 Auxiliary Heat Removal Operation

If the main feedwater system is not operable, a reactor scram will automatically be initiated when reactor water level falls to Level 3. Reactor water level will continue to decrease from boil-off until the low-low-level setpoint, Level 2, is reached. At this point, the HPCI system and the RCIC system will be automatically initiated to supply makeup water to the reactor pressure vessel. These systems will continue automatic injection until the reactor water level reaches Level 8, at which time the HPCI and RCIC turbines are tripped. These systems (HPCI/RCIC) will restart automatically once the high-level trip signal clears and a low-low-level (Level 2) signal is received.

The RCIC system will start automatically upon receipt of the initiation signal from the reactor vessel low-water-level sensor. During startup from standby, the following events occur automatically. (See Figure 7.4-1.)

a. Turbine speed control given to RCIC system flow indicator controller

b. RCIC test bypass valve to condensate storage tank closes (if open)

c. Steam supply valves to turbine open

d. Barometric condenser condensate pump discharge isolation valve closes

e. Pump discharge valve to feedwater line opens

f. Barometric condenser vacuum pump starts

g. Cooling water supply valve to lube oil cooler opens.

The turbine starts as soon as the steam supply valve opens, since the turbine trip throttle valve and control valve are open. The minimum flow bypass valve to suppression pool opens when pump discharge pressure increases. System flow starts when pump discharge pressure exceeds feedwater line pressure. As pump discharge pressure and steam inlet pressure change, the control signal adjusts the turbine to maintain constant pump flow. When pump flow reaches a prescribed value, the minimum flow bypass valve closes.

On occurrence of a low water level in the condensate storage tank, the suction to the RCIC pump changes automatically from condensate storage tank to the suppression pool.

The operator can switch the flow controller to the manual position and decrease flow rate to stabilize the water level in the reactor vessel. This would be done before reaching the high-water-level isolation. Even if the operator does not manually take control and the RCIC trips on high level, the RCIC will restart automatically once the high-water-level isolation signal clears and a Level 2 low-low-water-level signal is received.

The following sequence of events occurs in the case of an automatic initiation of the HPCI system (see Figure 7.3-2).

a. Steam supply outboard isolation valve opens

b. HPCI suction valve from condensate storage opens (if closed)

c. HPCI pump discharge inboard and outboard isolation opens

d. deleted

e. HPCI steam inlet valve opens

f. HPCI lube-oil cooling water supply valve opens

g. HPCI auxiliary oil pump starts

h. HPCI condenser vacuum pump starts (if initiation is by Level 2 low-low-water-level signal only)

i. HPCI test return valves close (if open).

With the turbine stop valve and control valves open, steam is admitted to the turbine, accelerating it quickly to speed.

On the occurrence of either a low water level in the condensate storage tank or a high level in the suppression pool, the suction valve to the HPCI pump changes over from condensate storage tank to the suppression pool.

The operator can switch the flow controller to the manual position and decrease flow rate to stabilize the water level in the reactor vessel. This would be done before reaching the high-water-level isolation. Even if the operator does not manually take control and the HPCI trips on high level, the HPCI will restart automatically once the high-water-level isolation signal clears and a Level 2 low-low-water-level signal is received.

For the loss-of-feedwater transient, the HPCI/RCIC systems are used to automatically provide the required makeup flow. No manual operations are required.

With the MSIVs closed, reactor pressure may rise to the setpoint of the safety/relief valves that will operate to reduce reactor pressure.

The heat added to the suppression pool from the operation of the safety/relief valves and the RCIC and HPCI systems will cause the suppression pool to heat up. As the average temperature of the suppression pool rises, the operator will initiate the suppression pool cooling mode of the residual heat removal (RHR) system to reduce this temperature before reaching the Technical Specifications limit.

Reactor vessel heat removal may also be accomplished through the manual actuation of any of the 15 safety/relief valves. In the event that reactor vessel pressure reduction and heat removal is required through safety/relief valve operation, the remote actuation of the safety/relief valves is available and would be used in conjunction with the suppression pool cooling mode of the RHR system. The operator actions necessary to place the RHR system in the suppression cooling mode emergency operations are as follows:

a. Verify RHR and RHRSW systems are in Standby condition
b. Open the associated RHR Torus Isolation Valve
c. Start the associated RHR pump
d. Throttle open the associated RHR Torus Cooling Isolation Valve
e. Start the associated RHRSW Pumps
f. Throttle the associated RHR HX Bypass and RHR HX Outlet Valves to control cooldown rate.

With the RHR system in the suppression pool cooling mode, the operator may actuate the required safety/relief valves while maintaining the required suppression pool temperature and heat distribution limits.

During this mode of operation, the automatic depressurization system remains fully operational and will automatically initiate if the conditions necessary for automatic depressurization should occur.

5.5.6.3.7 Physical Independence

The RCIC and HPCI systems are located in separate rooms in different corners of the reactor building. Piping runs are separated and the water delivered from each system enters the RPV via different nozzles.

5.5.6.3.8 Control Independence

Control independence is secured by using different battery systems to provide control power to the RCIC and HPCI systems.

5.5.6.3.9 Environmental Independence

The RCIC and HPCI systems are designed to meet Category I requirements. Environment in the equipment rooms is maintained by separate auxiliary systems.

5.5.6.4 Safety Evaluation

To ensure that the RCIC operates when necessary and in time to prevent inadequate core cooling, the power supply for the system is taken from immediately available energy sources of high reliability. Added assurance is given in the capability for periodic testing during station operation. Evaluation of the instrumentation configuration for the RCIC shows that no failure of a single initiating sensor either prevents or falsely starts the system.

The RCIC piping within the drywell up to and including the outer isolation valve is designed in accordance with ASME B&PV Code Section III. The RCIC, including the RCIC turbine speed control system, is also designed as Category I equipment. (See Subsection 7.3.2 for isolation signals.)

5.5.6.5 Inspection and Testing

A design flow functional test of the RCIC is performed during plant operation by taking suction from the condensate storage tank and discharging through the full flow test return line back to the condensate storage tank. The discharge valve to the feedwater line remains closed during the test, and reactor operation is undisturbed. Control of the pump discharge valve is obtained by first closing the upstream discharge valve. Control system design provides automatic return from test to operating mode when system operation is required during testing. Routine maintenance and tests, based on the manufacturer's recommendations and/or operating/maintenance experience, will be scheduled in accordance with the plant preventive maintenance program, including periodic inspection of the RCIC suppression pool suction strainer. Valve position indication and instrumentation alarms are displayed in the main control room.

5.5.6.6 Isolation

Arrangements of isolation valves include the following.

a. Two RCIC lines penetrate the reactor coolant pressure boundary. The first RCIC line is the RCIC steam line that branches off one of the main steam lines between the reactor vessel and the main steam isolation valve. This line has two automatic motor-operated isolation valves. One is located inside and the other outside the primary containment. The isolation signals noted earlier close these valves

b. The RCIC pump discharge line is the other line; however, it indirectly penetrates the reactor pressure vessel. This line enters the main feedwater line, described elsewhere, which provides required isolation valves inside the primary containment. The RCIC system provides the automatic motor-operated valve outside the primary containment for isolation

c. The RCIC turbine exhaust line vacuum breaker system line has two automatic motor-operated valves and two check valves. This line runs between the suppression pool air space and the turbine exhaust line downstream of the exhaust line check valve. Positive isolation shall be automatic via a combination of low reactor pressure and high drywell pressure

   The vacuum breaker valve complex is placed outside the primary containment due to a more desirable environment. In addition, the valves are readily accessible for maintenance and testing

d. The RCIC pump suction line, minimum flow pump discharge line, and turbine exhaust line all penetrate the primary containment and are submerged in the suppression pool. The isolation valves for the lines are all outside the primary containment and require remote-manual operation, except for the minimum flow valves, which actuate automatically. Additionally, the turbine gland seal system vacuum pump discharges beneath the suppression pool after penetrating the primary containment. The isolation valve for the line is located outside the primary containment and requires remote-manual operation.

5.5.6.7 Interlocks

The following define the various electrical interlocks (see Figure 7.4-1).

a. The steam line isolation valves, F007 and F008, are keylocked in the open position. The valves can still automatically close on a steam line isolation signal, but can be manually operated only when the keylock is placed in the "operate" position

b. The F029 and F031 limit switches activate when fully open, and close F010 and F022

c. The F001 limit switch activates when fully open, and clears the F045 and the F095 permissives so both F045 and F095 can open. The F045 and F095 valves are signaled to close if F001 moves to a position other than fully open

d. The F045 limit switch activates when fully closed and permits F004, F005, F025, and F026 to open, and closes F013 and F019

e. The turbine trip throttle valve (part of C002) limit switch activates when fully closed and closes F013 and F019

f. The combined pressure switches at reactor low pressure and high drywell pressure, when activated, close F062 and F084

g. A high turbine exhaust pressure, low pump suction pressure, or an isolation signal actuates and closes the turbine trip throttle valve

h. A 122.3 percent overspeed trips both the mechanical trip at the turbine and the trip throttle valve. The former is reset at the turbine and then the latter is reset by a combination of control room and local (near the RCIC skid) operator action

i. An isolation signal closes F007, F008, and other valves as noted above in Items e. and g

j. An initiation signal opens F010 and F012 if closed; opens F095, F045, F046, and F013 and starts the barometric condenser vacuum pump; and closes F022, if open. Drain isolation valves F004, F005, F025, and F026 will close automatically on receipt of F045 limit switch "not full closed" signal

k. High and low inlet RCIC steam line drain pot levels, respectively, open and close F054

l. The combined signal of low pump flow plus high pump discharge pressure opens F019. The F019 valve closes on a pump flow signal above the minimum flow setpoint

m. A reactor low water level (Level 1) or high drywell pressure signal trips the barometric condenser condensate and vacuum pumps

n. The F013 limit switch activates when not full closed and closes F022 and prevents F022 from opening

o. CST low level signal opens F029 and F031.

5.5.6.8 Limiting Single Failure

The most limiting single failure of the RCIC system and its HPCI backup system is the failure of HPCI. With an HPCI failure, if the capacity of the RCIC system is adequate to maintain reactor water level, the operator follows Subsection 5.5.6.3.2. If, however, the RCIC capacity is inadequate, the operator may also initiate the ADS system described in Subsection 6.3.2.2.2.

5.5.7 Residual Heat Removal System

5.5.7.1 Safety Design Bases

The RHR system meets the following safety design bases.

a. The system shall act automatically, in combination with other subsystems of the ECCS, to restore and maintain the coolant inventory in the RPV so that the core is adequately cooled to preclude fuel cladding temperatures from exceeding the acceptance criteria temperature of 2200°F following a design basis LOCA

b. The system, in conjunction with other subsystems of the ECCS, shall have such diversity and redundancy that only a highly improbable combination of events could result in the inability to adequately cool the core

c. The source of water for restoring RPV coolant inventory shall be so located within the primary containment as to establish a closed cooling water path

d. To ensure that the RHR system operates satisfactorily during a LOCA, each active component shall be testable during operation of the NSSS

e. A closed loop flow path between the suppression pool and the RHR heat exchangers shall be established so that the heat removal capability of these heat exchangers can be utilized for long-term containment heat removal.

See Subsection 3.1.2.4.5 for a discussion of conformance to General Design Criteria (GDC) 34. The RHR system design conforms to the single-failure requirement of GDC 34.

5.5.7.2 Power Generation Design Bases

The RHR system is designed to meet the following power generation design bases.

a. The system shall have enough heat removal capacity to cool down the reactor to 125°F within 20 hr after shutdown

b. Fuel pool connections shall be provided so that the RHR heat exchangers can be used to supplement the fuel pool cooling capacity

c. A closed loop flow path between the suppression pool and the RHR heat exchangers shall be established so that the heat removal capability of these heat exchangers can be used to cool the suppression pool.

5.5.7.3 Description

5.5.7.3.1 Summary

The RHR system is designed for three modes of operation to satisfy all the objectives and bases. To provide clarity to the information presented herein, each mode of operation is defined as a subsystem of the RHR system and is discussed separately. It is shown how each subsystem contributes toward satisfying all the objectives and bases of the RHR system.

The major equipment of the RHR system consists of two heat exchangers, four main system pumps, and four service water pumps. The equipment is connected by associated valves and piping, and the controls and instrumentation are provided for proper system operation. A schematic diagram of the RHR system is shown in Figure 5.5-13. A description of the controls and instrumentation is presented in Subsections 7.3.1.2.4 and 7.4.1.3. A description of how operation of the equipment in the RHR system in conjunction with other subsystems of the ECCS protects the core in case of a LOCA is presented in Section 6.3.

The main system pumps are sized for the flow required during LPCI operation, which is the subsystem that requires the maximum flowrate. Subsection 6.3.2 contains a discussion of the LPCI. The pumps are arranged and located so that adequate suction head is ensured for all operating conditions. The pump motor is air-cooled by the ventilation system.

The heat exchangers were originally sized on the basis of their required duty for the shutdown cooling function. The heat exchanger shell and tube sides are provided with drain connections. The shell side is provided with a vent to remove noncondensible gases. Thermal relief valves on the heat exchanger shell side and a relief valve on the RHR pump discharge protect the heat exchanger from overpressure.

The RHR heat exchanger duty for the shutdown cooling mode of operation is 41.6×10^6 Btu/hr.

The most limiting duty is that duty associated with torus cooling mode. See Section 6.2.2.3.

Detailed classification information for the RHR heat exchanger is presented in Table 3.2-1.

The RHR system can be connected to the fuel pool cooling and cleanup system, as shown in Figure 5.5-13, so that the RHR heat exchangers can assist fuel pool cooling during overload conditions. Subsection 9.1.3 contains a description of the fuel pool cooling and cleanup system.

One loop, consisting of a heat exchanger, two main system pumps in parallel, and associated piping, is located in one area of the reactor building. The other heat exchanger, pumps, and piping, all of which form a second loop, are located in another area of the reactor building to minimize the possibility of a single physical event causing the loss of the entire system. The two loops of the RHR system are cross-connected by a single header, making it possible to supply either loop from the pumps in the other loop. Water is supplied through a low pressure regulator and two check valves to ensure that the RHR discharge piping is continuously filled. This arrangement precludes water hammer effects. Figure 5.5-14 shows the RHR valve positions during normal reactor operation. Figures 5.5-15 through 5.5-17 show the RHR valve positions for the three RHR modes of operation as described in Subsections 5.5.7.3.2 and 5.5.7.3.3.

5.5.7.3.2 Shutdown Cooling

The shutdown cooling system is an integral part of the RHR system. It is operated during a normal shutdown and cooldown.

The RHR lines can be flushed prior to initiation of the shutdown cooling mode. Flushing is accomplished by establishing flow through the warm-up line to the suppression pool. Flow in this line is limited to approximately 500 gpm by a restricting orifice. The warm-up line isolation valve (F026B) is manually closed after flushing. If the operator fails to close the warm-up line valve, the potential loss of mass inventory could cause water level to drop. The low reactor water level isolation will automatically close the shutdown cooling valves and interrupt the outflow of water. Although it is preferred to flush the lines before RPV injection, no significant consequences will occur if flushing is omitted. The RHR piping will normally be filled with demineralized water or water from the suppression pool. The quality of the suppression pool water is maintained by the torus water management system.

The initial phase of nuclear system cooldown is accomplished by dumping steam from the RPV to the main condenser. When the nuclear system temperature has decreased to where the steam supply pressure is not sufficient to maintain the turbine shaft gland seals, the vacuum in the main condenser cannot be maintained and the RHR system is placed in the shutdown cooling mode of operation. The shutdown cooling system is able to complete cooldown to 125°F within 20 hours after the control rods have been inserted, and can maintain the nuclear system at 125°F for reactor refueling and servicing.

The allowable cooldown rate of the reactor coolant system should not exceed 100°F per hour. To achieve this condition, the heat exchanger's shell-side bypass valve (F048) is throttled to control the cooldown rate.

The RHR shutdown cooling mode is shown in Figure 5.5-15. Reactor coolant is pumped from one of the RRS loops by one or both of the RHR main system pumps and is discharged through the RHR heat exchangers, where cooling occurs by heat being transferred to the service water. Reactor coolant can be returned to the RPV through either RRS loop. When transitioning between the RRS and RHR shutdown cooling, a single RRS pump may be kept in operation while an RHR pump is started. During this time of simultaneous operation the operating RHR pump and the operating RRS pump may not inject into the same loop.

The high RPV water level provides conduction cooling to most of the mass of metal of the RPV and therefore limits thermal stress in the RPV during cooldown.

During a nuclear system shutdown following a scram, the decay heat level decreases rapidly enough that one RHR heat exchanger is capable of accommodating the entire shutdown cooling load.

FPCCS and natural circulation have been analyzed to be capable of serving as an alternate method of decay heat removal to enable RHR Shutdown Cooling to be taken out of service for maintenance during refueling (References 7 and 8). When operating in this alternate shutdown cooling mode, the fuel pool gates are removed and the RPV cavity is flooded. Entry into this mode requires satisfying the refuel technical specification associated with high RPV water level. FPCCS is normally operated with two pumps and two heat exchangers in service. In this capacity, FPCCS and natural circulation maintain FPCCS suction temperature less than 140°F, cooling both the old and freshly off-loaded assemblies in the fuel pool as well as those remaining in the RPV. RWCU may also be placed in operation with the regenerative heat exchanger bypassed to provide additional cooling and in-vessel mixing. This ability to enter this mode of FPCCS operation for RHR maintenance activities is evaluated on a per cycle basis using the expected vessel and spent fuel pool heat loads. The activity is managed such that normal shutdown cooling can be restored within 8 hrs. This is an arbitrary time frame that conservatively assures cooling can be restored prior to the onset of pool and core boiling. In addition, the operation of this mode restricts the operation of temporary auxilliary pool water filtration units such that the flow discharge does not interfere with the core exit flow and thereby impede natural circulation cooling.

5.5.7.3.3 Containment Cooling Subsystem

The containment spray cooling subsystem provides containment cooling for postaccident conditions (see Figure 5.5-16). Water pumped through the RHR heat exchangers can be diverted to spray headers in the drywell and above the suppression pool. The spray removes energy from drywell atmosphere by condensing the water vapor. The spray collects in the bottom of the drywell until the water level rises to the level of the pressure suppression chamber vent lines. The water then overflows to the suppression pool. Approximately 5 percent of this flow can be directed to the suppression chamber spray ring to cool any noncondensible gases collected in the free volume above the suppression pool.

The RHR system is serviced by an automatic fill system that maintains the containment spray lines filled up to the outermost containment isolation valves.

NRC Generic Letter (GL) 2008-01, “Managing Gas Accumulation in Emergency Core Cooling , Decay Heat Removal, and Containment Spray Systems” requested each licensee evaluate the licensing basis, design, testing, and corrective action programs for the Emergency Core Cooling Systems (ECCS), Decay Heat Removal (DHR) systems, and Containment Spray systems, to ensure that the piping systems are maintained full of water, and that appropriate action is taken when gas accumulation is discovered. Fermi’s initial response to this GL is documented in Ref. 9. During the GL response effort, NRC clarified the meaning of the phrase “full of water” (Ref. 10). The NRC concluded that when some voids are discovered in piping, the system can be considered filled with water as long as reasonable expectation of the system’s ability to perform its specified function is established.

The containment spray cooling subsystem of the RHR system normally cannot be operated unless the core flooding requirements of the LPCI subsystem have been satisfied. The operator can bypass these requirements by using a keylock switch in the main control room (Subsection 7.3.1.2).

On initiation of the RHR containment spray mode, the inner isolation valve is fully opened. The outermost isolation valve is a throttling-type valve, and the extent of the valve opening is determined by the time the open pushbutton is kept depressed. The valve open, mid-open, or closed indications are provided on the control panels to inform the operator of the valve position. The operators for the outermost valves are designed to open slowly. After a steady-state condition has been reached, the outermost isolation valve is fully opened. In this manner, dynamic loadings imposed on the empty portions of the containment spray lines and on the system supports and restraints are limited to within design values during the initial spray period as well as during the steady-state operating condition.

The suppression pool cooling subsystem (see Figure 5.5-17) cools the suppression pool by using the RHR pumps and heat exchangers in a closed loop with the suppression pool. The suppression pool cooling subsystem is put into operation to limit the water temperature immediately after a blowdown to 170°F when reactor pressure is above 135 psig. During this mode of operation, water is pumped from the suppression pool through the RHR system heat exchanger and back to the suppression pool.

The equipment purchase specifications for the RHR heat exchangers that are used for the containment cooling and suppression pool cooling modes specify fouling factors.

The fouling factors are a function of the nature of the fluids, the temperatures involved, and the fluid velocities. The heat exchanger designer includes the fouling factor in calculating the overall thermal resistance and provides sufficient surface area to allow the required heat transfer rate while in the fouled condition.

The heat exchanger performance data sheets supplied by the heat exchanger designer/manufacturer show the expected (designed) performance of the heat exchanger under fouled conditions. Fouling beyond the extent specified in the purchase specification and used during the heat exchanger design will result in a decrease in the heat transfer rate.

5.5.7.3.4 Low Pressure Coolant Injection System

The LPCI system is an integral part of the RHR system. It operates to restore and, if necessary, maintain the coolant inventory in the RPV after a LOCA. A description of the salient features of the LPCI system is given in Sections 6.3 and 7.3.

The LPCI is a low-head, high-flow function that delivers its rated flow to the RPV through one of the RRS loops. It is designed to reflood the RPV to at least two-thirds core height and to maintain this level. After the core has been flooded to this height, the capacity of one RHR main system pump is sufficient to make up for shroud leakage and boiloff. The LPCI subsystem operates in con-junction with the HPCI system, ADS, and the core spray system to restore and maintain the coolant inventory in the RPV after a LOCA.

The HPCI is a high-head, low-flow system that can pump water into the RPV when the NSSS is at high pressure. If the HPCI fails to deliver the required flow of cooling water to the RPV, the automatic depressurization feature of the overpressurization protection system described in Subsection 5.2.2 functions to reduce nuclear system pressure so that LPCI and core spray may operate to inject water into the RPV. The HPCI turbine is manually shut down after both core spray and LPCI are in operation. When RHR is lined up in the shutdown cooling mode and RPV pressure is less than or equal to the cut in pressure, manual operation is required to permit LPCI to align and initiate. This includes manually lining up the suction path from the torus for the loop which is in shutdown cooling. Otherwise, these operations are carried out automatically.

During LPCI operation, the RHR system pumps take suction from the suppression pool and discharge to the RPV into the core region through one of the RRS loops. Instrumentation is provided to detect the undamaged path for injection of LPCI flow (Subsection 7.3.1.2). Any spillage through a break in the lines within the primary containment returns to the suppression pool through the pressure suppression vent lines. A minimum-flow bypass line to the suppression pool is provided so that the pumps are not damaged if operating with the discharge valves shut.

Service water flow to the RHR heat exchangers is not required immediately after a LOCA because heat rejection from the containment is not necessary during the time it takes to flood the reactor. Power for the main RHR and RHRSW pumps normally comes from an auxiliary ac power bus; but if offsite power is lost, power is made available from the standby ac power source to supply the RHR and RHRSW pumps.

To provide a source of water if any postaccident flooding of the primary containment is required, a cross tie exists from the piping on the discharge side of a pair of service water pumps to the discharge piping on the shell side of an RHR heat exchanger. This connection is provided with redundant valving appropriate to a primary containment penetration. The valves are remotely operable from the main control room. The pair of service water pumps that provide this function can add water to either RRS loop through the cross-connection between the piping of each RHR loop.

5.5.7.3.5 Residual Heat Removal System Overpressure Protection

The design basis for overpressure protection in the RHR system is the conformance of the entire system to applicable portions of ANSI B31.7.

Failures due to overpressurization can result from the inadvertent opening of reactor coolant system (RCS) pressure boundary valves or RCS pressure boundary valve leakage. The RHR low-pressure piping is connected to the RCPB at the RHR shutdown suction and discharge connections to the recirculation system. Each of these lines is discussed in the following paragraphs.

a. The RHR suction from the recirculation system: This line has an inside containment isolation valve and an outside containment valve. Each valve is interlocked with a separate pressure switch that prohibits opening of the associated valve if the recirculation pressure exceeds the shutdown range. The design complies with GDC 55.

b. The RHR shutdown return line: This line has two valves outside containment. Each valve is interlocked to at least a control permissive of low reactor pressure. The line also has a testable check valve inside the containment that functions automatically to prevent outflow from the vessel. This design complies with GDC 55.

Reactor coolant system pressure boundary isolation valve leakage is accommodated by 1-in. or larger relief valves. This size of the valve is considered large enough to accommodate any postulated leakage. Valve F029 relieves shutdown cooling isolation valve leakage pressure; valves F025A and F025B relieve injection isolation valve leakage pressure. The heat exchangers contain their own relief valves, and the suction piping is relieved by valves F030A, F030B, F030C and F030D whenever the respective pool suction valves are closed.

5.5.7.4 Safety Evaluation

Because the LPCI and containment cooling subsystems act with other subsystems of the ECCS to satisfy the safety objective, they are evaluated in conjunction with the other subsystems of the ECCS in Section 6.3. The safety evaluation of the controls and instrumentation of the LPCI system is contained in Subsection 7.3.1.

There are two complete containment cooling systems. The RHR pumps in each of these systems receive power from ac power buses having standby power source backup supply. The two RHR pump motors and their associated motor-operated valves receive power from two separate buses. The pump's piping, controls, and instrumentation are separated and protected so that any single physical event or missile cannot make both loops inoperable.

The Fermi 2 design includes two parallel ac-powered inboard isolation valves (F009 and F608) fed from opposite electrical power divisions (F009 from Division I and F608 from Division II) and a dc-powered outboard isolation valve (F008) fed from Division II power. To prevent any inadvertent valve opening, the power fuses of the outboard isolation valve E1150F008 are removed during normal plant operation.

The following assumptions are used for the analyses of the procedures for attaining cold shutdown in the shutdown cooling mode.

a. The vessel is at about 70 psig and in a saturated condition

b. No offsite power is available

c. A worst single failure is assumed to occur (i.e., loss of a division of emergency power).

If a single failure (loss of Division II ac and dc power) were to cause an outboard suction valve (F008) to fail in the closed position, a handwheel is provided on the valve to allow manual operation. The shutdown would then continue in a normal manner using Division I of the RHR system.

Because manual operation cannot compensate for an electrical failure applied to inboard suction valve F009 (loss of Division I), the operator would open parallel valve F608, which is fed from the opposite division (Division II). Administrative controls would be used to enable the opening of valve F608 only when valve F009 could not be opened. These administrative controls require operation of a local key lock switch, the control room key lock switch and a push-button switch (in the control room) to open the valve. The local key lock switch prevents the valve opening from Multiple Spurious Operation (MSO). An auditory and visual feedback is provided by a control room alarm following the key lock switch operation. This is to prevent any inadvertent valve opening. Once valve F608 is open, the shutdown continues in the normal manner using Division II of the RHR system.

Thus, RHR system design conforms to the single-failure requirement of GDC 34.

5.5.7.5 Inspection and Testing

A design flow functional test of the RHR main system pumps is performed for each pump during normal plant operation by taking suction from the suppression pool and discharging through the test lines back to the suppression pool. The discharge valves to the RRS loops remain closed during this test, and reactor operation is undisturbed. An operational test of these discharge valves is performed by shutting the upstream valve after it has been satisfactorily tested, thereby establishing the RCPB at the downstream valve, and then operating the discharge valve. The discharge valves to the containment spray headers are checked in a similar manner by operating upstream and downstream valves individually. All these valves can be actuated from the main control room using remote manual switches. Control system design provides automatic return from test to operating mode if LPCI initiation is required during testing.

Testing of the sequencing of the LPCI mode of operation is performed after the reactor is shut down. Testing the operation of the valves required for the remaining modes of operation of the RHR system is performed as stated in the Technical Specifications and the pump and valve testing program (see Subsection 5.2.8.7).

Routine maintenance and tests, based on the manufacturers' recommendations and/or operating/maintenance experience, will be scheduled in accordance with the plant preventive maintenance program for the main system pumps, pump motors, and heat exchangers.

Preoperational tests are conducted during the final stages of plant construction prior to initial startup. These tests ensure correct functioning of all controls, instrumentation, pumps, piping, and valves. System reference characteristics such as pressure differentials and flow rates are documented during the preoperational testing and are used as base points for measurements obtained in subsequent operational tests.

For the containment spray cooling system, preoperational tests confirm that the containment spray headers and piping are clear of obstructions and the spray nozzles are capable of delivering rated flow. Air is injected into the drywell spray header via the blind flange connection on the outside of the primary containment. Unrestricted flow is verified through each spray nozzle. The spray nozzles in the suppression pool are checked with water during the suppression pool cooling tests.

For the suppression pool cooling system, the preoperational tests verify that the RHR heat exchanger shell-side design flow rate can be obtained while circulating water from the suppression pool. During the test, head versus flow curves are developed for reference in evaluating the future performance of the suppression pool cooling mode and the RHR pumps.

During plant operations, the pumps, valves, piping, instrumen-tation, wiring, and other components outside the primary containment can be inspected visually at any time. Components inside the primary containment can be inspected when the drywell is open for access. Testing frequencies are correlated with testing frequencies of the associated controls, and instrumen-tation is tested by the same action. When a system is tested, operation of the components is indicated by installed instrumentation.

The leak testing of all valves performing an isolation function between the high-pressure and the low-pressure boundary in the RHR system cannot be performed at the frequency prescribed in Section XI of the ASME Code. Because the testing removes one division of the RHR system from service, it is prudent to test only near the end of refueling outages or during maintenance on these systems. The Technical Specifications specify requirements for continued plant operation should the other division become inoperable.

Leakage tests are performed on these valves with high-pressure water. In every case, the low-pressure portion of the system is protected from overpressure with relief valves. The criterion for leakage tests is between 0.4 and 10 gpm which are values far below the capacity of the relief valves.

These valves cannot be exercised to any degree during plant operation. The exercising program for the gate and globe valves is part of the system functional tests described in the Technical Specifications. The check valves also are exercised at this time, using a mechanical exerciser as described in IWV-3522(b).

The RHR relief valves are removed as scheduled at refueling outages for bench tests and setting adjustments.

RHR heat exchanger tube leakage will be determined on a monthly basis by monitoring the service water return radiation levels. The effluent will be sampled such that significant leakage of reactor water into the RHR service water will be detected. Appropriate corrective actions will then be taken.

5.5.8 Reactor Water Cleanup System

5.5.8.1 Power Generation Design Bases

The principal function of the RWCU system is to provide a means for reducing the concentration of radioactive and corrosive species in the reactor.

The RWCU system shall

a. Discharge excess reactor water during startup, shutdown, and hot standby conditions

b. Minimize reactor heat loss during system operation, except when used for Decay Heat Removal.

c. Remove solid and dissolved impurities from recirculated reactor coolant

d. Minimize temperature gradients in the RRS piping and vessel during periods of low flow rates.

e. Assist decay heat removal and coolant mixing during periods when the Reactor Pressure Vessel is under 250°F.

5.5.8.2 Description

The RWCU system, shown in Figure 5.5-19, continuously purifies the reactor water. The system continuously removes water from the suction line of each RRS pump and from the reactor bottom head and returns it to the feedwater system. Water may also be sent to the main condenser (preferably) or to the radwaste system.

A regenerative heat exchanger is provided to maintain thermal efficiency during most operating modes of RWCU. However, a bypass line may be opened during times when the Reactor Pressure Vessel is under 250°F to allow cooled water to return to the reactor vessel. The RWCU system is operated at all times, when possible.

The major equipment of the RWCU system, located in the reactor building, includes pumps, regenerative and nonregenerative heat exchangers, and two filter-demineralizers with supporting equipment. The entire system is connected by associated valves and piping; controls and instrumentation provide proper system operation. Design data for the major pieces of equipment are presented in Table 5.5-2.

Reactor water is cooled in the regenerative and/or nonre-generative heat exchangers (or the nonregenerative heat exchangers alone when the shell side of the regenerative heat exchanger is bypassed), then filtered, demineralized, and returned to the reactor feedwater system through the shell side of the regenerative heat exchanger. A process diagram of the RWCU system is shown on Figure 5.5-20.

Because the maximum temperature of the filter-demineralizer units is limited by the ion exchange resin operating temperatures (Table 5.5-2), the reactor coolant must be cooled before being processed in the filter-demineralizer units. The regenerative heat exchanger transfers heat from the influent water to the effluent water. The nonregenerative heat exchanger cools the influent water further by transferring heat to the reactor building closed cooling water (RBCCW) system. The nonregenerative heat exchanger is designed to maintain the required filter- demineralizer operating temperature, even when the effectiveness of the regenerative heat exchanger is reduced by diversion of excess reactor water from the filter-demineralizer effluent to either the main condenser or the radwaste system or the regenerative heat exchanger is bypassed. A motor-operated valve in the suction line to the RWCU pumps automatically closes to prevent damage of the filter-demineralizer resins if the outlet temperature of the nonregenerative heat exchanger is high.

The filter-demineralizer units shown in Figure 5.5-21 are pressure-precoat type filters using mixed ion-exchange resins and fiber as a filter and ion-exchange medium. Spent resins are backwashed from a filter-demineralizer unit to a resin receiver tank from which they are transferred to the radwaste system for processing and disposal.

The suction line of the RCPB portion of the RWCU system contains two motor-operated isolation valves which automatically close in response to signals from the RCPB leak detection system. This action prevents the loss of reactor coolant and the release of radioactive material from the reactor. Subsections 7.6.1 and 5.2.7 and Table 5.2-11 describe the RCPB leak detection system.

The outermost isolation valve also automatically closes to prevent removal of liquid poison in the event of standby liquid control system actuation. These isolation valves may be remote manually operated to isolate the system equipment for maintenance or servicing.

A remote manually operated gate valve on the return line to the reactor provides long-term backup isolation of the system for the reactor. Instantaneous reverse-flow isolation is provided by two check valves in the RWCU return line, as shown in Figure 5.5-19. A motor operated isolation valve is provided in the RWCU line as shown in Figure 5.5-19. This valve automatically closes to isolate the RWCU system upon receipt of an isolation signal, or it may be remote manually operated.

5.5.8.3 Safety Evaluation

To minimize the introduction of resins into the reactor in the event of septa failure in a filter-demineralizer, a strainer is installed on the outlet of each filter-demineralizer unit. Each strainer has a main control room alarm that is energized by high differential pressure. A bypass line is provided around the filter-demineralizer units for bypassing the units when necessary.

In the event of low flow or loss of flow in the system, flow is maintained through each filter-demineralizer by its own holding pump. Sample points are provided in the influent header and effluent line of each filter-demineralizer unit for continuous indication and recording of system conductivity. High conductivity is annunciated in the main control room. The alarm setpoints for the conductivity meters are 0.5 and 0.9 μ S/cm for the inlet and 0.09 μ S/cm for the outlet. The influent sample point is also used as the normal source of reactor coolant samples. Sample analysis also indicates the effectiveness of the filter-demineralizer units.

Operation of the RWCU system is controlled from the main control room except for the regenerative heat exchanger bypass. The manual bypass line isolation valve is administratively controlled and locked-closed during periods of nonuse. Figure 7.6-1 shows the RWCU system instrumentation and control logic.

Resin-changing operations, which include backwashing and precoating, are controlled from a local control panel in the reactor building.

5.5.8.4 Inspection and Testing

Because the RWCU system is usually in service during plant operation, satisfactory performance is demonstrated without the need for any special inspection or testing beyond that specified in the manufacturers' instructions.

5.5.9 Main Steam Lines and Feedwater Piping

5.5.9.1 Safety Design Bases

To satisfy the safety design bases, the main steam lines and feedwater piping have been designed

a. To accommodate operational stresses, such as internal pressures and earthquake loads, without a failure that could lead to the release of radioactivity in excess of the guideline values in published regulations

b. With suitable access to permit inservice testing and inspections.

5.5.9.2 Power Generation Design Bases

The main steam lines and feedwater piping meet the following power generation design bases.

a. The main steam lines shall conduct steam from the RPV over the full range of reactor power operation

b. The feedwater lines shall conduct water to the RPV over the full range of reactor power operation.

5.5.9.3 Description

The main steam lines, consisting of four 24-in. diameter lines, are described in Section 10.3.

The feedwater piping is shown in Figure 10.4-10; at the drywell penetrations, it consists of two 20" lines. Each line includes two containment isolation valves. One simple check valve is inside the drywell. The isolation valve outside the drywell is an air actuated spring assist to close check valve. An additional check valve is located outside the drywell between the drywell wall and the spring assist to close check valve. In addition, a stop valve is provided between the isolation check valve and the reactor so that maintenance can be performed on the isolation valving and the HPCI system when the reactor is out of service. The design pressure and temperature of the feedwater piping between the reactor and the outermost isolation valve are 1275 psig and 450°F. The design pressure and temperature of the remaining reactor feedwater system are 1750 psig and 450°F. The Category I design requirements are placed on the feedwater piping from the reactor through the outboard isolation check valves and connected piping of 2-1/2 in. or larger nominal pipe size, up to and including the first valve that is either normally closed or capable of automatic closure during all modes of normal reactor operation.

The materials used in the piping are in accordance with the applicable design code and supplementary requirements described in Section 3.2.

The reactor feedwater system is described in Subsection 10.4.7.

The penetration assemblies serve as a flexible joint, pressure boundary, and pipe jacket for process piping that penetrates the primary containment and its surrounding biological shield. The penetration assemblies, which are part of the primary pressure boundary, located between the inboard and outboard containment isolation valves, are rated as Class 1 in accordance with l0 CFR 50, Paragraph 50.55(a). Type I penetrations serve the primary pressure boundary process lines. Use of a flexible bellows and a penetration anchor is required because of fluctuations in operating temperature. Type I penetrations are provided with a hinged guard pipe around the process pipe to protect the bellows and the penetration sleeve from the effects of a postulated pipe rupture (Subsection 6.2.1.2.1.4).

The design, materials, and fabrication of the penetration assemblies are in accordance with the ASME B&PV Code Section III, 1971 edition, including the 1971 summer and winter addenda.

5.5.9.4 Safety Evaluation

Differential pressure on reactor internals under the assumed accident condition of a ruptured steam line is limited by the use of flow restrictors and by the use of four main steam lines. All main steam and feedwater piping is designed in accordance with the requirements defined in Section 3.2. Design of the piping in accordance with these requirements ensures meeting the safety design bases.

5.5.9.5 Inspection and Testing

Inspection and testing are carried out in accordance with Subsections 10.3.4 and 10.4.7. Inservice inspection is considered in the design of the main steam and feedwater piping. This consideration ensures adequate working space and access for the inspection of selected components.

The penetration assemblies are tested and inspected in accordance with the 1971 ASME Code Sections III and XI. They are designed for a 40-year service life.

5.5.10 Pressurizer

This subsection is not applicable to BWRs.

5.5.11 Pressurizer Relief Tank

This subsection is not applicable to BWRs.

5.5.12 Valves

Components beyond the RCPB that are part of systems or subsystems closely allied with the reactor coolant system consist of

a. Reactor feedwater system
b. RHR system
c. RCIC system
d. RWCU system
e. HPCI system
f. Standby liquid control (SLC) system
g. Core spray (CS) system.

5.5.12.1 Safety Design Bases

Line valves such as gate, globe, and check valves are located in the fluid systems to perform a mechanical function. Valves are components of the system pressure boundary and, having moving parts, are designed to operate efficiently to maintain the integrity of this boundary.

The valves shall operate under the internal pressure/temperature loading as well as the external loading experienced during the various system transient operating conditions. Table 3.9-27 lists the code class and design pressures and temperatures. The design criteria are described in Subsection 3.9.2.

5.5.12.2 Description

Class 2 and Class 3 line valves are designed in accordance with MSS-SP-66 or ANSI-B16.34. Original plant valves were procured in accordance with the then applicable ANSI-

B16.5 design. Materials used for Class 2 valves conform to the requirements of NC-3512 (a) and (b), and for Class 3 valves to ND-3512 (a) and (b). All materials, exclusive of seals and packings, are selected for 40-year plant operational life under full service conditions. Stress analyses show that Class 2 valves with motor, diaphragm, and piston operators only do not become inoperative under static seismic acceleration of 5g in the horizontal plane and 3g in the vertical plane.

Valve operators are sized to operate successfully under the maximum differential pressure determined in the design specification.

5.5.12.3 Safety Evaluation

Line valves are shop tested by the manufacturer for performability. Pressure-retaining parts shall be subject to the testing and examination requirements of the appropriate ASME Code. To minimize internal and external leakage past seating surfaces, maximum allowable leakage rates are stated in the valve specifications for both the valve stem as well as the main seat for gate and globe valves.

Valve construction materials are compatible with the maximum anticipated radiation dosage for the service life of the valves.

5.5.12.4 Inspection and Testing

Inspection and tests of line valves shall be in accordance with the applicable Code Class of the ASME B&PV Code Sections III and XI.

Valves that serve as containment isolation valves and that must remain closed or open during normal plant operation may be partially exercised during this period to ensure their operability at the time of an emergency or faulted condition. Other valves, serving as system block or throttling valves, may be fully exercised without jeopardizing system integrity for the same reason.

5.5.13 Safety and Relief Valves

Overpressurization protection, in the form of relief valves, is provided to systems and subsystems closely related to the reactor coolant system, such as

a. CS system

b. HPCI system

c. RCIC system

d. RHR system and its subsystems

e. SLC system

f. Control rod drive (CRD) system

g. RWCU system

h. Reactor recirculation seal purge subsystem.

The safety/relief valves of the reactor primary coolant system are discussed in Subsection 5.2.2. Table 5.5-3 shows relief valve characteristics for the above systems.

5.5.13.1 Safety Design Bases

The piping systems that are normally isolated by at least two power-operated isolation valves or one check valve and one power-operated valve from the RCPB are provided with relief valves to protect the piping from overpressurization caused by one or more of the following mechanisms.

a. Isolation valve leakage

b. Pump operation with system isolation

c. External radiant heat

d. Hot fluid impingement from broken pipes.

The relief valves are conservatively sized and designed by taking into account all the possible causes of overpressurization and their effects.

These valves are designed in accordance with the requirements of ASME B&PV Code Section III, NC-7000. Relief valves in Group D piping are exempt from the ASME B&PV Code Section III requirements.

5.5.13.2 Description

5.5.13.2.1 Core Spray System Relief Valves

The core spray pump suction lines and discharge lines are equipped with relief valves. The setpoints and capacities for these valves are shown in Table 5.5-3. The core spray system is not subject to any kind of energy input, except pump motor energy when pumps are operating against closed valves. The piping system is designed to withstand the shutoff head of the pumps. All relief valves installed in the system provide thermal relief for isolable portions of the system, with sufficient capacities to relieve the volume change of the entrapped fluid due to thermal expansion.

5.5.13.2.2 High Pressure Coolant Injection System Relief Valves

The HPCI pump suction line and the line to the gland seal condenser are equipped with relief valves to prevent overpressurization of the lines.

The setpoints and capacities for these valves and rupture disks are listed in Table 5.5-3.

The HPCI system is not subject to any kind of energy input except the hydraulic oil pump motor and the motors for the gland seal condenser vacuum and drain pumps.

5.5.13.2.3 Reactor Core Isolation Cooling System Relief Valves

The RCIC pump suction line and the cooling water line to the gland seal condenser are provided with relief valves with the capacities and setpoints listed in Table 5.5-3.

There is a rupture disk on the steam turbine for the turbine casing protection with the setpoint at 150 ± 10 psig and the capacity of 60,000 lb/hr at 165 psig.

The RCIC system is not subject to any kind of energy input, except when the pumps operate with closed valves.

5.5.13.2.4 Residual Heat Removal System Relief Valves

The RHR pump suction and discharge lines are provided with a relief valve in each line. The setpoints and capacities are listed in Table 5.5-3.

The overpressure protection relief valves have sufficient capacity to relieve the volume change of the entrapped fluid that results from thermal expansion in isolable portions of the system. The piping is designed to withstand the shutoff head of the pumps.

The RHR heat exchangers are also provided with a relief valve in each heat exchanger as listed in Table 5.5-3.

5.5.13.2.5 Standby Liquid Control System Relief Valves

A relief valve is provided in the discharge line of each pump. The setpoint and capacity of each valve are listed in Table 5.5-3.

5.5.13.2.6 Control Rod Drive System Relief Valves

The CRD pump suction lines are equipped with relief valves. The setpoints and capacities are listed in Table 5.5-3.

5.5.13.2.7 Reactor Water Cleanup System Relief Valves

The relief valves are installed on the shell and tube sides of the heat exchangers and on the line to the condenser.

The setpoints and capacities of the relief valves are listed in Table 5.5-3.

5.5.13.2.8 Feedwater System Relief Valves

The feedwater system is designed to the maximum pressure of the reactor coolant system up to and including the outermost isolation valve. Beyond the outermost isolation valve, the system is designated as a nonsafety class. Details of the feedwater system are discussed in Section 10.4.

5.5.13.3 Safety Evaluation

The assumptions made in the evaluation of the adequacy of the relief valves provided are conservative, and the setpoints and capacities of the valves are sufficiently conservative to protect the system and subsystem pipings and components from the effects of overpressurization.

Some of the conservative assumptions made are

a. Conservative isolation valve leakage values are used in sizing the relief valves

b. The system is considered isolated with the pump(s) operating at shutoff conditions. A 100 percent energy conversion from the pump motor horsepower to heat is assumed, neglecting heat losses and mechanical work

c. Jet impingement of steam from a nearby broken pipe is taken into account in sizing the relief valves. To be conservative, heating of the piping is assumed to be from the condensation of steam by the piping

d. The piping subject to heating is assumed to be uninsulated

e. Reaction force on the piping from relief valve operation is assumed to be R = 2 x P x A, where R is the reaction force, P is the pressure setting of the valve, and A is the area of the valve inlet.

The radiation fields considered for the EQ Program relief valve designs are given in Table 3.11-5. Other valve characteristics can be found in Table 5.5-3.

5.5.13.4 Inspection and Testing

Inspection and testing were carried out in accordance with ASME (PTC) 25.2, ASME B&PV Code Section III. Inservice inspection of ASME Class 1, 2, and 3 valves will be performed in accordance with ASME B&PV Code Section XI.

5.5.14 Component Supports

Support elements are provided for those components beyond the RCPB that are in systems or subsystems closely allied with the reactor coolant system. These systems include

a. Reactor feedwater system

b RHR system

c. RCIC system

d. RWCU system

e. HPCI system

f. SLC system.

5.5.14.1 Safety Design Bases

The design procedures, design loading, and acceptability criteria are as described in Subsection 3.9.2. Flexibility calculations and seismic analysis for Class 2 and 3 components are made in accordance with NC/ND 3600 of the ASME B&PV Code Section III. Support types, materials used for fabricated support elements, and recommended pipe support spacing are in accordance with established industry practice and AISC Specifications.

5.5.14.2 Description

The use and location of rigid-type supports, variable or constant spring-type supports, and anchors or guides are determined by flexibility and stress analysis. Component support elements are manufacturers' standard items. Direct weldment to thin-wall pipe is avoided where possible.

5.5.14.3 Safety Evaluation

Design loadings used for flexibility and seismic analysis toward the determination of adequate component support systems include all transient loading conditions expected by each component.

Provisions are made to restrain spring-type supports for the initial deadweight loading due to hydrostatic testing of steam systems to prevent damage to this type of support.

5.5.14.4 Inspection and Testing

After completion of the installation of a support system, hanger elements will be visually examined to ensure that they are in correct adjustment to their cold setting position. Thermal expansion testing for selected piping systems will be conducted during the preoperational and startup phases. Spring-type hangers will be inspected to ensure that they will function properly between their hot and cold setting positions.

5.5 COMPONENT AND SUBSYSTEM DESIGN

REFERENCES

1. P. W. Ianni, Effectiveness of Core Standby Cooling Systems for General Electric Boiling Water Reactors, APED-5458, March 1968.
2. Letter, "GE Recirculation Pump Potential Overspeed," Revision 2, March 30, 1979.
3. General Electric Company, Analysis of Recirculation Pump Under Accident Conditions, Revision 2, submitted to the NRC March 30, 1979.
4. J. Grimaldi, Analysis of Recirculation Pump Overspeed in a Typical General Electric Co. BWR, NEDO-l0677, October l972.
5. General Electric Company, Design and Performance of General Electric Boiling Water Reactor Main Steam Line Isolation Valves, APED-5750, March l969.
6. NUTECH, Fermi 2 Long Term Program Plant Unique Analysis Report for the Torus Attached Piping (PUAR-TAP), DET-19-076-6, transmitted to NRC per EF2-63925, June 10, 1983.
7. GE-NE-E11-00071-01, "Alternate SDC With Natural Circulation", June 1995.
8. JNL-95-8-01, “Alternate SDC Supplemental Analysis”, August, 16, 1995.
9. NRC-08-0064, dated 10-14-08, Fermi 2 Nine-Month Response to NRC Generic Letter 2008-01, “Managing Gas Accumulation in Emergency Core Cooling, Dacay Heat Removal, and Containment Spray Systems”
10. NRC Letter, dated 5-28-09, to James H. Riley from William H. Ruland, “Preliminary Assessment of Responses to GL 2008-01 and Future NRC Staff review Plans”
11. DTE Electric, NRC-14-0028, “Fermi 2 License Renewal Application”, dated April 24, 2014.

TABLE 5.5-1 REACTOR RECIRCULATION SYSTEM DESIGN CHARACTERISTICS

External loops	
Number of loops	2
Pipe sizes (nominal O.D.)	
Pump suction, in.	28
Pump discharge, in.	28
Discharge manifold, in.	22
Recirculation inlet line, in.	12
Design pressure, psig/design temperature, °F	
Suction piping and valve up to and including pump suction nozzle	1250/575
Pump	1525/562[a]
Discharge piping up to vessel	1500/575
Discharge valve	1525/575
Pump auxiliary piping and cooling water piping	150/212
Vessel bottom drain	1250/575
Operation at rated conditions	
Reactor recirculation system pump	
Flow, gpm	45,200
Flow, lb/hr	17.1×10^6
Total developed head, ft	710
Suction pressure (static), psia	1033
Required NPSH, ft	135
Water temperature, °F	535.4
Pump brake HP (min)	7050
Flow velocity at pump suction (approximate), ft/sec	28.4

[a] The reactor recirculation system pump design pressure and temperature conditions envelop the system discharge piping design requirements.

TABLE 5.5-1 REACTOR RECIRCULATION SYSTEM DESIGN CHARACTERISTICS

Pump motor	
Voltage rating	4160
Phase	3
Frequency, Hz	60
Jet pumps	
Number	20
Total jet pump flow, lb/hr	105×10^6
Throat I.D., in.	8.18
Diffuser I.D., in.	19.0
Nozzle I.D. (representative), in.	3.14
Diffuser exit velocity, ft/sec	15.8
Jet pump head, ft	87.8
Reactor recirculating system loop valves	
Type	Gate valve
Actuator	Motor
Material	Austenitic stainless steel
Valve size diameter, in.	28

TABLE 5.5-2 REACTOR WATER CLEANUP SYSTEM EQUIPMENT DESIGN DATA

Reactor water cleanup system pumps

Number required - two

Capacity (each) - 50 percent of system flow

Discharge flow, gpm/pump - 180

Design temperature, °F - 575

Design pressure, psig – 1400

Heat exchangers

	Regenerative	Nonregenerative
Reactor coolant flow rate, lb/hr	133,000	133,000
Shell-side pressure, psig	1450	150
Shell-side temperature, °F	575	370
Tube-side pressure, psig	1450	1450
Tube-side temperature, °F	575	564

Filter-Demineralizers

Number required - two

Capacity (each) - 50 percent of system flow

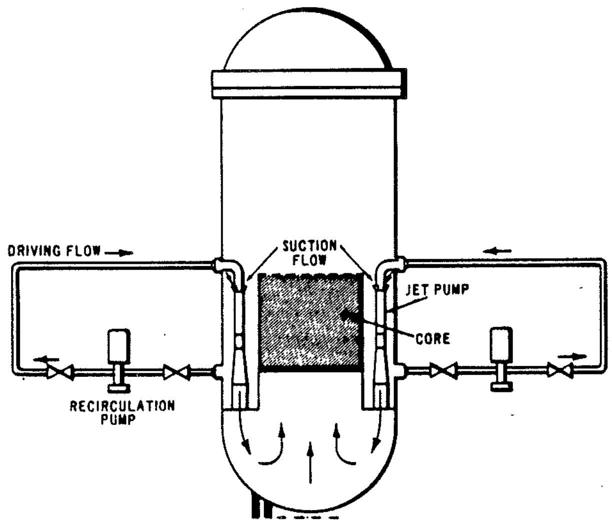
Flow rate/unit, lb/hr - 66,500 (Nominal)

Design temperature, °F - 150

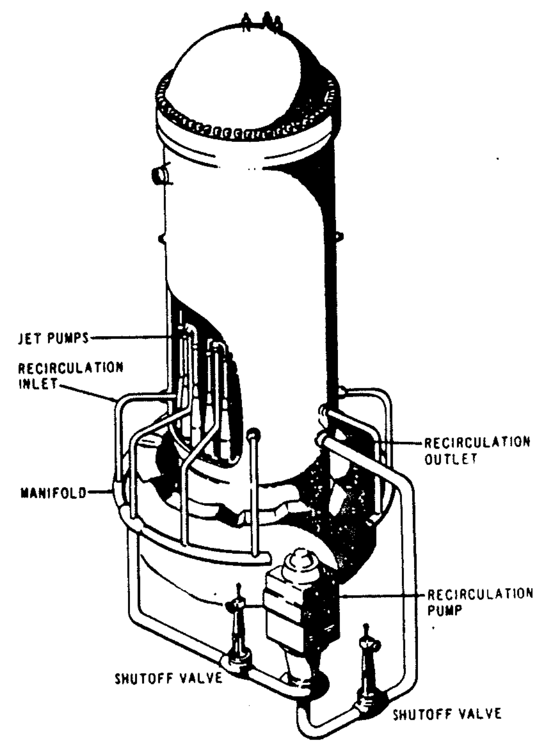
Design pressure, psig - 1400

TABLE 5.5-3 RELIEF VALVES

Valve	Location	Setpoint (psig)	Capacity
E1100F029	RHR pump suction (Shutdown Cooling Header)	140	20 gpm
E1100F030A	RHR pump suction	150	20 gpm
E1100F030D	RHR pump suction	150	20 gpm
E1100F030C	RHR pump suction	150	20 gpm
E1100F030B	RHR pump suction	150	20 gpm
E1100F025A	RHR pump discharge	450	9,000 lb/hr
E1100F025B	RHR pump discharge	450	9,000 lb/hr
E1100F001A	RHR heat exchanger	450	46 gpm
E1100F001B	RHR heat exchanger	450	38 gpm
C1100F001A	CRD pump suction	250	90 gpm
C1100F001B	CRD pump suction	250	90 gpm
G3300F036	RWCU system to condenser	150	270 gpm
G3300F023B	RWCU system nonregenerative heat exchanger – shell	150	39 gpm
G3300F023A	RWCU system nonregenerative heat exchanger – tube	1,450	thermal relief
G3300F025C	RWCU system regenerative heat exchanger – tube	1,450	thermal relief
G3300F025A	RWCU system regenerative heat exchanger - shell	1,450	thermal relief
E5100F017	RCIC pump suction	100	10 gpm
E5100F018	RCIC condenser cooling	125	10 gpm
C4100F029B	SLCS pump discharge	1,370	41 gpm
C4100F029A	SLCS pump discharge	1,370	41 gpm
E2100F011A	CSS pump discharge	500	100 gpm
E2100F011B	CSS pump discharge	500	100 gpm
E2100F012A	CSS pump discharge	500	100 gpm
E2100F012B	CSS pump discharge	500	100 gpm
E2100F032B	CSS pump suction	100	20 gpm
E2100F032A	CSS pump suction	100	20 gpm
E4100F020	HPCI pump suction	100	10 gpm
E4100F050	HPCI cooling water line	125	10 gpm
B3100F015A	Reactor Recirculation Seal Purge Subsystem	1,250 (Approximately)	thermal relief
B3100F015B	Reactor Recirculation Seal Purge Subsystem	1,250 (Approximately)	thermal relief
E4150D003	HPCI turbine exhaust rupture disk	165 - 185 psig burst pressure	43 lbm/sec
E4150D004	HPCI turbine exhaust rupture disk	165 - 185 psig burst pressure	43 lbm/sec



ELEVATION



ISOMETRIC

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FIGURE 5.5-1

REACTOR RECIRCULATION SYSTEM ELEVATION AND ISOMETRIC

Figure Intentionally Removed
Refer to Plant Drawing M-2833

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FIGURE 5.5-2, SHEET 1

REACTOR RECIRCULATION SYSTEM
NUCLEAR BOILER SYSTEM

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Refer to Plant Drawing I-2106-01

Figure Intentionally Removed
Refer to Plant Drawing I-2106-02

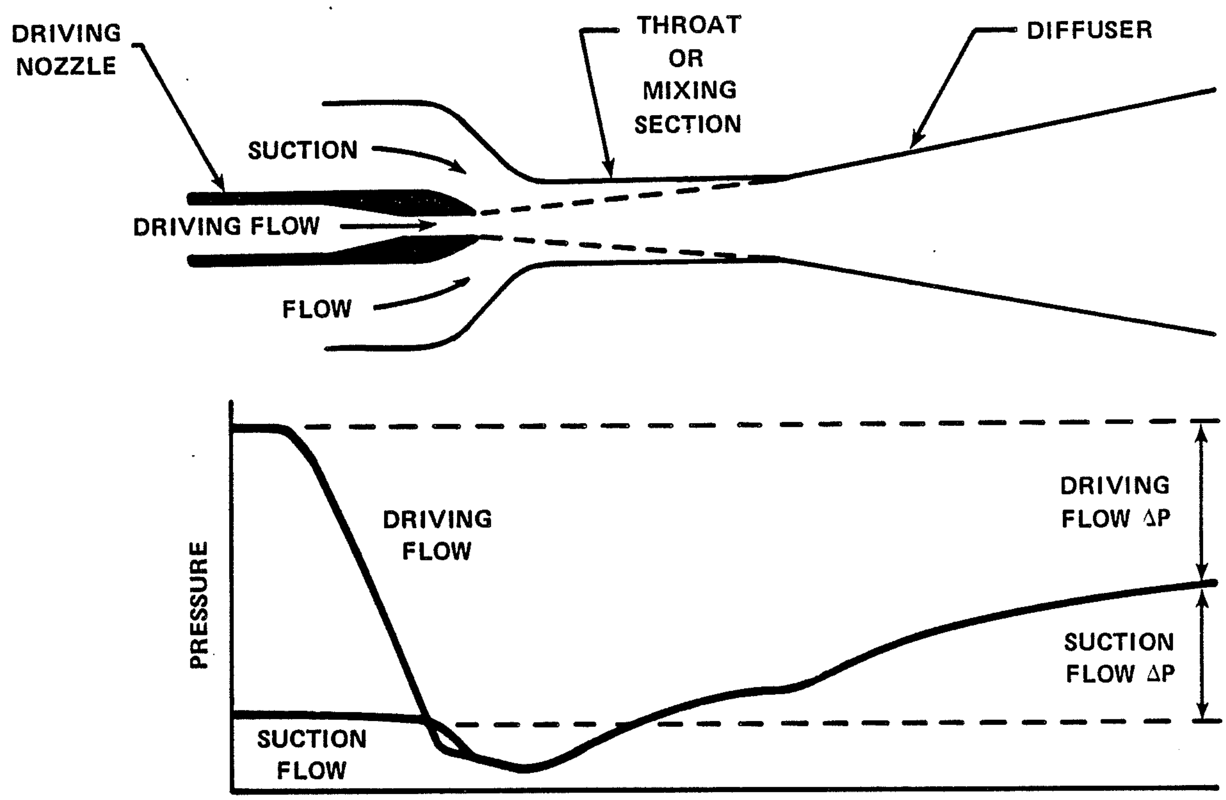

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FIGURE 5.5-3

OPERATING PRINCIPLE OF JET PUMP

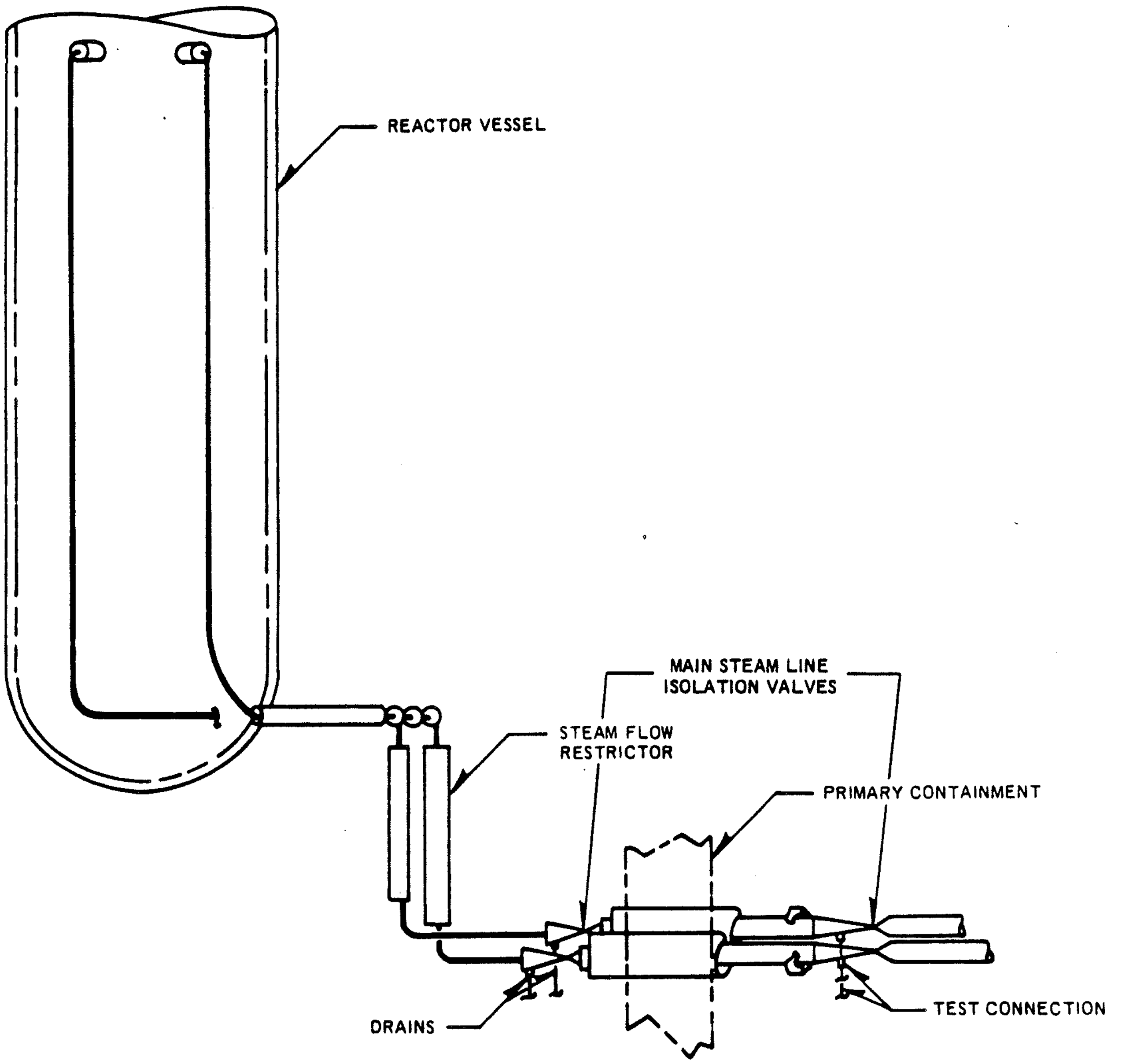

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FIGURE 5.5-4

MAIN STEAM LINE FLOW RESTRICTOR LOCATION

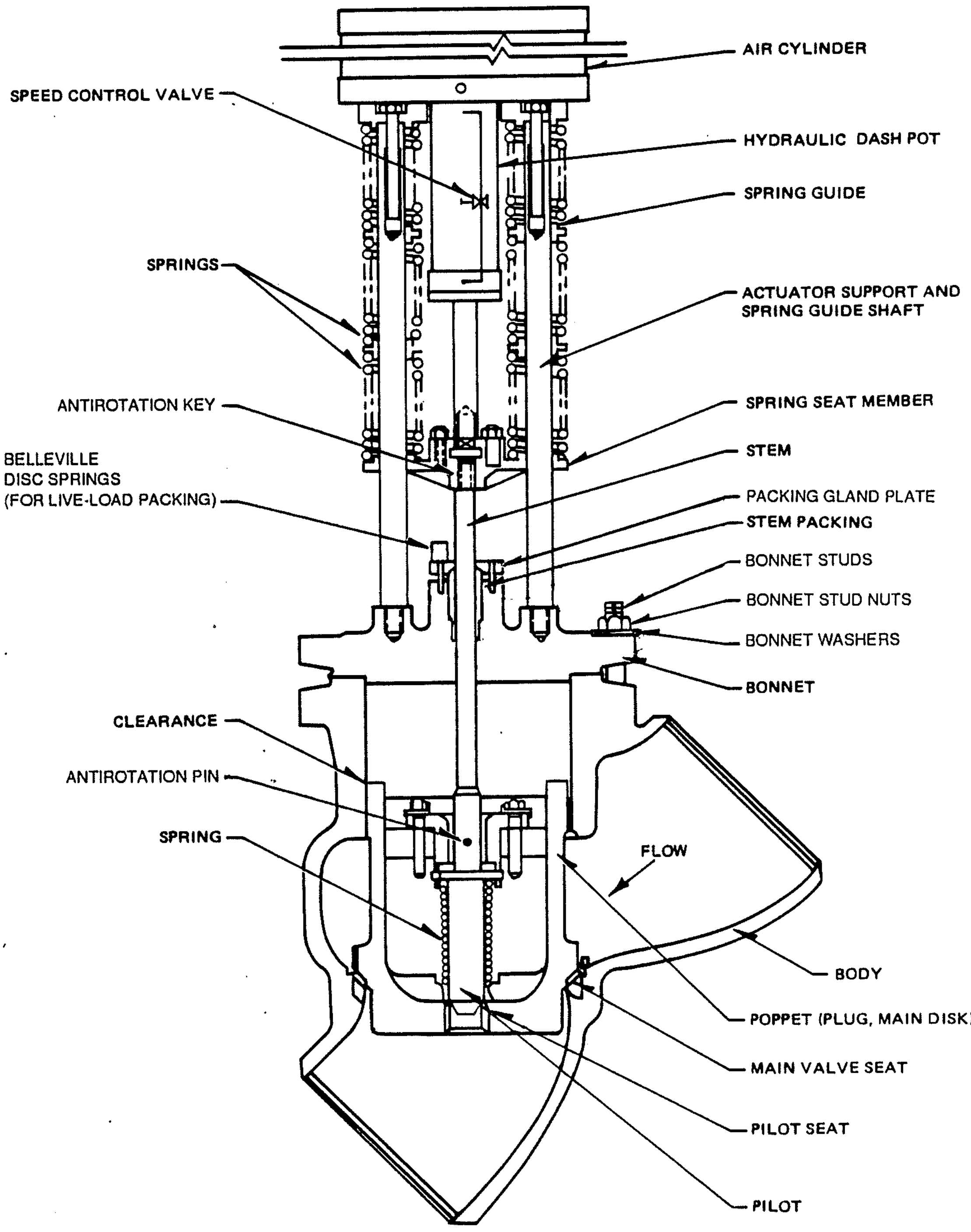

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FIGURE 5.5-5

TYPICAL MAIN STEAM LINE ISOLATION VALVE

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Refer to Plant Drawing M-5859

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FIGURE 5.5-6

REACTOR CORE ISOLATION COOLING SYSTEM
PROCESS DIAGRAM

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Refer to Plant Drawing M-2044

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FIGURE 5.5-7, SHEET 1
REACTOR CORE ISOLATION COOLING SYSTEM P&ID

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Refer to Plant Drawing M-2045

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FIGURE 5.5-7, SHEET 2
REACTOR CORE ISOLATION COOLING SYSTEM P&ID

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Refer to Plant Drawing M-5876

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FIGURE 5.5-8

REACTOR CORE ISOLATION COOLING VALVE POSITIONS DURING NORMAL OPERATION

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Refer to Plant Drawing M-5877

FIGURE 5.5-9

REACTOR CORE ISOLATION COOLING INITIAL COOLING FOLLOWING MAIN CONDENSER ISOLATION

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Refer to Plant Drawing M-5878

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FIGURE 5.5-10

REACTOR CORE ISOLATION COOLING FOLLOWING MAIN CONDENSER ISOLATION USING SUPPRESSION POOL AS A BACKUP WATER SOURCE

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Refer to Plant Drawing M-5879

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FIGURE 5.5-11

REACTOR CORE ISOLATION COOLING TEST MODE

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Refer to Plant Drawing M-5880

FIGURE 5.5-12

REACTOR CORE ISOLATION COOLING MINIMUM FLOW MODE

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Refer to Plant Drawing M-2083

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FIGURE 5.5-13, SHEET 1

RESIDUAL HEAT REMOVAL SYSTEM P&ID

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FIGURE 5.5-13, SHEET 2

RESIDUAL HEAT REMOVAL SYSTEM P&ID

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Refer to Plant Drawing M-5862

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FIGURE 5.5-14

RESIDUAL HEAT REMOVAL VALVE POSITIONS DURING NORMAL REACTOR OPERATION

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Refer to Plant Drawing M-5863

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FIGURE 5.5-15

RESIDUAL HEAT REMOVAL SHUTDOWN COOLING

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Refer to Plant Drawing M-5864

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FIGURE 5.5-16

RESIDUAL HEAT REMOVAL CONTAINMENT COOLING MODE

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Refer to Plant Drawing M-5865

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FIGURE 5.5-17

RESIDUAL HEAT REMOVAL SUPPRESSION POOL COOLING MODE

FIGURE 5.5-18 HAS BEEN DELETED

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FIGURE 5.5-19

REACTOR WATER CLEANUP
REACTOR BUILDING

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Refer to Plant Drawing M-5858

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FIGURE 5.5-20

REACTOR WATER CLEANUP SYSTEM
PROCESS DIAGRAM

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Refer to Plant Drawing M-2047

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FIGURE 5.5-21

REACTOR WATER CLEANUP FILTER
DEMINERALIZER SYSTEM P&ID

5.6 INSTRUMENTATION REQUIREMENTS

The functional requirements for the reactor coolant system instrumentation are discussed in the following subsections. Details of the design and logic of the instrumentation are discussed in Chapter 7.

5.6.1 Neutron Monitoring System

This system is described in Subsection 7.1.2.1.4.

5.6.2 Reactor Pressure Vessel Instrumentation

Reactor pressure vessel (RPV) instrumentation is designed to provide the operator with sufficient indication of reactor core flow rate, RPV water level, RPV pressure, and nuclear system leakage to maintain proper operating conditions.

5.6.2.1 Reactor Pressure Vessel Temperature

The RPV temperature is determined on the basis of reactor coolant temperature. Temperatures needed for operation and for compliance with the Technical Specifications operating limits are obtained from one of several sources, depending on the operating condition. During normal operation, either reactor pressure and/or the inlet temperature of the coolant in the RRS loops can be used to determine the RPV temperature. Below the operating span of the temperature detectors in the RRS loop, the pressure is used for determining the temperature. Below 212°F the coolant temperature in the RPV, and thus the RPV temperature, is reasonably determined by the reactor water cleanup (RWCU) system inlet temperature.

5.6.2.2 Reactor Pressure Vessel Water Level

The number of RPV water level indications is sufficient to provide the operator with information to determine the adequacy of the coolant inventory to cool the fuel. In addition, by verifying that RPV water level is not rising to an abnormally high level, the operator is ensured that turbines are not endangered by the possibility of water carried into the steam lines. The common zero reference point for all vessel level instruments at Fermi 2 is the top of the active fuel.

5.6.2.3 Reactor Pressure Vessel Coolant Flow Rates and Differential Pressures

Flow instruments, differential pressure instruments, and recorders are provided so that the core coolant flow rates and the hydraulic performance of RPV internals can be determined.

5.6.2.4 Reactor Pressure Vessel Internal Pressure

Pressure switches, indicators, and transmitters detect RPV internal pressure from the same instrument lines used for measuring RPV water level.

5.6.2.5 Reactor Pressure Vessel Top Head Flange Leak

A connection is provided on the RPV flange into the annulus between the two metallic seal rings used to seal the RPV and top head flanges. This connection permits detection of leakage past the inner seal ring, and is described further in Subsection 5.2.7.

CHAPTER 6: ENGINEERED SAFETY FEATURES

6.1 GENERAL

Engineered safety feature (ESF) systems are provided to mitigate the consequences of postulated accidents. The following ESF systems are discussed in this chapter:

a. Containment structures

   1. Primary

   2. Secondary.

b. Containment systems

c. Emergency core cooling system

   1. High pressure coolant injection system

   2. Automatic depressurization system

   3. Core spray system

   4. Low pressure coolant injection mode of residual heat removal system.

d. Main control room habitability systems.

In addition to the ESF systems discussed in this chapter, other ESF systems discussed elsewhere are provided to limit the consequences of postulated accidents. The ESF systems are covered in Chapter 6 and those other locations referenced in Table 6.1-1.

The information provided herein demonstrates the following:

a. The concepts upon which the operation of each system is predicated have been proven by tests under simulated accident conditions and/or by conservative extrapolations from present knowledge and experience

b. Component reliability, system independency, redundancy, and separation of components or portions of systems ensure that the feature will accomplish its intended purpose and will function for the period required

c. Provisions for test, inspection, and surveillance have been made to ensure that the feature will be dependable and effective upon demand

d. The material used will withstand the postulated accident environment, including radiation levels, and the radiolytic decomposition products which may occur will not interfere with ESF systems.

TABLE 6.1-1 ENGINEERED SAFETY FEATURES DISCUSSED IN OTHER CHAPTERS OF FERMI 2 UFSAR

Engineered Safety Fearures	UFSAR Location
Chapter 4	
Control rod velocity limiter	4.5.2
Control rod drive housing supports	4.5.3
Chapter 5	
Main steam line flow restrictors	5.5.4
Main steam line isolation valves	5.5.5
Chapter 7	
Main steam line monitoring system	7.3.2, 11.4.3
Chapter 8	
Onsite power systems	8.3
AC power systems	8.3.1
DC power systems	8.3.2
Chapter 9	
Emergency equipment cooling water and emergency equipment service water systems	9.2.2
Ultimate heat sink	9.2.5
RHR service water system	9.2.5.1
RHR complex reservoir	9.2.5.2.1
Mechanical draft cooling towers	9.2.5.2.2
ESF cooling and ventilation units	9.4.2

6.2 CONTAINMENT SYSTEMS

6.2.1 Containment Functional Design

On September 9, 1992, the NRC issued Amendment 87 to the Fermi 2 operating license authorizing a change in the thermal power limit from 3293 MWt to 3430 MWt, a 4.2 percent increase in the thermal power and a 5 percent increase in steam flow. The Fermi 2 Power Uprate Program followed GE Nuclear Energy guidelines and evaluations for BWR power plants (References 1, 2, 3, and 4).

On February 10, 2014, the NRC issued Amendment 196 to the Fermi 2 operating license authorizing a change in the thermal power limit from 3430 MWt to 3486 MWt, a 1.64 percent increase in thermal power and a 1.88 percent increase in steam flow. This changed the net electrical capacity from 1150 MWe to approximately 1170 MWe. This power uprate was performed in accordance with 10 CFR 50, Appendix K and reflects the improvement in feedwater flow measurement. The Fermi 2 Measurement Uncertainty Recapture (MUR) power uprate followed the GE generic guidelines and evaluations for BWR plants provided in GEH Topical Report NEDC-32938P-A, “Generic Guidelines and Evaluations for General Electric Boiling Water Reactor Thermal Power Optimization,” Revision 2, May 2003 (Reference 30). The analyses performed at 102% of the pre-MUR licensed thermal power (3430 MWt) remain applicable at the MUR uprated thermal power (3486 MWt) because the 2% uncertainty factor discussed in Regulatory Guide 1.49 is effectively reduced by the improvement in feedwater flow measurements.

Short-term and long-term containment analyses results are reported in Subsection 6.2.1.3. The short-term analysis is directed primarily at determining the drywell pressure responses during the initial blowdown of the reactor vessel inventory to the containment following a large break inside the drywell. The long-term analysis is directed primarily at the pool temperature response, considering the decay heat addition to the pool.

6.2.1.1 Design Bases

The containment system design meets the following safety design bases:

a. The containment systems shall have the capability to withstand the peak transient pressures and temperatures that could occur due to a postulated design-basis accident (DBA), intermediate-break accident (IBA), or small-break accident (SBA). The assumptions and criteria used to conservatively predict the short-term pressure and temperature response of the containment system drywell and suppression chamber during these accident conditions are provided in the Mark I Owners Group Load Definition Report (Reference 5), the Fermi 2 Plant Unique Load Definition Report (Reference 6), and in NUREG-0661 (Reference 7). The reevaluation of containment response for power uprate is provided in References 3 and 4. The long-term response of the drywell and suppression chamber is described in Subsection 6.2.1.3.3.

   No one accident results in the simultaneous occurrence of the maximum values of pressure and temperature (drywell design pressure and temperature, suppression chamber design pressure and temperature)

b. The containment systems shall accommodate the effects of metal/water reactions and other chemical reactions following the postulated DBA to values consistent with Regulatory Guide 1.7

c. The containment shall have the capability to maintain its functional integrity indefinitely after a postulated DBA, IBA, or SBA

d. The containment design shall permit filling the containment system drywell with water to a level above the reactor core

e. The containment system shall be protected against missiles from internal or external sources and excessive motion of pipes that could directly or indirectly endanger the integrity of the containment

f. The containment shall withstand jet forces associated with the flow from the postulated rupture of any pipe within the containment

g. The containment shall limit leakage during and following a postulated accident to values less than leakage rates that would result in offsite doses greater than the limits established in 10 CFR 50.67 or 10 CFR 100

h. It shall be possible to periodically conduct such leakage tests as may be appropriate to confirm the integrity of the containment at calculated peak pressure resulting from the accident condition that produces the maximum pressure response (DBA)

i. There shall be means to direct the flow from postulated pipe ruptures to the pressure suppression pool, to distribute such flow uniformly throughout the pool, to condense the steam portion of the flow rapidly, and to limit the pressure differentials between the drywell and the wetwell during the various postaccident cooling modes. The hydrodynamic events of pool swell, condensation oscillation, and chugging that occur during these flow and steam condensation regimes are defined by NUREG-0661 (Reference 7) and the Mark I Owners Group Load Definition Report (Reference 5). The design basis of the containment system includes the loading conditions associated with these hydrodynamic events

j. Capability for rapid closure or isolation of all pipes or ducts that penetrate the containment shall be provided by means that provide a containment barrier in such pipes or ducts sufficient to maintain leakage within permissible limits

k. There shall be the means for stable steam condensation of safety/relief valve (SRV) discharges into the suppression pool during transient and accident plant conditions. The containment system design basis includes the SRV actuation events, associated hydrodynamic loading conditions, and pool temperature limits described in NUREG-0661 (Reference 7), NUREG-0783 (Reference 8), and the Mark I Owners Group Load Definition Report (Reference 5)

    l. During the DBA, with the minimum emergency core cooling system (ECCS) pumps operating, and the available service water at the design maximum temperature, the long-term peak pool temperature shall not exceed the design temperature.

6.2.1.2 System Design

There are two passive provisions for containment of possible postaccident airborne contamination, the primary containment system and the secondary containment system. A perspective drawing illustrating these systems and their relationship is presented in Figure 5.1-4.

In addition to these two passive containment systems, the gases in either the primary or secondary containment can be exhausted through the standby gas treatment system (SGTS). This arrangement ensures that any accident-related discharge will be filtered by the SGTS before release. The SGTS is discussed in Subsection 6.2.3.

6.2.1.2.1 Primary Containment

The primary containment is a pressure suppression system. It consists of a drywell that houses the reactor pressure vessel (RPV); reactor coolant recirculating loops, and other branch connections of the reactor coolant system; a pressure suppression chamber that stores a large volume of water; a vent system connecting the drywell and the pressure suppression chamber water; a vacuum relief system; isolation valves; and service equipment.

In the event of a process system piping failure within the drywell, reactor water and steam would be released into the drywell. The resulting increased drywell pressure would force a mixture of air, steam, and water through the vents into the pool of water that is stored in the suppression chamber. The steam would condense in the suppression pool, resulting in a rapid pressure reduction in the drywell. The hydrodynamic events of pool swell, condensation oscillation, and chugging associated with the venting and steam condensation processes are described in NUREG-0661 (Reference 7) and the Mark I Owners Group Load Definition Report (Reference 5). Noncondensable gases trans-ferred to the suppression chamber pressurize the chamber and are subsequently vented back to the drywell to equalize the pressure between the two vessels. Cooling of the primary containment under accident conditions is provided by the containment cooling and spray modes of the residual heat removal (RHR) system, as discussed in Subsection 6.2.2. Appropriate isolation valves are actuated to ensure containment of radioactive materials that might otherwise be released from the primary containment.

Detailed design information of the primary containment is given in Subsection 3.8.2 and in References 9 and 10. The information given there includes the dynamic loads that could be imposed on the torus, the vent system, the torus internal structures, and the torus attached piping following a LOCA. Also given there is a description of the methods used to determine these loads and how these loads were incorporated in the structural and attached piping design. A summary of important design parameters of the primary containment is presented in Table 6.2-1. The more important features of the primary containment system are described below.

6.2.1.2.1.1 Drywell

The drywell is a steel pressure vessel with a spherical lower portion, 68 ft in diameter, and a cylindrical upper portion, 38 ft 10 in. in diameter. The overall height is approximately 114 ft 8 in. The drywell design pressure is 56 psig at a temperature of 281°F. The design temperature is 340°F with a coincident pressure of 25 psig.

The design, fabrication, inspection, and testing of the drywell vessel comply with requirements of the ASME Boiler and Pressure Vessel (B&PV) Code Section III, Nuclear Vessels, 1968 Edition with Summer 1969 Addenda, Subsection B, Requirements for Class B Vessels, which pertain to containment vessels for nuclear power plants. The steel head and shell of the drywell are fabricated of SA-5l6GR70 steel plate, firebox quality, aluminum-killed to SA-300 requirements. Thermal stress in the steel shell due to temperature gradients is considered in the design. Special procedures not required by code have been used in the fabrication of the steel drywell shell. For seams exceeding 1-1/4-in. thickness, the plate was heated to a minimum temperature of 200°F prior to welding. For seams 1-1/4 in. or less, the plate was heated to a minimum temperature of l00°F if the ambient temperature was below 40°F.

Charpy V-notch impact tests were performed on specimens of all plate and forged materials.

Plates, forgings, and pipes of the drywell have an initial nil ductility transition (NDT) temperature of approximately 0°F when tested in accordance with the appropriate code for these materials. It can be reasonably expected that the drywell will not be pressurized or subjected to a substantial stress at temperatures below 30°F.

The drywell is enclosed in reinforced concrete for shielding purposes. Resistance to deformation and buckling of the drywell is provided over areas where the concrete backs up the steel shell. Above Elevation 572 ft 1 in., the drywell is separated from the reinforced concrete by a gap of approximately 2 in. This gap is filled with a compressible polyurethane material to allow for movement between the drywell and concrete. The bottom portion of the shell is totally embedded in concrete and therefore is not subject to significant thermal stresses. The transition zone (below Elevation 572.5 ft) is backed by compacted sand to allow for thermal expansion and to aid in the drainage of condensate that may accumulate in the gap outside the drywell. Sand in the four drain lines at azimuths 0, 90, 180, and 270 degrees have been removed up to the pipe upstream of the 90 degree elbow. Sand in the sand cushion or transition zone is still intact.

Provisions for protection of the drywell against earthquakes, missiles, and pipe whip, which could damage the primary containment, are discussed in Chapter 3.

6.2.1.2.1.2 Pressure Suppression Chamber

The pressure suppression chamber is a steel pressure vessel, in the shape of a torus, below and encircling the drywell. It has a major diameter of 112 ft 6 in. and a cross-sectional diameter of 30 ft 6 in. It contains a total volume of approximately 251,980 ft^3. The suppression chamber is supported vertically by inside and outside columns and by a saddle support that spans the inside and outside columns. The support system transmits dead weight and seismic and hydrodynamic loading to the reinforced-concrete foundation slab of the reactor building. Space is provided outside the chamber for inspection and maintenance.

The pressure suppression chamber is designed for a temperature of 281°F and a pressure of 56 psig. The suppression chamber was originally designed to the same material and code requirements as the drywell vessel. The suppression chamber has been subsequently reevaluated for the effects of LOCA-related loads and SRV-discharge-related loads defined by the NRC Safety Evaluation Report NUREG-0661, the GE Reports NEDO-21888 (Mark I Containment Program Load Definition Report) and NEDC-31897P-1 (Generic Guidelines for General Electric Boiling Water Reactor Power Uprate). The criteria set forth in NUREG-0661 have been applied as the basis for acceptance of the analysis methods and the suppression chamber design. A detailed discussion of these reevaluations and their results is provided in the Fermi 2 Plant Unique Analysis Report (References 9 and 10) and in the Power Uprate Safety Analysis (Reference 3). All materials have an initial NDT temperature of approximately 0°F.

Where safety/relief valves terminate inside the suppression chamber, T-quencher devices are provided to aid in mitigating the associated SRV discharge loads in the suppression chamber. Reference 5 contains a description of the T-quencher design and its performance.

6.2.1.2.1.3 Vent Systems

Eight vent pipes connect the drywell and the pressure suppression chamber. Each pipe has a diameter of 6 ft 0 in. The vent pipes are designed for an internal pressure of 56 psig at 281°F. They will withstand an external pressure of 2 psig. Jet deflectors are provided in the drywell at the inlet of each vent pipe to prevent possible damage from jet forces, which might accompany a pipe break in the drywell. The vent pipes are fabricated of SA-516GR70 steel plate, firebox quality, aluminum-killed to SA-300 requirements, and comply with requirements of the ASME B&PV Code Section III, Subsection B. The pipes are enclosed with sleeves and provided with expansion joints to accommodate differential motion between the drywell and suppression chamber.

These vent pipes connect to a vent header in the form of a torus located in the air space of the suppression chamber. The vent header is nominally 1/4-in. thick and has an inside diameter of 4 ft 3 in. Near the vent line-vent header intersection, the vent header has an inside diameter of 6 ft 0 in. Conical transition segments connect the smaller and larger diameter portions of the vent header.

The vent header and downcomer system inside the torus was designed, fabricated, and erected in accordance with ASME B&PV Code Section III, 1968 Edition through winter 1969 addenda, Class B requirements but it is not leak tested.

Projecting downward from the header are 80 downcomer pipes, each 24 in. in diameter and terminating below the surface of the water in the suppression chamber pool. The pool water level is maintained to ensure a 3.00- to 3.33-ft submergence of the downcomer pipes. The header is designed to meet the same temperature and pressure requirements as the vent pipes.

The vent system has also been evaluated for the effects of LOCA-related loads and SRV-discharge-related loads defined by NUREG-0661 and NEDO-21888. As with the suppression chamber discussed above, a detailed discussion of these evaluations is provided in References 3 and 9.

Vacuum breakers discharge from the suppression chamber into the vent header system. Vacuum breaker sizing is based on the Moss Landing (Reference 11) test configuration.

Both the drywell and the pressure suppression chamber can be vented to the atmosphere through the SGTS or reactor building ventilation system.

6.2.1.2.1.4 Pipe Penetrations

Primary containment penetrations are designed for peak transient conditions to be expected during a LOCA. They will withstand, or are shielded from, the forces caused by impingement of fluid from the rupture of the largest local pipe or connection. Specific evaluations of the suppression chamber penetrations to address the requirements of NUREG-0661 are described in Reference 10.

These penetrations are designed to accommodate, without failure, any combination of thermal and mechanical stresses, which may be encountered during all modes of operation. (Refer to Subsection 3.8.2.1.3.)

Primary containment system piping penetrations are enumerated in Table 6.2-2. Electrical penetrations are listed in Table 6.2-3.

Relative movement between the containment penetrations and the drywell is accommodated by using bellows-type expansion joints (Figure 6.2-1). For this type of penetration, a sleeve passes through concrete and is welded to the primary containment vessel. The process line that passes through the penetration is anchored to allow only radial thermal expansion. A guard pipe surrounds the process line to protect the bellows and maintain containment integrity should the process line fail within the penetration. Insulation and air gaps are provided to reduce radiant heating of the guard pipe and the penetration sleeve and bellows. The dual-ply bellows arrangement permits periodic leak testing of these penetrations at a pressure equal to the primary containment DBA pressure (see Subsection 6.2.1.4) as well as continuous monitoring capability.

Figure 6.2-1 presents the containment penetration configuration for a typical process line of the reactor coolant pressure boundary (RCPB). As it passes through the drywell containment vessel and the concrete biological shield, the process line is enclosed in a guard pipe that is attached to it through a multiple head fitting. This fitting is a one-piece forging with integral flues or nozzles made to SA-105, Grade II requirements, and designed to meet all requirements of the ASME B&PV Code Section III, Class l. The guard pipe design is based on 90 percent of the material yield stress when pressurized to 1250 psi due to process line rupture. The process line penetration sleeve is welded to a bellows which in turn is welded to the guard pipe. The bellows assembly accommodates the differential thermal expansion and seismic movements between the process pipe and the drywell in the three mutually perpendicular directions.

Pipe penetrations for those applications not requiring provisions for relative movement between pipe and containment shell are illustrated in Figures 6.2-2 and 6.2-3.

The design of the penetrations takes into account the simultaneous stresses associated with normal thermal expansion, live and dead loads, seismic loads, and loads associated with LOCAs within the drywell. For all of these conditions, including appropriate combinations of these loads, the resultant combined stresses in the pipe and penetration components do not exceed design limits allowable by applicable codes. If, in addition, the jet force loadings resulting from random failures of the steam pipe are included, the resultant stresses in the pipe and penetration do not exceed allowable code stresses for fault conditions.

Cold piping and ventilation duct penetrations are welded directly to the sleeves. Bellows and guard pipes are not necessary in these applications because the thermal stresses are small and accounted for in the design of the weld joints.

6.2.1.2.1.5 Electrical Penetrations

Figure 6.2-4 shows a typical electrical penetration used for transmitting electric power, and instrumentation and control signals from the reactor building into the primary containment. Separation of divisions is obtained by locating penetrations on the semi-peripheries of the containment at Elevation 604 ft. The division boundary is the east-west diameter. Division I is on the north half; Division II, the south half.

One group of six penetrations is used to transmit power to two 7100-hp, three-phase, 3920-V reactor coolant recirculation pump motors.

One group of two penetrations is used for low-voltage power, motor control three-phase, 480-V, 208-V, and single-phase 120-V, and 125-V-dc loads.

One group of two penetrations is used for 120-V signals for limit and level switches. These penetrations also contain an isolated penetration within a penetration for the reactor protection system (RPS).

One group of six penetrations is used for low-voltage instrumentation cable to transmit control and temperature signals for control rod position from reactor to recorders and computer.

One penetration is used for analog signals, to be used for vibration tests and miscellaneous primary signals.

One group of two penetrations for low-voltage shielded instrumentation thermocouple extension lead wire is used to transmit RPV and other equipment temperature signals to recording and readout equipment.

One group of four penetrations is used for neutron monitoring. The penetrations include the following coaxial and triaxial cables per penetration:

a. Three triaxial - for intermediate-range monitors

b. Two triaxial - for source range monitor

c. 48 coaxial - for local power range monitor.

All penetrations are sized for a 12-in.-diameter nozzle and are hermetically sealed, with provisions for continuous leak detection at design pressure. The penetrations are factory assembled, prewired and tested, and do not require field welding for installation due to the flange mount design. Radiation shielding is integral, thus minimizing radiation shine, and eliminating overhanging moments which would occur if shielding were mounted externally.

Edison made a review of the primary containment electrical penetrations to determine that the electrical penetration assemblies were designed to withstand, without the loss of mechanical integrity, the maximum available fault current versus time conditions that could occur, given single random failures of circuit overload devices as recommended by Regulatory Guide 1.63, Revision 1.

In making the review, the following assumption was primary: The I^2t characteristics of the penetration conductors as furnished by Conax Corp. were used as a basis for determining integrity. The I^2t curves as furnished by Conax Corp. were conservative in nature and the I^2t curve points were not necessarily the points of damage to the mechanical integrity of the penetrations.

The following positions are in line with the guidelines set forth in Regulatory Guide 1.63, which were taken by Edison, based on the results of this review.

a. For low-energy penetrations, maximum fault current does not approach the I^2t of the penetration conductor. No backup or redundant protection is provided

b. On low-voltage power penetrations where maximum fault current versus time will exceed the I^2t of the penetration conductor (considering single random failure of the primary protection), backup protection is provided by one of the two following methods:

   1. If adequate backup protection can be obtained from the feeder position and the fault can be cleared in sufficient time to prevent reaching the I^2t of the penetration conductor - no additional redundant protective devices are provided

   2. Where the feeder position cannot provide adequate clearing time, an additional protective device, fuse or breaker as necessary, is provided.

There are six medium voltage power penetrations, and they are used for the reactor recirculation pump motor M-G set output from the generator to the pump motors. In these cases the primary protection is provided by tripping the main M-G set motor drive incoming circuit breaker positions. Backup protection is provided by tripping the generator field breakers. Proper relaying ensures operation of the field breaker.

Loads to the primary containment not necessary for reactor operation (i.e., lighting and welding) are maintained in a deenergized condition.

6.2.1.2.1.6 Traversing In-Core Probe Penetrations

A total of five traversing in-core probe (TIP) guide tubes and two spare penetrations pass through the primary containment. Penetrations of these guide tubes through the primary containment are sealed with a Class I drywell penetration seal weld which meets the requirements of the ASME B&PV Code Section III. These seals also meet the intent of Section III of the Code even though the Code has no provisions for qualifying the procedures or performance.

6.2.1.2.1.7 Personnel and Equipment Access Lock

One personnel access lock is provided for access to the drywell (Figure 6.2-5). The lock has two gasketed doors in series. The inner door has a double seal gasket and the outer door a single gasket. The doors are designed and constructed to withstand the drywell design pressure. The doors are mechanically interlocked to ensure that at least one door is locked. The locking mechanisms are designed so that a tight seal will be maintained when the doors are subjected to either internal or external pressure. The seals are capable of being tested for leakage. Two equipment access hatches and a control rod drive (CRD) removal hatch are in the spherical portion of the drywell. These hatches have double testable seals and are bolted in place (Figure 6.2-6).

6.2.1.2.1.8 Access To the Pressure Suppression Chamber

Access from the reactor building to the pressure suppression chamber is provided at two locations. These are two 4-ft-diameter manhole entrances with double-gasketed bolted covers connected to the chamber by 4-ft-diameter steel pipes. These access ports are bolted closed when the primary containment is secured.

6.2.1.2.1.9 Access for Refueling Operations

The head or top portion of the drywell vessel is removed during refueling operations. This head is held in place by studs and is sealed with a double seal. It is closed when the primary containment is required and is opened only when the primary coolant temperature is below 212°F and the pressure suppression system is not required to be operational.

A double seal on the head flange is provided to permit checking leaktightness after the drywell head has been replaced.

6.2.1.2.1.10 Venting and Vacuum Relief System

The primary containment is designed for an external pressure of 2 psi. It can be vented through the SGTS or the reactor building ventilation system to limit pressure fluctuations caused by temperature changes during various operating modes. For normal operation, this can be accomplished through the small dedicated lines of the containment atmospheric control system that controls the venting or makeup of nitrogen. During normal operation, the primary containment is maintained at a slightly positive pressure by the Nitrogen Inerting System as described in Subsection 9.3.6.1. Containment pressure is monitored as described in Subsection 7.6.1.12.3.1. The same penetrations that are used for makeup nitrogen are also used to vent the containment for pressure control. The large ventilation purge connections are normally closed while the reactor is at a temperature greater than 212°F, except for inerting or purging. Vacuum breakers are between the drywell and the suppression chamber. Automatic vacuum relief devices are used to prevent the external primary containment pressure from exceeding the design value. The drywell vacuum relief valves draw gas from the pressure suppression chamber, and the pressure suppression chamber vacuum relief device draws air from the reactor building.

A vacuum breaker in series with an air-operated normally closed butterfly valve is used in each of two lines from the suppression chamber to the reactor building atmosphere. One valve (a pilot-operated butterfly valve) is actuated by a differential pressure signal. The second valve is a self-actuating vacuum breaker, opening at a maximum differential pressure of 0.5 psid. The valves are sized to provide sufficient mass flow rate to equalize the pressure between the suppression chamber and the reactor building in case of an inadvertent operation of the suppression chamber spray. The flow rate calculation assumed that the vacuum breaker valves failed to open until the differential pressure reached 1.0 psid. The two separate lines are redundant in that either can provide adequate venting.

The vacuum breakers connecting the suppression chamber and the drywell are sized on the basis of the pressure suppression system test program conducted for Bodega Bay at Moss Landing (Reference 11). The vacuum breaker flow area is proportional to the flow area of the vents connecting the drywell and suppression pool. Their chief purpose is to prevent excessive water-level variation in the portion of the vent discharge line that is submerged in suppression pool water. The tests relating to vacuum breaker sizing were conducted by simulating a small system rupture, which tended to cause vent water-level variation as a preliminary step in the large rupture test sequence. The vacuum breaker capacity selected on this test basis is more than adequate (typically by a factor of four) to limit the suppression chamber-drywell pressure differential during postaccident drywell cooling operations to within containment system design values.

The Fermi 2 vacuum breakers are described in Table 6.2-4. The number of suppression-chamber-to-drywell vacuum breaker valves was chosen so that 25 percent (three of 12) could fail to open and adequate venting would still be provided.

The vacuum breaker valves are provided with a magnetic latch that holds the valve disk against the seat so that vibration does not cause the valve to chatter. The close limit switches, located near the bottom of the valve body, are actuated directly by the pallet. This design allows a precise adjustment of the limit switch setpoint to a very slight opening of the pallet. The transfer point of the switch from the closed to open position is measured electrically using an ohm meter or other continuity device. With the switch properly adjusted, the maximum distance the valve may be unseated and still indicate the closed position is 0.03 in. After limit-switch adjustment, the opening gap of the pallet at the switch is verified to be less than or equal to 0.03 in. Inspection of vacuum breaker instrumentation during reactor refueling will include verification of the opening gap for switch actuation. The bypass opening for the suppression-chamber-to-drywell vacuum breaker corresponding to a 0.03-in. disk opening is 0.009 ft^2, well within the maximum allowable leakage area of 0.25 ft^2 discussed in Subsection 6.2.1.3.6.

A suppression-chamber-to-drywell vacuum breaker valve similar to the Fermi 2 vacuum breaker valves has also been tested by the Mark I Owners Group in the full-scale test facility (FSTF). During several FSTF tests, the pressure fluctuations in the vent system produced during downcomer chugging caused the vacuum breaker to cycle open and closed. The measured FSTF pressure data have been used to evaluate the expected structural performance of the Fermi 2 vacuum breaker valves. The results of this evaluation are described in the report, Mark 1 Wetwell to Drywell Differential Pressure Load and Vacuum Breaker Response for the Fermi Atomic Power Plant Unit 2, by Continuum Dynamics, Inc., submitted to the NRC by Edison letter NE-85-0707 (Reference 12).

The secondary containment to torus vacuum breaker open and closed valve disk positions are indicated by lights on the main control room panel H11-P808. The drywell-to-torus vacuum breakers are provided with open and closed position indicators on panel H11-P808, and a second set of closed position indicators on panel H11-P817. The drywell-to-torus closed indicating circuits are powered by Class 1E power supplies and are wired to meet the requirements of IEEE 279-1971.

There is no annunciation of the valve position. The position switches and circuits do not control or affect the operation of the vacuum breakers. Any single failure of the indicating circuits or switches will not prevent proper action of the vacuum breakers.

The drywell-to-torus and the secondary containment to torus vacuum breakers are equipped with pneumatic actuators operated by pushbuttons from the main control room. The purpose of these actuators is to enable verification of the operability of the vacuum breakers by observing the response of limit switches. The operability of the vacuum breakers will be verified as required by the Technical Specifications.

The actuators are sized such that they have insufficient power to open the vacuum breakers if a backflow differential pressure exists. The drywell-to-torus vacuum breakers and test actuator supports are designed to Category I criteria. The drywell-to-torus vacuum breaker nitrogen supply components downstream of the testing actuator solenoids are designed to Category II/I criteria. The drywell-to-torus vacuum breaker test actuator solenoids meet QA1 and Category I seismic requirements and are environmentally qualified because they form part of the primary containment inboard closed boundary associated with penetrations X204A – M. The secondary containment-to-torus vacuum breakers and test actuators (including actuator supports) are also designed to seismic Category I criteria.

A negative pressure analysis was performed to demonstrate the adequacy of the containment vacuum relief system (Reference 13).

The most severe negative pressures in containment would result from events that challenge the vacuum relief system. The events are associated with operation of the containment spray mode of the RHR system under accident and transient conditions which result in high depressurization rates.

The bounding accident events involve actuation of the drywell spray following a steam leak in the drywell (small-break accident) and following a DBA. All intermediate-line break events are enveloped by these cases. The inadvertent drywell spray actuation during plant operation has been evaluated. The inadvertent drywell spray scenario is an event characterized by multiple operator errors and was not part of the original License application and review. The confirmatory evaluation of this event takes credit for both reactor building to suppression chamber vacuum breakers being operable and assumes the initial drywell ambient temperature of 145°F as described in License Amendment 20. The assumed scenarios and respective bases that lead up to the initial condition for these three cases and the analysis of these three cases are described in Reference 13.

The drywell and torus pressure/temperature responses resulting from these three cases were calculated using a computer program for the calculation of mass and energy balances at successive time intervals using basic thermodynamic, flow, and ideal gas law equations.

The mass flow of spray water through each loop increases in proportion to the opening flow characteristic of the outboard drywell spray isolation valve E1150F016A(B). The model employed assumes a linear valve flow characteristic that is scaled appropriately to accurately model the actual flow as a function of valve position. A linear ramp assuming 60 sec to reach maximum flow accurately reproduces the flow characteristic for a spray isolation valve having a 98-sec open stroke time. In order to model the flow characteristic of spray isolation valves having shorter opening stroke times, the time used to calculate the linear coefficient of mass flow acceleration is based on the 60-sec value scaled by the ratio of the actual minimum value of the valve open stroke time to 98 sec.

Many conservative assumptions are made in the calculational model. The spray is not accounted for in the drywell mass balances and only serves as a heat sink. The addition of water mass to the control volume atmospheres would tend to increase pressure and some vaporization of the spray would be expected. The butterfly valve opening setpoint was arbitrarily set at 0.5 psi. The actual setpoint is 0.25 psi. Any delay in butterfly valve opening time tends to increase depressurization.

The small break accident case was determined to be the most severe of the three bounding cases considered. A resulting drywell pressure of (-1.87 psid) was predicted for this case. This value is below the design pressure for the containment structures of (-2.00) psid.

6.2.1.2.2 Secondary Containment System

The reactor building completely encloses the reactor and its pressure suppression primary containment.

This building provides secondary containment when the primary containment is closed and in service, and provides primary containment when the primary containment is open, as it is during refueling. The reactor building houses the refueling and reactor servicing equipment; new- and spent-fuel storage facilities, and reactor auxiliary and service equipment, including the reactor core isolation cooling (RCIC) system; reactor cleanup demineralizer system, standby liquid control system (SLCS), CRD system equipment, emergency core cooling system (ECCS), and electrical equipment components.

The reactor building includes the "tunnel" containing the outboard main steam isolation valves (MSIVs), the main steam lines up to the turbine building, the feedwater lines, and the outboard feedwater line isolation valves. The tunnel is equipped with hinged doors which, upon pressure buildup due to a break in one of these lines, will relieve the steam pressure to the first and second floors of the turbine building. The net volume of the secondary containment is 2.8×10^6 ft^3.

The reactor building is a Category I structure designed and constructed in accordance with all applicable local and state building code requirements.

Substructures and exterior walls of the building up to the refueling floor consist of poured-in-place, reinforced concrete. The building structure above the refueling floor is a steel frame covered with insulated metal siding and is sealed against leakage. The building is designed for an external pressure of 0.295 psig and for low inleakage and outleakage (depending on wind conditions) during reactor operation.

6.2.1.2.2.1 Reactor Building Penetrations

Access openings for personnel and equipment are equipped with weather-strip-type seals, except for the railroad bay entry, for airtightness to meet secondary containment negative building pressure requirements. The railroad bay entry doors have inflatable seals which provide the airtightness requirements as well as site flood protection. The railroad bay rail pockets have seals which provide the airtightness requirements as well as site flood protection. Personnel entrances to the secondary containment are at the following locations:

a. The reactor core isolation cooling system/core spray pump room at Elevation 551 ft 0 in.

b. The auxiliary building basement from the CRD pump room at Elevation 551 ft 0 in.

c. Between the turbine and auxiliary building at Elevation 564 ft 0 in.

d. Outdoor entry to the reactor building at 583 ft 6in.

e. Railroad bay entry to the reactor building at 583 ft 6 in.

f. Between the reactor building and the auxiliary building at Elevation 613 ft 6 in.

g. Between the reactor building refueling floor and the auxiliary building at Elevation 684 ft 6 in.

h. Between the reactor building refueling floor and the auxiliary building at Elevation 701 ft 0 in.

All of these entries have a vestibule with double doors to maintain secondary containment integrity. The double doors are administratively controlled to prevent both doors from being open at the same time, thus maintaining secondary containment integrity. Additionally, as an administrative aid, the doors have either interlocks to prevent the opening of one door until the other door is closed or one of the doors is key locked closed. The interlock feature is not considered QA1 safety related. Failure of these interlock circuits would not cause the doors to open on their own accord. Keys for the locked closed doors are administratively controlled by the Shift Manager. In the case of the railroad bay airlock, the doors have inflatable seals which are considered active components. Therefore, to meet single failure criteria and maintain secondary containment integrity, the inner door seal is supplied from Division I of non-interruptible control air and the outer door seal is supplied from Division II of non-interruptible control air. The railroad bay airlock doors also have low seal pressure alarms which are monitored in the main control room.

Penetrations for piping and ducts are designed for leakage characteristics consistent with containment requirements for the entire building. Electrical cables and instrument leads pass through ducts sealed into the building wall.

6.2.1.2.2.2 Reactor Building Ventilation Systems

The reactor building has two ventilation systems: the normal ventilation system and the SGTS. During normal power operation, shutdown, or refueling, the normal ventilation system provides outside filtered air to all levels and building equipment rooms. This system provides a minimum of one reactor building free volume change of air per hour. Air flows from the filtered supply to uncontaminated areas, to potentially contaminated areas, and then to the release vent (a short stack) on the reactor building roof.

The fans for the normal ventilation system are automatically shut down in the event a high radiation level in the building exhaust ducts is detected by the radiation monitoring system (RMS), or if there is high pressure in the drywell, low RPV water level, or high static pressure in the building, or if high radiation is detected by the east or west fuel pool radiation monitors. The normal ventilation may be isolated manually from the control room.

Shutting down the fans closes the dual ventilation duct isolation dampers. The fans are controlled from the main control room.

During emergencies when the normal ventilation system is not operating, the reactor building is ventilated through the SGTS. The SGTS filters and exhausts the atmosphere of the reactor building via the roof vent.

6.2.1.2.2.3 Bypass Leakage Paths

One purpose of the secondary containment (reactor building) is to collect and filter leakage from the primary containment prior to release to the environment and thereby reduce offsite doses after a LOCA. This purpose is accomplished by

a. Minimizing reactor building leakage

b. Maintaining the reactor building at a negative pressure

c. Passing all exhaust from the reactor building through the SGTS after a LOCA.

A study has been made to evaluate the secondary containment system and determine all potential paths that could result in a fraction of the primary containment leakage going directly to the environment (i.e., without passing through the SGTS). The study encompasses three areas

a. Lines that are connected to the primary containment and pass through the secondary containment

b. Electrical penetrations

c. Reactor building leakage.

Primary Containment Lines

Lines that are connected to the primary containment and pass through the secondary containment are potential paths for leakage of radioactivity directly from the primary containment to the environment, bypassing the SGTS. The containment penetrations through which potential bypass leakage paths are possible are identified in Table 6.2-2.

All the bypass leakage paths listed in Table 6.2-2 will not contribute more leakage than 10 percent L_A, where L_A is the maximum allowable leak rate in the Type A containment integrated leak rate test (see Subsection 6.2.4.4). The radiological impacts of MSIV leakages of up to 100 scfh per steam line, and up to 250 scfh of total MSIV leakage are analyzed separately from L_A controlled leakages. Fermi 2 uses air or water sealing systems that eliminate leakage through certain valves:

a. The torus water management system suction lines (penetrations X-213A and B) are sealed with water in the torus

b. The high pressure coolant injection system suction line from suppression chamber (penetration X-225) and reactor core isolation cooling system suction line from suppression chamber (penetration X-226) are sealed with water in the torus.

The bypass leakage program will maintain a running total of leak rate measurements through all other bypass leakage paths as listed in Table 6.2-2 and will compare it with the maximum allowable. Valve maintenance will be performed when necessary.

With the exception of two leakage paths, all the valves in the bypass leakage program are containment isolation valves, and, as such, leak rates will be measured in accordance with 10 CFR 50, Appendix J, Type C tests (see Subsection 6.2.4.4). These paths accordingly are protected by redundant and diversely powered isolation valves. In the case of the reactor vessel instrument line backfill system leakage through the CRD piping when the CRD pressure is lost, certain noncontainment isolation valves are used in the program to meet criteria equivalent to those met by the other leakage paths. These valves will be tested in accordance with Section XI, Category A, of the ASME Code.

In summary, the following valves are encompassed in the bypass leakage program for Fermi 2:

System	Valve	Test
Reactor Feedwater	B2100F010A	Appendix J, Type C
	B2100F010B	Appendix J, Type C
	B2100F076A	Appendix J, Type C
	B2100F076B	Appendix J, Type C
Steam line drain	B2103F016	Appendix J, Type C
	B2103F019	Appendix J, Type C
HPCI	E4150F006	Appendix J, Type C
	E4150F002	Appendix J, Type C
	E4150F003	Appendix J, Type C
	E4150F600	Appendix J, Type C
RCIC	E5150F013	Appendix J, Type C
	E5150F007	Appendix J, Type C
	E5150F008	Appendix J, Type C
Drywell sumps	G1154F600	Appendix J, Type C
	G1100F003	Appendix J, Type C
	G1154F018	Appendix J, Type C
	G1100F019	Appendix J, Type C
Reactor Vessel Instrument Line Backfill	B2100F248A	Section XI, Category A
	B2100F248B	Section XI, Category A
	B2100F249A	Section XI, Category A
	B2100F249B	Section XI, Category A
Emergency Equipment Cooling Water System (EECW)	P4400F282A	Appendix J, Type C
	P4400F606A	Appendix J, Type C
	P4400F616	Appendix J, Type C
	P4400F607A	Appendix J, Type C
	P4400F282B	Appendix J, Type C
	P4400F606B	Appendix J, Type C
	P4400F615	Appendix J, Type C
	P4400F607B	Appendix J, Type C
Post Accident Sampling System (PASS)	P34F403A	Appendix J, Type C
	P34F404A	Appendix J, Type C
	P34F403B	Appendix J, Type C
	P34F404B	Appendix J, Type C
	P34F401A	Appendix J, Type C
	P34F401B	Appendix J, Type C
	P34F408	Appendix J, Type C
	P34F410	Appendix J, Type C
	P34F405B	Appendix J, Type C
	P34F406B	Appendix J, Type C
	P34F405A	Appendix J, Type C
	P34F406A	Appendix J, Type C

The EECW penetrations are normally open. The listed valves are Remote Manual Isolation valves that are closed by the Operators responding to alarm response procedures. The EECW leakage detection equipment and other EECW system indications will provide the required information to the Operators. The analysis of the available sealing water in the EECW/RBCCW systems indicate that over two hours is available prior to required Operator actions to close these valves. Closure of these valves will ensure that this path will not exceed measured bypass leakage.

Leakage through the primary containment exhaust lines is collected by the SGTS and is not discharged through the exhaust fans. The large purge/inert lines and the small "on-line" pressure control lines are tied to both the reactor building ventilation system and the SGTS. High radiation in the reactor building heating, ventilation, and air conditioning (RBHVAC) exhaust isolates these valves and starts the SGTS. A suction line to the SGTS is connected to the inerting supply line as shown in Figure 9.3-14. This line collects any leakage past the containment isolation valve and processes it through the SGTS.

Category I design requirements are met (1) on the main steam piping from the reactor, up to and including the third set of MSIVs, and (2) on all branch piping, up to and including the first valve that is either normally closed or capable of automatic closure during all modes of normal nuclear steam supply system (NSSS) operation.

Electrical Penetrations

Electrical cables exit from the primary containment via penetrations sealed at both internal and external ends; the external end is within the secondary containment. The cables leaving these penetrations run in cable trays. Thus there are no electrical wiring conduits or ducts that go directly from the primary containment to the environment, bypassing the secondary containment.

Reactor Building Leakage

The reactor building, under both normal and emergency conditions, is maintained at a negative pressure so that leakage is inward. The reactor building is maintained at 0.25 in. plus or minus 0.125 in. water gage. However, due to the kinetics of gas at high velocities, the pressure on the leeward side of the building will be negative at high wind speeds. Consequently, above a threshold wind speed, air could be drawn from the reactor building, bypassing the SGTS.

An exfiltration/infiltration analysis has been made on the building to determine inward and outward leakage rates as a function of wind speed. The analysis was based on the following:

a. The SGTS maintains the building at l/4 in. H_2O negative pressure

b. Leakage to the environment occurs only through the metal siding and only when the pressure differential across the siding is outward

c. The rate of leakage is 0.015 $ft^3/minute/ft^2$ at 1/4 in. H_2O and varies as the square root of pressure differential. The leakage rate is the same for positive and negative differentials

d. The wind force acts on two sides of the building; the other two sides are at a negative pressure

e. The positive and negative pressures due to wind are based on the equation

$$P = 0.002558\ S\ (GV)^2$$

where

P	=	wind pressure (lb/ft^2)		
S	=	shape factor	=	0.9 windward s
G	=	gust factor	=	1.1
V	=	wind velocity (mph)		

The study shows the threshold wind velocity for any leakage outward from the building is 30 mph. The study also shows that the net leakage (inward) through the siding is not a strong function of wind velocity; consequently, the operating parameters of the SGTS are independent of wind velocity.

Since there is siding only above the refueling floor, this leakage path is not directly from the primary containment to the environment, but rather from the secondary containment the reactor building. The estimate of the fraction of primary leakage bypassing the SGTS will be conservative if this fraction is assumed to be equal to the fraction of building leakage to total discharge from the reactor building. This statement can be expressed by the following equation:

$$B = \frac{S}{S+G}$$

Where:

B	=	fraction of primary leakage bypassing SGTS
S	=	outward leakage rate of siding (function of wind speed) (scfm)
G	=	discharge rate of SGTS (scfm)

The results of this study are summarized in the following table:

Wind Velocity (mph)	Fraction of Time per Year**	Reactor Building Leakage* Total Outward From Siding (scfm)	Reactor Building Leakage* Fraction of Primary Leakage Bypassing SGTS
0	0.65	0	0
10	0.34	0	0
20	0.01	0	0
30	0.001	52	0.017
40	--	246	0.076
50	--	370	0.110

*The radiological dose from exfiltration will result in inconsequential increases, i.e., less than 1 percent, in the total calculated doses since the fraction of time the leakage occurs is so very small. In addition, if an atmospheric dispersion parameter (χ/Q), which is inversely proportional to wind speed, is calculated for the higher wind speeds associated with exfiltration, it will further decrease the dose values.

**Winds of 15-minute duration as measured from the 10-m level on the 60-m tower during the 12-month period from June 1, 1974, to May 31, 1975.

6.2.1.3 Design Evaluation

6.2.1.3.1 Introduction

In the design of the primary containment vessel, certain extreme conditions were hypothesized; the design then proceeded so that maximum stress levels under these conditions did not exceed the maximum allowable values specified in the appropriate code.

The key parameters of stress are vessel temperature, pressure, and hydrodynamic loads. The containment vessel for Fermi 2 was designed under ASME B&PV Code Section III, Nuclear Vessels (1968), including Summer 1969 Addenda. This code specifies that the internal pressure used for design conditions shall not be less than 90 percent of the maximum containment internal pressure, and that the design temperature shall not be less than the maximum containment temperature at the coincident maximum containment pressure.

The containment vent system and suppression shell, supports, internals, and attachments have been reevaluated (References 9 and 10) to include the hydrodynamic loading events and analysis methods defined by GE Topical Report NEDO-21888 (Mark I Containment Program Load Definition Report) and the NRC Safety Evaluation Report, NUREG-0661. The appropriate edition of, Section III of the ASME Code and service-level limits specified in NUREG-0661, have been applied in the reevaluation.

The maximum drywell pressure occurs during the reactor blowdown phase of a LOCA. It is dependent upon the rate at which primary system energy and fluid enter the drywell. The largest pipe in the primary coolant system is the 28-in.-diameter main recirculation line. The instantaneous guillotine rupture of this pipe is the DBA for the containment design pressure. The same pressure is conservatively used for suppression chamber design.

The most severe drywell temperature condition would occur as a result of a small primary system rupture above the reactor water level that results in the blowdown of reactor steam to the drywell. Because of the nature of the blowdown process, this would produce high-temperature steam in the drywell.

The blowdown phase of an intermediate-size break was also evaluated to demonstrate that breaks smaller than the rupture of the largest primary system pipe can be accommodated safely without any of the containment design parameters being exceeded.

In Subsections 6.2.1.3.2 through 6.2.1.3.8, the various extreme conditions that have been hypothesized and analyzed as part of the original licensing basis for the containment design are described as modified by power uprate. The initial conditions, assumptions, and break flow model applied in these analyses maximize the containment temperatures and pressures that could be expected during postulated LOCAs. The discussions of the analysis results in these subsections include the conservatively predicted short-term and long-term response of the containment. However, as part of the Fermi 2 Mark I containment long-term program (References 9 and 10), and the subsequent reevaluation of limiting events for the Power Uprate Safety Analysis (Reference 3), the spectra of postulated pipe breaks have been reinvestigated to determine the worst loading conditions for each of the affected containment structural elements. The loading conditions associated with the long-term program analyses included pool swell, condensation oscillation, chugging, and safety/relief valve discharge. To establish a conservative load basis, the initial conditions, assumptions, and models differed, in some cases, from those used in the original licensing-basis containment analyses. The load bases and application methods used in the Mark I containment analyses are completely described in Reference 5 and have been accepted by the NRC in NUREG-0661 (Reference 7). The plant-unique load definition (Reference 6) describes the pressure and temperature responses of the drywell, vent system, and suppression chamber volumes used in the Fermi 2 containment longterm program analyses. Since the long-term program-related loads occur early in the postulated LOCA events, Reference 6 only describes the short-term containment responses (less than 1100 sec). The break flow model used in the plant-unique load definition analyses is described in Reference 14.

6.2.1.3.2 Recirculation Line Break - Short-Term Response

The instantaneous guillotine rupture of a main recirculation line results in the maximum flow rate of primary system fluid and energy into the drywell. This in turn results in the maximum containment differential pressure. Figure 6.2-7 is a diagram showing the location of a recirculation line break.

Immediately following the rupture, the flow out both sides of the break will be limited to the maximum allowed by critical-flow considerations. Figure 6.2-7 shows a schematic view of the flow paths to the break. In the side adjacent to the suction nozzle, the flow will correspond to critical flow in the nozzle pipe cross section. In the side adjacent to the injection nozzle, the flow will correspond to critical flow at the 10 jet pump nozzles associated with the broken loop. In addition, there is a 4-in. cleanup line cross tie that will add to the critical flow area, yielding a total of approximately 4.1 ft^2.

The short-term analysis was performed for the limiting DBA/LOCA which assumes a double-ended guillotine break of a recirculation suction line that results in the maximum flow rate of primary system fluid and energy into the drywell. The analysis predicted the peak drywell pressure at 49.9 psig which is less than the containment allowable design limit of 62 psig. The peak drywell pressure of 49.9 psig is bounded by the Technical Specification value of 56.5 psig which has not been changed.

The short-term analysis covers the blowdown period during which the maximum drywell pressure and differential pressure between the drywell and wetwell occurs. The analysis assumed 102 percent power (102 percent of 3430 MWt, 3499 MWt) and was done using the M3CPT computer code which is used to model short-term containment pressure and temperature response. The M3CPT code is based on References 14 and 15 and has been reviewed and accepted by the NRC (Reference 7) during the Mark I Long Term Program (LTP) for application to the Mark I plants, including Fermi 2. The inputs for the short-term analysis (M3CPT code) are shown in Table 6.2-1, Section II.

Figure 6.2-8 shows the blowdown flow rates from the primary system to the containment. Table 6.2-5 shows the primary system energy distribution at the time of the break. (Reference 31)

The calculated primary containment pressure and temperature responses to this DBA/LOCA are shown in Figures 6.2-9 and 6.2-10.

The calculated peak drywell pressure is 49.9 psig. After the discharge of primary coolant from the RPV into the drywell, the temperature of the suppression chamber water approaches

135°F and the suppression chamber pressure stabilizes at approximately 25 psig. The drywell pressure stabilizes at a slightly higher pressure, the difference being equal to the downcomer submergence. During the RPV depressurization phase, most of the noncondensable gases in the drywell initially are forced into the suppression chamber. However, the noncondensables will redistribute between the drywell and suppression chamber via the vacuum breaker system as the drywell pressure is decreased by steam condensation.

The LPCI and/or core spray system removes decay heat and stored heat from the core, thereby controlling core heatup and limiting any metal/water reaction. The RPV is flooded to the height of the jet pump nozzles and the excess flow discharges through the recirculation line break into the drywell. This flow of water transports the core decay heat out of the RPV, through the broken recirculation line in the form of hot water that flows into the suppression chamber via the drywell-to-suppression chamber vent pipes. Steam flow is negligible. This flow, in addition to heat losses to the drywell walls, offers considerable cooling to the drywell atmosphere and causes a depressurization of the containment as the steam in the drywell is condensed.

The LPCI/RHR pumps that are used to flood the core are also used as the containment spray and cooling pumps. Prior to activation of the containment cooling mode (arbitrarily assumed at 20 minutes after the accident), all of the LPCI pump flow may be used only to flood the core. After 20 minutes, the RHR pump flow will have to be diverted from the RPV to the containment cooling mode. This is a manual operation. Actually, the containment spray need not be activated at all to keep the containment pressure below the containment peak allowable pressure. As discussed above, the peak drywell pressure is less than the containment design limit of 62 psig.

6.2.1.3.3 Recirculation Line Break Long Term Response

The primary purpose of this analysis is to calculate the peak suppression pool temperature following a DBA/LOCA. The GE SUPERHEX (SHEX) code is used to predict the long-term containment response following a DBA/LOCA event.

The limiting case assumes that one RHR loop is operating in the containment cooling mode at partial pumping capacity. This includes one RHR heat exchanger, one RHR main system pump, and two service water pumps. During this mode of operation the RHR pump draws suction from the suppression pool and discharges flow through the RHR heat exchangers where it is cooled and then injected back into the suppression pool. Core cooling is provided by the core spray system and the RHR/LPCI pump prior to activation of the containment cooling mode at 20 minutes after the accident.

The long term analysis using the SHEX code with conservative input values yielded a peak post DBA/LOCA pool temperature of 196.5°F. This temperature shows margin remains to the controlling limit of 198°F which comes from NPSH requirement for pumps taking suction from the suppression pool with no credit for containment pressure per Regulatory Guide 1.1 (Subsection 6.3.2.14).

The input parameters for the long term response are shown in Table 6.2-1, Section III. Figures 6.2-11, 6,2-12, and 6.2-13 show the drywell and wetwell airspace pressure response, the drywell and wetwell airspace temperature response, and the suppression pool temperature response, respectively. The accident chronology is shown in Table 6.2-7. The conservatisms built into some of the inputs are described below.

<u>Service Water</u>

a. The Technical Specification limit for cooling tower reservoir temperature is 80°F. An energy balance calculation was used to determine the post-LOCA RHRSW temperature increase as a function of time from the initial condition of 80°F to the cooling tower maximum design temperature of 90°F. The temperature profile, which is non-linear, was conservatively bounded by a linear profile with the initial temperature of 80°F increasing in a linear way to 90°F over an 8-hour period. (Note: The current maximum analyzed service water supply temperature is below the assumed maximum 90°F).

b. The minimum technical specification RHR reservoir water level was used. This is conservative because it minimizes the heat capacity of the reservoir and maximizes the reservoir heatup.

c. Evaporative and drift losses were used to reduce reservoir inventory during the heatup period.

d. Complete mixing is assumed in the reservoir. This is conservative because hot water is discharged into the cooling towers and is sprayed down to the surface of the reservoir. Cooler water is drawn from the bottom of the reservoir where the pump suctions are located. No credit is taken for temperature stratification which lowers the reservoir discharge temperature profile.

<u>Suppression Pool Volume</u>

A pool volume of 117,161 ft^3 is used for the long-term containment analysis. The technical specification minimum value is 121,080 ft^3. This lower pool volume of 117,161 ft^3 adds conservatism to the calculated pool temperature, since a lower initial pool volume results in higher calculated values for pool temperature.

<u>Initial Pool Temperature</u>

The initial pool temperature of 95°F was used in the analysis. The 95°F is the Technical Specification limit for normal operation.

<u>Feedwater Addition</u>

For conservatism the analysis includes all water in the feedwater system that can contribute to higher calculated pool temperatures. This was achieved by adding all feedwater in the feedwater system during normal operation that has a temperature greater than the maximum expected pool temperature. This translates to all feedwater through feedwater heaters nos. 3, 4, 5, and 6.

In addition, a conservative calculation of the energy in the feedwater piping is added to the RPV/containment system. This water mass and energy addition assures that the pool temperature calculation conservatively reflects the effect of feedwater temperature on suppression pool temperature.

Initiation Time for Containment Cooling

The plant emergency operating procedures require that containment cooling be started for any suppression pool temperature greater than 95°F (that is within the first few minutes of a DBA/LOCA). However, the UFSAR does not take credit for operator action for the first 10 minutes into the accident. Added conservatism is built into the analysis by assuming containment cooling is initiated at 20 minutes resulting in a higher pool temperature than will be obtained with the 10 minute initiation time. Also the RHR heat exchangers providing cooling to the suppression pool water are assumed to be fouled, adding more conservatism.

Decay Heat

The decay heat based on the ANS 5.1 model (Reference 16) as described in Appendix B of Reference 17 has been used for the containment long-term analysis. This decay heat includes contributions due to fission heat induced by delayed neutrons, decay heat from fission products, decay heat from actinides (heavy elements), and decay heat from irradiated structural materials. For conservatism additional margin which corresponds to two standard deviations (10%) was added to the decay heat as described in Reference 17, Appendix B.

6.2.1.3.4 Intermediate Breaks

Intermediate breaks were not reanalyzed for power uprate since they were not the limiting case. The analysis presented below is based on the original power of 3358 MWt (102 percent of 3293 MWt).

The failure of a recirculation line results in the most severe pressure loading on the drywell structure. However, as part of the containment performance evaluation, the consequences of intermediate breaks are also analyzed. This classification covers those breaks for which operation of the ECCS will occur during the blowdown and which result in reactor depressurization. These breaks can involve either reactor steam or liquid blowdown. This section describes the consequences to the containments of a 0.l-ft^2 break below the RPV water level. This break area was chosen as being representative of the intermediate-break-area range. Figures 6.2-15 and 6.2-16 show the drywell and suppression chamber pressure and temperature response.

Following the 0.1-ft^2 break, the drywell pressure increases at 0.5 psi/sec. This drywell pressure transient is sufficiently slow so that the dynamic effect of the water in the vents is negligible and the vents will clear when the drywell-to-suppression chamber differential pressure is equal to the vent submergence pressure. For this containment design, the distance between the pool surface and the bottom of the vents is 3 ft 4 in. maximum. Thus, the water level in the vent will reach this point when the drywell-to-suppression chamber pressure differential reaches 1.5 psi, i.e., approximately 3 sec after the 0.1-ft^2 break occurs. At this time, air, steam, and water will start to flow from the drywell to the suppression pool; the steam will be condensed and the air will enter the suppression chamber free space. After 3 sec there will be a constant pressure differential between the drywell and the suppression chamber. The continual purging of drywell air to the suppression chamber will result in a gradual pressurization of the latter. By approximately 300 sec, all the drywell air will have been swept over to the suppression chamber and the pressure increase terminated. After this time, the drywell and wetwell pressures will remain relatively constant and all the steam being released to the drywell will be condensing in the pool. Some continuing containment pressurization will occur because of the continued pool heatup. The ECCS will be initiated by the 0.1-ft^2 break via high drywell pressure and will provide emergency cooling of the core. The operation of these systems is such that the reactor will be depressurized in approximately 600 sec.

This will terminate the blowdown phases of the transient. The drywell will be at approximately 25 psig and the suppression chamber at approximately 23 psig.

In addition, the suppression pool temperature will be the same as from the recirculating line break because essentially the same amount of primary system energy would be released during the blowdown. After reactor depressurization, the flow through the break will condense the drywell steam and will eventually cause the drywell and suppression chamber pressures to equalize in the same manner as following a recirculation line rupture.

The subsequent long-term suppression pool and containment heatup transient that follows is essentially the same as for the recirculation break without containment spray.

From this description, it can be concluded that the consequences of an intermediate break are less severe than a recirculation line rupture over short time periods and essentially the same over a long time period.

Additionally, as discussed in Subsection 6.2.1.3.1, the containment response due to intermediate breaks has also been calculated using the bases provided in References 5 and 7. The corresponding short term containment response is reported in Reference 6. These predicted results also support the above conclusions.

6.2.1.3.5 Small Breaks

Small breaks were not reanalyzed for power uprate since they were not the limiting case. The analysis presented below is based on the original power of 3358 Mwt (102 percent of 3293 MWt).

This subsection discusses the containment transient associated with small primary system blowdowns. The sizes of primary system blowdowns in this category are those blowdowns that will not result in reactor depressurization due either to loss of reactor fluid or automatic operation of the ECCS equipment. The underlying assumption is that, following the manifestation of a break of this size, the reactor operators will initiate an orderly shutdown and depressurization of the plant.

The thermodynamic process associated with the blowdown of primary system fluid is one of constant enthalpy. If the primary system break is below the water level, the blowdown flow will consist of reactor water. Upon depressurizing from reactor pressure to the drywell pressure, approximately one-third of this water will flash to steam and two-thirds will remain as liquid. Both phases will be at saturated conditions corresponding to the drywell pressure. Thus, if the drywell is at atmospheric pressure, the steam and liquid associated with a liquid blowdown would be at 212°F. Similarly, if the containment is assumed to be at its maximum allowable pressure, the reactor liquid would blow down to approximately 309°F steam and water. If the primary system rupture is located so that the blowdown flow consists of reactor steam, the resultant steam temperature in the containment is significantly higher than the temperature associated with liquid blowdown. This is because a constant enthalpy decompression of high-pressure, saturated steam will result in a superheat condition. For example, decompression of 1000 psia steam to atmospheric pressure will result in 298°F superheated steam (86°F of superheat).

The conclusion is that a small reactor steam leak will impose the most severe temperature conditions on the drywell structures and the safety equipment in the drywell. The superheat temperature for large steam-only blowdowns would be the same as for small breaks, but the duration of the high temperature condition would be less. This is because the larger breaks will depressurize the reactor more rapidly than the orderly reactor shutdown that is assumed to terminate the small break.

For drywell design evaluation, the following sequence of events was assumed to occur. With the reactor and containment operating at the maximum normal conditions defined in Table 6.2-1, a small break occurs that allows blowdown of reactor steam to the drywell. The resulting pressure increase in the drywell will lead to a high-drywell-pressure signal that will scram the reactor and activate the containment isolation system. The drywell pressure will continue to increase at a rate dependent upon the size of the assumed steam leak. This pressure increase will depress the water level in the vents until the level reaches the bottom of the vents. At this time, air and steam will start to enter the suppression pool. The steam will be condensed and the air will pass to the suppression chamber free space. The latter will result in a gradual pressurization of the containment at a rate dependent upon the air carryover rate. Eventually, the entrainment of the drywell air in the steam flow through the vents will result in all the drywell air being carried over to the suppression chamber. At this time, pressurization of the containment will cease and the system will reach an equilibrium condition with the drywell pressure at 25 psig and the suppression chamber at approximately 23 psig. The drywell will be full of superheated steam. Continued blowdown of reactor steam will be condensed in the pool.

The reactor operators will be alerted to the incident by the high-drywell-pressure signal and the reactor scram. For the purposes of evaluating the duration of the superheat condition in the drywell, it is assumed that their response is to shut the reactor down in an orderly manner using the safety/relief valves, or main condenser, and limiting the reactor cooldown rate to 100°F per hour. This will result in the reactor primary system being depressurized within 6 hr. At this time, the blowdown flow to the drywell will cease and the superheat condition will be terminated. If the plant operators elect to cool down and depressurize the reactor primary system more rapidly than at 100°F per hour, then the drywell superheat condition will be shorter.

The temperature resulting from the blowdown is determined by finding the combination of primary system pressure and containment pressure that produces the maximum superheat temperature. These are 450 psia, 35 psig, and 340°F, respectively. This temperature is assumed to exist for the initial 3 hr of the blowdown.

Additionally, as described in Subsection 6.2.1.3.1, the containment response due to small breaks has also been calculated using the bases provided in References 5 and 7. The corresponding short-term response is reported in Reference 6. Assumed operator actions that will minimize cyclic loads on suppression chamber and vent system structures are discussed in Reference 9.

6.2.1.3.6 Steam Bypass

The Fermi 2 containment has been examined to determine what leakage between the drywell and suppression chamber can be tolerated as a function of primary system break area; i.e., what leakage will result in a peak pressure equal to the maximum allowable pressure for the system. For this calculation, the following assumptions were made:

a. Flow through the postulated leakage path is pure steam. For a given leakage path, postulating that the leakage flow consisted of a mixture of liquid and vapor would increase the total leakage mass flow rate but would decrease the steam flow rate. Since it is the steam entering the suppression chamber free space that is resulting in the containment pressurization, this is a conservative assumption

b. There is no condensation of the leakage flow on either the suppression pool surface or the torus and vent system structures. Since any condensation results in less steam being in the suppression chamber free space, this is a conservative assumption. In practice, there would be condensation, especially for the larger primary system breaks when there will be vigorous agitation at the pool surface during blowdown.

Leakage capacity is expressed in terms of A, the area of the leakage flow path, and K, the geometric loss coefficient. These terms are interrelated such that the allowable leakage capacity for a system is expressed in units of $A/\sqrt{K}$.

The calculation shows that the limiting leakage capacity occurs for a primary system break area of 0.4 ft^2. For this break area, the allowable leakage capacity is 0.147. Typically, the geometric loss factor K would be three or greater; thus, the maximum allowable leakage area would be about 0.25 ft^2. This corresponds to a 7-in. line.

Primary system breaks greater than about 0.4 ft^2 will result in rapid system depressurization, and, for the given primary allowable leakage area, would result in the containment pressure being less than the maximum allowable pressure at the end of the reactor blowdown period.

Primary system breaks less than about 0.4 ft^2 will not result in rapid primary system depressurization and some operator action is required to terminate the pressure rise in the containment. The operators have several options available to them. If the source of the leakage is undefined, they would probably depressurize the primary system via either the main condenser or relief valves, or they could activate the suppression chamber or drywell sprays.

6.2.1.3.7 Small-Break Temperature Consideration

The Fermi 2 containment vessel was designed in accordance with the ASME B&PV Code Section III, Nuclear Vessels (1968), including the Summer 1969 Addenda. The primary containment design parameters, as shown in Part I of Table 6.2-1, were chosen on the basis of conditions discussed in the Fermi 2 PSAR. The design-basis conditions have since changed, as discussed in Subsection 6.2.1.3.2. However, no change in design pressure was necessary.

A small steam leak inside the primary containment, followed by an orderly shutdown and RPV depressurization, presents a different drywell atmosphere temperature transient. This situation is discussed in Subsection 6.2.1.3.5. The drywell temperature is calculated to be 340°F for 3 hr, and 320°F for 6 hr. During this period the calculated maximum drywell pressure is 35 psig, and during the following 24-hr period the temperature is 250°F with a pressure maximum of 25 psig. The containment vendor has analyzed the containment capability and found it adequate for these conditions.

6.2.1.3.8 Line Breaks in Sacrificial Shield Annulus

6.2.1.3.8.1 Description of System Configuration

The sacrificial shield is approximately 49-ft high cylindrical shell, with a 25 ft 7 in. inside diameter, a 29 ft 1 in. outside diameter, and a thickness of 1 ft 9 1/4 in. It has steel liners on its exterior and interior surfaces, and is meridionally stiffened by 12 vertical steel columns. The steel liner plates are welded to the columns, and the annular space between these plates is filled with concrete. The wall is rigidly attached to the reactor support at the bottom and attached to the drywell and RPV at the top by means of stiff leg supports and snubbers, respectively. The RPV sits inside the sacrificial shield with annular clearance of approximately 18 in. Of this 18 in., approximately 3 in. is occupied by insulation and 3 in. by a ventilation space between the shield and the insulation. This leaves a 12-in. annular space between the insulation and the RPV.

A detailed description of the sacrificial shield is given in Subsections 3.8.3.1.1 and 3.8.3.3.1. Openings are provided in the shield for the passage of lines from the RPV to the drywell. Those openings which lie within an area 9 ft above and 16 ft below the centerline of the core are required to be shielded and are equipped with shielding doors; these doors are locked closed and will not open during a pipe break within the annulus. The openings above and below this band have no shielding requirements; they are covered with a light-weight rupture diaphragm designed to help relieve the annulus pressure should a break occur.

The nozzles of the RPV are connected to the main piping using a short transition piece called a safe-end. The postulated break is the weld at either end of the safe-end. There are 26 penetrations in the wall, of which 17 occur where shield doors are required. Of these 17 lines, the major ones are the two 28-in. diameter recirculation outlet lines and the ten 12-in. recirculation inlet lines. The safe-end welds for these nozzles lie within the thickness of the shield wall or in the annular space. These two sets of lines were considered the critical cases, because the rest of the lines either are smaller, or may vent directly to the drywell because of the absence of any shield doors. One more case was considered: the feedwater line safe- end break. Because this line is located at the top of the sacrificial shield, forces generated during a postulated line break have a large moment which can lead to high stresses. The analysis requires modeling the system to predict what forces and pressures are generated following a postulated failure of safe- ends from these three lines and then using these in a structural design assessment.

Subsection 3.9.1.5 presents the GE analysis of the loads on the reactor vessel and internals due to a line break in the sacrificial shield annulus. Part of that work also includes computation of forces and moments for the RPV pedestal, RPV anchor bolts, and stabilizer truss. For these components, Sargent & Lundy used the larger of the stresses computed from their analysis or the GE analysis. This procedure has been incorporated in Revision 2 to SL-3647, dated March 14, 1980 (Reference 18).

The conclusion of Reference 18 states that the existing design of the sacrificial shield, reactor pedestal, stabilizer truss, RPV, and shield anchor bolts can safely accommodate the effects of annulus pressurization resulting from a postulated safe-end break.

6.2.1.3.8.2 Summary of Study

A study was performed in 1973 using state-of-the-art methods. A detailed report of that study was filed with the AEC in response to Open Item No. 12 and Question 12.4, Amendment 11 of the PSAR (Refer to Reference 15 in Section 3.8). During the review of the original FSAR, the NRC questioned whether certain aspects of the model used to predict the pressure distribution were adequately conservative and requested that the calculation be repeated using models currently available.

The recalculation was broken down into three tasks: calculation of mass energy release, calculation of annulus pressure distribution history, and the structural design assessment.

Mass Energy Release

This task was performed using a method developed by GE. The method assumes that the initial fluid velocity is zero. After the break, a finite time is required to accelerate the fluid to steady-state velocities; this is called the inventory period. The flow rate during this period is computed by two methods; one includes the effect of inventory and subcooling on flow in the pipe, the other accounts for the finite break opening time. The smaller of the two flow rates at any time is used. Both methods produce maximum flow rates based on different limiting areas. The transfer from one curve to the other represents a change in the point where the flow is choked. Following the inventory period, the flow is assumed to be choked at the limiting cross-sectional flow area. Mass flux is calculated using the Moody steady-slip flow model with subcooling. Results of this calculation are in Reference 20.

Annulus Pressurization

The computation of pressure distribution in the annulus following these breaks was based on the use of the computer code COMPARE. The model for Fermi 2 used 42 nodes in the annulus and four nodes in the drywell. The analysis considered movement of insulation at penetrations and the resulting venting of fluid to the drywell. The code was modified to account for variable junction area as a function of time. A Moody multiplier of 0.6 was used for all junctions except that from the break to the annulus, where 1.0 was used. All junctions had an inertia term, and sub-critical flow was calculated on the basis of a solution to the momentum equation with constant density. Reference 20 is the report of this work.

Structural Design Assessment

The structure was analyzed using the Sargent & Lundy thin-shell- of-revolution computer code, DYMAX. The Fermi 2 model for this study consisted of 76 nodes. Reference 18 is the report of this work.

The loads included in the study were:

a. Annulus pressurization

b. Jet impingement

c. Pipe-whip reaction

d. Dead load

e. Thermal effect due to accident

f. Seismic effect due to operating-basis earthquake (OBE) and safe-shutdown earthquake (SSE).

The structural components assessed were:

a. Sacrificial shield

b. Reactor pedestal

c. Stabilizer truss

d. Reactor anchor bolts

e. Sacrificial shield anchor bolts.

6.2.1.4 Inspection and Testing

6.2.1.4.1 Primary Containment

The Fermi 2 containment has been designed and constructed as a Class B vessel in compliance with Section III of the ASME Code, 1968 Edition, including the Summer 1969 Addenda. The containment vent system and suppression shell, supports, internals, and attachments have also been reevaluated (References 9 and 10) to include the hydrodynamic loading events and analysis methods defined by GE Topical Report NEDO-21888 (Mark I Containment Program Load Definition Report) and the NRC Safety Evaluation Report, NUREG-0661. The appropriate edition of Section III of the ASME Code and service-level limits specified in NUREG-0661 have been applied in the reevaluation. All inspections and tests prescribed by these editions of the Code have been successfully completed.

Containment boundary integrity has been verified during the construction of the Fermi 2 plant using the reference-vessel method. This method involves measuring the pressure differential between the containment vessel and a reference system of copper vessels that are interconnected with copper tubing and located in the upper and lower portions of the drywell and in the suppression chamber. This initial test, begun March 3, 1973, was performed in accordance with 10 CFR 50, Appendix J, and ANSI N45.4-1972, "Leakage Rate Testing of Containment Structures for Nuclear Reactors." The leak rate was determined to be 0.079 ±0.035 percent per 24 hr at 56 psig.

A preoperational, integrated leak-rate test using the absolute method was performed at the peak containment pressure calculated from DBA considerations in accordance with 10 CFR 50, Appendix J. This integrated leak-rate test was a Type A test. The test was conducted over a minimum of 8 hr with at least 20 value data points.

Type A tests will be performed periodically throughout the life of the plant in accordance with Fermi 2 Technical Specifications.

Permanently installed piping penetrations are provided through the containment structure for both the compressor system and the pressure-indication piping required for the Type A tests. An electrical penetration is provided for the leads to the temperature instrumentation in the containment.

Containment atmosphere-circulation fans are operable during the elevated-pressure conditions of the Type A tests to minimize local variations in temperature and humidity.

Personnel entry into the containment is not required during the Type A tests. Therefore, no provisions have been made for this kind of activity.

6.2.1.4.1.1 Penetrations

Airlock doors, access hatches, and the drywell head are equipped with double seals and instrument taps which permit pressurization of the space between them to verify seal integrity.

Piping penetrations with bellows seals which allow relative movement between pipe and containment wall are provided with double bellows and a space between them which can be pressurized. These penetrations are equipped with test fittings necessary to facilitate pressurization and testing of the penetration boundaries without pressurizing the entire containment.

Electrical penetrations are equipped with double seals and test connections and are capable of being tested at containment design pressure without pressurization of the containment.

6.2.1.4.1.2 Isolation Valves

Tests will be performed on isolation valves including reactor-building-to-torus vacuum breakers to verify their operability, pressure boundary integrity, and seat-and-stem leaktightness. Design provisions have been made when possible to accommodate the specific leak-test requirements of 10 CFR 50, Appendix J, Type C tests. Alternative methods are used where necessary and technically justifiable. The alternative methods are identified and discussed in Table 6.2-2.

Edison performed opening force tests on the Fermi 2 vacuum breakers during preoperational testing and will include these tests in the inservice testing. With the valve air cylinder properly adjusted using a predetermined air pressure, the pallet will close smoothly, without banging, in 2 to 5 sec. The closing time of the pallet is measured and set as part of the normal valve inspection and adjustment during refueling. This testing, along with the opening force measurement, provides assurance that the pallet is not binding and the valve will open with the proper opening time.

6.2.1.4.1.3 Pressure Suppression System

Drywell-to-suppression-chamber gross-leak tests will be conducted periodically as defined in the Technical Specifications to ensure that bypass of the pressure suppression feature of the containment has not developed. The test will be based on determination of the rate of change of pressure in the suppression chamber and drywell at a drywell-to-suppression-chamber differential pressure of 1 psi. In addition, individual drywell-to-torus vacuum breakers will be inspected and their position-switch setting will be verified. During plant operation, these valves will be periodically exercised to verify the operability of the valve and the closed-position instrumentation. These tests are documented in the Technical Specifications.

6.2.1.4.1.4 Test Frequencies

Test frequencies for the Type A test will be in accordance with Fermi 2 Technical Specifications. Type B and C test frequencies are based on the requirements of 10 CFR 50, Appendix J, Option B.

Data, data reduction, and test acceptability requirements for all tests are described in ANSI/ANS 56.8-2002 or other alternative testing methods that have been approved by the NRC and are based on the requirements of 10 CFR 50, Appendix J, Option B.

If the result of any test indicates that leakage exceeds the limits established in the Technical Specifications, repairs shall be made and a retest performed. In addition, for unsuccessful Type A tests, the provisions of 10 CFR 50, Appendix J, Option B, shall apply.

6.2.1.4.2 Secondary Containment

The reactor building leakage rate may be tested by complete isolation of the building except for the effluent from the SGTS. The SGTS is placed in operation and the system will maintain a constant flow. The building inleakage is small enough to ensure that the building negative pressure exceeds the value required by the Technical Specifications. The rate at which air is exhausted through the system is an accurate measure of building inleakage.

Visual inspection of reactor building penetrations will be possible. Penetration leakage is determined as a part of the gross reactor building inleakage as discussed above.

Frequency of these tests and inspections as defined in the Technical Specifications is based upon expected lifetime of the various seals, components, and penetrations and anticipated failure modes. The test and inspection schedule is intended to ensure that gross failures do not occur and that such failures, should they occur, are discovered and corrected within a reasonable time.

6.2.1.5 Instrumentation

6.2.1.5.1 Primary Containment

The primary containment monitoring system is designed to make available to the plant operators sufficient information to permit normal operation, to assist the operator in assessing the consequences of an accident or an incident, and to determine the effectiveness of control actions taken to mitigate the effects of the postulated event.

Functions of the primary containment monitoring system include multipoint measurement and recording of hydrogen and oxygen concentrations, gaseous radiation levels, pressure, temperatures, and water levels in the drywell and pressure suppression chamber. Suppression chamber water temperatures and drywell vessel wall and atmospheric temperatures are also measured and recorded. This system provides information for operator control of suppression pool cooling. Details of the primary containment monitoring system, its subsystems, sensors, and logic are described in Subsections 7.1.2 and 7.6.1.

Radiation monitors and pressure transmitters and the logic associated with the initiation of primary containment isolation as well as actuation of the ECCS and other engineered safety feature (ESF) systems are described in Subsections 7.1.2 and 7.3.2. The primary containment high-range radiation monitors are discussed in Subsection 11.4.3.

6.2.1.5.2 Secondary Containment

Secondary containment pressure is normally controlled by the reactor/auxiliary building ventilation system. Pressure sensors outside the building are arranged so that the lowest pressure on the building (due to wind) is compared with the building internal pressure which is maintained at 0.25 in. of water below the lowest outside pressure. The building fans are shut down in the event that a differential pressure of approximately ±2 in. occurs. Time-delay relays prevent spurious shutdown of the ventilation system caused by wind gusts.

The secondary containment is isolated on the same signals that actuate the SGTS; i.e., high drywell pressure, level 2 low reactor water level, reactor building ventilation exhaust radioactivity high, fuel pool area ventilation exhaust radioactivity high, or a manual pushbutton in the control room.

The SGTS is also actuated, and the secondary containment isolated, upon Loss of Offsite Power (LOOP). A LOOP causes a failure of the radiation monitors located in the reactor building ventilation exhaust system and in the fuel pool ventilation exhaust system which initiates a downscale trip signal. The radiation monitors' downscale trip signal isolates the reactor building ventilation (RBHVAC) exhaust system and initiates the SGTS system.

The systems whose signals initiate secondary containment isolation are discussed in Subsections 7.3.2 and 7.6.1.

6.2.1.6 Materials

Organic materials used in the Fermi 2 primary and secondary containments have been selected for extended life during normal operation and for resistance to expected accident environmental conditions. Thermal insulations used are inorganic and are not sensitive to high radiation fields, steam, or high temperature.

Table 6.2-8 lists the type of protective coatings used, their thicknesses, and their locations within the primary and secondary containments.

Table 6.2-9 lists organic materials used for wiring insulation in the primary and secondary containments.

Table 6.2-10 lists other organic materials of significant quantity and the amounts used in the primary and secondary containments.

Evaluations of these materials have been made. It has been determined that they will satisfactorily endure accident environmental conditions and that their expected products of decomposition, if any, will not adversely affect the operability of any ESF system.

The following paragraphs describe the coatings and paint used within the primary containment, including pertinent information regarding the following:

a. Identification of material used, location, and function

b. Physical and chemical characteristics

c. Performance under accident conditions including washdown, radiation, steam, temperature, and jet impingement effects

d. Data on effect of any coating material that may be dissolved or carried by the fluids that flow in the spray systems of the ECCS that may affect the functioning of the systems

e. Effect of coating on core and heat exchanger heat-transfer surfaces

f. Clogging and other effects on fluid flows in Class 1 systems from coatings.

Additional information is available in Reference 21.

<u>Reactor Vessel Support Pedestal</u>

The inside and outside surfaces of the reactor vessel support pedestal are coated with Ameron Nu-klad surfacer 110 AA primer and one finish coat of Ameron polyamide epoxy 66. Damaged areas of Ameron Nu-klad 110 AA are repaired with Ameron Nu-klad 111. The function of this coating system is to protect and seal the pedestal surfaces against attack by either demineralized (aggressive) water or radiation contamination and to facilitate washdown.

The physical and chemical characteristics of the Ameron Nu-klad surfacer 110 AA primer are excellent adhesion to clean concrete and good adhesion to steel, resistance to attack by demineralized water or hot condensate, excellent abrasion resistance, considerable radiation resistance, excellent chemical resistance, and indefinite repairability. Both primer and finish are modified epoxy. Ameron polyamide epoxy 66 has properties similar to those of the primer. Both coatings withstand temperatures to 200°F continuously and to 300°F intermittently.

Required DBA testing has been performed, and the coating system is capable of withstanding the rigors of a LOCA. A washdown removes contamination.

The coating effect on the core and heat-transfer surfaces is negligible because the coating system is nonleachable.

No clogging or other effects on fluid flow in Class 1 systems are expected since the coating is nonleachable and has excellent adhesion.

The Ameron 66 top coat has been applied in accordance with the recommendations of Regulatory Guide 1.54 and ANSI N101.4 and the coating system has met the pull-test requirements of ANSI N5.12. The coating of the reactor vessel support pedestal and other concrete surfaces of the drywell have been designated as a QA Level 1, safety-related activity. The coating system as described above is a qualified coating.

Drywell Concrete Floors and Walls

The concrete surfaces of the drywell floors and walls are coated with Ameron Nu-klad surfacer 110 AA primer and a top coat of Ameron polyamide epoxy 66. The function, physical and chemical characteristics, and other properties of this coating are discussed under "Reactor Vessel Support Pedestal" above.

Sacrificial Shield Wall

The exterior surface of the sacrificial shield is coated with Carboline Carbozinc 11 and repaired with Carboline Carbozinc 11 SG. This is a self-curing, zinc-filled, inorganic, two-part basic zinc silicate complex that readily accepts top coats. The function of this coating is to provide long-term protection against corrosion, attack by radiation or radioactive water, and to facilitate washdown.

The physical characteristics are a hard surface resistant to aggressive water, very good impact resistance, and a temperature use range up to 750°F continuous and 800°F intermittent. Flexibility is fair. Chemical characteristics are insolubility in water and resistance to aggressive water and solvents. Relatively wide application temperatures (0-200°F) and humidity ranges (to 95 percent) are permissible.

Contaminants on the coated surface can be easily washed down with water. The coating has high radiation resistance, resists steam to 180°F, and has excellent temperature resistance up to 750°F.

The coating has no effect on core heat transfer or heat exchanger heat-transfer surfaces since it is not soluble.

Carbozinc 11 and Carbozinc 11 SG coatings have been subjected to extensive DBA testing for a variety of application techniques and were found acceptable for use in BWR environments under LOCA conditions.

Report DECO 12 2191 notes that some particle separation could occur under accident conditions in areas subjected to continuous scouring by water and steam spray. Such scouring would occur only in the immediate vicinity of a pipe break. In such areas, the coating is not lost in large flakes, however, but rather in particles less than 20 microns in size. ECCS suction strainer head loss calculations include the recommended Utility Resolution Guidance (NEDO-32686) for qualified paint assumed to degrade from a direct steam jet impingement.

Most of the initial Carbozinc 11 coatings in the primary containment were applied in accordance with the original 1969 specification, prior to the issuance of Regulatory Guide 1.54 and ANSI N101.4. The industry standard at that time was to apply Carbozinc 11 in accordance with the manufacturer's recommendations. This type of coating has been successfully used in operating BWRs and for years has withstood a variety of adverse conditions.

In 1984, the commercial name of the Carbozinc 11 coating was changed to Carbozinc 11 SG. Consequently, in cases where repairs to the original Carbozinc 11 coating were needed after 1984, Carbozinc 11 SG was used.

Drywell Interior Steel

All exposed interior surfaces of the drywell pressure boundary, including the drywell jet deflectors and surfaces in contact with concrete, are coated with Carboline Carbozinc 11 and repaired with Carbozinc 11 SG. The function of this coating system is to protect the surfaces from corrosion, from attack by aggressive water, radioactive water, or radiation, and to facilitate washdown.

Those coatings which cover the drywell pressure boundary are maintained under Fermi 2 QA Level I criteria to ensure long-term corrosion protection for the pressure boundary. This coating is not considered to be in full compliance with ANSI N101.4.

Drywell Interior Structural Steel

The primary structural steel within the drywell is coated with Carboline Carbozinc 11 and repaired with Carboline Carbozinc 11 SG. The purpose of the coating is to provide long-term protection against corrosion and to facilitate washdown.

The Drywell dado region was recoated with Carboline Carboguard 890 N, and is classified as an acceptable coating (as defined in ASTM D4538).

Substantial modifications were made to the primary structural members in two separate phases due to load reevaluations that resulted in varying degrees of surface preparation. Welding and nondestructive examination procedures necessitated removing existing coatings at tie-ins and welded connections. Due to completed installation of equipment, generally very tight working quarters, and complex components placement, sandblasting and recoating of steel members were not routinely completed.

Surfaces of Suppression Chamber

The interior surfaces of the suppression chamber, including the exterior surfaces of the downcomers and vent header, the exterior surfaces of the vent pipes, vent header supports, ring girders, catwalks, monorail, stiffeners, supporting steel, piping, hangers, and penetration nozzles, are coated with the Wisconsin Protective Coating Plasite 7155 system above elevation 558’-2” and with the Carboline Carboguard 6250 N system below elevation 558’-2”. The Carboguard coating overlaps the Plasite coating at the intersection of the coatings. The interior surface of the downcomers is coated with Plasite 7155. The Plasite coating is a water-resistant phenolic coating cross-linked with epoxy resin and polymerized with an alkaline curing agent. The Carboguard coating is a solventless epoxy novolac coating designed to handle exposures inside nuclear containment facilities. The function of these coatings is to provide long-term protection from corrosion and radiation, and to facilitate washdown.

These coatings resist temperatures up to 400°F intermittently, develop good hardness and abrasion resistance, can withstand cyclic thermal shock, and provide a broad range of long-term chemical resistance.

The Plasite coating was applied in accordance with Regulatory Guide 1.54, ANSI N101.4, meets pull-test requirements of ANSI N5.12, Section 6.4, has been DBA tested, and is considered a fully qualified coating capable of withstanding accident conditions. Its application is a safety-related, QA Level 1 activity.

The Carboguard tie-in band that overlaps the Plasite coating is considered unqualified. There are additional minor areas in the wetwell with unqualified Carboguard coating. The unqualified coatings are tracked as indicated in Table 6.2-8. The unqualified coating amounts have been evaluated and are within established limits for unqualified coatings inside containment. The remainder of the Carboguard 6250 N coating is in accordance with Regulatory Guide 1.54 and ANSI N101.4 except that later ASTM standards endorsed by Revision 2 of Regulatory Guide 1.54 were used for test panel preparation, radiation qualification testing, chemical resistance qualification testing, and test panel evaluation. The coating, except for the tie-in band, is considered a fully qualified coating capable of withstanding accident conditions. Its application is a safety-related, QA Level 1 activity.

The interior surface of the vents from the drywell shell down to a transition point approximately 20 in. from the vent header is coated with Carboline Carbozinc 11 SG coating system. The remainder of the interior surface of the vents (from the transition point to the vent header) and the interior of the vent header are coated with a qualified Carboline Carboguard 6250 N coating system. A small qualified overlap band of Carboguard 6250 N over Carbozinc 11 SG exists at the transition point between the two coating systems. The interior surface of the vacuum breaker extensions and downcomers are coated with Plasite 7155 coating system described above in this section. The Carboline Carboguard 6250 N coating overlaps the Plasite 7155 coating on the inside surface of each downcomer and vacuum breaker penetration in the vent header. The Carboguard 6250 N coating in this overlap band is classified as an acceptable coating (as defined in ASTM D4538).

Touch-up repairs to the suppression chamber interior coating under submerged or dry conditions are made using compatible safety-related coatings complying with the original requirements and standards.

<u>Miscellaneous Coatings</u>

Coatings on miscellaneous equipment and components in the drywell are discussed below. These coatings were included in the evaluation of the Fermi 2 primary containment coatings, and will not impair plant operation under normal or abnormal conditions.

a. Galvanized Surfaces

   The drywell cooling system ducting and dampers are completely galvanized without any further coatings. At welded joints, the galvanized surface was ground off to clean metal, and in some locations these ground areas were touched up with Galvanox I or Galvanox V, zinc-rich coatings similar in properties to Carboline Carbozinc 11. In addition, all electrical conduit, terminal boxes, cable trays, and supporting unistruts are galvanized. The only exceptions are some large flexible conduits made of stainless steel

b. Hangers and Supports

   Hanger and support components, including clamps, rods, spring cans, snubber attachments, pipe-whip restraint components, and secondary support steel, were originally coated with Carboline Carbozinc 11. Significant changes in the hanger and support design resulted in addition of secondary support steel, change-out of hanger components, and welding of attachments. Coating repair and touch-up of these areas is not safety related

c. Piping

Most of the piping within the drywell is insulated with reflective metallic insulation panels (Mirror Insulation), consisting of removable sections and having an outer cover of stainless steel. Encapsulated NUKON or encapsulated silicon (Min-K) is used where clearance restrictions exist, i.e., drywell penetrations and spaces between pipe whip restraints and pipe. Normally, cold fluid system piping is not insulated or coated. The uninsulated carbon steel piping was shop coated with a protective varnish. Tight mill scale and some rust is apparent on the piping surfaces. The varnish and mill scale are considered unqualified coatings

d. Unidentified and Unqualified Coatings

These coatings consist largely of manufacturer's shop coatings and primers such as red lead, aluminum base, enamels, polymer, and phenolic paints. These coatings are present on valve bodies, yokes and bonnets, motor and air operators, handwheels, electric motors, etc. Another category of unqualified coatings consists of identification marking and banding of electrical conduit, terminal boxes, and trays.

Coatings of this category that have thicknesses of 3 mils or less are postulated to fail in small particles and will not clog strainers.

Unqualified coatings greater than 3 mils DFT have either been removed, and the surfaces have been recoated with Carbozinc 11 where appropriate (see Reference 21 for additional information); or have been evaluated for use in the primary containment. Design calculations have been prepared to evaluate the addition of materials to the primary containment. These are updated as necessary as part of the plant’s response to NRC Generic Letter 98-04.

6.2.2 Primary Containment Heat Removal System

6.2.2.1 Design Bases

Containment heat removal is provided by operating the RHR system in the suppression pool cooling mode or the containment spray mode. The system meets the following safety design bases:

a. The source of coolant inventory shall be located within the containment so as to establish a closed cooling water path

b. A closed-loop flow path between the suppression pool and the RHR heat exchangers shall be established so that the heat-removal capability of these heat exchangers can be utilized

c. This system, in conjunction with other ESF systems, shall have diversity and redundancy such that no single failure can result in its inability to cool the containment adequately

d. Each active component shall be testable during operation of the nuclear system. Testing is described in Section 5.5.7.5.

6.2.2.2 System Design

The containment cooling subsystem is an integral part of the RHR system, as described in Subsection 5.5.7. Redundancy is achieved by having two complete containment cooling systems.

Consideration of the fouling of heat exchangers and the selection of temperatures for heat exchanger design is discussed in Subsection 5.5.7.

6.2.2.3 Design Evaluation

The discussion in this subsection has been updated for power uprate conditions.

In the event of the postulated LOCA, the short-term energy release from the reactor primary system will be dumped to the suppression pool. Subsequent to the accident, fission product decay heat will result in a continuing energy dump to the pool. Unless this energy is removed from the containment system, it will eventually result in unacceptable suppression pool temperatures and containment pressures. The containment cooling mode of the RHR system is used to remove heat from the suppression pool, the suppression chamber, and the drywell.

When the RHR system is in the containment cooling mode, the pumps draw water from the suppression pool, pass it through the RHR heat exchangers, and inject it back into the suppression pool or into the containment via sprays.

The adequacy of the RHR system has been evaluated considering, two sequences of events with different assumed single active failures. Both scenarios assume the occurrence of a LOCA coincident with a loss of offsite power with the reactor initially at maximum power. The original licensing and design basis scenario assumes a loss of offsite power occurs and the single failure of one divisional power supply for the duration of the accident. Immediately following the accident, the ECCS initiates automatically as designed in response to the accident initiation signals.

Under the original scenario, due to the assumed loss of offsite power and one division of onsite power, two core spray pumps and two RHR pumps will be operating. (Section 6.3 describes the ECCS equipment.) Twenty minutes later the plant operators activate one RHR heat exchanger in order to start containment heat removal. This involves shutting down one of the two LPCI pumps and starting up the service water pumps for the heat exchanger. Once containment cooling has been established (including RHR cooling towers), no further operator actions are required.

Subsequent to the original plant analysis it was determined that a single failure of an RHRSW isolation valve to open would result in the same available suppression pool cooling capability (namely one RHR heat exchanger) but would result in additional operating ECCS pumps – four RHR pumps and four core spray pumps; thus, resulting in additional ECCS pump heat to the suppression pool. Consistent with the original containment analysis, this scenario assumes plant operators activate the remaining operable RHR heat exchanger and the associated division of the Ultimate Heat Sink [See Section 9.2.5] twenty minutes after the initiating event.

The evaluations of both scenarios use the SUPERHEX (SHEX) code to calculate the long-term containment response for Fermi 2 with power uprate (Reference 22). SUPERHEX evolved from two previously approved codes (Reference 14 and 15) and was shown to give equivalent pool temperature response to the predecessor code. The long-term analysis for Fermi 2 with the SUPERHEX computer code using conservative inputs yields a peak post DBA/LOCA pool temperature of 196.5°F. This temperature shows margin remains to the controlling limit of 198°F which comes from NPSH requirement for pumps taking suction from the suppression pool with no credit for containment pressure per Regulatory Guide 1.1.

The input parameters used for SUPERHEX for the long-term containment response analyses for Fermi 2 with power uprate are identified in Table 6.2-1.

Service Water Temperature

The original containment analysis used a constant RHR service water (RHRSW) temperature of 90°F which is the maximum design cooling tower outlet temperature. The Technical Specifications prohibit operation with the cooling tower reservoir temperature above 80°F. An energy balance calculation was used to determine the post LOCA RHRSW temperature increase as a function of time from the initial condition of 80°F to the cooling tower maximum design temperature of 90°F. The temperature profile, which is non-linear, was conservatively bounded by a linear profile which was used in the containment analysis (Table 6.2-1). The following are the important assumptions used in the energy balance. (Note: The current maximum analyzed service water supply temperature is below the assumed maximum 90°F).

a. The maximum Technical Specification reservoir temperature of 80°F was used as an initial condition.

b. The maximum design cooling tower outlet temperature of 90°F was used.

c. The minimum Technical Specification RHR reservoir water level was used. This is conservative because it minimizes the heat capacity of the reservoir and maximizes the reservoir heatup.

d. Evaporative and drift losses were used to reduce reservoir inventory during the heatup period.

e. Complete mixing was assumed in the reservoir. This is conservative because hot water is discharged into the cooling towers and is sprayed down to the surface of the reservoir. Cooler water is drawn from the bottom of the reservoir where the pump suctions are located. No credit was taken for temperature stratification which would have lowered the reservoir discharge temperature profile.

Suppression Pool Volume

The initial suppression pool volume used for the power uprate long-term containment analysis was 117,161 ft^3 which is less than the pool volume of 121,080 ft^3 that corresponds to the Technical Specification minimum value. The lower pool volume of 117,161 ft^3 adds conservatism to the calculated pool temperature since a lower initial pool volume results in higher calculated values for pool temperature.

Initial Pool Temperature

The initial pool temperature for the containment analysis was set at 95°F which is the Technical Specification limit for normal operation.

Feedwater Addition

All water in the feedwater system which could contribute to higher calculated pool temperatures was added to the RPV and containment system for the power uprate analysis. This was achieved by adding all feedwater which is in the feedwater system during normal operation that has a temperature greater than the maximum expected pool temperature. This translates to all feedwater through Feedwater Heaters Nos. 3, 4, 5, and 6.

In addition, a conservative calculation of the energy in the feedwater piping is added to the RPV/containment system. This water mass and energy addition assures that the pool temperature calculation conservatively reflects the effect of feedwater addition on suppression pool temperature.

Initiation Time for Containment Cooling

The long-term containment response analysis has assumed that the containment cooling is initiated at twenty minutes.

Decay Heat

The original analysis identified decay heat values used for the long-term containment analysis which correspond to the May-Witt decay heat model values after 60 seconds. For the power uprate analysis a more realistic decay heat has been included. This decay heat is based on the ANS 5.1 model (Reference 16) and is described in Appendix B of Reference 17. This decay heat includes contributions due to fission heat induced by delayed neutrons, decay heat from fission products, decay heat from actinides (heavy elements), and decay heat from irradiated structural materials. For conservatism additional margin which corresponds to two standard deviations (10%) was added on the decay heat as described in Reference 17, Appendix B, for the Fermi 2 long-term containment power uprate analysis.

Suppression Pool Temperature Response

The suppression pool temperature response has also been evaluated following several other plant transient events in which steam is discharged to the suppression pool. General Electric Report NEDC-24388-P (Reference 23) describes transient events, the assumed RHR system modes of operation, and the predicted pool temperature results. The report concludes that the peak pool temperatures in the vicinity of SRV discharge quencher devices are below the limit established to ensure stable steam condensation.

6.2.2.4 Testing and Inspections

The preoperational and operational testing and the periodic inspection of components of the containment heat removal system are described in Subsection 5.5.7.5.

6.2.2.5 Instrumentation Requirements

The containment spray and the suppression pool cooling modes of the RHR system are manually initiated. Once initiated, containment cooling performance is monitored by monitoring pump performance, flow and pressure, and coolant temperature.

6.2.2.6 Materials

Materials used are reviewed and evaluated with regard to radiolytic and pyrolytic decomposition and attendant effects on safe operation of the system. For example, fluorocarbon plastic (Teflon) is not permitted in environments that attain temperatures greater than 300°F, or radiation exposures above 10^4 rads. Only inorganic thermal insulation, which does not decompose due to radiation or temperature, is used in these environments. An inorganic zinc primer is used on all exterior surfaces of carbon steel components that are treated. All paints used are suitable for the temperature conditions expected.

6.2.3 Secondary Containment Air Purification and Cleanup System

The SGTS is designed to minimize the release-related offsite dose rates by permitting the venting and purging of both the primary and the secondary containment atmospheres under accident or abnormal conditions, and at the same time containing any airborne particulate or halogen contamination that might be present.

6.2.3.1 Design Bases

Under postaccident conditions, it is possible that the primary containment atmosphere could become contaminated with radioactive particulates and halogens. Any air from this volume finding its way to the secondary containment is therefore likely to be similarly contaminated. The SGTS is designed to permit controlled ventilation of this area by maintaining it under slightly negative pressure with respect to the outside atmosphere to ensure that any air leaving is filtered to remove particulates and halogens. The system is also capable of filtering gases exhausted from the primary containment and the HPCI barometric condenser. The system is designed to function under postaccident conditions of high radiation levels, temperatures, and relative humidity.

The SGTS flow rate is sufficient to provide a secondary containment air volume change at least once per day and to maintain the reactor building at approximately negative 1/4-in. water pressure for accident and abnormal conditions.

Particulate- and halogen-removal capability permits venting of the primary and secondary containment volumes following an accident while maintaining offsite dose rates well within the guidelines set by 10 CFR 100. For those design basis accidents reanalyzed per Regulatory Guide 1.183, SGTS limits offsite dose within the limits of 10 CFR 50.67.

The SGTS is designed to operate with influent air temperatures up to 135°F and relative humidity up to 100 percent. The system is periodically tested such that a decontamination efficiency of 99 percent can be assumed for removal of all forms of gaseous and particulate iodine. System retention capacity, originally based on the requirements of Regulatory Guide 1.3 and TID-14844, and amounts of up to 1300 gm (Reference 24), is currently evaluated against the 2.5 mg/g Regulatory Guide 1.52 limit for 30-day post-accident iodine accumulation based on the Regulatory Guide 1.183 Alternative Source Term. (Reference 26)

The SGTS is a Quality Level I, Category I ESF system meeting all applicable portions of IEEE 344; IEEE 308; ORNL-NSIC 65; UC-80 Reactor Technology, "Design, Construction and Testing of High Efficiency Air Filtration Systems for Nuclear Application;" ASME B&PV Code Section IX, "Welding Qualifications" (1971); Air Moving and Conditioning Association (AMCA), "Standard Test Code for Air Moving Devices" and "Standards Handbook;" and Savannah River Laboratory Report DP-812, "Application of Moisture Separators and Particulate Filters in Reactor Containment."

The SGTS meets the intent and functional objective requirements of Regulatory Guide 1.52. Some detail design requirements of this guide, however, are not met because system fabrication was commenced before the guide was issued. All areas of noncompliance have been reviewed and in each case it has been determined that design and hardware changes required to bring these areas into compliance would not improve the system performance or capability to meet the design objectives. (See Appendix A, Subsection A.1.52.)

6.2.3.2 System Design

The SGTS is a 100 percent-redundant ESF system and is shown schematically in Figure 6.2-20. Major system components are listed and briefly described in Table 6.2-11. The system is designed to meet reactor building containment tests.

The SGTS consists of two separate and parallel 100 percent capacity trains. In addition to its associated ducts, controls, instrumentation, isolation valves, and protection systems, each train consists of the following items listed sequentially and in the direction of air flow:

a. A moisture separator to remove entrained water droplets, thus minimizing water loading of the prefilter. The moisture separator meets design requirements specified in Savannah River Laboratory Report DP-812

b. A prefilter to reduce the loading on the absolute filter. The prefilter is fire resistant and capable of operation at temperatures up to 250°F

c. An electric heater to reduce the relative humidity of the influent air to 70 percent or less under the "worstcase" conditions

d. A high-efficiency particulate air (HEPA) filter with a design DOP filtration efficiency of 99.97 percent for particles 0.3 μm in diameter or larger. Four parallel filter elements, each rated at 1000 scfm, are provided. These elements meet the intent of Military Specification MIL-F-51068-C. They are Underwriters Laboratories (UL) approved, fire resistant, and suitable for service under the temperatures, mass, and heat loading expected. The filters are mounted and sealed in a welded steel frame to ensure against possible bypass flow. The filters are tested periodically for bypass leakage such that a 99 percent decontamination efficiency can be assumed for removal of particulate iodine

e. A deep-bed, gasketless, all-welded construction adsorber containing activated carbon

f. A HEPA filter identical to the one described above to trap charcoal fines and decay daughters entrained by the air stream

g. An exhaust fan designed for 4000 ft^3/minute

h. A cooling air fan installed in parallel with the exhaust fan, designed and built to the same standards and codes as the exhaust fan. The purpose of this blower is to provide cooling air flow to the charcoal filter in order to maintain charcoal temperature below 310°F under design loading conditions, in the event of high charcoal adsorber bed temperature.

Piping connections and valving exist between the SGTS and the secondary containment building ventilation system, the primary containment drywell, the suppression chamber, and the HPCI turbine barometric condenser vacuum pump discharge.

When the cooling air fan is in use, suction is taken from a roof vent. Discharge under both modes is to a vent located on the reactor building roof.

Full access and interior compartment lights with external light switches are provided for the spaces between filter train components where required to facilitate inspection, testing, and replacement of components.

Injection nozzles, sample points, and pressure taps are provided to facilitate periodic inservice inspection tests.

6.2.3.3 Design Evaluation

6.2.3.3.1 General

The SGTS is designed to permit controlled venting of the primary or secondary containment following an accident or abnormal occurrence which might cause abnormally high airborne contamination in these areas.

Achievement of acceptable offsite dose rates following a DBA depends on the proper functioning of the SGTS. Therefore, the system, along with its power supplies and surrounding structures, has been designed to meet ESF system standards. All necessary equipment and surrounding structures are of Category I design. The equipment is powered from essential buses which will supply power to the SGTS in the event of a loss of offsite power. All power and control circuits meet the requirements of IEEE 279. Redundant active components are provided where necessary to ensure that a single failure does not impair or prevent system operation. An SGTS failure analysis is presented in Table 6.2-12.

The SGTS removal efficiency was successfully tested (Reference 24) for radioactive and nonradioactive forms of iodine and for particulate matter 0.3 mm or larger. The thyroid dose at the site boundary and low-population zone has been calculated on the basis of iodine-removal efficiency of 99 percent. Credit for 99 percent removal efficiency is dependent on in-place testing per Regulatory Guide 1.52, as stated in the Technical Specifications.

6.2.3.3.2 Secondary Containment Pressurization During Design Basis LOCA

The pressure of the secondary containment volume after a LOCA has been studied. The analysis included infiltration and thermal loads from the primary containment, operating equipment, and emergency lighting.

The SGTS is designed to maintain a secondary containment pressure of -0.25 in. of water, thus ensuring that any airborne radioactive material in the secondary containment is not released to the surrounding atmosphere without passing through the SGTS filters. In the event of a design-basis LOCA, loss of offsite power is assumed; consequently, there is a delay from the start of the event to the activation of the SGTS and the emergency area coolers.

During the delay, the secondary containment pressure increases because of heat generated by emergency equipment and other sources. Upon initiation of the SGTS and emergency area coolers, a short time is required to reduce the secondary containment pressure to a negative pressure at or below -0.25 in. of water.

The purpose of the calculation was to generate the secondary containment pressure response during a design-basis LOCA and to determine the period of time when the secondary containment pressure is above -0.25 in. of water. The method of analysis and the assumptions and results are described in the following paragraphs.

Method of Analysis and Assumptions

The computer code GOTHIC (Reference 25) was used to generate the secondary containment pressure response.

All major assumptions are given below:

a. No credit was taken for exfiltration from the secondary containment

b. Infiltration to the secondary containment was included in the pressure response analysis

c. No heat transfer was allowed to the outdoor atmosphere

d. Heat transfer to interior secondary containment walls, floors, and ceilings was included

e. Heat transfer from the torus room to the secondary containment is based on flow through the pressure relieving doors in the corner room basement walls

f. Only one SGTS filter train is available with a minimum volumetric flow rate of 3800 cfm

g. Offsite power is lost at the start of the design-basis LOCA event

h. The activation of the SGTS is delayed by 33 sec and the activation of the emergency area coolers is delayed by 38 sec (see Table 8.3-5)

i. The RHR, core spray, and RCIC pump rooms in the reactor building subbasement are treated separately from the main secondary containment volume. These rooms have their own emergency coolers to handle emergency equipment and lighting heat loads. Because the heat loads and cooling are confined to partially enclosed volumes at the very bottom of the secondary containment, the area coolers will absorb the heat loads within the confines of the corner rooms

j. The heat loads from the RHR, core spray, and RCIC pump rooms will not affect the main secondary containment volume before the initiation of the area coolers. The RHR pumps are activated 13 sec after the start of the design-basis LOCA event (see Table 8.3-5). The emergency coolers are activated at 38 sec. For the heat loads to affect the main volume, the pumps, piping, and subsequently the corner room atmospheres must heat up. After the corner room atmospheres have heated up, the only mode of heat transfer to the main volume is natural convection. Considering that natural convection is a rather slow process, no significant heat transfer to the main secondary containment volume from the corner rooms is expected during the 25 sec from the initiation of the RHR pumps to the initiation of emergency cooling

k. An outdoor temperature of 95°F was used in the analysis

l. The reactor building closed cooling water system is inoperable and both divisions of the emergency equipment cooling water system are operating

m. All ECCS equipment starts

n. The fuel pool cooling and cleanup system, the reactor water cleanup system, and the recirculation pump motor-generator set cooling system are shut down

o. The fuel pool is at an operating temperature of 125°F.

   Any increase in fuel pool temperature in the range of 125°F to 130°F will have negligible effects on the results of the analysis

p. An initial secondary containment pressure of 0.0 in. water gage was assumed.

<u>Results</u>

The secondary containment response due to a design-basis LOCA is shown in Figure 6.2-21. During the first 33 sec, the pressure increases to a slightly positive value. With the activation of the SGTS at 33 sec and the activation of the area coolers at 38 sec, the pressure decreases slightly.

At approximately 50 seconds, pressure-relieving doors on the common wall between the torus room and the corner rooms open and allow heated torus room air to enter the rest of the secondary containment. This step input of heat into the secondary containment appears as a sharp pressure spike in Figure 6.2-21.

The pressure then decreases past -0.25 in. of water to a steady-state secondary containment pressure. Less than 1020 sec elapses from the start of the design-basis LOCA event to the point where the secondary containment pressure decreases to and subsequently stays below -0.25 in. of water. For conservatism, the 1020 sec (17 minutes) is maintained for the LOCA dose assessment (Subsection 15.6.5.5.2).

6.2.3.4 Tests and Inspections

The SGTS and its components are thoroughly tested in a program consisting of the following classifications:

a. Predelivery and component qualification tests

b. Onsite preoperational acceptance tests

c. Operational surveillance tests.

Written test procedures establish acceptance criteria for all test results. Operational test results are recorded and compared with previous performance records, thus enabling early prediction of end of component life and appropriate corrective action.

For the various components of the system, the following predelivery qualification tests were applied:

a. Equipment Train Housing - Leak tests at +20 in. of water internal pressure. Magnetic-particle or liquid-penetrant testing of all welds and discontinuities which could cause bypass leakage around the HEPA filters or adsorber beds

b. Demister - Qualification test or objective evidence to demonstrate compliance with requirements specified in Savannah River Laboratory Report DP-812

c. HEPA Filters - Qualification test to demonstrate a minimum of 99.97 percent efficiency when measured using a 0.3 mm DOP aerosol in conformance with MIL-STD-282

d. HEPA Filter Frames - Soap-bubble leak test across filterless covered bank

e. Adsorber Beds - Available objective evidence demonstrates acceptable flow-pressure characteristics and channeling effects

f. Adsorbent -

   1. Ignition test

   2. Methyl iodide removal test

   3. Hardness test

   4. Impregnant content test.

To demonstrate the integrity of the potassium iodide impregnated charcoal, required factory tests have been performed by the manufacturer prior to acceptance

g. Fans - Fan tests in accordance with the latest revision of AMCA Standard 210, "Air Moving and Conditioning Association Test Code for Air Moving Devices," to establish characteristic curves

h. Prefilter - Objective evidence and certification that NBS efficiency specified is attained

i. Valves, Dampers, and Actuators - Shop tests demonstrating seal effectiveness and ability to perform intended functions under the anticipated conditions.

Onsite preoperational tests for the SGTS are listed in Subsection 14.1.3.2.47.

Onsite periodic testing will be performed. Items such as design conditions of flow, drawdown time, and differential pressure will be verified during these routine tests performed in compliance with the Technical Specifications.

6.2.3.5 Instrumentation and Controls

Each SGTS unit and its controls, power supplies, valves, dampers, and auxiliary equipment are designed and installed so that they are both physically and electrically independent. The system conforms to single-failure criteria outlined in IEEE 279.

A separate control system is provided for each SGTS unit, including all items necessary for control and for determining the status of all components. The SGTS instrumentation is presented in Figure 6.2-20, a brief summary of which is presented below.

Differential pressure indicators are provided to measure the pressure drop across each filter and charcoal bed. Differential pressure switches are provided to signal abnormal conditions.

Each adsorber bed is equipped with the following controls:

a. Charcoal adsorber bed high-temperature-detection temperature element to actuate CO_2 injection

b. Charcoal adsorber bed overheat temperature element to actuate standby cooling fan

c. Charcoal adsorber bed temperature controller to operate dryer (heater).

Fire protection for the adsorber bed is provided by a CO_2 system which is actuated automatically by adsorber bed high temperature. Actuation of the system is signaled in the main control room.

Every isolation valve is supplied with position switches to provide positive indication of valve status.

High-temperature cutouts are provided as an integral part of the single-stage electric heaters. Local temperature indication is provided upstream and downstream of the electric heaters.

Flow signals are transmitted to the main control board for indication and record. The flow transmitter directly controls the flow-control valve.

Manual switches are provided on the main control panel for each fan.

A continuous isokinetic sample is taken from the discharge of the operating filter train and processed through radiation detectors, a particulate filter, and an adsorber bed, and is returned to the SGTS roof vent.

High radiation levels are indicated by audible and visible alarms in the main control room.

The SGTS electrical equipment and instrumentation required to function in a postaccident harsh environment are environmentally qualified and in compliance with NUREG-0588.

When the SGTS filter units are shut down (auto standby mode with no actuation signal), all valves are closed and exhaust fans are deactivated. The charcoal adsorber blanket heater may or may not be on, depending on the charcoal temperature.

Standby cooling fans and associated valves will automatically be activated on high charcoal bed temperature. The system is actuated and put into service automatically in response to any one of the following signals:

a. Auto standby mode

1. High drywell pressure
2. Low reactor water level
3. Reactor building ventilation exhaust radioactivity high
4. Fuel pool area ventilation exhaust radioactivity high.

b. Manual mode.

On actuation in the auto standby mode, both trains are started. The SGTS can be manually started by placing the control switch for the selected train in the run position.

The exhaust fans start, associated isolation valves open, normal reactor building ventilation system is tripped, and valves are automatically realigned to exhaust into the SGTS.

Adsorber-blanket heaters are automatically shut down if they were operating prior to system startup.

Activation of the SGTS in either mode is accompanied by audible and visible alarms in the main control room. The operator would then manually shut down one of the operating trains, leaving the other to perform as intended.

In the event of failure of the operating train for any reason, that train would be shut down and isolated by the operator in the main control room, and the redundant filter train would manually be put into service.

Main control room visible and audible alarms include the following:

a. Both SGTS trains "Auto Start"
b. High relative humidity ahead of charcoal bed
c. Low system flow rate (interlocked with primary blower "Run" signal)
d. High airborne contamination at the roof vent
e. Failure of either train to start up and operate on signal
f. Cooling fan "Auto Start"
g. Carbon dioxide fire protection system actuation.

Functions that can be accomplished manually from the main control room include the following:

a. Startup or shutdown of either or both SGTS trains
b. Startup of alternative SGTS train upon failure of operating train
c. Startup or shutdown of either standby cooling air fan

d. Isolation of SGTS train upon manual shutdown command from main control room.

Automatic functions include the following:

a. Startup of both SGTS trains and proper alignment of isolation valves

b. Activation of adsorber heater on low temperature

c. Startup of standby cooling air fan system when adsorber temperature exceeds its setpoint

d. CO_2 injection on high adsorber bed temperature

e. CO_2 shutoff when adsorber bed temperature is below its setpoint.

6.2.3.6 Materials

Materials for fabrication, coating, and sealing the SGTS are chosen because of their capability for a satisfactory normal service life of 40 years, and 6 months of service under post-LOCA conditions at the maximum cumulative radiation exposure, without any adverse effects on service, performance, operation, or appearance. All materials of construction, including metal components, seals, gaskets, lubricants, and finishes, such as paints, are compatible with these objectives and are capable of satisfactory service under the expected radiation exposure.

Gaskets and seal pads are unicellular, ozone-resistant, oil-resistant neoprene or silicone-rubber sponge, Grade SCE-43, in accordance with ASTM Dl056.

Only adhesives listed and approved in AEC Health and Safety Bulletin 306, dated March 31, 1971, or Military Specification MIL-F-5l068C, dated June 8, 1970, are used.

Organic compounds included in the filter train are as follows.

a. Charcoal

b. HEPA filter media binder - The total weight of media binder per filter element is approximately 4 lb, or a total of 32 lb per equipment train

c. Filter adhesive - Approximately 1 liquid qt of fire-retardant neoprene adhesive is used to manufacture each HEPA filter

d. HEPA filter, pre-filter and coverplate gaskets - Filter and coverplate gaskets are unicellular neoprene per ASTM Dl056, Grade SCE-43

e. Door and access port gaskets - Door and access port gaskets are unicellular neoprene per ASTM D735-SCE-516, or ASTM D2000-BC-516

f. All painted metals (inside and out) are coated with 0.003-in. MOBIL 13R56B primer and 0.003-in. MOBIL VALCHEM Series 89 white top coat. Stainless components are not painted

g. Wire Coatings and Insulation - Approximately 15 lb of Cerro Products "Rockbestos" silicone rubber is used. Of this amount, less than 0.5 lb is inside the SGTS. Approximately 10 lb of EPR neoprene is used, none of which is inside the SGTS.

6.2.4 Containment Isolation System

6.2.4.1 Design Bases

The containment isolation system consists of valves and controls required for the isolation of lines penetrating the primary containment. The primary objective of this system is to provide protection against release of radioactive materials to the environment as a result of accidents occurring to the nuclear steam supply system (NSSS), auxiliary systems, and support systems. This objective is accomplished by automatic isolation of appropriate lines that penetrate the primary containment. The containment isolation system is actuated automatically when specific limits are reached.

The containment isolation system, in general, closes fluid penetrations that support those systems not required for emergency operation. Fluid penetrations supporting ESF systems have remote manual isolation valves which may be closed from the main control room, if necessary. The automatic isolation valves close on receipt of an isolation signal from a sensor. For example, the main steam isolation valves (MSIVs) may be closed by signals indicating low water level in the reactor, main steam line tunnel high temperature, high steam flow, low steam line pressure, or low condenser vacuum. Isolation signals for each valve are specified in Table 6.2-2.

It is neither necessary nor desirable that every isolation valve close simultaneously with a common isolation signal. For example, if a process pipe were to rupture in the drywell, it would be important to close all lines that are open to the drywell and some effluent process lines, such as the main steam lines. However, under these conditions it would be essential that the containment and core cooling systems be operable. Therefore, several specific signals are used for isolation of various process and safety systems.

The design of isolation valving for lines penetrating the containment conforms to the intent of 10 CFR 50, Appendix A, General Design Criteria (GDC) 54, 55, 56, and 57. Redundancy and physical separation are provided in the electrical and mechanical design to ensure that no single failure in the containment isolation system prevents the system from performing its intended functions.

Where a penetration is part of a redundant train in an ESF system, isolation valves for that train may receive power from a single electrical division. This is desirable so that a single failure of an electrical division cannot disable both trains of the ESF system. In these cases a redundant mechanical barrier (i.e., closed systems beyond the isolation valves) exists so that containment isolation is not lost as a result of a single electrical failure.

Protection of primary containment isolation system components from missiles, and the integrity of these components to withstand seismic occurrences without loss of operability, was considered in the design of this system. The containment isolation system is Category I.

On signals of high drywell pressure or low water level in the reactor vessel all isolation valves that are part of systems not required for emergency shutdown of the plant are closed. The same signals initiate the operation of systems associated with the emergency core cooling system (ECCS). Isolation valves that are part of the ECCS may be closed remote manually from the control room.

Criteria for the design of the containment isolation control system are listed in Subsection 7.1.2.1.2. The bases for assigning certain signals for primary containment isolation are listed and explained in Chapter 7.

6.2.4.2 System Design

The containment isolation system is designed to provide a minimum of one protective barrier between the reactor and the environs under all postulated conditions. A detailed discussion of the controls associated with the containment isolation system is included in Subsection 7.3.2. Table 6.2-2 specifies the plant protection system signals that initiate closure of the containment isolation valves.

6.2.4.2.1 Design Requirements

Containment isolation valves were designed in accordance with the requirements of the ASME B&PV Code Section III, in effect at the time of purchase as required by 10 CFR 50, Section 50.55. Where necessary, a dynamic system analysis, which includes the impact effect of rapid valve closure under operating conditions, is included in the design specifications of piping systems that require containment isolation valves. Quality Assurance (QA) procedures are followed to ensure compliance with these specifications.

All containment isolation valves are located inside either the drywell or the secondary containment. Both structures are of Category I design and are protected against damage from missiles. The primary containment vessel is enclosed completely in a reinforced-concrete structure having a thickness of 4 to 7 ft. This concrete structure provides a major mechanical barrier for protection against missiles that may be generated external to the primary containment. Protection against damage from missiles is provided for isolation valves, actuators, and controls. Refer to Section 3.5 for a discussion of missile protection. Section 3.6 contains a discussion of protection provided against the dynamic effects of pipe whip, while Section 3.7 contains a discussion of the design analyses performed on containment penetration piping.

Each containment isolation valve is designed to ensure its performance under all anticipated environmental conditions including maximum differential pressure, extreme seismic occurrences, steam-laden atmosphere, high temperature, and high humidity. Section 3.11 presents a discussion of the environmental conditions, both normal and accident, for which the containment isolation system is designed.

Closed systems used as an isolation barrier, either inside or outside the primary containment, meet the following requirements:

a. The systems are protected against postulated missiles and pipe whip

b. The systems are designed to Category I

c. The systems are at least Quality Group B, except for specific instrument line applications noted in Table 6.2-2 (Note 12)

d. The systems are designed to at least the maximum temperature and pressure of the containment.

In addition, closed systems inside the containment meet the following requirements:

a. They are designed to withstand external pressure from the containment structural acceptance test

b. They are designed to withstand the design-basis accident and accompanying environment

c. They do not communicate with either the reactor coolant system or the containment atmosphere.

Power-operated containment isolation valves have limit switches that indicate valve position in the main control room. Containment isolation valves are designed to fail in the safe position. Containment isolation valves are either automatically actuated by the signals shown in Table 6.2-2 or are remote manually operated. Some containment isolation check valves inside containment are provided with supplemental air operators to verify free disk movement during opening and closing and zero pressure differentials across the valves. This arrangement provides a means by which to periodically verify valve operability.

Containment isolation valves that are remote manually operated are required to be provided with a leakage detection capability or be administratively closed (Standard Review Plan [SRP] 6.2.4). Table 6.2-13 lists the remote manual containment isolation valves that have a leak detection capability.

Remote manual containment isolation valves that are locked closed (and are thus under administrative control) are as follows.

Penetration	Valve
X-12	V8-3407
X-21	V5-2006
	V5-2007

The only other containment isolation valves with a remote manual primary actuation mode are the N_2 supply to the drywell-to-torus vacuum breakers, penetrations X-204A-M (valves V4-2036, V4-2065, V4-2075, V4-2077, V4-2082, V4-2084, V4-2086, V4-2088, V4-2090, V4-2092, V4-2094, and V4-2096). (Table 6.2-2 provides the F valve numbers.) These valves are locked closed to comply with Technical Specification 3.6.1.3.2 and are opened during the testing of the drywell-to-torus vacuum breakers. These valves are under administrative control and considered locked closed as defined in SRP 6.2.4 to preclude the possibility of their being inadvertently opened during normal reactor operations. Thus, as all remote manual containment isolation valves are either provided with leak detection capability or locked closed, Fermi 2 meets the guidance set forth in SRP 6.2.4.

6.2.4.2.2 Conformance To General Design Criteria

As stated in Subsection 6.2.4.1, the design of isolation valving for lines penetrating the containment follows the intent of GDC 54 through 57. Isolation valving for instrument lines that penetrate the containment follows the guidance of Regulatory Guide 1.11. Those cases where literal interpretation of GDC 54 through 57 has not been followed are included in the discussions in the following subsections.

6.2.4.2.2.1 General Design Criterion 54

General Design Criterion 54 in 10 CFR 50 states

> Piping systems penetrating primary reactor containment shall be provided with leak detection, isolation, and containment capabilities having redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating these piping systems. Such piping systems shall be designed with a capability to test periodically the operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

Criterion 54 Conformance

All piping penetrations meet the intent of GDC 55, 56, or 57. In doing so, they also conform to the intent of GDC 54 to the extent that all piping systems penetrating the primary containment are provided with leak detection, isolation, and containment capabilities which reflect the importance to safety of isolating these piping systems. In addition, each piping penetration is designed to be tested periodically in accordance with 10 CFR 50, Appendix J, as described in Table 6.2-2. Specifically, the following systems have containment isolation provisions consistent with the provisions of GDC 54.

Traversing In-Core Probe (TIP) System (Penetrations X-35B, C, D, E, F

The TIP system detector signal and drive cable neither comprise a portion of the reactor coolant pressure boundary nor directly communicate with the primary containment atmosphere. Thus, GDC 55 and 56 are not directly applicable to this specific class of lines. The basis on which TIP system lines are designed is described more closely in GDC 54, which states, in effect, that systems penetrating the primary containment are to be provided with isolation capabilities commensurate with the importance of isolating the system. Thus, even though the failure of TIP system lines presents no safety hazard, additional conservatism is provided in TIP system isolation capabilities, which reflects the intent of GDC 55.

The TIP system detector signal and drive cable are stored outside the primary containment behind a normally closed ball valve and an explosively actuated shear valve. The valves are located outside the containment for inspection and maintenance accessibility, and the position of each is indicated in the control center. The ball valve remains closed at all times except during operation of the associated TIP system channel. Prior to use of the TIP system, the ball valve is manually opened. All five TIP machines may be used simultaneously, however any one guide tube is used, at most, only a few hours per year.

After TIP system cable retraction, the ball valve is manually closed. Should a containment isolation signal be received while the TIP system cable is inserted, the cable will withdraw automatically, and this will be followed by automatic closure of the ball valve.

The function of the shear valve is to ensure the integrity of the containment in the unlikely event that the ball valve should fail to close or the drive cable should fail to retract from the guide tube during the time containment isolation is required. The valve is designed to shear the TIP drive cable and seal the drive tube upon command from the control center. In addition to valve position, the condition of each shear valve dc firing circuit is monitored continuously in the control center. Additional testing requirements are discussed in Note 17 to Table 6.2-2.

Control Rod Drive Insert and Withdrawal Lines (Penetrations X-37A, B, C, D and X-38A, B, C, D)

Control rod drive (CRD) insert and withdrawal lines penetrate the primary containment, but they neither directly communicate with the containment atmosphere nor comprise part of the reactor coolant pressure boundary. Thus, GDC 55 and 56 are not directly applicable to this class of lines. The basis on which the CRD lines are designed is described more closely in GDC 54, which requires such systems to have isolation capabilities commensurate with the importance of isolating the system. Since these lines are necessary for the scram function, the reliability of their operation is of utmost concern. Thus, isolation valves should not be incorporated in the design of this system. The probability of reliable and timely operation is enhanced by simplicity of design and by minimizing, where possible, the introduction of possible failure mechanisms. Even though multiple breaks postulated and analyzed in Section 4.0 pose no threat to public health and safety, CRD insert and withdrawal isolation capabilities were designed to reflect the conservative intent of GDC 55.

Both the CRD insert and withdrawal lines are provided with normally closed, fail-closed, solenoid-operated directional control valves, which open only during routine movement of their associated control rod. The normally closed, fail-open, air-operated scram inlet and exhaust valves open only when required to effect a rapid reactor shutdown (scram). In addition, manual shutoff valves are provided for positive isolation in the unlikely event of a pipe break within a hydraulic control unit. (These units and the valves described above are located outside the containment to satisfy testing, inspection, and maintenance requirements.) In addition, each CRD insert line is provided with an automatically actuated flange ball check valve inside containment; the flange ball check valve is part of the CRD mechanism.

During post-LOCA, the scram inlet and outlet valves will remain open if the scram cannot be reset. Therefore, due to CRD seal leakage, the scram discharge volume (SDV) could experience reactor vessel pressure. To ensure the integrity of the SDV, it will be included in the Type A tests.

6.2.4.2.2.2 General Design Criterion 55

General Design Criterion 55 in 10 CFR 50 states:

> Each line that is part of the reactor coolant pressure boundary and that penetrates primary reactor containment shall be provided with containment isolation valves as follows, unless it can be demonstrated that the containment isolation provisions for a specific class of lines such as instrument lines, are acceptable on some other defined basis:
>
> (1) One locked closed isolation valve inside and one locked closed isolation valve outside containment; or
>
> (2) One automatic isolation valve inside and one locked closed isolation valve outside containment; or

(3) One locked closed isolation valve inside and one automatic isolation valve outside containment. A simple check valve may not be used as the automatic isolation valve outside containment; or

(4) One automatic isolation valve inside and one automatic isolation valve outside containment. A simple check valve may not be used as the automatic isolation valve outside containment.

Isolation valves outside containment shall be located as close to containment as practical and upon loss of actuating power, automatic isolation valves shall be designed to take the position that provides greater safety.

Other appropriate requirements to minimize the probability or consequences of an accidental rupture of these lines or of lines connected to them shall be provided as necessary to assure adequate safety. Determination of the appropriateness of these requirements, such as higher quality in design, fabrication, and testing, additional provisions for inservice inspection, protection against more severe natural phenomena, and additional isolation valves and containment, shall include consideration of the population density, use characteristics, and physical characteristics of the site environs.

Criterion 55 Conformance

The reactor coolant pressure boundary (RCPB) (as defined in 10 CFR 50, Section 50.2[v]) consists of the reactor pressure vessel (RPV), pressure-retaining appurtenances attached to the RPV, and valves and pipes that extend from the RPV up to and including the outermost isolation valve. The lines of the RCPB that penetrate the primary containment are capable of isolation, thereby precluding any significant release of radioactivity. Similarly, lines that do not penetrate the primary containment but form a portion of the RCPB (such as connecting lines up to and including the second isolation valve) are designed to ensure that isolation of the reactor pressure boundary can be achieved.

6.2.4.2.2.2.1 Influent Lines

Influent lines that penetrate the primary containment and connect directly to the RPV are equipped with two isolation valves: one inside the containment, the other outside the containment. Both valves are located as close to the containment as practical. Influent lines which comprise part of the RCPB are listed below and discussed in detail in the remainder of this section.

Penetration No.	System
X-9A	Feedwater HPCI supply
X-9B	Feedwater RCIC supply RWCU return
X-13(A, B)	RHR pump discharge to recirculation loops
X-16(A, B)	Core spray pump discharge to core spray spargers

Penetration No.	System
X-42	Standby liquid control system
X-49A and X-51A	Recirculation pump seal purge

Feedwater System

The feedwater line penetrating the primary containment is part of the RCPB. This penetration is supplied with one automatic isolation valve inside and one automatic isolation valve outside the containment. The isolation valve inside the containment is a check valve. The isolation valve outside the containment is an air-operated, spring-to-close, positive-acting check valve.

Should a break occur in the feedwater line, the valves will prevent significant loss of fluid inventory and offer immediate isolation. During the postulated LOCA, it is desirable to maintain reactor coolant makeup from all sources of supply. For this reason, the outer containment isolation valve does not automatically isolate on a signal from the containment isolation system. However, the valve is capable of remote closure from the control room to provide long-term leakage protection when, based on operator judgment, continued makeup from the feedwater system is no longer necessary. A second check valve is located outside the containment--between the air-operated isolation valve and the containment wall--for added isolation capability.

RWCU, HPCI, and RCIC Systems

Influent lines that use the feedwater piping and penetrations in order to transfer fluid to the RPV consist of the reactor water cleanup (RWCU) return, and reactor core isolation cooling (RCIC), high-pressure coolant injection (HPCI) supply, and standby feedwater. Each of these lines can be isolated by the feedwater check valve inside the containment. The RCIC and HPCI supply lines each have an isolation valve outside the containment. These valves are normally closed, dc power-operated, remote manually actuated gate valves. The RWCU return line has a motor operated, normally open, ac power-operated gate valve as its isolation valve outside the containment. This valve is capable of remote closure from the control room. Two check valves are provided between the isolation valve and the containment wall. Should a break occur in the RWCU line, these check valves will prevent significant loss of fluid inventory from the feedwater side.

RHR and Core Spray Systems

The residual heat removal (RHR) pump discharge lines to the recirculation system (low-pressure coolant injection and shutdown cooling modes) and the core spray pump discharge lines have testable check valves inside the containment that provide for immediate isolation in the event of a break upstream of these valves. The outer containment isolation valves are remote manually actuated gate valves. However, no licensing credit is taken for the containment isolation feature of the RHR inboard check valves (see Reference 25a). Each valve will receive an automatic opening signal in the event of the postulated LOCA.

Standby Liquid Control System

The standby liquid control line uses a check valve as the isolation valve inside, as well as outside, the primary containment. General Design Criterion 55 states that a simple check valve may not be used as the automatic isolation valve outside the containment; however, should insertion of the liquid poison become necessary, it is imperative that the injection line be open. In the design of this system, it has been accepted practice to omit an automatic valve that opens on signal, as this introduces a possible failure mechanism. As a means of providing assurance for reliable and timely actuation, an explosive valve is used.

In this manner, the availability of the line is ensured. Because the standby liquid control line is a normally closed and non-flowing line, rupture of this line is a very remote possibility.

Recirculation Pump Seal Purge System

The recirculation pump seal purge lines use two air-operated globe valves, one inside the containment and one outside the containment. The valves isolate automatically on high drywell pressure or low vessel water level (level 2).

6.2.4.2.2.2.2 Effluent Lines

With the exception of the postaccident pressurized reactor coolant sample lines, effluent lines that form part of the RCPB and penetrate the primary containment are equipped with two isolation valves, one inside the containment and the other outside the containment. Both valves are located as close to the containment as practical. Effluent lines that comprise part of the RCPB are listed below, and are discussed in detail in the remainder of this section.

Penetration No.	Section
X-7(A,B,C,D)	Main steam lines
X-8	Main steam line drains
X-10	Steam to RCIC turbine
X-11	Steam to HPCI turbine
X-12	RHR pump suction for recirculation piping (shutdown cooling mode)
X-28Cf	Postaccident pressurized reactor coolant sample
X-29A	Reactor water sample line
X-40Dd	Postaccident pressurized reactor coolant sample
X-43	Reactor water cleanup suction

Main Steam System

The MSIVs are air-operated, automatically actuated, Y-pattern globe valves. Two valves are provided in each line: one inside and one outside the containment. There is a third valve in each line outside the containment that is a gate valve.

The main steam drain line is provided with two automatic, motor-operated gate valves: one inside and one outside the containment. These valves are closed during normal reactor operation.

RCIC System

Both isolation valves in the RCIC steam supply line are normally open, remote manually actuated gate valves. These valves close automatically on indication of an RCIC system piping failure.

HPCI System

The isolation valves in the HPCI steam supply line consist of two gate valves and a 1-in. globe valve. All are remote manual motor-operated valves. The isolation valve inside the containment is open normally. The normally open, 1-in. globe valve bypasses the normally closed system supply valve outside the containment to keep the HPCI steam supply line warm. All HPCI steam supply line valves close automatically on indication of an HPCI system piping failure.

RHR System

The RHR shutdown cooling suction line is provided with two normally closed, automatically actuated, motor-operated gate valves and a locked-closed bypass valve. The bypass valve provides assurance that the normal shutdown cooling method will be available if the normally used valve fails. There is also a 3/4-in. bypass line with two check valves in series, which allows heated water trapped inside the RHR line to be relieved to the reactor vessel.

Reactor Coolant Sample System (Non-Postaccident)

The reactor water sample line is provided with two automatic, air-operated, fail-closed isolation globe valves: one inside and one outside the containment. These valves are closed during normal reactor operation, but receive an automatic closure signal in case they are open when containment isolation is required.

Postaccident Pressurized Reactor Coolant Sample

The two postaccident reactor coolant sample lines are connected to jet pump instrumentation lines outside the containment. Each line is provided with a solenoid-operated globe isolation valve outside the containment. These valves are closed during normal reactor operation and are opened only during postaccident conditions.

RWCU System

The RWCU suction line is provided with two normally open, automatic, motor-operated gate valves. These valves will close on receipt of a containment isolation or RWCU system piping failure signal.

Leak detection is provided for each line that has remote manual containment isolation valves and is evaluated against GDC 55.

6.2.4.2.2.3 General Design Criterion 56

General Design Criterion 56 in 10 CFR 50 states

> Each line that connects directly to the containment atmosphere and penetrates primary reactor containment shall be provided with containment isolation valves as follows, unless it can be demonstrated that the containment isolation provisions for a specific class of lines, such as instrument lines, are acceptable on some other defined basis:
>
> (1) One locked closed isolation valve inside and one locked closed isolation valve outside containment; or
>
> (2) One automatic isolation valve inside and one locked closed isolation valve outside containment; or
>
> (3) One locked closed isolation valve inside and one automatic isolation valve outside containment. A simple check valve may not be used as the automatic isolation valve outside containment; or
>
> (4) One automatic isolation valve inside and one automatic isolation valve outside containment. A simple check valve may not be used as the automatic isolation valve outside containment.

Isolation valves outside containment shall be located as close to the containment as practical and upon loss of actuating power, automatic isolation valves shall be designed to take the position that provides greater safety.

Criterion 56 Conformance

The lines that penetrate the primary containment and communicate with the containment atmosphere can be grouped into two categories: (1) pipes that penetrate the primary containment and connect directly to the suppression pool; and (2) pipes that penetrate the primary containment and connect directly to the drywell atmosphere.

6.2.4.2.2.3.1 Lines Connecting To the Suppression Pool

Lines in this category are listed below:

Penetration No.	System
X-205(A,B)	Torus to secondary containment vacuum breakers
X-205C	Suppression pool N_2 and air purge inlet
X-205D	Suppression pool exhaust and N_2 inlet
X-206(A, B, C, D, E, F)	Suppression pool water level and pressure instrumentation
X-210(A, B)	RHR minimum flow line RHR heat exchanger thermal relief RHR test line Torus water management return RHR suction thermal relief RHR heat exchanger discharge header thermal relief Postaccident liquid sample return RHR warmup and return
X-211(A, B)	RHR to suppression pool spray
X-212	RCIC turbine exhaust line
X-213(A, B)	Torus water management supply
X-214	RCIC vacuum breaker line
X-215	HPCI vacuum breaker line Combustible gas control suction Postaccident gaseous sample return

Penetration No.	System
X-217	Grab sample line
X-218	Combustible gas control return
X-219	Combustible gas control suction
X-220	HPCI turbine exhaust line
X-221	HPCI turbine exhaust drain
X-222	RCIC vacuum pump discharge
X-223(A, B, C, D)	RHR pump suction RHR pump suction header thermal relief
X-224(A, B)	Core spray pump suction
X-225	HPCI pump suction
X-226	RCIC pump suction
X-227(A, B)	Core spray pump suction thermal relief Core spray pump discharge header thermal relief Core spray pump minimum flow line Core spray pump test line Torus water management return HPCI minimum flow line RCIC minimum flow line
X-230	Primary containment monitoring system Post accident suppression pool atmosphere sample
X-231	Primary containment monitoring system
X-231	Postaccident suppression poolatmosphere sample

As stated in GDC 56, two isolation valves--one inside and one outside the containment--are required in lines that penetrate the primary containment and connect directly to the containment atmosphere. However, GDC 56 allows for alternatives to these explicit isolation requirements where the acceptable basis for each alternative is defined. The following are alternatives to explicit conformance with GDC 56. Notes in Table 6.2-2 identify the alternative basis to which each penetration is designed.

Two Isolation Valves Outside Containment

The primary containment radiation monitor system (PCRMS) is associated with Division I of the primary containment atmosphere monitoring system (PCAMS). The nonessential

PCRMS has two isolation valves on the inlet and two isolation valves on the outlet. These isolation valves are a normally open spring-to-close solenoid operated globe valve and an air operated ball valve. These inlet and outlet lines are connected to the containment atmosphere via PCAMS piping during normal operation. The isolation valves receive a containment isolation signal on a LOCA (see Subsection 6.2.4.2.2.3.2).

For lines that connect to the suppression pool, an isolation valve located inside the containment would necessitate placement of the valve either under water or in a high-humidity, nonaccessible area. Such placement would subject these valves to an extremely hostile environment, which could compromise their reliability and prevent routine inspection and maintenance. Thus, as an alternative to the explicit requirements of GDC 56 for lines in ESF or ESF-related systems, both isolation valves are located outside, and as close to, the containment wall as practical.

Relief Valves as Isolation Valves

Relief valves are provided in the RHR, core spray, HPCI, RCIC, and combustible gas control (CGC) systems as overpressureprotection devices. These valves are required for the design of Class B systems according to the ASME B&PV Code, Subsection NC-7000. The valves are installed in a manner that ensures their correct operation and reliability. Further, the Code requires that no stop valves or other devices be placed (in relation to a pressure relief device) so that it could impair the overpressure protection offered by the relief valve itself. Relief valves installed in these lines provide this required level of protection, and, if required to operate, would route the diverted fluid to the suppression pool.

Because of the orientation required, each of these relief valves is an isolation valve for the applicable penetration. The piping and valve designs are Quality Group B, Category I, and will withstand temperatures and pressures at least equal to the containment design pressure and temperature. Should the postulated LOCA occur, containment pressure would be felt on the downstream side of the relief valve, and would act in conjunction with the spring pressure setting of the relief valve to further enhance seating.

Remote Manual Isolation Valves

Remote manual valves are used as containment isolation valves in ESF and ESF-related systems. These systems include RHR, core spray, HPCI, RCIC, and reactor building closed cooling water (RBCCW) Emergency Equipment Cooling Water (EECW) systems. In each case, leak detection is provided.

Closed Systems Outside the Containment

The RHR, core spray, HPCI, and RCIC systems are closed-loop systems outside the containment. These systems can accommodate a single active failure and still maintain containment integrity. The systems are designed to Category I standards, are classified as Quality Group B, and will maintain their integrity should the containment experience its design temperature and pressure transient. Thus, as an alternative to the explicit requirements of GDC 56 for such lines in ESF or ESF-related systems, a single isolation valve is used outside the containment to enhance system reliability.

Lines that are not Quality Group B but that connect to these closed-loop systems are itemized in Table 6.2-14. By necessity, some of the valves in these lines are located near system pumps and are subject to missile damage should the pump fail. Should this occur, the system would be isolated either manually or automatically, and, therefore, failure of these valves as a result of missile damage would not constitute a breach of the primary containment.

Other Systems

The CGC, purge and inerting systems each use two isolation valves in series outside the suppression pool. Installing one of these valves inside the suppression pool could compromise reliability and prevent routine inspection and maintenance. These systems are built to the same quality standards as the primary containment and are protected against postulated missiles and pipe whip. The CGCS PCIVs are permanently de-energized and locked-closed.

The vacuum breakers to the secondary containment are essential for primary containment integrity. Isolation is provided through a power-to-close, spring-to-open butterfly valve and a testable check valve. Power from divisional electrical buses is applied to the butterfly valve to keep the valves closed, except when air is required to relieve a vacuum inside the primary containment. The butterfly valve will open on loss of power or degraded voltage but closes automatically once power is restored or voltage recovers. During a LOCA concurrent with a Loss of Offsite Power (LOP), the butterfly valves will de-energize and open until power is restored to the divisional electrical buses. Upon restoration of power, the butterfly valves will re-energize and reposition, closing the valves. During a LOCA concurrent with a low grid voltage, insufficient voltage during the time Core Spray and RHR pumps start may cause the Division I butterfly valve to pen. Once nominal voltage is restored after RHR and Core Spray pump starts, the butterfly valve will close. In either scenario, the time the butterfly valve is open is less than the 108 second allowed stroke time for containment isolation valves established in the accident analysis. The vacuum breaker testable check valves provide containment isolation and remain closed during the accident unless negative differential pressure exists. These lines and valves are Category I, Quality Group B and are located in missile-free areas.

6.2.4.2.2.3.2 Lines Connecting To the Drywell

Lines in this category are listed below and discussed in the remainder of this section. The lines are Category I and Quality Group B at least through the outermost containment isolation valve.

Penetration No.	System
X-15	CGC suction
X-17	Abandon RHR head spray
X-18	Drywell floor drain sump pump discharge
X-19	Drywell equipment drain sump pump discharge
X-20	Demineralized service water to drywell

Penetration No.	System
X-22	Control air and N_2 to drywell
X-23	RBCCW/EECW supply
X-24	RBCCW/EECW return
X-25	Drywell exhaust
X-26	Drywell N_2 and air inlet
X-27(a, b, c, d, e)	Containment atmosphere sample and postaccident drywell atmosphere sample (X-27b only)
X-27f	Drywell pressure instrumentation
X-29B (b,c)	Reactor protection system
X-29Be	Drywell instrumentation
X-31Ba	Drywell on line pressure control
X-34(A, B)	RBCCW/EECW supply and return
X-36	N_2 to dry
X-39(A, B)	RHR to containment spray header
X-44	CGC suction
X-47(a,b)	Reactor protection system
X-47e	Drywell instrumentation Nitrogen inerting instrumentation
X-48(a,b,c,d,e,f)	Containment atmosphere sample and postaccident drywell atmosphere sample (X-48f only)

Regulatory Guide 1.7 was revised in March 2007 to reflect the amended 10 CFR 50.44. The Combustible Gas Control System (CGCS) has been retired in place with its electrical circuits de-energized and fluid process piping isolated from primary containment with redundant locked-closed isolation valves. The valves are located external to the primary containment, and are accessible for inspection and testing during normal reactor operation.

Penetration X-17 for the abandoned RHR head spray line now conforms to the requirements of GDC-56 since the line is no longer directly connected to the RPV. Two normally closed motor operated valves are located in this line, one inside containment and one outside containment.

The drywell equipment and floor drain sump pump discharge lines each have a motor-operated, normally open gate valve inside the containment, and an air-operated, normally closed gate valve outside the containment. These valves receive containment isolation signals on the postulated LOCA. Rupture disc overpressure protection is installed to limit the pressure rise from LOCA heatup of the isolated penetrations per GL 96-06. The rupture disc discharges into a small discharge tank which provides a sealed closed barrier for containment isolation.

Demineralized service water line has an isolation valve inside containment and a spectacle flange assembly with blank installed outside containment. Control air and nitrogen lines have isolation valves inside and outside the drywell. The demineralized service water isolation valve is the only manual valve in this group. The valve remains locked closed at all times during reactor operation.

The drywell exhaust and air purge lines have isolation valves inside and outside the containment. The valves are either automatically or remote manually actuated. Leak detection is provided to inform the control room operator when closure of the remote manual valves is required.

The RHR pump discharge to the containment spray lines contains two isolation valves outside the containment. Since the spray header is integral to the drywell wall, placing an isolation valve inside the containment could compromise the structural integrity of the containment spray headers.

The RBCCW/EECW supply lines each have a check valve inside the containment and a motor-operated gate valve outside the containment. These motor-operated gate valves are remote, manually actuated and close on a high drywell pressure EECW initiation signal. The RBCCW/EECW return lines each have a remote, manually actuated, diverse electrically powered motor-operated gate valve inside and outside the containment.

The drywell instrumentation, nitrogen-inerting instrumentation, reactor protection system, and containment atmosphere sample systems are closed-loop systems outside the containment. These systems can accommodate a single active failure and still maintain containment integrity. The systems are designed and installed as Quality Group B, up to and including the isolation valves. The balance of the instrument piping is designed to meet Quality Group B design criteria. These design criteria include stress analysis with consideration given to deadweight, thermal, and seismic conditions. The systems are seismically supported.

Nuclear-grade materials are used throughout the fabrication of the piping system. They will maintain their integrity should the containment experience its design temperature and pressure transient. Thus, as an alternative to the explicit requirements of GDC 56 for such lines in ESF or ESF-related systems, a single air-operated isolation valve or solenoid-operated isolation valve is used outside the containment to enhance system reliability.

The lines that connect the nonessential PCRMS to Division I of the closed outside containment loop of the PCAMS have two isolation valves outside containment for both the inlet and outlet of the PCRMS. The PCRMS utilizes common piping of PCAMS; therefore, the valves are outside containment and placed as close as practical to the PCAMS piping loop. All other requirements of GDC 56 are met.

The drywell postaccident atmosphere sample lines contain two solenoid-operated globe isolation valves outside the containment. These lines are connected to the normal containment atmosphere sample system lines outside the containment. These valves are closed during normal reactor operation and are opened only during postaccident conditions.

6.2.4.2.2.4 General Design Criterion 57

General Design Criterion 57 in 10 CFR 50 states

> Each line that penetrates primary reactor containment and is neither part of the reactor coolant pressure boundary nor connected directly to the containment atmosphere shall have at least one containment isolation valve which shall be either automatic, or locked closed, or capable of remote manual operation. This valve shall be outside the containment and located as close to the containment as practical. A simple check valve may not be used as the automatic isolation valve.

Criterion 57 Conformance

Penetrations X-204 (A through M) for the drywell-to-torus vacuum breaker nitrogen supply and their associated isolation valves conform to the locked closed requirements of GDC 57 to comply with Technical Specification 3.6.1.3.2. A locked closed, air-operated globe valve as defined is SRP 6.2.4 is located in each line outside the containment.

6.2.4.2.3 Containment Isolation Dependability

Fermi 2 meets the NRC requirements developed for reliable containment isolation as follows.

a. The containment isolation design complies with the recommendation of SRP 6.2.4 in that there is diversity in the parameters sensed for the initiation of containment isolation. Safety-grade signals are provided for the detection of abnormal conditions in the reactor coolant system and containment; these are low reactor vessel water level and high drywell pressure

   Several lines are not isolated on the high-drywell- pressure signal in order to retain system availability for small breaks or leaks. Justification for these cases is given under Comments in Table 6.2-15

b. Essential and nonessential systems containing piping systems that penetrate the containment are identified in Table 6.2-16. Those systems identified as essential are regarded as indispensable or are backup systems in the event of a LOCA. The nonessential systems have been judged to be not required in LOCA situations

c. Nonessential lines that are a possible open path out of the containment are automatically isolated by the containment isolation signals, by check valves that prevent flow out of the containment, or by manual valves that are normally closed. Normally closed valves are under administrative control to ensure that valves are closed during startup, power, hot-standby, and hot-shutdown modes of operation

   For instrument lines connected to the RCPB, each line is equipped with a flow-restricting orifice located as close as practical to the point of connection to the RCPB. A manual shutoff valve is located outside the containment and is located as close as practical to the containment wall. An excess-flow check valve is provided immediately downstream of the manual valve. This design and installation follows the guidance of Regulatory Guide 1.11

d. The resetting of containment isolation signals does not result in the automatic reopening of containment isolation valves. Deliberate operator action is required to reopen a containment isolation valve once the containment isolation signals are reset

e. Drywell high pressure initiates the containment isolation of nonessential systems and lines. The Technical Specifications specify the drywell high-pressure trip-point setting

f. The Fermi 2 purge valves satisfy the operability criteria set forth in Branch Technical Position (BTP) CSB 6-4, Revision 1, and Staff Interim Position dated October 23, 1979. The Fermi 2 position relative to BTP CSB 6-4 is provided in Subsection 6.2.5.2.5. Fermi 2 complies with the Staff Interim Position as follows: (1) the purge valves are intended to be operated only for inerting, deinerting, or pressure control in accordance with the Technical Specifications; and (2) the Fermi 2 valves are operable for DBA flows

g. Containment purge and ventilation isolation valves close automatically upon the detection of high airborne radiation in the reactor building exhaust line. This high-radiation isolation signal is in addition to the diverse containment isolation signals.

6.2.4.2.4 Valve Closure Times

Proper valve closing time is achieved by appropriate selection of valve type, operator type, and operator size. Isolation valve closing times were verified during the functional performance tests prior to reactor startup and are periodically retested at intervals specified in the Technical Specifications. The design of piping systems penetrating the reactor containment includes provisions for operability and leakage testing of isolation valves.

Motive power for the valves on process lines that require two valves is supplied from physically independent power sources to provide a high probability that no single event could interrupt power to both closure devices. Loss of valve actuation power is detected and annunciated in the main control room.

In general, isolation valves located outside the primary containment receive dc power from the Division II power supply, or alternate division ac power, while those located inside the primary containment receive ac power from the Division I power supply.

6.2.4.2.5 Instrument Lines Penetrating the Primary Containment

All instrument lines connected to the reactor coolant pressure boundary are Category I and Quality Group A. Physical separation is provided for redundant instrument lines to the extent practical, so that the failure of one line will not induce failure in another. The response time for all sensors connected to instrument lines is not affected by the valves or orifices in the line. The design and installation of instrument lines follows the guidance of Regulatory Guide 1.11 (Safety Guide 11).

The instrument-sensing lines listed below penetrate the primary containment and connect to the RCPB.

Number of lines	Instrument Description
24	Jet pump flow
1	Jet pump
14	RPV level/pressure*
8	Recirculation inlet to RPV DP
2	Recirculation system pressure
8	Recirculation system flow
4	Recirculation Pump DP
4	Recirculation pump seal pressure
4	Steam flow to HPCI turbine
4	Steam flow to RCIC turbine
16	Main steam flow
2	Feedwater pressure**

* The portion of the instrument line passing through the containment is part of a penetration assembly that is part of the containment and thus is Quality Group B, consistent with the Containment Quality Group.

Two check valves are provided in series for the isolation of each division of the reactor vessel instrument-sensing line backfill system from the RPV level/pressure instrument reference legs.

** These lines do not penetrate the containment. They tap in between the containment and the outer isolation valve.

Each line, except for the feedwater pressure-sensing line, is equipped with a flow-restricting orifice located as close as practical to the point of connection to the RCPB. No such device is necessary for the feedwater pressure-sensing lines because they tap in outside the containment, and the isolation valve inside the containment (check valve) serves the function of the restricting orifice. A manual shutoff valve is located outside the primary containment and is installed as close as practical to the containment wall or pipe (in the case of feedwater). An excess-flow check valve is provided immediately downstream of the manual valve. The excess-flow check valve will close automatically in the event of a line break downstream. Indicating lights on a control room panel monitor excess-flow-check-valve position. These valves may be reopened by actuation of a solenoid valve, which is operated from a local control panel, after repairs are made. This design and installation follows the guidance of Regulatory Guide 1.11. There are no instrument lines that penetrate both the primary and the secondary containments.

The postulated break of an instrument line attached to the RCPB is discussed and evaluated in Subsection 15.6.2. Leakage from such a rupture upstream of the excess-flow check valve is minimized by the restricting orifice in the line. The integrity and functional performance of the secondary containment and standby gas treatment systems are not impaired by this event, and the calculated potential offsite exposures are substantially below the guidelines of 10 CFR 100.

Each instrument line except the jet pump instrument lines is provided with a 0.25-in.-diameter orifice in addition to the excess-flow check valve. The jet pump lines are 0.25 in. diameter from the RPV nozzles to the jet pump taps. This orifice will restrict the coolant loss to a value whose equivalent steam volume is much less than the capacity of one standby gas treatment system (SGTS) train. Therefore, pressurization of the secondary containment will not result from an instrument line break and a failure of the associated excess-flow check valve to isolate the ruptured line. Coolant lost from such a break is inconsequential when compared to the makeup capabilities of the feedwater or RCIC system.

6.2.4.2.6 Leak Detection

For systems penetrating the primary containment, major leaks in the pipe are located by increased temperature, radiation, sump level, changes in pressure, differential pressure, process line flow, etc. These indications are monitored in the control room to alert the operator when remote manual valves should be closed. In addition, certain indications of leakage will cause automatic valves to close in response to a system accident.

Leak detection is further discussed in Sections 5.2 and 7.6.

6.2.4.2.7 Leak Rate Testing

The reactor containment and containment penetrations are designed to permit periodic leak rate testing in accordance with GDC 52 and 53, and Appendix J to 10 CFR 50. See also Subsection 6.2.4.4.

Testing requirements for piping penetration isolation barriers and valves have been established by using the intent of GDC 54 as interpreted in Appendix J to 10 CFR 50. Exceptions taken to Appendix J Type C tests are described in Table 6.2-2.

The primary containment isolation system is scheduled to undergo periodic testing during reactor operation. The functional capabilities of power-operated isolation valves are tested remote manually from the main control room. By observing position indicators and changes in the operation of the affected system, the closing ability of a particular isolation valve is demonstrated. Testable check valves are provided on influent lines whose operability is relied upon.

Test capabilities, incorporated in the primary containment system to permit leak testing of containment isolation valves, are separated into two categories. The first category consists of pipelines that open into the containment and do not terminate in closed loops outside the containment, but do contain two isolation valves in series. Test taps are provided between the two valves to permit leakage monitoring. The second category consists of pipelines that connect to the reactor cooling system and that also contain two isolation valves in series. A leakoff line is provided between the two valves, and a drain line is provided downstream of the outboard valve. This arrangement permits leakage monitoring of both the inboard and outboard valves. Valves subject to Type C testing are shown in Table 6.2-2.

Excess-flow check valves can be tested by opening a test drain valve downstream of each valve and verifying proper operation.

As these valves are outside the primary containment and are accessible, periodic visual inspection can be performed in addition to the operational check.

The only systems circulating contaminated water after a postulated LOCA are the core spray system (to cool the reactor core) and the RHR system (to remove the heat from the emergency coolant).

The potential sources for leakage are the pump mechanical seals. The available data indicate the leakage from the pump seals to be essentially zero. This is based on the manufacturer's design criteria, its technical manuals, and industrywide experience. Therefore, specifying a leakage limit would be quite arbitrary.

Only a seal failure could result in any significant leakage. This leakage would be indicated by the operation of the sump pumps in either one of the equipment drain sumps or the floor drain sumps located in each of the four corner rooms of the reactor building subbasement. Sump pump startup is indicated in the control room. Following sump pump startup and operator investigation, the leaking emergency core cooling system (ECCS) pump would be isolated.

Following a postulated LOCA, either one LPCI pump or two core spray pumps are required for core cooling and one RHR pump is required for long-term containment cooling. Should seal failure occur in one of these, there is sufficient redundancy to allow the leaking pump to be removed from service and isolated. Four RHR pumps and four core spray pumps are provided.

Radioactivity releases and resultant doses from this postulated seal leak would be negligible.

6.2.4.2.8 Environmental Qualification Tests

Qualification tests required to ensure the performance of the isolation valves under adverse environmental conditions are discussed in Section 3.11.

6.2.4.3 Design Evaluation

One of the basic purposes of the primary containment system is to provide a minimum of one protective barrier between the reactor and the environs. To fulfill its role as a barrier, the primary containment is designed to remain intact before, during, and subsequent to any failure involving process systems either inside or outside the primary containment. Where process lines penetrate the primary containment, the penetration has the same integrity as the primary containment structure itself. In addition, the process line isolation valves perform the containment isolation function for leakage through the process lines.

Since a rupture of a large line connected to the reactor coolant system and penetrating the primary containment may be postulated, isolation valves for lines of this type are required to be located within the primary containment. These isolation valves are required to close automatically on various indications of reactor coolant loss. A certain degree of additional reliability is added if a second valve, located outside and as close as practical to the primary containment, is included. This second valve also closes automatically. A single active failure can be accommodated since a second valve is available to perform the containment isolation function. By physically separating the two valves, there is less likelihood that a failure of one valve would cause failure of the second. Series valves of this type are provided with independent power sources.

As an example, the ability of the main steam line penetrations and the associated steam line isolation valves to fulfill the containment isolation objective for several break conditions in the steam line is shown by consideration of various assumed main steam line break locations.

a. The failure occurs inside the drywell, upstream of the inner isolation valve. Steam from the reactor is released into the drywell, and the resulting sequence is similar to that of the design-basis accident (DBA) except that the pressure transient is less severe since the reactor blowdown rate is slower. Both isolation valves close on receipt of a signal indicating low water level in the RPV. This action provides two barriers within the steam pipe passing through the penetration and prevents further flow of steam to the turbine. Thus, when the two isolation valves close subsequent to this postulated failure, containment integrity is attained and the reactor is effectively isolated from the external environment

b. The failure occurs inside the drywell, and it is assumed that the inner isolation valve is inoperable. Again, reactor steam will blow into the primary containment. The outer isolation valve will close on receipt of a signal indicating low water level in the RPV, and the reactor will become isolated within the primary containment, as delineated above

c. The failure occurs downstream of the inner isolation valve either inside the drywell or within the guard pipe. Both isolation valves will close on receipt of a signal indicating low water level in the RPV. The guard pipe is designed to accommodate such a failure without damage to the drywell penetration bellows. In addition, the design of the pipeline both supports and protects its welded juncture to the drywell vessel. Thus, the RPV is isolated within the primary containment by the inner isolation valve, and the primary containment integrity is main-tained by closure of the outer isolation valve. It should be noted that this condition provides two barriers between the reactor core and the external environment

d. The failure occurs outside the primary containment between the penetration and the outer isolation valve. Steam will blow directly into the pipe tunnel until the isolation valves are closed automatically. Closure of the inner isolation valve places a barrier between the reactor core and the external environment. This barrier serves to isolate the reactor and maintain containment integrity

e. The failure occurs outside the primary containment, and it is assumed that the outer isolation valve is inoperable. Containment isolation is established by the inner isolation valve, and containment integrity is maintained as described in Item d., above

f. The failure occurs outside the primary containment between the outer isolation valve and the turbine. Steam will blow directly into the pipe tunnel or the turbine building until both isolation valves are closed automatically. This action isolates the reactor, completes containment integrity, and places two barriers in series between the reactor core and the outside environment

Exceptions to the arrangement of isolation valves described above for lines connected directly to the primary containment atmosphere or reactor coolant system are made only in cases in which the above arrangement would lead to a less desirable situation because of required operation or maintenance of the system in which the valves are located.

Isolation valves must be closed before significant amounts of fission products are released from the reactor core during the DBA. Because the amount of radioactive material in the reactor coolant is small, a sufficient limitation of fission product release will be accomplished if the isolation valves are closed before the coolant drops to a level below the top of the reactor core. For a discussion of closure times for Class A and Class B isolation valves, refer to Section 7.3.2.2.

Valves, sensors, and other automatic devices essential to containment isolation are provided with means for periodic testing of their functional performance. Such tests provide reasonable assurance that the primary containment isolation system will perform properly when required.

6.2.4.4 Leak Rate Testing

A testing program has been implemented to measure containment leakage rates prior to initial operation of the unit, and to test the primary containment periodically throughout the operating life. The purpose of the testing is to verify that the leakage rate is within allowable limits given in the Technical Specifications and in the Inservice Testing Program for Pumps and Valves (Subsection 5.2.8.7).

The testing program includes performance of Type A tests to measure the overall integrated leakage rates, Type B tests to detect and measure local leakage from certain components, and Type C tests to measure valve leakage rates.

The leakage tests are performed in accordance with the Fermi 2 Primary Containment Leakage Rate Testing Program as defined in the Technical Specifications. The program, which is based on the requirements of 10 CFR 50 Appendix J, Option B, retains certain previously approved exemptions, and utilizes the approach as defined in Regulatory Guide 1.163 (see Appendix A, Subsection A.1.163).

6.2.4.4.1 Type A Tests

Type A tests are intended to measure the primary reactor containment overall integrated leakage rate after the containment has been completed and is ready for operation and at periodic intervals thereafter.

After the preoperational leakage rate test, testing will be scheduled in accordance with Fermi 2 Technical Specifications.

The Type A test will be performed using the Absolute Method or other alternative testing methods that have been approved by the NRC, and verification will be achieved by the Superimposed Leak Method, as described in ANSI/ANS 56.8-2002.

Prior to Type A testing, all lines are either isolated or drained and vented to reflect their status following a postulated LOCA. This ensures that Type A test results accurately reflect the most restrictive LOCA conditions. Systems that are provided with isolation capabilities to satisfy GDC 55 or 56 are either normally open to the containment atmosphere or will be vented to the containment during Type A tests. Exceptions to this are systems that must be in operation during the test.

The primary containment is pressurized and depressurized using existing system piping and equipment to the extent possible. Appropriate pressure controls are provided to attain the test pressure and for controlled depressurization to the plant vent stack via existing adsorber filters. Pressurization is carried out under conditions that will minimize containment air humidity and temperature.

Temperature-sensing devices are distributed throughout the containment and at different parts of the structure wherever local temperature variations are expected in the course of the test. Fans are used for air circulation as required to equalize temperatures.

Measurements are taken during each test period to provide a sufficient amount of data to determine leakage rates for the following tests.

a. Preoperational Leakage Rate Test

1. Peak Pressure Test

   A test was performed at pressure P_a (where P_a is the calculated peak containment internal pressure related to the DBA) to measure the leakage rate L_{am} (where L_{am} is the total measured leakage rate at pressure P_a obtained from testing the containment with equipment and systems in a state as close as practical to that which would exist under DBA conditions)

2. Acceptance Criteria

   L_{am} shall be no greater than L_d (where L_d is the design leakage rate at pressure P_a, as specified in the Technical Specifications), which conforms to the requirement of 10 CFR 50 Appendix J, Option B that L_{am} shall be less than 0.75 L_a (where L_a is the maximum allowable leakage at pressure P_a). See Table 6.2-1 for pressure and leakage values

3. Results

   The preoperational leak rate test was concluded on December 7, 1984. The calculated leak rates at the 95 percent confidence level were below the acceptance criterion of 0.375 weight percent/day. The Appendix J acceptance criterion at 95 percent confidence level is 0.75 L_a = (0.75)(0.50 weight percent/day) = 0.375 weight percent/day. The accuracy of the test was verified by means of a supplemental test.

b. Periodic Leak Rate Tests

1. The peak pressure tests shall be conducted at P_a

2. Acceptance Criteria - same as Item 2 above.

The accuracy of Type A tests will be verified by a supplemental test. The verification is intended to be conducted by the Superimposed Leak Method.

Results from the supplemental test are acceptable provided the difference between the supplemental test data and the Type A data is within 0.25 L_a.

If this should not be the case, the reason shall be determined, corrective action taken, and a successful supplemental test performed.

6.2.4.4.2 Type B Test

The Type B test is intended to detect local leaks and to measure leakage across each pressure-containing or leakage-limiting boundary for the following primary containment penetrations:

a. Contained penetrations whose design incorporates resilient seals, gaskets, or sealant compounds, piping penetrations fitted with expansion bellows, and electrical penetrations fitted with flexible metal seal assemblies

b. Air-lock door seals, including door-operating mechanism penetrations that are part of the containment pressure boundary

c. Doors with resilient seals or gaskets, except for seal-welded doors.

Table 6.2-2 lists those penetrations that require Type B testing. A detailed description of those penetrations is found in Subsection 6.2.1.2.1.

Type B tests (except the test for the air lock) shall be performed and scheduled in accordance with the Primary Containment Leakage Rate Testing Program as described in the Technical Specifications, based on 10 CFR 50 Appendix J, Option B. Air locks shall be tested at 30-month intervals or after maintenance is performed on the air lock. Additionally, the interior and exterior door seals of the air locks shall be tested after each air-lock opening in accordance with the Primary Containment Leakage Rate Testing Program as described in the Technical Specifications, based on 10 CFR 50 Appendix J, Option B.

All components subject to Type B testing are equipped with test connections to allow pressurization with a test medium.

Soap-bubble testing at design pressure P_a will be used, if necessary, to provide a sensitive and rapid method for qualitative determination of leakage over large areas. The quantitative leakage measurements are made by pressurizing the component to be tested with air or nitrogen to design pressure P_a and measuring the amount of gas required to maintain that pressure.

The personnel access lock and equipment access doors are tested for leakage in accordance with approved written procedure, specifically, the Type B test procedures. The drywell personnel access lock has two mechanically interlocked, gasketed doors. These are designed and fabricated to withstand drywell design pressure.

The Type B test for the personnel access lock is conducted in three steps:

a. The exterior door seals are tested by connecting the local leak-rate test (LLRT) panel to a pressure tap, which has been provided, pressurizing the space between the door's testable gasket to design pressure, and measuring the leak rate

b. The interior door seals are tested in a manner similar to that of the external door seals

c. The space between the shut interior and exterior doors is tested by connecting the LLRT panel to a pressure tap, which has been provided, pressurizing to design pressure, and measuring the leak rate. Prior to conducting this step, tie-downs are installed on the interior door to ensure proper seating of the interior door's testable gasket when pressure is applied in a direction that is not normally expected. By design, both the interior and exterior doors seal with internal pressure, thereby providing a better seal as the drywell pressure increases.

When the tie-downs are installed on the interior door, the air lock cannot be operated from within.

The tie-downs are adjusted to permit compression of the gasket until the door is about 1/16 in. away from the frame. The forces exerted on the door during the leak-rate test (Type B) are the sum of the forces caused by the mechanical tie-downs and the forces attributable to the test pressure.

6.2.4.4.3 Type C Test

Table 6.2-2 lists all containment isolation valves that require Type C testing, plus a sketch of piping configurations and test connections.

Type C tests will be performed and scheduled in accordance with the Primary Containment Leakage Rate Testing Program as described in the Technical Specifications, based on 10 CFR 50 Appendix J, Option B.

The boundaries for each test will be established with consideration for minimizing the test volume. Test connections for venting, draining, and pressurization are provided on penetration piping that includes valves requiring Type C testing. To the extent practicable, the piping between the containment penetrations and the test connection isolation valves is minimized.

The tests shall be performed by local pressurization applied in the same direction that the valve would be required to perform its safety function, unless it has been determined that applying the pressure in the opposite direction will provide equal or more conservative results.

Valves listed in Table 6.2-2 as being Type C tested, except those having a water seal which can be maintained for at least 30 days after an accident requiring containment isolation, shall be pressurized with air or nitrogen to the design pressure P_a. Valves that have a water seal shall be pressurized with that fluid to a pressure of not less than 1.10 P_a.

Type C LLRT testing is not required for containment isolation valves that are located in piping of systems which penetrate the Torus and terminate below the minimum water level in the Torus when the systems are closed both inside and outside of containment. The Torus is designed and operated so that it is always filled with water. The supply of water in the Torus is assured during all design basis post-accident modes of operation. Consequently, the subject isolation valves will remain “sealed” by the water.

The water seal inside the Torus, in conjunction with the design of the piping associated with the penetrations, is a passive post-accident containment bypass leakage barrier. It precludes any direct communication between the post-accident Primary Reactor Containment atmosphere and the subject Containment Isolation Valves, thereby eliminating the possibility of post-accident containment bypass leakage. The torus is assured to maintain its level 30 days post accident, as described in Section 6.2.4.4.3. As such, the torus is not a “seal-water fluid system” as intended by Appendix J. Therefore, 10 CFR 50, Appendix J, Type C water leak rate testing for the lines and valves is not appropriate and is not necessary to ensure post-accident, containment integrity.

The combined leakage rate for all penetrations and valves subject to Type B and C tests shall be less than 0.60 L_a. Leakage from those valves that are sealed with a fluid from a seal system may be excluded when determining the combined leakage rate provided that

a. The fluid leakage limit is based on a radiological analysis of the plant site

b. The installed isolation valve seal system fluid inventory is sufficient to ensure sealing function for at least 30 days at a pressure of 1.10 P_a.

Test, vent, and drain (TVD) connections on Class 1 systems which are a part of the containment boundary are provided with at least two isolation valves and are sealed with a threaded pipe cap except for the vents on the RHR return piping inside the drywell which are provided with one isolation valve and a threaded cap. All other TVD connections which are a part of the containment boundary are provided with at least one isolation valve and sealed with a threaded pipe cap. Test, vent, and drain connections shall be under administrative control, and they shall be subject to periodic surveillance to verify their integrity and to verify the effectiveness of the administrative controls in ensuring closure.

There are six types of valves that are not tested in the accident direction: globe valves, gate valves, ball valves, relief valves, stop check valves, and butterfly valves. Each valve type is discussed separately in the following paragraphs.

Globe Valves (Note 2, Table 6.2-2)

All globe valves that are tested in the reverse direction have test pressure applied beneath the disk. The seating force of a globe valve is the vector sum of the actuator force and the fluid force on the valve plug. For all globe valves being considered, accident pressure is above the seat and is thus acting in the same direction as the actuator force, tending to close the valve. When a valve of this configuration is tested in the reverse direction (pressure under the seat), test pressure will be acting in opposition to the actuator force, thus tending to unseat the valve. Therefore, the resultant force on the seating surface will be less when test pressure is applied in the reverse direction than when pressure is applied in the accident direction. As there is only one seating surface where the fluid pressure is applied in a direction opposite to the actuator force, leakage will tend to increase due to the reduced seating load. Because leakage during a test in the reverse direction tends to be greater than when fluid pressure is applied in the accident direction, a test in the reverse direction is conservative.

Gate Valves (Note 4, Table 6.2-2)

All gate valves that are not tested in the accident direction are wedge-disk-type gate valves. In lieu of testing these valves in the accident direction, Edison tests them through the bonnet. The gate valve may be tested through a body/bonnet tap. This valve has a tap through which the body/bonnet area is pressurized. Leakage is measured through both seating surfaces along with leakage through the bonnet and packing. Compared with testing in the accident direction, this method of leakage testing is more conservative.

Butterfly Valves (Note 11, Table 6.2-2)

Twenty-seven butterfly valves serve as containment isolation valves and are subject to Type C leak testing. Twelve of the valves are inboard isolation valves, and the remaining 15 are outboard isolation valves.

During Type C testing, the pipe volume or test volume between the inboard and outboard valves will be pressurized. Pressurizing between the valves is necessary because test volumes cannot be established on the containment side of the inboard isolation valve given the present valve and line configurations. Thus, the inboard valves will have the test differential pressure applied in the reverse direction to the accident pressure.

Of the ten inboard valves located outside the primary containment, eight of the valves will have their pipe-to-valve flanges nearest containment seal welded to ensure a leaktight pressure boundary. Because of this seal weld, the inboard valves will have to be maintained in place. In order to change the valve seat, access from the disk side of the valve is necessary. Therefore, for all inboard valves that are located outside the primary containment, the valve disk must face away from the primary containment. There are 10 inboard valves located outside the primary containment. With this orientation, stem leakage of the inboard valves is not measured while pressurizing the test volume. Additionally, two of the inboard containment isolation valves are located inside the primary containment and are flanged into place.

For Type C testing, the stem leakage is measured by pressurizing to P_a through the stem vent and adding this stem leakage to the test volume leakage. The valve manufacturer has stated that the leakage through the stem is not dependent on the direction of the differential pressure. Consequently, pressurizing through the stem vent will yield stem leakage results that are conservative or equivalent to applying the pressure differential in the accident direction.

There are two inboard isolation valves on the inside of the containment. These valves have the disk facing the containment so that the valve seats are accessible. Pressurizing the test volume between the inboard and outboard valves will provide the stem leakage along with the seat leakage.

All the outboard valves have the disk facing toward the containment; thus test and accident differential pressures are in the same direction.

Relief Valves (Note 29, Table 6.2-2)

In addition to the safety/relief valves on the main steam lines, there are 17 relief valves that blow down to the pressure suppression chamber and therefore are classified as isolation valves. During a LOCA, containment pressure will be acting over the relief valve seat. Therefore, the direction of the accident pressure differential will tend to seat the valves.

Of the 17 relief valves, 15 of them will not be Type C LLRT tested. These 15 relief valves are located in piping of systems which penetrate the Torus and terminate below the minimum water level in the Torus. The Torus is designed and operated so that it is always filled with water. The supply of water in the Torus is assured during all design basis, post-accident modes of operation. Consequently, the subject isolation valves will remain "sealed" by the water.

The water seal inside the Torus, in conjunction with the design of the piping associated with the penetrations, is a passive, post-accident containment bypass leakage barrier. It precludes any direct communication between the post-accident Primary Reactor Containment atmosphere and the subject CIVs, thereby eliminating the possibility of post-accident containment bypass leakage. The Torus is assured to maintain its level 30 days post accident, as described in Section 6.2.4.4.3. As such, the torus is not a "seal-water fluid system" as intended by Appendix J. Therefore, 10 CFR 50, Appendix J, Type C water leak rate testing for the lines and valves is not appropriate and is not necessary to ensure post-accident containment integrity.

The two remaining valves in the CGC system will be in-situ tested in the accident direction at a pressure of P_a.

Stop Check Valves (Table 6.2-2)

There are four stop check valves in the HPCI and RCIC systems. All of these stop check valves have uncoupled globe style disks and motor operators.

Operating procedures provide instructions for closing these stop check isolation valves following a post-LOCA event when the HPCI and RCIC systems are no longer needed.

These four stop check valves will not be LLRT Type C tested. All four are located in piping of systems which penetrate the Torus and terminate below the minimum water level in the Torus. The Torus is designed and operated so that it is always filled with water. The supply of water in the Torus is assured during all design basis, post-accident modes of operation. Consequently, the subject isolation valves will remain "sealed" by the water.

The water seal inside the Torus, in conjunction with the design of the piping associated with the penetrations, is a passive, post-accident containment bypass leakage barrier. It precludes any direct communication between the post-accident Primary Reactor Containment atmosphere and the subject Containment Isolation Valves thereby eliminating the possibility of post-accident containment bypass leakage. The torus is assured to maintain its level 30 days post accident, as described in Section 6.2.4.4.3. As such, the torus is not a "seal-water fluid system" as intended by Appendix J. Therefore, 10 CFR 50, Appendix J, Type C water leak rate testing for the lines and valves is not appropriate and is not necessary to ensure post-accident, containment integrity.

Ball Valves (Note 13, Table 6.2-2)

There are 23 ball valves used for containment isolation; 10 of these are tested in the forward direction and 13 are tested in the reverse direction. All of these valves were manufactured by Jamesbury and are air operated and spring assisted to fail in the closed position.

Valves of this type have the same sealing characteristics in either direction. Consequently, test results obtained in the present configuration (i.e., reverse direction) are equivalent to testing in the accident direction. Additionally, these valves have a "corner seal" design on the stem and stem packing. This design eliminates stem leakage.

The spring assist merely rotates the ball valve in its seat. It does not increase the seat pressure; therefore, the spring assist has no effect on the leakage regardless of the test direction.

6.2.5 Primary Containment Combustible Gas Control

The NRC amended 10 CFR 50.44, “Standards for combustible gas control system in light-water-cooled power reactors” on October 16, 2003 to eliminate the requirements for hydrogen recombiners. The hydrogen recombiner Technical Specification requirements were subsequently removed by License Amendment 159, dated March 15, 2004. Regulatory Guide 1.7 was revised in March 2007 to reflect the amended 10 CFR 50.44. The Combustible Gas Control System (CGCS) has been retired in place with its electrical circuits de-energized and fluid process piping isolated from primary containment with redundant locked-closed isolation valves. Combustible gas control of the primary containment is provided by inerting the primary containment with nitrogen.

General Design Criterion 41 of 10 CFR 50, Appendix A, requires that systems be provided to control the concentration of hydrogen or oxygen and other substances that might potentially be released to the containment atmosphere. Title 10 CFR 50, Section 50.44, establishes the standards for these systems. In Fermi 2, no substances of a combustible nature (other than hydrogen and oxygen) would potentially be released in significant amounts to the containment atmosphere under LOCA conditions. To ensure that containment integrity is not potentially impaired due to buildup of combustible gases following a LOCA, Fermi 2 has an inert containment atmosphere with mixing capability. Hydrogen and oxygen concentrations are monitored. A purge system that uses the reactor building ventilation system or the SGTS is available. The purge system is not required to be a qualified system.

6.2.5.1 Deleted

6.2.5.2 System Design

6.2.5.2.1 Deleted

6.2.5.2.2 Design Features

The CGCS is retired, but all components remain in place as shown in the piping and instrumentation diagram in Figure 6.2-23. The primary containment isolation valves associated with the CGCS have been manufactured, fabricated, and tested in accordance with the requirements of the ASME B&PV Code Section III, Class 2, 1971 edition, summer 1973 addenda.

6.2.5.2.3 Hydrogen/Oxygen Monitoring

Because Fermi 2 has an inerted primary containment atmosphere during reactor operation, the oxygen concentration, in the event of a LOCA, is the limiting parameter. The hydrogen and oxygen concentrations are continuously monitored, and are displayed in the main control room. Grab samples are obtained on a weekly basis to ensure the correct operation of the monitoring system. Samples are also taken prior to containment entry. Subsection 7.6.1.12 contains a description of the hydrogen/oxygen monitoring system. To ensure representative sampling, multiple ports allow gas to be drawn into the monitoring system from several locations in the containment. An alarm indicates when the oxygen concentration reaches a preset level.

6.2.5.2.4 Deleted

6.2.5.2.5 Containment Purge

Containment purge capability is provided for the purpose of removing fission product activity from the containment atmosphere and pressure control. Containment purge can also be utilized for combustible gas control following a significant beyond design-basis accident. Piping and valves are provided, connecting the containment atmospheres to the SGTS or reactor building heating, ventilation, and air conditioning (HVAC) system as shown in Figure 9.3-14. The purge system is comprised of the large purge piping used for purging and inerting and a smaller on-line purge system used for nitrogen vent/makeup and pressure control. Isolation valves and piping at the primary containment boundary meet the requirements of Section III ASME B&PV Code, Class 2, and are designed in conformance with Category I requirements. The SGTS treats the containment atmosphere prior to its release to the environment.

The drywell air purge inlet and vent outlet lines are 24 in. in diameter while the suppression chamber purge and vent lines are 20 in. in diameter. Both suppression chamber and drywell outboard isolation valves are supplied with a 6-in. bypass for use when the larger valve is to remain closed. The drywell bypass valve and suppression chamber bypass valve will isolate automatically.

During a power increase and drywell temperature increase, the drywell vent bypass line is opened periodically to maintain a constant drywell pressure. The drywell vent bypass line is also used to alleviate pressure buildup due to leakage from pneumatic solenoid valves. The purge system is not used during normal reactor operation to reduce airborne activity in the primary containment.

Containment vent line effluents are directed to the reactor building ventilation exhaust duct or to the SGTS for release. See Figure 6.2-20. The purge lines can open to the secondary containment volume, which is processed by the SGTS.

Because purging is initiated under the reactor operator's control, and the effluent from the SGTS is monitored for radioactivity, the incremental dose at the low-population zone during the purging will be controlled to ensure that the purge dose does not cause the total dose (LOCA plus purge dose) to exceed the limit specified in 10 CFR 100. High-radiation monitors prior to the reactor building HVAC exhaust fans isolate the containment purge valves and initiate the SGTS. The purge/inert valves comply with BTP CSB 6-4 of SRP 6.2.4. as follows:

a. The design basis for the valves includes the higher post-LOCA pressures

b. The operation of Fermi 2 containment purge and vent valves is in accordance with the Technical Specifications and is consistent with the guidance of the BTP for use of a single supply and exhaust line

c. The nitrogen purge supply valves for the torus and drywell are 6-in. and 10-in. valves, respectively. The exhaust line from both the torus and drywell are provided with 6-in. valves in parallel with the outboard isolation valve

d. Automatic isolation occurs on low reactor water level (level 2), high drywell pressure, or high radiation. The air-operated isolation valves fail closed on loss of air. The motor-operated isolation valves fail as is, but are only used in series with an air-operated isolation valve. Table 6.2-2 defines which of the above criteria are applicable to each specific isolation valve. The valves are listed in this table under penetration numbers X-25, X-26, X-205C, X-205D

e. The purge and vent valve closure times are consistent with the 5-sec requirement of the BTP

f. Debris screens have been provided for the purge valves inside the drywell to prevent debris from becoming entrained in the valves

g. The purge and vent system is not relied on for temperature and humidity control. The drywell cooling system is described in Subsection 9.4.5, and the vent/makeup of nitrogen for the containment is described in Subsection 9.3.6

h. Isolation valve testing of specific purge and inlet isolation valves is indicated in Table 6.2-2. The testing program is described in Subsection 6.2.4.4. The operability of the isolation function and the purge valve leakage rate are verified in accordance with the Technical Specifications

i. The radiological consequences of a LOCA while purging have been evaluated both specifically for Fermi 2, and generically by the NRC. Both a Fermi 2 specific analysis and the NRC's "Generic Evaluation of the Radiological Consequences of Accidents While Purging or Venting at Power-Multi-Plant Action Item B-24" indicate that while venting or purging at power, the dose contribution through open valves is small

j. The SGTS is downstream of the purge system isolation valves. Operation of the SGTS while purging will be limited and controlled to protect the SGTS from loss of function from the environment created by the escaping air and steam. The Technical Specifications delineate the limits on the use of the SGTS while purging or venting. This limit is further controlled by the Technical Specifications, which require that only one division of the SGTS be used.

k. Fermi 2 net positive suction head (NPSH) requirements for emergency core cooling system (ECCS) pumps are in conformance with Regulatory Guide 1.1. The Regulatory Guide allows no credit for positive containment pressure in the NPSH calculations. Therefore, a reduced containment pressure due to purging has no safety consequence on ECCS pump NPSH margins.

6.2.5.2.5.1 Hardened Torus Vent System

A hardened torus vent system has been installed at Fermi 2 under the 10 CFR 50.59 process in response to NRC Generic Letter 89-16, "Installation of Hardened Wetwell Vent".

During severe accidents which are outside the design basis, plant emergency procedures direct the operators to vent the wetwell airspace to prevent exceeding the primary containment pressure limit. Venting permits controlled releases by preventing permanent damage to the drywell. In addition, venting from the wetwell scrubs fission products from the effluent and reduces radioactive releases. The benefits of venting over a rupture of the drywell are reduced radiological consequences. The purpose of a hardened wetwell vent system is to provide a reliable design consistent with the safety objective of the plant emergency procedures.

The vent is sized to meet or exceed the BWR Owners Group (BWROG)/NRC general design criteria which require that under the conditions of (1) a constant heat input at a rate equal to 1.1 percent of rated thermal power and (2) containment pressure is equal to the primary containment pressure limit (PCPL), the exhaust flow through the vent is sufficient to prevent the containment pressure from increasing.

The hardened torus vent system consists of a 10-inch, Schedule 40, carbon-steel pipe routed from the 24-inch standby gas treatment system (SGTS) inlet header on the fifth floor Reactor Building through the Reactor Building siding into a stack which discharges at an elevated location. The 10-inch pipe contains two torus vent secondary containment fail closed isolation valves (TVSCIV), T4600F420 and T4600F421. The TVSCIVs air-operated butterfly valves (AOVs) are normally supplied by Division II non-interruptable control air supply (NIAS). The AC solenoid valves are normally powered by the reactor protection system (RPS) and divisionally separated. The inboard AOV is powered by Division I RPS and the outboard AOV is powered by the Division II RPS. Spectacle flanges, to facilitate maintenance of the AOVs, are installed upstream and downstream of the AOVs, with one outboard spectacle flange located outside the Reactor Building. Controls and position indications for the AOVs are located in the control room and are keylocked to prevent inadvertent positioning.

The piping from the first spectacle flange downstream from the existing header up to and including the second spectacle flange is Class D, QA Level I, and Seismic Category I. This is consistent with the original classification of SGTS. From the second spectacle flange through the remainder of the stack is QA Level 1M and Seismic II/I. The TVSCIVs maintain secondary containment integrity and are Class D, QA Level 1, Seismic Category I, and fail safe. The valves have been environmentally qualified to NUREG-0588 Category 2B (Mechanical) for pressure boundary integrity purposes. The leak tightness of the TVSCIVs is ensured by performing the secondary containment drawdown test at regular intervals.

Air supply for the primary containment isolation valves T4600F400, F401, and F412 in the SGTS has been changed from interruptable air supply (IAS) to Division 2 NIAS to improve venting reliability.

The pilot AC solenoid valves for the TVSCIVs are supplied by NIAS and are Class D, QA Level I, Seismic Category I, and have been environmentally qualified to NUREG-0588 Category 2B (Mechanical) and 2C (Electrical) to maintain the pressure boundary integrity of NIAS. The limit switches are QA Level non-Q, Seismic Category II/I.

A radiation monitor is installed on the 4th floor of the Auxiliary Building to enable monitoring of any radiological releases when the vent is open. The monitor is QA Level 1M, Seismic Category II/I, and has indication and alarm in the control center to alert the operators of a radiological release. The monitor also has an interface with the Integrated Plant Computer System (IPCS). Arrangement details are shown in Figure 11.4-4. The details of the radiation monitoring system are described in Subsection 11.4.3.11.3.

The torus hardened vent system components which require electrical power are the radiation monitor, solenoid valves, and the controls of the hardened vent air operated isolation valves. There are two TVSCI valves in series that are keylock switch controlled and fail closed. To preclude any inadvertent opening of the vent line to the atmosphere and jeopardizing secondary containment integrity due to a single failure, the two TVSCIV pilot solenoid valves are powered by different Divisions of RPS. The radiation monitor is powered as described in Subsection 11.4.3.11.3.

The hardened vent system is designed to be used for events that are outside the design basis of the plant. Therefore, the system does not comply with the design basis described in Subsection 6.2.5.1. The RPS power supply is selected to power the above components for reliable operation of the system. The RPS branch circuits feeding the hardened vent system components are adequately protected through properly coordinated safety grade fuses. Since RPS is a fail-safe system and the branch circuits used in the hardened vent system are properly protected, any single failure in the hardened vent system cannot prevent the RPS' ability to scram the reactor when it is needed. The power supply to each of these valves is divisionally separated and each valve control circuit is defeated through a normally open contact of a qualified keylocked selector switch; thus no single failure can inadvertently open the vent path nor can it prevent the ability of the RPS system from performing the scram action when it is needed. Furthermore, the RPS power to non-safety grade torus hardened vent system components is consistent with Fermi 2 design practices and by design any potential of full scram due to single failure or non-Q component failure in the hardened vent system is avoided. Therefore, the RPS system's intended design function to safely shut down the reactor is not compromised.

Beyond Design Basis Events:

As part of the response to the Fukushima Event, the NRC issued Order EA-13-109 and Interim Staff Guidance (ISG) JLD-ISG-2013-02 which requires Licensees:

a. Provide a reliable Hardened Containment Vent System (HCVS) to assist in preventing core damage when heat removal capability is lost.

b. Ensure that venting functions are also available during sever accident conditions. Sever accident conditions involving extensive core damage include elevated temperatures, pressures, radiation levels and combustible gas concentrations, such as hydrogen and carbon monoxide. This includes accidents involving a breach of the reactor vessel by molten core debris.

To comply with this order Fermi has modified the existing HCVS as follows:

a. Installed an alternate pneumatic gas supply to containment isolation valves, TVSCIVs and boundary valves associated with the Hardened Vent to allow control during and after a severe event.

b. Provided required panels, 130 VDC power supply, 120 VAC power supply, required instruments, and indications at panels outside and inside the control room.

c. Modified the HCVS exhaust stack to lengthen the stack, install a check valve to preclude backflow of air into the pip, and install a weather shroud.

During normal plant operation and during Design Basis Accidents the Hardened Containment Vent Equipment is de-energized and/or isolated. Upon declaration of a Hardened Containment Venting Scenario, the necessary hardened vent equipment is activated to support mitigation of the event. The intent being to address the station needs for the first 24 hours until the FLEX equipment can be brought on-line.

The provision of these modifications establishes alternate means of providing motive force (compressed gas) and electric power to assure the capability of the Hardened Vent to remain operable during and after a severe accident.

6.2.5.3 Safety Evaluation

The corrosion of containment materials was considered as a potential source of hydrogen. The corrosion of aluminum, zinc, and zinc-base paints located either in the drywell or torus was evaluated for a potential source of hydrogen. It was determined that these potential sources were insignificant for the following reasons:

1. The containment spray solution, if used, does not contain any chemical additives. The pH of the spray solution is 6.5 to 7.0

2. Aluminum corrosion is highly pH dependent. The Oak Ridge National Laboratory (ORNL) experiments described in Reference 29 have determined that at high pH (approximately 9.3), the corrosion of aluminum was about 100 times greater than at a pH 6.5 to 7.5, which was shown to be negligible

3. Although the corrosion of zinc does not exhibit the same pH dependence as aluminum, the corrosion of both zinc and aluminum is highly temperature dependent. The post-LOCA time/temperature profile in the drywell and torus is much less severe than that experienced in typical BWR

containments. The magnitude, as well as duration, of elevated temperature, is short-lived as shown in Figures 6.2-27, 6.2-29, 6.2-30, and 6.2-16

Because of these reasons, the corrosion of aluminum and zinc is relatively insignificant and does not represent a significant source of hydrogen.

6.2.5.4 Deleted

6.2.5.5 Deleted

6.2.5.6 Materials

There are no materials in the CGC system subject to radiolytic or pyrolytic decomposition under the conditions that would exist following a postulated LOCA. The principal materials used are

a. The heated components forming the containment boundary of the system are type 304 (or equivalent) stainless steel in accordance with the appropriate ASME material specifications, and Section III, Class 2 requirements

b. Unheated components forming the containment boundary conform with Section III, Class 2 of the ASME Code. Carbon steel, per SA-106, Grade B or SA-333, Grade 6, is used for piping, SA-216 for castings, and code allowable carbon steels for plate, forgings, weld rod, and other components, as appropriate.

6.2.6 Main Steam Isolation Valve Leakage Control System

Note: As a result of the re-analysis of the Loss-of-Coolant Accident (LOCA) using an Alternative Source Term (AST) methodology, it is no longer necessary to credit the Main Steam Isolation Valve Leakage Control System (MSIVLCS) for post-LOCA activity leakage mitigation.

6.2.6.6 Design of Main Steam System Piping and Valves

The main steam piping system, from the outboard MSIV to the appropriate anchor positions of all branch lines downstream of the third MSIV, is seismically qualified. The main portion of the main steam system is located in the turbine building, which is seismically qualified to withstand the effects of an operating-basis earthquake (OBE) or a safe-shutdown earthquake (SSE) event.

The main steam system has been seismically analyzed to ensure its integrity after either an OBE or an SSE event. The section of main steam piping analyzed begins at the anchor outside the primary containment and ends at the anchor in each of the branch lines downstream of the third MSIV. The seismic analysis of this portion of the main steam piping and included valves verifies that piping structural and pressure integrity will be maintained, and that included valves will remain in the elastic stress range after either an OBE or an SSE event.

6.2.6.6.1 Main Steam Lines

The main steam lines and branch connections downstream from the outboard containment isolation valve are classified as Group D, where these sections of pipes shall meet all pressure integrity requirements of Group D.

6.2.6.6.2 Valves in Branch Lines Connected To Main Steam Lines

The block valve(s) in branch lines connected to the main steam lines downstream of the outboard MSIV shall meet all the pressure integrity requirements of Group D.

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TABLE 6.2-1 CONTAINMENT PARAMETERS[a]

I. General Information

	Drywell	Torus
A. Calculated peak pressure, Pa, psig	49.9	28.3
B. Maximum allowable pressure, psig	62	62
C. Design temperature, °F	340	281
D. Free volume, ft^3	163,730	130,900
E. Design leak rate, Ld, percent/day	0.5	0.5
F. Maximum allowable leak rate, La, percent/day	0.5	0.5

II. Initial Conditions Short-Term Analysis (M3CPT Code)

INPUT PARAMETER	VALUE
Core Thermal Power, Mwt	3,499 (102% of 3430 MWt)
RPV Dome Pressure, psia	1,063
Core Inlet Enthalpy, Btu/lbm	531.1
Initial Liquid Mass in RPV, lbm	640,500
Feedwater Addition to RPV	0.
Drywell volume, ft^3	163,730
Initial Drywell Pressure, psig	0.75
Initial Drywell Rel., Humidity, %	20
Initial Drywell Temperature, °F	145
Vent Flow Area, ft^2	240.9
Vent Flow Loss Coefficient	5.51
Vent Submergence, ft	3.33
Suppression Pool Volume, ft^3	124,220

TABLE 6.2-1 CONTAINMENT PARAMETERS[a]

INPUT PARAMETER	VALUE
Wetwell Airspace Volume, ft^3	127,760
Suppression Pool Temperature, °F	95
Wetwell Airspace Pressure, psig	0.75

III. Initial Conditions Long-Term Analysis (SUPERHEX Code)

INPUT PARAMETER	SUPERHEX VALUE
Core Thermal Power, Mwt	3,499 (102% of 3430 MWt)
Vessel Dome Pressure, psia	1,063
Feedwater Addition, lbm	607,638
Decay Heat	ANS/5.1 + 2σ
Drywell Free Volume, ft^3	163,730
Supression Pool Volume, ft^3	117,161
Initial Suppression Pool Temp, °F	95
Initial Wetwell Air Temp, °F	95
Initial Wetwell Relative Humidity, %	100
Wetwell Airspace Free Volume, ft^3	134,819
RHR HXR K, Btu/sec - °F	321 (original analysis, loss of one division of AC) 366 (loss of one division of RHRSW, only) See Section 6.2.2.3
RHR Service Water Temperature, °F	80 – 90
RHR Pump Heat, Hp	2,100
LPCS Pump Heat, HP	1,600

TABLE 6.2-1 CONTAINMENT PARAMETERS[a]

Time to turn on RHR, minutes	20
Initial Drywell Relative Humidity, %	20
Initial Drywell Pressure, psia	15.45
Initial Drywell Temperature, °F	145
Initial Wetwell Pressure, psia	15.45
IV. Engineered Safety Features Systems Information	
	Full Capacity
High-pressure coolant injection	
No. of pumps	1
No. of lines	1
Flow rate, gpm	5,000
Core spray	
No. of pumps	4
No. of lines	2
Flow rate (rated), gpm/line	6,350
No. of spargers	2
Low pressure coolant injection mode of RHR system	
No of pumps	4
No. of lines	2
Flow rate, gpm/line	25,860
Heat exchangers (RHR system)	
Type – inverted U-tube, single pass shell, multi-pass tubes, vertical mounting	
Number	2

TABLE 6.2-1 CONTAINMENT PARAMETERS[a]

Heat transfer areas, ft^2	7,320
Overall heat transfer coefficient	321 (original analysis – loss of one division of AC.) 366 (loss of one division of RHRSW, only.) See Section 6.2.2.3
Flow of pumps, gpm	
Shell-side	10,000* with one RHR pump
Tube-side	9,000**
Source of cooling water	RHR service water
Flow begins	Manual, approximately 1200 sec (20 minutes)
Automatic depressurization system	
Total number of safety/relieve valves	15
No. actuated on ADS	5
Drywell spray (RHR system)	
No. of pumps	4
No. of lines	2
Flow rate gpm/line	
1 pump	9,500
Suppression pool spray (RHR system)	
No. of pumps	4
No of lines	2
No. of headers	1
Flow rate, gpm/line	

TABLE 6.2-1 CONTAINMENT PARAMETERS[a]

1 pump	500

* RHR heat exchanger performance maintained to assure credited overall heat transfer coefficient based on an RHR heat exchanger flow of 9250 gpm.

** RHRSW pump flow reduces below 9,000 gpm with time due to the RHR reservoir evaporative and drift losses.

V. Assumptions Used in Pressure Transient Analysis

Feedwater valve closure time	Instantaneous
MSIV closure time, seconds	3.5
Scram time, seconds	1
Liquid carryover, percent	100

VI. General Information for the Pressure Suppression Type Containment

Drywell	Value
Maximum code allowable pressure, psig	62
Internal design pressure, psig	56
External design pressure, psig	2
Design temperature, °F	340
Suppression Pool	
Maximum code allowable pressure, psig	62
Internal design pressure, psig	56
External design pressure, psig	2
Design temperature, °F	281
Drywell free volume, including vent system (minimum), ft^3	163,730
Suppression pool free (air) volume, ft^3	

TABLE 6.2-1 CONTAINMENT PARAMETERS[a]

Analytic	134,819
Tech Spec	130,900
Suppression pool water volume, ft^3	
Analytic	117,161
Tech Spec	121,080
Vent submergence, ft	
Minimum, ft	3
Maximum, ft	3.33
Vent loss coefficient	5.51
Pool cross sectional area, ft^2	731
Pool depth (normal), ft	14 ft 6 in.
No. of vents	8
Nominal vent diameter, ft	6
Nominal vent line area, ft^2	226
No. of downcomers	80
Nominal downcomer diameter, ft	2
Drywell free volume/pressure suppression chamber free volume	1.25
Deleted	
Containment heat removal capability per loop, using 85°F service water and 165 °F pool temperature; 1 RHR and 2 service water pumps, Btu/hr	66.5×10^6

VII. Recirculating Line Break Accident Initial Conditions and Calculated Response

	Value
Effective accident break area (total), ft^2	4.1

TABLE 6.2-1 CONTAINMENT PARAMETERS[a]

Componentsof effective break area	
Recirculation line (area), ft^2	3.5
Equalizer line (area), ft^2	N/A
RWCU line (area), ft^2	0.07
Jet pumps (area), ft^2	0.55
Break area/ vent area $\frac{4.1}{226}$ =	0.018
Reactor pressure vessel and attached piping initial liquid volume, ft^3	13,706
Drywell	
Initial temperature, °F	145
Initial pressure, psig	0.75
Relative humidity, percent	20
Suppression pool	
Initial temperature, °F	95
Initial pressure, psig	0.75
Relative humidity, percent	100
RHR complex reservoir initial temperature, °F	80 – 90[b]
Calculated peak drywell pressure, psig	49.9
Calculated drywell margin, percent	19.5[c]
Calculated peak suppression pool pressure, psig	28.3
Calculated suppression pool margin, percent	54.35c
Calculated peak deck differential pressure margin, psig	N/A
Calculated deck differential pressure margin, percent	N/A
Peak pool temperature during blowdown, °F	≈135

TABLE 6.2-1 CONTAINMENT PARAMETERS[a]

Long-term peak pool temperature from accident, °F (with degraded containment cooling system)	196.5

[a] This list of parameter and results corresponds to those referred to in Subsection 6.2.1.2, Primary Containment System Design.

[b] RHR service water varies linearly from 80 °F to 90 °F over a period of 8 hours.

[c] Percent below maximum allowable pressure of 62 psig.

TABLE 6.2-2 SUMMARY OF PRIMARY CONTAINMENT PENETRATIONS AND ASSOCIATED ISOLATION VALVES

PENETRATION DATA				ISOLATION VALVE DATA																	
												Valve Position									
Penetration Detail	P&ID Number	Design Criteria	Bypass Leakage Path	System Title	Valve Number	Valve Type	Actuator Type	Primary Actuation Mode	Secondary Actuation Mode	Containment Isolation Signal(s)	Accident Isolation Signal(s)	Normal	Shutdown	Post-LOCA (Accident)	Power Failure	ILRT	Engineered Safety Feature	Quality Group	Type C Test	Leak Detection	Remarks
X-1A	6C721-2304	--	--	Equipment Access Hatch	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type B Test
X-1B	6C721-2304	--	--	Equipment Access Hatch	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type B Test
X-2	6C721-2304	--	--	Personnel Airlock	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type B Test
X-3	--	--	--	Drywell Head	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type B Test
X-5A	6C721-2304	--	--	Vent Pipe	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type A Test, Note 1
X-5B	6C721-2304	--	--	Vent Pipe	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type A Test, Note 1
X-5C	6C721-2304	--	--	Vent Pipe	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type A Test, Note 1
X-5D	6C721-2304	--	--	Vent Pipe	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type A Test, Note 1
X-5E	6C721-2304	--	--	Vent Pipe	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type A Test, Note 1
X-5F	6C721-2304	--	--	Vent Pipe	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type A Test, Note 1
X-5G	6C721-2304	--	--	Vent Pipe	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type A Test, Note 1
X-5H	6C721-2304	--	--	Vent Pipe	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type A Test, Note 1
X-6	6C721-2304	--	--	Control Rod Drive Removal Hatch	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type B Test

TABLE 6.2-2 SUMMARY OF PRIMARY CONTAINMENT PENETRATIONS AND ASSOCIATED ISOLATION VALVES

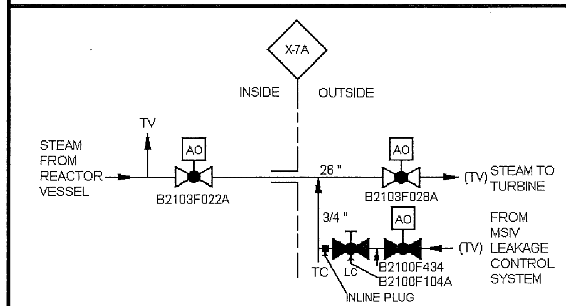
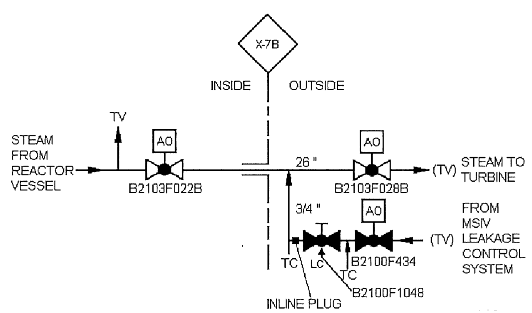
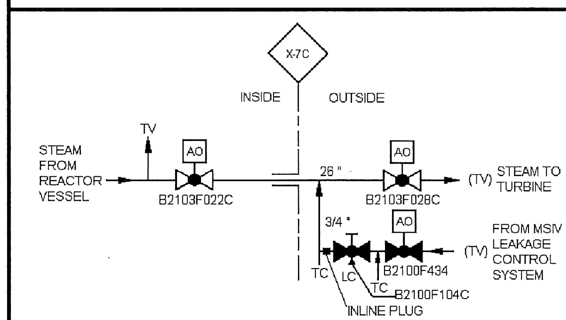
PENETRATION DATA				ISOLATION VALVE DATA																	
												Valve Position									
Penetration Detail	P&ID Number	Design Criteria	Bypass Leakage Path	System Title	Valve Number	Valve Type	Actuator Type	Primary Actuation Mode	Secondary Actuation Mode	Containment Isolation Signal(s)	Accident Isolation Signal(s)	Normal	Shutdown	Post-LOCA (Accident)	Power Failure	ILRT	Engineered Safety Feature	Quality Group	Type C Test	Leak Detection	Remarks
	6M721-2089	55	Yes	Main Steam Line A	B2103F022A (V17-2003)	GLB	AO	A	RM	A	E, F, G, J, P	O	C	C	C	C	No	A	Yes	Yes	Notes 2 and 3
					B2103F028A (V17-2007)	GLB	AO	A	RM	A	E, F, G, J, P	O	C	C	C	C	No	A	Yes	Yes	Note 3
	6M721-3045	--	No	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Note 42
	6M721-2089	55	Yes	Main Steam Line B	B2103F022B (V17-2001)	GLB	AO	A	RM	A	E, F, G, J, P	O	C	C	C	C	No	A	Yes	Yes	Notes 2 and 3
					B2103F028B (V17-2005)	GLB	AO	A	RM	A	E, F, G, J, P	O	C	C	C	C	No	A	Yes	Yes	Note 3
	6M721-3045	--	No	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	**Note 42**
	6M721-2089	55	Yes	Main Steam Line C	B2103F022C (V17-2002)	GLB	AO	A	RM	A	E, F, G, J, P	O	C	C	C	C	No	A	Yes	Yes	Notes 2 and 3
					B2103F028C (V17-2006)	GLB	AO	A	RM	A	E, F, G, J, P	O	C	C	C	C	No	A	Yes	Yes	Note 3
	6M721-3045	--	No	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Note 42

TABLE 6.2-2 SUMMARY OF PRIMARY CONTAINMENT PENETRATIONS AND ASSOCIATED ISOLATION VALVES

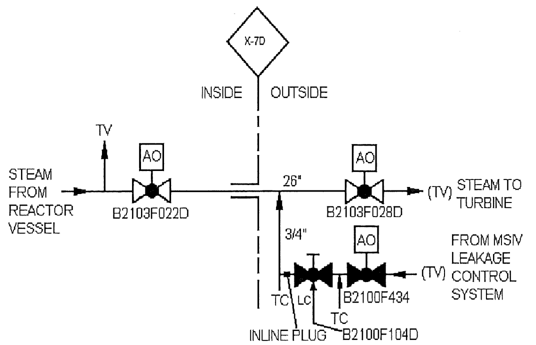
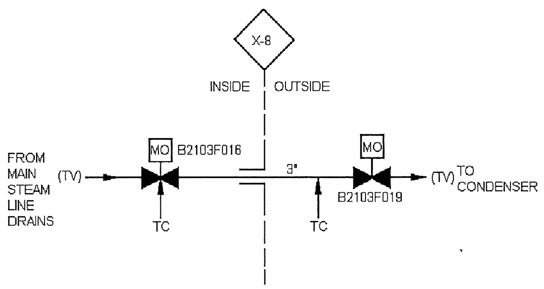
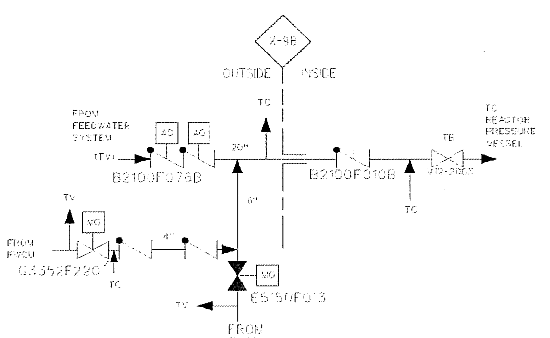
PENETRATION DATA				ISOLATION VALVE DATA																	
												Valve Position									
Penetration Detail	P&ID Number	Design Criteria	Bypass Leakage Path	System Title	Valve Number	Valve Type	Actuator Type	Primary Actuation Mode	Secondary Actuation Mode	Containment Isolation Signal(s)	Accident Isolation Signal(s)	Normal	Shutdown	Post-LOCA (Accident)	Power Failure	ILRT	Engineered Safety Feature	Quality Group	Type C Test	Leak Detection	Remarks
	6M721-2089	55	Yes	Main Steam Line D	B2103F022D (V17-2004)	GLB	AO	A	RM	A	E, F, G, J, P	O	C	C	C	C	No	A	Yes	Yes	Notes 2 and 3
					B2103F028D (V17-2008)	GLB	AO	A	RM	A	E, F, G, J, P	O	C	C	C	C	No	A	Yes	Yes	Note 3
	6M721-3045	--	No	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Note 42
	6M721-2089	55	Yes	Main Steam Line Drains	B2103F016 (V30-0259)	GAT	MO	A	RM	A	E, F, G, J, P	C	O	C	AIS	C	No	A	Yes	Yes	Note 4
					B2103F019	GAT	MO	A	RM	A	E, F, G, J, P	C	O	C	AIS	C	No	A	Yes	Yes	
	6M721-2023	55	Yes	Feedwater	B2100F010B (V12-2007)	CHK	--	RF	--	--	--	O	C	C	--	C	R	A	Yes	Yes	--
					B2100F076B (V12-2001)	CHK	AO	RF	RM	--	--	O	C	C	C	C	R	A	Yes	Yes	Note 5
	6M721-2044	55	Yes	Reactor Core Isolation Cooling	E5150F013 (V8-2228)	GAT	MO	RM	M	--	Z	C	C	O	AIS	C	R	A	Yes	Yes	Note 6
	6M721-2046	55	No	Reactor Water Clean-up	G3352F220 (V30-0322)	GAT	MO	A	RM	B	W	O	C	C	AIS	C	No	A	Yes	Yes	Note 35

TABLE 6.2-2 SUMMARY OF PRIMARY CONTAINMENT PENETRATIONS AND ASSOCIATED ISOLATION VALVES

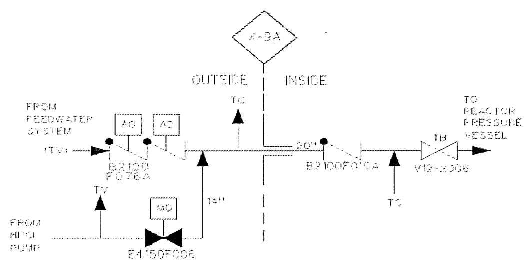
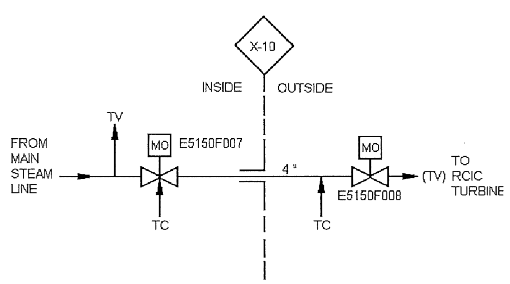
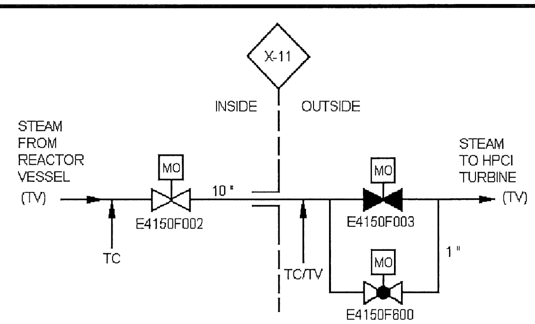
PENETRATION DATA				ISOLATION VALVE DATA																	
												Valve Position									
Penetration Detail	P&ID Number	Design Criteria	Bypass Leakage Path	System Title	Valve Number	Valve Type	Actuator Type	Primary Actuation Mode	Secondary Actuation Mode	Containment Isolation Signal(s)	Accident Isolation Signal(s)	Normal	Shutdown	Post-LOCA (Accident)	Power Failure	ILRT	Engineered Safety Feature	Quality Group	Type C Test	Leak Detection	Remarks
	6M721-2023	55	Yes	Feedwater	B2100F010A (V12-2008)	CHK	--	RF	--	--	--	O	C	C	--	C	R	A	Yes	Yes	--
					B2100F076A (V12-2002)	CHK	AO	RF	RM	--	--	O	C	C	C	C	R	A	Yes	Yes	Note 5
	6M721-2035	55	Yes	High Pressure Coolant Injection	E4150F006 (V8-2194)	GAT	MO	RM	M	--	Z	C	C	O	AIS	C	Yes	A	Yes	Yes	Note 7
	6M721-2044	55	Yes	Steam to Reactor Core Isolation Cooling Turbine	E5150F007 (V17-2030)	GAT	MO	RM	M	--	Y	O	C	O	AIS	C	R	A	Yes	Yes	Notes 4, 6, and 31
					E5150F008 (V17-2031)	GAT	MO	RM	M	--	Y	O	C	O	AIS	C	R	A	Yes	Yes	Notes 6 and 31
	6M721-2035	55	Yes	Steam to High Pressure Coolant Injection Turbine	E4150F002 (V17-2020)	GAT	MO	RM	M	--	X	O	C	O	AIS	C	Yes	A	Yes	Yes	Notes 4, 7, and 31
					E4150F003 (V17-2021)	GAT	MO	RM	M	--	X	C	C	O	AIS	C	Yes	A	Yes	Yes	Notes 4 and 7
					E4150F600 (V17-2088)	GLB	MO	RM	M	--	X	O	C	C	AIS	C	Yes	A	Yes	Yes	Notes 7 and 31

TABLE 6.2-2 SUMMARY OF PRIMARY CONTAINMENT PENETRATIONS AND ASSOCIATED ISOLATION VALVES

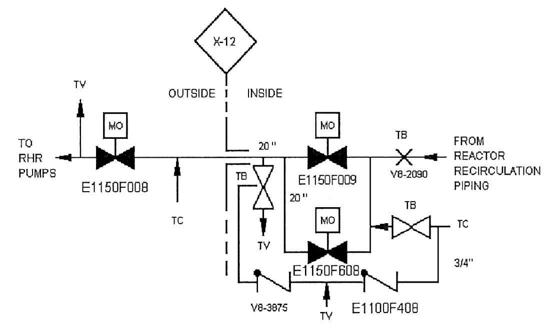
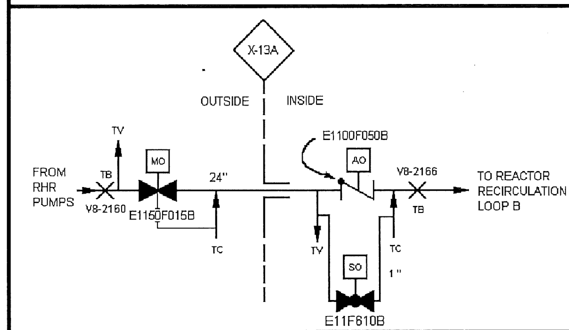
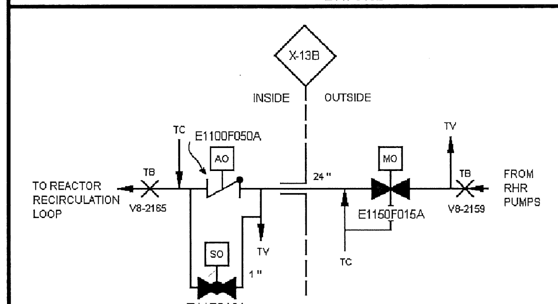
PENETRATION DATA				ISOLATION VALVE DATA																	
												Valve Position									
Penetration Detail	P&ID Number	Design Criteria	Bypass Leakage Path	System Title	Valve Number	Valve Type	Actuator Type	Primary Actuation Mode	Secondary Actuation Mode	Containment Isolation Signal(s)	Accident Isolation Signal(s)	Normal	Shutdown	Post-LOCA (Accident)	Power Failure	ILRT	Engineered Safety Feature	Quality Group	Type C Test	Leak Detection	Remarks
	6M721-2083	55	No	Residual Heat Removal Pump Suction From Recirculation Piping	E1150F009 (V8-2091)	GAT	MO	A	RM	C	L	C	O	C	AIS	C	No	A	Yes	No	Note 8
					E1150F608 (V8-3407)	GAT	MO	RM	M	--	--	LC	LC	LC	AIS	C	No	A	Yes	No	Note 9
					E1150F008 (V8-2092)	GAT	MO	A	RM	C	L	C	O	C	AIS	C	No	A	Yes	No	Note 8
					E1100F408 (V8-3874)	CHK	SA	RF	--	--	--	C	C	C	--	C	No	A	Yes		
	6M721-2083	55	No	Residual Heat Removal Pump Discharge to Recirculation Loop	E1100F050B (V8-2164)	CHK	SA	RF	--	--	--	C	O	O	--	C	Yes	A	No	Yes	Note 36
					E1150F015B (V8-2162)	GAT	MO	RM	M	--	Z	C	O	O	AIS	C	Yes	A	No	Yes	Notes 7, 12, 37 and 38
					E11F610B (V13-7688)	GLB	SO	RM	M	--	--	C	C	C	C	C	No	A	No	Yes	Notes 7 and 36
	6M721-2084	55	No	Residual Heat Removal Pump Discharge to Recirculation Loop	E1100F050A (V8-2163)	CHK	SA	RF	--	--	--	C	O	O	--	C	Yes	A	No	Yes	Note 36
					E1150F015A (V8-2161)	GAT	MO	RM	M	--	Z	C	O	O	AIS	C	Yes	A	No	Yes	Notes 7, 12, 37, and 38
					E11F610A (V13-7687)	GLB	SO	RM	M	--	--	C	C	C	C	C	No	A	No	Yes	Notes 7 and 36
X-14	--	--	--	Spare	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type A Test

TABLE 6.2-2 SUMMARY OF PRIMARY CONTAINMENT PENETRATIONS AND ASSOCIATED ISOLATION VALVES

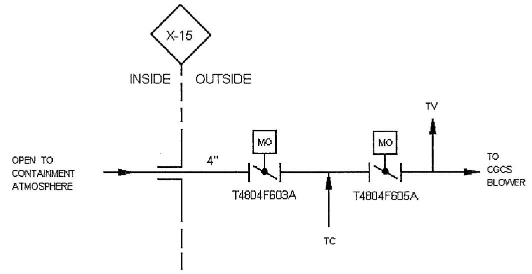
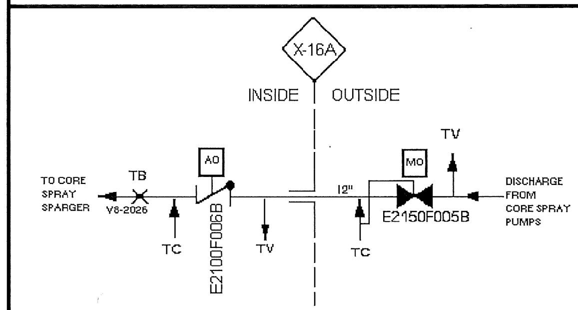
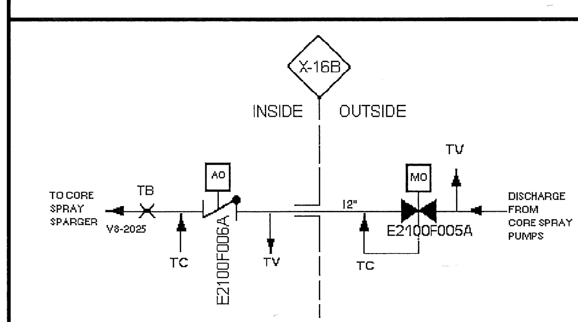
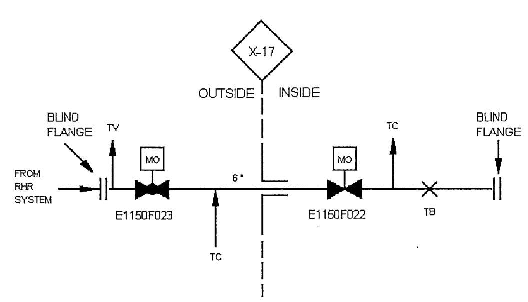
PENETRATION DATA				ISOLATION VALVE DATA																	
												Valve Position									
Penetration Detail	P&ID Number	Design Criteria	Bypass Leakage Path	System Title	Valve Number	Valve Type	Actuator Type	Primary Actuation Mode	Secondary Actuation Mode	Containment Isolation Signal(s)	Accident Isolation Signal(s)	Normal	Shutdown	Post-LOCA (Accident)	Power Failure	ILRT	Engineered Safety Feature	Quality Group	Type C Test	Leak Detection	Remarks
	6M721-2087	56	No	Combustible Gas Control System Suction	T4804F603A (V4-2144)	BFY	M	M	--	--	--	LC	LC	LC	LC	LC	No	B	Yes	No	Notes 9, 10, 11, and 45
					T4804F605A (V4-2154)	BFY	M	M	--	--	--	LC	LC	LC	LC	LC	No	B	Yes	No	Notes 9 and 45
	6M721-2034	55	No	Core Spray Pump Discharge	E2100F006B (V8-2024)	CHK	SA	RF	--	--	--	C	C	O	--	C	Yes	A	Yes	Yes	
					E2150F005B (V8-2022)	GAT	MO	RM	M	--	--	C	C	O	AIS	C	Yes	A	Yes	Yes	Notes 7 and 38
	6M721-2034	55	No	Core Spray Pump Discharge	E2100F006A (V8-2023)	CHK	SA	RF	--	--	--	C	C	O	--	C	Yes	A	Yes	Yes	
					E2150F005A (V8-2021)	GAT	MO	RM	M	--	--	C	C	O	AIS	C	Yes	A	Yes	Yes	Notes 7 and 38
	6M721-2083	56	No	Residual Heat Removal Discharge to Head Spray	E1150F023 (V8-2171)	GLB	MO	A	RM	C	L	C	C	C	AIS	C	No	B	Yes	No	Notes 8 and 33
					E1150F022 (V8-2172)	GAT	MO	A	RM	C	L	C	C	C	AIS	C	No	B	Yes	No	Notes 8 and 33

TABLE 6.2-2 SUMMARY OF PRIMARY CONTAINMENT PENETRATIONS AND ASSOCIATED ISOLATION VALVES

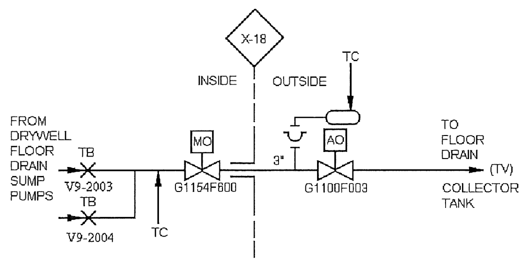
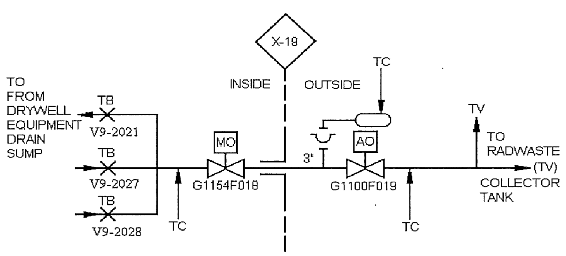
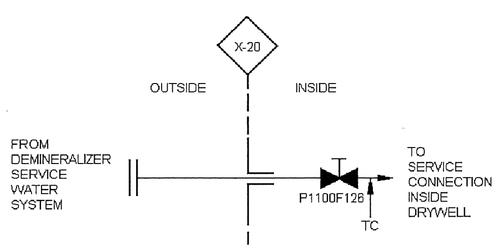
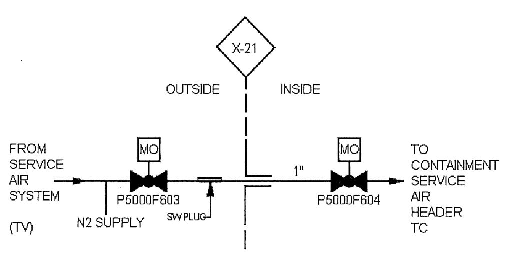
PENETRATION DATA				ISOLATION VALVE DATA																	
												Valve Position									
Penetration Detail	P&ID Number	Design Criteria	Bypass Leakage Path	System Title	Valve Number	Valve Type	Actuator Type	Primary Actuation Mode	Secondary Actuation Mode	Containment Isolation Signal(s)	Accident Isolation Signal(s)	Normal	Shutdown	Post-LOCA (Accident)	Power Failure	ILRT	Engineered Safety Feature	Quality Group	Type C Test	Leak Detection	Remarks
	6M721-2032	56	Yes	Drywell Floor Drain Sump Pump Discharge	G1154F600 (V9-2044)	GAT	MO	A	RM	C, K	--	O	O	C	AIS	C	No	B	Yes	No	--
					G1100F003 (V9-2005)	GAT	AO	A	RM	C, K	--	O	C	C	C	C	No	B	Yes	No	--
	6M721-2032	56	Yes	Drywell Equipment Drain Sump Pump Discharge	G1154F018	GAT	MO	A	RM	C, K	--	O	O	C	AIS	C	No	B	Yes	No	--
					G1100F019 (V9-2023)	GAT	AO	A	RM	C, K	--	O	C	C	C	C	No	B	Yes	No	--
	6M721-2678	56	No	Demineralized Service Water to Drywell Connection	P1100F126 (V8-3120)	GAT	M	M	--	--	--	LC	LC	LC	--	LC	No	B	Yes	No	Note 9 Flange Type B Tested
	6M721-2085	--	No	Service Air to Drywell	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Note 41 Type A Test

TABLE 6.2-2 SUMMARY OF PRIMARY CONTAINMENT PENETRATIONS AND ASSOCIATED ISOLATION VALVES

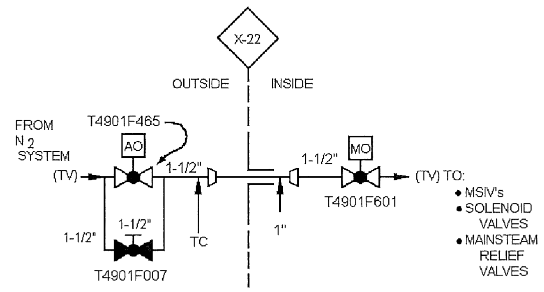
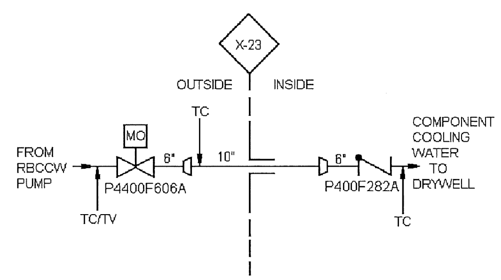
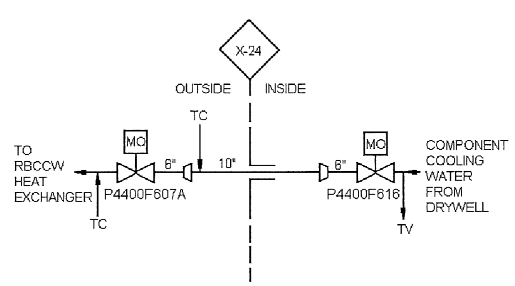
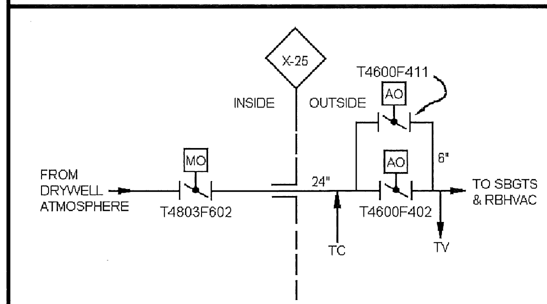
PENETRATION DATA				ISOLATION VALVE DATA																	
												Valve Position									
Penetration Detail	P&ID Number	Design Criteria	Bypass Leakage Path	System Title	Valve Number	Valve Type	Actuator Type	Primary Actuation Mode	Secondary Actuation Mode	Containment Isolation Signal(s)	Accident Isolation Signal(s)	Normal	Shutdown	Post-LOCA (Accident)	Power Failure	ILRT	Engineered Safety Feature	Quality Group	Type C Test	Leak Detection	Remarks
	6M721-5007	56	No	Nitrogen to Drywell	T4901F601	GLB	MO	A	RM	B, K	--	O	O	C	AIS	C	R	B	Yes	Yes	Notes 2 and 32
					T4901F465	GLB	AO	A	RM	B, K	--	O	O	C	C	C	R	B	Yes	Yes	Note 32
					T4901F007	GLB	M	M	--	--	--	LC	LC	LC	LC	LC	No	B	Yes	Yes	Note 9
	6M721-5444	56	Yes	Reactor Building Component Cooling Water / Emergency Equipment Cooling Water Supply	P4400F282A	CHK	SA	RF	--	--	--	O	O	O	--	O	Yes	B	Yes	Yes	--
					P4400F606A	GAT	MO	RM	M	--	--	O	O	O	AIS	O	Yes	B	Yes	Yes	Note 34
	6M721-5444	56	Yes	Reactor Building Component Cooling Water / Emergency Equipment Cooling Water Return	P4400F616	GAT	MO	RM	M	--	--	O	O	O	AIS	O	Yes	B	Yes	Yes	Note 4
					P4400F607A	GAT	MO	RM	M	--	--	O	O	O	AIS	O	Yes	B	Yes	Yes	
	6M721-3445	56	No	Drywell Exhaust and Air Purge	T4803F602	BFY	MO	A	RM	B, K, R	--	C	O	C	AIS	C	R	B	Yes	No	Note 11
					T4600F402	BFY	AO	A	RM	B, K, R	--	C	O	C	C	C	R	B	Yes	No	--
	7M721-2709				T4600F411	BFY	AO	A	RM	B, K, R	--	C	O	C	C	C	R	B	Yes	No	--

TABLE 6.2-2 SUMMARY OF PRIMARY CONTAINMENT PENETRATIONS AND ASSOCIATED ISOLATION VALVES

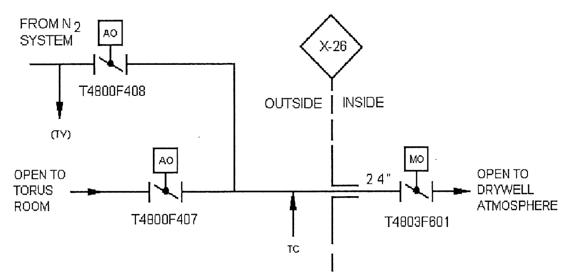
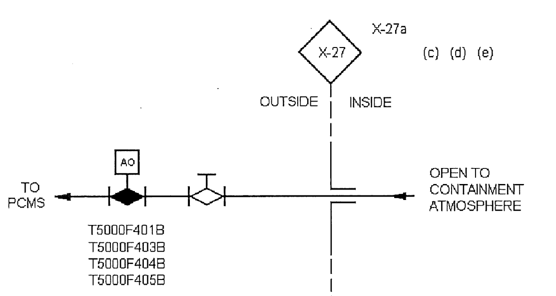
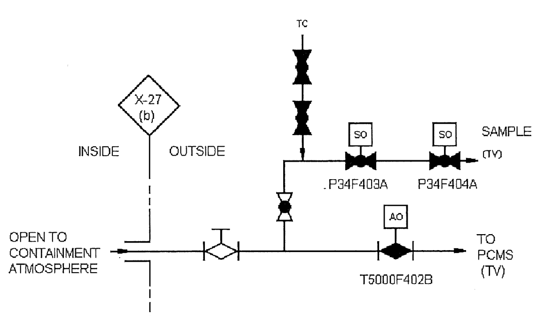
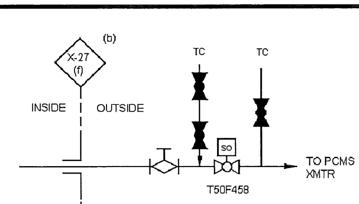
PENETRATION DATA				ISOLATION VALVE DATA																	
												Valve Position									
Penetration Detail	P&ID Number	Design Criteria	Bypass Leakage Path	System Title	Valve Number	Valve Type	Actuator Type	Primary Actuation Mode	Secondary Actuation Mode	Containment Isolation Signal(s)	Accident Isolation Signal(s)	Normal	Shutdown	Post-LOCA (Accident)	Power Failure	ILRT	Engineered Safety Feature	Quality Group	Type C Test	Leak Detection	Remarks
	6M721-3445	56	No	Drywell Air Purge Inlet	T4803F601 (VR3-3011)	BFY	MO	A	RM	B, K, R	--	C	O	C	AIS	C	R	B	Yes	No	Note 11
					T4800F407 (VR3-3012)	BFY	AO	A	RM	B, K, R	--	C	O	C	C	C	R	B	Yes	No	--
	7M721-2709				T4800F408 (V4-2060)	BFY	AO	A	RM	B, K, R	--	C	C	C	C	C	R	B	Yes	No	--
	6I721-2679-1	56	No	Containment Atmosphere Sample	Typical of Four T5000F401B (V5-2159) T5000F403B (V5-2161) T5000F404B (V5-2162) T5000F405B (V5-2163)	BAL	AO	RM	M	--	--	C	O	O	C	O	No	B	Yes	Yes	Notes 12 and 13
	6I721-2679-1	56	Yes	Containment Atmosphere Samples	T5000F402B (V5-2160)	BAL	AO	RM	M	--	--	C	O	O	C	O	No	B	Yes	Yes	Note 12
					P34 F403A (V13-7364)	GLB	SO	RM	--	--	--	C	C	C	C	C	No	B	Yes	Yes	Note 10
	6I721-2400-10	56	Yes		P34 F404A (V13-7374)	GLB	SO	RM	--	--	--	C	C	C	C	C	No	B	Yes	Yes	Note 10
	6I721-2679-1	56	--	Containment Atmosphere Monitoring System	T50F458	GLB	SO	RM	--	--	--	O	O	O	AIS	O	No	B	Yes	--	Note 12

TABLE 6.2-2 SUMMARY OF PRIMARY CONTAINMENT PENETRATIONS AND ASSOCIATED ISOLATION VALVES

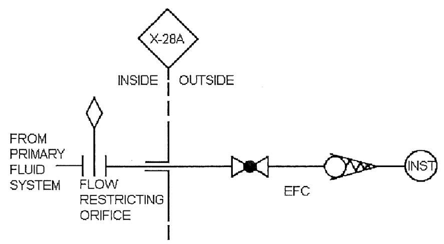
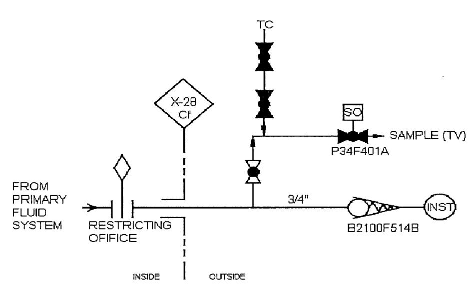
PENETRATION DATA				ISOLATION VALVE DATA																	
												Valve Position									
Penetration Detail	P&ID Number	Design Criteria	Bypass Leakage Path	System Title	Valve Number	Valve Type	Actuator Type	Primary Actuation Mode	Secondary Actuation Mode	Containment Isolation Signal(s)	Accident Isolation Signal(s)	Normal	Shutdown	Post-LOCA (Accident)	Power Failure	ILRT	Engineered Safety Feature	Quality Group	Type C Test	Leak Detection	Remarks
	6M721-2090	55	No	Jet Pump Flow Instrumentation		EFC	SA	HF	--	--	--	O	O	O	--	O	No	A	No	Yes	Note 14, Type A Test
X-28B	--	--	--	Spare	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type A Test
X-28C a,b,c,d,e	6M721-2090	55	No	Jet Pump Flow Instrumentation	Typical of Five	EFC	SA	HF	--	--	--	O	O	O	--	O	No	A	No	Yes	Note 14, Type A Test See Penetration Detail X-28A
	6M721-2090	55	No	Jet Pump Flow Instrumentation	B2100F514B (V13-2329)	EFC	SA	HF	--	--	--	O	O	O	--	O	No	A	No	Yes	Note 14, Type A Test
	6I721-2400-10		Yes	Postaccident Pressurized Reactor Coolant Sample	P34 F401A	GLB	SO	RM	--	--	--	C	C	C	C	C	No	B	Yes	Yes	--
X-28D	6M721-2090 2833	55		Jet Pump Instrumentation (1) and Recirculation Inlet ΔP (4)	Typical of Five	EFC	SA	HF	--	--	--	O	O	O	--	O	No	A	No	Yes	Notes 15 and 16, Type A Test See Penetration Detail X-28A
X-28E	--	--	--	Spare	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type A Test
X-28F	--	--	--	Spare	--	--	--	--	--	--	--	C	C	--	C	--	--	--	--	--	Type A Test
X-28G	--	--	--	Spare	--	--	--	--	--	--	--	C	C	--	C	--	--	--	--	--	Type A Test

TABLE 6.2-2 SUMMARY OF PRIMARY CONTAINMENT PENETRATIONS AND ASSOCIATED ISOLATION VALVES

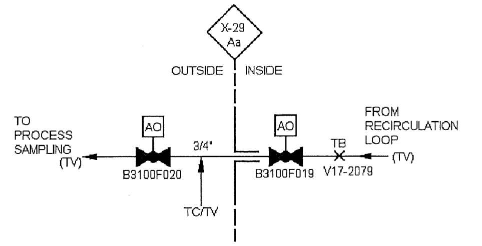
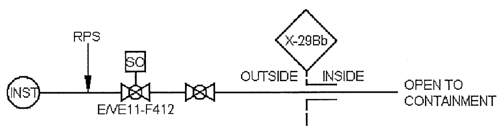
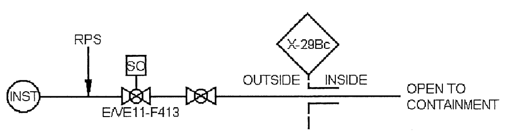
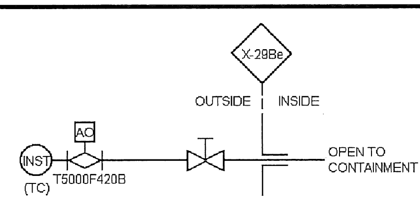
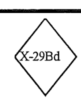
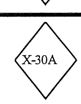
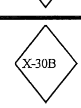
PENETRATION DATA				ISOLATION VALVE DATA																	
												Valve Position									
Penetration Detail	P&ID Number	Design Criteria	Bypass Leakage Path	System Title	Valve Number	Valve Type	Actuator Type	Primary Actuation Mode	Secondary Actuation Mode	Containment Isolation Signal(s)	Accident Isolation Signal(s)	Normal	Shutdown	Post-LOCA (Accident)	Power Failure	ILRT	Engineered Safety Feature	Quality Group	Type C Test	Leak Detection	Remarks
	6M721-2833	55	No	Reactor Water Sample	B3100F019 (V17-2077)	GLB	AO	A	RM	B, K	D	C	C	C	C	C	No	A	Yes	No	Note 2
					B3100F020	GLB	AO	A	RM	B, K	D	C	C	C	C	C	No	A	Yes	No	--
	6M721-2083	56	No	Reactor Protection System	E/VE11-F412 (V5-2546)	GLB	SO	RM	--	--	--	O	O	O	AIS	O	No	B	Yes	Yes	Notes 2, 12, and 15
	6M721-2083	56	No	Reactor Protection System	E/VE11-F413 (V5-2547)	GLB	SO	RM	--	--	--	O	O	O	AIS	O	No	B	Yes	Yes	Notes 2, 12, and 15
	6M721-2083 6I721-2679-1	56	No	Drywell Instrumentation	T5000F420B (V5-2231)	BAL	AO	RM	M	--	--	O	O	O	C	O	No	B	Yes	Yes	Notes 12, 13, 15, and 43
	6M721-2090	55	No	Reactor Pressure Vessel Level Instrumentation	B2100F509 (V13-2320)	EFC	SA	HF	--	--	--	O	O	O	--	O	No	A	No	Yes	Note 16 See Penetration Detail X-28A
	6M721-2833 2046	55	No	RPV Pressure (1), Recirculation Pressure (1), and Recirculation Loop Flow (2)	Typical of Four	EFC	SA	HF	--	--	--	O	O	O	--	O	No	A	No	Yes	Notes 15 and 16 See Penetration Detail X-28A
	6M721-2833	55	No	Recirculation Pump Inst. (2), Recirculation Pump ΔP (2), Recirculation Loop Flow (2)	Typical of Six	EFC	SA	HF	--	--	--	O	O	O	--	O	No	A	No	Yes	Note 16 See Penetration Detail X-28A
	--	--	--	Spare	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type A Test

TABLE 6.2-2 SUMMARY OF PRIMARY CONTAINMENT PENETRATIONS AND ASSOCIATED ISOLATION VALVES

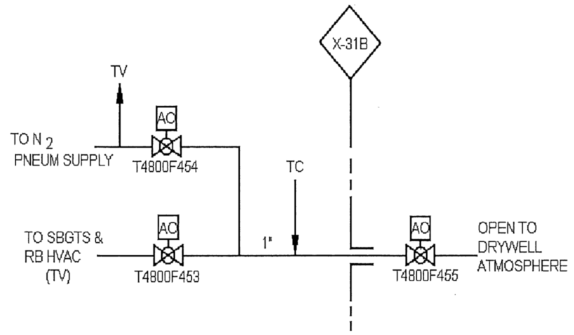
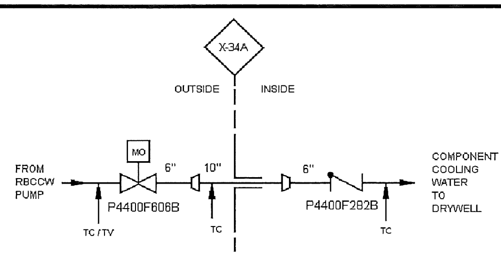
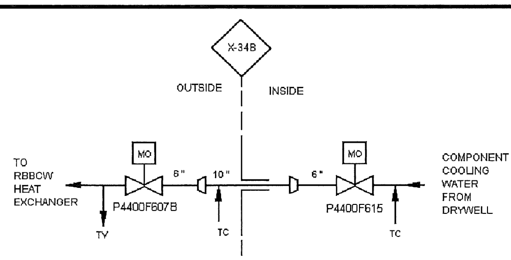
PENETRATION DATA				ISOLATION VALVE DATA																	
												Valve Position									
Penetration Detail	P&ID Number	Design Criteria	Bypass Leakage Path	System Title	Valve Number	Valve Type	Actuator Type	Primary Actuation Mode	Secondary Actuation Mode	Containment Isolation Signal(s)	Accident Isolation Signal(s)	Normal	Shutdown	Post-LOCA (Accident)	Power Failure	ILRT	Engineered Safety Feature	Quality Group	Type C Test	Leak Detection	Remarks
	6M721-3445	56	No	Drywell On-Line Pressure Control	T4800F455	GLB	AO	A	RM	B, K, R	--	O	C	C	C	C	R	B	Yes	No	Note 2
					T4800F454	GLB	AO	A	RM	B, K, R	--	O	C	C	C	C	R	B	Yes	No	--
					T4800F453	GLB	AO	A	RM	B, K, R	--	O	C	C	C	C	R	B	Yes	No	--
X-32A	6M721-2090	55	No	Reactor Pressure Vessel Pressure	B2100F516C	EFC	SA	HF	--	--	--	O	O	O	--	O	No	A	No	Yes	Notes 15 and 16 See Penetration Detail X-28A
X-32B	6M721-2833 2035	55	No	Steam Flow to High-Pressure Coolant Injection (2) and Recirculation Loop Flow (4)	Typical of Six	EFC	SA	HF	--	--	--	O	O	O	--	O	No	A	No	Yes	Note 16 See Penetration Detail X-28A
X-33A	6M721-2833	55	No	Recirculation Pump ΔP (2), Recirculation Pump Inst. (2), and Recirculation Pressure (1)	Typical of Five	EFC	SA	HF	--	--	--	O	O	O	--	O	No	A	No	Yes	Notes 15 and 16 See Penetration Detail X-28A
X-33B	6M721-2090 2035 2034	55	No	RPV Pressure (1), Steam Flow to High Pressure Coolant Injection (2), and Feedwater Pressure (1)	Typical of Four	EFC	SA	HF	--	--	--	O	O	O	--	O	No	A	No	Yes	Notes 15 and 16 See Penetration Detail X-28A
	6M721-5357	56	Yes	Reactor Building Component Cooling Water/Emergency Equipment Cooling Water Supply	P4400F282B	CHK	SA	RF	--	--	--	O	O	O	--	O	Yes	B	Yes	Yes	--
					P4400F606B	GAT	MO	RM	M	--		O	O	O	AIS	O	Yes	B	Yes	Yes	Note 34
	6M721-5357	56	Yes	Reactor Building Component Cooling Water/Emergency Equipment Cooling Water Return	P4400F615	GAT	MO	RM	M	--		O	O	O	AIS	O	Yes	B	Yes	Yes	Note 4
					P4400F607B	GAT	MO	RM	M	--		O	O	O	AIS	O	Yes	B	Yes	Yes	
X-35 A, B, C, D, E, F, G	6I721-2837-6	54	No	TIP System Flanges	--	--	--	--	--	--	--	--	--	--	--	--	No	--	No	Yes	Type B Test

TABLE 6.2-2 SUMMARY OF PRIMARY CONTAINMENT PENETRATIONS AND ASSOCIATED ISOLATION VALVES

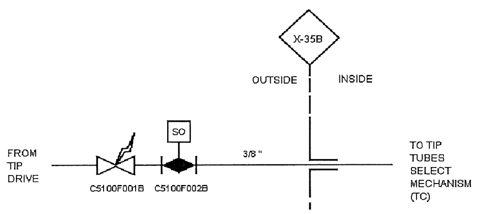
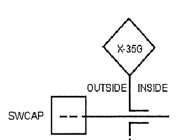
PENETRATION DATA				ISOLATION VALVE DATA																	
												Valve Position									
Penetration Detail	P&ID Number	Design Criteria	Bypass Leakage Path	System Title	Valve Number	Valve Type	Actuator Type	Primary Actuation Mode	Secondary Actuation Mode	Containment Isolation Signal(s)	Accident Isolation Signal(s)	Normal	Shutdown	Post-LOCA (Accident)	Power Failure	ILRT	Engineered Safety Feature	Quality Group	Type C Test	Leak Detection	Remarks
X-35A	6I721-2837-6	--	--	TIP System (Spare)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type A Test
	6I721-2837-6	54	No	TIP System	C5100F002B (C5102J004B)	BAL	SO	--	--	C, K	--	C	C	C	C	C	No	--	Yes	Yes	Note 17
					C5100F001B	SHR	EX	RM	--	--	--	O	O	O	O	O	No	--	No	Yes	Note 17
X-35C	6I721-2837-6	54	No	TIP System	C5100F002A (C5102J004A)	BAL	SO	--	--	C, K	--	C	C	C	C	C	No	--	Yes	Yes	Note 17
					C5100F001A	SHR	EX	RM	--		--	O	O	O	O	O	No	--	No	Yes	See Penetration Detail X-35B
X-35D	6I721-2837-6	54	No	TIP System	C5100F002C (C5102J004C)	BAL	SO	--	--	C, K	--	C	C	C	C	C	No	B	Yes	Yes	Note 17
					C5100F001C	SHR	EX	RM	--		--	O	O	O	O	O	No	B	No	Yes	See Penetration Detail X-35B
X-35E	6I721-2837-6	54	No	TIP System	C5100F002E (C5102J004E)	BAL	SO	--	--	C, K	--	C	C	C	C	C	No	B	Yes	Yes	Note 17
					C5100F001E	SHR	EX	RM	--		--	O	O	O	O	O	No	B	No	Yes	See Penetration Detail X-35B
X-35F	6I721-2837-6	54	No	TIP System	C5100F002D (C5102J004D)	BAL	SO	--	--	C, K	--	C	C	C	C	C	No	B	Yes	Yes	Note 17
					C5100F001D	SHR	EX	RM	--		--	O	O	O	O	O	No	B	No	Yes	See Penetration Detail X-35B
	6I721-2837-6	--	No	TIP System (Spare)	--	--	--	-- --	-- --	--	-- --	--	--	--	--	--	--	--	--	--	Note 18 Type A Test

TABLE 6.2-2 SUMMARY OF PRIMARY CONTAINMENT PENETRATIONS AND ASSOCIATED ISOLATION VALVES

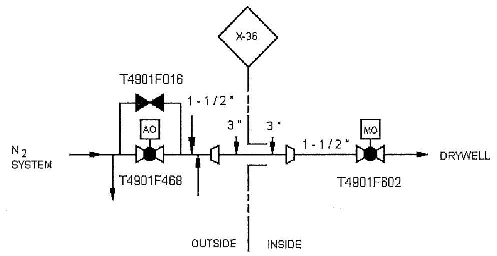
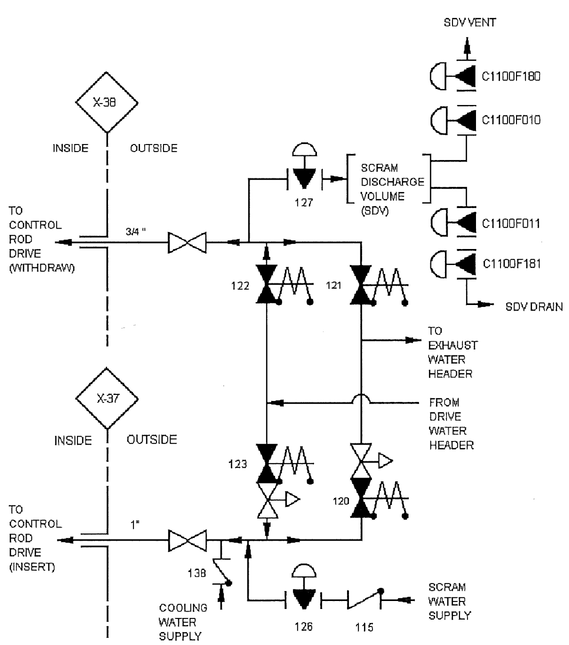
PENETRATION DATA				ISOLATION VALVE DATA																	
												Valve Position									
Penetration Detail	P&ID Number	Design Criteria	Bypass Leakage Path	System Title	Valve Number	Valve Type	Actuator Type	Primary Actuation Mode	Secondary Actuation Mode	Containment Isolation Signal(s)	Accident Isolation Signal(s)	Normal	Shutdown	Post-LOCA (Accident)	Power Failure	ILRT	Engineered Safety Feature	Quality Group	Type C Test	Leak Detection	Remarks
	6M721-5007	56	No	Nitrogen to Drywell	T4901F468 (V4-2187)	GLB	AO	A	RM	B, K	--	O	O	C	C	C	Yes	B	Yes	Yes	Note 32
					T4901F602 (V4-2188)	GLB	MO	A	RM	B, K	--	O	O	C	AIS	C	Yes	B	Yes	Yes	Notes 2 and 32
					T4901F016 (V8-4140)	GLB	M	--	--	--	--	LC	LC	LC	LC	LC	No	B	Yes	Yes	Note 9
	6M721-2081	54	No	Control Rod Drive Insert and Withdrawal Lines	--	BCK	SA	RF	--	--	--	O	O	C	--	O	Yes	B	No	No	Note 19
					115	BCK	SA	RF	--	--	--	O	C	C	C	C	Yes	B	No	No	This Information Applies to Penetrations X-37 (A, B, C, D) and X-38 (A, B, C, D)
					121	GAT	SO	A	RM	--	--	C	C	C	C	C	Yes	B	No	No	
					123	GAT	SO	A	RM	--	--	C	C	C	C	C	Yes	B	No	No	
					120	GAT	SO	A	RM	--	--	C	C	C	C	C	Yes	B	No	No	
				Typical of 185 Units	122	GAT	SO	A	RM	--	--	C	C	C	C	C	Yes	B	No	No	
					126	GLB	AO	A	RM	--	--	C	C	O	O	O	Yes	B	No	No	
					127	GLB	AO	A	RM	--	--	C	C	O	O	O	Yes	B	No	No	
					138	BCK	SA	RF	--	--	--	O	C	C	C	C	Yes	B	No	No	
					C1100F010 (V8-2073)	REG	AO	A	RM			O	O	C	C	C	Yes	B	Yes	No	
					C1100F011	REG	AO	A	RM			O	O	C	C	C	Yes	B	Yes	No	
					C1100F180 (V8-3876)	REG	AO	A	RM			O	O	C	C	C	Yes	B	Yes	No	
					C1100F181	REG	AO	A	RM			O	O	C	C	C	Yes	B	Yes	No	

TABLE 6.2-2 SUMMARY OF PRIMARY CONTAINMENT PENETRATIONS AND ASSOCIATED ISOLATION VALVES

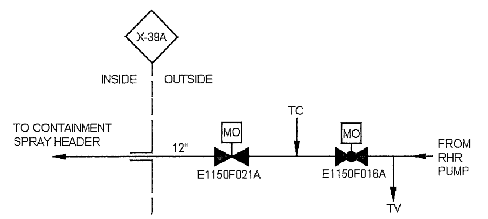
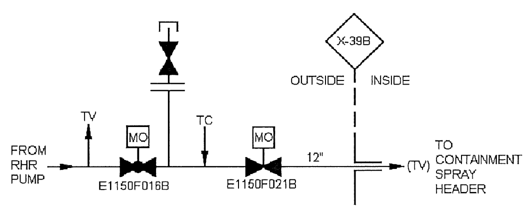
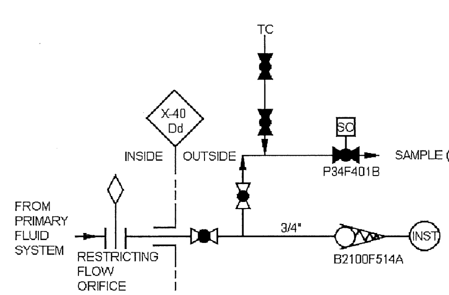
PENETRATION DATA				ISOLATION VALVE DATA																	
												Valve Position									
Penetration Detail	P&ID Number	Design Criteria	Bypass Leakage Path	System Title	Valve Number	Valve Type	Actuator Type	Primary Actuation Mode	Secondary Actuation Mode	Containment Isolation Signal(s)	Accident Isolation Signal(s)	Normal	Shutdown	Post-LOCA (Accident)	Power Failure	ILRT	Engineered Safety Feature	Quality Group	Type C Test	Leak Detection	Remarks
	6M721-2084	56	No	Residual Heat Removal to Containment Spray Header	E1150F021A (V8-2169)	GAT	MO	A	RM	A, K	--	C	C	O	AIS	C	Yes	B	Yes	No	Notes 4, 10, 20 and 21
					E1150F016A (V8-2167)	GLB	MO	A	RM	A, K	--	C	C	O	AIS	C	Yes	B	Yes	No	Note 20
	6M721-2083	56	No	Residual Heat Removal to Containment Spray Header	E1150F021B (V8-2170)	GAT	MO	A	RM	A, K	--	C	C	O	AIS	C	Yes	B	Yes	No	Notes 4, 10, 20 and 21 Note 20
					E1150F016B (V8-2168)	GLB	MO	A	RM	A, K	--	C	C	O	AIS	C	Yes	B	Yes	No	Flange to be Type B Tested
X-40A	6M721-2833 2090	55	No	Recirculation Inlet ΔP (4) and Reactor Pressure Vessel Pressure (2)	Typical of Six	EFC	SA	HF	--	--	--	O	O	O	--	O	No	A	No	Yes	Note 16 See Penetration Detail X-28A
X-40B	6M721-2089 2090	55	No	Reactor Pressure Vessel Pressure (1) and Main Steam Flow (4)	Typical of Five	EFC	SA	HF	--	--	--	O	O	O	--	O	No	A	No	Yes	Notes 15 and 16 See Penetration Detail X-28A
X-40C	6M721-2090	55	No	Jet Pump Flow Instrumentation	Typical of Six	EFC	SA	HF	--	--	--	O	O	O	--	O	No	A	No	Yes	Note 14 See Penetration Detail X-28A
X-40D a,b,c,e,f	6M721-2090	55	No	Jet Pump Flow Instrumentation	Typical of Five	EFC	SA	HF	--	--	--	O	O	O	--	O	No	A	No	Yes	Note 14 See Penetration Detail X-28A
	6M721-2090	55	Yes	Jet Pump Flow Instrumentation and Postaccident Reactor Coolant Sample	B2100F514A (V13-2328)	EFC	SA	HF	--	--	--	O	O	O	--	O	No	A	No	Yes	Note 14
	6I721-2400-10				P34F401B	GLB	SO	RM	--	--	--	C	C	C	C	C	No	B	Yes	Yes	--
X-41	--	--	--	Spare	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type A Test

TABLE 6.2-2 SUMMARY OF PRIMARY CONTAINMENT PENETRATIONS AND ASSOCIATED ISOLATION VALVES

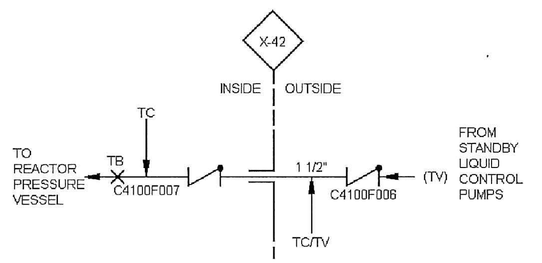
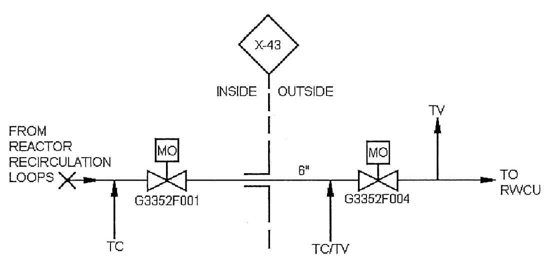
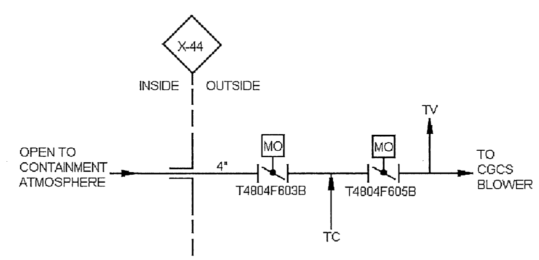
PENETRATION DATA: Penetration Detail	P&ID Number	Design Criteria	Bypass Leakage Path	ISOLATION VALVE DATA: System Title	Valve Number	Valve Type	Actuator Type	Primary Actuation Mode	Secondary Actuation Mode	Containment Isolation Signal(s)	Accident Isolation Signal(s)	Valve Position: Normal	Valve Position: Shutdown	Valve Position: Post-LOCA (Accident)	Valve Position: Power Failure	Valve Position: ILRT	Engineered Safety Feature	Quality Group	Type C Test	Leak Detection	Remarks
	6M721-2082	55	No	Standby Liquid Control	C4100F007 (VR4-2037)	CHK	SA	RF	--	--	--	C	C	C	--	C	R	A	Yes	No	--
					C4100F006 (VR4-2036)	CHK	SA	RF	--	--	--	C	C	C	--	C	R	A	Yes	No	Note 22
	6M721-2046	55	No	Reactor Water (Cleanup From Recirculation Piping)	G3352F001 (V8-2252)	GAT	MO	A	RM	B	W	O	O	C	AIS	C	No	A	Yes	Yes	Alternate-Note 4
					G3352F004 (V8-2253)	GAT	MO	A	RM	B	W	O	O	C	AIS	C	No	A	Yes	Yes	Note 35
	6M721-2087	56	No	Combustible Gas Control System Suction	T4804F603B (V4-2143)	BFY	M	M	--	--	--	LC	LC	LC	LC	LC	No	B	Yes	No	Notes 9, 10, 11, and 45
					T4804F605B (V4-2153)	BFY	M	M	--	--	--	LC	LC	LC	LC	LC	No	B	Yes	No	Notes 9 and 45
X-45	--	--	--	Spare	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type A Test
X-46A	6M721-2089	55	No	Main Steam Flow	Typical of Four	EFC	SA	HF	--	--	--	O	O	O	--	O	No	A	No	Yes	Notes 15 and 16 See Penetration Detail X-28A
X-46B	6M721-2089	55	No	Main Steam Flow	Typical of Four	EFC	SA	HF		--	--	O	O	O	--	O	No	A	No	Yes	Notes 15 and 16 See Penetration Detail X-28A

TABLE 6.2-2 SUMMARY OF PRIMARY CONTAINMENT PENETRATIONS AND ASSOCIATED ISOLATION VALVES

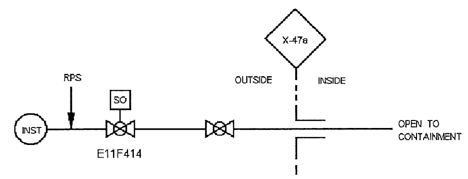
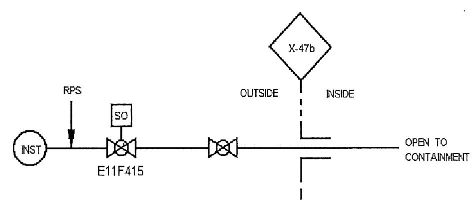
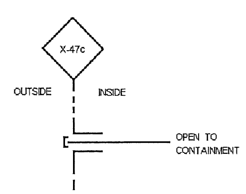
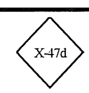
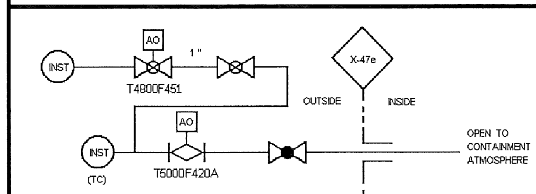
PENETRATION DATA				ISOLATION VALVE DATA																	
												Valve Position									
Penetration Detail	P&ID Number	Design Criteria	Bypass Leakage Path	System Title	Valve Number	Valve Type	Actuator Type	Primary Actuation Mode	Secondary Actuation Mode	Containment Isolation Signal(s)	Accident Isolation Signal(s)	Normal	Shutdown	Post-LOCA (Accident)	Power Failure	ILRT	Engineered Safety Feature	Quality Group	Type C Test	Leak Detection	Remarks
	6M721-2084	56	No	Reactor Protection System	E11F414 (V5-2548)	GLB	SO	RM	--	--	--	O	O	O	AIS	O	No	B	Yes	Yes	Notes 2, 12, and 15
	6M721-2084	56	No	Reactor Protection System	E11F415 (V5-2549)	GLB	SO	RM	--	--	--	O	O	O	AIS	O	No	B	Yes	Yes	Notes 2, 12, and 15
	6M721-3445		No																		Note 15
	6M721-2090	55	No	Reactor Pressure Vessel Level	B21F507 (V13-2318)	EFC	SA	HF	--	--	--	O	O	O	--	O	No	A	No	Yes	Notes 15 and 16 See Penetration Detail X-28A
	6M721-2084 6I721-2679-1	56	No	Drywell Pressure Nitrogen Inerting Instrumentation	T5000F420A (V5-2230)	BAL	AO	RM	M	--	--	O	O	O	C	O	No	B	Yes	Yes	Notes 2, 12, 13, and 15

TABLE 6.2-2 SUMMARY OF PRIMARY CONTAINMENT PENETRATIONS AND ASSOCIATED ISOLATION VALVES

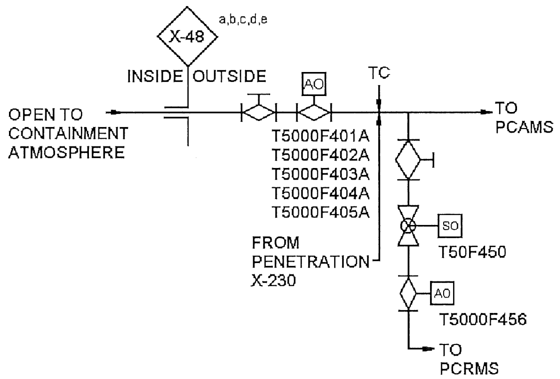
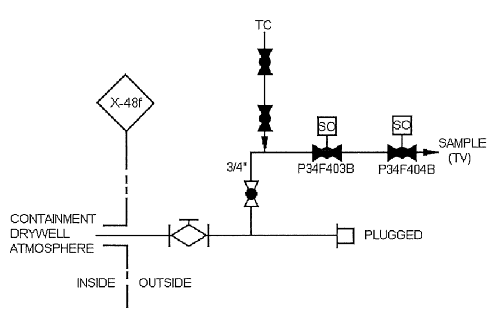
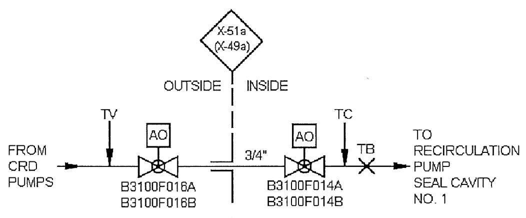
PENETRATION DATA				ISOLATION VALVE DATA								Valve Position									
Penetration Detail	P&ID Number	Design Criteria	Bypass Leakage Path	System Title	Valve Number	Valve Type	Actuator Type	Primary Actuation Mode	Secondary Actuation Mode	Containment Isolation Signal(s)	Accident Isolation Signal(s)	Normal	Shutdown	Post-LOCA (Accident)	Power Failure	ILRT	Engineered Safety Feature	Quality Group	Type C Test	Leak Detection	Remarks
	6I721-2679-1	56	No	Containment Atmosphere Samples	T5000F401A (V5-2151)	BAL	AO	RM	M	--	--	O	O	O	C	O	No	B	Yes	Yes	See Penetration Detail X-27
					T5000F402A (V5-2152)																
					T5000F403A (V5-2153)																
					T5000F404A (V5-2154)																
					T5000F405A (V5-2155)																
					T50F450 (V5-3083)	GLB	SO	A	--	B, K	B, K	O	O	C	C	C	No	B	Yes	Yes	Note 10
					T5000F456 (V5-2235)	BAL	AO	A	M	B, K	B, K	O	O	C	C	C	No	B	Yes	Yes	Note 10
	6I721-2679-1	56	Yes	Containment Atmosphere Samples																	
	6I721-2400-10				P34F403B (V13-7365)	GLB	SO	RM	--	--	--	C	C	C	C	C	No	B	Yes	Yes	Note 10
					P34F404B (V13-7375)	GLB	SO	RM	--	--	--	C	C	C	C	C	No	B	Yes	Yes	Note 10
	6M721-2833	55	No	Recirculation Pump Seal Purge	B3100F014B (V8-3590)	GLB	AO	A	M	B, K	--	O	O	C	C	C	No	B	Yes	Yes	Note 15
					B3100F016B (V8-3768)	GLB	AO	A	M	B, K	--	O	O	C	C	C	No	B	Yes	Yes	Note 15
					B3100F014A (V8-3710)	GLB	AO	A	M	B,K	--	O	O	C	C	C	No	B	Yes	Yes	Note 15
					B3100F016A (V8-3767)	GLB	AO	A	M	B,K	--	O	O	C	C	C	No	B	Yes	Yes	Note 15
X-50	--	--	--	Spare	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type A Test
X-52	6M721-2089 2044	55	No	Main Steam Flow (4) and Steam Flow to Reactor Core Isolation Cooling (2)	Typical of Six	EFC	SA	HF	--	--	--	O	O	O	--	O	No	A	No	Yes	Note 16 See Penetration Detail X-28A

TABLE 6.2-2 SUMMARY OF PRIMARY CONTAINMENT PENETRATIONS AND ASSOCIATED ISOLATION VALVES

PENETRATION DATA				ISOLATION VALVE DATA																	
												Valve Position									
Penetration Detail	P&ID Number	Design Criteria	Bypass Leakage Path	System Title	Valve Number	Valve Type	Actuator Type	Primary Actuation Mode	Secondary Actuation Mode	Containment Isolation Signal(s)	Accident Isolation Signal(s)	Normal	Shutdown	Post-LOCA (Accident)	Power Failure	ILRT	Engineered Safety Feature	Quality Group	Type C Test	Leak Detection	Remarks
X-53	6M721- 2044 2034 2090	55	No	Steam Flow to Reactor Core Isolation Cooling (2), Feedwater Pressure (1), and Reactor Pressure Vessel Pressure (1)	Typical of Four	EFC	SA	HF	–	–	–	O	O	O	–	O	No	A	No	Yes	Notes 15 and 16 See Penetration Detail X-28A
X-54Ad	6M721- 2090	55	Yes	Reactor Level, Pressure	B2100F506 (V13-2317)	EFC	SA	HF	–	–	–	O	O	O	–	O	No	A	No	Yes	Notes 15 and 16 See Penetration Detail X-28A
X-54B	6M721- 2090	55	Yes	Reactor Level, Pressure	B2100F508 (V13-2397)	EFC	SA	HF	–	–	–	O	O	O	–	O	No	A	No	Yes	Notes 15 and 16 See Penetration Detail X-28A
X-55Ac	6M721- 2090	55	No	Reactor Level, Pressure	B2100F510 (V13-2321)	EFC	SA	HF	–	–	–	O	O	O	–	O	No	A	No	Yes	Notes 15 and 16 See Penetration Detail X-28A
X-55Bb X-55Be	6M721- 2090	55	No	Reactor Level, Pressure	B2100F512 (V13-2323) B2100F511 (V13-2396)	EFC	SA	HF	–	–	–	O	O	O	–	O	No	A	No	Yes	Notes 15 and 16 See Penetration Detail X-28A
X-100A	6E721-2831- 8	–	–	Neutron Monitor	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	Type B Test
X-100B	6E721-2831- 8	–	–	Low Voltage Switching Reactor Protection System	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	Type B Test
X-100F	6E721-2831- 8	–	–	Spare	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	Type A Test
X-100G	6E721-2831- 8	–	–	Neutron Monitor	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	Type B Test
X-101A	6E721-2831- 8	–	–	Recirculation Pump Power, 5kV	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	Type B Test
X-101B	6E721-2831- 8	–	–	Recirculation Pump Power, 5kV	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	Type B Test
X-101C	6E721-2831- 8	–	–	Recirculation Pump Power, 5kV	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	Type B Test
X-101D	6E721-2831- 8	–	–	Recirculation Pump Power, 5kV	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	Type B Test
X-101E	6E721-2831- 8	–	–	Recirculation Pump Power, 5kV	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	Type B Test

TABLE 6.2-2 SUMMARY OF PRIMARY CONTAINMENT PENETRATIONS AND ASSOCIATED ISOLATION VALVES

PENETRATION DATA				ISOLATION VALVE DATA																	
												Valve Position									
Penetration Detail	P&ID Number	Design Criteria	Bypass Leakage Path	System Title	Valve Number	Valve Type	Actuator Type	Primary Actuation Mode	Secondary Actuation Mode	Containment Isolation Signal(s)	Accident Isolation Signal(s)	Normal	Shutdown	Post-LOCA (Accident)	Power Failure	ILRT	Engineered Safety Feature	Quality Group	Type C Test	Leak Detection	Remarks
X-101F	6E721-2831-8	--	--	Recirculation Pump Power, 5kV	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type B Test
X-102A	6E721-2831-8	--	--	Neutron Monitor	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type B Test
X-102B	6E721-2831-8	--	--	Low Voltage Switching/ Reactor Protection System	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type B Test
X-105B	6E721-2831-8	--	--	Low Voltage Switching/ Reactor Protection System	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type B Test
X-105C	6E721-2831-8	--	--	Low Voltage Switching/ Reactor Protection System	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type B Test
X-103A	6E721-2831-8	--	--	Drywell Thermocouples	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type B Test
X-103B	6E721-2831-8	--	--	Neutron Monitor	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type B Test
X-104A	6E721-2831-8	--	--	Control Rod Drive Position Indicator	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type B Test
X-104B	6E721-2831-8	--	--	Control Rod Drive Position Indicator	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type B Test
X-104C	6E721-2831-8	--	--	Control Rod Drive Position Indicator	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type B Test
X-104D	6E721-2831-8	--	--	Control Rod Drive Position Indicator	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type B Test
X-104E	6E721-2831-8	--	--	Control Rod Drive Position Indicator	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type B Test
X-104F	6E721-2831-8	--	--	Control Rod Drive Position Indicator	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type B Test
X-105A	6E721-2831-8	--	--	Low Voltage Power (480 V)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type B Test

TABLE 6.2-2 SUMMARY OF PRIMARY CONTAINMENT PENETRATIONS AND ASSOCIATED ISOLATION VALVES

PENETRATION DATA				ISOLATION VALVE DATA																	
												Valve Position									
Penetration Detail	P&ID Number	Design Criteria	Bypass Leakage Path	System Title	Valve Number	Valve Type	Actuator Type	Primary Actuation Mode	Secondary Actuation Mode	Containment Isolation Signal(s)	Accident Isolation Signal(s)	Normal	Shutdown	Post-LOCA (Accident)	Power Failure	ILRT	Engineered Safety Feature	Quality Group	Type C Test	Leak Detection	Remarks
X-105D	6E721-2831-8	--	--	Low Voltage Power (480 V)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type B Test
X-106A	6E721-2831-8	--	--	Spare	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type A Test
X-106B	6E721-2831-8	--	--	Low Level Signal Vibration Test	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type B Test
X-200A	--	--	--	Torus Access Hatch	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type B Test
X-200B	--	--	--	Torus Access Hatch	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type B Test
X-201A	6C721-2305	--	--	Vent Line Bellows	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type B Test
X-201B	6C721-2305	--	--	Vent Line Bellows	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type B Test
X-201C	6C721-2305	--	--	Vent Line Bellows	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type B Test
X-201D	6C721-2305	--	--	Vent Line Bellows	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type B Test
X-201E	6C721-2305	--	--	Vent Line Bellows	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type B Test
X-100C	6E721-2831-8	--	--	Blanked Off Electrical Penetration (Spare)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type B Test, Double O-Ring Testable Seal
X-100E	6E721-2831-8	--	--	Blanked Off Electrical Penetration (Spare)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type B Test, Double O-Ring Testable Seal
X-100D	6E721-2831-8	--	--	Low Level Signal Vibration Test	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type B Test

TABLE 6.2-2 SUMMARY OF PRIMARY CONTAINMENT PENETRATIONS AND ASSOCIATED ISOLATION VALVES

PENETRATION DATA				ISOLATION VALVE DATA																	
												Valve Position									
Penetration Detail	P&ID Number	Design Criteria	Bypass Leakage Path	System Title	Valve Number	Valve Type	Actuator Type	Primary Actuation Mode	Secondary Actuation Mode	Containment Isolation Signal(s)	Accident Isolation Signal(s)	Normal	Shutdown	Post-LOCA (Accident)	Power Failure	ILRT	Engineered Safety Feature	Quality Group	Type C Test	Leak Detection	Remarks
X-107B	6E721-2831-8	–	–	Drywell Thermocouples	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	Type B Test
X-107A	6E721-2831-8	–	–	Spare	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	Type A Test
X-201F	6C721-2305	–	–	Vent Line Bellows	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	Type B Test
X-201G	6C721-2305	–	–	Vent Line Bellows	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	Type B Test
X-201H	6C721-2305	–	–	Vent Line Bellows	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	Type B Test
X-202A	6C721-2305	–	–	Vacuum Breaker (Inside Torus)	–	–	–	–	–	–	–	–	–	–	–	O	–	–	–	–	Note 23
X-202B	6C721-2305	–	–	Vacuum Breaker (Inside Torus)	–	–	–	–	–	–	–	–	–	–	–	O	–	–	–	–	Note 23
X-202C	6C721-2305	–	–	Vacuum Breaker (Inside Torus)	–	–	–	–	–	–	–	–	–	–	–	O	–	–	–	–	Note 23
X-202D	6C721-2305	–	–	Vacuum Breaker (Inside Torus)	–	–	–	–	–	–	–	–	–	–	–	O	–	–	–	–	Note 23
X-202E	6C721-2305	–	–	Vacuum Breaker (Inside Torus)	–	–	–	–	–	–	–	–	–	–	–	O	–	–	–	–	Note 23
X-202F	6C721-2305	–	–	Vacuum Breaker (Inside Torus)	–	–	–	–	–	–	–	–	–	–	–	O	–	–	–	–	Note 23
X-202G	6C721-2305	–	–	Vacuum Breaker (Inside Torus)	–	–	–	–	–	–	–	–	–	–	–	O	–	–	–	–	Note 23
X-202H	6C721-2305	–	–	Vacuum Breaker (Inside Torus)	–	–	–	–	–	–	–	–	–	–	–	O	–	–	–	–	Note 23

TABLE 6.2-2 SUMMARY OF PRIMARY CONTAINMENT PENETRATIONS AND ASSOCIATED ISOLATION VALVES

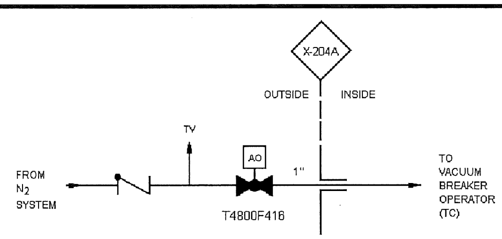
PENETRATION DATA				ISOLATION VALVE DATA																	
												Valve Position									
Penetration Detail	P&ID Number	Design Criteria	Bypass Leakage Path	System Title	Valve Number	Valve Type	Actuator Type	Primary Actuation Mode	Secondary Actuation Mode	Containment Isolation Signal(s)	Accident Isolation Signal(s)	Normal	Shutdown	Post-LOCA (Accident)	Power Failure	ILRT	Engineered Safety Feature	Quality Group	Type C Test	Leak Detection	Remarks
X-202J	6C721-2305	--	--	Vacuum Breaker (Inside Torus)	--	--	--	--	--	--	--	--	--	--	--	O	--	--	--	--	Note 23
X-202K	6C721-2305	--	--	Vacuum Breaker (Inside Torus)	--	--	--	--	--	--	--	--	--	--	--	O	--	--	--	--	Note 23
X-202L	6C721-2305	--	--	Vacuum Breaker (Inside Torus)	--	--	--	--	--	--	--	--	--	--	--	O	--	--	--	--	Note 23
X-202M	6C721-2305	--	--	Vacuum Breaker (Inside Torus)	--	--	--	--	--	--	--	--	--	--	--	O	--	--	--	--	Note 23
	6M721-3445	57	No	Drywell to Torus Vacuum Breaker Nitrogen Supply	T4800F416 (V4-2036)	GLB	AO	RM	M	--	--	LC	LC	LC	C	C	No	B	Yes	No	Note 9
X-204B	6M721-3445	57	No	Drywell to Torus Vacuum Breaker Nitrogen Supply	T4800F417 (V4-2065)	GLB	AO	RM	M	--	--	LC	LC	LC	C	C	No	B	Yes	No	See Penetration Detail X-204A
X-204C	6M721-3445	57	No	Drywell to Torus Vacuum Breaker Nitrogen Supply	T4800F418 (V4-2075)	GLB	AO	RM	M	--	--	LC	LC	LC	C	C	No	B	Yes	No	See Penetration Detail X-204A
X-204D	6M721-3445	57	No	Drywell to Torus Vacuum Breaker Nitrogen Supply	T4800F419 (V4-2077)	GLB	AO	RM	M	--	--	LC	LC	LC	C	C	No	B	Yes	No	See Penetration Detail X-204A
X-204E	6M721-3445	57	No	Drywell to Torus Vacuum Breaker Nitrogen Supply	T4800F420 (V4-2082)	GLB	AO	RM	M	--	--	LC	LC	LC	C	C	No	B	Yes	No	See Penetration Detail X-204A
X-204F	6M721-3445	57	No	Drywell to Torus Vacuum Breaker Nitrogen Supply	T4800F421 (V4-2084)	GLB	AO	RM	M	--	--	LC	LC	LC	C	C	No	B	Yes	No	See Penetration Detail X-204A
X-204G	6M721-3445	57	No	Drywell to Torus Vacuum Breaker Nitrogen Supply	T4800F422 (V4-2086)	GLB	AO	RM	M	--	--	LC	LC	LC	C	C	No	B	Yes	No	See Penetration Detail X-204A
X-204H	6M721-3445	57	No	Drywell to Torus Vacuum Breaker Nitrogen Supply	T4800F423 (V4-2088)	GLB	AO	RM	M	--	--	LC	LC	LC	C	C	No	B	Yes	No	See Penetration Detail X-204A

TABLE 6.2-2 SUMMARY OF PRIMARY CONTAINMENT PENETRATIONS AND ASSOCIATED ISOLATION VALVES

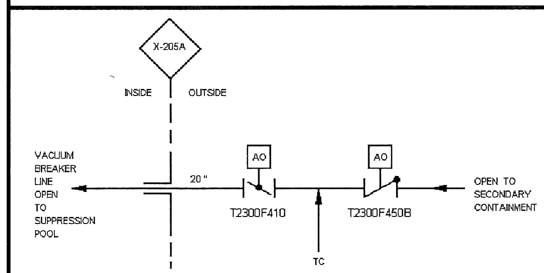
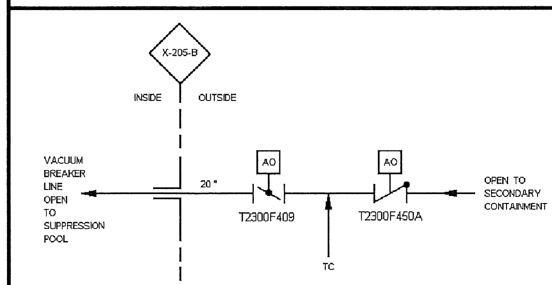
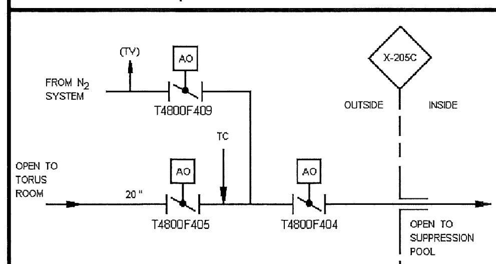
PENETRATION DATA				ISOLATION VALVE DATA																	
												Valve Position									
Penetration Detail	P&ID Number	Design Criteria	Bypass Leakage Path	System Title	Valve Number	Valve Type	Actuator Type	Primary Actuation Mode	Secondary Actuation Mode	Containment Isolation Signal(s)	Accident Isolation Signal(s)	Normal	Shutdown	Post-LOCA (Accident)	Power Failure	ILRT	Engineered Safety Feature	Quality Group	Type C Test	Leak Detection	Remarks
X-204J	6M721-3445	57	No	Drywell to Torus Vacuum Breaker Nitrogen Supply	T4800F424 (V4-2090)	GLB	AO	RM	M	--	--	LC	LC	LC	C	C	No	B	Yes	No	See Penetration Detail X-204A
X-204K	6M721-3445	57	No	Drywell to Torus Vacuum Breaker Nitrogen Supply	T4800F425 (V4-2092)	GLB	AO	RM	M	--	--	LC	LC	LC	C	C	No	B	Yes	No	See Penetration Detail X-204A
X-204L	6M721-3445	57	No	Drywell to Torus Vacuum Breaker Nitrogen Supply	T4800F426 (V4-2094)	GLB	AO	RM	M	--	--	LC	LC	LC	C	C	No	B	Yes	No	See Penetration Detail X-204A
X-204M	6M721-3445	57	No	Drywell to Torus Vacuum Breaker Nitrogen Supply	T4800F427 (V4-2096)	GLB	AO	RM	M	--	--	LC	LC	LC	C	C	No	B	Yes	No	See Penetration Detail X-204A
	6M721-3445-1	56	No	Secondary Containment to Torus Vacuum Breaker	T2300F410 (V21-2016)	BFY	AO	RM	--	--	H	C	C	C	O	C	Yes	B	Yes	No	Notes 10, 11, and 24
					T2300F450B (V21-2014)	CHK	SA	RF	RM	--	--	C	C	C	--	C	Yes	B	Yes	No	Notes 10 and 25
	6M721-3445-1	56	No	Secondary Containment to Torus Vacuum Breaker	T2300F409 (V21-2015)	BFY	AO	RM	--	--	H	C	C	C	O	C	Yes	B	Yes	No	Notes 10, 11, and 24
					T2300F450A (V21-2013)	CHK	SA	RF	RM	--	--	C	C	C	--	C	Yes	B	Yes	No	Notes 10 and 25
	6M721-3445-1	56	No	Suppression Pool Air Purge Inlet	T4800F404 (VR3-3013)	BFY	AO	A	RM	B, K, R	--	C	O	C	C	C	R	B	Yes	No	Notes 10 and 11 Flanges type B tested
	7M721-2709				T4800F405 (VR3-3014)	BFY	AO	A	RM	B, K, R	--	C	O	C	C	C	R	B	Yes	No	Note 10
					T4800F409 (VR3-2061)	BFY	AO	A	RM	B, K, R	--	C	C	C	C	C	R	B	Yes	No	Note 10

TABLE 6.2-2 SUMMARY OF PRIMARY CONTAINMENT PENETRATIONS AND ASSOCIATED ISOLATION VALVES

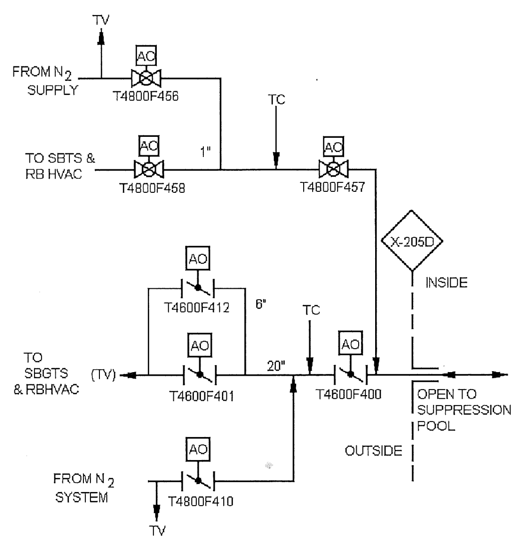
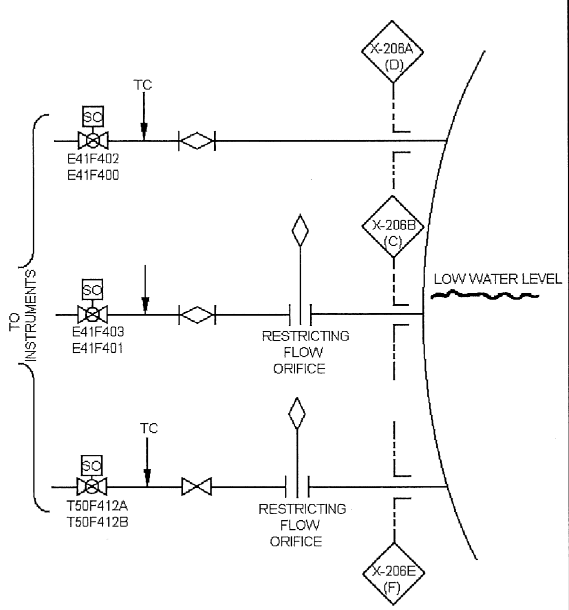
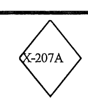
PENETRATION DATA				ISOLATION VALVE DATA																	
												Valve Position									
Penetration Detail	P&ID Number	Design Criteria	Bypass Leakage Path	System Title	Valve Number	Valve Type	Actuator Type	Primary Actuation Mode	Secondary Actuation Mode	Containment Isolation Signal(s)	Accident Isolation Signal(s)	Normal	Shutdown	Post-LOCA (Accident)	Power Failure	ILRT	Engineered Safety Feature	Quality Group	Type C Test	Leak Detection	Remarks
	7M721-2709	56	No	Suppression Pool Exhaust and Nitrogen Inlet	T4600F400 (VR3-3015)	BFY	AO	A	RM	B, K, R	--	C	O	C	C	C	R	B	Yes	No	Notes 10, 11, and 44 Flanges type B tested
	6M721-3445-1				T4600F401 (VR3-3016)	BFY	AO	A	RM	B, K, R	--	C	O	C	C	C	R	B	Yes	No	Note 10 and 44
					T4600F412 (VR3-3019)	BFY	AO	A	RM	B, K, R	--	C	C	C	C	C	R	B	Yes	No	Note 10
					T4800F410 (V4-2063)	BFY	AO	A	RM	B, K, R	--	C	C	C	C	C	R	B	Yes	No	Note 10
					T4800F456 (VR3-2826)	GLB	AO	A	RM	B, K, R	--	O	C	C	C	C	R	B	Yes	No	Note 10
					T4800F457 (VR3-2827)	GLB	AO	A	RM	B, K, R	--	O	C	C	C	C	R	B	Yes	No	Notes 2 and 10
					T4800F458 (VR3-2828)	GLB	AO	A	RM	B, K, R	--	O	C	C	C	C	R	B	Yes	No	Note 10
	6I721-2679-1	56	No	Torus Pressure and Liquid Level Instrumentation	E41F402 (V5-2552)	GLB	SO	RM	M	--	--	O	O	O	AIS	O	No	B	Yes	Yes	Note 12
					E41F403 (V5-2553)	GLB	SO	RM	M	--	--	O	O	O	AIS	O	No	B	Yes	Yes	Notes 12 and 26
					E41F401 (V5-2551)	GLB	SO	RM	M	--	--	O	O	O	AIS	O	No	B	Yes	Yes	Notes 12 and 26
					E41F400 (V5-2550)	GLB	SO	RM	M	--	--	O	O	O	AIS	O	No	B	Yes	Yes	Note 12
					T50F412A (V5-2555)	GLB	SO	RM	M	--	--	O	O	O	AIS	O	No	B	Yes	Yes	Notes 12 and 26
					T50F412B (V5-2556)	GLB	SO	RM	M	--	--	O	O	O	AIS	O	No	B	Yes	Yes	Notes 12 and 26
	6C721-2305	--	--	Drain Line (Inside Torus)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Note 23

TABLE 6.2-2 SUMMARY OF PRIMARY CONTAINMENT PENETRATIONS AND ASSOCIATED ISOLATION VALVES

PENETRATION DATA				ISOLATION VALVE DATA																	
												Valve Position									
Penetration Detail	P&ID Number	Design Criteria	Bypass Leakage Path	System Title	Valve Number	Valve Type	Actuator Type	Primary Actuation Mode	Secondary Actuation Mode	Containment Isolation Signal(s)	Accident Isolation Signal(s)	Normal	Shutdown	Post-LOCA (Accident)	Power Failure	ILRT	Engineered Safety Feature	Quality Group	Type C Test	Leak Detection	Remarks
X-207B	6C721-2305	--	--	Drain Line (Inside Torus)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Note 23
X-207C	6C721-2305	--	--	Drain Line (Inside Torus)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Note 23
X-207D	6C721-2305	--	--	Drain Line (Inside Torus)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Note 23
X-207E	6C721-2305	--	--	Drain Line (Inside Torus)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Note 23
X-207F	6C721-2305	--	--	Drain Line (Inside Torus)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Note 23
X-207G	6C721-2305	--	--	Drain Line (Inside Torus)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Note 23
X-207H	6C721-2305	--	--	Drain Line (Inside Torus)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Note 23
X-208A	6C721-2305	--	--	Electromagnetic Relief Valve Discharge (Inside Torus)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Note 23
X-208B	6C721-2305	--	--	Electromagnetic Relief Valve Discharge (Inside Torus)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Note 23
X-208C	6C721-2305	--	--	Electromagnetic Relief Valve Discharge (Inside Torus)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Note 23
X-208D	6C721-2305	--	--	Electromagnetic Relief Valve Discharge (Inside Torus)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Note 23
X-208E	6C721-2305	--	--	Electromagnetic Relief Valve Discharge (Inside Torus)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Note 23
X-208F	6C721-2305	--	--	Electromagnetic Relief Valve Discharge (Inside Torus)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Note 23
X-208G	6C721-2305	--	--	Electromagnetic Relief Valve Discharge (Inside Torus)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Note 23

TABLE 6.2-2 SUMMARY OF PRIMARY CONTAINMENT PENETRATIONS AND ASSOCIATED ISOLATION VALVES

PENETRATION DATA				ISOLATION VALVE DATA																	
												Valve Position									
Penetration Detail	P&ID Number	Design Criteria	Bypass Leakage Path	System Title	Valve Number	Valve Type	Actuator Type	Primary Actuation Mode	Secondary Actuation Mode	Containment Isolation Signal(s)	Accident Isolation Signal(s)	Normal	Shutdown	Post-LOCA (Accident)	Power Failure	ILRT	Engineered Safety Feature	Quality Group	Type C Test	Leak Detection	Remarks
X-208H	6C721-2305	--	--	Electromagnetic Relief Valve Discharge (Inside Torus)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Note 23
X-208J	6C721-2305	--	--	Electromagnetic Relief Valve Discharge (Inside Torus)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Note 23
X-208K	6C721-2305	--	--	Electromagnetic Relief Valve Discharge (Inside Torus)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Note 23
X-208L	6C721-2305	--	--	Electromagnetic Relief Valve Discharge (Inside Torus)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Note 23
X-208M	6C721-2305	--	--	Electromagnetic Relief Valve Discharge (Inside Torus)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Note 23
X-208N	6C721-2305	--	--	Electromagnetic Relief Valve Discharge (Inside Torus)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Note 23
X-208O	6C721-2305	--	--	Electromagnetic Relief Valve Discharge (Inside Torus)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Note 23
X-208P	6C721-2305	--	--	Electromagnetic Relief Valve Discharge (Inside Torus)	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Note 23
X-209A	--	--	--	Thermocouple	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type B Test
X-209B	--	--	--	Spare	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type A Test
X-209C	--	--	--	Torus Thermocouple	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type B Test
X-209D	--	--	--	Spare	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type A Test

TABLE 6.2-2 SUMMARY OF PRIMARY CONTAINMENT PENETRATIONS AND ASSOCIATED ISOLATION VALVES

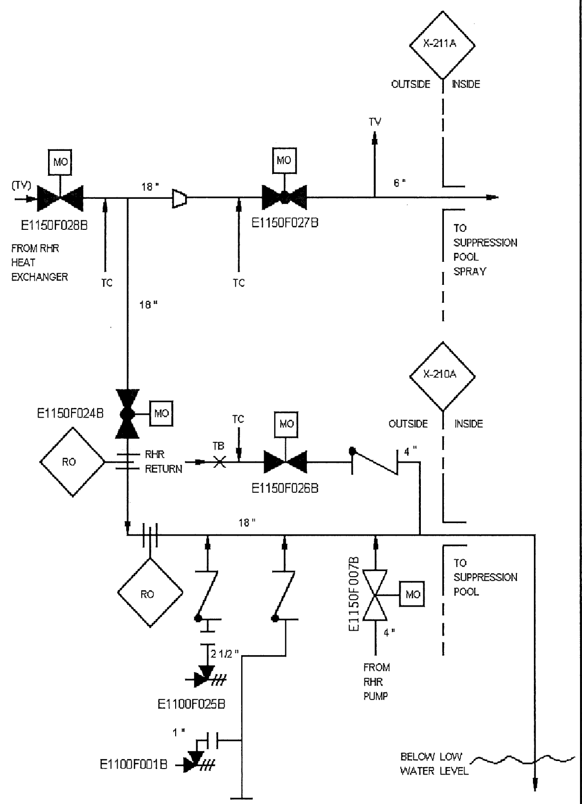
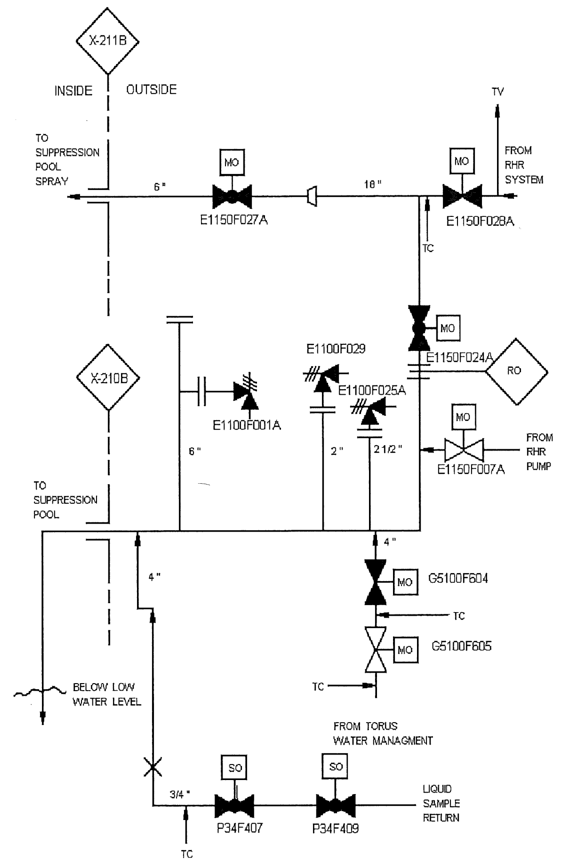
PENETRATION DATA				ISOLATION VALVE DATA																	
												Valve Position									
Penetration Detail	P&ID Number	Design Criteria	Bypass Leakage Path	System Title	Valve Number	Valve Type	Actuator Type	Primary Actuation Mode	Secondary Actuation Mode	Containment Isolation Signal(s)	Accident Isolation Signal(s)	Normal	Shutdown	Post-LOCA (Accident)	Power Failure	ILRT	Engineered Safety Feature	Quality Group	Type C Test	Leak Detection	Remarks
	6M721-2083	56	No	Residual Heat Removal Minimum Flow	E1150F007B (V8-4679)	GAT	MO	RM	M	--	Z	O	C	C	AIS	C	Yes	B	No	Yes	Notes 12 and 39
		56	No	Residual Heat Removal Heat Exchanger Discharge Header Thermal Relief	E1100F025B	REL	SA	--	--	--	--	C	C	C	--	C	Yes	B	No	Yes	Notes 27, 28 and 39
		56	No	Residual Heat Removal Test Line	E1150F024B (V8-2136)	GLB	MO	A	RM	A,K	--	C	C	C	AIS	C	Yes	B	Yes	Yes	Notes 2, 10 and 26
		56	No	Residual Heat Removal to Suppression Pool Spray	E1150F027B (V8-2158)	GLB	MO	A	RM	A,K	--	C	C	C	AIS	C	Yes	B	Yes	Yes	Notes 2 and 10
					E1150F028B (V8-2156)	GAT	MO	A	RM	A,K	--	C	C	O	AIS	C	Yes	B	Yes	Yes	--
		56	No	Residual Heat Removal Heat Exchanger Thermal Relief	E1100F001B (V22-2642)	REL	SA	--	--	--	--	C	C	C	--	C	Yes	B	No	Yes	Notes 27, 28, and 39
		56	No	Residual Heat Removal Warmup and Flush Line	E1150F026B (V8-2152)	GAT	MO	RM	M	--	--	C	C	C	AIS	C	Yes	B	No	Yes	Notes 39, and 40 Flanges Type B Tested

TABLE 6.2-2 SUMMARY OF PRIMARY CONTAINMENT PENETRATIONS AND ASSOCIATED ISOLATION VALVES



PENETRATION DATA				ISOLATION VALVE DATA																	
												Valve Position									
Penetration Detail	P&ID Number	Design Criteria	Bypass Leakage Path	System Title	Valve Number	Valve Type	Actuator Type	Primary Actuation Mode	Secondary Actuation Mode	Containment Isolation Signal(s)	Accident Isolation Signal(s)	Normal	Shutdown	Post-LOCA (Accident)	Power Failure	ILRT	Engineered Safety Feature	Quality Group	Type C Test	Leak Detection	Remarks
	6M721-4100	56	No	Torus Water Managment System	G5100F605 (V8-4680)	GAT	MO	A	RM	B,K	M	O	C	C	AIS	C	No	B	Yes	Yes	Note 26
					G5100F604 (V8-3849)	GAT	MO	A	RM	B,K	M	C	C	C	AIS	C	No	B	Yes	Yes	Notes 4 and 26
	6M721-2083	56	No	Residual Heat Removal Suction Thermal Relief	E1100F029 (V22-2033)	REL	SA	--	--	--	--	C	C	C	--	C	Yes	B	No	Yes	Notes 27, 28, and 39
	6M721-2084	56	No	Residual Heat Removal Heat Exchanger Discharge Header Thermal Relief	E1100F025A	REL	SA	--	--	--	--	C	C	C	--	C	Yes	B	No	Yes	Notes 27, 28, and 39
		56	No	Residual Heat Removal Heat Exchanger Relief	E1100F001A (V22-2643)	REL	SA	--	--	--	--	C	C	C	--	C	Yes	B	No	Yes	Notes 27, 28, and 39
		56	No	Residual Heat Removal Minimum Flow	E1150F007A (V8-2133)	GAT	MO	RM	M	--	Z	O	O	C	AIS	C	Yes	B	No	Yes	Notes 7, 12, and 39
		56	No	Residual Heat Removal Test Line	E1150F024A (V8-2135)	GLB	MO	A	RM	A,K	--	C	C	C	AIS	C	Yes	B	Yes	Yes	Notes 2, 10, and 26
		56	No	Residual Heat Removal Suppression Pool Spray	E1150F028A (V8-2155)	GAT	MO	A	RM	A,K	--	C	C	C	AIS	C	Yes	B	Yes	Yes	--
					E1150F027A (V8-2157)	GLB	MO	A	RM	A,K	--	C	C	C	AIS	C	Yes	B	Yes	Yes	Note 10
	6I721-2400-10	56	No	Liquid Sample Return	P34F407 (V13-7368)	GLB	SO	RM	--	--	--	C	C	C	C	C	No	B	Yes	Yes	Notes 10 and 26
					P34F409 (V13-7378)	GLB	SO	RM	--	--	--	C	C	C	C	C	No	B	Yes	Yes	Notes 10 and 26 Flanges Type B Tested

TABLE 6.2-2 SUMMARY OF PRIMARY CONTAINMENT PENETRATIONS AND ASSOCIATED ISOLATION VALVES

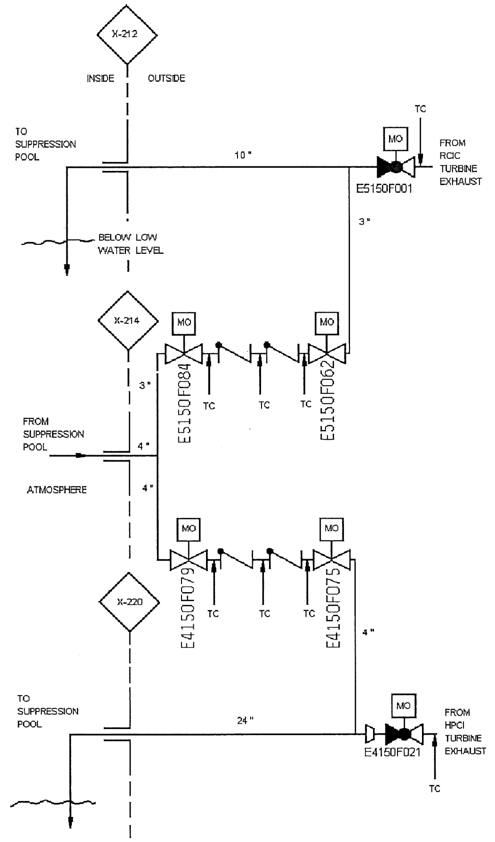
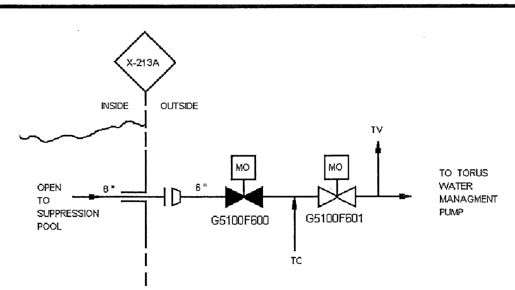
PENETRATION DATA				ISOLATION VALVE DATA																	
												Valve Position									
Penetration Detail	P&ID Number	Design Criteria	Bypass Leakage Path	System Title	Valve Number	Valve Type	Actuator Type	Primary Actuation Mode	Secondary Actuation Mode	Containment Isolation Signal(s)	Accident Isolation Signal(s)	Normal	Shutdown	Post-LOCA (Accident)	Power Failure	ILRT	Engineered Safety Feature	Quality Group	Type C Test	Leak Detection	Remarks
	6M721-2044	56	No	Reactor Core Isolation Cooling Turbine Exhaust Line	E5150F001 (V11-2002)	SCK	MO	RF	RM	--	--	O	O	O	AIS	C	R	B	No	Yes	Notes 6,12 and 39
				Reactor Core Isolation Cooling Vacuum Breaker Line	E5150F062 (V11-2020)	GAT	MO	A	RM	K&Y(4)	--	O	O	O	AIS	C	R	B	Yes	No	Note 6
					E5150F084 (V11-2026)	GAT	MO	A	RM	K&Y(4)	--	O	O	O	AIS	C	R	B	Yes	No	Notes 4 and 6
	6M721-2035			High-Pressure Coolant Injection Vacuum Breaker Line	E4150F075 (V11-2013)	GAT	MO	A	RM	K&X4)	--	O	O	O	AIS	C	Yes	B	Yes	No	Note 7
					E4150F079 (V11-2019)	GAT	MO	A	RM	K&X(4)	--	O	O	O	AIS	C	Yes	B	Yes	No	Notes 4 and 7
				High-Pressure Coolant Injection Turbine Exhaust Line	E4150F021 (V11-2006)	SCK	MO	RF	RM	--	--	O	O	O	AIS	C	Yes	B	No	Yes	Notes 7, 12 and 39
	6M721-4100	56	No	Torus Water Management Suction	G5100F601 (V8-3834)	GAT	MO	A	RM	B,K	M	O	C	C	AIS	C	No	B	Yes	No	Notes 10 and 26
					G5100F600 (V8-3832)	GAT	MO	A	RM	B,K	M	C	C	C	AIS	C	No	B	Yes	No	Notes 4, 10, and 26

TABLE 6.2-2 SUMMARY OF PRIMARY CONTAINMENT PENETRATIONS AND ASSOCIATED ISOLATION VALVES

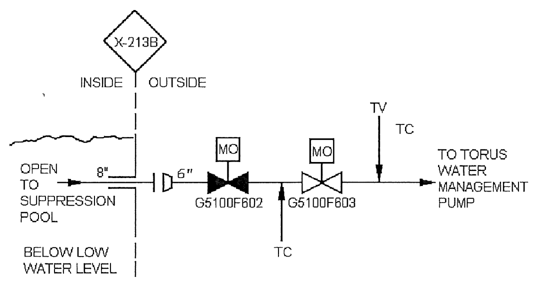
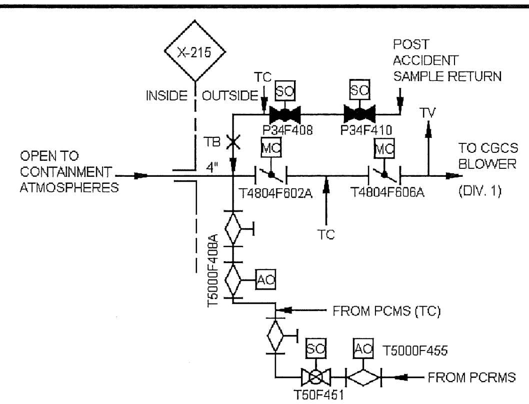
PENETRATION DATA				ISOLATION VALVE DATA																	
												Valve Position									
Penetration Detail	P&ID Number	Design Criteria	Bypass Leakage Path	System Title	Valve Number	Valve Type	Actuator Type	Primary Actuation Mode	Secondary Actuation Mode	Containment Isolation Signal(s)	Accident Isolation Signal(s)	Normal	Shutdown	Post-LOCA (Accident)	Power Failure	ILRT	Engineered Safety Feature	Quality Group	Type C Test	Leak Detection	Remarks
	6M721-4100	56	No	Torus Water Management Suction	G5100F602 (V8-3831)	GAT	MO	A	RM	B, K	M	C	C	C	AIS	C	No	B	Yes	No	Notes 4, 10, and 26
					G5100F603 (V8-3833)	GAT	MO	A	RM	B, K	M	O	C	C	AIS	C	No	B	Yes	No	Notes 10 and 26
X-214	--	--	--	Vacuum Breaker Line, High-Pressure Coolant Injection/ Reactor Core Isolation Cooling	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	See Penetration Detail X-212
	6M721-2087	56	No	Combustible Gas Control System Suction and Gaseous Sample Returns	T4804F602A (V4-2142)	BFY	M	M	--	--	--	LC	LC	LC	LC	LC	No	B	Yes	No	Notes 9, 10, 11, and 45
	6I721-2679-1	56	No		T5000F408A (V5-2158)	BAL	AO	RM	M	--	--	O	O	O	C	O	No	B	Yes	Yes	Notes 12 and 13
	6M721-2087	56	No		T4804F606A (V4-2156)	BFY	M	M	--	--	--	LC	LC	LC	LC	LC	No	B	Yes	No	Notes 9 and 45
	6I721-2400-10	56	Yes		P34F408 (V13-7369)	GLB	SO	RM	--	--	--	C	C	C	C	C	No	B	Yes	Yes	Note 10
		56	Yes		P34F410 (V13-7379)	GLB	SO	RM	--	--	--	C	C	C	C	C	No	B	Yes	Yes	Note 10
	6I721-2679-1	56	No		T50F451 (V5-3084)	GLB	SO	A	--	B, K	B, K	O	O	C	C	C	No	B	Yes	Yes	Note 10
	6I721-2679-1	56	No		T5000F455 (V5-2239)	BAL	AO	A	M	B, K	B, K	O	O	C	C	C	No	B	Yes	Yes	Note 10
X-216A	--	--	--	Spare	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type A Test
X-216B	--	--	--	Spare	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type A Test
X-217	--	--	--	Spare	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type A Test

TABLE 6.2-2 SUMMARY OF PRIMARY CONTAINMENT PENETRATIONS AND ASSOCIATED ISOLATION VALVES

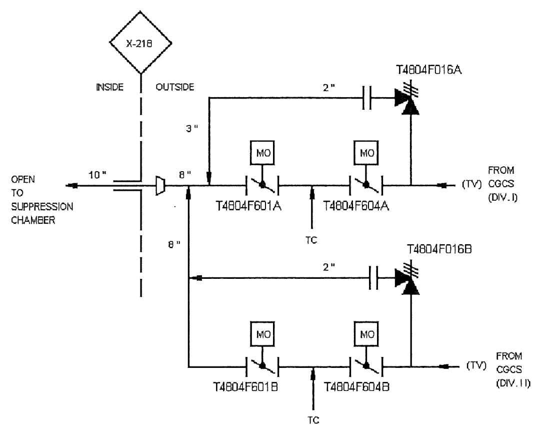
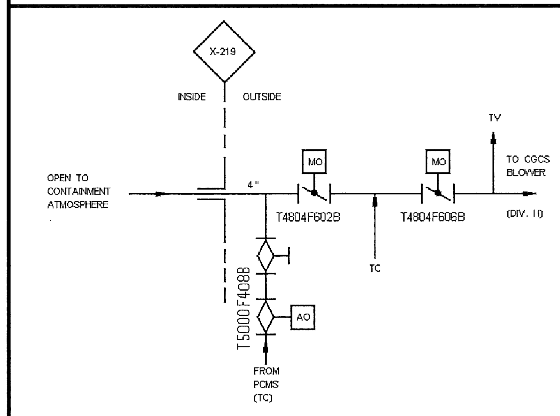
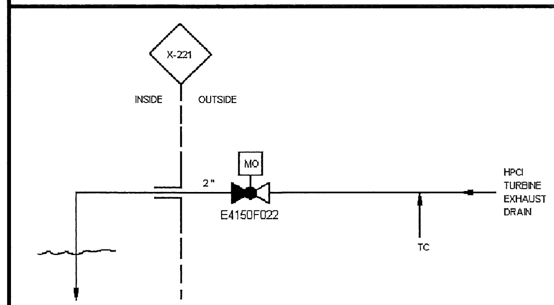
PENETRATION DATA				ISOLATION VALVE DATA																	
												Valve Position									
Penetration Detail	P&ID Number	Design Criteria	Bypass Leakage Path	System Title	Valve Number	Valve Type	Actuator Type	Primary Actuation Mode	Secondary Actuation Mode	Containment Isolation Signal(s)	Accident Isolation Signal(s)	Normal	Shutdown	Post-LOCA (Accident)	Power Failure	ILRT	Engineered Safety Feature	Quality Group	Type C Test	Leak Detection	Remarks
	6M721-2087	56	No	Combustible Gas Control System Return	T4804F601A (V4-2140)	BFY	M	M	--	--	--	LC	LC	LC	LC	LC	No	B	Yes	No	Notes 9, 10, 11, and 45
					T4804F604A (V4-2148)	BFY	M	M	--	--	--	LC	LC	LC	LC	LC	No	B	Yes	No	Notes 9 and 45
					T4804F016A (V22-2122)	REL	SA	--	--	--	--	C	C	C	--	C	Yes	B	Yes	Yes	Notes 27 and 28
					T4804F601B (V4-2139)	BFY	M	M	--	--	--	LC	LC	LC	LC	LC	No	B	Yes	No	Notes 9, 10, 11, and 45
					T4804F604B (V4-2149)	BFY	M	M	--	--	--	LC	LC	LC	LC	LC	No	B	Yes	No	Notes 9 and 45
					T4804F016B (V22-2121)	REL	SA	--	--	--	--	C	C	C	--	C	Yes	B	Yes	Yes	Notes 27 and 28
	6M721-2087	56	No	Combustible Gas Control System Suction	T4804F602B (V4-2141)	BFY	M	M	--	--	--	LC	LC	LC	LC	LC	No	B	Yes	No	Notes 9, 10, 11, and 45
	6I721-2679-1	56	No		T5000F408B (V5-2166)	BAL	AO	RM	M	--	--	O	O	O	C	O	No	B	Yes	Yes	Notes 12 and 13
	6M721-2087	56	No		T4804F606B (V4-2155)	BFY	M	M	--	--	--	LC	LC	LC	LC	LC	No	B	Yes	No	Notes 9 and 45
X-220	--	--	--	High-Pressure Coolant Injection Turbine Exhaust	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	See Penetration Detail X-212
	6M721-2035	56	No	High-Pressure Coolant Injection Turbine Exhaust Drain	E4150F022 (V11-2008)	SCK	MO	RF	RM	--	--	O	O	O	AIS	C	Yes	B	No	Yes	Notes 7, 12 and 39

TABLE 6.2-2 SUMMARY OF PRIMARY CONTAINMENT PENETRATIONS AND ASSOCIATED ISOLATION VALVES

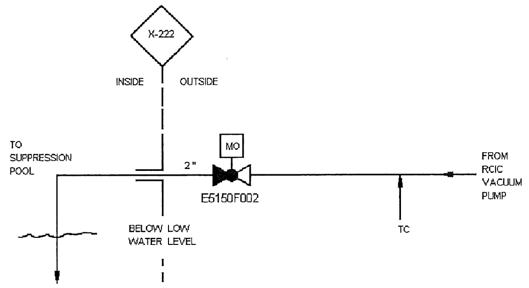
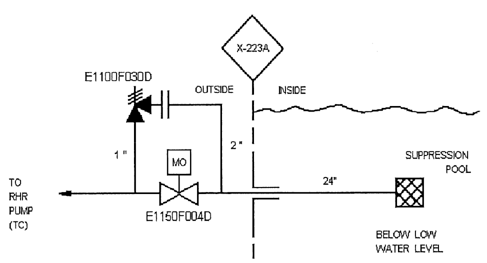
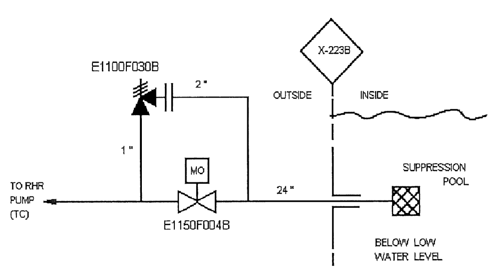
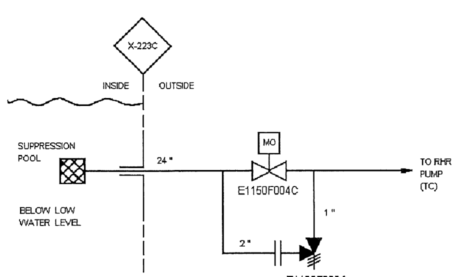
PENETRATION DATA				ISOLATION VALVE DATA																	
												Valve Position									
Penetration Detail	P&ID Number	Design Criteria	Bypass Leakage Path	System Title	Valve Number	Valve Type	Actuator Type	Primary Actuation Mode	Secondary Actuation Mode	Containment Isolation Signal(s)	Accident Isolation Signal(s)	Normal	Shutdown	Post-LOCA (Accident)	Power Failure	ILRT	Engineered Safety Feature	Quality Group	Type C Test	Leak Detection	Remarks
	6M721-2044	56	No	Reactor Core Isolation Cooling Vacuum Pump Discharge	E5150F002 (V8-2235)	SCK	MO	RF	RM	--	--	O	O	O	AIS	C	R	B	No	Yes	Notes 6, 12 and 39
	6M721-2083	56	No	Residual Heat Removal Pump Suction	E1150F004D (V8-2100)	GAT	MO	RM	M	--	--	O	O	O	AIS	O	Yes	B	No	Yes	Notes 7, 12, and 39
				Residual Heat Removal Pump Suction Header Thermal Relief	E1100F030D (V22-2035)	REL	SA	--	--	--	--	C	C	C	--	C	Yes	B	No	Yes	Notes 27, 28, and 39
	6M721-2083	56	No	Residual Heat Removal Pump Suction	E1150F004B (V8-2102)	GAT	MO	RM	M	--	--	O	O	O	AIS	O	Yes	B	No	Yes	Notes 7, 12, and 39
				Residual Heat Removal Pump Suction Header Thermal Relief	E1100F030B (V22-2037)	REL	SA	--	--	--	--	C	C	C	--	C	Yes	B	No	Yes	Notes 27, 28, and 39
	6M721-2084	56	No	Residual Heat Removal Pump Suction	E1150F004C (V8-2101)	GAT	MO	RM	M	--	--	O	O	O	AIS	O	Yes	B	No	Yes	Notes 7, 12, and 39
				Residual Heat Removal Pump Suction Header Thermal Relief	E1100F030C (V22-2036)	REL	SA	--	--	--	--	C	C	C	--	C	Yes	B	No	Yes	Notes 27, 28, and 39

TABLE 6.2-2 SUMMARY OF PRIMARY CONTAINMENT PENETRATIONS AND ASSOCIATED ISOLATION VALVES

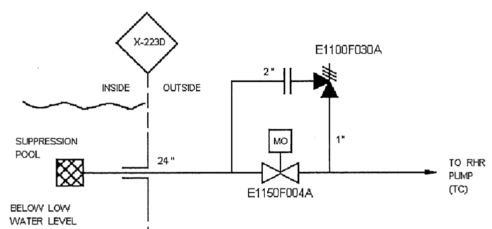
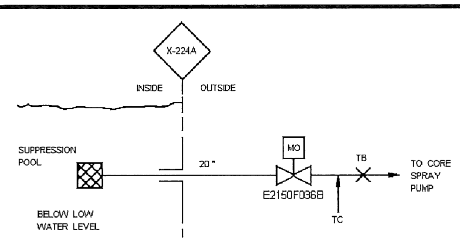
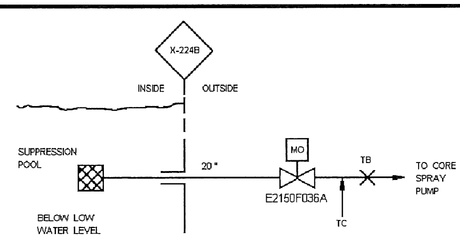
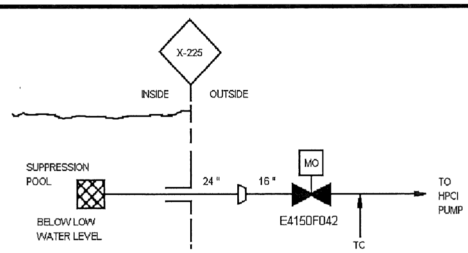
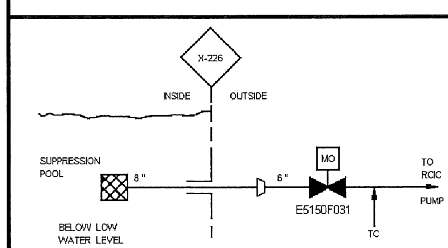
PENETRATION DATA				ISOLATION VALVE DATA																	
												Valve Position									
Penetration Detail	P&ID Number	Design Criteria	Bypass Leakage Path	System Title	Valve Number	Valve Type	Actuator Type	Primary Actuation Mode	Secondary Actuation Mode	Containment Isolation Signal(s)	Accident Isolation Signal(s)	Normal	Shutdown	Post-LOCA (Accident)	Power Failure	ILRT	Engineered Safety Feature	Quality Group	Type C Test	Leak Detection	Remarks
	6M721-2084	56	No	Residual Heat Removal Pump Suction	E1150F004A (V8-2099)	GAT	MO	RM	M	--	--	O	O	O	AIS	O	Yes	B	No	Yes	Notes 7, 12, and 39
				Residual Heat Removal Pump Suction Header Thermal Relief	E1100F030A (V22-2034)	REL	SA	--	--	--	--	C	C	C	--	C	Yes	B	No	Yes	Notes 27, 28, and 39
	6M721-2034	56	No	Core Spray Pump Suction	E2150F036B (V8-2008)	GAT	MO	RM	M	--	--	O	O	O	AIS	O	Yes	B	No	Yes	Notes 7, 12, and 39
	6M721-2034	56	No	Core Spray Pump Suction	E2150F036A (V8-2007)	GAT	MO	RM	M	--	--	O	O	O	AIS	O	Yes	B	No	Yes	Notes 7, 12, and 39
	6M721-2035	56	No	High-Pressure Coolant Injection Pump Suction	E4150F042 (V8-2202)	GAT	MO	RM	M	--	X	C	C	O	AIS	C	Yes	B	No	Yes	Notes 7, 12, 31, and 39
	6M721-2044	56	No	Reactor Core Isolation Cooling Pump Suction	E5150F031 (V8-2225)	GAT	MO	RM	M	--	--	C	C	O	AIS	C	R	B	No	Yes	Notes 6, 12, and 39

TABLE 6.2-2 SUMMARY OF PRIMARY CONTAINMENT PENETRATIONS AND ASSOCIATED ISOLATION VALVES

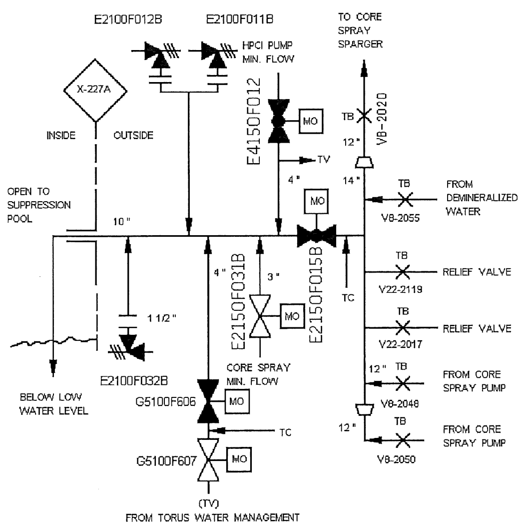
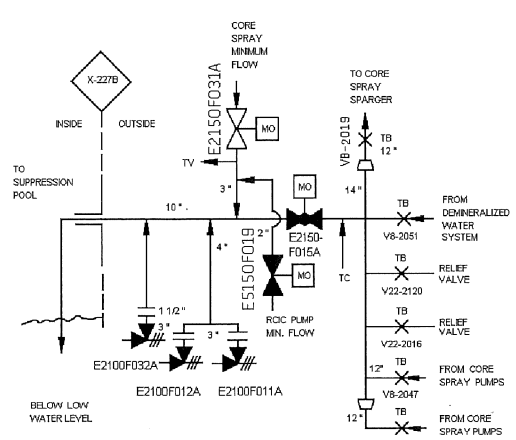
PENETRATION DATA				ISOLATION VALVE DATA																	
												Valve Position									
Penetration Detail	P&ID Number	Design Criteria	Bypass Leakage Path	System Title	Valve Number	Valve Type	Actuator Type	Primary Actuation Mode	Secondary Actuation Mode	Containment Isolation Signal(s)	Accident Isolation Signal(s)	Normal	Shutdown	Post-LOCA (Accident)	Power Failure	ILRT	Engineered Safety Feature	Quality Group	Type C Test	Leak Detection	Remarks
	6M721-2034	56	No	Core Spray Pump Suction Thermal Relief	E2100F032B (V22-2004)	REL	SA	--	--	--	--	C	C	C	--	C	Yes	B	No	Yes	Notes 12, 27, 28, and 39
		56	No	Core Spray Pump Discharge Header Relief	E2100F012B (V22-2017)	REL	SA	--	--	--	--	C	C	C	--	C	Yes	B	No	Yes	Notes 12, 26, 27, 28, and 39
					E2100F011B (V22-2119)	REL	SA	--	--	--	--	C	C	C	--	C	Yes	B	No	Yes	Notes 12, 27, 28, and 39
		56	No	Core Spray Pump Minimum Flow	E2150F031B (V8-2032)	GAT	MO	RM	M	--	Z	O	O	C	AIS	C	Yes	B	No	Yes	Notes 7, 12, and 39
		56	No	Core Spray Pump Test Line	E2150F015B (V8-2034)	GLB	MO	A	M	A,K	--	C	C	C	AIS	C	Yes	B	No	Yes	Notes 12 and 39
	6M721-4100	56	No	Torus Water Managment System	G5100F606 (V8-4679)	GAT	MO	A	RM	B,K	M	C	C	C	AIS	C	No	B	Yes	No	Notes 4 and 26
					G5100F607 (V8-4682)	GAT	MO	A	RM	B,K	M	O	C	C	AIS	C	No	B	Yes	No	Note 26
	6M721-2035	56	No	High-Pressure Coolant Injection Minimum Flow	E4150F012 (V8-2196)	GLB	MO	RM	M	--	Z	C	C	C	AIS	C	Yes	B	No	Yes	Notes 7, 12, and 39
	6M721-2034	56	No	Core Spray Pump Suction Thermal Relief	E2100F032A (V22-2019)	REL	SA	--	--	--	--	C	C	C	--	C	Yes	B	No	Yes	Notes 12, 27, 28, and 39
		56	No	Core Spray Pump Discharge Header Relief	E2100F012A (V22-2016)	REL	SA	--	--	--	--	C	C	C	--	C	Yes	B	No	Yes	Notes 12, 27, 28, and 39
					E2100F011A (V22-2120)	REL	SA	--	--	--	--	C	C	C	--	C	Yes	B	No	Yes	Notes 12, 27, 28, and 39
		56	No	Core Spray Pump Test Line	E2150F015A (V8-2033)	GLB	MO	A	RM	A,K	--	C	C	C	AIS	C	Yes	B	No	Yes	Notes 12 and 39
	6M721-2044	56	No	Reactor Core Isolation Cooling Minimum Flow	E5150F019	GAT	MO	RM	M	--	Z	C	C	C	AIS	C	R	B	No	Yes	Notes 6, 12, and 39
	6M721-2034	56	No	Core Spray Minimum Flow	E2150F031A (V8-4683)	GAT	MO	RM	M	--	Z	O	O	C	AIS	C	Yes	B	No	Yes	Notes 7, 12, and 39
X-228A	--	--	--	Torus - Low Voltage Switching	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type B Test
X-228B	--	--	--	Torus - Low Voltage Switching	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type B Test
X-228C	--	--	--	Torus - Low Voltage Switching	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type B Test

TABLE 6.2-2 SUMMARY OF PRIMARY CONTAINMENT PENETRATIONS AND ASSOCIATED ISOLATION VALVES

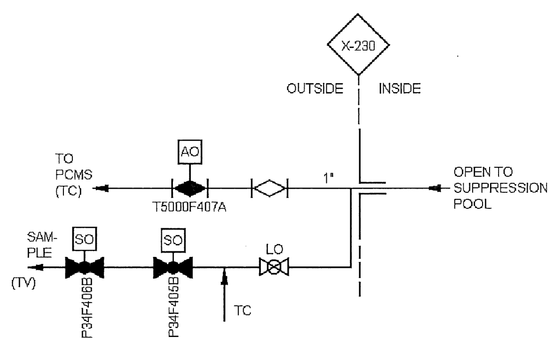
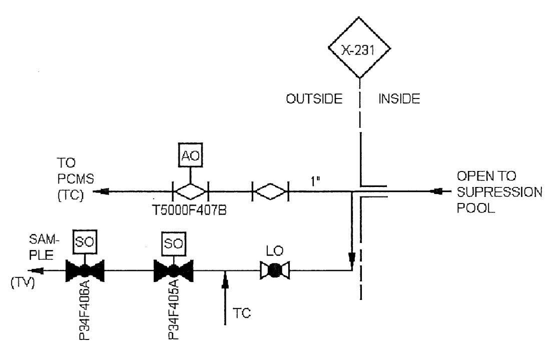
PENETRATION DATA				ISOLATION VALVE DATA																	
												Valve Position									
Penetration Detail	P&ID Number	Design Criteria	Bypass Leakage Path	System Title	Valve Number	Valve Type	Actuator Type	Primary Actuation Mode	Secondary Actuation Mode	Containment Isolation Signal(s)	Accident Isolation Signal(s)	Normal	Shutdown	Post-LOCA (Accident)	Power Failure	ILRT	Engineered Safety Feature	Quality Group	Type C Test	Leak Detection	Remarks
X-228D	--	--	--	Torus - Low Voltage Switching	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type B Test
X-229	--	--	--	Spare	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Type A Test
	6I721-2679-1	56	No	Primary Containment Monitoring System Suction Division I	T5000F407A (V5-2157)	BAL	AO	RM	M	--	--	C	C	C	C	O	No	B	Yes	Yes	Notes 12, 13 and 31 (See Penetration X-48)
				and																	
	6I721-2400-10	56	Yes	Suppression Pool Postaccident Atmosphere Sample Suction	P34F405B (V13-7367)	GLB	SO	RM	--	--	--	C	C	C	C	C	No	B	Yes	Yes	--
					P34F406B (V13-7377)	GLB	SO	RM	--	--	--	C	C	C	C	C	No	B	Yes	Yes	--
	6I721-2679-1	56	No	Primary Containment Monitoring System Suction Division II	T5000F407B (V5-2165)	BAL	AO	RM	M	--	--	O	C	C	C	O	No	B	Yes	Yes	Notes 12 and 13
				and																	
	6I721-2400-10	56	Yes	Suppression Pool Postaccident Atmosphere Sample Suction	P34F405A (V13-7366)	GLB	SO	RM	--	--	--	C	C	C	C	C	No	B	Yes	Yes	--
					P34F406A (V13-7376)	GLB	SO	RM	--	--	--	C	C	C	C	C	No	B	Yes	Yes	--

TABLE 6.2-2 SUMMARY OF PRIMARY CONTAINMENT PENETRATIONS AND ASSOCIATED ISOLATION VALVES

CODES AND SYMBOLS

Penetration Details

Standard mechanical symbols are employed to represent piping details. Each penetration detail provides the following information:

Symbol	Description
1. ◇	- Penetration details in numerical order
2. (TC)	- Test connection for Type C testing
3. (TV)	- Test vent for Type C testing
4. TB	- Test Barrier

Valve Type

The following codes are used to identify valve type:
CHK - Check
GAT - Gate
GLB - Globe
BFY - Butterfly
REG - Regulating
BAL - Ball
REL - Relief
EFC - Excess Flow Check
SCK - Stop Check
BCK - Ball Check
SHR - Shear

Actuator Type

The following codes are used to identify valve actuator type:

AO - Air Operator
SO - Solenoid Operator
MO - Motor Operator
M - Manual
SA - Self Actuated
EX - Explosive

Valve Position

The following codes are used to identify different valve positions:

O - Open
C - Closed
AIS - As Is
LC - Locked Closed
LO - Locked Open

Miscellaneous

A dash (-) indicates that technical information is not applicable to this column

This column references the appropriate General Design Criteria of 10 CFR 50, Appendix A (or other defined basis) with which the penetration is in compliance.

Bypass Leakage

Bypass leakage paths are identified in this table by a "Yes or a "No". Bypass leakage paths are further discussed in Section 6.2.1.2.2.3.

Primary/Secondary Actuation Modes

These columns indicate the nature of the containment isolation signal as follows:
A - Automatic
RM - Remote Manual
RF - Reverse Flow
M - Manual
HF - High Flow

Engineered Safety Feature

Valves in Engineered Safety Feature systems are identified in this column by a "yes" entry. An "R" entry identifies a valve in an Engineered Safety Feature-related system. Such Systems are not required to function following the design basis loss-of-coolant accident. However, if the system is available, it can be used to accomplish a function similar to an Engineered Safety Feature system.

Containment/Accident Isolation Signals

The following codes are used to abbreviate isolation signals:

Signal	Description
A	Reactor Vessel Low Level 1
B	Reactor Vessel Low Level 2
C	Reactor Vessel Low Level 3
D	Main Steam Line High Radiation
E	Main Steam Line High Flow
F	Main Steam Line Tunnel High Temperature
G	Main Steam Line Low Pressure
H	Torus Pressure ≥ Secondary Containment Pressure
J	Low Condenser Vacuum
K	High Drywell Pressure
L	High Reactor Vessel Pressure
M	High-High Sump Level Torus Area or High-High Drywell Floor Drain Sump Level
N	High Sump Level or High Sump Temperatures
P	Turbine Building High Temperatures
R	Reactor Building Exhaust Radiation High
W	RWCU System Line 1) SLCS Initiation (Outboard Valve Only) 2) High RWCU Differential Flow 3) High RWCU Area Temperature 4) High RWCU Area Ventilation Differential Temperature 5) Reactor Vessel Low Water Level 2
X	HPCI System Steam Lines 1) HPCI Space High Temp. 2) High Steam Flow 3) High Turbine Exhaust Pressure 4) HPCI Steam Line Low Pressure
Y	RCIC System Steam Lines 1) RCIC Space High Temp 2) High Turbine Exhaust Pressure 3) High Steam Flow 4) RCIC Steam Line Low Pressure
Z	Closes Through Electrical Interlocks With Other System Valves of Pump Motors

NOTES

Note	Description
1.	This piping consists of the eight vent pipes that connect the drywell and pressure suppression chamber. As part of the primary containment structure, they are Type A tested.
2.	Globe valve tested in the reverse direction. Results obtained in this test configuration are conservative since test pressure tends to unseat the valve disk.
3.	These valves will be tested at a differential pressure of 25 psi with the reactor at atmospheric pressure (i.e., 25 psig).
4.	Gate valve tested through the bonnet. This valve has a bonnet tap through which the bonnet area is pressurized. Leakage is measured through both seating surfaces along with leakage through the bonnet. Compared with testing in the accident direction, the bonnet test leakage is conservative.
5.	Air-operated, spring-to-close, positive-acting check valve. Can be closed by remote manual operation from the control room when system isolation is required.
6.	Remote manual containment isolation valve in an ESF-related system. Provisions are made to detect leakage from this line outside the containment. See Table 5.2-11.
7.	Remote manual containment isolation valve in an ESF system. Provisions are made to detect leakage from this line outside the containment. See Table 5.2-11.
8.	Valve isolates when reactor pressure exceeds 75 psig.
9.	Manual or remote manual valve that is locked closed and remains closed after a LOCA.
10.	Two containment isolation valves located outside the containment. Due to the design of both the containment and the system, it is not practical to locate one of the two valves inside the containment. Both valves are located outside the containment as close as practical to the containment wall.
11.	Butterfly valve tested in the reverse direction. Reverse flow tests are designed to provide equivalent or conservative results compared with testing in the accident direction. In cases where stem leakage is not measured by the leakage out of the test volume, stem leakage is determined by testing through the stem vent and this leakage is added to the test volume leakage. Additional tests on purge system butterfly valves are set forth in the Technical Specifications.
12.	Single isolation valve and closed system outside the containment. This line contains a single isolation valve based on a. The line is in an ESF or ESF-related system b. System reliability is greater with one isolation valve c. The system is a closed system outside the containment d. A single active failure can be accommodated with one isolation valve in the line. The specific closed system requirements met by this system outside the containment include missile protection, Category I, and Quality Group B design standards. For instrumentation piping, the systems are designed and installed as Quality Group B, up to and including the isolation valves. The balance of the instrument piping is designed to meet Quality Group B design criteria. These design criteria include stress analysis with consideration given to dead-weight, thermal, and seismic conditions. The systems are seismically supported. Nuclear grade material is used throughout the fabrication of the piping system. The design temperature and pressure ratings of the systems are greater than those of the containment.
13.	Ball valve tested in the reverse direction. Results obtained in this configuration are equivalent to testing in the accident direction, since valves of this type have the same sealing characteristics in either direction.
14.	Jet pump flow instrumentation lines are provided with manual globe valves and excess-flow check valves outside the containment. Also, flow is restricted to a 1/4-in. orifice at the nozzle. Therefore, these instrumentation lines are designed in accordance with the recommendations of Regulatory Guide 1.11 (Safety Guide 11). All instrument line penetrations will be Type A tested.
15.	Instrumentation penetration. Standard instrumentation penetrations are provided with six instrument tubes. In this table, only those tubes that are utilized by instrument lines are addressed. All other instrument tubes associated with the penetration are spares and are Type A tested.
16.	Instrument lines of this type are provided with a flow-restricting orifice inside the containment and a manual globe valve and excess-flow check valve outside the containment in accordance with the recommendations of Regulatory Guide 1.11 (Safety Guide 11). All instrument line penetrations will be Type A tested.
17.	The TIP system lines do not communicate freely with the containment atmosphere or the reactor coolant. General Design Criteria 55 and 56 are not directly applicable to this specific class of lines. The basis to which these lines are designed is more closely described by GDC 54, which states in effect that the isolation capability of a system should be commensurate with the safety importance of that isolation. Furthermore, even though the failure of the TIP system lines presents no safety consideration, the TIP system guide tubes have redundant isolation capabilities. The safety features have been reviewed by the NRC for BWR/4 (Duane Arnold), BWR/5 (Nine Mile Point) and BWR/6 (GESSAR), and it was concluded that the design of the containment isolation system meets the objectives and intent of the GDC. The TIP guide tube assembly and the portion of the tubing between the guide tube assembly and the containment flange are considered to be instruments and as a result are not classified as ASME components but are purchased and installed as safety-related assemblies. A valve system is provided with a valve on each guide tube entering the primary containment. These valves are closed except when the TIP system is in operation (open an average of 15 hr/month). A ball valve and a cable-shearing valve are mounted in the guide tubing just outside the primary containment. They prevent the loss of containment integrity. The ball valve position is indicated in the control room. The shear valve is used only if containment isolation is required when the TIP is beyond the ball valve and when power to the TIP system fails. The shear valve, which is controlled by a manually operated keylock switch, can cut the cable and close off the guide tube. The shear valves are actuated by detonation squibs. The continuity of the squib circuits is monitored by indicator lights in the main control room. Identical-design shear valves are shop tested by statistical

TABLE 6.2-2 SUMMARY OF PRIMARY CONTAINMENT PENETRATIONS AND ASSOCIATED ISOLATION VALVES

Note	Description
	sampling methods to ensure operability and leaktightness. The Technical Specification testing requirements for the TIP shear and ball valves are a. Verifying the continuity of the explosive charges at least every 31 days b. Initiating one of the explosive charges once every fuel cycle. The replacement charge shall be from the same manufactured batch as the one fired or from another batch that has been certified by having one of -that batch successfully fired c. Replacing all charges according to the manufacturer's recommended lifetime for the charges d. Performing Type C tests on the ball valves in accordance with a performance based leak testing program in Technical Specification 5.5.12.
18.	A plant modification, EDP-4940, changed the routing of the nitrogen purge supply line to the TIP system. The nitrogen source is taken from a primary containment pneumatic system line inside the drywell. Penetration X-35G thus becomes a spare, the pipe penetrating the drywell is capped and welded, and GDC 56 no longer applies.
19.	The control rod drive (CRD) insert and withdrawal line. Each of the 185 CRD withdrawal lines is separated from the RPV by a redundant seal design in the CRD units. Each of the 185 CRD insert lines has a CRDM flange ball check valve that isolates the line from the RPV following a scram. The redundant seal system, the CRDM flange ball check valve, and a manual isolation valve provide adequate isolation in the event of a line break in the hydraulic control unit (HCU) or the scram discharge volume (SDV). During a scram, the 185 outlet scram valves open and the four SDV vent and drain valves close. If the scram system is not reset, thus closing the scram inlet and outlet valves, CRD seal leakage could slowly pressurize the SDV to the RPV pressure. Therefore, the SDV vent and drain valves along with 185 drive and 185 cooling water ball check valves will be Type A tested. Leakage from the CRD system into the reactor building is detected for the full spectrum of leakage rates. Small leaks will be detected by observation during daily inspection rounds of the control unit areas by operators. Large leaks will be detected by duty timers on the reactor building floor drain sump pumps. A large leak of reactor coolant from any insert line will be automatically isolated by the ball check valve in the CRD housing. Leaks of CRD supply water will be indicated by increased flow as continuously recorded in the control room. The CRD directional control valves are normally closed and are automatically closed upon a reactor scram signal. Excessive leakages through the scram valves will be detected by duty timers on the sump pumps.
20.	The residual heat removal (RHR) system discharge line to the containment spray header receives an automatic containment isolation signal. The operator may, however manually override the isolation signal as needed to reduce containment temperature and pressure.
21.	Due to system configuration, the test pressure is not in the same direction as the pressure existing when the valve is required to perform its containment isolation function. The valve will be tested in the correct direction during the Type A tests.
22.	The standby liquid control system (SLCS) has been designed to reflect the importance of the functions it may perform. The probability of reliable and timely actuation of this system is enhanced by inclusion of fewer valves and simplicity of design. The use of a check valve outside the containment is consistent with these system design requirements.
23.	This is a penetration of the vent pipe inside the torus and thus is not a bona fide containment penetration. It is included in this table for completeness only.
24.	This butterfly valve is normally closed and opens automatically to prevent formation of negative pressure in the torus. This butterfly valve closes automatically upon increasing torus pressure and remains closed during containment high-pressure conditions. Upon loss of power or degraded voltage, the butterfly valve will open but closes automatically once power is restored or voltage recovers.
25.	Secondary containment to torus vacuum breaker. This vacuum breaker opens automatically to prevent formation of a negative pressure in the torus. This line is essential to ensure primary containment structural integrity. The probability of system operation is enhanced by using fewer valves and by the simplicity of design. The use of a check valve outside containment is consistent with these system design requirements.
26.	The flow path associated with this penetration inside containment terminated below the low water level in the suppression pool. A water seal is assured during normal plant operation and for more than 30 days following an accident requiring containment isolation. It is not credible that these isolation valves will be exposed to the containment atmosphere at any time following the accident. These penetration containment isolation valves will be Type C seat leak tested using water or air as the test medium. In some cases, due to system configuration, the Type C test pressure will not be in the same direction as the pressure existing when the valve is required to perform the containment isolation function. The valves will be a part of the periodic Type A tests where the test pressure is applied in the correct direction.
27.	Relief valve used as a containment isolation valve. The construction and orientation of this valve is such that increased containment pressure acts in conjunction with spring pressure to increase the seating force of the valve and tends to reduce leakage. Thus the relief valve setpoint has no bearing on containment isolation.
28.	Flange on relief valve discharge to be Type B tested.
29.	Due to system configuration, the test pressure on the relief valve is not in the same direction as the pressure existing when the relief valve is required to perform its containment isolation function. The test pressure is applied under the relief valve seat. This is conservative since it tends to unseat the relief valve.
30.	Not used.
31.	These valves do not close on the containment isolation signals, but automatically close on accident isolation signal as identified in Table 6.2-2.
32.	These valves close on the containment isolation signals but are also provided with a manual override to these signals to reopen the valves. This is done to provide divisional control air/nitrogen for the controls of pneumatic equipment/instruments inside the drywell.
33.	Flanged portion of the residual heat removal head spray piping, between reactor pressure vessel and the refueling floor bulkhead penetration, is permanently removed. Remaining line within the drywell is blind flanged.
34.	Valve closes on a high drywell pressure signal to isolate the drywell heat load.
35.	SLCS initiation signal is not a containment isolation signal. This signal prevents removal of liquid poison in the event of standby liquid control system actuation.
36.	Penetrations X-13A and X-13B will have a 30-day water seal during and following a postulated LOCA. Therefore valves E1100-F050A, F610A, F050B, and F610B are not considered containment isolation valves and therefore are not subject to Type C testing (see TS Amendment 98).
37.	30-day water seal for penetrations X-13A and X-13B (during and following a postulated LOCA) requires external water leakage, through valves E1150-F015A and F015B, to be less than 5 ml/min. at 1.1 Pa, i.e., 62.2 psig. As these valves will be subjected to a more conservative PIV test that demonstrates external leakage less than 5 ml/min. at a pressure of 1045 psig, TS Amendment 98 exempts these valves from Type C air test.
38.	Flexible wedge gate valve tested in the accident direction and through a body\bonnet tap from a single test connection. Leakage is measured past the outboard seating surface.
39.	Single isolation valves on a closed system both inside and outside of containment. The flow path associated with this penetration inside containment terminates below the low water level in the suppression pool. A water seal is assured during normal plant operation and for more than 30 days following an accident requiring containment isolation. It is not credible that these isolation valves will be exposed to the containment atmosphere at any time following the accident. Also many of the valves are required to be open post-accident to fulfill their safety function. Type C LLRT testing is not required when the valve is located on a closed system and on a line which terminates below the minimum water level of the suppression chamber.
40.	Valve is interlocked to inhibit opening on low reactor water level signal (Level 1) to ensure all RHR flow is directed to the reactor vessel.
41.	A plant modification, EDP 33297, modified the service air piping to the drywell. The pipe penetrating the drywell is plugged and welded and GDC 56 no longer applies.
42.	A plant modification, EDP 35267, plugged the Main Steam Isolation Valve Leak Control System at the Main Steam Line interface. Therefore, GDC 55 no longer applies.
43.	In case of a loss of power event, T5000F420B can be reopened using a DC solenoid valve with a dedicated nitrogen supply system.
44.	In case of a Beyond Design Basis External Event, T4600F400 and T4600F401 can be reopened using a 3-way piloted shuttle valve with a dedicated nitrogen supply system.
45.	The Combustible Gas Control System (CGCS) has been retired in place with its electrical circuits de-energized and fluid process piping isolated from primary containment with redundant isolation valves. These valves are locked closed and can only be operated locally.

TABLE 6.2-3 ELECTRICAL PENETRATION SCHEDULE

Penetration Number	Penetration Type
T2301-X-100A	Neutron monitor
T2301-X-100B	“
T2301-X-100F	“
T2301-X-100G	“
T2301-X-101A	Medium voltage power (5kV)
	Recirculating pump power
T2301-X-101B	“
T2301-X-101C	“
T2301-X-101D	“
T2301-X-101E	“
T2301-X-101F	“
T2301-X-102A	Low-voltage switching/RPS
T2301-X-102B	“
T2301-X-102C	“
T2301-X-102D	“
T2301-X-103A	Thermocouples
T2301-X-103B	“
T2301-X-104A	Control rod drive position indicators
T2301-X-104B	“
T2301-X-104C	“
T2301-X-104D	“
T2301-X-104E	“
T2301-X-104F	“
T2301-X-105A	Low-voltage power (480 V)
T2301-X-105D	“
T2301-X -106A	Low level signal vibration test
T2301-X-106B	“

TABLE 6.2-4 DRYWELL TO SUPPRESSION CHAMBER VACUUM BREAKER VALVE DATA

1.	Number of drywell-to-suppression chamber vacuum breaker valves	12
2.	Valve size	20 in. seat x 18 in. flanged outlet
3.	Valve location	
	Elevation	Valve centerline 562 ft 8.5 in.
	Position	Two valves on each drywell support chamber downcomer with azimuth locations 22° - 30', 67° - 30' 112° - 30', 247° - 30', 292° - 30', and 337° - 30'
4.	Differential pressure to open	0.5 psid
5.	Valve manufacturer	GPE Controls of Morton Grove, Illinois
6.	Design temperature	350 °F
7.	Design pressure	62 psig
8.	Hydrostatic test pressure	87 psig
9.	Valve position indication	Limit switches, circuitry, and indicator lights. Closed limit switches are redundant
10.	Main control room panel number	Indicating lights are on panel H11-P808 and H11-P817

TABLE 6.2-5 PRIMARY SYSTEM ENERGY DISTRIBUTION AT THE TIME A RECIRCULATION LINE BREAK ACCIDENT OCCURS

Fluid Energy[a]	Energy (10^6 Btu)
1. Steam	30.6
2. Liquid	346.8
Sensible Energy	
1. Reactor pressure vessel	103
2. Reactor internals (less core)	78.9
3. Core	7.5

[a] All energy values are based on a 32 °F datum. Fuel energy is based on a datum of 285 °F.

TABLE 6.2-6 HAS BEEN INTENTIONALLY DELETED

TABLE 6.2-7 ACCIDENT CHRONOLOGY DESIGN BASIS RECIRCULATION LINE BREAK ACCIDENT

		Time (sec) Minimum ECCS Available
1.	Vents cleared	0.2
2.	Drywell reaches peak pressure	4.6
3.	Maximum positive differential pressure occurs	4.6
4.	Initiation of the ECCS	60**
5.	Vessel reflooded	220*
6.	Introduction of RHR heat exchanger	1200
7.	Containment reaches peak secondary pressure	1×10^4 (2.8 hr)

* This value taken from the containment analysis models; it is onlysignificant in confirming that core reflooding occurs before pool cooling or other RHR functions are needed.

** The containment analysis was based on a 30-sec maximum analyzed HPCI response time. The HPCI design basis has been subsequently revised to incorporate a 60-sec maximum system response time. The containment analysis is not impacted by increasing the HPCI response time from 30 sec to 60 sec. The short-term containment analysis calculates a peak containment pressure before the HPCI injects. The long-term calculation assumes one RHR loop is operating in the containment cooling mode at partial pumping capacity. Core cooling is provided by the core spray system and the RHR/LPCI pump and no credit was taken for the HPCI system (UFSAR Section 6.2.1.3.3) for long-term core makeup.

TABLE 6.2-8 PRIMARY AND SECONDARY CONTAINMENTS SURFACE COATING SCHEDULE PRIMARY CONTAINMENT[f]

Type of Coating	Location	Approx. Average DFT[a] (mils)	Approx. Total Surface (ft^2)
Carbozinc 11	Drywell interior steel Interior structural steel hangers and supports Vent line interior	7	120,000
Plasite 7155[bc]	Torus interior	12	38,000
Carboguard 6250 N[b,c,e]	Torus interior Vent header interior Vent line interior tie-in to vent header	40	34,300
Ameron 66 and Surfacer[b]	RPV support pedestal Drywell concrete floors Drywell concrete walls	1/16 in. plus10 mils	7,380
Unqualified Paints[e]	Miscellaneous	Note e	Note e
Carboguard 890N	Drywell dado region	6	232

SECONDARY CONTAINMENT

Location	Area(ft^2)	Primer	Thickness, Approx. (in.)	Top Coat	Thickness, Approx. (in)
Drywell exterior steel	36,200	Carbozinc 11	0.002 ± 0.002 0.001	None	-
Torus exterior steel	84,000	Carbomastic 15	0.002 - 0.009	None	-
Secondary containment concrete	109,200	Carboline 295	0.020 - 0.040	Carboline 288	0.008
Secondary containment structural steel	29,000	Type II red lead[d]	0.001 to 0.00153	Cook's Amercote Enamel[d]	0.002

[a] DFT = Dry Film Thickness.

[b] Qualified Coating; other coatings are unqualified.

[c] Other compatible touch-up coatings are used inside the torus.

[d] Other compatible coatings per Specification 3071-055 per painting system PS-2 are used on top or in lieu of Cook's Amercote Enamel and Type II red lead.

[e] For current unidentified and unqualified coating totals, see the design calculations for the Torus strainers.

[f] Coating materials listed in this table are estimated quantities of significant coating materials inside containment. Actual coating materials and quantities inside containment are managed as indicated in design calculations for the Torus strainers.

TABLE 6.2-9 WIRING INSULATION

	Type	Approximate Amount (lb)
Primary Containment Cable		
Power and control cable	EPR Hypalon Silicone Rubber	5,340
		25
Instrument	Cross-linked Polyethylene or Polyolefin	
		5
Thermocouple	Polyamide Capton	18
Secondary Containment Cable		
Power	EPR Hypalon and Neoprene	137,000[a]
Control	EPR Hypalon and Neoprene	14,000[a]
Instrument	Cross-linked Polyethylene by Raychem	99,000[a]
Thermocouple	Polyamide Capton	25

[a] In addition to the amounts shown here in cable trays, there is an approximate additional 15 percent in conduit.

TABLE 6.2-10 OTHER ORGANIC COMPOUNDS

	Commercial Name	Compound	Quantity (approx.)
Primary Containment			
Shell to concrete joints	Dow Corning/ DOWSIL 790*	Silicone rubber	1900 $in.^3$
Concrete floor to wall joints	Carboline 225	Epoxy polysulfide	400 $in.^3$
Secondary Containment			
Steel wall panel gaskets	Blanchard Foam Guard	Polyvinyl chloride	40 ft^3-340 lb to 620 lb
Steel wall panel caulking	3M THIOKOL Weatherban	Polysulfide rubber	40 ft^3-580 lb
Concrete floor joints	Carboline 225	Epoxy polysulfide	14 ft^3

* Note: Dow Corning 790 is retained as a historic information as Dow Corning 790 product name was rebranded to DOWSIL 790.

TABLE 6.2-11 STANDBY GAS TREATMENT SYSTEM MAJOR COMPONENT DESCRIPTION

Filter Train	
Type	Multiple filters for removal or particulates, elemental iodine, and organic iodine from air
Quantity	Two 100 percent-capacity trains
Capacity, scfm air	4000 each
Demister (Each Train)	
Type	Impingement
Quantity	One
Water removal rate, lb/min	20
Static resistance at design flow in. H_2O	1 max at 4000 scfm with 0.005 lb/ft^3 of free moisture
Prefilter (Each Train)	
Type	Dry disposable cartridge
Quantity	One bank
Capacity, scfm air	4000
Media	Glass fiber
Efficiency, percent	85 (NBS dust spot)
Heater (Each Train)	
Type	Electric, open, single-stage, on-off
Quantity	One
Capacity, kW	24
Accessories	Overload cutout
HEPA Filters (Each Train)	
Type	High-efficiency, dry

TABLE 6.2-11 STANDBY GAS TREATMENT SYSTEM MAJOR COMPONENT DESCRIPTION

Quantity	Two banks (one before and one after charcoal absorber)
Elements per bank	Four
Capacity, scfm air	4000
Media	Waterproof, glass
Separator material	Aluminum
Frame material	Steel
Charcoal Adsorber Bed (Each Train)	
Type	Deep bed
Quantity	One
Capacity, scfm air	4000
Media	Impregnated Carbon
Quantity of media, lb	1250-1500 lbm (nominal)
Efficiency	Lab tested to ensure 99.9 percent removal efficiency for methyl iodide. Installed and tested in the adsorber housing such that an overall decontamination efficiency of 99 percent is assumed for removal of all forms of gaseous iodine.
Charcoal volume, ft^3	50 (approximately)
Charcoal density, lb/ft^3	23.7 Min^m
Depth of bed, in.	6
Face velocity, ft/minute	40
Residence time, seconds	0.75
Ignition temperature, °F	625 (approximately)
Iodine desorption temperature, °F	355

TABLE 6.2-11 STANDBY GAS TREATMENT SYSTEM MAJOR COMPONENT DESCRIPTION

Charcoal loading, mg iodine/g carbon (30-day accident duration)	2.5 (approximately)

Media Particle Size Distribution USS Mesh

8	3 percent
12	51 percent
16	40 percent
18	5 percent
Fines	1 percent

SGTS Exhaust Blower (Each Train)

Quantity and type	One Centrifugal (with inlet vanes)
Capacity, scfm	4000
Static pressure, in. H_2O	20
Drive	V-belt
Motor, hp	25

Standby Cooling Air Fan

Quantity and type	One centrifugal
Capacity, scfm air	1000
Static pressure, in. H_2O	18
Drive	V-belt
Motor, hp	10

TABLE 6.2-12 STANDBY GAS TREATMENT SYSTEM EQUIPMENT FAILURE ANALYSIS

Component	Failure	Failure Detected By	Action
SGTS primary blower	Monitor burnout, drive shaft break, trip, etc.	Flow monitor – low pressure switch	Main control board alarm Operating equipment train shutdown (manual) Redundant train startup (manual)
Electric heating coil	Element overheat	High temperature cutout on coil	Circuit trip
Electric heating coil	Element burnout	Temperature indicator or moisture detector upstream of adsorber	High moisture alarm Operating equipment train shutdown (manual) Redundant train startup (manual)
Standby cooling fan	No start or failure results in high charcoal adsorber temperature	Temperature switches	Alarm sounds in main control room (automatic if setpoint achieved) CO_2 is auto backup to cooling fan if charcoal bed temperature raises to 310 °F
Flow-control valve	Falls in open position	High ΔP indicator across filters, demisters, and adsorber	Main control board alarm
		High building vacuum alarm	Operating equipment train shut-down (manual) Redundant train startup (manual) Isolation valves positioned (automatic)
Isolation valve	Falls in open position	Local indicator light	No automatic action. Requires backflow prevention and building isolation accomplished by series valves

TABLE 6.2-12 STANDBY GAS TREATMENT SYSTEM EQUIPMENT FAILURE ANALYSIS

Component	Failure	Failure Detected By	Action
	Falls in closed position	Flow monitor – low-pressure switch	Main control board alarm Operating equipment train shutdown (manual) Redundant train startup (manual) Isolation valve positioned (automatic)
HEPA filter	High particulate loading	High ΔP indication	Operating equipment train shutdown (manual) Redundant train startup (manual) Isolation valves positioned (automatic)
Charcoal filter	High temperature	Temperature elements	Alarm sounds start cooling fan

TABLE 6.2-13 REMOTE MANUALLY OPERATED CONTAINMENT ISOLATION VALVES WITH LEAK DETECTION CAPABILITY

Penetration	Valve	Penetration	Valve
		X-27	T5000F401B
			T5000F402B
			T5000F403B
			T5000F404B
			T5000F405B
			T50-F458
			P34F403A
			P34F404A
X-9A	E4150F006		
X-9B	E5150F013	X-29Be	T5000F420B
X-10	E5150F007	X-34A	P4400F606B
	E5150F008	X-34B	P4400F615
			P4400F607B
X-11	E4150F002		
	E4150F003	X-35B-F	TIP shear valves
	E4150F600		
X-13A	E1150F015B		
	E1150F610B	X-40Dd	P34F401B
X-13B	E1150F015A		
	E1150F610A		
		X-47e	T5000F420A
X-16A	E2150F005B	X-48	T5000F401A
			T5000F402A
X-16B	E2150F005A		T5000F403A
			T5000F404A
			T5000F405A
		X-219	T5000F408B
X-23	P4400F606A		
X-24	P4400F616		
	P4400F607A	X-223A	E1150F004D
		X-223B	E1150F004B
X-48	P34F403B		
	P34F404B	X-223C	E1150F004C

TABLE 6.2-13 REMOTE MANUALLY OPERATED CONTAINMENT ISOLATION VALVES WITH LEAK DETECTION CAPABILITY

Penetration	Valve	Penetration	Valve
		X-223D	E1150F004A
		X-224A	E2150F036B
		X-224B	E2150F036A
X-206A	E41F402	X-225	E4150F042
X-206B	E41F403	X-226	E5150F031
X-206C	E41F401	X-227A	E2150F031B E4150F012
X-206D	E41F400		
		X-227B	E5150F019 E2150F031A
X-210A	E1150F007B E1150F026B		
X-210B	E1150F007A P34F407 P34F409	X-230	T5000F407A P34F405B P34F406B
		X-231	T5000F407B
X-215	T5000F408A P34F408 P34F410		P34F405A P34F406A
		X-206E	T50F412A
		X-206F	T50F412B
X-28Cf	P34F401A		
X-29Bb	E11F412		
X-29Bc	E11F413		
X-47a	E11F414		
X-47b	E11F415		

TABLE 6.2-14 PRIMARY CONTAINMENT PENETRATION PIPE LINES CONNECTING CLOSED-LOOP QUALITY GROUP B SYSTEMS TO QUALITY GROUP D SYSTEMS

System	Line	Line Diameter (in.)	Separation Valve
Emergency core cooling – high pressure coolant injection	Turbine exhaust drain to barometric condenser	1	SOV
	Interstage tap to barometric condenser	2	MOV
	Pressure source from the condensate system through the Torus Water Management System (TWMS) supplying HPCI pump discharge piping	3/4	CV, CV
	Condensate to radwaste	1	CV, AOV, AOV (1)
	Suction from condensate storage	14	CV, MOV (1)
	Discharge to condensate storage	10	MOV, AOV (1)
	Steam drain to main condenser	1	AOV, AOV (1)
Emergency core cooling – core spray	Suction from condensate storage	16	LCV
	“Keep full” line from demineralizer water system	3, 3	CV, CV
Emergence core cooling - residual heat removal	“Keep full” line from demineralizer water system	4, 4	CV, CV
	Supply from RHRSW system	12	TC, MOV (1)
	RHR drain to radwaste	4	MOV, MOV (1)
	To fuel pool cleanup	8	LCV
	From fuel pool cleanup	8	LCV
	From chemical clean	4, 4	MV (NC)
	To process sampling system	1/2	AOV, AOV (1)
	From FLEX supply piping Div 1	8	LCV
	From FLEX supply piping Div 2	8	LCV
Reactor core isolation cooling	Turbine exhaust drain to barometric condenser	3/4	MV, MV, MV

TABLE 6.2-14 PRIMARY CONTAINMENT PENETRATION PIPE LINES CONNECTING CLOSED-LOOP QUALITY GROUP B SYSTEMS TO QUALITY GROUP D SYSTEMS

System	Line	Line Diameter (in.)	Separation Valve
	Discharge to lube oil cooler	2	MOV
	Condensate to radwaste	1	CV, AOV, AOV (1)
	Suction from condensate storage	6	CV, MOV (1)
	Steam drain to main condenser	1	SOV, SOV (1)
Combustible gas control	None		

Symbols:

SOV = solenoid-operated valve

MOV = motor-operated valve

CV = check valve

AOV = air-operated valve

LCV = locked-closed valve

TC = testable check valve

MV = manual valve

(1) = on isolation panel

(NC) = normally closed

TABLE 6.2-15 ESSENTIAL/NONESSENTIAL LINES

Containment Penetration Number	System/Line	Valve Number	Classification	Containment Isolation Signals[a]	Comments
X-7A	Main steam line A MSIV leakage control	B2103F022A B2103F028A	Nonessential Nonessential		These lines provide a heat- sink path for the reactor pressure vessel. It is desirable to keep the MSIVs open for this function during postulated small leaks or breaks. Therefore, high drywell pressure has been deliberately omitted from isolation of main steam lines. The MSIVs and the main steam line drains also isolate on signals D, E, F, G, J, P, and RM.
X-7B	Main steam line B MSIV leakage control	B2103F022B B2103F028B	Nonessential Nonessential		
X-7C	Main steam line C MSIV leakage control	B2103F022C B2103F028C	Nonessential Nonessential		
X-7D	Main steam line D MSIV leakage control	B2103F022D B2103F028D	Nonessential Nonessential		
X-8	Main steam line drains	B2103F016 B2103F019	Nonessential Nonessential		
X-9A	Feedwater line A	B2100F010A B2100F032A	Essential Essential		The portion of the feed-water line that is Class 1 is essential. During the postulated LOCA, it is desirable to maintain reactor coolant makeup from all sources of supply.
		B2100F076A	Essential		This valve is provided for long-term leaktightness only. Remote manual control is provided in the control room to close the valve upon indication of loss of feedwater flow.
X-9A	High-pressure coolant Injection	E4150F006	Essential		Automatically opens and closes with HPCI pump operation.
X-9B	Feedwater line B	B2100F010B B2100F032B	Essential Essential		The portion of the feedwater line that is Class 1 is essential. During the postulated LOCA, it is desirable to maintain reactor coolant makeup from all sources of supply.
		B2100F076B	Essential		This valve is provided for long-term leaktightness only. Remote manual control is provided in the control room to close the valve upon indication of loss of feedwater flow.
X-9B	Reactor core isolation Cooling	E5150F013	Essential (safety system)		Automatically opens and closes with RCIC pump operation.
X-9B	Reactor water cleanup	G3352F220	Nonessential		Inadvertent isolation of this line due to inclusion of the high drywell pressure signal is undesirable, as it results in reactor coolant chemistry problems, fuel leaks, and RPV bottom thermal problems. RWCU is desirable for post-accident sampling of reactor coolant. The system includes break detection mechanisms that will automatically isolate on unbalanced flow or high temperature. Therefore, isolation on high drywell pressure is not needed.
X-10	Steam to RCIC turbine	E5150F007 E5150F008	Essential Essential		

TABLE 6.2-15 ESSENTIAL/NONESSENTIAL LINES

Containment Penetration Number	System/Line	Valve Number	Classification	Containment Isolation Signals[a]	Comments
X-11	Steam to HPCI turbine	E4150F002 E4150F003 E4150F600	Essential Essential Essential		
X-12	RHR/RHR pump suction from recirculation piping	E1150F009 E1150F608 E1150F008	Nonessential Nonessential Nonessential		High drywell pressure has been deliberately omitted from this line's isolation initiation to avoid the loss of the shutdown cooling mode of RHR for small breaks or leaks.
X-13A	RHR/RHR pump discharge to recirculation loop	E1100F050B E1150F015B	Essential Essential		Not a containment isolation valve.
X-13B	RHR/RHR pump discharge to recirculation loop	E1100F050A E1150F015A	Essential Essential		Not a containment isolation valve.
X-15	Combustible gas control system suction	T4804F603A T4804F605A	Nonessential Nonessential		The CGCS PCIVs are permanently de-energized and locked closed.
X-16A	Core spray pump discharge	E2100F006B E2150F005B	Essential Essential		
X-16B	Core spray pump discharge	E2100F006A E2150F005A	Essential Essential		
X-17	RHR/RHR head spray (piping within the drywell is blanked off)	E1150F023 E1150F022	Nonessential Nonessential		High drywell pressure was deliberately omitted from this line's isolation initiation to avoid the loss of the head spray mode of RHR for small breaks or leaks.
X-18	Radwaste system/drywell floor drains sump pump discharge	G1100F003 G1154F600	Nonessential Nonessential		
X-19	Radwaste system/drywell equipment drains sump pump discharge	G1100F019 G1154F018	Nonessential Nonessential		
X-20	Demineralized service water to drywell	P1100F126	Nonessential		
X-22	Station and control air/ nitrogen inerting system/ drywell equipment pneumatic supply Division I	T4901F465 T4901F601 T4901F007	Essential Essential Essential		Manual override is available to operator.
X-23	Reactor building closed cooling water and emergency equipment cooling water systems supply	P4400F606A P4400F282A	Essential Essential		Closes on high drywell pressure
X-24	Reactor building closed cooling water and emergency cooling water systems return	P4400F616 P4400F607A	Essential Essential		
X-25	Reactor building HVAC/ drywell exhaust and air purge	T4600F402 T4803F602 T4600F411	Nonessential Nonessential Nonessential		
X-26	Nitrogen inerting system and reactor building HVAC/ drywell air purge inlet	T4800F408 T4803F601 T4800F407	Nonessential Nonessential Nonessential		
X-27a	PCMS containment atmosphere sample	T5000F401B	Essential		

TABLE 6.2-15 ESSENTIAL/NONESSENTIAL LINES

Containment Penetration Number	System/Line	Valve Number	Classification	Containment Isolation Signals[a]	Comments
X-27b	PCMS containment atmosphere sample	T5000F402B	Essential		
X-27c	PCMS containment atmosphere sample	T5000F403B	Essential		
X-27d	PCMS containment atmosphere sample	T5000F404B	Essential		
X-27e	PCMS containment atmosphere sample	T5000F405B	Essential		
X-27f	Drywell pressure instrumentation	T50-F458	Essential		
X-27b	PASS[b]/containment drywell atmosphere sample	P34F403A P34F404A	Nonessential Nonessential		Administrative control utilized.
X-28Cf	PASS/pressurized reactor coolant sample	P34F401A	Nonessential		Administrative control utilized. Orifice in line inside containment.
X-29Aa	Process sample/reactor recirculation water sample	B3100F019 B3100F020	Nonessential Nonessential		
X-29Bc	PCMS/drywell instrumentation	E11F413	Essential		
X-29Bb	PCMS/drywell instrumentation	E11F412	Essential		
X-29Be	PCMS/drywell instrumentation	T5000F420B	Essential		
X-30Aa	RWCU/RPV pressure	G33F583	Essential		
X-31Ba	Nitrogen inerting system/ drywell nitrogen makeup and vent	T4800F453 T4800F454 T4800F455	Nonessential Nonessential Nonessential		
X-32Ba	Steam flow to HPCI (instrumentation)	E4100F503	Essential		
X-32Bb	Steam flow to HPCI (instrumentation)	E4100F502	Essential		
X-33Bc	Core spray/RPV pressure (instrumentation)	E21F500A	Essential		
X-33Ba	Steam flow to HPCI (instrumentation)	E4100F501	Essential		
X-33Bb	Steam flow to HPCI (instrumentation)	E4100F500	Essential		
X-34A	RBCCW and emergency cooling water systems supply	P4400F606B P4400F282B	Essential Essential		Closes on high drywell pressure
X-34B	RBCCW and emergency cooling water systems return	P4400F607B P4400F615	Essential		
X-35B	NMS/TIP system		Nonessential		System normally isolated and closed inside containment.
X-35C	NMS/TIP system		Nonessential		

TABLE 6.2-15 ESSENTIAL/NONESSENTIAL LINES

Containment Penetration Number	System/Line	Valve Number	Classification	Containment Isolation Signals[a]	Comments
X-35D	NMS/TIP system		Nonessential		
X-35E	NMS/TIP system		Nonessential		
X-35F	NMS/TIP system		Nonessential		
X-35G	TIP system spare		Nonessential		
X-36	Station and control air/ nitrogen inerting system/ drywell equipment pneumatic supply, Division II	T4901F468 T4901F602 T4901F016	Essential Essential Essential		Manual override is available to operator.
X-37A,B,C,D	CRD/control rod drive insertion line	None	Essential		
X-38A,B,C,D	CRD/control rod drive withdrawal line	None	Essential		
X-39A	RHR/RHR to containment spray header	E1150F021A E1150F016A	Essential Essential		
X-39B	RHR/RHR to containment spray header	E1150F021B E1150F016B	Essential Essential		
X-40Dd	PASS/pressurized reactor coolant sample	P34F401B	Nonessential		Administrative control utilized. Orifice in line inside containment.
X-42	SLCS/standby liquid control	C4100F007 C4100F006	Essential Essential		
X-43	RWCU/reactor water (cleanup from recirculation piping)	G3352F001 G3352F004	Nonessential Nonessential		Inadvertent isolation of this line due to inclusion of the high-drywell-pressure signal is undesirable, as it results in reactor coolant chemistry problems, fuel leaks, and RPV bottom thermal problems. RWCU is desirable for postaccident sampling of reactor coolant. The system includes break-detection mechanisms that will automatically isolate on unbalanced flow or high temperature. Therefore, isolation on high drywell pressure is not needed.
X-44	CGCS/combustible gas control system suction	T4804F603B T4804F605B	Nonessential Nonessential		The CGCS PCIVs are permanently de-energized and locked closed.
X-47a	PCMS/drywell instrumentation	E11F414	Essential		
X-47b	PCMS/drywell instrumentation	E11F415	Essential		
X-47e	PCMS/drywell pressure	T5000F420A	Essential		
X-48b	PCMS/containment atmosphere sample	T5000F402A	Essential		See also containment penetration "PCRMS."
X-48c	PCMS/containment atmosphere sample	T5000F403A	Essential		See also containment penetration "PCRMS."
X-48d	PCMS/containment atmosphere sample	T5000F404A	Essential		See also containment penetration "PCRMS."
X-48e	PCMS/containment atmosphere sample	T5000F405A	Essential		See also containment penetration "PCRMS."

TABLE 6.2-15 ESSENTIAL/NONESSENTIAL LINES

Containment Penetration Number	System/Line	Valve Number	Classification	Containment Isolation Signals[a]	Comments
X-48f	PASS/containment drywell atmosphere sample	P34F403B P34F404B	Nonessential		Administrative control utilized.
X-49a	Reactor recirculation/ recirculation pump seal purge	B3100F016A B3100F014A	Nonessential Nonessential		High-pressure line with globe valves inside and outside containment, and an orifice in the line to prevent backflow.
X-51a	Reactor recirculation/ recirculation pump seal purge	B3100F016B B3100F014B	Nonessential Nonessential		High-pressure line with globe valves inside and outside containment, and an orifice in the line to prevent backflow.
X-52e	Steam flow to RCIC (instrumentation)	E51F506	Essential		
X-52f	Steam flow to RCIC (instrumentation)	E51F505	Essential		
X-53a	Steam flow to RCIC (instrumentation)	E51F503	Essential		
X-53b	Steam flow to RCIC (instrumentation)	E51F504	Essential		
X-53c	Core spray/RPV pressure (instrumentation)	E21F500B	Essential		
X-204A	Nitrogen inerting system/drywell to torus vacuum breaker nitrogen supply, vacuum breaker valve T2300F400A	T4800F416	Nonessential		Electrically de-energized
X-204B	Nitrogen inerting system/drywell to torus vacuum breaker nitrogen supply, vacuum breaker valve T2300F400B	T4800F417	Nonessential		Electrically de-energized
X-204C	Nitrogen inerting system/drywell to torus vacuum breaker nitrogen supply, vacuum breaker valve T2300F400C	T4800F418	Nonessential		Electrically de-energized
X-204D	Nitrogen inerting system/drywell to torus vacuum breaker nitrogen supply, vacuum breaker valve T2300F400D	T4800F419	Nonessential		Electrically de-energized
X-204E	Nitrogen inerting system/drywell to torus vacuum breaker nitrogen supply, vacuum breaker valve T2300F400E	T4800F420	Nonessential		Electrically de-energized
X-204F	Nitrogen inerting system/ drywell to torus vacuum breaker nitrogen supply, vacuum breaker valve T2300F400F	T4800F421	Nonessential		Electrically de-energized
X-204G	Nitrogen inerting system/ drywell to torus vacuum breaker nitrogen supply, vacuum breaker valve T2300F400G	T4800F422	Nonessential		Electrically de-eneregized

TABLE 6.2-15 ESSENTIAL/NONESSENTIAL LINES

Containment Penetration Number	System/Line	Valve Number	Classification	Containment Isolation Signals[a]	Comments
X-204H	Nitrogen inerting system/ drywell to torus vacuum breaker nitrogen supply, vacuum breaker valve T2300F400H	T4800F423	Nonessential		Electrically de-energized
X-204J	Nitrogen inerting system/ drywell to torus vacuum breaker nitrogen supply, vacuum breaker valve T2300F400J	T4800F424	Nonessential		Electrically de-energized
X-204K	Nitrogen inerting system/ drywell to torus vacuum breaker nitrogen supply, vacuum breaker valve T2300F400K	T4800F425	Nonessential		Electrically de-energized
X-204L	Nitrogen inerting system/ drywell to torus vacuum breaker nitrogen supply, vacuum breaker valve T2300F400L	T4800F426	Nonessential		Electrically de-energized
X-204M	Nitrogen inerting system/ drywell to torus vacuum breaker nitrogen supply, vacuum breaker valve T2300F400M	T4800F427	Nonessential		Electrically de-energized
X-205A	Primary containment system/ to secondary containment to torus vacuum breaker	T2300F450B T2300F410	Essential Essential		Provisions for administrative control ensure that the valve is not inadvertently positioned open by the operator. This does not prevent automatic operation to control primary containment vacuum formation.
X-205B	Primary containment system/secondary containment to torus vacuum breaker	T2300F450A T2300F409	Essential Essential		Provisions for administrative control ensure that the valve is not inadvertently positioned open by the operator. This does not prevent automatic operation to control primary containment vacuum formation.
X-205C	Nitrogen inerting system and reactor building HVAC/suppression pool air purge inlet	T4800F409 T4800F404 T4800F405	Nonessential Nonessential Nonessential		
X-205D	Nitrogen inerting system and reactor building HVAC/suppression pool exhaust air purge to standby gas treatment	T4600F400 T4600F401 T4600F412	Nonessential Nonessential Nonessential		
	Torus nitrogen inerting inlet	T4800F410	Nonessential		
	Torus nitrogen makeup and Vent	T4800F456 T4800F457 T4800F458	Nonessential Nonessential Nonessential		
X-206A	PCMS/liquid level indicators	E41F402	Essential		Accident monitoring instrumentation.
X-206B	PCMS/liquid level indicators	E41F403	Essential		
X-206C	PCMS/liquid level indicators	E41F401	Essential		
X-206D	PCMS/liquid level indicators	E41F400	Essential		Valves fail as is.
X-206E	PCMS/liquid level indicators	T50F412A	Essential		

TABLE 6.2-15 ESSENTIAL/NONESSENTIAL LINES

Containment Penetration Number	System/Line	Valve Number	Classification	Containment Isolation Signals[a]	Comments
X-206E	PCMS/suppression pool liquid level indicators		Essential		
X-206F	PCMS/liquid level indicators	T50F412B	Essential		
X-206F	PCMS/suppression pool liquid level indicators		Essential		
X-210A	RHR/RHR minimum flow	E1150F007B	Essential		
	RHR heat exchanger discharge header thermal relief	E1100F025B	Essential		
	RHR/RHR test line	E1150F024B	Essential		Manual override available to operator.
	RHR/RHR heat exchanger thermal relief	E1100F001B	Essential		
	RHR warmup line	E1150F026B	Nonessential		
X-210B	PASS/containment liquid sample return	P34F407 P34F409	Nonessential Nonessential		Administrative control utilized.
X-210B	TWMS	G5100F604 G5100F605	Nonessential Nonessential		
X-210B	RHR/suction thermal relief	E1100F029	Nonessential		
	RHR/heat exchanger discharge header thermal relief	E1100F025A	Essential		
	RHR/heat exchanger relief	E1100F001A	Essential		
	RHR/minimum flow	E1150F007A	Essential		
	RHR/test line	E1150F024A	Essential		
X-211A	RHR/RHR suppression pool Spray	E1150F027B E1150F028B	Essential Essential		
X-211B	RHR/RHR suppression pool Spray	E1150F028A E1150F027A	Essential Essential		
X-212	RCIC turbine exhaust line	E5150F001	Essential		
X-213A	TWMS suction	G5100F600 G5100F601	Nonessential Nonessential		
X-213B	TWMS suction	G5100F602 G5100F603	Nonessential Nonessential		
X-214	HPCI vacuum breaker line	E4150F075 E4150F079	Essential Essential		
X-214	RCIC vacuum breaker line	E5150F062 E5150F084	Essential Essential		
X-215	PCMS return Division I	T5000F408A	Essential		See also containment penetration "PCRMS."
X-215	CGCS/combustible gas control system suction	T4804F602A T4804F606A	Nonessential Nonessential		The CGCS PCIVs are permanently de-energized and locked closed.
X-215	PASS/containment gaseous sample return	P34F408 P34F410	Nonessential Nonessential		Administrative control utilized.

TABLE 6.2-15 ESSENTIAL/NONESSENTIAL LINES

Containment Penetration Number	System/Line	Valve Number	Classification	Containment Isolation Signals[a]	Comments
X-218	CGCS/combustible gas control system return	T4804F601A T4804F604A T4804F016A T4804F601B T4804F604B T4804F016B	Nonessential Nonessential Nonessential Nonessential Nonessential Nonessential		The CGCS PCIVs are permanently de-energized and locked closed.
X-219	CGCS/combustible gas control system suction	T4804F602B T4804F606B	Nonessential Nonessential		The CGCS PCIVs are permanently de-energized and locked closed.
X-219	PCMS return Division II	T5000F408B	Essential		
X-220	HPCI turbine exhaust line	E4150F021	Essential		
X-221	HPCI turbine exhaust drain	E4150F022	Essential		
X-222	RCIC vacuum pump discharge	E5150F002	Essential		
X-223A	RHR/RHR pump suction	E1150F004D	Essential		
X-223A	RHR/RHR pump suction header thermal relief	E1100F030D	Essential		
X-223B	RHR/RHR pump suction	E1150F004B	Essential		
X-223B	RHR/RHR pump suction header thermal relief	E1100F030B	Essential		
X-223C	RHR/RHR pump suction	E1150F004C	Essential		
X-223C	RHR/RHR pump suction header thermal relief	E1100F030C	Essential		
X-223D	RHR/RHR pump suction	E1150F004A	Essential		
X-223D	RHR/RHR pump suction header thermal relief	E1100F030A	Essential		
X-224A	Core spray pump suction	E2150F036B	Essential		
X-224B	Core spray pump suction	E2150F036A	Essential		
X-225	HPCI pump suction	E4150F042	Essential		
X-226	RCIC pump suction	E5150F031	Essential		
X-227A	TWMS discharge	G5100F606 G5100F607	Nonessential Nonessential		
X-227A	HPCI minimum flow	E4150F012	Essential		
X-227A	Core spray pump suction thermal relief	E2100F032B	Essential		
X-227A	Core spray pump discharge header relief	E2100F012B E2100F011B	Essential		
X-227A	Core spray pump minimum flow	E2150F031B	Essential		
X-227A	Core spray pump test line	E2150F015B	Nonessential		
X-227B	RCIC minimum flow	E5150F019	Essential		
X-227B	Core spray pump suction thermal relief	E2100F032A	Essential		
X-227B	Core spray pump discharge header relief	E2100F012A E2100F011A	Essential Essential		

TABLE 6.2-15 ESSENTIAL/NONESSENTIAL LINES

Containment Penetration Number	System/Line	Valve Number	Classification	Containment Isolation Signals[a]	Comments
X-227B	Core spray pump test line	E2150F015A	Nonessential		
X-227B	Core spray minimum flow	E2150F031A	Essential		
X-230	PASS/suppression pool Atmosphere sample	P34F405B P34F406B	Nonessential Nonessential		Administrative control utilized
X-230	PCMS suction Division I	T5000F407A	Essential		
X-231	PCMS suction Division II	T5000F407B	Essential		
X-231	PASS/suppression pool atmosphere sample	P34F405A P34F406A	Nonessential Nonessential		Administrative control utilized.
PCRMS	Primary containment radiation monitor	T50F450 T5000F456 T50F451 T5000F455	Nonessential Nonessential Nonessential Nonessential		Sample suction X-48. Sample suction X-48. Sample return X-215. Sample return X-215.

[a] Containment Isolation Signals are contained in UFSAR Table 6.2-2.

[b] PASS is postaccident sampling system.

TABLE 6.2-16 ESSENTIAL/NONESSENTIAL SYSTEMS

System	Classification	Comments
Main Steam	Nonessential	Not required for shutdown.
Feedwater	Nonessential	Not required for shutdown. Portion that is Class 1 is essential.
Reactor core isolation cooling	Essential	Necessary for core cool-down following isolation from the turbine condenser and feedwater makeup.
Reactor water cleanup	Nonessential	Not required during and immediately following an accident.
High pressure coolant injection	Essential	Safety system.
Core spray	Essential	Safety system.
Standby liquid Control	Essential	Should be available as a post LOCA pH control system and backup to CRD system.
Drywell floor/equipment drains	Nonessential	Not necessary for core cooldown.
Torus water management	Nonessential	Not required for reactor shutdown cooling.
Primary containment monitoring system	Essential	Required for postaccident monitoring of containment atmosphere hydrogen concentration.
Primary containment radiation monitoring system	Nonessential	Not required during or immediately after an accident.
Residual heat removal		
Heat exchangers	Essential	Main heat sink during isolation.

TABLE 6.2-16 ESSENTIAL/NONESSENTIAL SYSTEMS

System	Classification	Comments
Shutdown cooling	Nonessential	Nonessential, but desirable to use if available. Not redundant, but safety grade.
Drywell/suppression pool spray	Essential	Necessary to control pressure.
LPCI function	Essential	Safety function.
Keep-filled system	Nonessential	Not required after accident.
Control rod drive	Essential	Necessary for shutdown. No credit taken for reflood, but is desirable.
Emergency equipment cooling water	Essential	Necessary to cool safety system pumps and motors.
Station and control air		
Pneumatic supply to primary containment	Essential	For safety/relief valves on steam lines and ADS accumulators.
Demineralized service water	Nonessential	Not assumed available in ECCS analysis.
Nitrogen inerting	Nonessential	Not required during and immediately after accident.
Reactor building closed cooling water	Nonessential	Used for normal operation only.
Reactor recirculation	Nonessential	Not required because core can be cooled by natural circulation.
Traversing in-core probe	Nonessential	Not required for reactor shutdown cooling.

TABLE 6.2-16 ESSENTIAL/NONESSENTIAL SYSTEMS

System	Classification	Comments
Primary containment (vacuum breakers between secondary containment and suppression pool)	Essential	Vacuum breakers automatically open to prevent formation of excessive negative pressure in the suppression pool chamber. They close automatically upon increasing suppression pool chamber pressure and remain closed during all containment high-pressure conditions.
Reactor building heating, ventilation and air conditioning	Nonessential	Reactor building purge and vent functions are nonessential. Essential cooling is provided by equipment outside primary containment.

Figure Intentionally Removed
Refer to Plant Drawing M-2501

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FIGURE 6.2-1

PRIMARY CONTAINMENT SYSTEM
PROCESS LINE FLEXIBLE PENETRATION

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Refer to Plant Drawing M-2502

FIGURE 6.2-2

PRIMARY CONTAINMENT SYSTEM
PROCESS LINE PENETRATIONS

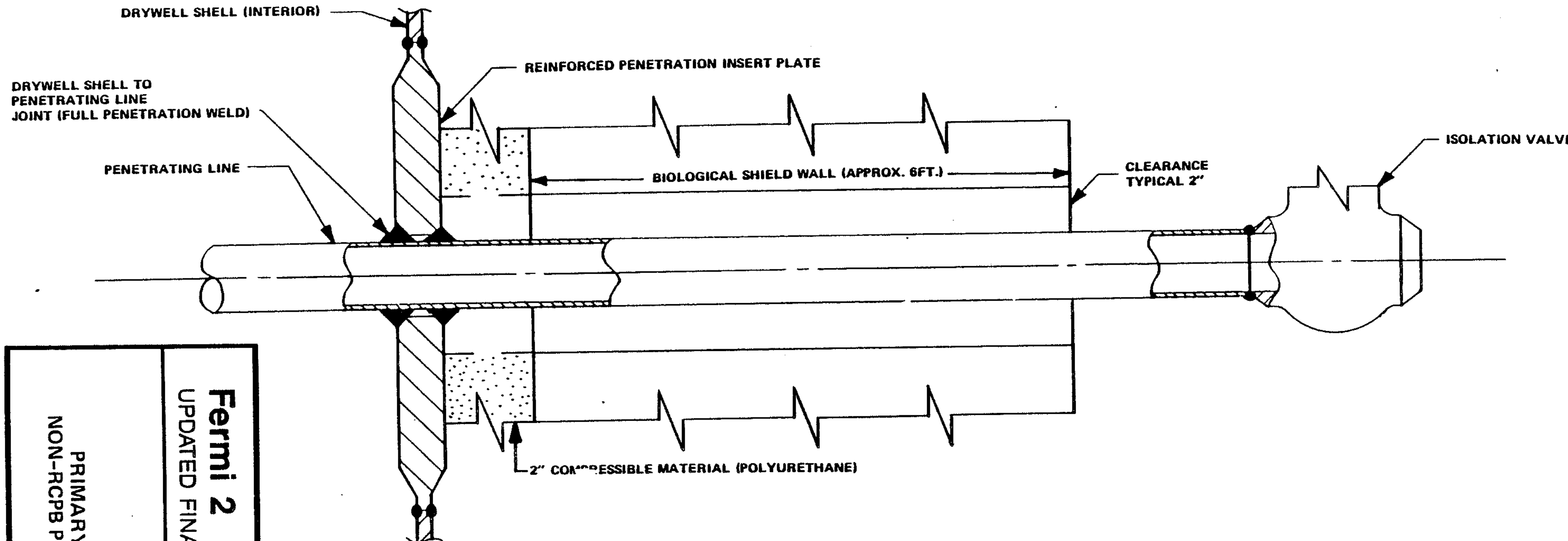

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FIGURE 6.2-3

PRIMARY CONTAINMENT SYSTEM

NON-RCPB PROCESS LINE PENETRATION

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Refer to Plant Drawing E-2831-08

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FIGURE 6.2-4

TYPICAL PRIMARY CONTAINMENT
SYSTEM ELECTRICAL PENETRATION

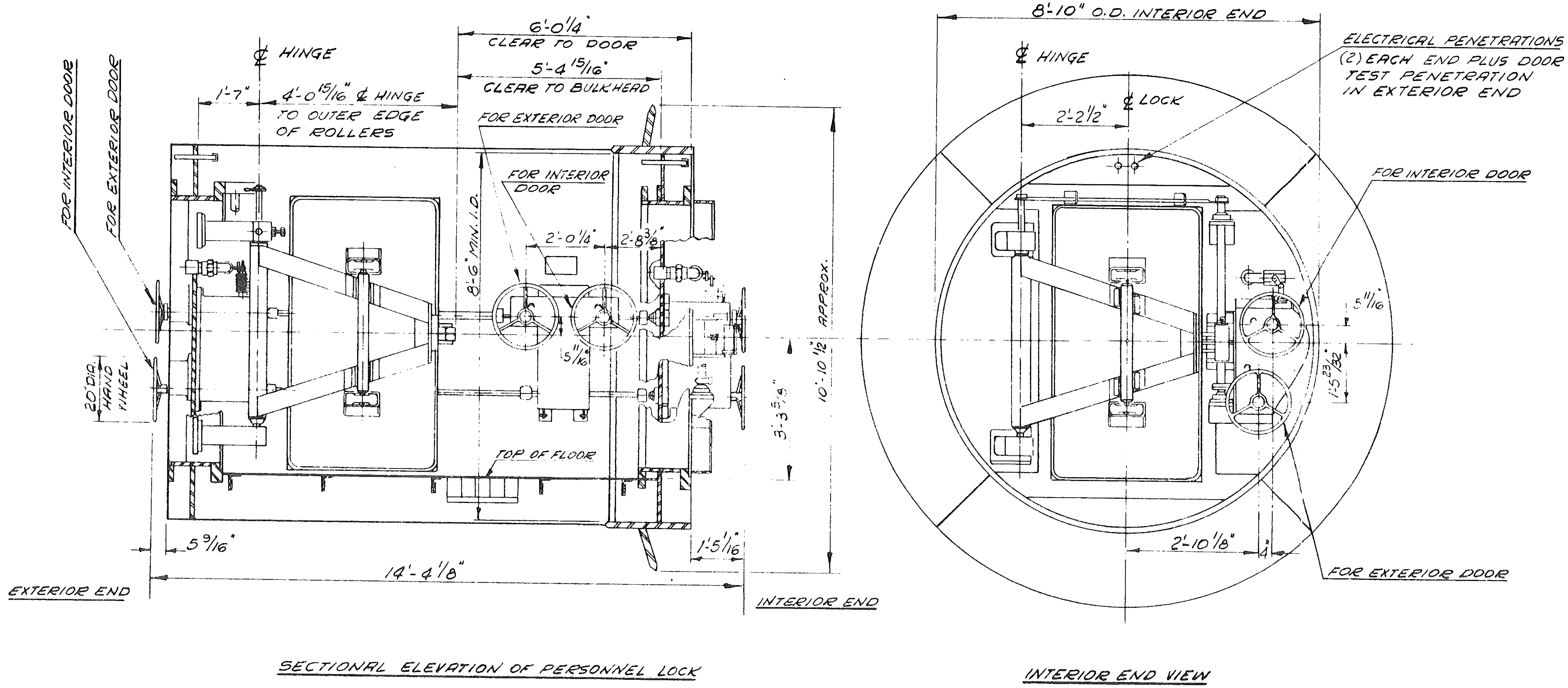

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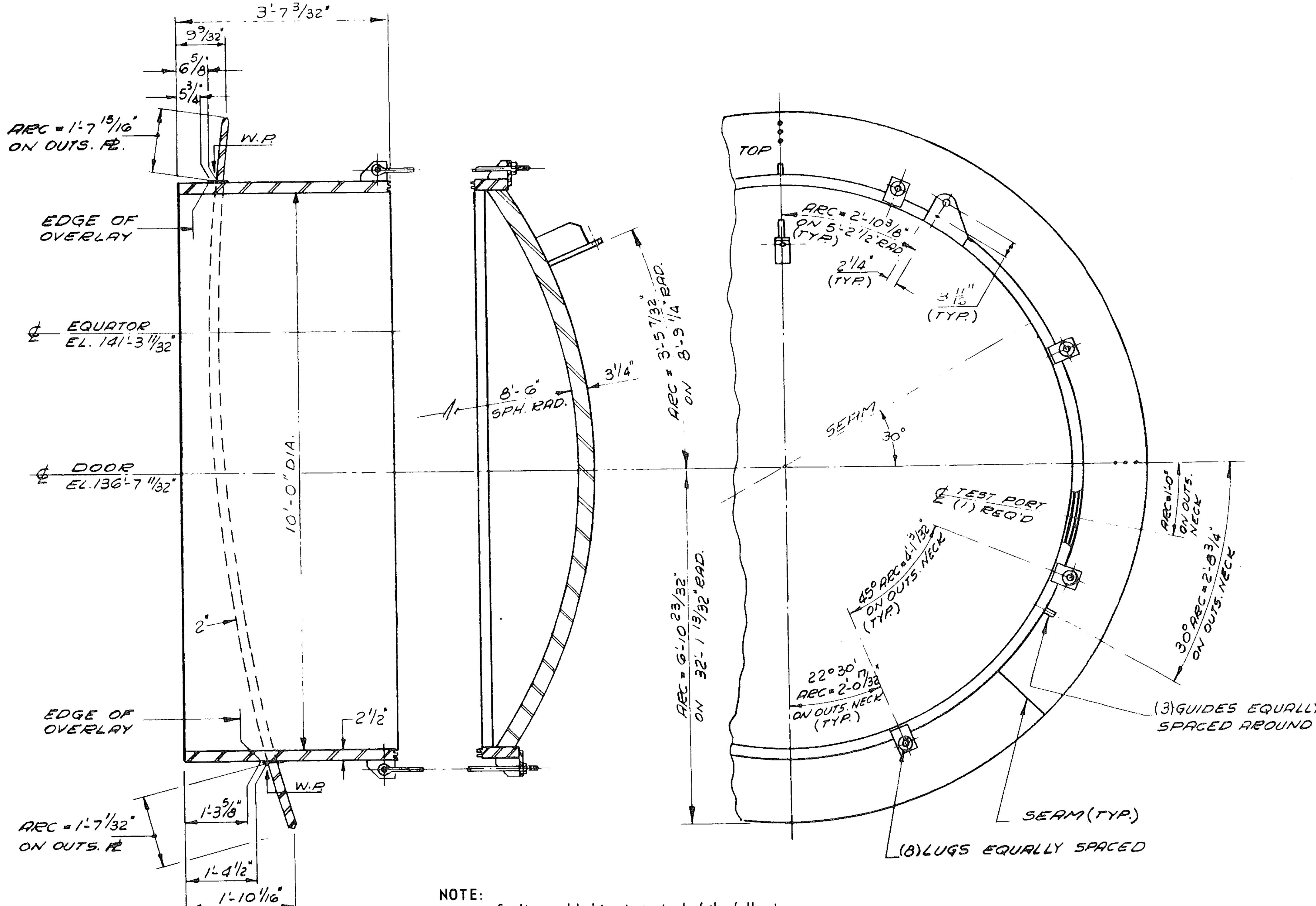
FIGURE 6.2-5

PRIMARY CONTAINMENT
PERSONNEL HATCH



NOTE:

Sealing and bolting is typical of the following

1. Drywell head.
2. Equipment access hatch in cylindrical portion of Drywell.
3. Rod removal hatch in the spherical portion of Drywell.
4. Access to the pressure suppression chamber

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FIGURE 6.2-6

PRIMARY CONTAINMENT EQUIPMENT HATCH

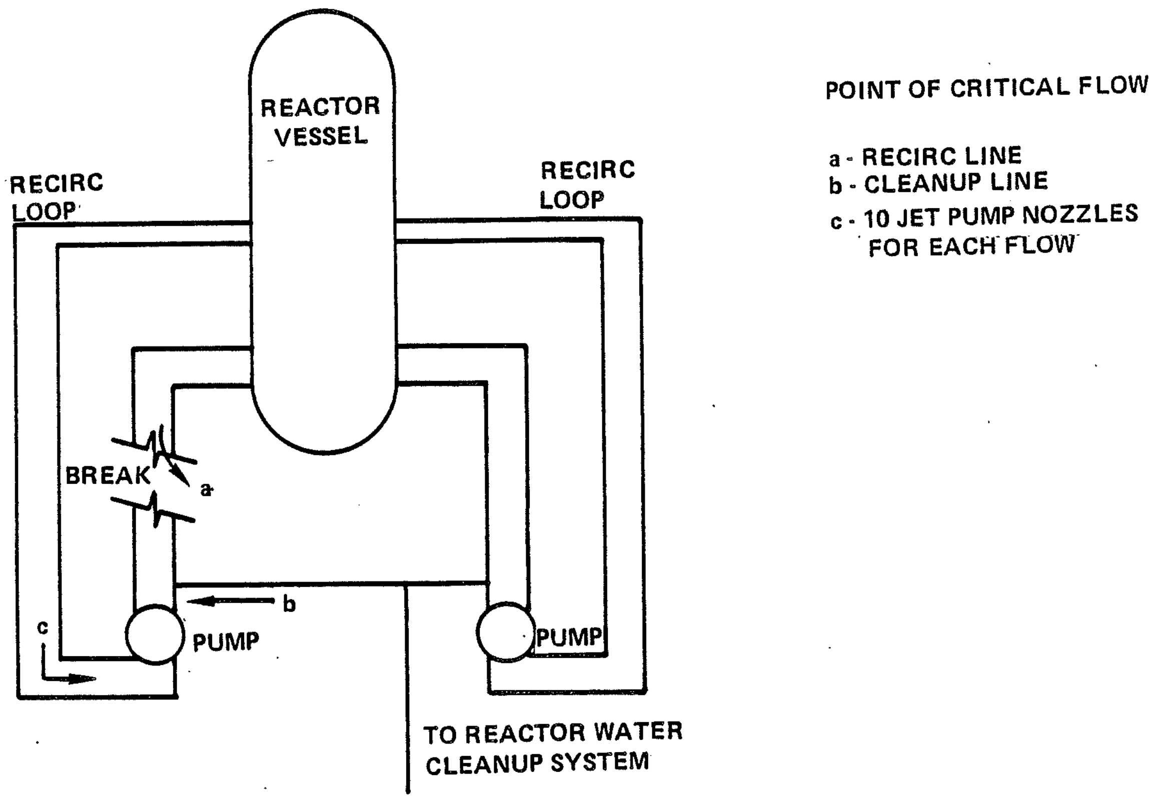

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FIGURE 6.2-7

DIAGRAM SHOWING LOCATION OF RECIRCULATION LINE BREAK

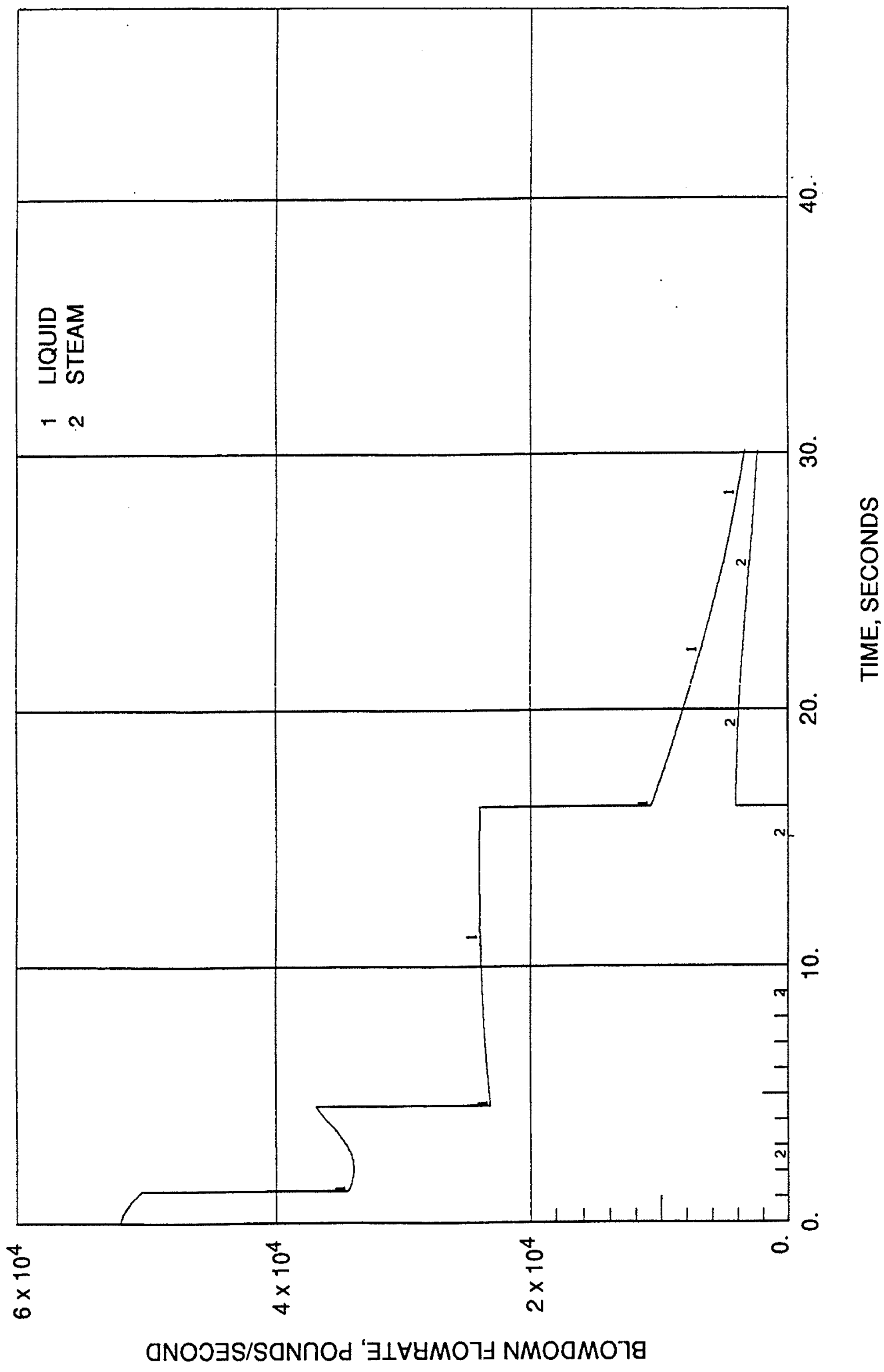

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FIGURE 6.2-8

RECIRCULATION BREAK BLOWDOWN FLOWRATES (3499 MWT)

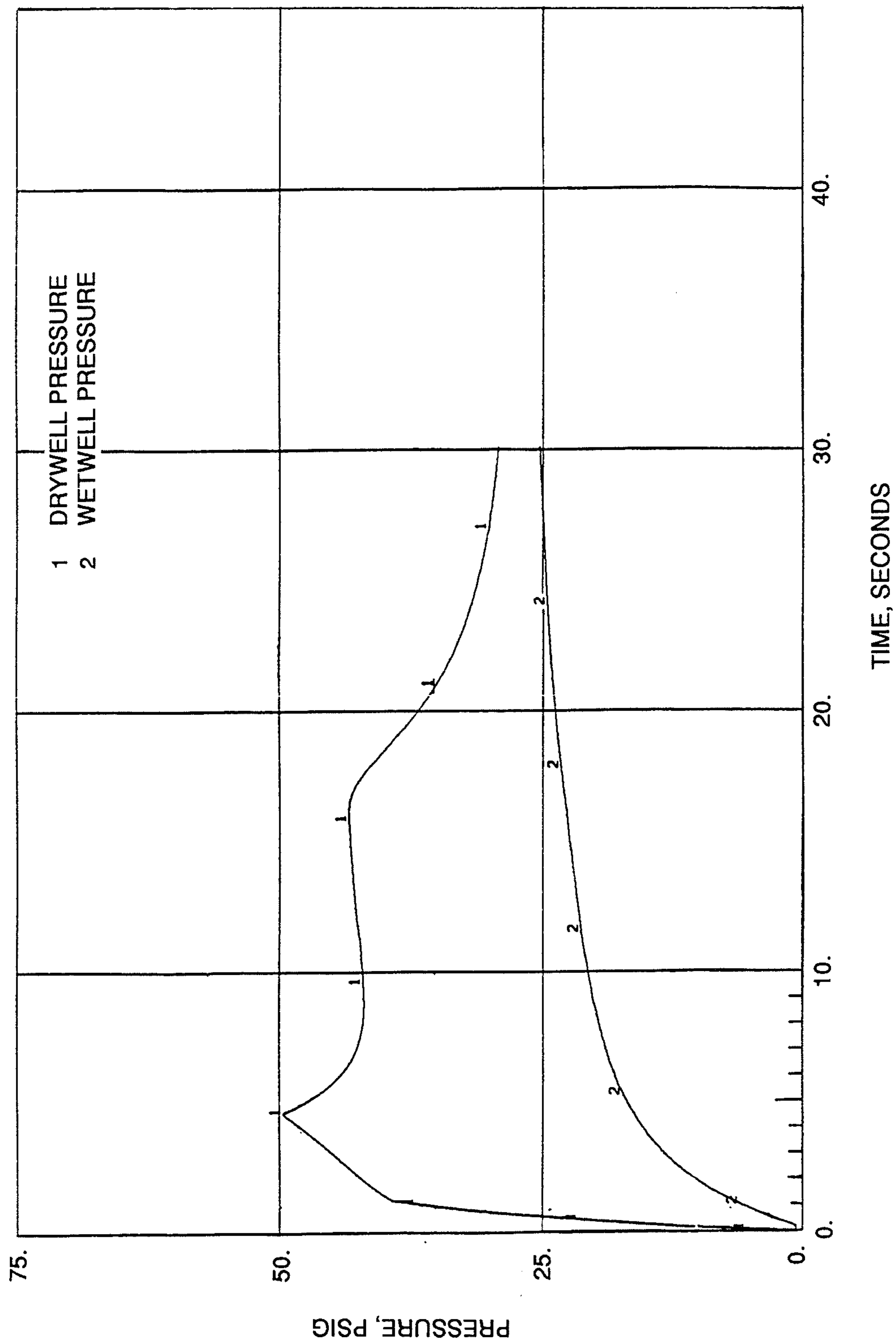

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FIGURE 6.2-9

RECIRCULATION LINE BREAK PRIMARY CONTAINMENT INITIAL PRESSURE TRANSIENT (3499 MWT)

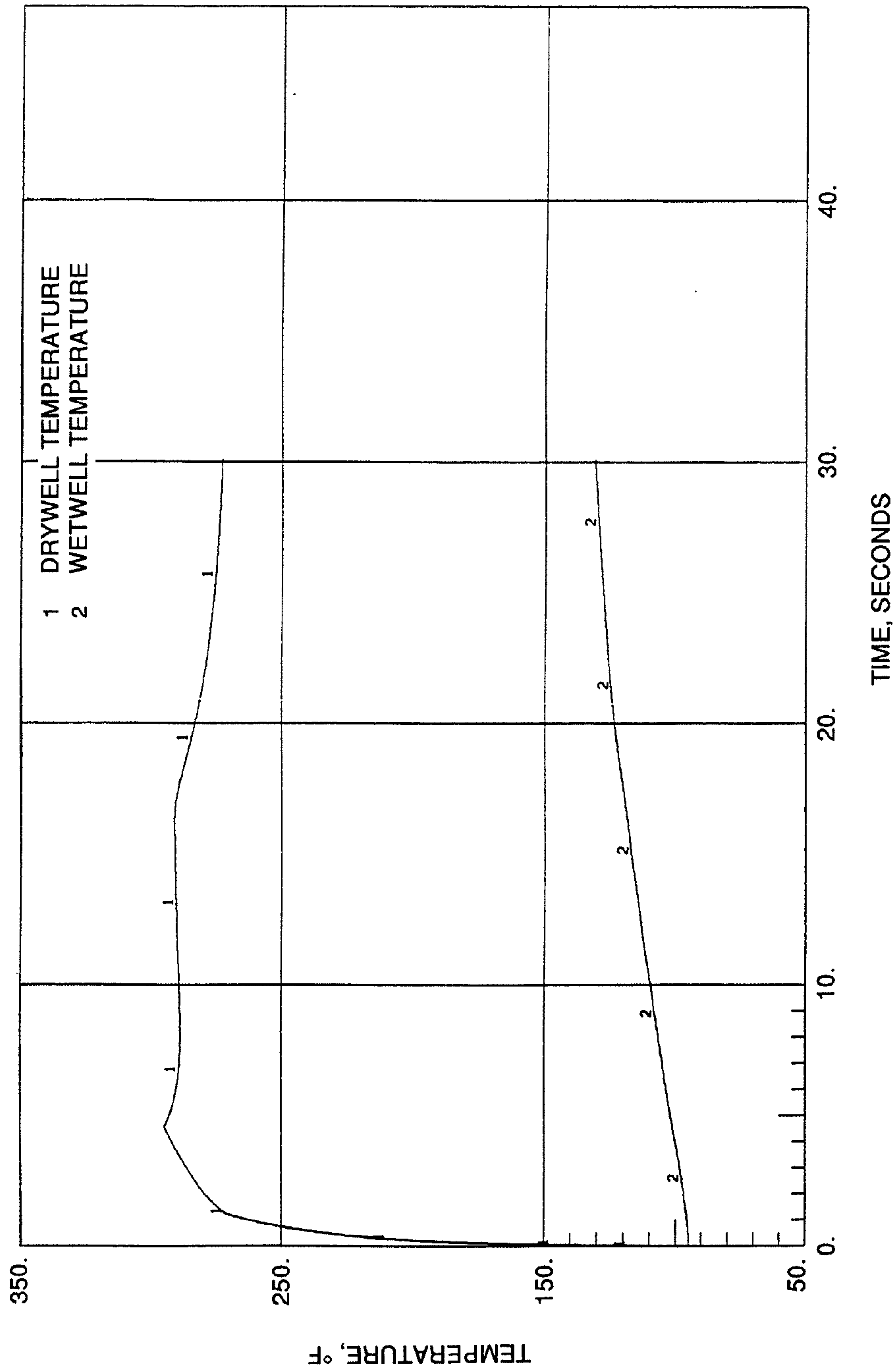

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FIGURE 6.2-10

RECIRCULATION LINE BREAK
PRIMARY CONTAINMENT INITIAL
TEMPERATURE TRANSIENT (3499 MWT)

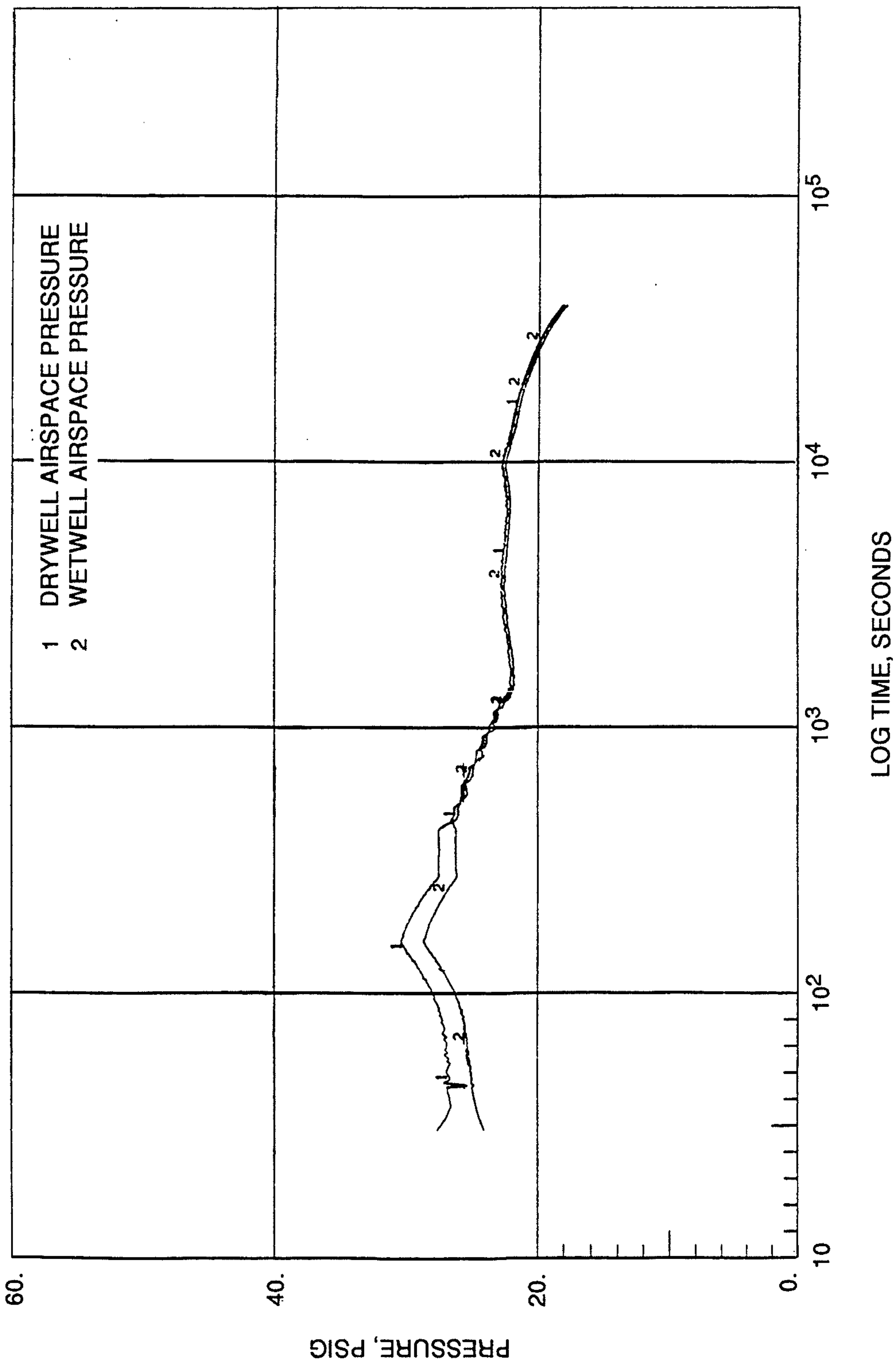

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FIGURE 6.2-11

PRIMARY CONTAINMENT PRESSURE LONG TERM RESPONSE (3499 MWT)

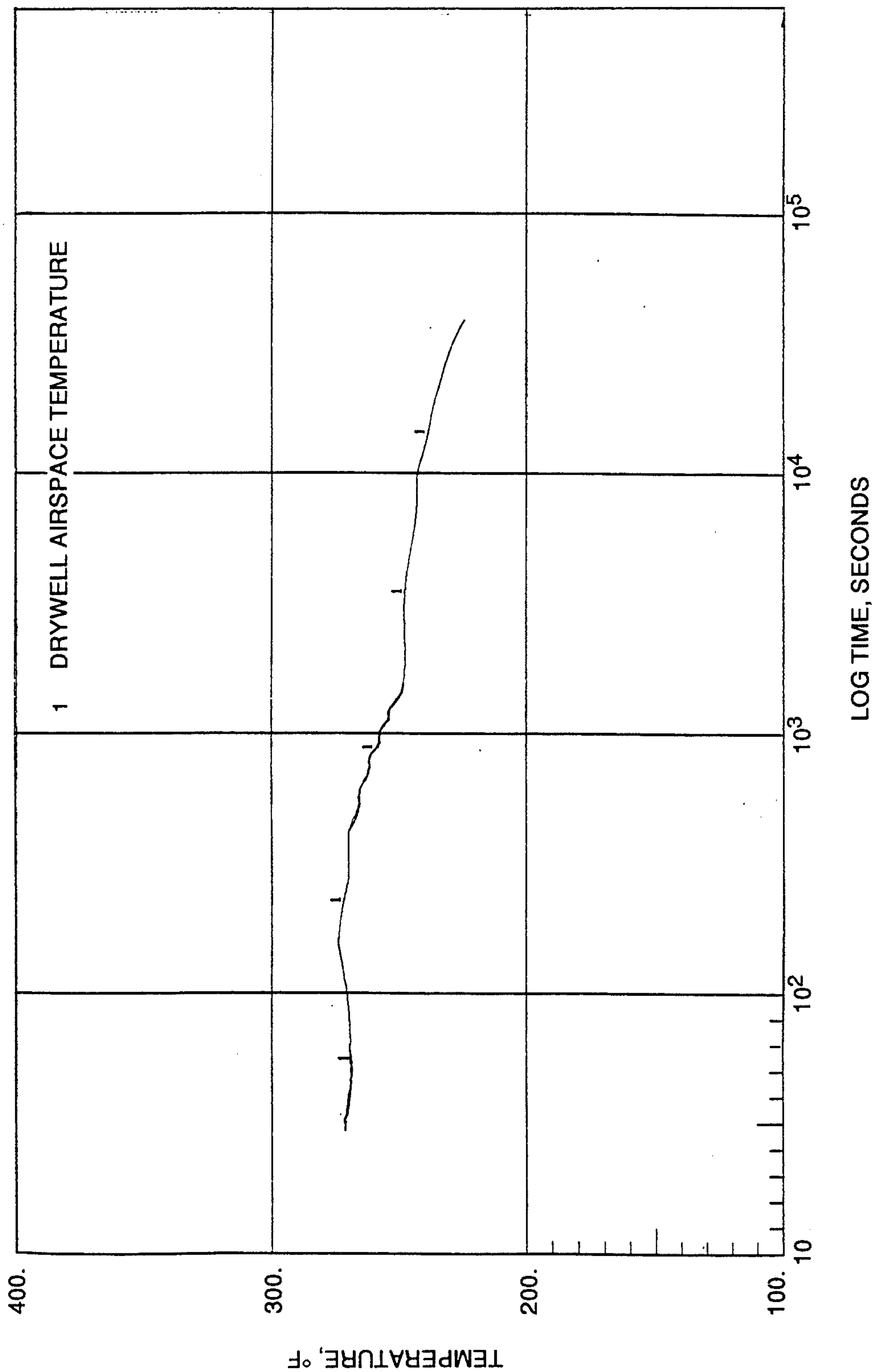

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FIGURE 6.2-12

DRYWELL TEMPERATURE
LONG TERM RESPONSE
(3499 MWT)

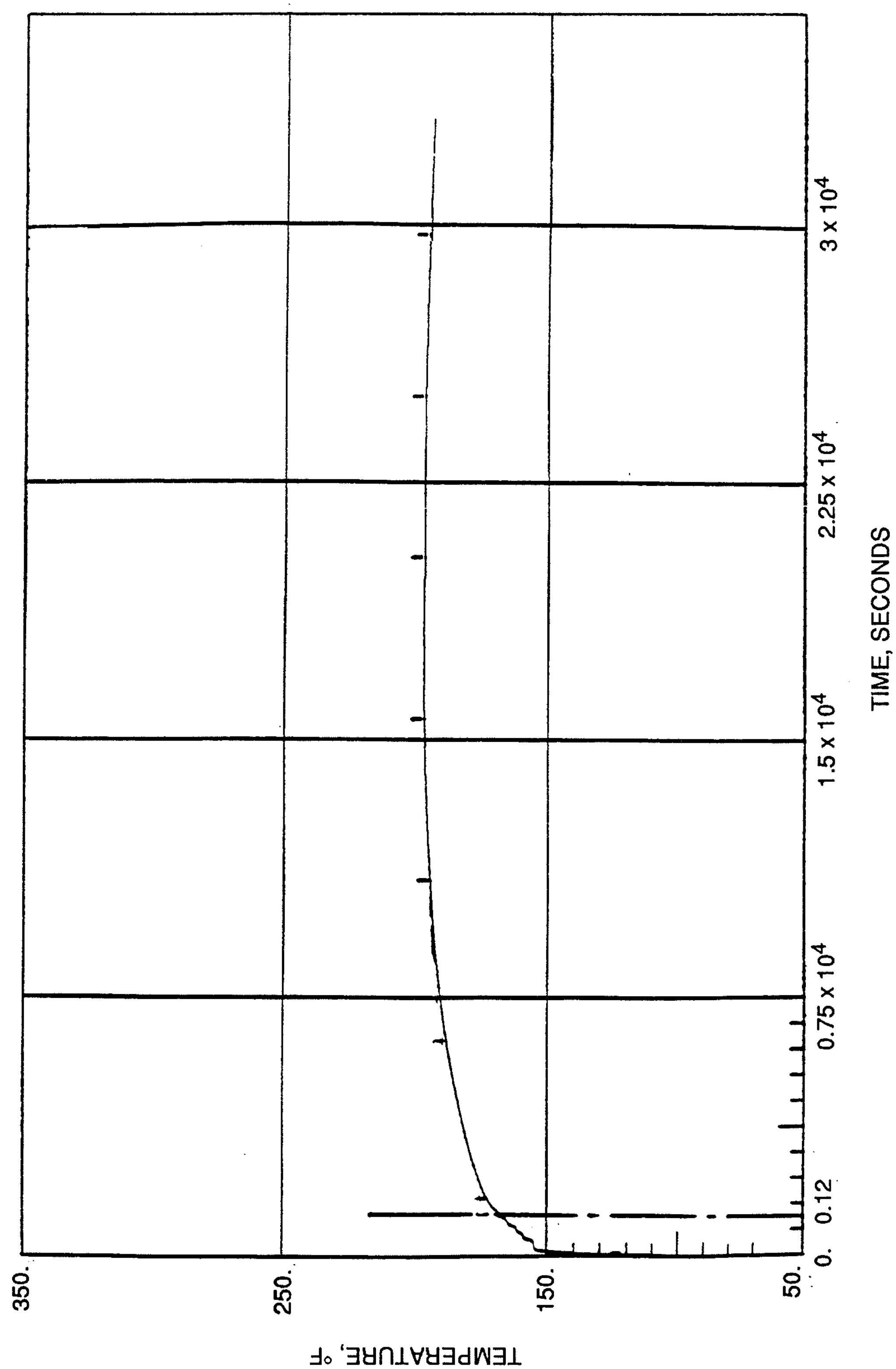

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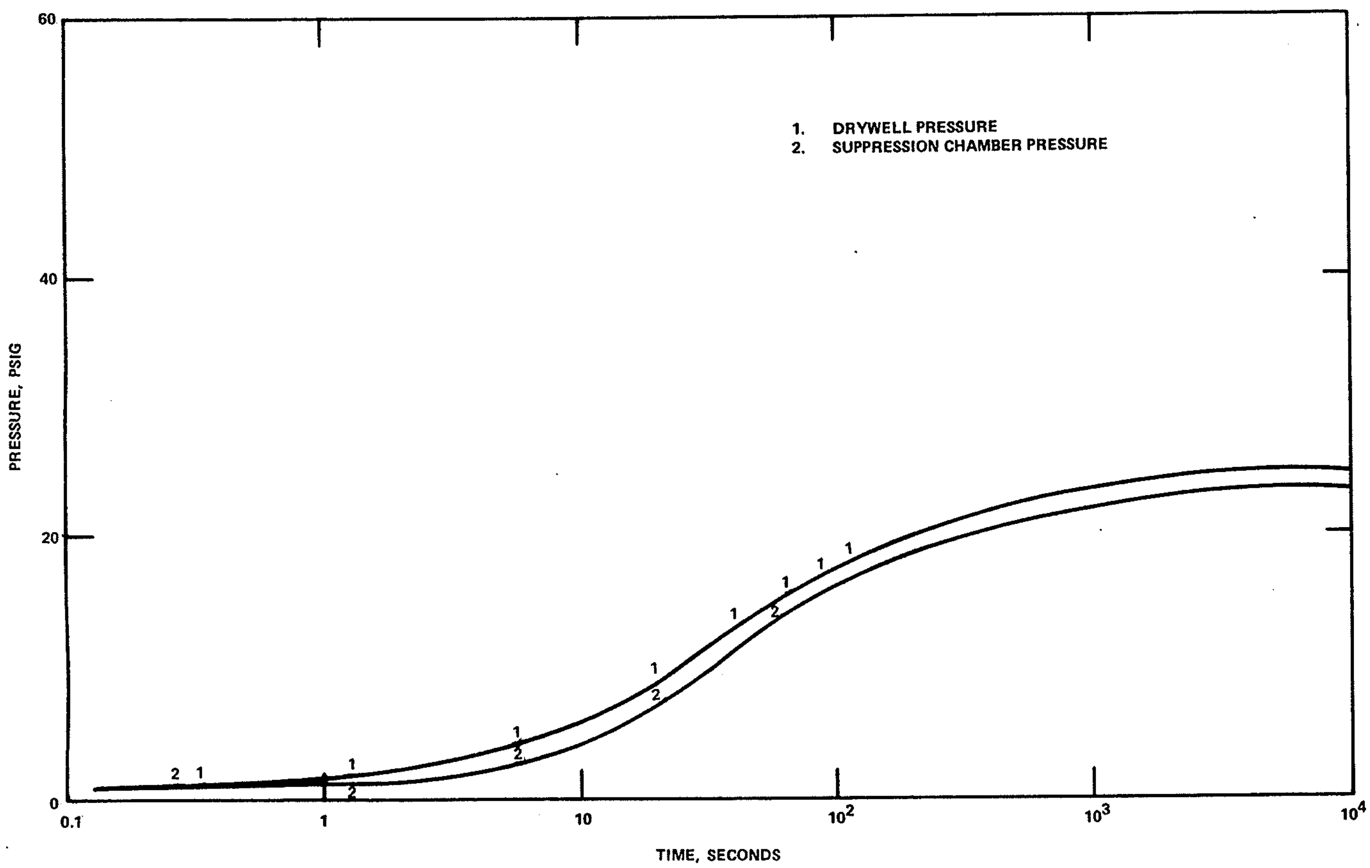
FIGURE 6.2-13

SUPPRESSION POOL TEMPERATURE
LONG TERM RESPONSE
(3499 MWT)

FIGURE 6.2-14

HAS BEEN INTENTIONALLY DELETED



*NOTE:

THE CONTAINMENT TEMPERATURE RESPONSE DUE TO THE SBA HAS ALSO BEEN RE-EVALUATED USING THE BASES PROVIDED IN REFERENCES 1 AND 3. THE PREDICTED SHORT-TERM RESPONSE IS REPORTED IN REFERENCE 2.

*EDISON NOTE TO GE DRAWING

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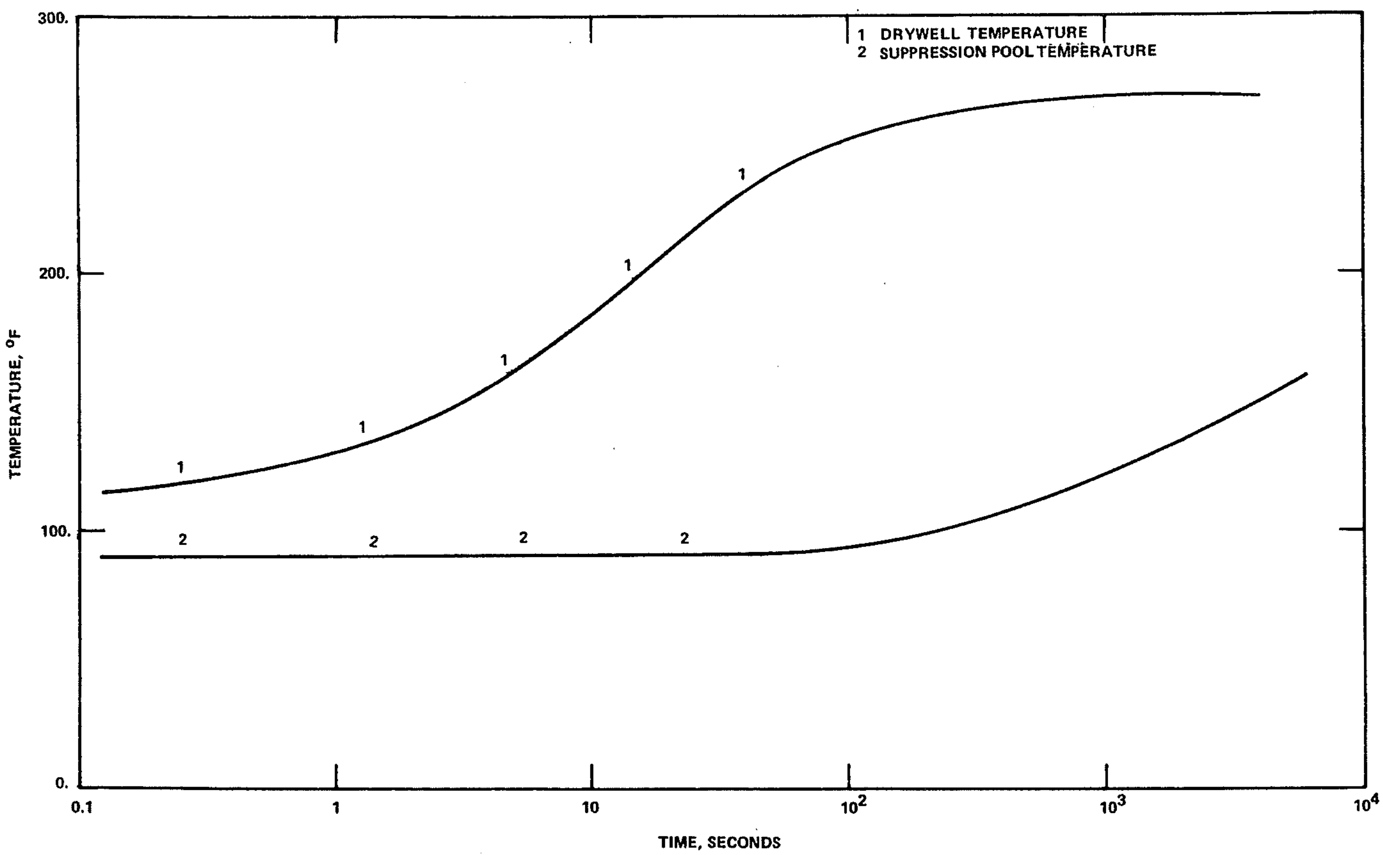
FIGURE 6.2-15

0.1 FT^2 LIQUID BREAK
PRIMARY CONTAINMENT PRESSURE RESPONSE
(BASED ON ORIGINAL POWER OF 3358 MWT)



*NOTE:

THE CONTAINMENT TEMPERATURE RESPONSE DUE TO THE SBA HAS ALSO BEEN RE-EVALUATED USING THE BASES PROVIDED IN REFERENCES 1 AND 3. THE PREDICTED SHORT-TERM RESPONSE IS REPORTED IN REFERENCE 2.

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FIGURE 6.2-16

0.1 FT^2 LIQUID BREAK
PRIMARY CONTAINMENT TEMPERATURE RESPONSE
(BASED ON ORIGINAL POWER OF 3,358 MWT)

FIGURES 6.2-17 THROUGH 6.2-19

HAVE BEEN INTENTIONALLY DELETED

Figure Intentionally Removed
Refer to Plant Drawing I-2649-01

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FIGURE 6.2-20

STANDBY GAS TREATMENT SYSTEM
P&ID

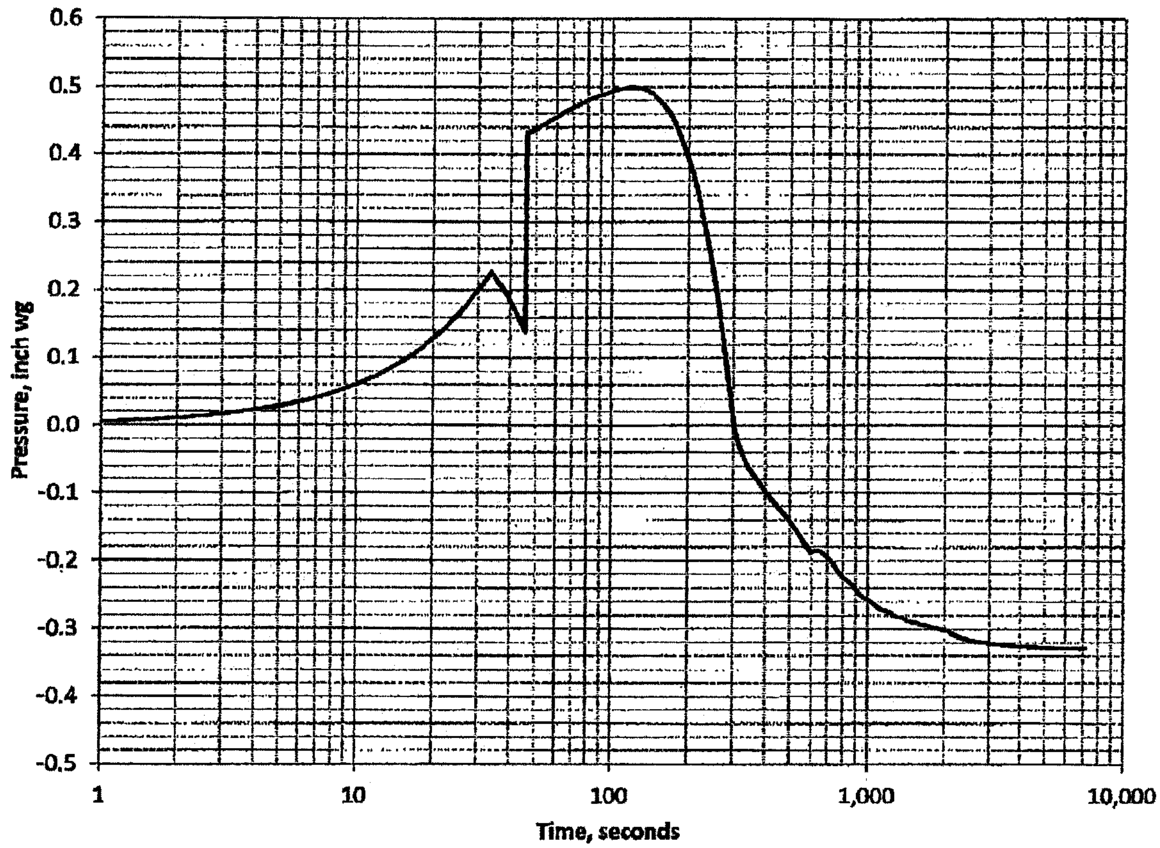

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FIGURE 6.2-21

SECONDARY CONTAINMENT RESPONSE
DUE TO A DBA-LOCA

FIGURE 6.2-22
HAS BEEN INTENTIONALLY DELETED

Figure Intentionally Removed
Refer to Plant Drawing M-2087

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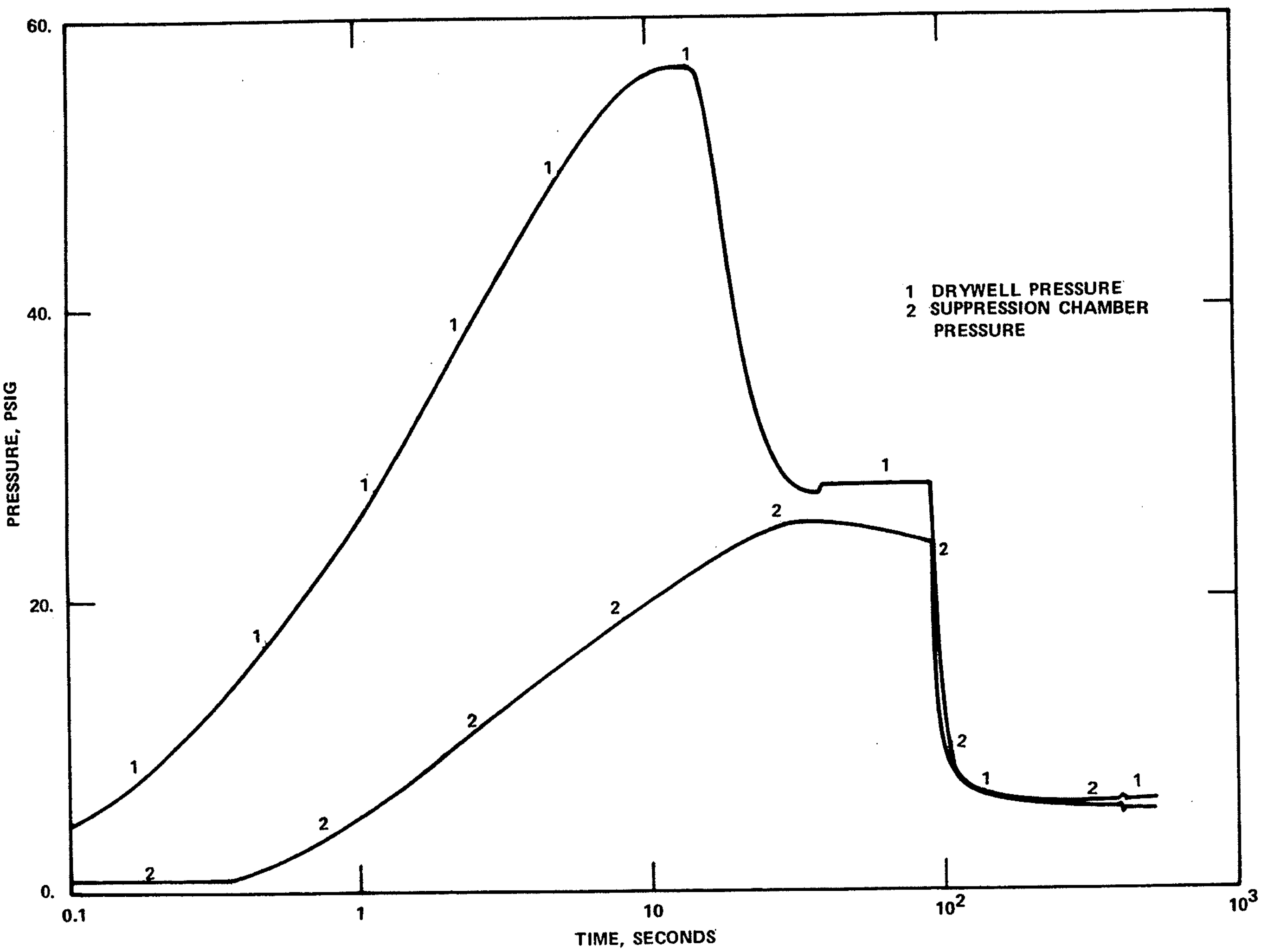
FIGURE 6.2-23

POST-LOCA RECOMBINER P&ID

FIGURE 6.2-24
HAS BEEN INTENTIONALLY DELETED

FIGURE 6.2-25
HAS BEEN INTENTIONALLY DELETED



*NOTE:

THE CONTAINMENT PRESSURE RESPONSE DUE TO THE RECIRCULATION LINE BREAK HAS ALSO BEEN RE-EVALUATED USING THE BASES PROVIDED IN REFERENCES 1 AND 3. THE PREDICTED SHORT-TERM RESPONSE IS REPORTED IN REFERENCE 2.

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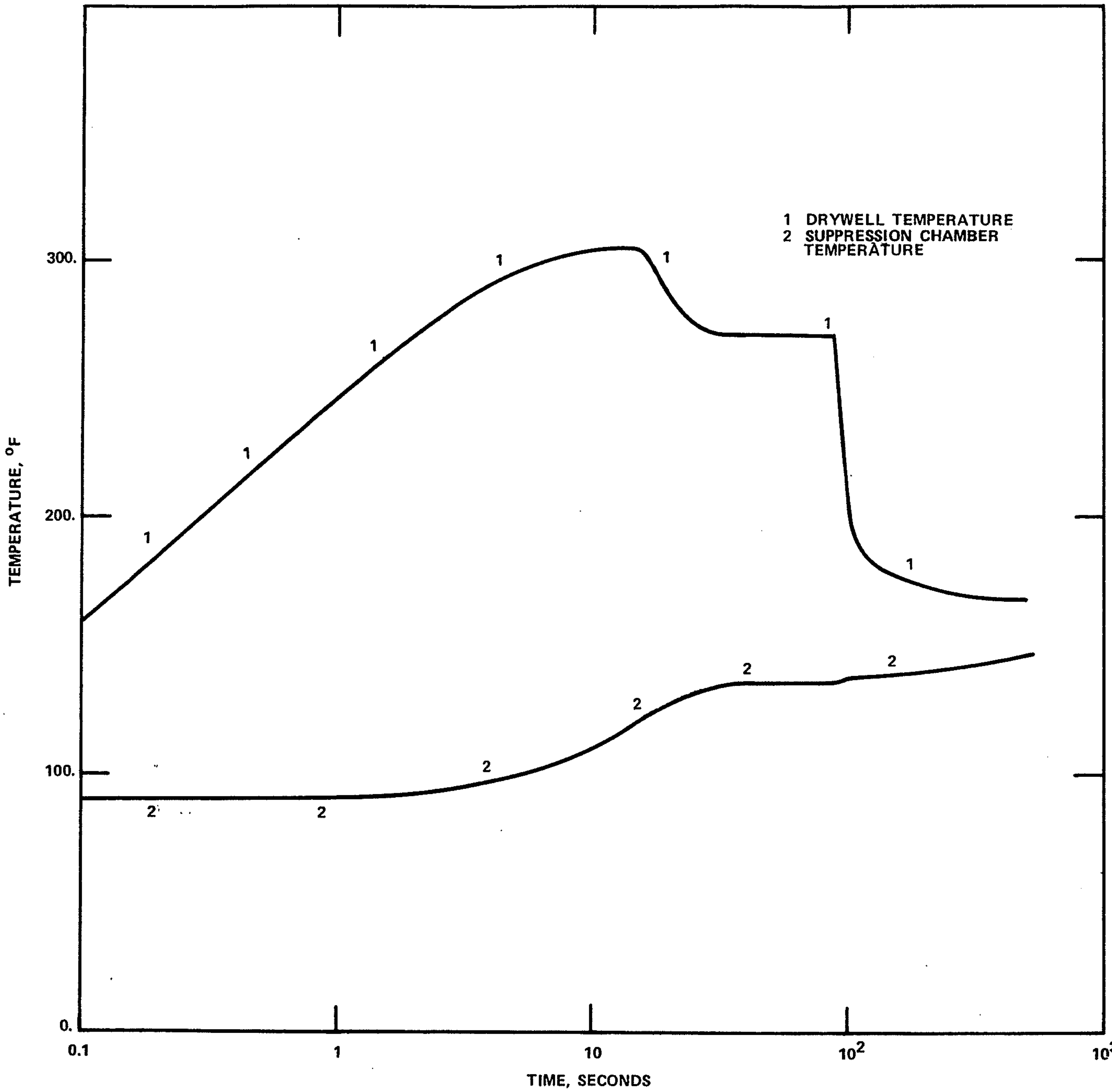
FIGURE 6.2-26

RECIRCULATION LINE BREAK PRIMARY CONTAINMENT INITIAL PRESSURE TRANSIENT (3358 MWT)



*NOTE:

THE CONTAINMENT TEMPERATURE RESPONSE DUE TO THE RECIRCULATION LINE BREAK HAS ALSO BEEN RE-EVALUATED USING THE BASES PROVIDED IN REFERENCES 1 AND 3. THE PREDICTED SHORT-TERM RESPONSE IS REPORTED IN REFERENCE 2.

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FIGURE 6.2-27

RECIRCULATION LINE BREAK PRIMARY CONTAINMENT INITIAL TEMPERATURE TRANSIENT (3358 MWT)

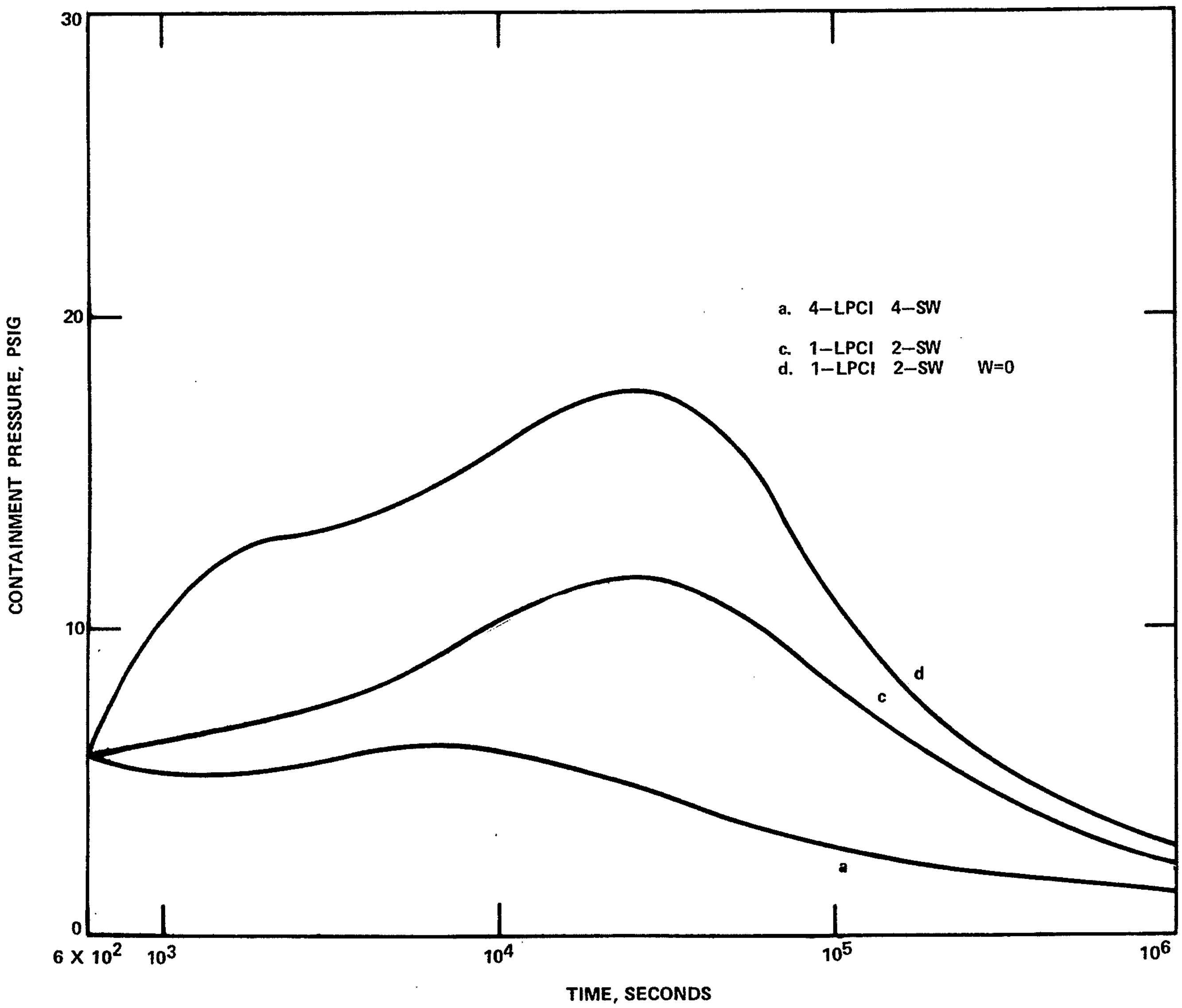

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FIGURE 6.2-28

PRIMARY CONTAINMENT PRESSURE LONG TERM RESPONSE (3358 MWT)

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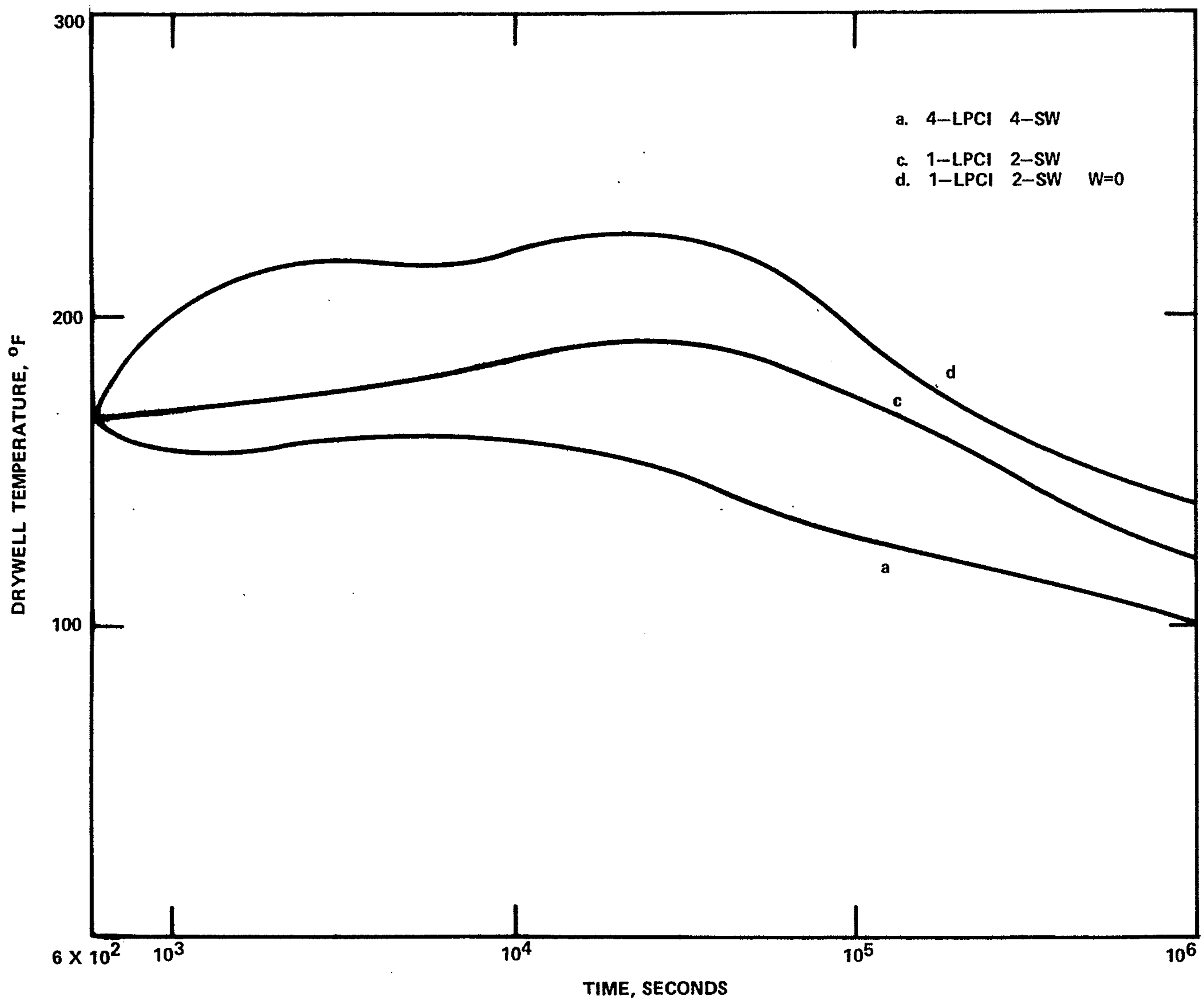

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FIGURE 6.2-29

DRYWELL TEMPERATURE LONG TERM RESPONSE (3358 MWT)

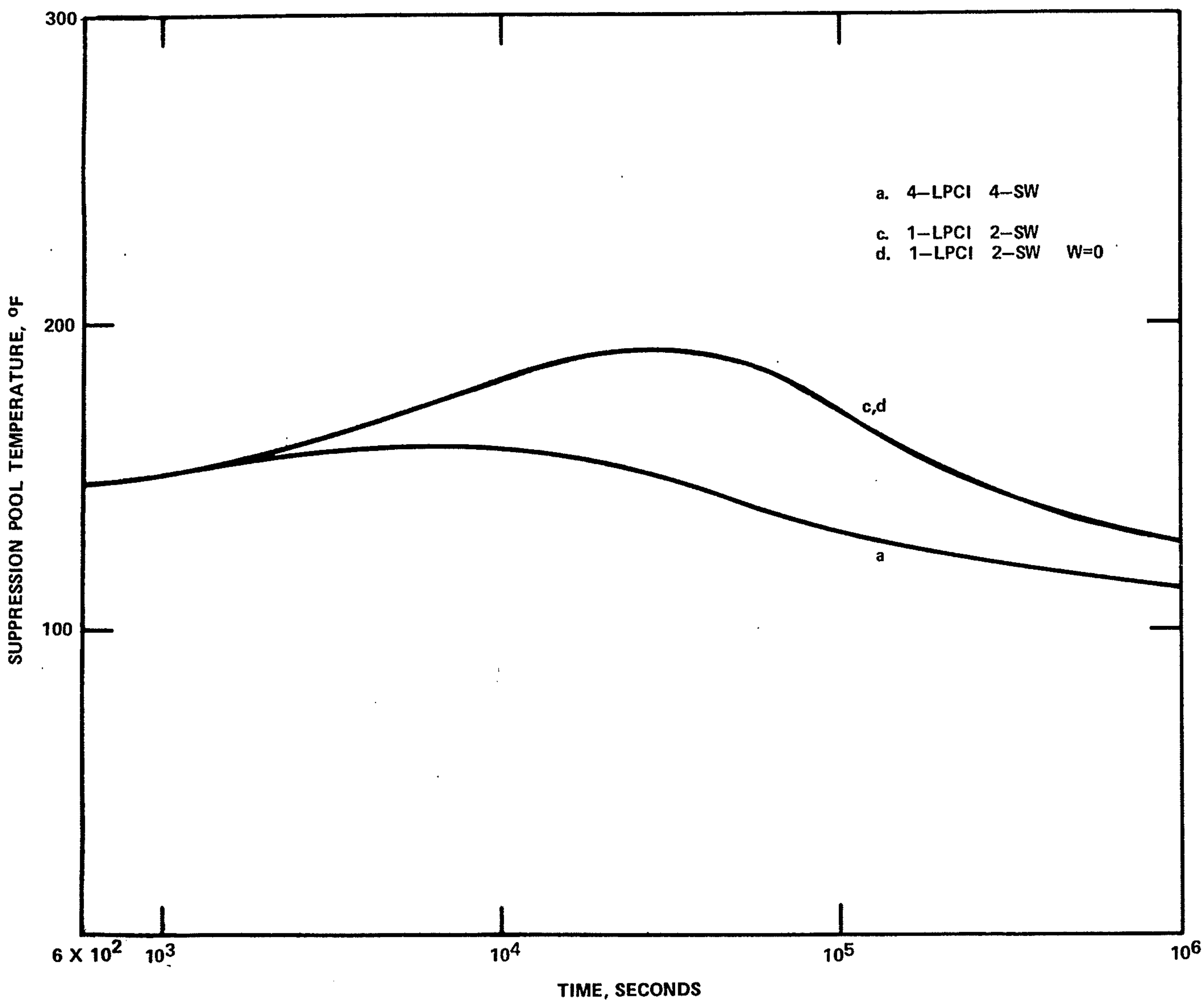

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FIGURE 6.2-30

SUPPRESSION POOL TEMPERATURE LONG TERM RESPONSE (3358 MWT)

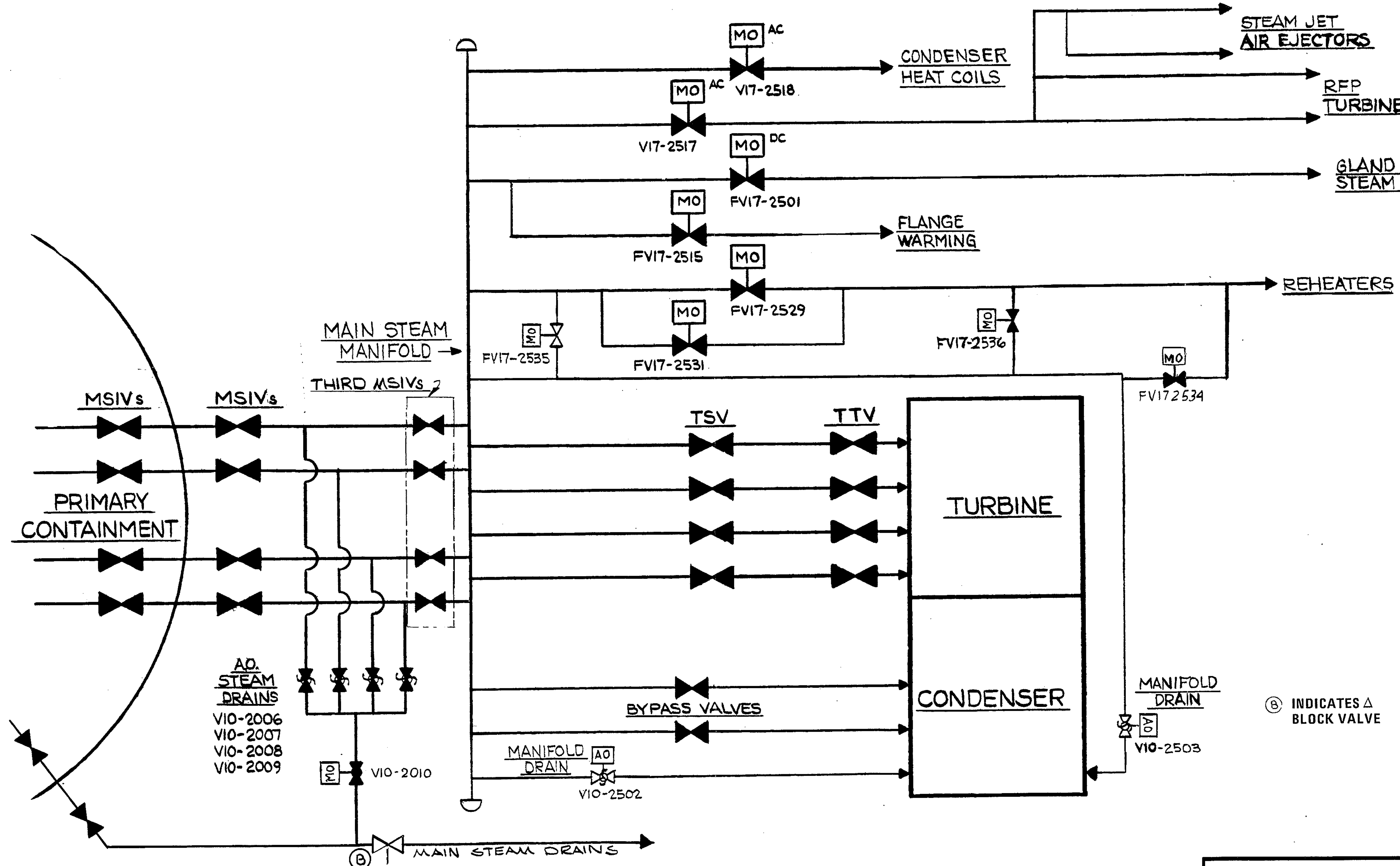

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FIGURE 6.2-31

MAIN STEAM SYSTEM PIPING AND VALVES

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Figure Intentionally Removed
Refer to Plant Drawing M-3045

FIGURE 6.2-32

MAIN STEAM ISOLATION
VALVE LEAKAGE CONTROL SYSTEM

6.3 EMERGENCY CORE COOLING SYSTEMS

Four systems are provided to protect the core against various sizes of hypothetical pipe breaks. Three of these inject emergency core cooling water into the reactor and one is a reactor pressure vessel (RPV) automatic depressurization system (ADS). The three injection systems consist of the high-pressure coolant injection (HPCI), low-pressure coolant injection (LPCI), and core spray system. The protection afforded by these systems meets the NRC criteria given in 10CFR 50.46.

6.3.1 Design Bases

The objective of the emergency core cooling systems (ECCS), in conjunction with the containment, is to limit the release of radioactive materials should a LOCA occur, so that resulting radiation exposures are kept within the guideline values given in 10 CFR 50.67 or 10 CFR 100 as applicable.

Safety design bases for the subsystems of the ECCS are given in the following subsections.

6.3.1.1 Range of Coolant Ruptures and Leaks

The ECCS provides adequate core cooling in the event of any break or leak in the piping of the nuclear system process barrier up to and including the double-ended break of the largest line connected to the RPV. The selection of break sizes and break locations is discussed in Subsection 6.3.3.7.3.

6.3.1.2 Fission Product Decay Heat

In the event of a LOCA, the ECCS removes delayed neutron fission heat, residual stored heat, and radioactive decay heat from the reactor core at a rate that limits the maximum fuel cladding temperature to a value less than the 10 CFR 50.46 limit of 2200°F. The amount of heat to be removed is discussed in Subsection 6.2.1.3.8.

6.3.1.3 Reactivity Required for Cold Shutdown

The reactor is designed to be in the cold-shutdown condition with the control rod of highest reactivity worth fully withdrawn and all other control rods fully inserted. Refer to Subsection 4.3.2 for a complete discussion.

6.3.1.4 Capability To Meet Functional Requirements

The following functional requirements are met:

a. The ECCS is provided with sufficient capacity, diversity, reliability, and redundancy to cool the reactor core under all accident conditions

b. The ECCS is initiated automatically by conditions that indicate the potential inadequacy of the normal core cooling

c. The ECCS is capable of startup and operation regardless of the availability of offsite power supplies and the normal generating system of the plant

d. Action taken to effect containment integrity does not negate the ability to achieve core cooling. All ECCS pumps are designed to operate without benefit of containment pressure

e. The components of the ECCS within the RPV are designed to withstand the transient mechanical loadings during a LOCA so that the required core cooling flow is not restricted

f. The equipment of the ECCS is designed to withstand the physical effects of a LOCA so that the core can be effectively cooled. Effects considered are missiles, fluid jets, pipe whip, high temperature, pressure, humidity, and seismic acceleration

g. A reliable supply of water for the ECCS is provided. The prime source of liquid for cooling the reactor core after a LOCA is a stored source located within the containment. The source is located so that a closed cooling water path is established during ECCS operation

h. The flow rate and sensing networks of each ECCS are testable during reactor shutdown. All active components are testable during normal operation of the nuclear system.

6.3.2 System Design

6.3.2.1 Emergency Core Cooling System Design

The bounds within which system parameters must be maintained and the acceptable inoperable components are discussed in the Technical Specifications.

The ECCS, containing four separate subsystems, is designed to satisfy the following performance objectives:

a. To limit the peak cladding temperature to 2200°F, to prevent a cladding metal/water reaction in excess of 1 percent of the cladding, and to maintain long-term coolability of the core in the event of a mechanical failure of the piping or the nuclear system process barrier, up to and including a break equivalent to the largest nuclear steam supply system (NSSS) pipe

b. To provide this protection by at least two independent, automatically actuated cooling systems

c. To function with or without external (offsite) power sources

d. To permit testing of the ECCS by acceptable methods, including, wherever practical, testing during power plant operations.

The aggregate of the ECCS is designed to protect the reactor core against fuel clad damage in excess of the limits set forth in 10 CFR 50.46 across the entire spectrum of line break accidents.

The operational capabilities of the various subsystems of the ECCS meet the functional requirements and performance objectives described below. Table 6.3-1 lists the types of LOCAs and the ECCS that would operate in response to each.

During the first 10 minutes following the initiation of operation of the ECCS, the functional requirement is satisfied for all combinations of single active component failures and single pipe breaks, including pipe breaks in any ECCS subsystem which might partially or completely disable that subsystem.

After the first 10 minutes following the initiation of operation of the ECCS, and in the event of an active or passive component failure in the ECCS or its essential support system, long-term core and containment cooling is provided by any one LPCI or core spray loop delivering water to the RPV and by one residual heat removal (RHR) pump supported by one RHR heat exchanger with 100 percent service water flow. Containment cooling, using one RHR pump supported by one RHR heat exchanger, can be delayed up to twenty minutes following the DBA LOCA.

The power for operation of the core spray and LPCI is from regular ac power sources. Upon loss of the regular power, operation is from onsite standby ac power sources. Standby sources have sufficient diversity and capacity so that all core spray and LPCI requirements are satisfied. One core spray loop and one LPCI loop are powered from one ac division and the other core spray loop and LPCI loop are powered from a second and separate ac division. Four diesel generators are the site backup power supplies, with two diesel generators and two buses per division.

With the exception of LPCI while lined up in shutdown cooling and RPV pressure is less than or equal to the cut in pressure, all systems start automatically. The starting signal comes from independent and redundant sensors of drywell pressure and low RPV water level. Refer to Subsection 7.3.1 for a complete discussion of the ECCS instrumentation and starting and control logic.

Piping and instrumentation diagrams for the subsystems and components that constitute the ECCS are provided and referenced under the discussion of the subsystem or component.

6.3.2.2 Equipment and Component Descriptions

The four types of core cooling systems (HPCI, ADS, core spray, and LPCI) are described in this section with reference to the appropriate piping and instrumentation diagrams and system process diagrams.

6.3.2.2.1 High Pressure Coolant Injection System

The HPCI system is provided to ensure that the reactor core is adequately cooled to meet the design bases in the event of a small break in the nuclear system and loss of coolant that does not result in rapid depressurization of the RPV. Liquid breaks up to approximately 0.1 ft^2 break area and steam breaks up to approximately 0.5 ft^2 break area are within the capability of the HPCI system alone. This permits the plant to be shut down while maintaining sufficient RPV water inventory until the RPV is depressurized. The HPCI system continues to operate until RPV pressure is below the maximum pressure at which LPCI operation or core spray system operation can maintain core cooling.

The HPCI system consists of a steam turbine assembly driving a constant-flow pump assembly and system piping, valves, controls, and instrumentation. The HPCI piping and instrumentation diagram is shown in Figure 7.3-1. The HPCI system process and valve lineup diagrams are shown in Figures 6.3-1 through 6.3-5. The schematic drawing is shown in Figure 6.3-1.

The principal HPCI equipment is installed in the reactor building. The turbine-pump assembly is located in a shielded area to ensure that personnel access to adjacent areas is not restricted during operation of the HPCI system and to be protected from the physical effects of design-basis accidents (DBAs) such as pipe whip, flooding, and high temperature.

The pump assembly is located below the level of the condensate storage tank and below the water level in the suppression pool to ensure positive suction head to the pumps.

Two sources of water are available. The HPCI system initially injects water from the condensate storage tank (see Figure 6.3-2). When the water level in the tank falls below setpoint level or when suppression pool level is high, the pump suction is auto-matically transferred to the suppression pool. This transfer may also be made from the main control room using remote controls. The transfer requires the opening of normally closed valves F041 and F042 in the pump suction line leading from the suppression pool. The opening of these valves automatically closes valve F004 in the pump suction line leading from the condensate storage tank. When the pump suction has been transferred to the suppression pool, a closed loop is established for recirculation of water escaping from a break (see Figure 6.3-3).

Injection water is piped to the reactor feedwater pipe at a T-connection.

The HPCI turbine is driven by steam from the RPV which, after reactor shutdown, is generated by decay and residual heat. The steam is extracted from a main steam line upstream of the main steam isolation valves (MSIVs). The HPCI inboard isolation valve (F002) and the bypass valve around the HPCI outboard isolation valve (F600) in the steam line to the HPCI turbine are normally open to keep the piping to the turbine at elevated temperatures. This permits rapid startup of the HPCI system. Signals from the HPCI control system open (with oil pressure available) or close the turbine control/stop valve.

A condensate drain pot is provided upstream of the turbine steam admission valve to prevent the HPCI steam supply line from filling with water. The drain pot normally routes the condensate to the main condenser, but upon receipt of a HPCI initiation signal or a loss of non-interruptible control air pressure, isolation valves on the condensate line automatically close.

The turbine has two devices for controlling power. One is a speed governor that limits turbine speed to its maximum operating level, and the other is a control governor with automatic speed setpoint control that is positioned by a demand signal from a flow controller to maintain constant flow over the pressure range of HPCI operation.

As reactor steam pressure decreases, the HPCI governor valves open further to pass the steam flow required to provide the necessary pump flow. The capacity of the system is selected to provide sufficient core cooling to prevent excessive clad temperatures while the pressure in the RPV is above the pressure at which core spray and LPCI become effective.

Startup of the HPCI system is completely independent of ac power. Only dc power from the station battery and steam extracted from the nuclear system are necessary. The HPCI controls automatically start the system and bring it to design flow rate within 60 sec from receipt of a primary containment (drywell) high-pressure signal or an RPV low water level signal. This time interval for HPCI injection is used in the Fermi 2 TRACG-LOCA analyses that demonstrate conformance to 10 CFR 50.46 (Reference 42).

High-pressure coolant injection operation automatically actuates the following valves:

a. HPCI pump discharge shutoff valve

b. HPCI steam supply shutoff valves

c. HPCI turbine stop valve

d. HPCI turbine control valves

e. HPCI steam line drain isolation valves

f. HPCI pump suction valve from condensate storage.

Startup of the hydraulic oil pump and proper functioning of the hydraulic control system is required to open the turbine valves. Operation of the barometric condenser components is functionally illustrated in Figure 7.3-2 and their failure does not prevent the HPCI system from fulfilling its core cooling objective. The same initiating signal automatically starts the turbine oil pump, and when sufficient oil pressure is developed, the stop valve begins to open. Contacts actuated by the HPCI turbine stop and turbine steam supply valve limit switches initiate the speed control ramp generator which slowly increases the control valve position from closed to the value demanded by the flow controller. As a result, the turbine smoothly accelerates from rest to the speed at which rated pump flow is developed. When rated flow is established, the flow controller signal adjusts the setting of the control governor so that rated flow is maintained as nuclear system pressure decreases.

A minimum flow bypass is provided for pump protection (see Figure 6.3-4). The bypass valve (F012) automatically opens when a low flow combined with a high discharge pressure signal is sensed. It automatically closes on a high-flow signal or if the closing of either the turbine stop valve or steam inlet valve is sensed. Pump discharge pressure is sensed by PS N027, and flow is sensed by FS N006. When the bypass is open, flow is directed to the suppression pool.

A full-flow functional test of the HPCI can be performed during plant operation by drawing suction from the condensate storage tank and returning the water to the tank through a full-flow test line (see Figure 6.3-5). During this test, a signal to initiate the HPCI automatically stops the test mode and starts the water injection to the feedwater line. This transfer from the test mode to the accident mode requires the closing of the normally closed (but open for the test mode) valves F008 and F0ll located in the test line connecting the pump discharge and the condensate storage tank.

A cross connection is provided from the HPCI Test Line piping to the GSW piping to be used as part of the Flexible and Diverse Coping Strategy (FLEX) to mitigate Beyond Design Basis External Events (BDBEE) in response to NRC Order EA-12-049.

Exhaust steam from the HPCI turbine is discharged to the suppression pool. A drain pot at the low point in the exhaust line collects moisture present in the steam. Collected moisture is discharged to the suppression pool or bypassed to the barometric condenser.

The HPCI turbine gland seals are vented to the barometric seal condenser. Noncondensable gases from the barometric condenser are pumped to the standby gas treatment system (SGTS).

A redundant system of check valves and isolation valves has been installed as a vacuum breaker line that connects the air space in the suppression pool with the HPCI turbine exhaust line. This eliminates any possibility of water from the suppression pool being drawn into the HPCI turbine exhaust line. The two isolation valves (electrically separated) in series in this vacuum breaker line operate automatically via a combination of low reactor pressure and high drywell pressure. Test connections are provided on either side of the two check valves.

The system component classifications plus additional requirements are described in Chapter 3. The pump is designed and tested in accordance with the standards of the Hydraulic Institute.

The system is designed for a service life of 40 years, accounting for corrosion, erosion, and material fatigue. The various operations of the HPCI components are summarized below.

The HPCI turbine is shut down automatically by any of the following signals:

a. Turbine overspeed--prevents damage to the turbine casing

b. Reactor pressure vessel high water level--indicates that core cooling requirements are satisfied

c. High-pressure coolant injection pump low suction pressure--prevents damage to the pump due to loss of flow

d. High-pressure coolant injection turbine exhaust high pressure--indicates a turbine or turbine control malfunction.

If an initiation signal is received after the turbine is shut down, the system will restart automatically if no shutdown signals exist.

Because the steam supply line to the HPCI turbine is part of the nuclear system process barrier, certain signals automatically isolate this line, causing shutdown of the HPCI turbine. Automatic shutoff of the steam supply is described in Section 7.3. However, automatic depressurization and the low-pressure systems of the ECCS act as backup, and automatic shutoff of the steam supply does not negate the ability of the ECCS to satisfy the safety objective.

In addition to the automatic operational features of the system, provisions are included for remote manual startup, operation, and shutdown (provided automatic initiation or shutdown signals do not exist). Remote controls for valve and turbine operation are provided in the main control room. The controls and instrumentation of the HPCI system are described, illustrated, and evaluated in detail in Section 7.3.

6.3.2.2.2 Automatic Depressurization System

In case the capability of the feedwater pumps, control rod drive (CRD) pumps, reactor core isolation cooling (RCIC) system, and HPCI system is not sufficient to maintain the reactor water level, the ADS functions to reduce the reactor pressure to a value low enough (<300 psig) to allow the LPCI and core spray systems to pump water to the RPV in time to cool the core consistent with the design bases.

The ADS uses five of the 15 safety/relief valves of the nuclear system pressure relief system to achieve the automatic blowdown to the suppression pool. The capacity of each relief valve is about 900,000 lb/hr at set pressure. The ADS starts operating soon enough after failure of the HPCI and dumps steam fast enough to ensure that the LPCI and core spray systems begin to operate and cool the fuel adequately.

To activate, the ADS must have drywell high pressure (2 psig) and RPV low water level (level 1) signals. Simultaneous occurrence of these drywell high pressure and RPV low water level conditions initiate a time delay of 120 seconds to allow the HPCI system time to recover level. After that time delay, ADS safety relief valves will operate if at least one RHR pump or both core spray pumps in either division are running (developing pressure). RPV low water level (level 1) signal also activates a bypass timer set for 8 minutes. This bypass time delay is provided to bypass the drywell pressure high logic circuit. If for some reason the drywell high pressure is not detected, the RPV low water level signal alone will activate the ADS safety relief valves after the 8 minute bypass time delay, plus the original 120 second time delay, provided that appropriate discharge pressure signals are present. The values shown above are based on analysis (Reference 34); refer to Technical Requirements Manual Table 3.5.1-1 for operating setpoints.

Opening of the relief valve requires pneumatic pressure to the valve's diaphragm actuator. This pneumatic supply is controlled by a solenoid-operated pilot valve. For the ADS to function, this valve control system must be operable, and there must be a pneumatic supply. The accumulator associated with the relief valves used with the ADS has sufficient capacity to allow for five operations of the pilot valves to cover interruptions if the pneumatic supplies are switched from the normal to the emergency backup sources. The relief valve pneumatic supply and backup supply systems are capable of performing their function for the long-term period of 100 days following an accident as required by NUREG-0737, Item II.K.3.28. (See also Section 5.2.2.2.3 for a description of the accumulator system.) The accumulator and pneumatic supply systems are capable of performing their design function during and following exposure to a harsh environment and/or a seismic event. In the automatic depressurization mode, the relief valves do not reset to normal safety/relief valve setpoints on low RPV pressure. To ensure proper cooling under all circumstances, including a postulated failure of ADS, reactor pressure relief can still be provided by operation of the non-ADS safety/relief valves. This ensures that the low pressure systems can be actuated with a HPCI failure and one additional single failure of the ADS, since any single failures affecting ADS will not impair remote operation of eight non-ADS safety relief valves.

The ADS valves stay open once activated until the reactor pressure is 50 psi higher than the containment pressure. These valves close when the reactor pressure decays to less than 50 psi above the containment pressure, and reopen when the reactor pressure is 100 psi above the containment pressure. Thus, the maximum pressure that can exist during the long-term period following a LOCA is 100 psi plus containment pressure.

The design, description, and evaluation of the pressure relief valves are discussed in detail in Subsection 5.2.2. See Section 7.3 for details on instrumentation and control.

The relief valve setpoints cannot be tested while they are in place on the steam lines. The safety/relief valves are designed to allow removal for bench testing of the setpoints during shutdown.

6.3.2.2.3 Core Spray System

The core spray system protects the core in the event of a large break in the nuclear system if the feedwater pumps, the CRD pumps, the RCIC, and the HPCI systems are unable to maintain RPV water level.

The protection provided by the core spray system also extends to a small break if the feedwater pumps, CRD pumps, RCIC, and HPCI systems are all unable to maintain the RPV water level and the ADS has operated to lower the RPV pressure so that LPCI and the core spray system provide core cooling.

Two independent loops are provided as a part of the core spray system. Each loop consists of two single-stage, in-line water pumps with suction and discharge connected in parallel and each pump driven by an 800-hp electric motor; a spray sparger in the RPV above the core; piping and valves to convey water from the suppression pool to the pumps and to the sparger; and the associated controls and instrumentation. Figures 6.3-7 through 6.3-11 show the schematic process and valve lineup diagrams of the core spray system. The piping and instrumentation diagram is shown in Figure 7.3-7.

In case of low water level in the RPV or high pressure in the drywell, the core spray system automatically starts and the pumps in the two core spray loops are signaled to start after a 5-sec delay on auxiliary ac power. This signal also starts without delay the diesel generator set and the LPCI system. In case auxiliary ac power is lost, the pumps start in sequence (with time delay) on standby ac power. Pump suction valves F001A, B, C, and D are normally locked open to ensure a positive suction head for the pumps. The test bypass motor-controlled valves F0l5A and B, normally closed, are signaled to close if open. When the reactor pressure is permissive (<500 psig), valves F004A and B (normally open) and F005A and B are signaled to open automatically. The pumps take water from the suppression pool and discharge to the sparger ring and nozzle spray. This condition is shown in Figure 6.3-8.

When the system is actuated, water is taken from the screened suction line in the suppression pool. Flow then passes through a normally open, motor-operated valve. A keylock switch is installed in the control circuit with position indication available in the main control room. This valve is located in the core spray pump suction line as close to the suppression pool as practical. It can be closed by a remote manual switch from the main control room to isolate the system from the suppression pool in case of a leak from the core spray system.

The four core spray pumps are located in the reactor building below the water level in the suppression pool to ensure positive pump suction. The pumps, piping, controls, and instrumentation of each loop are separated and protected so that any single physical event, or missile generated by rupture of any pipe in any system within the containment drywell, cannot make both core spray loops inoperable. The switchgear for each loop is in a separate emergency bus room for the same reason.

A vent line with two normally closed valves is provided from the pump casing for filling the pump with water. A shaft seal drain is provided, which drains to the radwaste system, along with the vent line. Leakage from the drain line is measured during primary containment leakage tests.

A low-flow bypass line is provided from the pump discharge to below the surface of the suppression pool. The bypass flow is required to prevent the pump from overheating when pumping against a closed discharge valve. An orifice limits the bypass flow. A manual valve that is normally locked open is used to close the bypass line for maintenance. A motor-operated valve on the bypass line closes upon receipt of a signal from a flow switch in the main discharge line.

Two relief valves, set for 500 psig, protect each low pressure core spray system loop upstream of the outboard shutoff valve from reactor pressure. The relief valves discharge to the suppression pool.

Two motor-operated valves are provided to isolate the core spray system from the nuclear system when the core spray pump is not running. These valves admit core spray water to the inboard check valve when signaled to open at approximately 500-psig RPV pressure. Both valves are installed outside the drywell to facilitate operation and maintenance, but as close as practical to the drywell to limit the length of line exposed to reactor pressure. The valve nearer the containment is normally closed to back up the inside check valve for containment purposes. The outboard valve is normally open to limit the equipment needed to operate in an accident condition. A test line is normally closed with two normally closed valves and a pipe cap to ensure containment.

A check valve is provided in each core spray line just inside the primary containment to prevent loss of reactor coolant outside containment in case the core spray line breaks. A normally locked-open manual valve is provided downstream of the inside check valve to shut off the core spray system from the reactor during shutdown conditions for maintenance of the upstream valves. The two core spray system pipes enter the RPV through nozzles l20° apart. Each pipe then divides into a semicircular header with a downcomer at each end which turns through the shroud near the top. A semicircular sparger is attached to each of the four outlets to make two practically complete circles, one above the other inside the shroud head. Short elbow nozzles are spaced around the spargers to spray the water radially into the tops of the fuel assemblies.

Core spray piping upstream of the outboard shutoff valves F004A and B is designed for the lower pressure and temperature of the core spray pump discharge. The outboard shutoff valve and downstream piping are designed for RPV pressure and temperature. The pumps, piping, and valves are designed to meet requirements described in Chapter 3. The pumps are also designed and tested in accordance with the standards of the Hydraulic Institute. Pump operability testing under the plant technical specifications and the in-service testing program ensures pump operation at or above the minimum required performance assumed in the plant safety analyses. Pump test acceptance criteria developed for this purpose are required to include consideration of the lowest allowed emergency diesel generator (EDG) operating frequency based on the maximum allowed frequency control tolerance as well as pressure and flow test instrument accuracies.

The core spray pumps and all automatic valves can be operated individually by manual switches in the main control room. Operating information is provided in the main control room with pressure indicators, flowmeters, and indicator lights. Automatic signals to start the system preempt all other signals while the system is in auto mode. In the manual condition, the pump or valve will be under total operator control. The manual condition is indicated to the operator in the main control room.

6.3.2.2.3.1 Core Spray Test Mode During Plant Operation

A test line for the rated core spray system flow rate is provided to route the suppression pool water from the pump discharge to the suppression chamber without entering the reactor pressure vessel (see Figure 6.3-9). During reactor operation, the core spray injection valves are normally closed. The pumps are started by the operator using the remote manual control in the main control room. Valves F015A and B in the test lines are opened partially to achieve the rated flow through the test lines. This mode of operation permits testing of pump operation and ensures that rated flow is achieved. It also permits testing of control and operation of components of the low pressure section of the core spray system.

6.3.2.2.3.2 Core Spray Test During Plant Shutdown

To provide for system testing during a plant shutdown (see Figure 6.3-10), a connection is provided from the condensate storage tank to the pump suction. This condensate is used for flow testing of the spray nozzles inside the pressure vessel. A normally closed manual valve is provided between the condensate storage tank and the pump suction line to minimize the possibility of communication of the condensate to the suppression pool and to avoid extension of the primary containment.

During plant shutdown, the core spray system can be tested by manually opening valves F002A and B. The pumps are started by remote manual control, and valves F004A and B and F005A and B are opened by remote manual switch. System operation including sparger rings can be tested in this manner during shutdown conditions. Any system maintenance or repairs may be made on the core spray system during plant shutdown by manually closing valves F007A and B, which are normally locked open.

System operability is determined by performing a system functional test which includes simulated automatic actuation of the system throughout its emergency operating sequence and verifying that each automatic valve in the flow path actuates to its correct position. Actual injection of coolant into the reactor vessel may be excluded from this test, which is performed every 24 months. Such testing was performed during initial plant startup and periodic performance is not needed as the continued operability of the LPCS header is assured by means of the break detection logic discussed in Subsection 7.3.1.2.3.9.

6.3.2.2.3.3 Core Spray Minimum Flow Bypass Mode

The pump discharge line is provided with a low-flow bypass line to protect the core spray pumps from overheating during operation at high vessel pressure (see Figure 6.3-11). Flow-measuring element FE N002 is coupled to flow switch FS N006, which at a nominal flow rate of less than 2100 gpm, signals bypass line motor-operated valve F031 to open automatically. Water from the suppression pool is then routed through the bypass lines back to the suppression pool. As soon as flow is established in the pump discharge lines, the signal from FS N006 signals the minimum bypass motor-operated valves F03lA and B to close automatically.

6.3.2.2.4 Low Pressure Coolant Injection System

In case of low water level in the reactor or high pressure in the containment drywell, the LPCI mode of operation of the RHR system pumps water into the RPV in time to cool the core consistent with the design bases. The core spray system starts from the same signals and operates independently to achieve the same objective. The isolation valves for these two systems are opened when reactor pressure is less than 500 psig, but injection flow does not occur until the differential pressure across the check valves permits. This occurs when the RPV pressure is less than 300 psig.

Low-pressure coolant injection operation provides protection to the core for the case of a large break in the nuclear system when the feedwater pumps, the CRD pumps, and RCIC and HPCI systems are unable to maintain RPV water level. Manual override of LPCI operation is prevented by two keylocked switches. Conditions for manual override of LPCI operation are described in the Fermi 2 Containment Control Emergency Procedures.

Protection provided by LPCI also extends to a small break in which the feedwater pumps, CRD pumps, and RCIC and HPCI systems are all unable to maintain the RPV water level, and the ADS has operated to lower the reactor vessel pressure so that LPCI and core spray systems start to provide core cooling.

In the event of a break in one of the two reactor recirculation system loops, logic is provided to sense the broken loop and to inject the LPCI flow into the unbroken loop. Thus, the flows from the two LPCI system loops are interconnected by valving. Since electrical power to each LPCI loop is isolated (Divisions I and II), it is necessary to have a swing bus arrangement that permits the valves of an LPCI loop that has been disabled by a single failure of a divisional electrical supply to be energized. This feature preserves the ability of the LPCI to cross-connect flow and inject into the unbroken recirculation loop.

The Fermi 2 LPCI valve logic also provides for closing only the valve in the discharge side of the unbroken reactor recirculation loop as opposed to earlier logic that closed both the discharge and suction valves in the unbroken reactor recirculation system loop. The logic change provides for continued depressurization (permitting coolant injection by the core spray system) in the event that the single failure is the LPCI logic that selects the broken reactor recirculation system loop.

6.3.2.2.4.1 Accident Mode

Valves F048A and F048B open automatically. Also, valves F015 and F017 in the loop corresponding to the undamaged recirculation loop receive a signal to open automatically upon receipt of reactor vessel low pressure (<500 psig) signal. See Figure 6.3-14.

The system pumps take water from the suppression pool and pump it into the core region of the reactor vessel through the undamaged recirculation loop. The system pumps are rated at 10,000 gpm per pump. The rated flow of 30,000 gpm is delivered with three-pump operation at 20 psid pressure difference between the reactor vessel and the primary containment. A redundancy of pumps is provided so there is one more pump available than the number required for the rated flow in the LPCI. The core is flooded to an adequate height and the level maintained by the LPCI operating alone with three of four pumps operating.

Soon after the LOCA (assuming offsite power is also lost), the high-drywell-pressure or reactor-low-water signal initiates the selected valves in the LPCI and core spray systems to open. These valves receive power as soon as it is restored by the emergency diesel generators. The LPCI system pumps are also signaled to start. The core spray system pumps start with 5-sec delay, i.e., within 18 sec of the accident. The LPCI injection valves are fully open and the recirculation loop discharge valve (in the undamaged loop) closes within 77 seconds. This interval is the maximum allowable time from the high drywell pressure initiating signal to pump at rated speed and ready to inject flow to the vessel with emergency power that is used in Fermi 2 TRACG-LOCA analyses (Reference 42).

6.3.2.2.4.2 Low Pressure Coolant Injection Loop Selection Logic

This system is described in Subsection 7.3.1.2.4.

6.3.2.2.4.3 Low Pressure Coolant Injection Test Mode

A design flow (10,000 gpm per pump) functional test of the RHR system pumps is performed for each pair of pumps during plant operation by taking suction from the suppression pool and discharging through the test lines back to the suppression pool (see Figure 6.3-15). Discharge valve F015 to the reactor recirculation line remains closed, and reactor operation is undisturbed. The upstream and downstream valves for the containment spray headers (F016 and F021) are tested or exercised individually by remote manual switches in the main control room.

The control system is designed to provide automatic return from test mode to operating mode if LPCI injection is required during testing.

6.3.2.2.4.4 Low Pressure Coolant Injection Minimum Flow Bypass Mode

This mode of operation is provided to protect the system pumps from overheating at low flow rates, by routing the pump flow through the minimum bypass lines to the suppression chamber. A single motor-operated valve F007 in each bypass line automatically opens upon sensing low flow after either RHR pump within the associated division is started. This valve automatically closes whenever the flow from either of the associated main system pumps is above the low-flow setting. One switch (N021) is used for each loop. (See Figure 6.3-16).

Low-pressure coolant injection pump and piping equipment is described in detail in Subsection 5.5.7, which also describes the other functions served by the same pumps if not needed for the LPCI function.

6.3.2.2.5 Emergency Core Cooling System Discharge Line Fill System

One design requirement of any core cooling system is that cooling water flow to the RPV be initiated rapidly when the system is called on to function. This quick-start system characteristic is provided by quick-opening valves and quick-start pumps. By always keeping the HPCI, LPCI, and core spray pump discharge lines full, the lag between the signal for pump start and the initiation of flow into the RPV can be minimized. If for some reason these lines were empty when the systems were called for, not only would the lag time be increased, but also the lines would be subjected to unnecessarily large momentum forces associated with accelerating fluid into an empty pipe. To prevent draining of the ECCS-discharge lines, a fill system is provided to keep the core spray lines charged with demineralized water and the RHR lines charged with condensate water by a pressure regulating valve. A system is provided to maintain the HPCI pump discharge piping between the normally closed injection valve and pump discharge check valve charged with condensate water.

Since the core cooling pumps are located in the subbasement of the reactor building, approximately 75 ft below the point where the discharge piping enters the RPV, check or stop-check valves are provided near the pumps to prevent backflow from emptying the lines into the suppression pool. These valves will leak slightly, producing a small backflow that will eventually empty the discharge piping. The core spray lines are kept charged with demineralized water and the RHR lines are kept charged with condensate water by a pressure regulating valve. The HPCI pump lines are charged by the head (gravity) from the condensate storage tanks. The HPCI pump discharge piping valves up to the normally closed injection valve are also kept charged with condensate water. Alarms are provided for RHR and core spray fill line low pressure.

The demineralized water storage system supplies water to the reactor building, turbine building, radwaste building, auxiliary steam boilers, and core spray fill systems from a common manifold. The demineralized water supply from the manifold to the fill system is controlled by the pressure regulating valve. The water supply to the manifold is pumped from the demineralized storage system by a demineralized water jockey pump (DWJP) and, as required, by one or two demineralized water transfer pumps (DWTP).

The condensate water storage system supplies water to the RHR keep fill system from a reactor building second floor header. The condensate water supply from the header to the fill system is controlled by a pressure regulating valve. The water supply to the header is from the condenser pumps through a 4-inch supply line located downstream of the polishing demineralizers. During a plant shutdown, condensate is supplied by the condensate storage jockey pump and as required by the normal hotwell supply Pump.

When the demand for demineralized water is less than 20 gpm, the DWJP maintains the manifold pressure at 82 psig. If the quantity of water supplied by the DWJP exceeds 20 gpm, the manifold pressure drops. When the pressure reaches a defined setpoint, a pressure switch on the common manifold activates and one of the two DWTPs automatically starts. Should the demineralized water demand exceed the capability of the DWJP and one DWTP, the manifold pressure would continue to drop. At a lower setpoint, a second switch would activate to start the second DWTP and activate an alarm in the main control room.

The RHR fill system consists of two fill lines (branching from a single valve) supplied with condensate water from the header and terminates at the connections to the RHR pump discharge lines.

The core spray fill system consists of two fill lines (involving one pressure control valve in each line) supplied with demineralized water from the common manifold and terminates at the connections to the core spray pump discharge lines.

Vent and drain connections have been incorporated at all high and low points in the RHR and core spray piping systems. Prior to initial start (such as after maintenance to the RHR or core spray system) the discharge lines are filled by manually venting the high-point vents of the RHR and core spray discharge lines to avoid any trapped air pockets in the discharge lines. The pressure control valve keeps the lines filled after initial filling.

The suction and discharge piping to the RCIC system is kept full up to the normally closed RCIC injection valve by static head from the condensate storage tanks and by appropriate high-point venting during initial fill and as required periodically by the Technical Specifications. The elevation of the injection valve is lower than the low level of the condensate storage tanks.

The HPCI piping from the discharge of the pump, through the check valves up to the normally closed injection valve is kept full from the static head of the Condensate Storage Tank (CST), and by appropriate high-point venting during initial fill and as required periodically by Technical Specifications. The elevation of the injection valve is below the minimum level of the CST, and any leakage from the system is made up by CST water. The relative height of the feedwater line connection for HPCI is such that the water in the feedwater lines keeps the remaining portion of the HPCI discharge line full of water.

However, the HPCI system discharge piping near the injection valve to the feedwater system absorbs heat from feedwater via conduction and valve leakage, that has the potential to form a localized steam void. When the HPCI turbine-driven pump is started, rapid pressurization of this line causes the void to collapse and produce a momentum transient which stresses the piping and related supports.

The momentum transient that is present during HPCI start has been analyzed and shown not to produce any damage to the HPCI piping, components, and supporting structure. However, the condensate water storage system is utilized to maintain the HPCI discharge piping between the normally closed injection valve and pump discharge check valve charged with condensate water to prevent possible void formation and minimize momentum transient effects. The pressure of the condenser pumps, connected to the HPCI discharge piping by a supply line located downstream of the condensate polishing demineralizers, maintains the piping charged with condensate water to prevent steam void formation.

In addition, the HPCI pump discharge piping just upstream of the injection valve is provided with cooling fins to remove heat and provide additional subcooling margin in the area of void formation.

6.3.2.2.6 Emergency Equipment Cooling Water System

The emergency equipment cooling water system (EECWS) consists of two (redundant) systems that supply cooling water to emergency equipment that is automatically operable on high drywell pressure, low reactor building closed cooling water system (RBCCWS) differential pressure, or on a loss of offsite ac power or that may be manually initiated upon failure of the RBCCWS. In addition, the EECWS may be manually initiated with the non-essential loads subsequently restored to facilitate RBCCW heat exchanger cleaning, to enhance drywell cooling during high lake water (GSW) temperature, for testing, or to provide RHR Reservoir freeze protection during extreme cold weather. The system diagram is presented in Figure 9.2-2. The EECWS is designed to provide equipment cooling and ventilation space cooling for HPCI, RCIC, RHR, and core spray systems.

Each of the two supply and return cooling loops (Division I and Division II) consists of one circulating pump of sufficient capacity to circulate water through the system and return the cooling water to a full capacity heat exchanger. The demineralized water in the system is cooled by the emergency equipment service water system (EESWS).

Both the EECWS and the EESWS are discussed in Subsection 9.2.2.

6.3.2.2.7 Emergency Core Cooling System Suction Lines

The two core spray, four RHR, and HPCI suction lines have remote manual motor-operated gate valves.

The piping is classified as Class 2 piping in accordance with ASME Boiler and Pressure Vessel (B&PV) Code Section III, 1971, and has been stress analyzed for thermal and deadweight flexibility and seismic dynamic response. This analysis established nozzle loads on the torus connections which in turn are analyzed in accordance with ASME B&PV Code Section III-B. As these connections are situated below the torus, they are protected against possible missiles originating from the slab above the torus or any high-pressure lines situated above the torus.

To prevent the loss of torus water due to an ECCS suction line break, a leak-detection system is provided. Any postulated break in the ECCS pump suction line is detected and the appropriate isolation valve can be activated to isolate the break.

The maximum distance between the containment nozzle and the center line of the isolation valve occurs on the four 24-in. RHR suction lines. This distance is 11 ft 8 in.

Leak detection for the ECCS suction lines is provided by a system that measures the rate of change of the liquid level in the sump of the floor drain. The operator can isolate the leaking line and verify that the leak is stopped by observing the sump level.

6.3.2.3 Applicable Codes and Classification

All ECCS piping, components, and system designs comply, as a minimum, with applicable codes, code cases, and addenda in effect at the time the equipment was procured. These systems are designed and constructed in accordance with Category I criteria and Quality Assurance Level 1.

The RHR/LPCI, HPCI, and core spray systems are each divided into two classes.

The Class 1 portion of each system includes all piping and components that are a part of the reactor system pressure boundary out to and including the second isolation valve.

The Class 1 portions of the RHR/LPCI, core spray systems, and HPCI are designed and constructed in accordance with Subsection NB of ASME B&PV Code Section III, 1971 or later issue and addenda of this code in effect at the date of purchase order, and conform with 10 CFR 50.55a, whichever is more restrictive.

The remaining portions of the RHR/LPCI, HPCI, and core spray systems are designated Class 2 and are designed and constructed in accordance with Subsection NC of ASME B&PV Code Section III, 1971 or later addenda in effect at the date of purchase order. The only exceptions to the foregoing are

a. The RHR/LPCI and core spray pumps were purchased in 1970 and therefore meet the requirements of Section B ASME Code for pumps and valves for nuclear power (1968 draft issue)

b. The shell sides of the RHR heat exchangers are designed and constructed in accordance with ASME B&PV Code Section III (1968), Class C, and Tubular Exchanger Manufacturers Association (TEMA) Class C Standard

c. The tube sides of the RHR heat exchangers are designed and constructed in accordance with ASME Section VIII, Division I, and TEMA Class C Standard

d. Relief valve code and standards are defined in Chapter 5

e. The HPCI turbine is a non-ASME component per ASME B&PV Section III, 1971 Edition, Article NE-1130

f. The HPCI barometric condenser is designed and constructed in accordance with the ASME B&PV Code Section VIII.

6.3.2.4 Materials Specifications and Compatibility

Subsection 5.2.3 discusses general material considerations. Refer to Table 5.2-6 for a presentation of the specifications that generally apply to the selection of materials used in the ECCS. Nonmetallic materials such as lubricants, seals, packings, paints, primers, and insulation, as well as metallic materials, are selected as a result of an engineering review and evaluation for compatibility with other materials in the system and the surroundings with concern for chemical, radiolytic, mechanical, nuclear radiation, and temperature effects.

Subsection 6.3.2.19 contains a discussion by commercial name of materials in the primary containment that may conceivably interfere with ECCS performance as a result of their deterioration under LOCA conditions.

Materials for the principal components are listed in Table 6.3-2.

6.3.2.5 Design Pressures and Temperatures

The design pressures and temperatures at various points in the system during each of several modes of operation of the ECCS subsystems can be obtained from the information blocks on the following process diagrams: Figures 6.3-1 through 6.3-5 for the HPCI system, Figures 6.3-7 through 6.3-11 for the core spray system, and Figures 6.3-14 through 6.3-16 for the LPCI. The operational characteristics of the ADS valves are presented in Chapter 5.

6.3.2.6 Coolant Quantity

The HPCI system normally takes suction from the condensate storage tank. This tank is designed so that the last 150,000 gal is reserved for use by the HPCI or RCIC systems by the tank's standpipe design. Not all of this 150,000 gal is usable since the suction is switched to the suppression pool automatically upon a condensate storage tank low level (equivalent to about 45,000 gal of water in the tank based on a nominal trip setpoint). However, while the plant is operating, the condensate storage tank is maintained at a normal level considerably higher than that required to provide 150,000 usable gallons. The HPCI suction is also switched to the suppression pool upon suppression pool high level signal (approximately 3.5

in. above normal water level) or at any time manually. The suppression pool contains approximately 880,000 gal of water. The core spray and LPCI systems take suction from the suppression pool.

The residual heat removal service water (RHRSW) system serves as the ultimate heat sink. Its design includes two 3,465,000-gal reservoirs (described in detail in Section 9.2). They are sized in accordance with the recommendations of Regulatory Guide 1.27.

6.3.2.7 Pump Characteristics

The HPCI pump is driven by a high-pressure turbine fed by reactor steam. The rated horsepower of the turbine at high speed (4100 rpm) is 4750 hp. The turbine produces 1000 hp at low speed (2100 rpm).

The core spray pump is driven by an open, drip-proof, induction motor rated at 800 hp. Power required is 102 amp at 4160 V ac.

The RHR pumps are each driven by a type-K, squirrel cage, induction motor rated at 2000 hp. Power required is 255 amp at 4l60 V ac.

6.3.2.8 Heat Exchanger Characteristics

There are no heat exchangers in the closed cooling water path associated with the emergency core cooling subsystems. The heat exchangers in the RHR system are discussed in Section 5.5.

6.3.2.9 Emergency Core Cooling System Flow Diagram

A schematic diagram, the flow rates, and the pressures of the various ECCS subsystems can be obtained from the information blocks on the following process diagrams: Figures 6.3-1 through 6.3-11, and Figures 6.3-14 through 6.3-16. These parameters are presented for several modes of operation, including LOCA and test conditions.

6.3.2.10 Relief Valves and Vents

The RHR/LPCI and the core spray systems are not designed to withstand normal reactor system pressures. Relief valves are provided to protect the low-pressure portions of these subsystems against possible overpressurization due to valve leakage and pump heat input. Pressurized portions of the HPCI system are designed for service at reactor pressure and therefore do not require overpressure protection.

The design basis for the relief valves to protect the core spray and RHR systems from overpressurization is given in Subsection 5.5.13.

6.3.2.11 System Reliability

The ECCS reliability has been achieved through an evolutionary process. Initially a proposed system configuration was submitted for evaluation. A reliability model of the proposed system was constructed and an estimate of the system success probability was made. Reliability models were then constructed for alternative ECCS configurations and a comparative trade-off study yielded the most reliable system configuration. Upon completion of the final design, a formal reliability analysis was performed to

a. Determine the expected system availability (average reliability)

b. Set safe system test intervals and allowable repair times

c. Qualitatively evaluate the system for conformance to the original design concepts, as well as existing industry standards and criteria for reactor protection and safety systems.

System availability is evaluated and selected test intervals and allowable repair times were determined by well-established reliability/availability methods. The qualitative analysis includes a functional system failure modes and effects analysis (FMEA). The FMEA results are used to verify conformance to industry criteria, develop reliability models, and ensure that the original design redundancy and diversity have been retained.

Availability, as applied to the ECCS, is defined as the probability that the system is operable when required. The ECCS availability is a function of the component system test intervals and the failure rates of the component parts used in the systems. The component parts used in the ECCS have low failure rates, as evidenced by historical field operating experience. The ECCS availability required to ensure adequate plant safety is established as a system design requirement. To ensure adherence to the availability design requirement, the periodic test intervals and allowable repair times for inoperable systems are defined in the Technical Specifications.

The power sources required for successful system operation are arranged in redundant configurations such that the power availability is not a limiting factor in determining the overall system success probability.

6.3.2.12 Protection Provisions

The ECCS piping and components are designed to accommodate the effects of movement, missiles, thermal stresses, the effects of the LOCA, and the safe-shutdown earthquake (SSE).

The reactor coolant pressure boundary (RCPB) has been analyzed for four categories of design transients: normal, upset, emergency, and faulted conditions. These categories are generally described in the ASME B&PV Code Section III, 1968 Edition. Subsection 5.2.1 contains details of this analysis.

Protection of the mechanical, instrumentation, and electrical portions of the engineered safety feature (ESF) system and reactor protection systems (RPS) against environmental conditions is discussed in Section 3.11.

Subsection 6.3.2.2.5 describes the features protecting against water-hammer effects in ECCS discharge lines.

The components of the core spray system, the HPCI, the LPCI, and the RHR systems are protected from becoming functionally inoperative as a result of flooding the lower levels of the reactor building due to excessive leakage from the ECCS complex. Section 3.4 describes design protection against flooding.

Response 3.1.2, Amendment 11 of the Fermi 2 PSAR discusses thermal stresses generated by high-temperature and high-pressure jet streams impinging on spherical plate sections. Also presented is an analysis of the uplift force on the RPV associated with a main steam line break. The methods used to provide assurance that thermal stresses do not cause damage to the ECCS are described in Subsection 6.3.3.9.

The ECCS is protected against the effects of the pipe whip, which might result from piping failures up to and including the LOCA, by separation barriers, pipe-whip restraints, or energy-absorbing materials. One or more of these three methods have been applied to provide protection against cascading damage to piping and components of the ECCS that could otherwise result in a reduction of ECCS effectiveness to an unacceptable level. Section 3.6 describes the design protection and analysis performed for pipe whip.

The ECCS piping and components located outside the containment are protected from internally and externally generated missiles by the reinforced-concrete structure of the ECCS pump rooms. In addition, the watertight construction of the ECCS pump rooms below grade level protects against damage by flooding. Section 3.5 describes design protection against postulated missile damage.

6.3.2.13 Provisions for Performance Testing

a. High pressure coolant injection system

    1. A full-flow test line is provided to route water from and to the condensate storage tank without entering the RPV

    2. Instrumentation is provided to indicate system performance during normal and test operations

    3. All motor-operated and air operated valves are capable of manual operation, either local or remote for test purposes

    4. Drains are provided to leak test the major system valves.

b. Core spray system

    1. A full-flow test line is provided to route water from and to the suppression pool without entering the RPV

    2. In the event the torus is unavailable to provide suction, a test line from the condensate storage tank provides reactor grade water to test pump discharge to simulate injection into the RPV. Direct injection to the vessel is not performed (Subsection 6.3.2.2.3.2)

    3. Instrumentation is provided to indicate system performance during normal and test operations

    4. All motor-operated valves, air-operated valves, and check valves are capable of manual operation for test purposes

    5. Relief valves are removable for bench testing.

c. Low pressure coolant injection system

1. Discharge test lines are provided for the four pumps to route suppression pool water back to the suppression pool without entering the RPV
2. Instrumentation is provided to indicate system performance during normal and test operations
3. All motor-operated valves, air-operated valves, and check valves are capable of manual operation for test purposes
4. Shutdown cooling lines taking suction from the recirculation system are provided to allow testing of pump discharge into the RPV during normal plant shutdown
5. All relief valves are removable for bench testing.

d. Automatic depressurization system

Actual operation of each safety/relief valve pilot valve associated with the ADS was verified during the Preoperational Test Program.

6.3.2.14 Net Positive Suction Head

The RHR/LPCI and core spray pump systems are designed to ensure adequate net positive suction head (NPSH) margin availability under all combinations of foreseeable adverse conditions. The point of minimum margin for all pumps occurs at the peak suppression pool temperature, calculated on the basis of conservative assumptions. No dependence is placed upon positive containment pressure. The Regulatory Position stated in Regulatory Guide 1.1, dated November 2, 1970, is met.

The conditions assumed for calculating the peak suppression pool temperature and the available NPSH margin are as follows:

a. Reactor at 3499 MWt (102% of 3430 MWt)
b. Suppression pool volume is 117,161 ft^3
c. Initial suppression pool water temperature 95°F
d. Temperature of RHRSW reservoir varies linearly from 80°F to 90°F over 8 hours and stabilizes at 90°F
e. Pump suction strainers plugged to maximum design per UFSAR Section A.1.82
f. All of the energy in the RPV is absorbed by the suppression pool water following a LOCA
g. Pumps operating at rated flows
h. The heat loads considered were pump heating; Zr-H_2O reaction; peak sensible heat in RPV, steam, all water in the feedwater system, recirculation loops, fuel; and decay heat

i. The primary containment long-term response to a recirculation line break LOCA scenario in Subsection 6.2.1.3.3

j. Bounding minimum RHR heat exchanger heat transfer coefficient is 366 BTU/sec-°F

k. RHR system is placed in the suppression pool cooling mode 20 minutes after LOCA

The analysis yielded a peak suppression pool temperature of 196.5°F which occurs approximately 5 hours after LOCA. This temperature is less than the suppression pool temperature of 198°F used in the RHR and the core spray NPSH margin calculations described below. The NPSH margins for the RHR and core spray pump systems using a peak suppression pool temperature of 198°F and other conservative calculational methods are positive, even allowing for instrument tolerances to cause flow to be above nominal design values. The 198°F pool temperature for NPSH is the controlling limit for the bulk pool temperature.

A hydraulic analysis has been performed for each RHR operating mode shown in the General Electric process diagram (Figure 6.3-14, Sheet 2). The NPSH required was obtained by using the most conservative RHR pump performance curve and corresponds to the flow rate through the pump. In calculating the NPSH available for each mode, the design conditions on the process diagram were used and the suction strainers were assumed to be plugged to maximum design per UFSAR Section A.1.82. The results of the RHR hydraulic analysis are as follows, assuming pumps with maximum allowed degradation:

Mode	Description	GE Nominal Design Flow per Pump (gpm)	NPSH Required (ft absolute)	NPSH Available (ft absolute)
A	LPCI accident, three pumps, RPV pressure equals 20 psig	10,000	15	30
B	LPCI accident, two pumps, RPV pressure equals 20 psig	13,000	17	27
C2	Containment spray, one pump, RPV pressure equals 0 psig	10,000	12.8	13.9*
D2	Suppression pool Cooling, one pump	10,000	12.8	31 14*
E	Shutdown cooling, two pumps, RPV pressure equals 97 psig	9,625	13	49

F	Shutdown cooling, two pumps, RPV pressure equals 0 psig	9,750	13	76
G	LPCI accident, two pumps, RPV pressure equals 0 psig	13,000	17	19**
H	LPCI test, one pump	10,300	13	42
J2, J4	Minimum flow bypass, two pumps	480	8	44

* Suppression pool at 198°F

** Margin consistent with GE process diagram fluid temperature. Long-term operation at the higher suppression pool design maximum temperature of 198°F requires throttling flow consistent with EOP procedures consistent with UFSAR Section 6.3.2.17.

From the above cases, it is apparent that Modes C2 and G have the lowest NPSH margin. Since NPSH margin is typically reduced at higher flow rates, Modes C2 and G were also examined using LPCI pumps operating on the vendor supplied pump curve (not degraded) and with 2% over-frequency applied. Under this condition, while NPSH margin is reduced to less than 1 ft for the worst case pump, the margin remains positive without containment overpressure.

The RHR pump suction strainers are 11-gage perforated plate stacked discs with 1/8-in.-diameter holes. Therefore, the largest particles that could pass through the strainers are 1/8 in. in diameter.

After a postulated LOCA, debris released to the suppression pool would tend to sink to the bottom of the pool. The accumulation of this debris on the RHR pump suction strainers is minimized because the strainer is located at a 45° angle above the bottom of the pool, with a 10° mitre bend between the suction flange and the strainer flange. Any particles that could pass through the strainer perforations are not of sufficient size to affect RHR pump suction flow.

Local heating in the suppression pool is a phenomenon that occurs when high-energy steam is released into the suppression pool for quenching. The most severe local heating occurs during a safety/relief valve discharge. In general, local-to-bulk temperature differences at the time of maximum temperatures are about 15° for cases where two RHR loops are assumed available and about 30° for cases where one RHR loop is assumed available. The pool temperature during normal plant conditions is limited by Technical Specifications so that localized heating from safety/ relief valve discharges will not nullify the NPSH of the ECCS pumps, even for prolonged operation of the valves.

Local heating also occurs during the RPV depressurization stage of a postulated LOCA when steam and noncondensable gases are blown through the downcomers into the suppression pool. Local heating during this event will be significantly less than the temperature achieved during safety/relief valve blowdown because of lower energy in the steam and high turbulence in the water.

As described in Subsection 6.2.1.3.2, at about 100 sec after the design-basis accident (DBA), hot water only will be discharged out of the break; at 1200 sec, the suppression pool temperature has reached 168°F. Thus, up to this point, there would be a very large margin on NPSH even if local heating were significant. At the time the suppression pool reaches its peak temperature, approximately 5 hr after LOCA, local heating cannot be significant for the small ΔT in the water being discharged is quickly blended with the pool water.

The preceding conditions describe the containment system after full blowdown following a large break. Consequently, they are not applicable to the HPCI system. The HPCI pump is located below the level of the condensate storage tank (CST), from which suction is normally taken, and below the water level in the suppression pool.

A low-water level in the condensate storage tank (2 ft 8 in. above the bottom of the tank) or a high-water level in the suppression pool (3.5 in. above normal level), would cause the two normally closed, motor-operated gate valves located in the suppression pool suction line to automatically open. The normally open, motor-operated gate valve located in the condensate storage tank suction line would remain open until the two suppression pool suction valves fully open. At that time, the condensate storage tank suction valve would close. In this way, NPSH is maintained.

In the case of an ECCS passive failure such as pump seals or valve seals, the operator has adequate time to take corrective action and isolate the failure before the NPSH would become inadequate for the remaining ECCS pumps due to reduced suppression pool level.

Adequate minimum submergence is available to prevent vortex formation and air ingestion during operation. With the exception of suction from the CST, minimum required submergence is computed in accordance with NUREG/CR-2772 as endorsed in Reg. Guide 1.82 Rev. 2. Under the RHR RUNOUT scenario, available submergence is sufficient to ensure minimal air entrainment and still meet NPSH requirements under Regulatory Guide 1.82, Rev. 2 for the minimum required compliment of pumps. The predicted CST suction minimum submergence is acceptable based on analytical analysis and the use of mechanical vortex suppression assemblies. The analytical method establishes the minimum submergence for straight (non-circular) spill over flow into the suction piping in accordance with Reference 2. For circular flow or vortex flow considerations, mechanical vortex suppression assemblies are installed that eliminate flow vortexes from introducing the potential for air entrainment into the pump suction. The pertinent data are summarized below:

System	Suction Source	Available Submergence (ft)	Predicted Submergence for Incipient Air Ingestion (ft)
RHR	Suppression pool	8.7	7.35 (LPCI) 9.0 (LPCI RUNOUT)†
Core spray	Suppression pool	9.2	3.9
HPCI	Suppression pool	8.2	1.2
HPCI	Condensate storage tank	1.45 (including 0.44 foot silt block)	0.98

† Under the limiting RUNOUT condition, the minimum submergence of the most limited of four available RHR pumps is not sufficient to ensure zero air ingestion. Here, the LPCI function is not credited to meet 10CFR50.46 ECCS performance requirements. With consideration of the standard applied NPSH penalties one or more RHR pumps have sufficient NPSH. This ensures RHR is available for subsequent use to provide long-term containment cooling in suppression pool cooling mode.

A postulated minimum level of 14 in. below the torus centerline was used to determine the level of suppression pool submergence.

The precaution taken to preclude vortex formation in the HPCI-RCIC condensate storage tank suction is to transfer suction to the suppression pool on low tank level. This is supplemented by the installation of a vortex suppression assembly over the suction intake for the HPCI-RCIC systems to mechanically preclude vortex formation.

6.3.2.15 Residual Heat Removal Pump Runout Evaluation

The Fermi 2 design was reexamined also to determine whether a failure in the LPCI logic could disable the RHR pumps. The single failures that potentially could disable the RHR pumps have been identified as the following.

Case A The LPCI logic correctly selects the unbroken loop, but a single failure causes inadvertent opening of LPCI injection valve E11-F015 into the broken loop. This condition results in four RHR pumps injecting into both recirculation loops with one loop broken

Case B All four RHR pumps start for LPCI injection, but a single failure causes the LPCI loop selection logic to select the wrong (broken) loop. This condition results in all four RHR pumps injecting into the broken recirculation loop

Case C The LPCI logic correctly selects the unbroken loop, but a single failure causes the recirculation pump discharge valve B31-F031 to remain unclosed. This condition results in four RHR pumps injecting into the vessel through one recirculation loop inlet and discharge lines.

Under the above conditions, the RHR pump operation was examined for cavitation, pump motor overload, and emergency diesel generator overload.

6.3.2.15.1 Analysis Assumptions

As shown in Figure 6.2-13, the initial LOCA blowdown causes an almost immediate temperature increase to approximately 135°F in the torus with a continued increase to 168°F after 20 minutes. A water temperature of 168°F was assumed for the entire time period and for each of the cases (A, B, and C) listed above.

As described in Subsection 6.3.2.1, after 10 minutes the operator begins the post-LOCA manual control of the RHR system, which includes throttling the RHR system and initiating containment cooling. However, the operator can delay the containment cooling for up to 20 minutes. Therefore, it is assumed that the RHR pump runout condition occurs during the 0- to 20-minute part of the DBA.

Although the LOCA blowdown will cause a pressure increase in the primary containment, the drywell and torus pressure assumed for the analysis is 0 psig.

Reactor vessel pressure was determined from the LPCI process diagram Figures 6.3-14 through 6.3-16. A vessel pressure of 20 psig given in mode A was assumed, because the runout condition lasts only during the short term portion of the LOCA analysis. The RHR suction strainers were assumed to be plugged.

For Case B, no jet pump resistance is available as the broken injection loop bypasses the normal injection path through the jet pumps. For Cases A and C, an equivalent jet pump resistance value was determined and used in the analysis.

The reactor core level was assumed to flood to two-thirds of the core height.

The Technical Specifications allow only 7 days of continuous plant operation with an inoperable LPCI pump. Therefore, the analysis did not consider any pumps to be out of service for maintenance.

6.3.2.15.2 Calculation Procedure and Results

From the description of cases A, B, and C, it is clear that case A is the limiting case. This is because case A allows all four pumps to pump into parallel paths consisting of both the normal injection path and to the broken loop. Case A bounds case B, since case B simply eliminates the parallel path to the desired injection line. Case C is the least limiting. Like case B, case C involves only one flow path, but it would inject against a greater residual pressure in the reactor and intact recirculation loop piping. Therefore, only case A is analyzed in detail. The vendor-certified RHR pump performance curves provided a record of pump performance test data up to a pumping condition of 14,000 gpm. Operating conditions beyond this point were assessed using extrapolated vendor pump performance curves and data from the preoperational testing for RHR pumps. The results for each case are discussed below.

Case A

Case A results in four RHR pumps pumping into both LPCI loops, with one loop broken. Under the most limiting scenario for minimum overall available NPSH, the RHR pumps are required to operate at approximately 15,500 gpm. The analysis of the available NPSH margins for this condition determines that adequate margins are available for torus water temperatures less than 168°F consistent with the time available for operators to take action to establish containment cooling within 20 minutes in accordance with the plant design as described in Section 6.3.2.14. For the Case A pump operating condition, pump motor and emergency diesel generator overloads will not be experienced.

6.3.2.15.3 Conclusion

A failure of the LPCI logic will not result in RHR pump operating conditions that would allow pump cavitation, pump motor overload, or emergency diesel generator overload. The limiting case failure does allow the pumps to operate at a point that is not part of the manufacturer's performance test data. Extrapolated performance data were used as a basis for the analysis conclusion. The extrapolated data has been confirmed by expanding the scope of the preoperational testing for the RHR pumps to provide performance data for the 14,000-gpm to 15,300-gpm range. No design changes to the RHR system are required; therefore, the performance of the RHR system, with respect to process diagram requirements, has not changed and there is no impact on the Appendix K analysis discussed in Subsection 6.3.3.

6.3.2.16 Motor-Operated Valves and Controls

The LPCI and the core spray systems are not designed to withstand reactor system pressures. Provisions have therefore been made to ensure that these ESF systems are not subjected to damaging pressures. These provisions include appropriate relief valves, discussed in Subsection 6.3.2.10, and isolation valves with system interlocks and alarms that are discussed below. Refer to Section 7.3 for a further discussion of controls for these valves. The LPCI/RHR system is isolated from the reactor system by the following:

Valves	Line Isolation	Isolation Signal
F008	RHR pump suction	Pressure trip unit B31-N611B signals “close” above permissive pressure
F009	RHR pump suction	Pressure trip unit B31-N611A signals “close” above permissive pressure
F022	RPV head spray (RHR pump discharge)	Pressure trip unit B31-N611A signals “close” above permissive pressure
F015A, B	RHR pump discharge to RPV	B21-N690A, B and logic signal prevent opening above interlock pressure
F050A, B	RHR pump discharge to RPV	Check valve (air operator on valve for testing)

If either trip unit B31-N611A or B31-N611B fails in a nonconservative manner, the system is still protected because the other unit sends a "close" signal to the valve in series with the valve controlled by the failed trip unit. In the event of valve leaks, the system is protected by the pressure relief valves as outlined in Subsection 6.3.2.10.

Provisions have been made to allow for thermal expansion of water trapped between valves F008 and F009 (penetration X-12), by way of a line that returns the trapped water to the RPV.

The core spray system is isolated from the reactor system by the following

Valves	Line Isolation	Logic
F005A, B	Core spray pump discharge	Manual control room pushbutton to close
F006A, B	Core spray pump discharge	Check valve

Check valves are backed up by normally closed motor-operated valves. In the event of operator failure and check valve leak, the system is protected by relief valves as outlined in Subsection 6.3.2.10.

All motor-operated ECCS valves have position indication in the control room.

6.3.2.17 Manual Actions

With the exception of LPCI while RHR is in the shutdown cooling mode, the initiation of the ECCS is completely automatic. No operator action is required for the initiation of postaccident modes of operation. When RHR is lined up in the shutdown cooling mode and RPV pressure is less than or equal to the cut in pressure, manual operation is required to permit LPCI to align and initiate. This includes manually lining up the suction path from the torus for the loop which is in shutdown cooling. No manual valve is required to change position to accomplish a safety-related mode of any ECCS. Manual valves generally do not have position indication in the control room. Administrative procedures require the position of any critical manual valve to be verified and recorded after each time it is operated and the position of critical manual valves to be verified and recorded during a refuel outage prior to plant operation following refueling. Thus, all critical manual valves are under rigid administrative control.

Following is a list of manual valves critical to the operation of ECCS that are controlled by administrative procedures:

Safety System	Valve Number(s)
HPCI system	P1100-F042
LPCI mode of RHR	E1100-F034 A (B, C, D)
Core Spray	E2100-F001 A (B, C, D)
	E2100-F037 A (B, C, D)

Operators are instructed and trained to observe the values and rates of change of the plant parameters that have the greatest significance for plant safety (e.g., RPV water level, containment pressure, torus temperature, radiation monitors, operation of ECCS, standby gas treatment system, emergency diesel generator loads, etc.). From these parameters, together with his training and use of the symptom-oriented emergency operating procedures, the operator is able to logically evaluate the condition of the plant and is prepared to take appropriate action at the end of the initial interval.

A timer is used in each ADS logic. The time-delay setting before actuation of the ADS is long enough that the HPCI system has time to operate, yet not so long that the LPCI and core spray systems are unable to adequately cool the fuel if the HPCI system fails to start. Manual reset circuits are provided for the ADS initiation signal. By resetting this signal manually, the delay timers are recycled. The operator can use the reset pushbuttons to delay or prevent automatic opening of the relief valves if such delay or prevention is necessary.

A manual inhibit switch is also provided for each ADS trip system. These switches allow the operator to inhibit ADS operation without repeatedly pressing the reset pushbuttons. Operation of the manual inhibit switch will activate a white indicating light and an annunciator to alert the operator of the inhibit action. Enabling the inhibit function will not terminate an ADS logic actuation after the 120 second time delay has elapsed. At this point, only the reset pushbutton can be used to affect the ADS operation. Guidance is contained in the Emergency Operating Procedures.

6.3.2.18 Process Instrumentation

Sufficient instrumentation is available to the operator in the main control room to assist him in accurately assessing the post-LOCA conditions if LOCA should occur. Basically, these indications are of two varieties: those that indicate the pressures, temperatures, and levels in the RPV and containment, and those that provide indication of operations of the ECCS position of valves and circuit breakers, flows, temperatures, and pressures of ECCS.

The most significant instruments in the first category are

a. Reactor pressure vessel level

b. Reactor pressure vessel pressure

c. Containment pressure

d. Containment temperature

e. Suppression pool level

f. Suppression pool temperature.

The most significant instruments in the second category are as follows.

a. LPCI flow and pressure

b. Core spray flow and pressure

c. HPCI flow and pressure.

Other available instrumentation is listed on the piping and instrumentation diagram included with the description of the above system in Chapter 5. Discussion of instrumentation also appears in Chapter 7. See Subsection 7.5.1.4.2 for a detailed listing of the process information available in the main control room that permits accurate assessment of postaccident conditions.

6.3.2.19 Materials

Materials used in or on the ECCS are reviewed and evaluated with regard to radiolytic and pyrolytic decomposition and attendant effects on safe operation of the ECCS. For example, fluorocarbon plastic (Teflon) is not permitted in environments that attain temperatures greater than 300°F or radiation exposures above 10^4 rads.

Organic materials used in the Fermi 2 primary and secondary containments have been selected for extended life during normal operations for their resistance to expected accident environmental conditions. Thermal insulation used is inorganic and is not sensitive to high radiation fields, steam, or high temperature.

Evaluations of the protective coatings used within the containment (Subsection 6.2.1.6) have been made. It has been determined that they will satisfactorily endure accident environmental conditions and their expected products of decomposition, if any, will not adversely affect the operability of any ESF system.

6.3.2.20 Maintenance and Operability

The capability of the ECCS to provide core cooling is verified by regularly scheduled functional tests on each component and system. Subsection 6.3.4 discusses these tests and the testing program.

The configuration of the ECCS systems has placed most of the components in concrete cubicles so that maintenance on any component has a minimum of complications due to radiation from the primary system or from other components (see Figures 1.2-6 and 1.2-8). Drains for all pumps, heat exchangers, and low points in piping runs are piped directly to radwaste collection points. Flushing and makeup are provided from the demineralized water or CSTs.

Because of these features, maintenance of ECCS components during a long-term LOCA mode of operation may be possible depending upon which component has failed. However, special facilities for this situation have not been provided, since the system designs inherently account for component failures without overall loss of intended function (usually by redundancy of systems, see Subsection 3.12.2.2). In addition, the following design provisions have been included to increase system operational reliability during a LOCA:

a. All components essential to ECCS operation are capable of continued operation under LOCA conditions of pressure, temperature, and radiation

b. Suction strainers have been provided on all ECCS pumps to prevent pump seizure due to entrained foreign particulates

c. Adequate fouling factors have been included in the determination of the design heat transfer capacities of the RHR heat exchangers.

The core spray and RHR pumps and motors are designed for the operating life of the plant (40 years) and for a postulated single continuous operation of 100 days for an accident during that 40-year operating life.

The following table shows the maximum expected accumulated operating time of these pumps for the life of the plant (40 years):

Mode of Operation	RHR (hr)	Core Spray (hr)
In-shop testing	4	4
Preoperational testing	168	168
Monthly testing	480	480
Yearly testing	40	40
Post LOCA	2,400	2,400
Shutdown	28,800	N/A
Total	31,892	3,092

The severe operating conditions to which the HPCI pumps are exposed are temperatures to 212°F, radiation, and dynamic loads from seismic and hydrodynamic effects. The pumps are mainly fabricated of metallic materials that will not be degraded by the temperature and radiation environment. The nonmetallic gaskets and seals are made of materials with a demonstrated resistance to the environment. The dynamic load inputs are addressed analytically and evaluated against appropriate criteria to ensure operation of the pump while undergoing dynamic loading. The above ensures that the expected service life will exceed the expected operating time of 500 hr. (Surveillance tests are performed once a month for 40 years equaling 480 tests plus a possible 20 real starts equaling 500 operating hours.)

CS pumps are analyzed for the effects of dynamic loads resulting from seismic and hydrodynamic effects. Operability under the worst loadings is ensured by the operability assurance program described in Section 3.9.4.3.

6.3.3 Emergency Core Cooling System Performance Evaluation

The performance of the ECCS was determined originally by applying the 10 CFR 50, Appendix K, evaluation models and then showing conformance to the acceptance criteria of 10 CFR 50, Section 50.46. Reference 3 provided a complete description of the LOCA events and the methods used to perform the original calculations.

The original methodology was updated (Reference 4) for the power uprate program (Reference 5) for GE11 (Reference 19), and for the GE14 fuel introduction (Reference 16). The LOCA analysis was then revised using the SAFER/PRIME-LOCA analytical model and methodology (Reference 39). Then the TRACG-LOCA evaluation model replaced the SAFER/PRIME-LOCA for the ECCS-LOCA analysis for the GNF3 fuel introduction (Reference 42). The updated methodology and a description of the LOCAs are summarized here.

The ECCS performance is evaluated for the entire spectrum of break sizes for postulated LOCAs. The discussion includes information on the radiological consequences of the following events:

a. Feedwater piping break, Subsection 15.6.6

b. Spectrum of BWR steam system piping failures outside containment, Subsection 15.6.4

c. Loss-of-coolant accidents, Subsection 15.6.5.

Cycle-specific reload information is in Reference 15.

6.3.3.1 Emergency Core Cooling System Bases for Technical Specifications

The maximum average planar linear heat generation rates (MAPLHGR) calculated in this performance analysis provide the basis for Technical Specifications designed to ensure conformance with the acceptance criteria of 10 CFR 50, Section 50.46. Minimum ECCS functional requirements are specified in Subsections 6.3.3.4 and 6.3.3.5; testing requirements are discussed in Subsection 6.3.4. Limits on minimum suppression pool water level are discussed in Section 6.2.

The plant is licensed for average power range monitor (APRM) rod block monitor (RBM) Technical Specification (ARTS) improvement program (Reference 6, 7, 8, and 20) and has both power and flow dependent limits imposed on the operating limit MAPLHGR (Reference 8 and 20). The flow dependent MAPLHGR, $MAPLHGR_f$, is determined from the product of the standard MAPLHGR and a flow dependent term, $MAPFAC_f$, which is defined as a function of the core flow rate and positioning of the scoop tube on the recirculation pump motor. The plant specific $MAPFAC_f$ versus flow curve is shown in the Core Operating Limits Report (COLR).

The power dependent operating limit MAPLHGR, $MAPLHGR_p$, is determined from the product of the standard MAPLHGR and the power dependent term, $MAPFAC_p$. For powers between 25 percent rated and the bypass point for the turbine stop valve/turbine control valve fast closure scram signal (29.5 percent rated), there are two values for $MAPFAC_p$, one for core flows >50 percent rated and one for core flows ≤50 percent rated, as shown in the COLR. Once the power exceeds this bypass point, the $MAPFAC_p$ is determined from a single curve which must be multiplied by the standard MAPLHGR to produce the reduced power operating limit MAPLHGR, $MAPLHGR_p$.

The operating limit MAPLHGR to be used becomes the most limiting value of either $MAPLHGR_f$ or $MAPLHGR_p$.

6.3.3.2 Acceptance Criteria for Emergency Core Cooling System Performance

The applicable acceptance criteria, quoted from 10 CFR 50, Section 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light-Water-Cooled Nuclear Power Reactors," are listed here. A detailed description of the methods used to show compliance are in Subsection 6.3.3.7 and Reference 1.

a. Criterion 1, peak cladding temperature - "The calculated maximum fuel element cladding temperature shall not exceed 2200°F." Conformance to Criterion 1 is shown in Table 6.3-4

b. Criterion 2, maximum cladding oxidation - "The calculated total local oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation." Conformance to Criterion 2 is shown in Table 6.3-4

c. Criterion 3, maximum hydrogen generation - "The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam shall not exceed 0.01 times the hypothetical amount that would be generated if all the metal in the cladding cylinder surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react." Conformance to Criterion 3 is shown in Table 6.3-4

d. Criterion 4, coolable geometry - "Calculated changes in core geometry shall be such that the core remains amenable to cooling." As described in Reference 1, conformance to Criterion 4 is demonstrated by conformance to Criteria 1 and 2

e. Criterion 5, long-term cooling - "After any calculated successful initial operation of the ECCS, the calculated core temperature shall be maintained at an acceptably low value and decay heat shall be removed for the extended period of time required by the long-lived radioactivity remaining in the core." Conformance to Criterion 5 is demonstrated in Reference 9. Briefly summarized, the core remains covered to at least the jet pump suction elevation, and the uncovered region is cooled by spray cooling and/or by steam generated in the covered part of the core.

6.3.3.3 Single-Failure Considerations

The functional consequences of potential operator errors, single failures, and the potential for submerging valve motors in the ECCS are discussed in Subsection 6.3.2. This Subsection includes information on errors that could cause any manually controlled, electrically operated valve in the ECCS to move to a position that could adversely affect the ECCS. There it was shown that all potential single failures are no more severe than one of the single failures identified in Table 6.3-5.

It is therefore only necessary to consider each of these single failures in the emergency-core-cooling-system performance analyses.

The specific analysis (Reference 42) included break sizes ranging from the minimum size that meets the definition of a LOCA to 200% of the largest applicable pipe cross-sectional area. Different single failure assumptions were investigated in order to identify the limiting case. Non-recirculation line breaks were found to be non-limiting. The feedwater line break accident analysis assumes operator actions are required to depressurize the reactor during a Division I battery failure. This assumption was reviewed and accepted by the NRC per the Ref. 24 SER.

The TRACG LOCA analysis (Reference 42) indicates that the small recirculation line breaks with Division II DC Power Source (Div II Battery) failure are limiting. This analysis was performed at maximum core thermal power, including uncertainty allowance (see Table 6.3-6, Section A Plant Parameters).

6.3.3.4 System Performance During the Accident

In general, the system response to an accident can be described as

a. Receiving an initiation signal

b. A small lag time (to open all valves and have the pumps up to rated speed)

c. Finally the ECCS flow entering the vessel.

Key ECCS actuation setpoints and time delays for all the ECCSs are provided in Table 6.3-6. The minimization of the delay from the receipt of signal until the ECCS pumps have reached rated speed is limited by the physical constraints on accelerating the diesel generators and pumps. The delay time resulting from valve motion in the case of a high-pressure system provides a suitably conservative allowance for valves available for this application. In the case of the low-pressure system, the time delay for valve motion is such that the pumps are at rated speed before the vessel pressure reaches the pump shutoff pressure.

Simplified piping and instrumentation and functional control diagrams for the ECCS are provided in Subsection 6.3.2. The operational sequence of ECCS for the DBA is shown in Table 6.3-7.

Operator action is not required, except as a monitoring function and as noted in Section 6.3.3.3, during the short-term cooling period following a LOCA. During the long-term cooling period, the operator will take action as specified in Subsection 6.2.2.3 to place the containment cooling system into operation.

6.3.3.5 Use of Dual Function Components for Emergency Core Cooling System

With the exception of the LPCI system, the systems of the ECCS are designed to accomplish only one function: to cool the reactor core following a loss of reactor coolant. To this extent, components or portions of these systems (except for pressure relief) are not required for operation of other systems that have emergency core-cooling functions, or vice versa. Because either the ADS initiating signal or the overpressure signal opens the safety/relief valve, no conflict exists.

The LPCI subsystem, however, uses the RHR pumps and some of the RHR valves and piping. When the reactor water level is low, the LPCI subsystem has priority through the valve control logic over the other RHR subsystems for containment cooling. When RHR is lined up in the shutdown cooling mode and RPV pressure is less than or equal to the cut in pressure, manual operator action is required for LPCI injection. Immediately following a LOCA, the RHR system is directed to the LPCI mode.

6.3.3.6 Limits on Emergency Core Cooling System Parameters

The limits on the ECCS parameters are discussed in Subsection 6.3.3.1 and Subsection 6.3.3.7.1.

Any number of components in any given system may be out of service, up to and including the entire system. The maximum allowable out-of-service time is a function of the level of redundancy and the specified test intervals. The limiting conditions for operation and surveillance requirements are given in the Technical Specifications.

6.3.3.7 Emergency Core Cooling System Analyses for Loss-of- Coolant Accident

6.3.3.7.1 Loss-of-Coolant Accident Analysis Procedures and Input Variables

The procedures approved for LOCA analysis conformance calculations were originally performed and approved in accordance with the methodology described in Reference 3. This methodology has been updated in accordance with the procedures in detail in Reference 40, commonly referred to as SAFER/PRIME methodology. The SAFER/PRIME methodology has been replaced with the procedures in Reference 41, commonly referred to as TRACG-LOCA, for GNF3 and GE14 fuel types. The new methodology, which is an ECCS evaluation model developed to analyze BWR LOCA in accordance with 10 CFR 50.46, is a best estimate plus uncertainty type of evaluation model. Potentially limiting break locations, initial conditions, and ECCS performance are determined using inputs that correspond to the "nominal" trial associated with the statistical analysis in the break spectrum calculations. Statistical analyses are performed for at least the most limiting small break, intermediate break, and double-ended guillotine break (DEGB).

Two primary computer models were used to determine the LOCA response for plant Fermi 2 using the TRACG-LOCA method. These models are PRIME and TRACG, which are described below.

a. DELETED

b. DELETED

c. PRIME

   The PRIME model provides the parameters to initialize the fuel rod fission gas inventory and rod internal pressure at the onset of a postulated LOCA for input to TRACG. PRIME also provides the initial pellet-cladding gap conductance and other parameters used by TRACG to calculate the transient gap conductance.

d. TRACG

   TRACG calculates the system response of the reactor and the detailed fuel rod heat transfer over a complete spectrum of hypothetical break sizes and locations. TRACG is compatible with the PRIME fuel rod model for gap conductance and fission gas release. A simplified form of the PRIME fuel thermal conductivity model is built into TRACG. TRACG calculates the core and vessel water levels, system pressure response, ECCS performance, and other thermal-hydraulic phenomena occurring in the reactor as a function of time. TRACG conservatively models the sources of heat in the core such as fission power, decay heat, and metal-water reaction. TRACG realistically models all regimes of heat transfer to calculate the transient cladding temperatures and oxidation.

The significant input variables used by the LOCA codes are listed in Table 6.3-6.

6.3.3.7.2 Accident Description

A detailed description of the LOCA calculation is provided in Reference 40 and is supplemented by Reference 42. With the TRACG-LOCA methodology, the limiting break is the limiting small recirculation suction line break. The limiting single failure is the one which results in the highest PCT. This is the failure of the Division II DC power (battery).

Table 6.3-8 provides a listing of figures which summarizes LOCA results.

6.3.3.7.3 TRACG-LOCA Break Spectrum Calculations

The break spectrum calculations were performed in Reference 42 to determine all potentially limiting initial conditions, single failures, break locations, and break size combinations. All calculations were performed for both GNF3 and GE14 fuel, and all calculations were performed with a loss of offsite power coincident with the break. All break spectra were calculated assuming a maximum core thermal power corresponding to the current licensed thermal power, plus power uncertainty, of 3,499 MW with an initial dome pressure of 1045 psia.

Only three limiting single failures are evaluated for the standard LOCA analysis, which are Division I Battery, Division II Battery and LPCI Injection Valve. The other three single failures, which are Diesel Generator (DG), HPCI and One ADS Valve, result in more ECCS systems available than at least one of the three limiting single failures and, therefore, are not considered in the break spectrum calculations.

For Division I Battery Failure, the core spray line (CSL), feedwater line (FWL), recirculation suction line (RSL), recirculation discharge line (RDL), Main Steam Line (MSL) and Reactor Water Cleanup (RWCU) breaks are considered. The limiting break sizes are 0.3185, 0.3154, and 0.3743 ft^2 for RDL, RSL and FWL, respectively. The CSL, MSL and RWCU are clearly non-limiting compared to the recirculation line breaks.

For Division II Battery Failure, the CSL, FWL, RSL, RDL, MSL and RWCU breaks are considered. The limiting break sizes are 0.1280, 0.1056, and 0.4491 ft^2 for RDL, RSL and FWL, respectively. The CSL, MSL and RWCU are clearly non-limiting compared to the recirculation line breaks.

For LPCI Injection Valve Failure, the RSL, RDL and CSL breaks are considered. The limiting break sizes are 0.7924 and 0.7848 ft^2 for RDL and RSL, respectively. Other breaks are not included for this failure because they are not limiting.

The Double Ended Guillotine Break (DEGB) peak cladding temperature (PCT), vessel pressure, and water level for GNF3 are provided in Figures 6.3-79, 6.3-80, and 6.3-81. The PCT, vessel pressure, and water level at the most limiting break for GNF3 are provided in Figures 6.3-82, 6.3-83, and 6.3-84.

6.3.3.7.4 TRACG-LOCA Statistical Analyses

Based on the break spectra calculations, potentially limiting breaks were chosen for statistical analysis in Reference 42. The results of the statistical analyses are shown in Table 6-3.4, with the overall maximum peak cladding temperature, maximum local oxidation (MLO), and core wide oxidation (CWO) for GE14 and GNF3 fuel types.

6.3.3.7.5 Compliance Evaluations

The licensing basis PCT, maximum local fuel cladding oxidation (MLO), and total fraction of fuel cladding oxidized in the core (CWO) for GE14 and GNF3 are determined based on the results from the statistical analyses. The licensing basis PCT, MLO and CWO values are identified in Table 6.3-4.

6.3.3.7.6 Operating Mode Considerations

The ECCS performance (Reference 42) was also evaluated for the following operating mode considerations:

a. Maximum Extended Operating Domain (MEOD) - The MEOD and Maximum Extended Load Line Limit Analysis (MELLLA) provide an expanded operating rod line and an increased core flow range operating domain as shown in Figure 4.4-3.

b. Partial Feedwater Heating (PFH) - The Feedwater Heaters Out-of-Service (FWHOOS) and Final Feedwater Temperature Reduction (FFWTR) mode of the PFH mode of operation (References 6 and 7).

c. Single Loop Operation (SLO) - SLO is permitted when operation is below 66.1% of rated power with recirculation pump speed limited to 75% (References 12 and 14).

d. Out-of-Service Equipment - The Fermi-2 Technical Specifications allows the turbine bypass, moisture separator reheater and several SRVs to be inoperable without requiring a plant shutdown. The unavailability of the turbine bypass and moisture separator has no impact on the results of the ECCS analysis because no credit for these systems has been taken in the ECCS evaluation. The availability of SRVs does not impact the calculated licensing basis PCT results since the limiting break events produce only a mild pressurization during the early time period of the event.

6.3.3.8 Loss-of-Coolant Accident Analysis Conclusions

Having shown compliance with the applicable acceptance criteria of Subsection 6.3.3.2, it is concluded that the ECCS will perform its function in an acceptable manner and meet all of the 10 CFR 50, Section 50.46 acceptance criteria.

6.3.3.9 Thermal Shock Considerations

The ECCS pumps starting at some time after the accident are at ambient (greater than 40°F) and could be heated rapidly as they draw their suctions from the suppression pool.

The HPCI pump and piping system considers a rapid rise in suction temperature from ambient (greater than 40°F) to the maximum operating temperature. The suction is normally from the condensate storage tank (less than 100°F), but can be switched to the suppression pool. If the reactor is not depressurized, the suppression pool temperature rises slowly, providing ample time for the operator to either depressurize and use the LPCI and/or core spray, or to cool the suppression pool with the containment cooling subsystem of the RHR system.

The design of the ECCS pumps (except HPCI), therefore, considers the differences in the rate of expansion between stationary and rotating parts in order to ensure operability during the transients (sudden change in water temperature from 40° to 170°F).

The piping design similarly considers this thermal shock. The steam line in the HPCI turbine is kept warm since it is normally open from the reactor with a drain pot at the turbine end of the line. A design requirement for the turbine itself is for rapid start, i.e., admission of hot steam to a cold turbine. The turbine vendor has considered the possible thermal shock effects in his design. The turbine exhaust increases rapidly from ambient (greater than 40°F) to operating (300°F) temperature, which is considered in both turbine and piping design.

The output of these ECCS subsystems into the reactor introduces relatively cold water into a hot RPV, and thermal shock is considered in the design of the reactor vessel, its nozzles, and the feedwater lines. The LPCI discharges via the hot recirculation line, so this thermal shock is also considered in the recirculation system piping design.

Section 5.2 contains a summary of results of the cold water injection thermal stress analyses.

6.3.4 Inspection and Testing

Each active component of the ECCS required to operate in a DBA is designed to be operable for test purposes during normal operation of the nuclear steam supply system (NSSS).

Regular tests are performed on the system to verify operability. If a test shows some element of the system to be inoperative, repairs are made to return the system to fully operative status. A failure of the system occurring between tests may have serious consequences, depending on whether or not a need to function occurs before the next test is performed. There is, therefore, a direct relationship between the system unreliability, the rate of occurrence of system failures from all causes, and the testing interval for the system.

It has been shown that the test frequency as well as the failure rate affect system reliability. There are practical limits on test frequency, such as the possibility of wearing out system components with too much testing. The test frequency outlined in the Technical Specifications is based upon these considerations.

The HPCI system, ADS, and core spray system have no normal process uses, and therefore are tested periodically to provide assurance that the ECCS will operate to effectively cool the reactor core in an accident. The four LPCI pumps may be placed in use as part of the RHR system and, if so, their status is known from normal process uses. However, the LPCI pumps should be tested no less frequently than the rest of the ECCS. Other parts of the LPCI, such as the two testable check valves inside the primary containment drywell and the four shutoff valves outside the drywell, are intended for use only in an accident, so they are also tested periodically.

Preoperational tests of the ECCS were conducted during the final stages of plant construction prior to initial startup. These tests ensured the proper functioning of all controls and instrumentation, pumps, piping, and valves. System reference characteristics such as pressure differentials and flow rates were documented during the preoperational tests and will be used as base points for measurements obtained in the subsequent operational tests.

During plant operations, the pumps, valves, piping, instrumentation, wiring, and other components outside the primary containment can be visually inspected at any time. Components inside the primary containment can be inspected when the drywell is open for access. When the RPV is open, for refueling or other purposes, the spargers and other internals can be inspected. The testing frequencies of most components of the ECCS are correlated with the testing frequencies of the associated controls and instrumentation. When a pump or valve control is tested, the operability of the pump or valve and the associated instrumentation is also tested by the same action.

When the system is tested, the operation of most of the components is indicated in the main control room. There are exceptions that require local observation at the component and may require special tests for which there are special provisions and methods.

Pressure-operated relief valves may leak after operation and it is not advisable to overpressurize the system for test, so relief valves are removed as scheduled at refueling outages for bench tests and setting adjustments. Bench tests of automatic depressurization valves are discussed in Subsection 5.2.2.

A pressure-operated control valve such as the one upstream of the HPCI system barometric condenser is functionally tested and adjusted in place, in accordance with the valve manufacturer's manual and the system specification for pressure setting. A test pressure connection is provided to check and adjust the setting.

Reverse flow and excess flow check valves in the ECCS are tested periodically in accordance with the Technical Specifications and the Inservice Testing Program.

Test lines are provided between pairs of containment isolation valves in the ECCS to measure leakage when the containment is pressurized for tests. The test line is also used to pressurize between the closed valves to identify which one is leaking. Allowable valve leakage is in accordance with Section 6.2 and the Technical Specifications.

Allowable valve seat leakage during shop hydrostatic tests for nuclear Class 1, 2, and 3 gate, globe, and ball valves associated with these systems is 2 cm^3/hr/in. of seat diameter during hydrostatic test at design pressure. Leakage for check and stop- check valves is 10 cm^3/hr/in. diameter of valve seat at the design differential pressure across the valve. Valve packing leakage during the hydrostatic test is specified as "no visible leakage."

Pumps for the ECCS are equipped with face-type mechanical shaft seals.

A design flow functional test of the HPCI system up to the normally closed pump discharge valve is performed during normal plant operation by pumping water from the condensate storage tank and back through the full-flow test return line. The HPCI system turbine pump is driven at its rated output by steam from the reactor. The suction valves from the suppression pool and discharge valves to the reactor feedwater line remain closed.

The HPCI system test conditions are tabulated on the HPCI system process diagram, Figures 6.3-1 through 6.3-5. If an initiation signal occurs while the HPCI system is being tested, the system returns to the automatic startup mode and supplies water to the reactor.

The HPCI may be tested at full flow with condensate at any time except when the reactor vessel water level is low, the condensate level in the condensate storage tank is below the reserve level, or the valves from the suppression pool to the pump are open.

During the HPCI flow test, the minimum-flow bypass valve opens/closes as required per the logic. The turbine steam valves and the flow test valves to the condensate storage tank are opened to support the HPCI flow test.

To ensure proper operation of the valves when pumping from the suppression pool, the HPCI suction valve auto transfer test is performed to meet Technical Specification requirements. Credit is taken for the RHR and CS testing from the suppression pool as an indication of strainer performance/degradation.

The RHR, CS and HPCI suppression pool suction strainers are inspected periodically in accordance with the plant preventive maintenance program.

Each loop of the core spray systems may be tested during reactor operation. The test conditions are tabulated on the core spray system process diagram, Figures 6.3-7 through 6.3-11. The normal system test does not inject cold water into the reactor because the testable check valve is held closed by the reactor pressure which is higher than core spray pump pressure. To test the injection portion of the system, using demineralized water, the reactor must be shut down and depressurized. This prevents unnecessary thermal stresses.

To test the core spray pumps at rated flow, the pump suction valve from the suppression pool is open, the pump is started using the remote manual switches in the main control room and the test bypass valve is opened to the suppression pool. Proper operation is determined by observing the instruments in the main control room. The core spray system outside the drywell is checked for leaks.

The two motor-operated injection valves outside the drywell and the air-operated testable check valve inside the drywell are tested as described in the Fermi 2 Inservice Testing Program.

If an initiation signal occurs during the test, the core spray system is signaled to start and the system returns to the automatic startup mode and is ready to deliver water to the reactor.

Similarly, LPCI pumps and valves are tested periodically during reactor operations. With the injection valves closed and the return line open to the suppression pool, full-flow pumping capability is demonstrated. The injection valves are tested, and the testable check valves are operated, as described previously for the core spray valves. The system test conditions during reactor shutdown are shown on the RHR/LPCI system process diagram, Figures 6.3-14 through 6.3-16. The portion of the LPCI outside the drywell is inspected for leaks during tests. Controls and instrumentation are tested as described in Section 7.3.

On receipt of an LPCI initiation signal during tests, the valves in the test bypass lines and in the shutdown cooling system are closed automatically to ensure that the LPCI pump discharge is routed properly to the reactor vessel.

Detailed specifications for ECCS component testing are contained in Chapter 14 and the Technical Specifications.

The valves performing an isolation function between high-pressure and low-pressure portions of systems connected to the RCS are tested in accordance with the Technical Specifications.

Table 6.3-9 lists the valves that perform an isolation function between high-pressure and low-pressure portions of systems connected to the RCS. These pressure isolation valves meet the requirements of the ASME Code Section XI, Pump and Valve Testing Program, and are categorized as A or AC. The testing program for the valves, which is referenced in the Technical Specifications, consists of the following methods:

a. Exercise the valve and verify the valve position during refueling and after maintenance before the return to service in accordance with IWV-3300 or IWV-3522(b)

b. Exercise the valve (full stroke) for operability during the cold-shutdown mode as time permits, but not more frequently than once every 3 months

c. Measure the full-stroke time (not for check valves)

d. Leak test the valve seat before reaching power operation following refueling and after valve maintenance before the return to service.

These valves will not be routinely exercised every 3 months during plant operation as required by IWV-3410 because of the following.

a. Such tests remove one of the two barriers protecting the low-pressure portion of the ECCSs

b. The operators on testable check valves cannot overcome the force on the valve with reactor pressure on one side.

Instead, the valves will be exercised during cold-shutdown periods as time permits (but not more frequently than once every 3 months). If there is excessive leakage through the normally closed gate and check valves, the operator will be alerted by the high pressure alarm indicated in Table 6.3-10. The operator will then be procedurally required to close the normally open gate valve from the control room to effect isolation.

6.3.5 Instrumentation Requirements

Design details and logic of the instrumentation for the ECCS are discussed in Section 7.3.

6.3.5.1 High Pressure Coolant Injection Actuation Instrumentation

The HPCI is automatically actuated by the following sensed variables: (1) RPV low water level; or, (2) drywell high pressure.

In addition, the HPCI can be manually actuated from the main control room.

6.3.5.2 Automatic Depressurization System Actuation Instrumentation

The ADS is automatically actuated when the RPV low water level is coincident with drywell high pressure. A time delay is incorporated as discussed in Chapter 7. In addition, two core spray pumps or an RHR pump must be running. Each ADS valve can be manually actuated from the main control room.

6.3.5.3 Core Spray Actuation Instrumentation

The core spray is automatically actuated by the RPV low water level or drywell high pressure. In addition, the core spray can be manually actuated from the main control room.

6.3.5.4 Low Pressure Coolant Injection Actuation Instrumentation

The LPCI is automatically actuated by the RPV low water level or drywell high pressure. In addition, the LPCI can be manually actuated from the main control room.

Emergency Procedures contain adequate caution to deter the operator from premature LPCI flow diversion. The Emergency Procedures caution the operator against diversion unless adequate core cooling is assured. The containment cooling modes of the RHR are secondary to core cooling requirements except in those instances outside the design envelope involving multiple failures, for which maintenance of containment integrity is required to minimize risk to the environment.

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TABLE 6.3-1 SHUTDOWN COOLING AND EMERGENCY CORE COOLING SYSTEM OPERATION

Accident or condition	Required Operation	RHR or ECCS Subsystems and Components Used	Redundancy Provided Within System	Backup System(s)
Shutdown Cooling	For a normal shutdown and cooldown, the main condenser is used to condense decay-heat-generated steam until the condenser vacuum is lost. Makeup water is provided as for condenser isolation. When the condenser is no longer effective, primary system cooling is continued by taking water from one of the recirculation loops, through the RHR heat exchangers, and back to the recirculation loop using the RHR pumps. Should the reactor be isolated from the condenser by operation of the isolation valve (not a normal operation) steam is first dumped to the suppression pool rather than to the condenser (below).	Main condenser RHR heat exchangers, RHR main pumps	Two RHR heat exchangers (one heat exchanger sufficient) Four RHR pumps (two pumps sufficient)	RHR cooling subsystem backs up the main condenser used for shutdown cooling
Isolation of condenser (occurs when a reactor scram is accompanied by containment isolation)	Upon the closing of the main steam line valve following a scram, automatic operation of relief valves causes steam to be dumped to the suppression pool, the RHR removes heat from the pool. The single RCIC steam-driven pump takes water from condensate storage and discharges to the feedwater line. Signal: low reactor vessel water level.	Relief valves RHR heat exchangers RCIC pump Condensate (reserve storage)	Total of 15 safety/relief valves available (nine sufficient) Two RHR heat exchangers (one sufficient)	1. RCIC[a] 2. HPCI[a] 3. Control rod drive water systema 4. Core spray and LPCI[a]
Small leaks (accident condition)	First Level Feedwater system and control rod drive system can provide some makeup water.			Second level HPCI and/or RCIC
	Second Level The single HPCI steam-driven pump takes water from condensate storage and discharges to a feedwater line. Signal: low reactor vessel water level or high drywell pressure. The decay-heat-generated steam flows to the HPCI turbine and is exhausted to the suppression pool.	HPCI steam-driven pump, station battery (no ac required, 5000gpm) Five safety/relief valves	RCIC pump (600gpm) Water can also come from suppression pool Manual actuation of any of 15 safety/relief valves	Third level
	Third Level Automatic depressurization system vents steam to the suppression pool. With decreased pressure LPCI and core spray systems can provide water signals: low reactor vessel level and high drywell pressure and core spray or RHR pump running.	Three of four pumps of LPCI Two loops of core spray system (alternate) Standby ac power supply		At low pressure (RV approximately 300 psi) both LPCI and core spray can operate. SRVs
Large leaks (accident condition)	Core spray system pumps water from the suppression pool to core. Signal: low reactor vessel water level or high drywell pressure.	Pumps with electric motors, spray sparger, standby ac bus; different for each spray loop (6350 gpm per core spray system and 10,000 gpm per LPCI/RHR pump)	Two independent core spray systems standby ac bus available	LPCI
	LPCI operates. Three of the four RHR main pumps take water from the suppression pool and delivers it to a recirculation loop. Signal: low reactor vessel level or high drywell pressure.	Pumps and motors. Power from standby ac bus (30,000 gpm for 3 LPCI pumps plus 12,700 gpm for two core spray systems)	Three of the four RHR pumps required. All have ac standby as backup power source (four pumps are signaled to start)	Core spray

[a] Systems used for reactor water inventory control.

TABLE 6.3-2 MATERIALS FOR THE PRINCIPAL EMERGENCY CORE COOLING SYSTEM COMPONENTS

Item	Supplier	Impeller	Casing	Shaft
LPCI pump	Byron Jackson	Martensite SS	Carbon steel	Austenite SS
Core spray pump	Byron Jackson	Martensite SS	Carbon steel	Austenite SS
HPCI pump	Byron Jackson	Martensite SS	Carbon steel	Martensite SS
HPCI turbine	Terry	Low-alloy steel	Carbon steel	Low-alloy steel
ADS safety/relief valves	Target Rock two-stage walves	N/A	N/A	N/A

TABLE 6.3-3 HAS BEEN INTENTIONALLY DELETED

TABLE 6.3-4 SUMMARY OF RESULTS OF LOSS-OF-COOLANT ACCIDENT ANALYSIS

	Parameters	Results	Results	Acceptance Criteria
1.	Fuel Type	GE14 Fuel	GNF3 Fuel	
2.	Limiting Break	Recirculation Suction Small Break	Recirculation Suction Small Break	
3.	Limiting Failure	Division II DC Power (Battery)	Division II DC Power (Battery)	
4.	Peak Cladding Temperature (Licensing Basis)	< 1980 °F	< 2150 °F	≤ 2200 °F
5.	Maximum Local Oxidation	< 6.0 %	< 9.5 %	≤ 13 %[a]
6.	Core-Wide Metal-Water Reaction	< 0.02 %	< 0.02 %	≤ 1.0 %
7.	Coolable Geometry	Items 4 and 5	Items 4 and 5	PCT ≤ 2200 °F and Maximum Local Oxidation ≤ 13 %[a]
8.	Long Term Cooling	Core flooded above top of active fuel	Core flooded above top of active fuel	Core temperature acceptably low and long-term decay heat removed

[a] The MLO calculated by TRACG-LOCA is limited to 13% to ensure the 10CFR50.46 limit of 17% is satisfied.

TABLE 6.3-5 EMERGENCY CORE COOLING SYSTEM SINGLE - FAILURE EVALUATIONS[a]

Assumed Failure[b]	Suction Break Systems Remaining[c,d]
LPCI valve	All ADS, 2 core spray, HPCI
Divisional diesel generators (EDG)	All ADS, 1 core spray, HPCI, 2 LPCI
Battery (Division I)	HPCI, 2 LPCI, 1 core spray
Battery (Division II)	All ADS, 1 core spray, 2 LPCI
HPCI	All ADS, 4 LPCI, 2 core spray
One ADS valve	All ADS minus one, 2 core spray, HPCI, 4 LPCI

[a] This table shows the single active failures considered in the ECCS performance evaluation.

[b] Other postulated failures are not specifically considered because they all result in at least as much ECCS capacity as one of the above assumed failures.

[c] Systems remaining, as indentified in this table, are with concurrent loss-of-offsite power and are applicable to all non-ECCS line breaks. For a LOCA from an ECCS line break, the systems remaining are those listed, less the ECCS in which the break is assumed.

[d] Analyses performed with one ADS valve assumed unavailable in addition to the single failure (Table 6.3-6).

TABLE 6.3-6 ECCS ANALYSIS
SIGNIFICANT INPUT VARIABLES AND INITIAL CONDITION

Variable	Units	Value
A. Plant parameters		
Core Thermal Power, plus uncertainty	MWth	3499
Nominal Vessel Dome Pressure	psia	1045
Maximum Core Recirculation Flow	mlb/hr	105
Rated normal feedwater temperature	°F	426.5
Reduced feedwater temperature	°F	376.5
Nominal downcomer water level (above vessel zero)	inches	563.5
B. Emergency Core Cooling System Parameters		
Low-Pressure Coolant Injection (LPCI) System		
Vessel Pressure at Which Flow Credited to Commence	psid	264
Minimum Flow at Vessel Pressure of:	psid	20
Two pumps	gpm	21,850
Three pumps	gpm	26,260
Four pumps	gpm	27,625
Initiating Signals and Setpoints:		
Low Water Level	ft above TAF*	1.02
or		
High Drywell Pressure	psig	2.0
Assumed Injection Valve Stroke Time	sec	30
Maximum Vessel Pressure At Which LPCI Injection Valve Can Open	psig	350
Maximum Allowable Time from Drywell Pressure Initiating Signal to Pump at Rated Speed and Ready to Inject Flow to Vessel with Emergency Power	sec	77
Minimum Break Size for Which Loop Selection Logic Assumed to Select Unbroken Loop	ft^2	0.15

TABLE 6.3-6 ECCS ANALYSIS
SIGNIFICANT INPUT VARIABLES AND INITIAL CONDITION

Variable	Units	Value
Low Pressure Core Spray (CS) System		
Vessel Pressure at Which Flow May Commence	psid	280
Minimum Rated Flow at Vessel Pressure of:	psid	100
One Loop	gpm	5,625
Initiating Signals and Setpoints:		
Low Water Level	ft above TAF*	1.02
or		
High Drywell Pressure	psig	2.0
Runout Flow at Vessel Pressure of:	psid	0
One Loop	gpm	7,013
Assumed Injection Valve Stroke Time	sec	15
Maximum Vessel Pressure at Which LPCS Injection Valve Can Open	psig	350
Maximum Allowable Time from Drywell Pressure Initiating Signal to Pump at Rated Speed and Ready to Inject flow to Vessel with Emergency Power	sec	47
High Pressure Coolant Injection (HPCI) System		
Vessel Pressure at Which Flow May Commence	psia	1135
Minimum Rated Flow at Vessel Pressure of:	psia gpm	1135 to 165** 5000
Initiating Signals and Setpoints:		
Low Water Level	ft above TAF*	7.6
or		
High Drywell Pressure	psig	2.0
Maximum Allowable Time from Drywell Pressure Initiating Signal to Rated Flow Available and Injection Valve Wide Open	sec	60
Automatic Depressurization System (ADS)		
Total Number of Valves Installed	--	5
Number of Valves Assumed in Analysis	--	4

TABLE 6.3-6 ECCS ANALYSIS
SIGNIFICANT INPUT VARIABLES AND INITIAL CONDITION

Variable	Units	Value
Minimum Flow Capacity of any 4 Valves at	mlb/hr	3.48
Vessel Pressure	psig	1090
Initiating Signals and Setpoints:		
Low Water Level	ft above TAF*	1.02
and		
High Drywell Pressure	psig	2.0
Time Delay After Initiating Signal	sec	120

* TAF (Top of Active Fuel) = 366.3 inches from vessel zero

** HPCI pump is designed to produce a flow of 5000 gpm at an RPVpressure of 1184 psia, which exceeds LOCA input.

TABLE 6.3-7 OPERATIONAL SEQUENCE OF EMERGENCY CORE COOLING SYSTEMS FOR DESIGN-BASIS ACCIDENT[a]

Time (sec)	Events
0	Design-basis LOCA assumed to start; normal auxiliary power assumed to be lost.
0	Drywell high pressure and reactor low water level reached; scram; HPCI, LPCS, LPCI signaled to start on high drywell pressure.
3	Reactor low-low water level reached. Main steam isolation valves close; HPCI receives second signal to start, all diesel generators signaled to start.
7	Reactor low-low-low water level reached. Second signal to start LPCI and LPCS; autodepressurization sequence begins.
<13	All diesel generators ready to load; open HPCI injection valve; begin energizing LPCI pump motors.
18	Begin energizing LPCS pump motors.
≤47	LPCS pumps at rated flow; LPCS injection valves open, completing the LPCS startup.
≤77	LPCI pumps at rated flow; LPCI injection valves open, completing the LPCI startup.
See Figure 6.3-20	Core effectively reflooded assuming worst single failure; heatup terminated
≥10 minutes	Operator shifts to containment cooling.

[a] For the purpose of all but the next-to-last entry on this table, all ECCS equipment is assumed to function as designed. Performance analysis calculations consider the effects of single equipment failures. (See Subsections 6.3.2.5 and 6.3.3.3.)

TABLE 6.3-8 KEY TO FIGURES IN SECTION 6.3.3.7

Break Size Variable	Large Recirculation Line Break, DEGB	Small Recirculation Line Break
Peak Clad Temperature Vs. Time	Figure 6.3-79 (GNF3)	Figure 6.3-82 (GNF3)
RPV Pressure Vs. Time	Figure 6.3-80 (GNF3)	Figure 6.3-83 (GNF3)
Water Level Vs. Time	Figure 6.3-81 (GNF3)	Figure 6.3-84 (GNF3)

These curves indicate the trends of the variables post-LOCA.

TABLE 6.3-9 PRESSURE ISOLATION VALVES

System	P&ID	Valve Numbers	Type	Size (in.)	Function
RHR	6M721-2083	E11-F015A, B	Gate	24	Discharge to recirculation system
	6M721-2084	E11-F050A, B	Check	24	Discharge to recirculation system
		E11-F008	Gate	20	Suction from recirculation system
		E11-F009	Gate	20	Suction from recirculation system
		E11-F608	Gate	20	Suction from recirculation system
Core spray	6M721-2034	E21-F005A, B	Gate	12	Discharge to core spray sparger
		E21-F006A, B	Check	12	Discharge to core spray sparger
HPCI	6M721-2035	E41-F006	Gate	14	Discharge to feedwater line
		E41-F005	Check	14	Discharge to feedwater line
RCIC	6M721-2044	E51-F013	Gate	6	Discharge to feedwater line
		E51-F014	Check	6	Discharge to feedwater line

TABLE 6.3-10 PRESSURE ISOLATION PROTECTION AND MONITORING

System/Line Needing Protection	Relief Valve Overpressure Protection	Control Room Alarm	Control Room Indicator	Local Indicator
RHR discharge	F025A, B, 1-1/2 in.	E11-N022A, B at 400 psig	E11-R003A, B, C, D, 0-600 psig	--
RHR suction	F030A, B, C, D, F029, 1 in.	--	E11-R002A, B, C, D, 30 in. Hg, 150 psig	--
Core spray discharge	E2100F012A (V22-2016), E2100F012B (V22-2017), E2100F011B (V22-2119), E2100F011A (V22-2120)	E21-N007A, B at 440 psig	--	E21-R600A, B, 0-600 psig
HPCI	E41-F020 (V22-2044), 1-1/2 in.	E41-N031 at 70 psig	--	E41-R004, 30 in. Hg, 100 psig
RCIC suction	E51-F017 (V22-2002), 1 in.	E51-N030 at 70 psig	--	E51-R002, 30 in. Hg, 85 psig

Figure Intentionally Removed
Refer to Plant Drawing M-5860

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FIGURE 6.3-1

HIGH PRESSURE COOLANT INJECTION SYSTEM
PROCESS DIAGRAM

Figure Intentionally Removed
Refer to Plant Drawing M-5872

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FIGURE 6.3-2

HIGH PRESSURE COOLANT INJECTION SYSTEM
HIGH PRESSURE INJECTION
ACCIDENT CONDITION

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Refer to Plant Drawing M-5873

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FIGURE 6.3-3

HIGH PRESSURE COOLANT INJECTION SYSTEM
HIGH PRESSURE INJECTION MODE USING
SUPRESSION POOL AS BACKUP SOURCE

Figure Intentionally Removed
Refer to Plant Drawing M-5874

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FIGUE 6.3-4

HIGH PRESSURE COOLANT INJECTION SYSTEM
MINIMUM FLOW MODE

Figure Intentionally Removed
Refer to Plant Drawing M-5875

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FIGURE 6.3-5

HIGH PRESSURE COOLANT INJECTION SYSTEM
TEST MODE DURING PLANT OPERATION

FIGURE 6.3-6
HAS BEEN DELETED

Figure Intentionally Removed
Refer to Plant Drawing M-5861

Fermi 2
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FIGURE 6.3-7

CORE SPRAY SYSTEM PROCESS DIAGRAM

Figure Intentionally Removed
Refer to Plant Drawing M-5868

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FIGURE 6.3-8
CORE SPRAY - ACCIDENT CONDITION

Figure Intentionally Removed
Refer to Plant Drawing M-5869

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FIGURE 6.3-9

CORE SPRAY SYSTEM TEST MODE DURING PLANT OPERATION USING SUPPRESSION POOL

Figure Intentionally Removed
Refer to Plant Drawing M-5870

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FIGURE 6.3-10

CORE SPRAY SYSTEM TEST MODE DURING PLANT SHUTDOWN USING CONDENSATE STORAGE TANK

Figure Intentionally Removed
Refer to Plant Drawing M-5871

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FIGURE 6.3-11

CORE SPRAY SYSTEM MINIMUM FLOW BYPASS MODE – SUCTION FROM SUPPRESSION POOL

FIGURE 6.3-12
HAS BEEN DELETED

FIGURE 6.3-13
HAS BEEN DELETED

Figure Intentionally Removed
Refer to Plant Drawing M-5857

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FIGURE 6.3-14, SHEET 1

LOW PRESSURE COOLANT INJECTION SYSTEM
PROCESS DIAGRAM

Figure Intentionally Removed
Refer to Plant Drawing M-5690

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FIGURE 6.3-14, SHEET 2

LOW PRESSURE COOLANT INJECTION SYSTEM
PROCESS DIAGRAM

Figure Intentionally Removed
Refer to Plant Drawing M-5866

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FIGURE 6.3-15

LOW PRESSURE COOLANT INJECTION SYSTEM
TEST MODE DURING PLANT OPERATION

Figure Intentionally Removed
Refer to Plant Drawing M-5867

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FIGURE 6.3-16

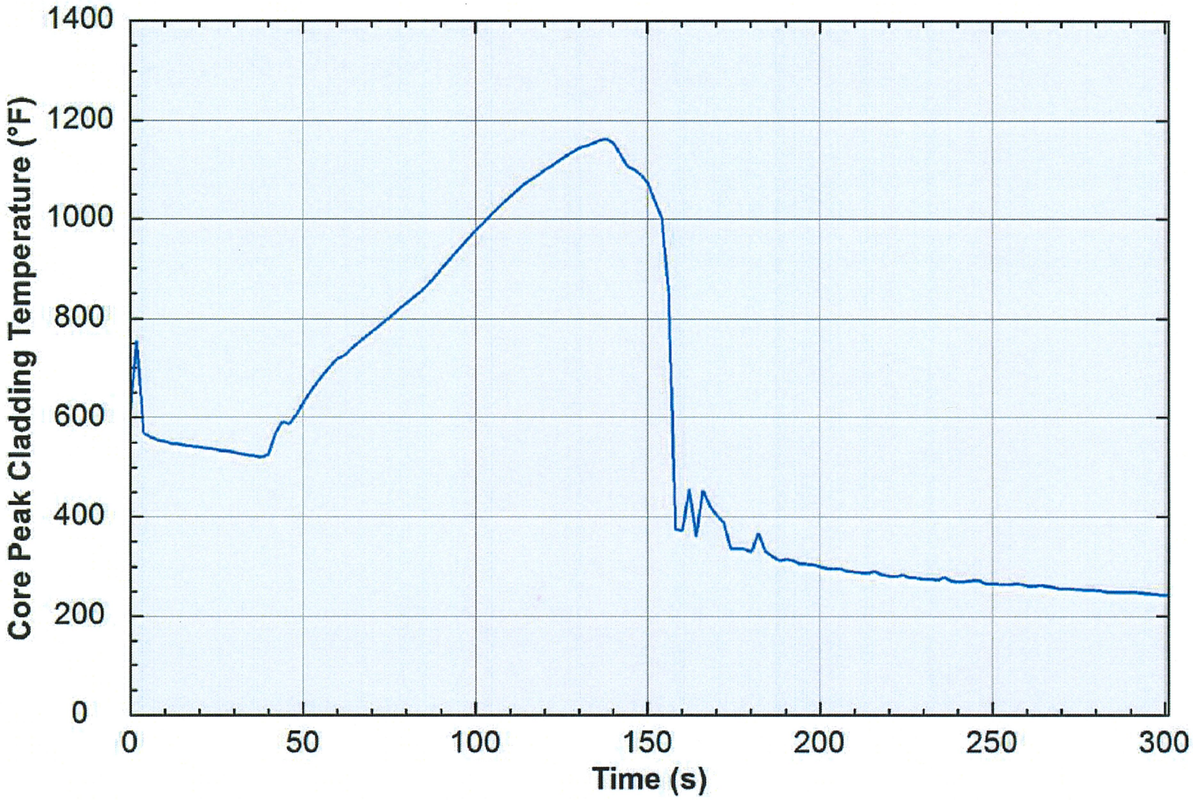
LOW PRESSURE COOLANT INJECTION SYSTEM
MINIMUM FLOW BYPASS MODE

FIGURE 6.3-17
HAS BEEN DELETED

FIGURES 6.3-18 THROUGH 6.3-23
HAVE BEEN DELETED

FIGURE 6.3-24 THROUGH FIGURE 6.3-78

HAVE BEEN DELETED



NEDC-33919P, Revision 0, Figure 9-33

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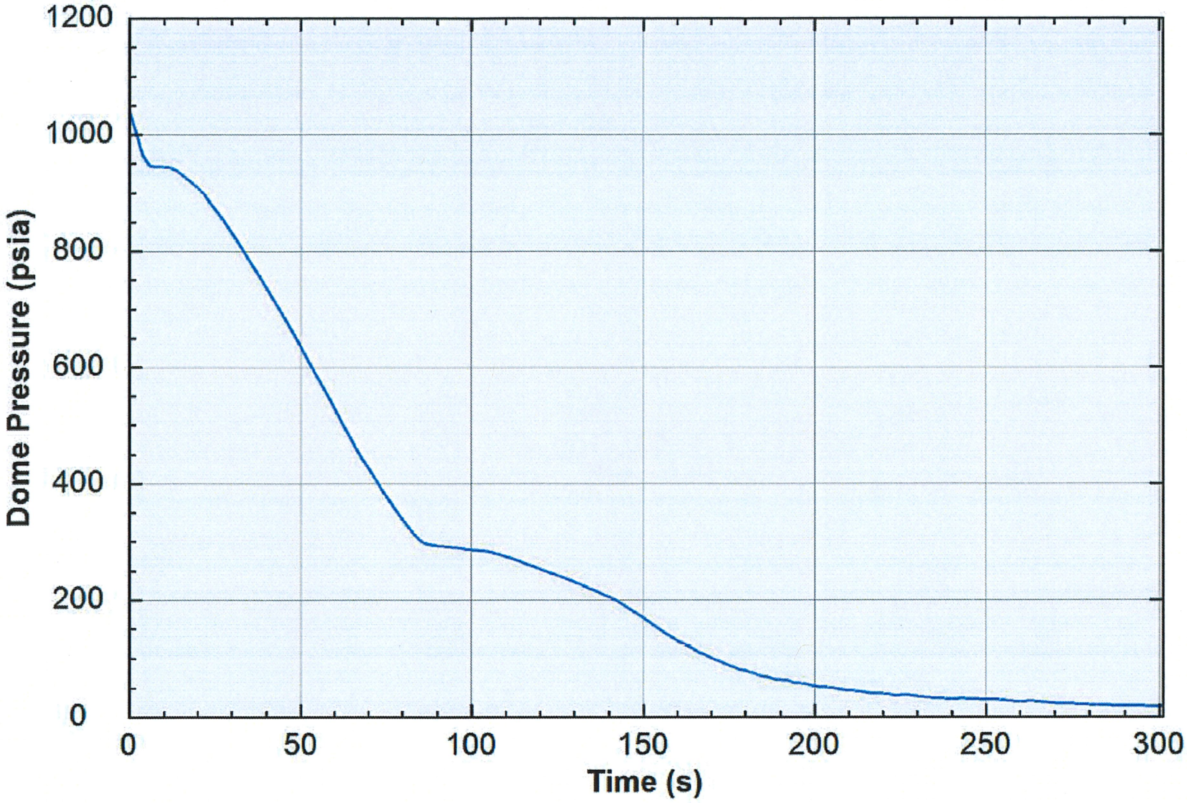
FIGURE 6.3-79

FERMI 2 GNF3 NOMINAL DEGB RDL BREAK FOR CLTP INITIAL CONDITIONS FOR DIV II BATTERY FAILURE – OVERALL CORE PCT



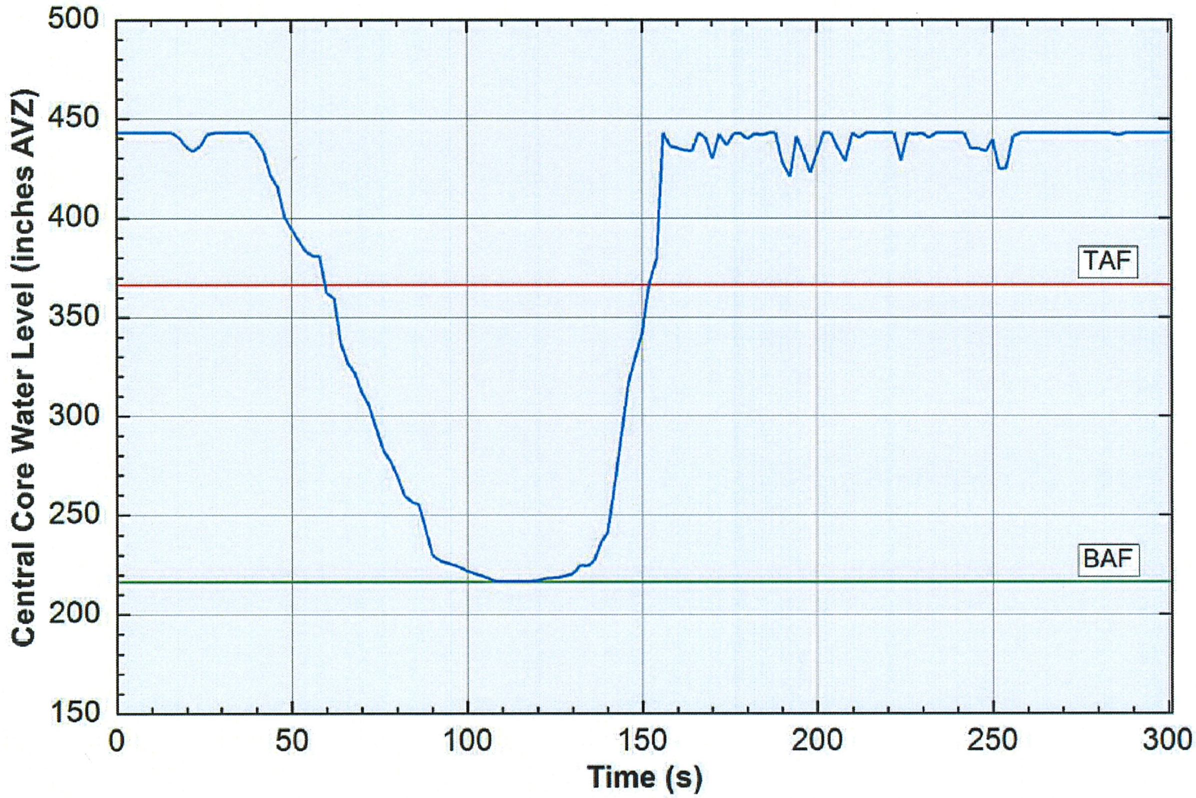
NEDC-33919P, Revision 0, Figure 9-29

Fermi 2

UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 6.3-80

FERMI 2 GNF3 NOMINAL DEGB RDL BREAK FOR CLTP INITIAL CONDITIONS FOR DIV II BATTERY FAILURE – REACTOR PRESSURE



NEDC-33919P, Revision 0, Figure 9-31

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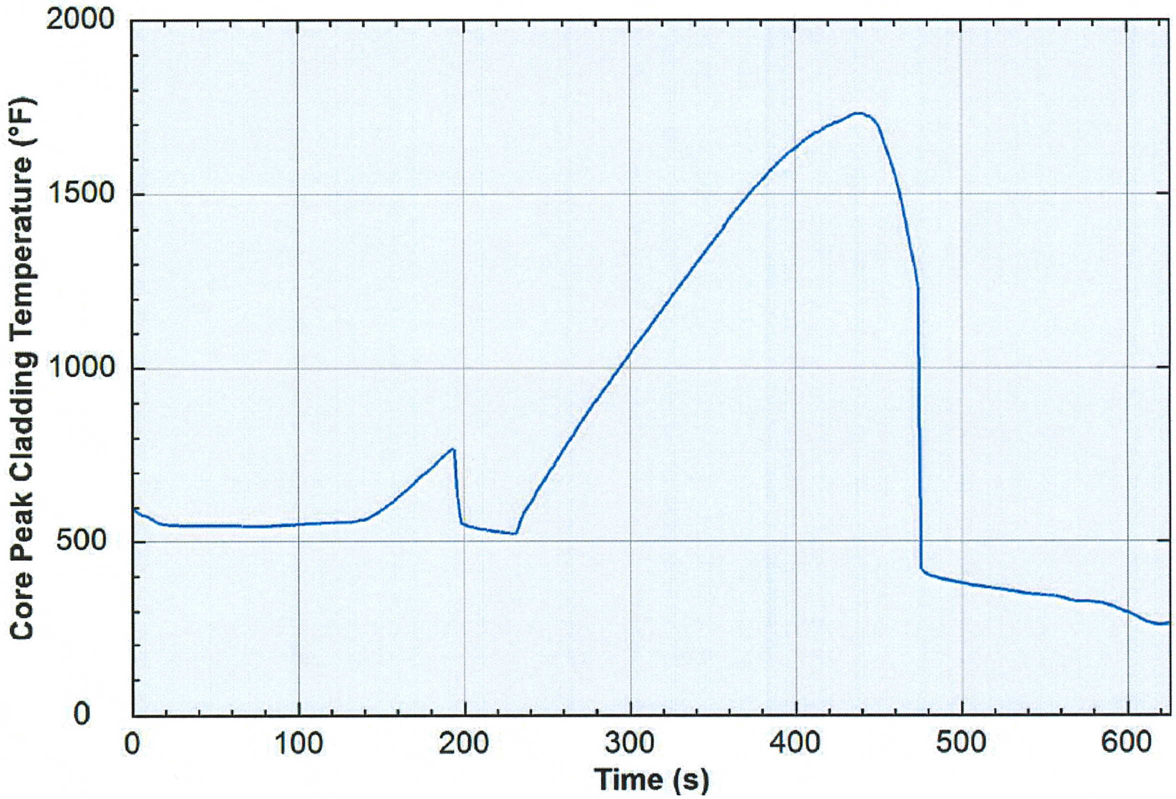
FIGURE 6.3-81

FERMI 2 GNF3 NOMINAL DEGB RDL BREAK FOR CLTP INITIAL CONDITIONS FOR DIV II BATTERY FAILURE – CENTRL CORE (BYPASS AND UPPER PLENUM) WATER LEVEL

REV 23 02/21



NEDC-33919P, Revision 0, Figure 9-6

Fermi 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 6.3-82

FERMI 2 GNF3 NOMINAL SMALL RSL BREAK FOR MELLLA INITIAL CONDITIONS FOR DIV II BATTERY FAILURE – OVERALL CORE PCT

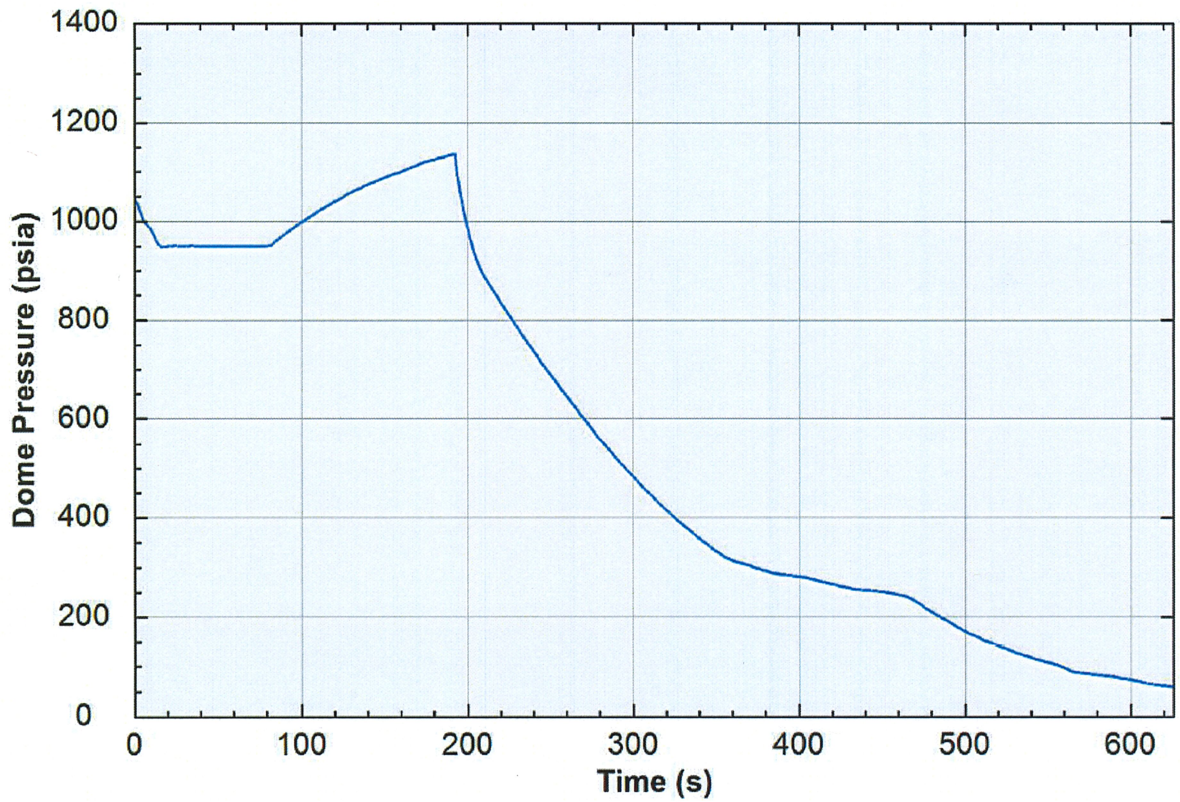


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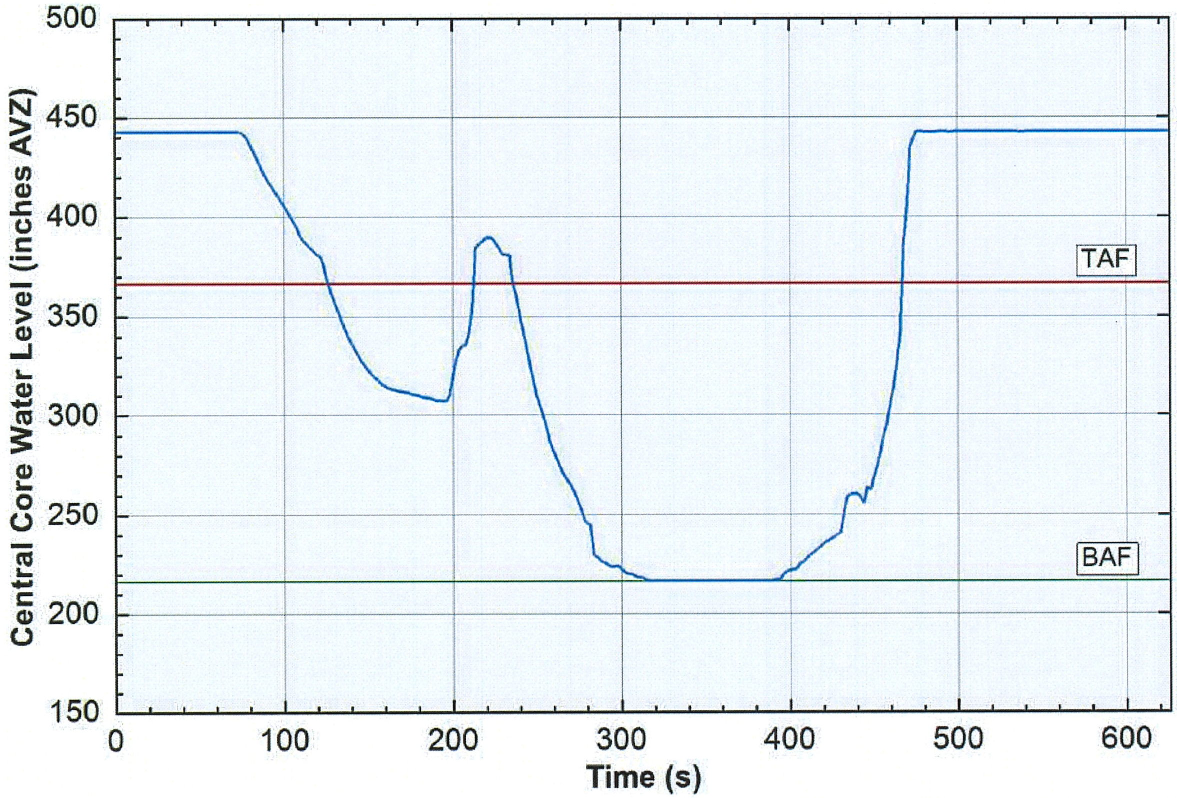
FIGURE 6.3-83

FERMI 2 GNF3 NOMINAL SMALL RSL BREAK FOR MELLLA INITIAL CONDITIONS FOR DIV II BATTERY FAILURE – REACTOR PRESSURE

NEDC-33919P, Revision 0, Figure 9-2



NEDC-33919P, Revision 0, Figure 9-4

Fermi 2

UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 6.3-84

FERMI 2 GNF3 NOMINAL SMALL RSL BREAK FOR MELLLA INITIAL CONDITIONS FOR DIV II BATTERY FAILURE – CENTRAL CORE (BYPASS AND UPPER PLENUM) WATER LEVEL

6.4 HABITABILITY SYSTEMS

Control center habitability systems ensure that the main control room can be occupied under normal, accident, and postaccident conditions. Habitability systems include the systems, components, facilities, supplies, and equipment required for safe habitation of the main control room.

6.4.1 Habitability Systems Design Bases

The bases for the functional design of the habitability systems are given below. The bases result in systems that ensure compliance with General Design Criterion 19, 10 CFR 50, Appendix A. Under any design-basis conditions, the environment within the main control room is safe, with personnel protected from radiation, fire, toxic gases, and noxious substances.

6.4.1.1 Radiation Shielding and Air Filtration

The total radiation dose to main control room personnel is the dose received while occupying the control center. Doses received while in the main control room are due to the radiation that penetrates the biological shielding and to the isotopes that enter the control center through the ventilation system or through inleakage. Source terms and individual contributions to total doses are given in Chapter 15, along with a further discussion of the assumptions, the physical models, and the methods of analysis.

Sufficient radiation shielding and air filtration are provided to ensure that radiation exposures of main control room personnel do not exceed 5 rem whole-body, or its equivalent to any part of the body, for the duration of a design-basis accident (DBA). For the DBA-LOCA and the Fuel Handling Accident, the dose to main control room personnel does not exceed 5 rem TEDE.

Following is a list of principal assumptions used in determining the control center personnel doses:

a. The plant personnel occupying the control center at the time the LOCA occurs remain in the control center for a period of 24 hr after that occurrence

b. Control center personnel shift changes occur twice per day, starting 24 hr after the occurrence

c. The occupancy factor is 1 for 0-1 day, 0.6 for 1-4 days, and 0.4 for 4-30 days

d. The breathing rates of the main control room personnel are 3.47×10^{-4} m^3/sec as specified by the International Committee on Radiation Protection (ICRP) (Reference 1)

e. In the event of a LOCA, the control center mode in operation is automatically shut down and the emergency makeup air filtration system is placed in operation.

f. When emergency makeup air is supplied to the main control room, the rate of introduction of outside air is 1800 cfm maximum

g. Radiation monitors in the reactor/auxiliary (i.e., fuel pool ventilation exhaust ducting) building detect airborne radiation concentrations above those specified in the Technical Specifications and cause the control center air conditioning system to automatically switch to its emergency mode of operation

h. Filter trains are provided for emergency makeup air as well as recirculated air. The filter trains are located outside the main control room

i. Charcoal filters (described in Table 9.4-1) have a assigned decontamination efficiency of 95 percent for removal of all forms of iodine; 99 percent efficiency could be claimed for the recirculation charcoal adsorber according to Regulatory Guide 1.52, but only 95 percent efficiency is claimed to avoid the more frequent testing and replacement of charcoal

j. Control center filter banks are in service throughout the course of the LOCA, filtering outside air makeup l800 cfm maximum and recirculated air 1200 cfm for a total filtered airflow of 3000 cfm

k. The mechanisms for introduction of radioisotopes into the main control room are

    1. Intake through filter trains during periods of air makeup

    2. Infiltration of outside air or exchange of inside-outside air due to opening and closing of main control room doors at shift-change times. The total quantity of unfiltered inleakage is not more than 173 cfm.

l. A radiation monitor in the control center air intake ducting, before filtration by the emergency makeup air intake and recirculation filter trains, provides radiation level information to the operators.

The assumed atmospheric dispersion factors and radioactive source terms used for each accident analysis are listed in Chapter 15.

Table 15.6.5-4 presents the doses to the control room operator from occupancy of the control room for the 30-day course of a LOCA. Table 12.1-14 presents the direct doses through the concrete walls and ceilings for the 30-day course of a LOCA as experienced by main control room personnel.

6.4.1.2 Physical Environment

Systems and controls are provided to ensure that the environment in the control center is safe and comfortable. The thermal environmental conditions are within the comfort range specified in American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE) Comfort Standard 55-66 (Reference 2), with a nominal dry bulb temperature of 75°F and a relative humidity not exceeding 60 percent, except for the mechanical equipment room (MER) and SGTS room which are discussed in Subsection 9.4.1.1. The emergency operating modes of the air conditioning system are designed to meet single-failure criteria and ensure l00 percent backup for the entire system, with the exception of the common ductwork and filters. The smoke/Halon dampers to the relay room, cable spreading room or computer room will close due to a single active failure in the Halon fire protection system.

Sufficient time is available to take manual action to reestablish airflow. Ventilation capability is provided by the air conditioning system in both the normal mode and the emergency air makeup mode of operation. Main control room environmental conditions, including radiation levels, are monitored. The air volume of the control center envelope is approximately 252,731 ft^3, which is sufficient to allow closing of the makeup air intake for a period of more than 28 days without exceeding permissible carbon dioxide concentrations when three workers occupy the main control room.

6.4.1.3 Fire Protection

Noncombustible and flame-retardant materials are used where practical, and equipment, electrical components, and control instrumentation are designed to minimize fire hazards. Fire and smoke detection and alarm systems are provided as required. Applicable NFPA codes and standards used for guidance are listed in Subsection 9.5.1.

Portable fire extinguishers are located in the main control room. The equipment is adequate to control fires that could originate inside the main control room. The air conditioning system has a purging capability to expedite the discharge of smoke from the main control room.

The control center can be isolated to prevent admission of smoke or noxious fumes resulting from a postulated fire outside the main control room. The control center is designed to be protected against exterior fire exposure by the 3-hr-rated walls. Personnel are not harmed and safety-related equipment is not damaged by the proper use of the portable fire extinguishers in the main control room.

Personnel training ensures that plant operators are cognizant of the proper use of fire extinguishers and know the emergency procedures to be taken in the event of fire.

6.4.1.4 Personnel Protection and First Aid

The control center contains emergency safety breathing apparatus for personnel use, as well as first aid supplies for immediate emergency use.

6.4.1.5 Utilities and Sanitation

Normal communications, lighting, kitchen, and sanitary facilities are provided in the control center to ensure habitability. The onsite power system supplies power for the main control room habitability systems when offsite power is not available.

6.4.2 System Design

6.4.2.1 Radiation Shielding

Accessibility to the main control room during normal operation is unlimited, with sufficient shielding provided to ensure that normal radiation levels are below 0.3 mrem/hr. In addition to its function during normal operation, the main control room shielding reduces direct radiation doses from the LOCA to levels that permit controlled occupancy by operating personnel following that accident.

Control center shielding is ordinary concrete. The actual floor of the main control room is 1 ft thick but, as a result of other structures, it has an effective thickness of 8 ft 4 in.; the outside (north) wall is 2 ft thick; the roof of the main control room is 5 ft thick over one portion and 1 ft thick over the remaining portion, with the total effective concrete thickness over the main control room varying, however, between 6 ft 6 in. and 10 ft 6 in.; the wall facing the reactor is 4 ft 4 in. thick, with an additional 7 ft of concrete biological shielding surrounding the reactor.

Section 12.1 includes a layout drawing of the control center, as well as a scaled isometric view of the main control room and its associated shielding. Section 12.1 also presents detailed descriptions of shield thicknesses, justifications for the thicknesses of shielding provided, descriptions of the geometric and physical models used, and information relative to the assumptions and data used in the design.

6.4.2.2 Radiation Monitoring System

The functional design of the radiation monitoring system (RMS) provides adequate and reliable radiological data for the evaluation of habitability of the main control room.

The outputs from area and process radiation monitors associated with main control room habitability are displayed, alarmed, and recorded, if necessary, in the main control room.

The area radiation monitor provides measurements of dose rates in the main control room. Location and the design criteria used in their selection are described in Subsection 12.1.4 along with operational characteristics, including type of detector, sensitivity, range, method of calibration, and setpoints.

Process monitors continuously monitor the levels of radioactivity in main control room ventilation systems. Inlet makeup air is monitored upstream of the filters in the emergency air makeup and recirculation systems. Airborne radioactivity monitoring is described in Subsection 12.2.4, which gives the locations and design criteria of the fixed instruments, as well as the criteria used to determine the necessity for and the location of the equipment. That section also provides information on the operational characteristics of the monitors, the detector type, the sensitivities, the ranges, and setpoints and their bases.

Personnel dosimetry under normal and under accident conditions is described in detail in Subsection 12.3.4.

6.4.2.3 Air Conditioning System

6.4.2.3.1 System Description

The control center air conditioning system (CCACS) is described in Section 9.4, which includes system, water control, and airflow diagrams.

The air conditioning system provides year-round comfort and safety from airborne radioactivity for control center personnel. The individual components of the Category I system are designed for an operational life of 40 years, accounting for corrosion and material fatigue. Electrical power for motor operation is supplied from the reactor building engineered safety feature (ESF) buses, maintaining separation and redundancy, and common-mode failure is prevented by physical separation.

The system is capable of maintaining the control center at a nominal temperature of 75°F and at a maximum relative humidity of 60 percent during normal operation, except for the mechanical equipment room (MER) and SGTS room which are discussed in Subsection 9.4.1.1. Noise level in the main control room, when measured in accordance with Appendix E1 of NUREG-0700, Guidelines for Control Room Design Reviews, does not exceed 65 dB(A). The noise level in the washroom and kitchen, on the same measurement basis, also does not exceed 65 dB(A). Conditioned air is supplied directly to the main control room, while the kitchen and washroom are conditioned by exhausting air that is drawn from the main control room.

There are four operating modes for the CCACS as follows:

a. Normal mode: A minimum of 2769 cfm outside air mixes with recirculated ventilating air, bypassing the emergency makeup and recirculation filters

b. Purge mode: 100 percent outside air is circulated through the control center and exhausted to the atmosphere to purge any smoke or fumes within the control center

c. Recirculation mode: A maximum of 1800 cfm outside air is filtered and mixes with 1200 cfm recirculated air; it is filtered again and mixed with recirculating ventilation air to prevent intrusion and to provide continuous removal of contaminants during a radiation-release emergency

d. Chlorine mode: All outside intakes are closed to prevent ingress during a chlorine-release emergency. Ventilating air is recirculated with 1200 cfm passing through the emergency recirculation filter.

Normal Operation Mode

During normal operation, the control center air conditioning system serves the main control room and several other areas. The supply airflow to the control center is 31,510 cfm and the return airflow is 30,440 cfm. Normal makeup air is passed through an electronic air cleaner and a roll-type filter.

The master selector switches in the main control room activate all components in the Division I or Division II system. The mixture of return and outside air is filtered, then cooled, heated, and dehumidified, as required, by a multizone air conditioning supply unit. Each zone thermostat modulates zone mixing dampers to obtain the supply-air temperature necessary to satisfy the zone cooling or heating requirements. Positive pressure is maintained in the control center by throttling the exhaust air-modulating damper. Exhaust fans are provided in the kitchen and washrooms.

Manual override is provided such that an operator in the main control room is able to select the purge mode, which opens the outside air dampers and closes the return air dampers.

Recirculation Mode

Upon an automatic isolation signal from the reactor protection system or the RMS, the CCACS is automatically transferred to the recirculation mode. Under emergency conditions, airflow rate into the control center is 31,510 cfm including 1800 cfm maximum makeup air to offset supply air lost through room leakage (maintaining the control center positive pressure of 1/4 ± 1/8-in. water gage). The kitchen and washroom individual exhaust ducts each contain dual isolation valves that are closed under emergency conditions.

During an emergency, the control center is isolated from all other areas of the plant. All air supplies to the standby gas treatment rooms and the normal operation of air intake and exhaust ducts are dampered closed.

The multizone air-handling unit, the chiller, chilled water pump and the return air fan continue to operate as during normal operation. The return air damper assumes a full-open position. Cooling water is supplied from the emergency equipment cooling water (EECW) system. The fan in the mechanical equipment room fan-coil cooling unit is also energized under room thermostat control. Chilled- water flow through the cooling coil of the unit continues unimpeded as during normal operation.

The emergency recirculation air fan is energized and the dampers on the emergency intake air duct are opened and the kitchen and washrooms exhaust fans are deactivated.

The emergency recirculation air filter train consists of a prefilter, a high-efficiency particulate air (HEPA) filter, a charcoal filter, another HEPA filter, and redundant fans. The emergency makeup air filter train consists of a filtering-type demister, two electric heaters, a HEPA filter, a charcoal filter, and another HEPA filter. Detailed descriptions of the filter trains are presented in Subsection 9.4.1, with summary descriptions of the train components given below:

a. The demister removes entrained water droplets and serves as a prefilter for the downstream HEPA filter. The demister meets design requirements specified in Savannah River Laboratory Report DP-812

b. The electric heater reduces the relative humidity of influent air under worst conditions to 70 percent or less

c. The HEPA filters have a design DOP filtration efficiency of 99.97 percent for particles 0.3 μm in diameter or larger. The elements meet the requirements of ANSI N509-1980. They are UL-approved fire resistant and suitable for service under the temperatures and mass peak loadings expected. The filters are installed and field tested such that a 95 percent decontamination efficiency can be assumed for removal of particulate iodine.

d. The charcoal adsorber in the emergency makeup air filter train is a deep-bed unit, as is that in the recirculation air filter train. These units contain impregnated activated carbon. Representative samples of the carbon are lab tested prior to installation and periodically while in service to demonstrate that the carbon is 99 percent efficient in removing methyl iodide. The carbon is installed and field tested for by-pass leakage such that a 95 percent decontamination efficiency can be assumed for removal of all forms of gaseous iodine.

e. Downstream HEPA filters are identical to the upstream HEPA units and serve to trap charcoal fines and decay daughters entrained in the air stream.

The CCACS design provides redundant alarms for main control room high/low pressure to ensure that a positive pressure in the main control room is maintained at all times. Additionally, alarms are provided in the control room to alert operators for large pressure drops across the CCHVAC emergency make-up and recirculation filters indicating the filter airflow is degrading.

Chlorine Mode

In the event that chlorine gas is detected, control room personnel will place CCHVAC in the chlorine mode, whereupon the normal intake and discharge isolation dampers would close and the emergency intake isolation dampers would remain closed; all other dampers and equipment would function as described in the recirculation mode. In this mode, airflow is circulated throughout the control center at the emergency flow rate, but the outside air intake and exhaust ducts are closed by dampers.

For all operating modes, damper position indications in the main control room allow continuous monitoring of the system performance and confirm all remote manual control actions taken.

Purge Mode

The air conditioning system has a smoke purge mode. In this mode, fresh air is brought into the main control room and no air is recirculated. This mode is initiated automatically when the gaseous fire suppression system actuates, or it can be initiated manually by the operator.

Ionization-type smoke detectors provide an alarm indicating conditions that require isolation of the control center.

For heat and smoke removal from the control center complex in the event of a fire in any of the air-conditioning zones, the fire- detection system will activate alarms in the control center. The control room operator can remote manually initiate the purge mode.

6.4.2.3.2 Control Center Air Intakes

The control center air conditioning system consists of two 100 percent-capacity air-conditioning supply units, an air- distribution system, and an emergency filtration system. The control center is heated, cooled, and pressurized by a recirculating air system. Figures 9.4-1 and 9.4-2 show the ventilating air circulating flow path, rates, and dampers and their positions for the different operating modes. The emergency filtration system processes control center recirculated air and makeup air through charcoal filters if the control center is subjected to airborne radioactive contamination. This system consists of two separate emergency air intakes. The intake that draws from the area having the lowest level of contamination is manually selected for operation.

The physical orientation between the normal and emergency intake openings and the potential source points of radiation are described in Section 2.3.4.2.4.

Each emergency intake has two parallel paths containing redundant dampers. One path in each intake contains two Division I isolation dampers and one Division I modulating damper, which maintains the control center at approximately 1/4 ± 1/8-in. water gage positive pressure in the recirculation mode. The other path contains identical dampers powered by Division II.

For normal operation, a separate normal intake supply is used, allowing the makeup and emergency filters to remain on standby with full filtering capacity available for emergencies. Two air- operated isolation dampers are provided on the normal air intake duct and on the system exhaust vent. One damper in each duct is designated as a Division I damper; the other damper in each duct is designated as a Division II damper. Each damper will close within 5 sec after an isolation signal is initiated and is designed to achieve "bubble-tight" full shutoff.

Two return air fans are provided and each fan is sized to return 95 percent of the total air supplied to the control center. One fan is for Division I and the other for Division II. In the normal mode, the exhaust air damper is modulated to maintain approximately 1/4 ± 1/8 in. of water difference between the lower of the outside ambient pressure or the turbine building pressure and the control center pressure when the system is in the normal operating mode.

6.4.2.4 Fire Protection System

The fire protection system is described in detail in Subsection 9.5.l. Portable fire extinguishers are provided at strategic locations in the main control room. High-sensitivity, ionization-type detectors for combustion products are located in the ceiling space. The fire protection system and specific construction materials are identified in the fire hazards analysis referenced in Subsection 9.5.1.

6.4.2.5 Personnel Protective Equipment and First Aid and Emergency Supplies

Operator respiratory protection in the main control room consists of a mask-hose apparatus connected to a bottled air supply. The supply is 3600 ft^3, which is adequate for 30 manhours of heavy work, with a 20 percent contingency. The size of the supply is based on the data supplied in Reference 3. This handbook indicates that an adult man performing heavy work requires 39.3 to 45.2 liters of air per minute. The size of the supply is based on the larger of these figures.

The supply consists of a rack outside the main control room containing 12 air cylinders (300-ft^3) connected to a manifold. This supply is piped to a five connection manifold in the main control room. Located at the manifold are five individual dual purpose airline/self-contained breathing apparatus (SCBA) respirator units with a length of hose adequate to permit operator movement throughout the main control room area.

The dual purpose airline/SCBA respirator may be attached to either the emergency air system via the manifold, or function independently via the on-board air supply. This provides the operators the capability to move about, and exit the main control room. Two spare bottles per SCBA are also maintained adjacent to the main control room. These units are of the type tested and approved by the Bureau of Mines and by the National Institute for Occupational Safety and Health (NIOSH), and supply fresh air for a period of approximately 20 minutes.

Possible first aid needs are met by a kit in the main control room.

A five-man-day supply of food is stored in the main control center complex and can be used for an emergency. In addition, sufficient potable water is reserved to provide a five-man-day supply during an emergency. Under the conditions that would exist in the event of long-duration accidents, the main control room is accessible for shift changes so that additional food and water can be brought to the main control room.

6.4.2.6 Utilities and Sanitation

The plant communications system is described in Subsection 9.5.2. This diverse system, which includes telephones, portable two-way radios, an intercom system, and a public address system, provides assurance that there is a means of communication between the main control room and plant or offsite areas.

Subsection 9.5.3 contains a description of the normal lighting system and the emergency lighting system. The design criteria and failure analysis ensure that these systems, in conjunction with the power supply system (Section 8.3), will provide adequate lighting for the main control room.

The kitchen area of the main control room contains an electric range, a refrigerator, a water heater, and cooking and eating utensils. The main control room washroom contains toilets, washing facilities, housekeeping supplies, and waste containers.

6.4.3 Design Evaluation

Operating systems that serve to ensure main control room habitability are discussed in detail in the following sections and subsections.

a. Control center air conditioning system - 9.4.l

b. Fire protection system - 9.5.l

c. Communications system - 9.5.2

d. Lighting system - 9.5.3

e. Onsite power systems - 8.3

f. Radiation monitoring systems - 12.1.4 and 12.2.4.

As the referenced sections and subsections state, the systems or portions of systems essential for main control room habitability meet the seismic, the component redundancy, and the power-supply redundancy requirements that ensure satisfactory performance under normal and accident conditions.

Summary evaluations of the designs of the systems that contribute to main control room habitability are provided in the following subsections.

6.4.3.1 Radiation Monitoring System

The design of the radiation monitoring equipment essential for main control room habitability meets all of the functional requirements given in Subsection 6.4.2.2. The monitor locations, types, sensitivities, ranges, and setpoints ensure that necessary information is available to main control room personnel and that those main control room habitability systems, which are actuated automatically, will receive initiation signals.

The portable radiation monitoring equipment applicable to main control room habitability is readily available as required. The equipment is described in Subsection 12.3.2, and personnel dosimetry is discussed in Subsection 12.3.4.

6.4.3.2 Air Conditioning System - Control of Main Control Center Thermal Environment

The CCACS is operated on a continuous basis to maintain a safe and comfortable thermal environment in the main control room. The state of readiness of this system is indicated by the system performance, as reflected in the main control room temperature and relative humidity. With the exception of the common ductwork and filters, the system has 100 percent backup and meets single- failure criteria. The smoke/Halon dampers to the relay room, cable spreading room or computer room will close due to a single active failure in the Halon fire protection system. Sufficient time is available to take manual action to reestablish airflow. The air conditioning system emergency mode and all essential components are designed to Category I requirements.

The air-conditioning functions provided include cooling, heating, humidification, air filtration, forced air circulation, exhaust, and positive pressure control. In normal operation, air filtration is provided by an electronic air cleaner and a fiberglass media roll filter. After the mixture of return and outside air is filtered, it is cooled and heated by the multizone air-handling unit.

The air conditioning system, sized in accordance with ASHRAE recommendations, is designed for an ambient temperature of 95°F dry bulb and 75°F wet bulb during summer operation and -10°F dry bulb for winter operation. The ambient temperature range specified prevails 99 percent, or more, of the total time at the plant location.

The total system flow is 31,510 cfm, of which 11,350 cfm is supplied directly to the main control room. The supply of conditioned air ensures that the thermal environment within the main control room permits habitation under any weather or plant conditions.

6.4.3.3 Air Conditioning System - Control of Main Control Room Airborne Radioactivity

During an emergency, the control center is isolated from all other areas of the plant. All air supply to the standby gas treatment rooms and the normal-operation air intake and exhaust ducts are dampered or valved closed. The multizone air-handling unit and the return air fan continue to operate as during normal operation, with the emergency air-handling system placed in operation by automatic or manual opening of the emergency air intake dampers and energizing the emergency recirculation air fan.

The 1800 cfm maximum emergency outside air required for pressurization and personnel physiology is drawn through the emergency outside air intake filter train. A mixture of filtered outside air and the emergency recirculation air is passed through the emergency recirculation filter train. The kitchen and washroom exhaust air ducts will be closed during emergency operation.

Airborne and fuel pool radioactivity levels in the reactor/ auxiliary building ventilation and exhaust air ducts are monitored. If the activity exceeds acceptable levels, isolation dampers or valves in the control center normal intake and exhaust air ducts and in the air conditioning equipment and standby gas treatment system (SGTS) room air ducts are actuated, placing the control center air conditioning system in an emergency recirculation mode. In this mode, air is brought in through the emergency makeup air filter train (1800 cfm maximum), mixed with 1200 cfm minimum recirculated air, and put through a 3000 cfm recirculation filter train.

Redundant and separate isolation dampers or valves are installed in all ducts of the air conditioning system that affect the isolation of the main control room from other building areas; the emergency intake air duct and the kitchen and washroom exhaust air ducts are also equipped with redundant isolation dampers.

The system design, the isolation capabilities, and the efficiencies of the components used in the emergency filter trains ensure that airborne radioactivity in the main control room does not rise to levels that prohibit habitability.

6.4.3.4 Air Conditioning System - Control of Main Control Room Chemical Environment

Adverse chemical effects on the main control room environment could result from the following three events:

a. A chlorine accident off the plant site

b. A fire outside the main control room

c. A fire inside the main control room

There are shipments of hazardous chemicals by rail and road routes within a 5-mile radius of the plant. The closest transportation line lies about 3.5 miles from the plant. At this distance, a release of a hazardous chemical is not a threat to Fermi 2 control room habitability. In accordance with the provisions of Regulatory Guide 1.78, Revision 1, control center habitability was analyzed for the rupture of a 90-ton chlorine railroad tankcar.

It was determined that the probability of a chlorine railcar accident and a spill resulting in a control room toxic concentration meets the Regulatory Guide criterion for not considering such scenario to be a credible event (Reference 6).

The CCACS ensures that the toxic or noxious substances that might result from one of the above events do not prevent occupancy of the main control room.

Upon manual initiation of chlorine mode, the (100 percent recirculation) chlorine mode of operation of the air conditioning system commences; in this configuration, there is no makeup airflow and approximately 1200 cfm of the main control room airflow is passed through the recirculation air filter train for cleanup.

The safety of main control room operators is further ensured by the provision of self-contained breathing apparatus units in the main control room, as described in Subsection 6.4.2.5. Storage provisions for the breathing apparatus and procedures for use permit operators to don appropriate respirators upon detection of toxic gases or chlorine odors. The emergency plan includes instructions for immediate donning of breathing apparatus on detection of chlorine release, and the training of main control room personnel includes rehearsal and the procedures necessary for rapid utilization of the equipment.

A fire-detection system is provided throughout the control center. The system consists of ionization or photoelectric detectors for alarming the presence of smoke or for actuating the automatic gaseous fire-suppression systems where provided.

In the chlorine mode, introduction of smoke and/or noxious fumes from outside fires into the main control room is prevented; in the unlikely event of a UL Class A fire inside the main control room, the smoke purge system is used to remove the products of the fire from the main control room.

For smoke purging, the normal air conditioning system can be operated on a zero-recirculation basis, with a greatly increased outside air intake. As the zero-recirculation terminology implies, airflow in the control center areas is on a once-through basis.

In summary, the CCACS is highly flexible, providing modes of operation that ensure acceptable air quality.

6.4.3.5 Fire Protection

A description of the fire protection system for the main control room is identified in Subsection 9.5.1.

6.4.3.6 Personnel Protection

Self-contained breathing apparatus is provided for emergency use in the main control room. The apparatus is selected according to the guidelines of ANSI Z88.2 (Reference 4). A respiratory protective program meeting the requirements of Occupational Safety and Health Administration (OSHA) 1910.134 (Reference 5) has been established and will be maintained, thereby ensuring the effectiveness of the provisions for personnel protection.

6.4.3.7 Utilities and Sanitation

Several communications channels are maintained open under all conditions. Most of the communications systems are in routine use. Those systems not frequently used are subjected to periodic maintenance and testing to ensure their state of readiness. The provision of diverse and redundant systems ensures a reliable communications capability.

Lighting is provided in the main control room at all times. The installation of normal and emergency systems, with power-source redundancy, ensures that the main control room is adequately illuminated. The normal lighting system is proven operable during regular operating periods and will continue to operate under most accident conditions; in the event that the normal system is inoperative, the emergency system provides illumination.

Kitchen and sanitary facilities are proven operable under normal conditions and will continue to function under accident conditions.

6.4.4 Testing and Inspection

6.4.4.1 Radiation Monitoring System

Testing and inspection of the RMS ensure that each functional requirement of the system is met. The RMS is tested in conjunction with the CCACS to ensure that the monitors perform the desired functions.

The area and process radiation monitors are readily accessible for testing, inspection, and calibration. The testing of the monitors does not interfere with normal operation of the habitability systems for the main control room. Portable equipment such as air samplers, personnel dosimeters, and other radiation analysis equipment applicable to main control room habitability is tested and inspected periodically as required.

Specific details of the measures taken to ensure the operability of radiation monitoring equipment are given in Subsections 12.1.4, 12.2.4, and 12.3.4.

6.4.4.2 Control Center Air Conditioning System

The CCACS is subjected to those tests and inspections required to ensure its capability to perform its designed functions throughout the lifetime of the plant. As indicated in the preceding subsection, those portions of the system that interact directly with other systems are subjected to testing concurrent with the other systems.

The system and its components are tested in accordance with the codes and standards to which they are designed, and with the tests and inspections specified in Section 9.4, the Technical Specifications, and the Technical Requirements Manual. The compliance of the emergency makeup air and emergency recirculation filter trains and their components with Regulatory Guide 1.52 is described in Subsection A.1.52. Testing of the filter trains and their components involves

a. Predelivery and component qualification tests

b. Onsite preoperational acceptance tests

c. Operational surveillance tests

The quantity of air supplied for pressurization of the control center is determined by performing a duct traverse measurement at the installed test ports in the ductwork. The static pressure differential in the control center complex is measured to verify that a pressure of 1/4 ± 1/8-in. water gage is maintained by the CCACS operating in the emergency mode.

Should a component or material in the CCACS fail to meet the required level of performance, the component or material is replaced. Should the system fail to meet performance standards in any mode of operation, the component(s) adversely affecting the system performance is replaced. The modes of operation considered for the main control room are normal mode, recirculation mode (radiation emergency), chlorine mode (complete isolation), and purge mode (smoke removal with zero recirculation).

6.4.4.3 Main Control Room Fire Protection System

Fire protection for the main control room is ensured by fire extinguishers inside the main control room, fire-detection equipment, the smoke purge capability of the CCACS, and the isolation provisions of that system. Inspection and testing requirements are provided in Subsection 9.5.1.

6.4.4.4 Other Control Center Habitability Systems

Self-contained breathing apparatus is inspected to ensure that pressures are at least equal to those required to supply air for the minimum acceptable breathing period. If cylinder pressure is insufficient, the cylinder is recharged or replaced. Regulators in the air packs are periodically inspected to verify operability; units that do not function properly are repaired or replaced.

The communications and lighting systems are proven operable, in part, by normal use, with backup or emergency facilities tested periodically by individual tests or intentional disabling of the primary system.

Kitchen and sanitation facilities are known to be operable through normal use.

6.4.5 Instrumentation

The individual system design sections of the UFSAR contain descriptions of the instrumentation used for monitoring and actuating those portions of the systems vital to main control room habitability. Design details and logic of the instrumentation are discussed in Chapter 7.

6.4 HABITABILITY SYSTEMS

REFERENCES

1. Report of ICRP Committee II on Permissible Dose for Internal Radiation (1959), Health Physics Journal, Vol. 3 (June 1960).
2. American Society of Heating, Refrigerating and Air- Conditioning Engineers (ASHRAE), 55-66, Standard on Thermal Comfort Conditions.
3. P. L. Altman, J. F. Gibson, and C. C. Wang, Handbook of Respiration, W. B. Saunders Company, 1958.
4. American National Standards Institute, ANSI F88.2-1969, Respiratory Protection.
5. Occupational Safety and Health Administration, Title 29, Part 1910.134, Respiratory Protection.
6. License Amendment No. 147, "Elimination of the Chlorine Detection Function from the Control Center Heating, Ventilation and Air Conditioning System", dated June 26, 2002.

Figure Intentionally Removed
Refer to Plant Drawing A-2100

Fermi 2
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FIGURE 6.4-1

PLOT PLAN - GRADE ELEVATION 583 FT

CHAPTER 7: INSTRUMENTATION AND CONTROLS

7.1 INTRODUCTION

7.1.1 Identification and Classification of Safety-Related and Power Generation Systems

7.1.1.1 General

Depending on their function, instrumentation and control systems may be classified as either power generation systems or safety systems. In some cases, portions of a system may have a safety function while other portions of the same system may be classified as power generation. A complete description of the reasoning behind this system of classification can be found in Subsection 1.2.1.

The systems presented in this chapter have been classified under safety design-basis systems, power generation design-basis systems, reactor protection systems (RPS), engineered safety feature (ESF) systems (containment isolation, emergency core cooling system, etc.), safe shutdown systems, other safety and power generation systems, and control systems. Figure 7.1-1 lists the Fermi 2 safety-related instrumentation, control, and supporting systems. Instrumentation and control systems identical to those of nuclear power plants of similar design that have recently received construction permits or operating licenses are identified in Table 7.1-1.

7.1.1.2 Identification of Individual Systems

The RPS instrumentation and control initiates an automatic reactor shutdown (scram) if monitored system variables exceed preestablished limits. This action prevents fuel damage, limits system pressure, and thus restricts the release of radioactive material.

The primary containment and reactor vessel isolation control system (CRVICS) initiates closure of various automatic isolation valves in response to a limiting value of a system variable. The closure of isolation valves enables containment of radioactive materials either inside the reactor pressure vessel (RPV) or inside the primary containment. The system responds to various indications of pipe breaks or radioactive material release.

The emergency core cooling system (ECCS) instrumentation and control provides initiation and control of specific core cooling systems such as the high-pressure coolant injection (HPCI) system, the automatic depressurization system (ADS), the core spray system, and the low-pressure coolant injection (LPCI) system.

The neutron monitoring system (NMS) instrumentation and control uses in-core neutron detectors to monitor core neutron flux. The NMS provides signals to the RPS to shut down the reactor when an overpower condition is detected. High average neutron flux is used as the overpower indicator during power operation. Intermediate range detectors are used as overpower indicators during startup and shutdown. The NMS also provides power level indication during planned normal operation.

The refueling interlocks instrumentation and control serves as a backup to procedural core reactivity control during refueling operations.

The reactor manual control system (RMCS) instrumentation and control allows the operator to manipulate control rods and to determine their positions. Various interlocks are provided in the control circuitry to prevent multiple operator errors or equipment malfunctions from requiring the action of the RPS.

The RPV instrumentation monitors and transmits information concerning key RPV operating variables.

The recirculation flow control system (RFCS) instrumentation and control controls the reactor recirculation pumps and motor-generator sets to vary the coolant flow rate through the core. This system permits either manual or automatic control. The recirculation pump trip (RPT) function of the RFCS is designed to mitigate the effects of an anticipated transient without scram (ATWS) event.

The feedwater system instrumentation and control regulates the feedwater system flow rate so that proper RPV water level is maintained. The feedwater control system uses RPV water level, main steam flow, and feedwater flow signals to regulate feedwater flow. The system is arranged to permit single-element (level only), three-element (level, steam flow, feed flow), or manual operation.

Pressure-regulator and turbine-generator instrumentation and control work together to allow proper generator and reactor response to load-demand changes. The pressure regulator acts to keep nuclear system pressure essentially constant, so that pressure-induced core reactivity changes are controlled. To maintain constant pressure, the pressure regulator adjusts the turbine control valves or turbine bypass valves. The turbine-generator controls regulate turbine speed during startup. If the generator electrical load is lost, the turbine-generator speed-load controls initiate rapid closure of the turbine control valves (coincident with fast opening of the bypass valves) to prevent excessive turbine overspeed.

The process radiation monitor system (PRMS) instrumentation and control for process liquid and gas lines provides control of radioactive material released from the Fermi site. The main steam line radiation monitors detect gross release of fission products from the fuel and isolate the reactor water sample system, trip condenser mechanical vacuum pumps, and trip gland seal exhausters.

The area radiation monitor system (ARMS) instrumentation provides gamma-sensitive detectors throughout the plant. Outputs are recorded on multipoint recorders.

Reactor core isolation cooling (RCIC) system instrumentation and control causes the addition of makeup water to the RPV in the event that the reactor feedwater supply system is lost during plant operation.

Standby liquid control system (SLCS) instrumentation and control provides for manual initiation of a reactivity control system redundant to manual control rod movement which can shut the reactor down from rated power to the cold condition if withdrawn control rods cannot be inserted to achieve reactor shutdown. In addition, SLCS instrumentation and control provides for manual initiation of a pH control system following a LOCA in the event of fuel failure.

Reactor water cleanup (RWCU) system instrumentation and control provides for manual initiation of system equipment to maintain high water purity and reduce concentrations of fission products in the reactor water.

The leak detection system (LDS) instrumentation and control uses various temperature, pressure, and flow sensors to detect, annunciate, and isolate (in certain cases) water and steam leaks in selected reactor systems.

The residual heat removal (RHR) system instrumentation and control provides for manual initiation of cooling to remove the decay and sensible heat from the RPV so that the reactor can be refueled and serviced.

Radwaste system instrumentation and control supports manual processing and disposing of the radioactive process wastes generated during power operation.

The emergency diesel generator (EDG) instrumentation and controls automatically provide ac power to those devices necessary to effect a safe shutdown with subsequent reactor decay heat removal should normal offsite power not be available.

The alternate rod insertion (ARI) function of the control rod drive (CRD) system is designed to mitigate the potential consequences of an ATWS. The ARI equipment is redundant and diverse to the RPS and has its own detection and actuation logic.

The various instrumentation and control system designers and fabricators are identified in Table 7.1-2.

Emergency support facilities, which include an onsite technical support center (TSC), an onsite operational support center (OSC), an onsite emergency operations facility (EOF), an alternate (offsite) EOF, and the Integrated Plant Computer System (IPCS) for data handling and computational capabilities are provided to support operations in the event of an emergency.

7.1.1.3 Classification

7.1.1.3.1 Safety-Related Systems

Safety systems are those systems whose actions are necessary to protect the integrity of radioactive material barriers and/or prevent the release of radioactive material. These systems may be components, groups of components, or groups of systems. A complete list of these systems is shown in Figure 7.1-1.

7.1.1.3.2 Power Generation Systems

Power generation systems are systems whose actions are not required to protect the integrity of radioactive material barriers and/or prevent the release of radioactive material. The instrumentation and control portions of these systems may, by their actions, prevent the plant from exceeding preset limits that would cause action of the safety systems. A complete list of these systems is shown in Figure 7.1-1.

7.1.1.3.3 General Functional Requirements

Power generation systems and safety systems may have both a safety design basis and a power generation design basis, depending on their function. The safety design basis states in functional terms the unique design requirements that establish limits for the operation of the system. The general functional requirements portion of the safety design basis is those requirements that have been determined to be sufficient to ensure the adequacy and reliability of the system from a safety viewpoint. Many of these requirements have been introduced into various codes, criteria, and regulatory requirements.

7.1.1.3.4 Specific Regulatory Requirements

All systems have been examined with respect to specific regulatory requirements applicable to instrumentation and control. These regulatory requirements consist of all applicable codes including 10 CFR 50, Appendix A, General Design Criteria; 10 CFR 50, Appendix B, Quality Assurance Criteria; and regulatory guides.

As a result of this examination, it has been determined that two IEEE standards are applicable to the instrumentation and control associated with every safety-related system: IEEE 344-1971 and IEEE 323-1971. Compliance with the requirements of IEEE 323-1971 and IEEE 344-1971 for GE-supplied systems is discussed in NEDO-10698 and NEDO-10678, respectively, and Sections 3.11 and 3.10 of the UFSAR.

Fermi 2 complies with IEEE 336-1971, except as modified by the Edison Quality Assurance (QA) procedures.

The specific regulatory requirements applicable to each system's instrumentation and control are specified in appropriate subsections. The four most important safety systems have been reduced to the subsystem level and the applicable regulatory requirements are specified. This information is contained in Figures 7.1-2 through 7.1-5.

7.1.2 Identification of Safety and Power Generation Criteria

Design bases and criteria for instrumentation and control equipment design are based on the need to have the system perform its intended function while meeting requirements of applicable general design criteria, regulatory guides, and industry standards.

The plant instrumentation and control systems are listed by functional classification and regulatory classification in Figure 7.1-1.

Nominal instrument setpoints and ranges are shown in Chapter 7. Final instrument setpoints are provided in the Technical Specifications.

7.1.2.1 Design Bases

IEEE 279-1971 defines the design requirements with respect to the design bases of safety-related systems. Using the IEEE 279-1971 format, the following fulfills these requirements:

a. The generating station conditions that require protective action are
    1. Excessive radioactive releases to the atmosphere
    2. Excessive nuclear system stress
    3. Excessive containment stress.

b. The generating station variables that require monitoring to provide protective actions are listed in Tables 7.2-2, 7.2-3, 7.3-5 through 7.3-8, and 7.3-10

c. The minimum number of sensors and locations required to monitor safety-related variables is shown in Tables 7.2-2, 7.2-3, 7.3-5 through 7.3-8, and 7.3-10

d. Conservative operational limits for each safety-related variable are discussed in the Technical Specifications

e. The margin between operational limits and the level of determining the onset of unsafe conditions is discussed in the Technical Specifications

f. Levels requiring protective action are discussed in the Technical Specifications

g. Range of energy supply and environmental conditions of safety systems is shown in Section 8.3 and Tables 3.11-1 through 3.11-4, respectively

h. Malfunctions, accidents, and other unusual events that could cause damage to safety systems are discussed in Subsections 7.2.2.2.2.1 and 7.3.1.3

i. Minimum performance requirements are shown in Tables 7.2-2, 7.2-3, 7.3-5, 7.3-6, 7.3-8, and 7.3-10.

7.1.2.1.1 Reactor Protection System

7.1.2.1.1.1 Safety Design Bases

General Functional Requirements

The RPS is designed to meet the following functional requirements:

a. The RPS initiates a reactor scram with precision and reliability to prevent or limit fuel damage following abnormal operational transients

b. The RPS initiates a scram with precision and reliability to prevent damage to the nuclear system process barrier as a result of excessive internal pressure: that is, to prevent nuclear system pressure from exceeding the limit allowed by applicable industry codes

c. To limit the uncontrolled release of radioactive materials from the fuel or nuclear system process barrier, the RPS precisely and reliably initiates a reactor scram upon gross failure of either of these barriers

d. To detect conditions that threaten the fuel or nuclear system process barriers, RPS inputs are derived from variables that are true direct measures of operational conditions

e. The RPS responds correctly to the sensed variables over the expected range of magnitudes and rates of change

f. An adequate number of sensors are provided for monitoring essential variables that have spatial dependence

g. The following bases ensure that the RPS is designed with sufficient reliability

   1. If failure of a control or regulating system causes a plant condition that requires a reactor scram but also prevents action by necessary RPS

channels, the remaining portions of the RPS meet the requirements of Items a., b., and c. above

2. Loss of one power supply neither causes nor prevents a reactor scram
3. Once initiated, a RPS action goes to completion. Return to normal operation requires deliberate operator action
4. There is sufficient electrical and physical separation between redundant instrumentation and control equipment monitoring the same variable to prevent environmental factors, electrical transients, or physical events from impairing the ability of the system to respond correctly
5. Earthquake ground motions, as amplified by building and supporting structures, do not impair the ability of the RPS to initiate a reactor scram. See also Section 3.10
6. No single failure within the RPS prevents proper RPS action when required to satisfy the safety design bases Items a., b., and c. above
7. Any one intentional bypass, maintenance operation, calibration operation, or test to verify operational availability does not impair the ability of the RPS to respond correctly
8. The system is designed for a high probability that when the required number of sensors for any monitored variable exceeds the scram setpoint, the event results in an automatic scram and does not impair the ability of the system to respond correctly as other monitored variables exceed their scram trip points.
9. The operation of the Hydrogen Water Chemistry System is prevented from affecting RPS operation by the use of contact-to-coil separation.

h. The following bases reduce the probability that RPS operational reliability and precision will be degraded by operator error:

1. Access to trip settings, component calibration controls, test points, and other terminal points are under the control of plant operations supervisory personnel
2. Manual bypass of instrumentation and control equipment components is under the control of the main control room operator. If the ability to trip some essential part of the system has been bypassed, this fact is continuously indicated in the main control room.

i. The RPS and ESF equipment is physically identified as safety equipment in the plant as follows:

1. Equipment associated with the RPS, primary containment isolation system, and ESF equipment is identified so that two facts are apparent: first, that the equipment is part of the RPS, primary containment isolation system, or an ESF system; and second, that the equipment is associated with a particular grouping (or division) of enforced segregation
2. Panels and racks associated with these systems are labeled with marker plates that are conspicuous by means of color, shape, or color of engraving fill. The information on the marker plate includes both system and division identification
3. Junction and/or pull boxes enclosing wiring for the RPS and an ESF system have identification similar to and compatible with the panels and racks described above
4. Wiring and cables outside cabinets and panels are suitably color-coded to identify the division. Identification tags or markers for wiring conduits are conspicuously different from other similar tags and markers and shall include both system and division identity
5. Those trays or conduits that carry RPS or ESF system wiring are to be identified with conspicuous tags at entrance and exit points of each room through which they pass.

Specific Regulatory Requirements

The RPS is designed to meet the following functional requirements:

a. Industry Standards - In addition to the previous functional design requirements, the RPS complies with the requirements of IEEE 279-1971. A point-by-point comparison of IEEE 279-1968 is contained in Topical Report NEDO-10139. Section 7.2.2.2.2 of the UFSAR lists those topics where IEEE 279-1971 differs from IEEE-279-1968 and shows conformance to those differences. IEEE 323-1971, IEEE 338-1971, IEEE 379-1972, and IEEE 344-1971 also apply to the RPS

b. General Design Criteria of (GDC) l0 CFR 50 - GDC 13,20-24, and 29 of l0 CFR 50, Appendix A, have also been implemented in the design of the RPS

c. Regulatory Guides - Regulatory Guide 1.22, Periodic Testing of Protection System Actuation Function, applies with respect to periodic testing, and Regulatory Guide 1.53, Trial-Use Guide for the Application of the Single-Failure Criterion to Nuclear Power Generating Station Protection Systems, applies with respect to single-failure criteria.

7.1.2.1.1.2 Power Generation Design Basis

The RPS has no power generation objective. The setpoints, power sources, and instrumentation and control are arranged in such a manner as to preclude spurious scrams.

7.1.2.1.2 Containment and Reactor Vessel Isolation Control System

Safety Design Bases - General Functional Requirements

The following functional design bases are implemented in the containment and reactor vessel isolation control system (CRVICS):

a. The time required to close the main steam isolation valves (MSIVs) is short in order to minimize the loss of coolant from a main steam line break

b. The time required to close the MSIVs is not so short that inadvertent isolation of steam lines causes a more severe transient than the transient resulting from closure of the turbine stop valves coincident with failure of the turbine bypass system. This ensures that the MSIV closure speed is compatible with the ability of the RPS to protect the fuel and nuclear system process barrier

c. To ensure the timely isolation of main steam lines, at least one of the isolation valves in each of the main steam lines does not rely on continuity of any variety of electrical power to achieve closure

d. To provide the operator with means redundant to the automatic isolation functions to take action in the event of a failure of the nuclear system process barrier, it is possible for the main control room operator to manually initiate isolation of the RPV

e. To limit the release of radioactive materials to the environs, the containment, drywell, and reactor vessel isolation control system, with precision and reliability, initiates timely isolation of penetrations through the containment and drywell structure whenever the values of monitored variables exceed preselected operational limits

f. To provide assurance that important variables are monitored with precision, an adequate number of sensors are provided (Table 7.3-9)

g. To provide assurance that conditions indicating a failure of the nuclear system process barrier are detected with sufficient timeliness and precision, primary CRVICS inputs are derived, to the extent feasible and practical, from variables that are direct measures of operational conditions

h. The steam resulting from a design-basis LOCA flows to the pressure suppression pool to limit pressure in the containment

i. The power supplies for the containment, drywell, and reactor vessel isolation control system are arranged so that loss of one supply cannot prevent automatic isolation when required

j. The system is designed so that, once initiated, automatic isolation action goes to completion. Return to normal operation after isolation action requires deliberate operator action

k. Earthquake ground motions do not impair the ability of the containment, drywell, and reactor vessel isolation control system to initiate automatic isolation

l. Any one failure, maintenance operation, calibration operation, or test to verify operational availability does not impair the functional ability of the isolation control system to respond correctly to essential monitored variables, assuming no other active failure occurs

m. The system is designed for a high probability that, should any essential monitored variable exceed the isolation setpoint, the event results in automatic isolation and does not impair the ability of the system to respond correctly as other monitored variables exceed their trip points

n. There is sufficient electrical and physical wiring and piping separation between trip channels monitoring the same essential variables to prevent environmental factors, electrical faults, and physical events from impairing the ability of the system to respond correctly, in accordance with Paragraph 4.6 of IEEE 279-1971.

Safety Design Bases - Specific Regulatory Requirements

The requirements of IEEE 279-1971 and IEEE 338-1971 are met by the CRVICS. See Section 3.10 for IEEE 344-1971 and Section 3.11 for IEEE 323-1971 conformance discussions.

7.1.2.1.3 Emergency Core Cooling System

Safety Design Bases - General Functional Requirements

The ECCS instrumentation and control is designed to meet the following functional safety design bases:

a. They automatically initiate and control the ECCS to prevent fuel cladding temperatures from reaching the NRC interim acceptance criterion

b. They respond to a need for emergency core cooling, regardless of the physical location of the malfunction or break that causes the need

c. The following safety design bases are specified to limit dependence on operator judgment in times of stress:

   1. The ECCS responds automatically so that no action is required of plant operators within 10 minutes after a LOCA

   2. The performance of the ECCS is indicated by main control room instrumentation.

d. Facilities for manual control of the ECCS are provided in the main control room.

Safety Design Bases - Specific Regulatory Requirements

The ECCS instrumentation and control is designed to meet the following specific regulatory requirements:

a. The instrumentation and control meets the requirements of IEEE 279-1971. The following safety design bases are specified to ensure reliability:

1. No single malfunction, maintenance, calibration, or test procedure prevents function of the ECCS, assuming no other active or passive failure occurs

2. No protective device automatically interrupts performance or availability of the ECCS unless continued operation would cause complete failure. Such protective devices indicate abnormal conditions for operator decision and action.

b. The instrumentation and control meets the requirements of IEEE 338-1971

c. The instrumentation and control meets the requirements of IEEE 323-1971 as discussed in Section 3.11

d. The instrumentation and control meets the requirements of IEEE 344-1971 as discussed in Section 3.10

e. The requirements of GDC 13, 35, 36, and 37 of 10 CFR 50, Appendix A, are met

f. The requirements of Regulatory Guide 1.22 are met.

7.1.2.1.4 Neutron Monitoring System

7.1.2.1.4.1 Source Range Monitor System

The source range monitor (SRM) system meets the following power generation design bases:

a. Neutrons generated by irradiated fuel and neutron detectors together provide a signal-to-noise ratio of at least 2:1 and a count rate of at least 3 counts per second with all control rods fully inserted prior to initial power operation

The minimum count rate may be reduced to ≥ 0.7 CPS provided the signal-to-noise ratio is ≥ 20 and is not applicable during certain refueling operations covered by Technical Specification 3.3.1.2 when the minimum count rate may not be able to be maintained.

b. The SRM system is able to

1. Indicate during the worst possible startup rod withdrawal conditions a measurable increase in output signal from at least one detecting channel before the reactor period is less than 20 sec

2. Indicate substantial increases in output signals with the maximum permitted number of SRM system channels out of service during normal reactor startup operations

3. Have channels on scale when the intermediate range monitor (IRM) system first indicates neutron flux during a reactor startup

4. Provide a measure of the time rate of change of the neutron flux (reactor period) for operational convenience

5. Generate interlock signals to block control rod withdrawal if the count rate exceeds a preset value or falls below a preset limit if the IRMs are not above the second range or if certain electronic failures occur.

7.1.2.1.4.2 Intermediate Range Monitor System

Safety Design Basis

The IRM system generates a trip signal that can be used to prevent fuel damage caused by abnormal operational transients that occur while operating in the intermediate power range. The independence and redundancy incorporated in the design of the IRM system are consistent with the safety design bases of the RPS. The IRM system is designed in accordance with the same federal codes, regulatory guides, and IEEE standards applied to the RPS.

Power Generation Design Bases

The IRM system generates a trip signal to block rod withdrawal if the IRM system reading exceeds a preset value or if the IRM system is not operating properly. The IRM system has overlapping neutron flux indications relative to the SRM system and power range monitoring subsystems.

7.1.2.1.4.3 Local Power Range Monitor System

Power Generation Design Bases

The local power range monitor (LPRM) system meets the power generation design bases and supplies the following:

a. Signals to the average power range monitor (APRM) system proportional to the local neutron flux at various locations within the reactor core

b. Signals to the rod block monitor (RBM) system to indicate changes in local relative neutron flux during the movement of control rods

c. Signals to alarm high or low local neutron flux

d. Signals proportional to the local neutron flux to operator display assemblies to be used for operator evaluation of power distribution, local heat flux, minimum critical power ratio, and fuel burnup rate

e. A sufficient number of LPRM signals to support the APRM safety design bases.

7.1.2.1.4.4 Average Power Range Monitor System

Safety Design Basis

During the worst permitted input LPRM system bypass conditions, the APRM system generates a trip signal in response to average neutron flux increases resulting from abnormal operational transients in time to prevent fuel damage. Each APRM also includes an OPRM

Upscale Function that generates a trip signal upon detection of thermal hydraulic induced power oscillations. The APRM system is designed in accordance with the requirements of the safety design bases of the RPS.

Power Generation Design Bases

The APRM system provides

a. A continuous indication of average reactor power from a few percent to 125 percent rated reactor power to the operator in the main control room

b. A continuous indication of average reactor power from a few percent to 125 percent rated reactor power to the Integrated Plant Computer System (IPCS)

c. Interlock signals for blocking further rod withdrawal to avoid an unnecessary scram actuation

d. A reference power level for the RBM system

7.1.2.1.4.5 Rod Block Monitor System

The power generation design bases for the RBM system meet the following power generation design bases:

a. Prevent local fuel damage that may result from a single rod withdrawal error

b. Provide a signal used by the operator to evaluate the change in the local relative power level during control rod movement

c. Prevent any single short or open of any single input to the RBM system from affecting any other inputs to the RBM system

d. Meet GDC 24 of 10 CFR 50, Appendix A.

7.1.2.1.4.6 Traversing In-Core Probe System

The traversing in-core probe (TIP) system meets the following power generation design bases:

a. Provides a signal proportional to the axial neutron flux distribution at selected small axial intervals over the regions of the core where LPRM system detector assemblies are located. This signal is of high precision to allow reliable calibration of LPRM system gains

b. Provides accurate indication of the position of the flux measurement which allows pointwise or continuous measurement of the axial neutron flux distribution.

7.1.2.1.5 Refueling Interlocks

Refueling interlocks meet the following safety design bases:

a. During fuel movements in or over the reactor core, all control rods are in their fully inserted positions

b. No more than one control rod can be withdrawn from its fully inserted position at any time when the reactor is in the refuel mode.

7.1.2.1.6 Reactor Manual Control System

Power Generation Design Basis

The RMCS provides the reactor operator with the means for controlling the power level and power distribution in the core. This is done by control rod positioning capability, which depends on electrical circuitry and switches. Position and power indicators provide surveillance of actions taken and the results of these actions.

Classification

This system is a power generation system, not essential for safety, and is classified in Chapter 3.

7.1.2.1.7 Reactor Vessel Power Generation Instrumentation

The power generation design bases for the RPV instrumentation consist of maintaining proper operating conditions. To maintain proper operating conditions, the RPV instrumentation is designed to provide the operator with sufficient indication of RPV temperature, reactor core flow rate, RPV water level, RPV pressure, and nuclear system leakage. These instruments augment existing information such that the operator can start up, operate, shut down, and service the reactor efficiently. Because the RPV instrumentation used for RPS, ESF, safe shutdown systems, and certain control systems is described and evaluated in other portions of this document, only those instruments not required for safety systems are described (Subsection 7.6.l.2).

7.1.2.1.8 Recirculation Flow Control System Safety Design Bases

The RFCS functions so that no abnormal operational transient resulting from a malfunction in the RFCS can result in damaging the fuel or exceeding nuclear system pressure limits.

Power Generation Design Bases

The RFCS is designed to allow manual recirculation flow adjustment, thereby enabling manual control of reactor power level.

7.1.2.1.9 Feedwater Control System

The feedwater control system meets the power generation design bases by regulating the feedwater flow to maintain adequate water level in the RPV according to the requirements of the steam separators, and to prevent uncovering of the reactor core over the entire power range of the reactor.

7.1.2.1.10 Pressure Regulator and Turbine-Generator Control

One of the main features of direct cycle BWRs is the direct passage of the nuclear steam supply system (NSSS) generated steam through the turbine. In this system the turbine is slaved to the reactor, in that all the steam generated by the reactor is normally accepted by the turbine. The operation of the reactor demands that the pressure regulator concept be applied to maintain a constant turbine inlet pressure with load-following ability handled by variation of the reactor recirculation flow or control rod position.

The turbine pressure regulator, in maintaining constant stop valve pressure, operates the steam bypass system such that up to 23.5 percent of nuclear boiler rated flow can be bypassed when operating below the maximum steam flow limit as well as during the startup and shutdown phases.

The pressure regulator and turbine-generator control system accomplishes the following control functions:

a. Controls turbine speed and turbine acceleration

b. Operates the steam bypass system to keep reactor pressure within limits, and avoids large power transients

c. Adjusts (manually) 52-in. manifold pressure to nullify a 30 psi drop over a reactor flow of 0 to 100 percent.

7.1.2.1.11 Process Radiation Monitor System

The process radiation monitor system is discussed in Section 11.4.

7.1.2.1.12 Area Radiation Monitor System

The area radiation monitor system is discussed in Section 12.1.

7.1.2.1.13 Offsite Environs Radiological Monitoring Programs

This material is discussed in the Offsite Dose Calculation Manual (ODCM).

7.1.2.1.14 Rad-Chem Radiation Monitoring Instruments

This material is discussed in Section 12.3.

7.1.2.1.15 Plant Computer Systems

7.1.2.1.15.1 Integrated Plant Computer System (IPCS)

The IPCS is a non-safety related computer system that combines various functions of legacy computer systems that it replaced. The IPCS provides the capability of monitoring, recording and displaying plant parameters via strategically located display devices.

The IPCS meets the following power generation design basees:

a. The IPCS is designed for use with, and has capacity for, the Fermi 2 plant alone.

b. The Scan, Log and Alarm (SLA) function provides continuous monitoring of plant parameters through on-line data acquisition equipment. Plant parameters are alarmed and logged based on pre-determined setpoints.

c. The IPCS supplies information to the operator via a man-machine interface (MMI) consisting of video displays and printers mounted within the operating panels.

d. Data archival of plant parameters is provided on both a short term (at process scan rates) and on a long term basis (at a reduced scan rate).

e. The Nuclear Steam Supply System (NSSS) function processes the heat balance data related to core operation into a condensed and usable form that assists in operating the core within prescribed limits.

   Reactor heat balance analysis is accomplished with both periodic and on-demand programs.

   The results from these calculations are displayed through alarms and on-demand and periodic computer printouts.

f. The Balance of Plant (BOP) function provides extended features beyond the NSSS function to other plant systems. The on-line data values required for monitoring BOP systems are obtained from BOP system sensors shared with other systems and from sensors installed specifically to provide input data for the computer. The IPCS is able to perform certain BOP calculations to aid with equipment operation and equipment operation documentation.

The on-line data-gathering and computation ability of the IPCS allows the display of on-line equipment performance indicators. These indicators provide a condensed summary of BOP equipment operational status.

g. The Emergency Response function is designed to gather data from selected plant parameters and data systems for use in the Safety Parameter Display System (SPDS) function and Emergency Response Data System (ERDS) function.

The SPDS function calculates and displays the value and status of the primary variables of the following systems:

1. Core Cooling
2. Fuel integrity
3. Reactivity
4. Reactor coolant system integrity
5. Containment integrity
6. Radioactivity effluent to the environment

The design basis of the SPDS function is to display to operating personnel a minimum set of parameters that define the status of the plant as necessary to assess plant safety status.

The ERDS function provides the NRC with SPDS data through a dedicated datalink.

h. The Meteorological (MET) function is designed to provide calculations using various meteorological parameters obtained from the Meteorological Data Acquisition System (MDAS). These calculations are used to support the requirements of Regulatory Guide 1.23 “Onsite Meteorological Programs”.

i. The Transient Recording and Analysis (TRA) function is designed to provide high-speed recording of select plant parameters that are of significant importance during plant transients. The analysis portion of the function provides statistical data reduction capabilities to aid operating personnel in understanding the event.

The IPCS interfaces with a wide variety of external systems through specialized data links for providing or obtaining process parameters. These systems include:

a. 3D-Monicore Computer System (3DM)

b. Power Range Neutron Monitor System (PRNM)

c. Rod Worth Minimizer System (RWM)

d. Radiological Dose Assessment Application (Raddose V)

e. Meteorological Data Acquisition System (MDAS)

7.1.2.1.15.2 3D-Monicore Computer System (3DM)

The 3DM computer is designed to determine periodically the three-dimensional power density distribution for the reactor core, and to provide printed logs that permit accurate assessment of core thermal performance.

The 3DM computer provides nearly continuous monitoring of the core margins to operating limits and appropriate alarms based on established core operating limits. This aids the operator in ensuring that the core is operating within acceptable limits at all times, especially during periods of power level changes.

7.1.2.1.16 Standby Gas Treatment System

Safety Design Basis - General Functional Requirements

The standby gas treatment system (SGTS) instrumentation and control meets the following safety design bases:

a. The instrumentation and control initiates the SGTS to provide filtration of air released from the reactor building following a fuel-handling accident or LOCA

b. The instrumentation and control limits the possibility of exfiltration from the reactor building to outdoors by maintaining negative pressure in the reactor building area

c. The SGTS responds automatically so that no initiating action is required of plant operators following a LOCA or fuel-handling accident

d. The responses of the SGTS are indicated on the main control panel

e. Facilities for the manual control of the SGTS are provided in the main control room

f. No single failure, maintenance, calibration, or test prevents operation of the SGTS

g. Any installed means of manually interrupting the availability of the SGTS is under the control of the operator or other supervisory personnel

h. Loss of interruptible instrument air and/or offsite electric power does not affect the normal function of the SGTS

i. The physical events accompanying a LOCA or fuel-handling accident could not prevent correct functioning of the instrumentation and controls

j. Seismic motions resulting from earthquake ground motion of the design-basis earthquake, missile, wind, and flood do not impair the operation of the instrumentation and control.

Safety Design Basis - Specific Regulatory Requirements

The requirements of IEEE 279-1971 and IEEE 344-1971 are met by the SGTS instrumentation and control. Additionally, GDC 13, 20-24, and 29 of 10 CFR 50, Appendix A, and Regulatory Guide 1.22 have been implemented in the design of this control system.

7.1.2.1.17 Control Center Atmospheric Control System

The control center atmospheric control is provided by the control center heating, ventilation, and air conditioning (HVAC) system, described in Subsection 9.4.1. The instrumentation and control for this system meets the following design bases.

Safety design bases include all the bases described under power generation design bases and the following:

a. The system controls are interlocked with the RMS to isolate the main control room and automatically route the outside makeup air for the control center HVAC system through the emergency and recirculation filter trains so that main control room habitability is maintained

b. The system operates in conjunction with ionization detection systems to annunciate in the main control room on detection of combustion products in the main control room ceiling space

c. The system has the capability to purge rooms manually with 100 percent outside air, or to route the outside air and recirculation air mixture of the control center HVAC system manually through odor, smoke, and halogen- removing filters that are normally bypassed

d. No single failure, maintenance, calibration, or test operation prevents the functioning of the control center HVAC instrumentation and control. A single active failure in the Halon fire protection system will cause closure of smoke/Halon dampers to the relay room, cable spreading room or computer room. Manual actions are required to reopen these dampers to reestablish airflow.

e. Any installed means of manually interrupting the availability of the control center HVAC system is under the control of the operator or other supervisory personnel

f. Loss of offsite electric power does not affect the normal functioning of instrumentation and controls

g. The physical events accompanying a LOCA or fuel-handling accident do not prevent correct functioning of the instrumentation and controls

h. Seismic motions resulting from earthquake ground motion, missile, wind, and flood do not impair the operation of the instrumentation and controls

i. The requirements of IEEE 279-1971, IEEE 323-1971, IEEE 338-1971, and IEEE 344-1971 are met by the control center HVAC system instrumentation and control. Additionally, GDC 13, 19, 20-24, and 29 of 10 CFR 50, Appendix A, and Regulatory Guide 1.22 have been implemented in the design of this control system.

j. The system has the following controls, interlocks, and overrides:

    1. The system can be manually selected to any of the four modes (i.e., normal, purge, chlorine or recirculation).

    2. The system will transfer to the purge or recirculation mode automatically upon receipt of the appropriate signals.

    3. The automatic purge mode will override the normal mode.

    4. The manual chlorine mode will override all modes except the automatic recirculation mode.

    5. The automatic recirculation mode will override all modes.

<u>Power Generation Design Bases</u>

The power generation design bases are

a. To control the temperature and humidity in the control center for operator comfort and electronic equipment stability. A small net positive pressure is maintained with respect to the outdoors and other areas of the plant on a year-round basis

b. To indicate temperature and status of operating equipment, such as supply and return air fans and the refrigeration unit, in the main control room

c. To annunciate on the control panel any operating transients that require operator's attention. This includes high temperature, loss of airflow from supply and return air fans, loss of refrigeration unit, high pressure drop across the supply air filters, and low positive pressure differential between the control center atmosphere and outdoors

d. To provide capability in the main control room to manually control and operate various components of the control center HVAC system

e. To provide a means to test instrumentation and controls and operation of redundant equipment to ensure availability at all times.

7.1.2.1.18 Emergency Equipment Cooling Water System

Safety Design Bases

General Functional Requirements - The instrumentation and control of the emergency equipment cooling water (EECW) system is designed to initiate and maintain operation of the EECW system automatically when normal operation of the reactor building closed cooling water (RBCCW) system is impaired (as indicated by a low differential header pressure), high drywell pressure is experienced, or upon loss of offsite ac power. The controls are provided

a. To open or close appropriate motor-controlled valves to retain essential cooling circuits and isolate those that are not required to be in service in an emergency

b. To start operation of the pumps of both loops to establish flow of the emergency equipment service water (EESW) system (the latter is used to remove heat from the EECW system heat exchangers)

c. To regulate the temperature of the EECW within the required range at the outlet of the EECW system heat exchanger

d. To maintain the demin level in the EECW makeup tank within the required range during normal plant operation.

Manual controls for initiating operation of the EECW system and its return to the standby state are also provided. The EECW makeup tanks are supplied with demineralized water during normal plant operation. The EECW system makeup tank is supplied via a crosstie line and a makeup pump from the EESW system to provide an alternate makeup supply for each division when the normal makeup supply to the tank is lost during and after the design basis accident. After EECW start, the EECW makeup tanks are replenished and pressurized by makeup pumps utilizing EESW water. The makeup pumps automatically start on makeup tank low pressure or low level, if the makeup tank isolation valve is open and normal makeup pump suction pressure is achieved. Instrumentation and controls are provided to automatically maintain EECW makeup tank pressure, and provide a source of safety-related water (EESW) during EECW system operation.

Specific Regulatory Requirements - The protection system functions contained in functions a. and b. above are required to comply with IEEE 279-1971, IEEE 308-1971, IEEE 323-1971, IEEE 336-1971, IEEE 338-1971 and IEEE 344-1971; GDC 18, GDC 20-24, and GDC 29 of 10 CFR 50, Appendix A and Appendix B; and Regulatory Guide 1.22. EECW system monitoring and control functions c. and d. are required to comply with the requirements of GDC 13.

Power Generation Design Basis

EECW may be manually initiated with the nonessential loads subsequently restored to facilitate RBCCW heat exchanger cleaning, to enhance drywell cooling during high lake water (GSW) temperature, for testing, or to provide RHR Reservoir freeze protection during extreme cold weather. A Loss of RBCCW while EECW is operating in this mode will not reinitiate EECW or re-isolate the nonessential loads. This action is not required, however, since this is not a condition requiring protective action as described in Section 7.1.2.1. The demineralized water level in the makeup tank is automatically maintained above a specified minimum amount during normal plant operation. Automatic makeup from EESW is provided for the condition when the normal demineralized water makeup supply is not available and the makeup tank is connected to the EECW loop (i.e., when the P4400F602A(B) valve is open).

7.1.2.1.19 Emergency Core Cooling System Auxiliary Systems

The ECCS auxiliary systems support operation of ECCS equipment. Instrumentation required for operation of this ECCS equipment, therefore, meets the redundancy and separation requirements of the ECCS equipment. The ECCS auxiliary systems consist of

a. Cooling water (EECW) system described in Subsection 7.1.2.1.18

b. Essential electric power systems described in Subsection 7.1.2.1.25

c. Area coolers for rooms and areas containing ECCS equipment (Section 9.4)

d. Leak detection in ECCS equipment rooms and areas, as described in Subsection 7.1.2.1.26.

Safety Design Basis

The EECW system is designed to be available for essential equipment as outlined in Subsection 7.1.2.1.18. The electric power available for the EECW system is also described in Subsection 7.1.2.1.25. Either the area coolers are designed for operation during emergency conditions, or the ECCS equipment is designed so that loss of the coolers does not jeopardize operation of the ECCS. Leak detection instrumentation monitors primarily for leaks of reactor water or steam. Leak detection instrumentation that automatically isolates ECCS equipment meets the redundancy/ separation requirements for those ECCSs. Subsection 7.1.2.1.26 describes the leak detection instrumentation design bases in more detail.

The EECW system is designed for the maximum expected heat load of ECCS emergency equipment that is used to provide equipment cooling and ventilation space cooling for the HPCI, RCIC, RHR, and core spray systems.

Power Generation Design Bases

The EECW and electrical power sources for the ECCS equipment are maintained in readiness so that they are available when needed. This includes maintaining a minimum level of condensate in the makeup tank. The room air ventilation system is also designed to filter and/or reroute air from rooms where airborne radiation may be present. The LDS initiates an alarm in the main control room in sufficient time for operating personnel to correct or isolate the leak. In some cases the LDS automatically isolates the leaking system.

7.1.2.1.20 Reactor Core Isolation Cooling System

Safety Design Basis - General Functional Requirements

The RCIC system is designed to meet the following general functional requirements:

a. The system is capable of maintaining sufficient coolant in the RPV in case of a loss of main feedwater flow

b. Provisions are made for automatic and remote manual operation of the system

c. To provide a high degree of assurance that the system operates when necessary, the power supply for the system is from immediately available energy sources of high reliability

d. To provide a high degree of assurance that the system operates when necessary, provision is made for periodic testing during reactor operation.

Safety Design Basis - Specific Regulatory Requirements

The RCIC system is considered a safety system rather than an ECCS because it is required for safe shutdown. The system is designed to meet the requirements, with exceptions as described in Subsection 7.4.2.2.2, of the federal codes, regulatory guides, and IEEE standards applied to the ESF systems.

7.1.2.1.21 Standby Liquid Control System

Safety Design Bases

General Functional Requirements - The major components of the SLCS consist of a storage tank, two positive displacement pumps, two explosive valves, and two check valves between the explosive valves and the reactor, as shown in Figure 7.4-3. The flow path is from the storage tank through the pumps, explosive valves, and check valves, and into the reactor to the bottom of the core plate. This system is capable of shutting the reactor down from full power to cold shutdown and maintaining the reactor in a subcritical state at atmospheric temperature and pressure conditions by pumping sodium pentaborate, a neutron absorber, into the reactor.

The sodium pentaborate also increases suppression pool pH to prevent iodine re-evolution following a LOCA in the event of fuel failure.

Dual components and dual circuits are used in portions of the system; however, this manually operated system is subject to single failure. Monitoring and testability have been provided for the components and circuits that are deemed most likely to fail. Redundant power sources supply power to this system.

The SLCS electrical components necessary for the injection of boron have been classified as QA Level 1M to indicate that they were not originally intended, procured, designed, or classified as safety related, but will be maintained and tested as a safety-related system.

Specific Regulatory Requirements - General Design Criterion 26 of 10 CFR 50, Appendix A, which requires the provision of an independent method of reactivity control, applies.

Power Generation Design Basis

The system is designed to shut the reactor down from full power to cold atmospheric conditions with sufficient margin to maintain the reactor subcritical at the cold condition in the event that manual control rod movement cannot be accomplished with the RMCS.

7.1.2.1.22 Primary Containment Monitoring System

The primary containment monitoring system consists of four instrumentation subsystems that collectively monitor the primary containment atmosphere for hydrogen concentration, oxygen concentration, gaseous radiation level, and temperature and pressure, and that monitor the pressure suppression pool water for temperature and level. The radiation monitor is principally provided to enhance the capability for detecting reactor water or steam leaks. The radiation monitor activates an alarm upon detecting radiation at or above a predetermined level. Monitoring of the other parameters is provided to secure information on transients resulting from a LOCA. The monitored parameters are indicated and recorded in the main control room.

The primary containment atmosphere monitoring system also serves to provide information on monitored parameters in the course of plant operations when conditions are normal. The four primary containment monitor subsystems are designated

a. Primary containment radiation monitor and the hydrogen/ oxygen monitor subsystem

b. Primary containment temperature monitor subsystem

c. Primary containment pressure monitor subsystem

d. Pressure suppression pool water level indicator subsystem.

The design bases and regulatory requirements for each of these subsystems are individually defined below.

7.1.2.1.22.1 Primary Containment Radiation Monitor and Hydrogen/ Oxygen Monitor Subsystems

Safety Design Bases

General Functional Requirements - The primary containment radiation monitor is designed to meet the following safety design bases:

a. Provide continuous radiation monitoring of the primary containment atmosphere during power operation, startup and hot shutdown of the reactor.

b. Provide particulate and halogen filters in the atmospheric sample flow line to collect integrated samples of these substances, on separate filters, for purposes of radiation analysis

c. Provides a high-radiation alarm with fully adjustable setpoints in the main control room.

d. Provide a diverse reactor coolant pressure boundary leak detection method using noble gas activity.

Specific Regulatory Requirements - The instrumentation and control of the primary containment radiation monitor subsystem is designed to conform to General Design Criterion 30 of 10 CFR 50, Appendix A and Regulatory Guide 1.45. The hydrogen/oxygen monitor subsystem is designed to meet Regulatory Guides 1.7 and 1.97, Category 3 and 2 requirements, respectively.

Power Generation Design Bases

The primary containment radiation monitor and hydrogen/oxygen monitor subsystems are designed to meet the following power generation design bases:

a. Provide indication in the main control room of the noble gas radioactivity and hydrogen/oxygen content of the primary containment atmosphere during normal operation

   The oxygen monitors provide verification of the status of the inerted atmosphere of containment and oxygen levels in the containment atmosphere following a significant beyond-design-basis accident for combustible gas control and accident management, including emergency planning.

   The hydrogen monitors provide diagnosis of the course of significant beyond-design-basis accidents for accident management, including emergency planning.

b. Provide means for obtaining radioactivity analysis of particulate and halogen content in the primary containment atmosphere

c. Provide an instrument failure (offscale low) alarm.

d. Provide high hydrogen and high oxygen alarms with fully adjustable setpoints in the main control room.

7.1.2.1.22.2 Primary Containment Temperature Monitor Subsystem

Safety Design Bases

General Functional Requirements - The primary containment temperature monitor subsystem is designed to meet the following safety design bases:

a. Provide continuous monitoring of the drywell atmosphere temperature with a distributed arrangement of temperature sensors to secure representative temperature data in the drywell region

b. Provide continuous monitoring of drywell cap atmospheric temperature with a sensor suitably located to secure representative temperature information in the cap region

c. Provide continuous measurement of drywell wall temperature with an arrangement of sensors distributed to obtain a representative determination of the wall temperature conditions in the drywell region

d. Provide continuous measurement of atmospheric temperature in the pressure suppression chamber

e. Provide continuous measurement of water temperature in the pressure suppression chamber.

Safety Design Bases

Specific Regulatory Requirements - The primary containment temperature monitor subsystem is designed to conform to GDC 13 of 10 CFR 50, Appendix A, and QA Criteria of 10 CFR 50, Appendix B, for nuclear power plants.

7.1.2.1.22.3 Primary Containment Pressure Monitor Subsystem

Safety Design Bases

General Functional Requirements - The primary containment pressure monitor subsystem is designed to meet the following safety design bases:

a. Provide continuous measurement of drywell atmospheric pressure

b. Provide continuous measurement of pressure suppression chamber atmospheric pressure.

Specific Regulatory Requirements - The primary containment pressure monitor subsystem is designed to meet GDC 13 of l0 CFR 50, Regulatory Guide 1.97, Appendix A, and QA Criteria of 10 CFR 50, Appendix B, for nuclear power plants.

Power Generation Design Basis

The primary containment pressure monitor subsystem provides a chart recorder in the main control room to continuously record and display the primary containment pressure monitored by this subsystem.

7.1.2.1.22.4 Pressure Suppression Pool Water Level Indicator Subsystem

Safety Design Bases

General Functional Requirements - The pressure suppression pool water level indicator subsystem is designed to provide measurement of water level in the pressure suppression chamber over the maximum practical range.

Specific Regulatory Requirements - The pressure suppression pool water level indicator system is designed to meet GDC 13 of 10 CFR 50, Regulatory Guide 1.97, Appendix A, and QA Criteria of 10 CFR 50, Appendix B, for nuclear power plants.

Power Generation Design Basis

The pressure suppression pool water level indicator subsystem is designed to provide a display in the main control room that indicates the water level in the pressure suppression chamber.

7.1.2.1.23 Radwaste Control System

7.1.2.1.23.1 Liquid Radwaste System

The safety design bases ensure that the liquid radwaste system instrumentation and control is designed to provide information to the liquid radwaste process operator. This information is needed to limit releases of radioactivity to the environment. Further discussion can be found in Subsection 7.7.1.6 and in Sections 11.2 and 11.4.

7.1.2.1.23.2 Gaseous Radwaste System

The safety design bases ensure that the gaseous radwaste system instrumentation and control system is designed to monitor and control the gaseous processing systems (offgas system and 2-minute holdup pipe system). It also detects, indicates, and alarms improper or abnormal conditions in the gaseous radwaste systems in time for corrective action. Further discussion can be found in Subsection 7.7.1.5 and in Sections 11.3 and 11.4.

7.1.2.1.24 Reactor Water Cleanup System

The purpose of the RWCU system is to provide continuous processing of the reactor water so that the purity is maintained within specified limits. The system also provides the means for removal of reactor water. For example, to maintain reactor water level during startup, it is necessary to dump water due to swell.

7.1.2.1.25 Power Systems

The power systems considered in this subsection include those electrical power sources used in, or associated with, shutting down the reactor and limiting the release of radioactive material following a design-basis event. The power systems include the standby ac system (Subsection 8.3.1), the plant dc system (Subsection 8.3.2), instrument ac power (Subsection 8.3.1), RPS power supplies (Subsection 8.3.1), and special power supplies for individual systems.

Electrical power supplies are available onsite as required to provide the electrical energy requirements of the ESF and safe- shutdown systems during all safety design-basis events and as long thereafter as required to satisfy safety requirements.

The design of the standby ac power system complies with accepted industrial standards for nuclear power plants and is compatible with the ESF system equipment design and arrangement.

Safety Design Bases

General Functional Requirements - The power systems are designed to meet the following general functional requirements:

a. Standby ac Power System

   1. General - The primary requirement of the standby ac power system is to maintain a high degree of reliability and timely availability of power sources for the ESF and safe-shutdown systems. This power is required to be made available promptly, within approximately 10 sec, and automatically on either a failure of preferred power sources at any time, or on a LOCA signal

      Before the diesel generator is connected to a bus, all offsite source breakers and bus load breakers, with the exception of certain selected breakers, are signaled to trip. The generator is then sequentially loaded to prevent overload or excessive voltage drop. Shutdown of the diesel generator is manual only, except for specific automatic trips to prevent equipment destruction

2. Load Assignment - Assignment of loads to emergency safety system buses is such that failure of a single standby power source does not prevent a safe shutdown of the reactor under conditions of a design- basis accident (DBA) concurrent with a design-basis event. "Design-basis event" is used here in the same sense as defined in IEEE 308-1971, i.e., any or all of a set of postulated environmental events for which the plant and ESF systems have been designed

   Automatic starting is required of all loads that may be required within 10 minutes after a LOCA. Automatically started loads may be stopped manually and other loads started manually as required by plant conditions.

   Automatically connected loads include the emergency core cooling pumps and valves, safety-related instrument power supply transformers, containment isolation valves (ac only), drywell cooling equipment, emergency lighting, standby gas treatment and control center heating, ventilation, and air- conditioning, main control room habitability, EECW system, ECCS room coolers, auxiliary building heating and ventilation, EDG auxiliary equipment, RHR complex ventilation equipment, and reactor building sumps

   Manually connectable loads are defined in Table 8.3-3.

b. Plant dc Power System - The primary requirement of the plant dc power system is to maintain highly reliable and continuously available sources of dc power for the control of a minimum complement of the ECCS and the ac power system equipment during operating conditions and during a DBA concurrent with a design-basis event

   Voltage variations are maintained within the demonstrated operating limits of each connected device with appropriate allowances for voltage drop in the cabling. Control battery terminal voltage range on a 130-V dc system is discussed in section 8.3.2.2.4

   The dc power sources for redundant ESF equipment must be arranged so as not to compromise the required independence or reduce redundancy below an acceptable level during a design-basis event (i.e., loss of one battery shall not disable any ESF function)

   The EDGs are equipped with sufficient protective devices to prevent destruction of the unit, e.g., overspeed trip, low oil pressure trip, generator differential relays, and crankcase overpressure. Other protective devices are used for protection when in test mode, but such devices alarm only when the unit is required to perform the designed safety function

c. Instrument ac Power - Power for process instrumentation associated with redundant ESF systems is to be provided by a standby source from the same division as the pump motors and ac valve motors for each system. This power is not classified as essential to nuclear safety, but is to be made available automatically when the bus to which it is connected is energized

The instrumentation power for the HPCI and RCIC systems is to be from a separate inverter that feeds from the same station battery that powers HPCI and RCIC controls, respectively.

d. Other Power Supplies

1. Reactor Protection System - Power supplies for the RPS are required to have sufficient stored energy to ride through switching transients within the switchyard or auxiliary power system. The safe failure characteristic of the RPS on loss of power exempts the RPS power supplies from being classified essential. However, redundancy is provided to avoid unnecessary plant shutdown on interruption of power to one RPS bus

2. Process Radiation Monitoring System - Certain aspects of the PRMS require 120-V ac power for purposes of recording and/or control. This power is provided from an instrument bus or an inverter power supply as appropriate.

Safety Design Bases

Specific Regulatory Requirements - The standby ac power and dc power systems are essential to safe shutdown of the reactor and/or for emergency core cooling, and therefore comply with all applicable AEC and IEEE standards for design, qualification, and testing. These include IEEE 279-1971, IEEE 308-1971, IEEE 323-1971, IEEE 338-1971, IEEE 344-l97l; GDC 1 through 5, 12, 18 and 19 of 10 CFR 50, Appendix A, and Regulatory Guides 1.6 and 1.9 (with exceptions as discussed in Subsection 8.3.1.2.2.2 and Appendix A.1.9).

7.1.2.1.26 Leak Detection System

7.1.2.1.26.1 Reactor Coolant Pressure Boundary Leakage Detection

Safety Design Bases

General Functional Requirements - The safety design basis for the LDS for setting leakage rate limits is that signals are provided to permit isolation of abnormal leakage before the results of this leakage become unacceptable.

The unacceptable results are a threat of significant compromise to the nuclear system process barrier and a leakage rate in excess of the coolant makeup capability to the reactor vessel.

Specific Regulatory Requirements - The part of leak detection that is related to isolation circuits is designed to meet requirements of the ESF systems and to conform to those federal codes, regulatory guides, and IEEE standards which apply to ESF systems.

Power Generation Design Basis

A means is provided to detect abnormal leakage from the nuclear system process barrier.

7.1.2.1.26.2 Emergency Core Cooling System Suction Line Detection

The ECCS suction line LDS is designed to provide information that would allow the manual closing of the valve in the broken line before the net positive suction head (NPSH) is lost to the redundant ECCS.

7.1.2.1.27 Reactor Shutdown Cooling System

Safety Design Bases

The instrumentation and control for the reactor shutdown cooling mode of the RHR system is designed to meet the following functional design bases:

a. Instrumentation and manual control are provided to enable the system to remove the residual heat (decay heat and sensible heat) from the RPV during normal shutdown

b. All facilities for manual control of the shutdown cooling system are provided in the main control room

c. Response of the shutdown cooling system is indicated by main control room instrumentation.

Power Generation Design Bases

The instrumentation and control for the reactor shutdown cooling system is designed to meet the following power generation design bases:

a. Provide cooling for the reactor during the shutdown operation when the vessel pressure is below the design pressure of the shutdown piping system

b. Cool the reactor water to a temperature which is practical for refueling and servicing operation.

7.1.2.1.28 Plant Cooling Systems

Two closed cooling water systems are used at Fermi 2 for removal of heat from equipment and space coolers. These are the RBCCW system and the turbine building closed cooling water (TBCCW) system, both described in Section 9.2. The EECW system, an ESF described in Subsection 7.3.4.2, forms an integral part of the RBCCW system.

7.1.2.1.28.1 Reactor Building Closed Cooling Water System Power Generation Design Bases

The instrumentation and control of the RBCCW system is designed in accordance with the following functional requirements:

a. It maintains the required flow of cooling water in the system and its two divisions during normal conditions and postulated abnormal conditions of the plant

b. On loss of offsite power, high drywell pressure, or on drop of differential pressure across the supply and return headers of either division beyond the preset limit, the EECW system will automatically isolate areas of the RBCCW system not essential for emergency cooling and to take over supplying the coolant flow that is required. A loss of RBCCW while EECW is operating for RBCCW heat exchanger cleaning, enhanced drywell cooling, testing, or RHR reservoir freeze protection will not reinitiate EECW or reisolate the nonessential loads. This action is not required, however, since this is not a condition requiring protective action as described in Section 7.1.2.1.

c. Restoration of the system to normal operation is by manual control.

7.1.2.1.28.2 Turbine Building Closed Cooling Water System Power Generation Design Bases

The instrumentation and control of the TBCCW system is designed in accordance with the following functional requirements.

a. It maintains the required flow of cooling water in this system during normal conditions of plant operation

b. It automatically becomes deactivated on loss of offsite power

c. Restoration of the system to normal operation after gain of power is by manual control.

7.1.2.1.29 Fuel Pool Cooling and Cleanup System

The fuel pool cooling and cleanup system (FPCCS) instrumentation and control is not required for power generation. Its function is to provide annunciation and control so that the FPCCS can maintain the spent fuel and equipment storage pools and the reactor water well below a desired temperature and at a degree of clarity necessary to refuel and service the reactor.

7.1.2.1.30 Post-LOCA Combustible Gas Control System

The NRC amended 10 CFR 50.44, “Standards for combustible gas control system in light-water-cooled power reactors” on October 16, 2003 to eliminate the requirements for hydrogen recombiners. The hydrogen recombiner Technical Specification requirements were subsequently removed by License Amendment 159, dated March 15, 2004. Regulatory Guide 1.7 was revised in March 2007 to reflect the amended 10 CFR 50.44. The Combustible Gas Control System (CGCS) has been retired in place with its electrical circuits de-energized and fluid process piping isolated from primary containment with redundant locked-closed isolation valves. Combustible gas control of the primary containment is provided by inerting the primary containment with nitrogen.

7.1.2.1.31 Control Air System

The instrumentation and control of the control air system is designed in accordance with the following functional requirements.

a. The control air system maintains the required quantity and quality of control air to both interruptible and noninterruptible control air users

b. On loss of control air pressure below a preset limit, the control air compressors are automatically started and the two divisions of the control air system are automatically isolated from all interruptible control air users and the station air system so that each control air compressor is supplying only its own essential division

c. It provides for manual actuation of the system from the main control room for testing of the system or for manual initiation of the system.

7.1.2.1.32 Alternate Rod Insertion

The safety design bases are as follows:

a. The sensors, transmitters, trip units, and associated logic for the ARI are Class 1E, redundant to the reactor protection system, and environmentally and seismically qualified to IEEE 323-1974 and IEEE 344-1975

b. The ARI sensors monitor reactor pressure and water level and trip the reactor if these variables reach their respective trip setpoints. The trip is accomplished by energizing the ARI valves, thereby venting the air supply holding the scram valves shut.

7.1.2.2 Independence of Redundant Safety-Related Systems

The criteria for the separation of safety-related mechanical and electrical equipment are discussed in Section 3.12 and Subsection 8.3.1. The independence of redundant safety-related systems satisfies the applicable requirements of IEEE 279-1971. The requirements of 10 CFR 50, Appendix B, are met as described in Chapter 17.

7.1.2.3 Physical Identification of Safety-Related Equipment

Equipment associated with the RPS, the ESF, the safe shutdown systems, and the auxiliary electrical equipment associated with these systems are identified so that it is apparent that

a. The equipment is part of the RPS, ESF, or safe shutdown system

b. The equipment item is associated with a particular grouping (or division) of enforced segregation.

The identification consists of marking panels and equipment racks with marker plates that are conspicuously different in color than those for other panels or racks. These markers include identification of the proper division of the equipment within the system.

The equipment identification number and the applicable segregation code, both numerical and color code, are applied to each piece of safety-related equipment either before or during that equipment's installation.

7.1.2.4 Conformance To IEEE-317

Qualification of the penetration assemblies and their associated electrical services is provided by compliance with IEEE 317-1972. Power cables are provided with reliable decoupling devices at their load centers to ensure fault interruption prior to any penetration damage. All cables having safety-related functions are separated from their redundant counterparts in different penetration assemblies.

7.1.2.5 Conformance To IEEE-323

IEEE 323-1971 applies to equipment purchased before November 15, 1974, and IEEE 323-1974 applies to equipment purchased on or after November 15, 1974.

Written procedures and responsibilities are developed for the design and qualification of all Class 1 electric equipment. This includes preparation of specifications, qualification procedures, and documentation for Class 1 equipment. Qualification testing or analysis is accomplished prior to release of the engineering design for production. Standards manuals are maintained containing specifications, practices, and procedures for implementing qualification requirements; and an auditable file of qualification documents is available for review.

7.1.2.6 Conformance To IEEE-336

The implementation of the Quality Assurance Procedures for construction activities ensures compliance with the requirements of IEEE 336-1971.

7.1.2.7 Conformance To IEEE-338 and Regulatory Guide 1.22

For a more detailed description of conformance, for all safety- related systems, see Subsections 7.2.2, 7.3.2, 7.4.2, and 7.6.2.

7.1.3 Protection System Inservice Testability

This section is provided to describe the analog transmitter/trip unit (AT/TU) system. The AT/TU system is a plant protection system testability feature generically applied to the reactor protection (trip) system, ESF systems, and the RCIC system.

The AT/TU system provides highly accurate continuous monitoring of process parameters, excellent setpoint stability, and convenient on-line testability.

For additional testability discussions, refer to Topical Report NEDO-21617-A, dated December 1978, Analog Transmitter/Trip Unit System for Engineered Safeguard Sensor Inputs (Reference 1).

7.1.3.1 General Description

The AT/TU system uses analog instrument channels to monitor important plant variables (e.g., reactor water level, reactor pressure, drywell pressure, and process flow). The analog transmitter converts the process variable sensed to a 4- to 20-mA linear signal. The signal is transmitted to electronic trip units located on the fourth floor of the auxiliary building. The trip units compare the transmitted signal with a fixed reference signal (setpoint). When the transmitted signal increases above or decreases below the setpoint, the trip unit activates an associated relay. The relay provides either open or closed contacts on activation.

The trip units consist of master trip assemblies, slave trip assemblies, and calibration units. The master trip unit is a plug-in printed circuit assembly designed to accept a 4- to 20-mA signal from a remote transmitter. The trip unit contains the circuitry necessary to condition the transmitter current, compare with the setpoint, provide trip output, and provide analog output signals. An alarm is generated by an inoperative or out-of- service trip unit. The master trip unit also contains a panel meter that displays transmitter current and is scaled in the units of the process variable being measured by the transmitter wired to the master trip unit. A switch position selection internal to the master trip unit allows for selection of either high trip point or low trip point. This allows the testing of trip circuitry for a particular channel with the trip circuitry either energized or deenergized during normal operation.

The slave trip unit is used in conjunction with a master trip unit when different setpoints from a common transmitter are desired. The slave trip unit receives its input signal from the analog output of a master trip unit. There is no direct connection to any 4- to 20-mA transmitter. No analog output signals are generated by the slave unit. Calibration of the slave unit is accomplished by commanding the master trip unit, which drives the slave unit under test into the calibration mode, and then performing the normal calibration procedure.

The calibration unit furnishes the means by which an in-place calibration check of the master and slave trip units can be performed. The calibration unit contains a stable current source and a transient current source. The stable current source is used to verify the calibration point of any given channel. The transient current source is used to provide step current input into a selected trip unit so that the response time of that channel can be determined.

During calibration, the trip action is displayed on the removable display assembly. The accuracy of the analog output of the master trip unit may also be checked during the calibration procedure with an external meter or recorder.

7.1.3.2 Analysis

For a discussion of conformance with regulatory guides and IEEE standards, see Reference 1.

7.1 INTRODUCTION

REFERENCES

1. General Electric Company, Analog Transmitter/Trip Unit System for Engineered Safeguard Sensor Inputs, NEDO-21617-A, December 1978.

TABLE 7.1-1 LICENSED REACTOR SYSTEMS FUNCTIONALLY IDENTICAL TO FERMI 2*

System	Plants With Construction Permit or Operating License
Reactor protection system	Hatch 1, Duane Arnold
Primary containment and RPV isolation control system	Hatch 1, Duane Arnold
Emergency core cooling system	Hatch 1, Duane Arnold
Neutron monitoring system	Hatch 1, Duane Arnold
Refueling interlocks	Hatch 1, Duane Arnold, Dresden 2 and 3
Reactor core isolation cooling system	Hatch 1, Duane Arnold
Standby liquid control system	Dresden 2 and 3
Reactor water cleanup system	Hatch 1, Duane Arnold
Shutdown cooling system	Hatch 1, Duane Arnold

* This table was a true comparison with the listed Nuclear Power Plants' systems at the time NRC issued NUREG-0798, "Safety Evaluation Report Related to the Operation of Enrico Fermi Atomic Power Plant, Unit No. 2.," July 1981. Refer to pages 7-1 and 7-2 in the SER for the NRC acknowledgement.

TABLE 7.1-2 INSTRUMENTATION AND CONTROL SYSTEMS DESIGNERS AND FABRICATORS

	System	Designer	Fabricator
1.	Reactor protection system	GE	GE
2.	Containment and RPV isolation control system	Edison/GE	GE
3.	Emergency core cooling system: a. HPCI c. ADS b. LPCI d. CS system	GE	GE
4.	Neutron monitoring system	GE	GE
5.	Refueling interlocks	GE	GE
6.	RPV power generator instrumentation	GE	GE
7.	Recirculation flow control system	GE	GE
8.	Feedwater control system	GE	GE
9.	Pressure regulator and turbine generator control system	GE/GEC	GEC
10.	Process radiation monitoring system	Edison/GE/ Mirion/Gulf GA	GE/Gulf GA/ Mirion/ Eberline
	a. Process liquid radiation monitoring system	GE/Gulf GA/ Mirion	GE/Gulf GA/ Mirion
	(1) Radwaste bldg. effluent radiation monitor	GE/Mirion	GE/Mirion
	(2) General service water effluent radiation monitor	GE/Mirion	GE/Mirion
	(3) Circulating water reservoir decant radiation monitor	Gulf GA	Gulf GA
	(4) RBCCW system radiation monitor	GE/Mirion	GE/Mirion
	(5) EECW system radiation monitor	Gulf GA	Gulf GA

TABLE 7.1-2 INSTRUMENTATION AND CONTROL SYSTEMS DESIGNERS AND FABRICATORS

		System	Designer	Fabricator
		(6) RHRSW radiation monitor	Gulf GA	Gulf GA
	b.	Main steam line radiation monitor system	GE	GE
	c.	Offgas system radiation monitors		
		(1) 2-minute holdup pipe radiation monitor	Gulf GA	Gulf GA
		(2) Offgas radiation monitor[a]	GE/Mirion	GE/Mirion
	d.	Reactor bldg. exhaust plenum radiation monitor	Edison	Eberline
	e.	Reactor bldg. ventilation exhaust radiation monitor	Edison	Gulf GA
	f.	Fuel pool ventilation exhaust radiation monitor	GE	GE
	g.	Standby gas treatment system exhaust radiation monitor	Edison	Eberline
	h.	Control Center makeup air radiation monitor	Edison	Gulf GA
	i.	Radwaste bldg. ventilation exhaust radiation monitor	Edison	Eberline
	j.	Deleted		
	k.	Turbine bldg. ventilation exhaust radiation monitor	Edison	Eberline
11.		Area radiation monitoring system	Edison/GE	GE
12.		Site environs radiation monitoring system	Edison	Refer to Chapter 11

[a] Ratemeters D11K600A/B have been removed and other associated components of the offgas vent pipe radiation monitor subsystem have been abandoned in place.

TABLE 7.1-2 INSTRUMENTATION AND CONTROL SYSTEMS DESIGNERS AND FABRICATORS

	System	Designer	Fabricator
13.	Health physics and laboratory analysis radiation monitoring system	Edison	Refer to Chapter 12
14.	Integrated plant computer system	DS&S	Various
15.	Standby gas treatment system	CVI Inc.	CVI Inc.
16.	Control center HVAC control system	Edison	Various
17.	Emergency equipment cooling water control system	Edison	Various
18.	Emergency core cooling system, auxiliary systems, control systems	Edison	Various
19.	Reactor core isolation cooling system	GE	GE
20.	Standby liquid control system	GE	GE
21.	Primary containment monitor system		
	a. Primary containment radiation monitor and hydrogen/oxygen monitoring system	Edison	Exo-Sensors/ GA
	b. Primary containment temperature monitor system	Edison	Various
	c. Primary containment pressure monitor system	Edison	Various
	d. Pressure suppression pool water level indicator system	Edison	Various
22.	Radwaste control system	GE	GE
	a. Liquid radwaste system	NUS	NUS/Edison
	b. Gaseous radwaste system	Edison/ Kraftwerk Union	Various
23.	Reactor water cleanup system	GE	GE

TABLE 7.1-2 INSTRUMENTATION AND CONTROL SYSTEMS DESIGNERS AND FABRICATORS

	System	Designer	Fabricator
24.	Power systems		
	a. Standby ac	Edison	Various
	b. Plant dc	Edison	Various
	c. Instrumentation ac	Edison	Various
25.	Leak detection system		
	Reactor coolant pressure boundary leakage detection	GE	GE
26.	Residual heat removal shutdown cooling control system	GE	GE
27.	Plant cooling system		
	a. Reactor building closed cooling water system	Edison	Edison/ Erector
	b. Turbine building closed cooling water system	Edison	Edison/ Erector
28.	Fuel pool cooling and cleanup system	GEGE	
29.	Reactor/Auxiliary building HVAC and pressure control	A. H. Smith Associates	Various
30.	Post-LOCA combustible gas control system	AI	AI
31.	Remote shutdown system	Edison	Reliance
32.	Turbine-generator overspeed trip	GEC/Edison/ GE (set points)	GEC/Edison
33.	Vital buses/load-shedding instrumentation and control	Edison	Various
34.	Plant emergency communication	Edison	GAI/Tronics
35.	Supplemental cooling chilled water system	Edison	Various

FUNCTIONAL CLASSIFICATION

SAFETY DESIGN BASIS SYSTEMS

REACTOR TRIP SYSTEM
CONTAINMENT AND RPV ISOLATION CONTROL SYSTEM
EMERGENCY CORE COOLING SYSTEMS
- HIGH PRESSURE COOLANT INJECTION (HPCI) SYSTEM
- CORE SPRAY (CS) SYSTEM
- AUTOMATIC DEPRESSURIZATION SYSTEM (ADS)
- RESIDUAL HEAT REMOVAL SYSTEM (RHR)
- RESIDUAL HEAT REMOVAL SYSTEM (RHR)
  - LOW PRESSURE COOLANT INJECTION SYSTEM (LPCI)
  - CONTAINMENT COOLING

NEUTRON MONITORING SYSTEM
- INTERMEDIATE RANGE MONITORS (IRM)
- AVERAGE POWER RANGE MONITORS (APRM)

REFUELING INTERLOCKS
REACTOR VESSEL INSTRUMENTATION
- LOW WATER LEVEL
- VESSEL PRESSURE

STANDBY LIQUID CONTROL SYSTEM
PROCESS RADIATION MONITORING SYSTEM
- MAIN STEAM LINE RADIATION MONITORING SYSTEM
- CONTAINMENT VENTILATION RADIATION MONITORING SYSTEM

ROD SEQUENCE CONTROL SYSTEM
STANDBY POWER SYSTEMS
REACTOR CORE ISOLATION COOLING (RCIC)
LEAK DETECTION SYSTEM
RESIDUAL HEAT REMOVAL SYSTEM (RHR)
- SHUTDOWN COOLING

CONTROL CENTER ATMOSPHERIC CONTROL SYSTEM
STANDBY GAS TREATMENT SYSTEM
POST LOSS OF COOLANT ACCIDENT GAS CONTROL SYSTEM

POWER GENERATION DESIGN BASIS SYSTEMS

REACTOR WATER CLEANUP SYSTEM
REACTOR MANUAL CONTROL SYSTEM
RECIRCULATION FLOW CONTROL SYSTEM
FEEDWATER CONTROL SYSTEM
PRESSURE REGULATORY AND TURBINE GENERATOR CONTROLS
AREA RADIATION MONITORING SYSTEM
INTEGRATED PLANT COMPUTER SYSTEM (IPCS)
NEUTRON MONITORING SYSTEM
- SOURCE RANGE MONITORS (SRM)
- ROD BLOCK MONITOR (RBM)
- TRAVERSING INCORE PROBE SUBSYSTEM (TIPS)

PROCESS RADIATION MONITORING SYSTEM
- (EXCEPT THOSE SUBSYSTEMS IN SAFETY SYSTEMS)

REACTOR VESSEL INSTRUMENTATION
- (EXCEPT THE INSTRUMENTATION IN SAFETY SYSTEMS)

RADWASTE SYSTEMS
TURBINE BUILDING CLOSED COOLING WATER (TBCCW) SYSTEM

REGULATORY CLASSIFICATION

REACTOR TRIP (PROTECTION) SYSTEM

REACTOR PROTECTION SYSTEM

ENGINEERED SAFETY FEATURE SYSTEMS

EMERGENCY CORE COOLING SYSTEMS
- HIGH PRESSURE COOLANT INJECTION
- CORE SPRAY
- AUTOMATIC DEPRESSURIZATION SYSTEM
- RESIDUAL HEAT REMOVAL SYSTEM
  - LOW PRESSURE COOLANT INJECTION
  - CONTAINMENT COOLING

PRIMARY CONTAINMENT AND REACTOR VESSEL ISOLATION SYSTEM
EMERGENCY CORE COOLING SYSTEM AUXILIARY SYSTEMS
CONTROL CENTER ATMOSPHERIC CONTROL SYSTEM
STANDBY GAS TREATMENT SYSTEM
STANDBY POWER SYSTEM
POST LOSS OF COOLANT ACCIDENT GAS CONTROL SYSTEM
EMERGENCY EQUIPMENT COOLING WATER (EECW) SYSTEM

SAFE SHUTDOWN SYSTEMS

REACTOR CORE ISOLATION COOLING SYSTEM
STANDBY LIQUID CONTROL SYSTEM
RESIDUAL HEAT REMOVAL SYSTEM
- REACTOR SHUTDOWN COOLING

OTHER SAFETY AND POWER GENERATION SYSTEMS

REFUELING INTERLOCKS
REACTOR VESSEL INSTRUMENTATION
PROCESS RADIATION MONITORING SYSTEM
AREA RADIATION MONITORING SYSTEM
OFFSITE ENVIRONS RADIATION MONITORING SYSTEM
HEALTH PHYSICS AND LABORATORY ANALYSIS RADIATION MONITORING SYSTEMS
REACTOR WATER CLEANUP SYSTEM
LEAK DETECTION SYSTEMS
ROD WORTH MINIMIZER (RWM)
INTEGRATED PLANT COMPUTER SYSTEM (IPCS)
NEUTRON MONITORING SYSTEM
PRIMARY CONTAINMENT MONITORING SYSTEM
REACTOR BUILDING CLOSED COOLING WATER (RBCCW) SYSTEM
SPENT FUEL COOLING SYSTEMS
ROD SEQUENCE CONTROL SYSTEM
CONTROL AIR SYSTEM

CONTROL SYSTEMS

REACTOR MANUAL CONTROL SYSTEM
RECIRCULATION FLOW CONTROL SYSTEM
FEEDWATER CONTROL SYSTEM
PRESSURE REGULATORY AND TURBINE GENERATOR CONTROLS
RADWASTE SYSTEMS

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FIGURE 7.1-1

PLANT INSTRUMENTATION AND CONTROL SYSTEMS CLASSIFICATION

	SCRAM DISCHARGE VOLUME	MSL ISOLATION VALVE CLOSURE	TURBINE STOP VALVE CLOSURE	TURBINE CONTROL VALVE FAST CLOSURE	REACTOR LOW WATER LEVEL	MSL HIGH RADIATION	NEUTRON MONITORING SYSTEM IRM	NEUTRON MONITORING SYSTEM APRM	DRYWELL HIGH PRESSURE	REACTOR HIGH PRESSURE	MANUAL SWITCH INPUTS	BYPASS INPUTS	TRIP LOGIC TRIP ACTUATOR OUTPUTS
IEEE-279	X	X	X	X	X	X	X	X	X	X	X	X	X
IEEE-308													
IEEE-317													
IEEE-323	X	X	X	X	X	X	X	X	X	X	X	X	X
IEEE-344	X	X			X	X	X	X	X	X	X	X	X
IEEE-336	X	X	X	X	X	X	X	X	X	X	X	X	X
IEEE-338	X	X	X	X	X	X	X	X	X	X	X	X	X
IEEE-334													
R.G. 1.6													
R.G. 1.9													
R.G. 1.11		X			X		X	X	X	X			
R.G. 1.12													
R.G. 1.21													
R.G. 1.22	X	X	X	X	X	X	X	X	X	X	X	X	X
R.G. 1.30	X	X	X	X	X	X	X	X	X	X	X	X	X
GDC 10								X					
GDC 12								X					
GDC 13	X	X	X	X	X	X	X	X	X	X			
GDC 17													
GDC 18													
GDC 19											X		
GDC 20	X	X	X	X	X	X	X	X	X	X		X	X
GDC 21	X	X	X	X	X	X	X	X	X	X	X	X	X
GDC 22	X	X	X	X	X	X	X	X	X	X	X	X	X
GDC 23	X	X	X	X	X	X	X	X	X	X	X	X	X
GDC 24	X	X	X	X	X	X	X	X	X	X	X	X	X
GDC 25													

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FIGURE 7.1-2

REACTOR PROTECTION SYSTEM MATRIX

	REACTOR LOW WATER LEVEL	MSL HIGH RADIATION	MSL HIGH FLOW	MSL SPACE HIGH TEMPERATURE	MSL SPACE HIGH DIFF. TEMPERATURE	REACTOR LOW PRESSURE	DRYWELL HIGH PRESSURE	PROCESS VENTILATION RADIATION MON	REACTOR CU LOOP HIGH FLOW	REACTOR CU LOOP HIGH SPACE TEMPERATURE	REACTOR CU LOOP HIGH SPACE DIFF TEMPERATURE	MANUAL SWITCH INPUTS	BYPASS INPUTS	TRIP LOGIC TRIP ACTUATOR OUTPUTS
IEEE-279	X	X	X	X	X	X	X	X	X	X	X	X	X	X
IEEE-308														
IEEE-317														
IEEE-323	X	X	X	X	X	X	X	X	X	X	X	X	X	X
IEEE-344	X	X	X	X	X	X	X	X	X	X	X	X	X	X
IEEE-336	X	X	X	X	X	X	X	X	X	X	X	X	X	X
IEEE-338	X	X	X	X	X	X	X	X	X	X	X	X	X	X
IEEE-334														
R.G. 1.6														
R.G. 1.9														
R.G. 1.11	X					X	X							
R.G. 1.12														
R.G. 1.21														
R.G. 1.22	X	X	X	X	X	X	X	X	X	X	X	X		X
R.G. 1.30	X	X	X	X	X	X	X	X	X	X	X	X	X	X
GDC 13	X	X	X	X	X	X	X	X	X	X	X			
GDC 17														
GDC 18														
GDC 19												X		
GDC 20	X	X	X	X	X	X	X	X	X	X	X		X	X
GDC 21	X	X	X	X	X	X	X	X	X	X	X	X	X	X
GDC 22	X	X	X	X	X	X	X	X	X	X	X	X	X	X
GDC 23	X	X	X	X	X	X	X	X	X	X	X	X	X	X
GDC 24	X	X	X	X	X	X	X	X	X	X	X	X	X	X
GDC 25														

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FIGURE 7.1-3

CONTAINMENT AND REACTOR VESSEL ISOLATION CONTROL SYSTEM MATRIX

	REACTOR LOW WATER LEVEL	DRYWELL HIGH PRESSURE	LPCI FLOW SUFFICIENT	LPCI BATTERY VOLTAGE	CSA/RHRA/RHRC BATTERY VOLTAGE	CSA/RHRA/RHRC EMERG BUS VOLTAGE	CSA/RHRA/RHRC FLOW SUFFICIENT	CSA/RHRA/RHRC INJECTION VALVE ΔP	CSB/RHRB/RHRD BATTERY VOLTAGE	CSB/RHRB/RHRD BUS VOLTAGE	CSB/RHRB/RHRD FLOW SUFFICIENT	CSB/RHRB/RHRD INJECTION VALVE ΔP	MANUAL SWITCH	BYPASS INPUTS	TRIP LOGIC TRIP ACTUATOR OUTPUTS
IEEE-279	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN
IEEE-308			XN		XN	XN	XN			XN	XN				
IEEE-317															
IEEE-323	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
IEEE-344	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
IEEE-336	XC	X	X	X	X	X	X	X	X	X	X	X	X	X	X
IEEE-338	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
IEEE-384															
IEEE-387			X				XN				XN				
R.G. 1.6			XN		XN	XN	XN			XN	XN				
R.G. 1.9			X				X				X				
R.G. 1.11	X	X													
R.G. 1.12															
R.G. 1.21															
R.G. 1.22	X	X											X		X
R.G. 1.30	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
GDC 13	X	X	X	X	X	X	X	X	X	X	X	X			
GDC 17			XN		XN	XN	XN			XN	XN				
GDC 18			X		X	X	X			X	X				
GDC 19			X										X		
GDC 20	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN		XN	XN
GDC 21	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN
GDC 22	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN
GDC 23	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN
GDC 24	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
GDC 25															
GDC 29	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN
GDC 35	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN
GDC 37	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN

x = Applicable
xn = Applicable on network basis

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FIGURE 7.1-4

LOW PRESSURE ECCS – LPCI, CS A, CS B, RHR A, RHR B, RHR C, RHR D NETWORK

	REACTOR LOW WATER LEVEL	PRIMARY CONTAIN-MENT HIGH PRESSURE	HPCI FLOW SUFFICIENT	HPCI BATTERY VOLTAGE	ADS A BATTERY VOLTAGE	ADS A A-C INTLK. PERMISSIVE	ADS A TIMER	ADS B BATTERY VOLTAGE	ADS B A-C INTLK. PERMISSIVE	ADS B TIMER	MANUAL SWITCH INPUTS	BYPASS INPUTS	TRIP LOGIC - TRIP ACTUATOR OUTPUTS
IEEE-279	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN
IEEE-308				XN	XN			XN					
IEEE-317													
IEEE-323	X	X	X	X	X	X	X	X	X	X	X	X	X
IEEE-336													
IEEE-338	X	X	X	X	X	X	X	X	X	X	X	X	X
IEEE-344	X	X	X	X	X	X	X	X	X	X	X	X	X
IEEE-334													
IEEE-387													
R.G. 1.6				XN	XN			XN					
R.G. 1.9													
R.G. 1.11	X	X											
R.G. 1.12													
R.G. 1.21													
R.G. 1.22	X	X									X		X
GDC 13	X	X	X	X	X	X		X	X				
GDC 17				XN	XN			XN					
GDC 18				X									
GDC 19											X		
GDC 20	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN		XN	XN
GDC 21	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN
GDC 22	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN
GDC 23	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN
GDC 24	X	X	X	X	X	X	X	X	X	X	X	X	X
GDC 29	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN
GDC 35	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN
GDC 37	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN	XN

X = APPLICABLE
XN = APPLICABLE ON NETWORK BASIS

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FIGURE 7.1-5

HIGH PRESSURE ECCS - HPCI AND ADS NETWORK

7.2 REACTOR PROTECTION SYSTEM

7.2.1 Description

7.2.1.1 Reactor Protection System Instrumentation and Control System Description

7.2.1.1.1 System Identification

7.2.1.1.1.1 Identification

The reactor protection system (RPS) includes the motor-generator power supplies, sensors, relays, bypass circuitry, and switches that cause rapid insertion of control rods (scram) to shut down the reactor. It also includes outputs to the Integrated Plant Computer System (IPCS) and annunciators, although these latter two systems are not part of the RPS. Trip functions are summarized in Figure 7.2-1.

A completely redundant capability, the alternate rod insertion function of the control rod drive (CRD) system is provided to mitigate anticipated transient without scram (ATWS) events (see Subsection 7.6.1.18).

7.2.1.1.1.2 Classification

The RPS is classified as Safety Class 2, Category I, and Quality Group B.

7.2.1.1.1.3 Reference Design

The Fermi 2 RPS is similar, except for system size, to the Edwin I. Hatch, Unit 1 RPS. There are no differences other than those instrument panel locations within the plant and manual scram logic arrangement.

7.2.1.1.2 Power Sources

The RPS receives power from two high-inertia ac motor-generator sets (Figure 7.2-2). A flywheel provides high inertia sufficient to maintain voltage and frequency within 5 percent of rated values for at least 1 sec following a total loss of power to the drive motor.

Alternate power is available to reach the RPS buses. The 120-V ac supply bus A is available to RPS bus A, and the 120-V ac alternate supply bus B is available to RPS bus B.

The RPS power supplies have been modified to prevent the inadvertent application of out-of-tolerance voltage or frequency power to the RPS relay trip logic. The electrical protection assembly consists of a GE type TFJ-175A circuit breaker with an under-voltage release controlled by a protection logic circuit card. The protection logic disconnects the RPS logic from the RPS power supply whenever voltage or frequency exceeds normal tolerances.

The protection is redundant and includes each alternate power supply, as shown in Figure 7.2-2. The electrical protection assemblies (EPA) are packaged in enclosures that are mounted seismically on the outside wall of each RPS motor-generator set cubicle. Two assemblies are connected in electrical series between each source of RPS power and the respective RPS distribution panel. Controls for testing and operation are provided on each assembly along with status indication for the particular trip parameters. Following a trip, the breaker must be reset locally.

The EPA's are qualified to meet IEEE 344-1975 and IEEE 323-1974.

The EPA trip setpoints are within $\underline{+}$10 percent of nominal ac voltage and -5 percent of the nominal frequency of 60 Hz.

Each protection logic has an independent time delay adjustable from 0.3 to 3.6 sec to prevent spurious trips and the resulting scrams.

7.2.1.1.3 Equipment Design

7.2.1.1.3.1 Initiating Circuits

Neutron monitoring system (NMS) instrumentation is described in Section 7.6. Figure 7.2-3 clarifies the relationship between NMS channels, NMS logics, and the RPS logics. The NMS channels are part of the NMS. The NMS logics are part of the RPS. As shown in Figure 7.2-4, there are four NMS logics associated with each trip system of the RPS. Each RPS logic receives inputs from two NMS logics. Each NMS logic receives signals from one intermediate range monitor (IRM) channel and one average power range monitor (APRM) voter channel. The position of the mode switch determines which input signals effect the output signal from the logic. The NMS logics are arranged so that failure of any one logic cannot prevent the initiation of a high neutron flux scram. The RPS logic is a "one-out-of-two-taken-twice" system as discussed in Subsection 7.2.l.l.3.2.

Reactor pressure is measured at two locations. A pipe from each location is routed through the primary containment and terminates in the reactor building. Two panel-mounted pressure transmitters monitor the pressure in each pipe. Cables from these transmitters are routed to the main control room. One pair of the transmitters is physically separated from the other pair. Each transmitter provides a high-pressure signal to one channel. The transmitters are arranged so that two transmitters provide an input to trip system A and two transmitters provide an input to trip system B, as shown in Figure 7.2-5. The physical separation and the signal arrangement ensure that no single physical event can prevent a scram caused by nuclear system high pressure.

Reactor pressure vessel (RPV) low-water-level signals are initiated from differential pressure transmitters that sense the difference between the pressure due to a constant reference column of water and the pressure due to the actual water level in the vessel. A reference leg backfill system provides a continuous flow of water from the CRD charging header to the reactor water level reference legs. This flow prevents accumulation of non-condensable gases in the reference leg, and the associated erroneous high water level indication which could result from degassing in the reference leg upon system depressurization. The transmitters are arranged on two sets of taps in the same way as the nuclear system high pressure transmitters (Figure 7.2-5).

Two instrument lines attached to taps on the RPV, one above and one below the water level, are required for the differential pressure measurement for each transmitter. The two pairs of lines terminate outside the primary containment and inside the reactor building. They are physically separated from each other and tap off the RPV at widely separated points. Other systems sense pressure and level from these same pipes. The physical separation and signal arrangement ensure that no single physical event can prevent a scram due to RPV low water level.

Turbine stop valve closure inputs to the RPS come from valve stem position switches mounted on the four turbine stop valves. To provide the earliest positive indication of closure, each of the double-pole, double-throw switches opens before the valve is more than 10 percent closed. Either of the two channels associated with one stop valve can signal valve closure, as shown in Figure 7.2-6. The logic is arranged so that closure of three or more stop valves initiates a scram, when the reactor is operating above 29.5 percent of rated power.

Turbine control valve fast closure inputs to the RPS come directly from contacts of the relays that effect control valve fast closure. Operation of any two of these relays will initiate control valve fast closure. Fast closure of one control valve in each RPS logic will initiate a scram whenever the reactor is operating above 29.5 percent of rated power.

Position switches mounted on the eight main steam isolation valves (MSIVs) signal MSIV closure to the RPS. To provide the earliest positive indication of closure, each of the double-pole, double-throw switches is arranged to open before the valve is more than 10 percent closed. Either of the two channels associated with one isolation valve can signal valve closure. To facilitate the description of the logic arrangement, the position-sensing channels for each valve are identified and assigned to RPS logics as follows:

Valve Identification	Position-Sensing Channels	Trip Channel Relays	Assignments
Main steam line A, inboard valve	F022A (1) and (2)	A, B	A1, B1
Main steam line A, outboard valve	F028A (1) and (2)	A, B	A1, B1
Main steam line B, inboard valve	F022B (1) and (2)	E, D	A1, B2
Main steam line B, outboard valve	F028B (1) and (2)	E, D	A1, B2
Main steam line C, inboard valve	F022C (1) and (2)	C, F	A2, B1
Main steam line C, outboard valve	F028C (1) and (2)	C, F	A2, B1
Main steam line D, inboard valve	F022D (1) and (2)	G, H	A2, B2
Main steam line D, outboard valve	F028D (1) and (2)	G, H	A2, B2

Thus, each logic receives signals from the valves associated with two steam lines as shown in Figure 7.2-7. The arrangement of signals within each logic requires closing of at least one valve in each of the steam lines associated with that logic to cause a trip of that logic. For example, closure of the inboard valve of steam line A and the outboard valve of steam line C causes a trip of logic B1. This in turn causes trip system B to trip. No scram occurs because no trips occur in trip system A. In no case does closure of two valves or isolation of two steam lines cause a scram due to valve closure. Closure of one valve in any three steam lines causes a scram.

Wiring for the position-sensing channels from one position switch is physically separated in the same way that wiring to duplicate sensors on a common process tap is separated. The wiring for position-sensing channels feeding the different trip logics of one trip system is also separated.

The MSIV closure scram function is effective only if the reactor mode switch is in RUN.

The effects of the logic arrangement and separation provided for the MSIV closure scram are as follows:

a. Closure of one valve for test purposes with one steam line already isolated will not cause a scram resulting from valve closure

b. Automatic scram will occur on isolation of any three steam lines

c. No single failure can prevent an automatic scram required for fuel protection due to MSIV closure.

Four nonindicating level switches (one for each channel) provide scram discharge volume (SDV) high-water-level inputs to the four RPS channels. An additional level-indicating switch (trip unit), with transmitter, in each channel is redundant to the level switch in that channel. This arrangement provides diversity to ensure that no single event could prevent a scram caused by SDV high water level. With the scram setting listed in Table 7.2-1 and in the Technical Specifications, a scram is initiated when sufficient capacity remains in the SDV to accommodate a scram. Both the amount of water discharged and the volume of air trapped above the free surface during a scram have been considered in the selection of the trip setting.

Drywell pressure is monitored by four pressure transmitters as described in Subsection 7.3.2.2.8.f. The transmitters are physically separated and electrically connected to the RPS so that no single failure can prevent a scram caused by primary containment high pressure.

Main condenser low vacuum trip will be effected indirectly through main steam line isolation. A main condenser vacuum of approximately 7 PSIA will cause steam line isolation valve closure, which in turn causes reactor trip.

Four turbine first-stage pressure transmitters are provided to initiate the automatic bypass of the turbine control valve fast closure and turbine stop valve closure scrams when the first-stage pressure is below some preset fraction of rated pressure corresponding to 29.5 percent of rated power. The transmitters are arranged so that no single failure can prevent a turbine stop valve closure scram or turbine control valve fast closure scram.

Channel and logic relays are fast-response, high-reliability relays. Power relays for interrupting the scram pilot valve solenoids are magnetic contactors. The system response time, from the opening of a sensor contact up to and including the opening of the trip actuator contacts, is less than 50 msec. The time requirements for control rod movement are discussed in Subsection 4.5.2.

Sensing elements have enclosures to withstand conditions resulting from a steam or water line break long enough to perform satisfactorily. Environmental specifications for the instruments of the RPS are given in Table 3.11-1.

To gain access to those calibration and trip setting controls located outside the main control room, operations personnel must remove a cover plate, access plug, or sealing device before any trip setting can be adjusted.

Wiring for the RPS, outside of the enclosures in the main control room, is run in rigid metallic conduits used for no other wiring. The wires from duplicate sensors on a common process tap are run in separate conduits. Wires from sensors of different variables in the same RPS logic can be run in the same conduit.

The scram pilot valve solenoids are powered from eight actuator logic circuits, four circuits from trip system A and four from trip system B. The four circuits associated with any one trip system are run in separate conduits.

Electrical panels, junction boxes, and components of the RPS are prominently identified by nameplates. Circuits entering junction boxes or pull boxes are conspicuously marked inside the boxes. Wiring and cabling outside cabinets and panels are identified by color, tag, or other conspicuous means.

7.2.1.1.3.2 Logic

The basic arrangement of the RPS actuators and actuator logic is illustrated in Figure 7.2-8. The system is arranged as two separately powered trip systems. Each trip system has two automatic trip logics, as shown in Figure 7.2-9. Each logic used for automatic trip receives input signals from at least one channel for each monitored variable. At least four channels for each monitored variable are required, one for each of its four automatic trip logics.

Each automatic trip logic provides two inputs into each of the actuator logics of one trip system, as shown in Figure 7.2-8. Thus, either of the two automatic trip logics associated with one trip system can produce a trip-system trip. The logic is a "one-out-of-two" arrangement. To produce a scram, the actuator logics of both trip systems must be tripped. The overall logic of the RPS is termed "one-out-of-two taken twice."

7.2.1.1.3.3 Scram Bypasses

A number of manual and automatic scram bypasses are provided. These account for the varying protection requirements that depend on reactor conditions. They also allow for instrument service during reactor operations. All manual bypass switches are in the main control room under the direct control of the main control room operator. The bypass status of trip system components is continuously indicated in the main control room.

To properly reset the RPS at plant shutdown and during initial plant startup, a bypass is required for the MSIV closure scram trip. This bypass has been designed to be in effect when the mode switch is in the SHUTDOWN, REFUEL, or STARTUP position.

Hence, the bypass is necessary to provide for proper RPS reset action whenever the MSIVs are closed during very low power operation.

In the terms of the power generation design bases, the actual pressure scram setpoint is established from considerations of reducing reactor overpressure in the event of isolation at high power levels.

Since the high-pressure scram and reactor relief valves provide protection against overpressure, there would be no safety problem if the reactor were held at normal operating pressure and at a low power level with the MSIVs closed.

The scram initiated by placing the mode switch in SHUTDOWN is automatically bypassed after a short time delay. The bypass allows the CRD hydraulic system valve lineup to be restored to normal. An annunciator in the main control room indicates the bypassed condition. The turbine control valve fast closure scram and turbine stop valve closure scram are automatically bypassed if the turbine first-stage pressure is less then 29.5 percent of rated power. Closure of these valves from a low initial power level does not threaten the integrity of any radioactive material release barrier.

Turbine and generator trip bypass is effected by four pressure switches associated with the turbine first stage. Any one channel in a bypass state produces a main control room annunciation.

Bypasses for the NMS channels are described in Subsection 7.6.1.13.

The scram discharge high water level trip bypass is controlled by the manual operation of two keylocked switches, a bypass switch, and the mode switch. The mode switch must be in either the SHUTDOWN or the REFUEL position. Four bypass channels emanate from the four banks of the RPS mode switch and are each connected into the RPS logic. This bypass allows the operator to reset the RPS scram relays so that the system is restored to operation while the operator drains the scram discharge volume. In addition, actuating the bypass initiates a control rod block. Resetting the trip actuators opens the scram discharge volume vent and drain valves. An annunciator in the main control room indicates the bypass condition.

The RPS reset switch is used to momentarily bypass the seal-in contacts of the final actuators of the reactor shutdown systems. These seal-in contacts are located downstream from the protection channel outputs. The reset is effected in conjunction with auxiliary relays. If a single channel is tripped, the reset is accomplished immediately upon operation of the reset switch. On the other hand, if a reactor scram situation is present, manual reset is prohibited for a 10-sec period to permit the control rods to achieve their fully inserted position.

7.2.1.1.3.4 Interlocks

The scram discharge volume high-water-level trip bypass signal interlocks with the reactor manual control system (RMCS) to initiate a rod block. The interlock is performed using isolating relay contacts so that no failure in the control system can prevent a scram.

The RPV low water level, primary containment high pressure, and turbine stop valve position signals are shared with the primary containment and reactor vessel isolation-control system

(CRVICS). The sensors feed sensor relays in the RPS. Contacts from these relays interlock to the primary containment and reactor vessel isolation system.

7.2.1.1.3.5 Redundancy and Diversity

The RPS is divided into two divisions. Each division duplicates the function of the other to the extent that either may perform the required function regardless of the state of operation or failure of the other.

Functional diversity is provided by monitoring dependent RPV variables. Pressure, water level, and neutron flux are all interdependent and are separate inputs to the system. Also, MSIV closure, turbine stop valve closure, and turbine control valve fast closure are anticipatory of an RPV high pressure and are separate inputs to the system.

7.2.1.1.3.6 Actuated Devices

The actuator logic opens when a trip signal is received, and then deenergizes the scram valve pilot solenoids. There are two pilot solenoids per control rod. Both solenoids must deenergize to open the inlet and outlet scram valves to allow drive water to scram a control rod. One solenoid receives its signal from trip system A and the other from trip system B. The failure of one control rod to scram will not prevent a complete shutdown.

The individual control rods and their controls are not part of the RPS. Further information on the scram valves and control rods is contained in Subsection 4.5.2.

7.2.1.1.3.7 Separation

Four sensor channels monitor these various process variables listed in Subsection 7.2.1.1.3.1. Separation criteria for the sensors are given in Section 3.12. The sensor devices are separated in such a way that no single failure can prevent a scram. All protection system wiring outside the control system cabinets is run in rigid metal conduit. Six physically separated cabinet bays are provided for the four scram logics. Where two RPS channels of the same trip system enter the same bay they are separated by barriers.

The mode switch, scram discharge volume high-water-level trip bypass switch, scram reset switch, and manual scram switch are all mounted on one control panel. Each device is mounted in a can and has a sufficient number of barrier devices to maintain adequate separation. Conduit is provided from the cans to the logic cabinets.

The outputs from the logic cabinets to the scram valves are run in four conduits for trip system A and four conduits for trip system B. The four conduits match the four scram groups shown in Figure 7.2-2. The groups are selected so that the failure of one group to scram will not prevent a reactor shutdown.

7.2.1.1.3.8 Testability

The RPS can be tested during reactor operation by six separate tests. The first of these is the manual actuator test. By depressing the manual scram button for one trip channel, the manual actuators are deenergized, opening contacts in the actuator logics. After the first trip channel is reset, the remaining three manual trip channels are tested sequentially in a similar manner. The total test verifies the ability to deenergize all eight groups of scram pilot valve solenoids by using the manual scram pushbutton switches. In addition to main control room and sequence recorder indications, scram group indicator lights verify that the actuator contacts have opened.

The second test is the automatic actuator test. It is accomplished by operating the keylocked test switches one at a time for each automatic logic. The switch deenergizes the actuators for that logic and causes the associated actuator contacts to open. The test verifies the ability of each logic to deenergize the actuator logics associated with the parent trip system. In addition to annunciator and sequence recorder indications, the actuator and contact action can be verified by observing the physical position of these devices.

The third test includes calibration of the NMS by means of simulated inputs from calibration logic. Subsection 7.6.1.13 describes the calibration procedure.

The fourth test is the single rod scram test, which verifies capability of each rod to scram. It is accomplished by operating a toggle switch on the RPS test cabinet in the control center particular CRD. Timing traces can be made for each rod scrammed. Prior to the test, a physics review must be conducted to ensure that the rod pattern during scram testing will not create a rod of excessive reactivity worth.

The fifth test involves applying a test signal to each RPS channel in turn and observing that a logic trip results. The test signals can be applied to the process type sensing instruments (pressure and differential pressure) through calibration taps.

The sixth test involves applying a test signal to each RPS trip channel associated with the CRD Scram Discharge Volume High Water Level, Drywell High Pressure, Reactor High Pressure, Reactor Low Water Level, and NMS Trip and observing a trip relay contact closure using the RPS Test Box (RTB). The RTB lamp connected across the contacts of the trip relay during the functional test maintains circuit continuity and keeps the RPS Scram contactors energized while monitoring the status of the trip relay contacts (open/closed).

RPS response times are verified on a channel basis during preoperational testing and can be verified thereafter by similar tests with exception to the sensors. The neutron flux and radiation sensors, the primary sensor response time is included in the measurement of overall channel response time. This measured response time is added to an allowance for instrument line delay, as appropriate, for each application. This approach is consistent with the definition of response time, which is the maximum allowable time from when the variable being measured just exceeds the trip setpoint to the deenergizing of the control rod scram solenoids. The applicable test criterion is that the adjusted test-based value must not exceed the value used for the safety analysis.

During preoperational testing, and subsequently on a surveillance basis, the sensor response time was measured using a hydraulic ramp-test method similar to that described in Electric Power Research Institute Report No. NP-267, Sensor Response Time Verification. To the results of this measurement is added the delay for instrument line length as appropriate for each application. Also, the noise analysis method can be used for the sensor response verification.

The periodic response time testing for the reactor vessel steam dome pressure-high and the reactor vessel low water level-L3 have been eliminated. The BWROG Report NEDO-32291A and Supplement 1 provide the required analyses as briefly described in 7.2.1.1.3.8.1.

The response time of the trip comparators and trip delays is determined using the transient current source test method described in NEDO 21617-A, Analog Transmitters/Trip Unit System for Engineered Safeguard Sensor Trip Inputs. This test is performed as part of the preoperational test.

The balance of the RPS channel logic response time is tested using accepted methods that are documented in existing preoperational test procedures.

The reactor protection system instrumentation response times are shown in Technical Requirements Manual Volume I Table 3.3.1.1-1, which is referenced in UFSAR Table 7.2-4. Response time testing is required by the Technical Specifications. Technical Specification Table 3.3.1-2 was deleted from the Technical Specifications and added to the UFSAR as Table 7.2-4 (TRM Table 3.3.1.1-1) in agreement with NRC Generic Letter 93-08 and Amendment Number 100 to the Technical Specifications. The response times information of UFSAR Table 7.2-4 was then relocated to the Technical Requirements Manual Volume I.

7.2.1.1.3.8.1 Elimination of Response Time Testing

The elimination of selected response time testing requirements are supported by the analyses performed by the Boiling Water Reactor Owner's Group (BWROG) report. The BWROG report demonstrated that other periodic tests required by Technical Specifications (TS), such as channel calibrations, channel checks, channel functional tests, and logic system functional tests provide adequate assurance that instrument response times are within acceptable limits. The evaluation is documented in NEDO-32291A and Supplement 1, "System Analyses for Elimination of Selected Response Time Testing Requirements." The analyses assert that the response time tests are of little safety significance and result in unnecessary personnel radiation exposure, reduced availability of systems during plant shutdown, increased potential for inadvertent actuations of safety systems, and a significant burden to utility resources.

The basis for eliminating response time testing is consistent with Regulatory Guide 1.118 (Revision 2) which endorses IEEE 338-1977 which states:

> "Response time testing of all safety equipment, per se, is not required if, in lieu of response time testing, the response time of safety system equipment is verified by functional testing, calibration checks or other tests, or both. This is acceptable if it can be demonstrated that changes in response time beyond acceptable limits are accompanied by changes in performance characteristics which are detectable during routine periodic tests."

NEDO-32291A and Supplement 1 identify the potential failure modes of components in the affected instrumentation loops which could potentially impact the instrument loop response time. In addition, industry operating experience was reviewed to identify failures that affect response times and how they were detected. The failure modes identified were then evaluated to determine if the effect on response time would be detected by other testing requirements contained in TS. The results of this analysis demonstrate that other TS testing requirements (channel calibrations, channel checks, channel functional tests, and logic system functional tests) are sufficient to identify failure modes or degradations in instrument response times and assure operation of the analyzed instrument loops within acceptable limits. Furthermore, there were no failure modes identified that can be detected by response time testing that cannot also be detected by other TS-required tests.

A BWROG survey has concluded that instrument response time delays of 5 seconds can be reasonably detected by instrument technicians. A safety evaluation has confirmed that a 5-second increase in the response time of individual specific functions has a very low safety significance. This realistic bases evaluation showed that significant margin exists in the licensing analysis.

Within the trip function, redundancy exists in most safety trip functions (e.g., neutron flux, water level, drywell pressure). Also for most of these instruments, the response times are insignificant compared to the system actuation times.

NEDO-32291A and Supplement 1 are applicable to Fermi 2 and the affected components are evaluated in NEDO-32291A and Supplement 1. The vendors do not require periodic response time testing for these components. Fermi is in compliance with the guidelines of Supplement 1 to NRC Bulletin 90-01.

The recommendations from EPRI NP-7243 "Investigation of Response Time Testing Requirements" are:

1. The response time testing is required after replacing or refurbishing the transmitter (e.g., sensor cell, or variable damping) prior to returning the transmitters to service.
2. The transmitters that utilize capillary tubes are not used in any application that requires response time testing.

Furthermore, the technicians are in direct communication to verify that the response of the transmitter to the step input change or fast ramp is prompt, and in all cases less than five seconds. During this excursion, the transmitter/instrument loop is monitored for sluggishness or erratic operation that would be indicative of degraded transmitter/instrument loop performance.

The sensor response time may be assumed to be the design sensor response time. This will allow Fermi 2 to use manufacturer response time data and eliminate the requirement for a separate measurement of the sensor response time. Prior to return to service of a new transmitter or following refurbishment of a transmitter (e.g., sensor cell or variable damping components), a hydraulic response time test will be performed to determine an initial sensor-specific response time value.

7.2.1.1.4 Environmental Considerations

Electrical modules for the RPS are located in the primary containment, in the reactor building, and in the turbine building. The environmental conditions for these areas are shown in Tables 3.11-1 and 3.11-4.

Cabling for the RPS will be run in conduit or in an enclosed ferromagnetic cable tray. Separation will be in accordance with Section 3.12 and Subsection 8.3.1.

7.2.1.1.5 Operational Considerations

7.2.1.1.5.1 Normal

During normal operation, all sensor and trip contacts essential to safety are closed; channels, logics, and actuators are energized. In contrast, however, trip contact bypass channels consist of normally open contact networks that close to bypass.

7.2.1.1.5.2 Scram Functions

The following paragraphs discuss the functional considerations for the variables or conditions monitored by the RPS. Table 7.2-1 lists the preliminary specifications for instruments that provide signals for the system. Figure 7.2-1 summarizes the locations from which the RPS may receive a signal that causes a scram.

There are two pilot scram valves and two scram valves for each control rod, arranged as shown in Figure 7.2-2. Each pilot scram valve is solenoid operated, with the solenoids normally energized. The pilot scram valves control the air supply to the scram valves for each control rod. When either pilot scram valve is energized, air pressure holds the scram valves closed. The scram valves control the supply and discharge paths for CRD water. As shown in Figure 7.2-2, one of the scram pilot valves for each control rod is controlled by actuator logics A, and the other valve is controlled by actuator logics B. There are two dc solenoid-operated backup scram valves that provide a second means of controlling the air supply to the scram valves for all control rods. The dc solenoid for each backup scram valve is normally deenergized. The backup scram valves are energized (initiate scram) when trip systems A and B are both tripped.

The functional arrangement of sensors and channels that constitute a single logic is shown in Figure 7.2-2. A simplified logic schematic is included in Figure 7.2-9. When a channel sensor contact opens, its sensor relay deenergizes, causing contacts in the logic to open. The opening of contacts in the logic deenergizes its actuators. When deenergized, the actuators open contacts in all of the actuator logics for that trip system. This action results in deenergizing the scram pilot valve solenoids associated with that trip system (one scram pilot valve solenoid for each control rod). However, the other scram pilot valve solenoid for each rod must also be deenergized before the rods can be scrammed.

If a trip also occurs in any of the logics of the other trip system, the remaining scram pilot valve solenoid for each rod is deenergized. This permits the air to vent from the scram valves and allows CRD drive water to act on the CRD piston. Thus, all control rods are scrammed. The water displaced by the movement of each rod piston is vented into a scram discharge volume. When the solenoid for each backup scram valve is energized, the backup scram valves vent the air supply for the scram valve. This action initiates insertion of any errant control rods regardless of the action of the scram pilot valves (Figure 7.2-2).

A scram can be initiated manually. There are two sets of manual scram pushbuttons located on the surface of the main operating panel. The first set associated with logics A1 and B1 is located directly above the control rod pushbutton matrix on the "A" surface of the reactor control panel as shown on Figure 7.5-1. A second set of pushbuttons associated with logics A2 and B2 is located on the "B" surface of the reactor control panel as shown in Figure 7.5-1.

These pushbuttons are approximately 21 in. apart and 12 in. from the first set of the manual scram pushbuttons. Each of the four manual scram pushbuttons is individually canned and the control wiring is run in conduit within the control panel. To cause a manual scram, at least one button in each trip system must be depressed.

The manual scram pushbuttons in the first set are close enough to permit one hand motion to initiate the scram. By operating the manual scram button for one logic at a time and then resetting that logic, each actuator logic can be tested for manual scram capability. The reactor operator also can scram the reactor by interrupting power to the reactor protection system or by placing the mode switch in its shutdown position.

To restore the RPS to normal operation following any single trip system trip or scram, the actuators must be reset manually. The actuators can be reset only after a 10-sec delay, and only if the conditions that caused the scram have been cleared. The actuators are reset by operating switches in the main control room. Figure 7.2-2 shows the functional arrangement of reset contacts for trip system A.

When an RPS sensor trips, it lights a printed red annunciator window, common to all the channels for that variable, which indicates the out-of-limit variable. This window is located on the reactor control panel in the main control room. Each trip system lights a red annunciator window which indicates which trip system has tripped. An RPS channel trip also sounds a buzzer or horn that can be silenced by the operator. The annunciator window lights latch in until the initiating contact is reset. Reset is not possible until the condition causing the trip has been cleared. A sequence-of-events recorder identifies each tripped channel; however, the physical position of the RPS relays may also be used to identify the individual sensor that tripped in a group of sensors monitoring the same variable. The location of alarm windows permits the operator to quickly identify the cause of RPS trips and to evaluate the threat to the fuel or nuclear system process barrier.

All RPS trip events are recorded on a sequence-of-events recorder that includes nuclear steam supply system (NSSS) inputs. This record permits analysis of operational transient events that occur too rapidly for operator recognition.

The sequence-of-events recorder provides the time and alarm type of each event and can resolve the order of occurrence down to 1 msec. A lesser time difference causes the events to be treated as simultaneous.

Use of the events recorder is not required for plant safety. The printout of trips is particularly useful in routinely verifying the correct operation of pressure, level, and valve position switches as trip points are passed during startup, shutdown, and maintenance operations.

Reactor protection system inputs to annunciators, recorders, and the computer are arranged so that no malfunction of the annunciating, recording, or computing equipment can functionally disable the RPS. Direct signals from RPS sensors are not used as inputs to annunciating or data-logging equipment. Relay contact isolation is provided between the primary signal and the information output.

7.2.1.1.5.3 Operation Information

Indicators

Indicators are installed in the manual scram switches to indicate a trip system manual trip. Scram group indicators extinguish when an actuator logic opens. Process indicators for all RPS trip variables are available in the main control room.

Annunciators

Each RPS input is provided to the annunciator system through isolated relay contacts. Manual and automatic trip system trips also signal the annunciator system.

7.2.1.1.5.4 Setpoints

Nominal values for trip system setpoints are summarized in Table 7.2-1.

In response to the NRC letter from J. F. Stolz to W. H. Jens dated April 12, 1977, that defined specific requirements for instrument trip setpoint values, Edison has instituted a formal program with the cooperation of GE to develop the required technical data. The referenced setpoint data are presently included in the Technical Specifications.

Neutron Monitoring System Trip

To protect the fuel against high heat generation rates, neutron flux is monitored and used to initiate a reactor scram. The NMS setpoints and their bases are discussed in Subsection 7.6.1.13.

Nuclear System High Pressure

High pressure within the nuclear system threatens to rupture the nuclear system process barrier. A nuclear system pressure increase during reactor operation compresses the steam voids and results in a positive reactivity insertion. This causes increased core heat generation that could lead to fuel failure and system overpressurization. A scram counteracts a pressure increase by quickly reducing core fission heat generation. The nuclear system high-pressure scram setting is chosen slightly above the RPV maximum normal operating pressure to permit normal operation without spurious scram, yet provides a wide margin to the maximum allowable nuclear system pressure. The location of the pressure measurement, as compared to the location of highest nuclear system pressure during transients, has also been considered in the selection of the high-pressure scram setting. The nuclear system high-pressure scram setting also protects the core from exceeding thermal-hydraulic limits due to pressure increases during events that occur when the reactor is operating below rated power and flow.

Reactor Vessel Low Water Level

Low water level in the RPV indicates that the fuel is in danger of being inadequately cooled. Decreasing the water level while the reactor is operating at power decreases the reactor coolant inlet subcooling. The effect is the same as raising feedwater temperature. Should water level decrease too far, fuel damage could result. A reactor scram protects the fuel by reducing the fission heat generation within the core. The RPV low-water-level scram setting has been selected to prevent fuel damage following abnormal operational transients. These transients are caused by either single equipment malfunctions or single operator errors, and result in a decreasing RPV water level. The scram setting is far enough below normal operational levels to avoid spurious scrams. The setting is high enough above the top of the active fuel to ensure that enough water is available to account for evaporation loss and displacement of coolant following the most severe abnormal operational transient involving a level decrease. The selected scram setting was used in developing thermal-hydraulic limits. The limits set operational limits on the thermal power level for various coolant flow rates.

Turbine Stop Valve Closure

Closure of the turbine stop valve with the reactor at power can result in a significant addition of positive reactivity to the core as the nuclear system pressure rise causes steam voids to collapse. The turbine stop valve closure scram initiates a scram earlier than does either the NMS or nuclear system high pressure. It provides a satisfactory margin below core thermal-hydraulic limits for this category of abnormal operational transients. The scram counteracts the addition of positive reactivity resulting from increasing pressure by inserting negative reactivity with control rods. Although the nuclear system high-pressure scram, in conjunction with the pressure relief system, is adequate to preclude overpressurizing the nuclear system, the turbine stop valve closure scram provides additional margin to the nuclear system pressure limit. The turbine stop valve closure scram setting provides the earliest positive indication of valve closure.

Turbine Control Valve Fast Closure

With the reactor and turbine generator at power, fast closure of the turbine control valves can result in a significant addition of positive reactivity to the core as nuclear system pressure rises. The turbine control valve fast closure scram initiates a scram earlier than either the NMS or nuclear system high pressure. It provides a satisfactory margin to core thermal-hydraulic limits for this category of abnormal operational transients. The scram counteracts the addition of positive reactivity resulting from increasing pressure by inserting negative reactivity with control rods. Although the nuclear system high-pressure scram, in conjunction with the pressure relief system, is adequate to preclude overpressurizing the nuclear system, the turbine control valve fast closure scram provides additional margin to the nuclear system pressure limit. The turbine control valve fast closure scram setting is selected to provide timely indication of control valve fast closure.

Main Steam Line Isolation

The MSIV closure scram protects the reactor on loss of the heat sink. The MSIV closure initiates scram earlier than the NMS or nuclear system high pressure. Automatic closure of the MSIVs is initiated when conditions indicate a steam line break. The main steam line isolation scram setting is selected to give the earliest positive indication of isolation valve closure. The logic allows functional testing of main steam line trip channels with one steam line isolated.

Scram Discharge Volume High Water Level

Water displaced by the CRD pistons during a scram goes to the scram discharge volume. If the scram discharge volume fills with the water so that insufficient capacity remains for the water displaced during a scram, control rod movement would be hindered during a scram. To prevent this situation, the reactor is scrammed when the water level in the discharge volume is filling up, yet is low enough to ensure that the remaining capacity in the volume can accommodate a scram.

Primary Containment High Pressure

High pressure inside the primary containment may indicate a break in the nuclear system process barrier. It is prudent to scram the reactor in such a situation, to minimize the possibility of fuel damage and to reduce energy transfer from the core to the coolant. The drywell high-pressure scram setting is selected to be as low as possible without inducing spurious scrams.

Manual Scram

Pushbuttons are located in the main control room to enable the operator to shut down the reactor by initiating a scram.

Mode Switch in SHUTDOWN

When the mode switch is in SHUTDOWN, the reactor is to be shut down with all control rods inserted. This scram is not considered a protective function because it is not required to protect the fuel or nuclear system process barrier, and it bears no relationship to minimizing the release of radioactive material from any barrier. The scram signal is removed after a short delay, permitting a scram reset that restores the normal valve lineup in the CRD hydraulic system.

7.2.1.1.5.5 Mode Switch

A conveniently located, multiposition, keylock mode switch is provided to select the necessary scram functions for various plant conditions. The mode switch selects the appropriate sensors for scram functions and provides appropriate bypasses. The switch also interlocks such functions as control rod blocks and refueling equipment restrictions, which are not considered here as part of the RPS. The switch is designed to provide separation between the two trip systems. The mode switch positions and their related scram functions are

a. SHUTDOWN - Initiates a reactor scram; bypasses main steam line isolation scram

b. REFUEL - Selects NMS scram for low neutron flux level operation; bypasses main steam line isolation scram

c. STARTUP - Selects NMS scram for low neutron flux level operation; bypasses main steam line isolation scram

d. RUN - Selects NMS scram for power range operation.

7.2.1.2 Design-Basis Information

The design-basis information required by Section 3 of IEEE 279-1971 is provided in Subsection 7.1.2.1.1.

7.2.2 Analysis

7.2.2.1 General

Presented below are analyses to demonstrate how the various general functional requirements and the specific regulatory requirements listed under the RPS design bases described in Subsection 7.1.2.1.1.1 are satisfied. Considerations of loss of instrument air and loss of cooling water to vital equipment are discussed in Chapter 15.

7.2.2.2 Reactor Protection System

7.2.2.2.1 Conformance With General Functional Requirements

The RPS is designed to provide timely protection against the onset and consequences of conditions that threaten the integrity of the fuel barrier and the nuclear system process barrier. Chapter 15 identifies and evaluates events that jeopardize the fuel barrier and nuclear system process barrier. The methods of assessing barrier damage and radioactive material releases, along with the methods by which abnormal events are sought and identified, are presented in that chapter.

Design procedure has been to select tentative scram trip setting such that spurious scrams and operating inconvenience are avoided. It is then verified by analysis that the reactor fuel and nuclear system process barriers are protected. In all cases, the specific scram trip point selected is a value that prevents damage to the fuel or nuclear system process barriers, taking into consideration previous operating experience.

The scrams initiated by NMS variables, nuclear system high pressure, turbine stop valve closure, turbine control valve fast closure, and RPV low water level, prevent fuel damage following abnormal operational transients. Specifically, these scram functions initiate a scram in time to prevent the core from exceeding the thermal-hydraulic safety limit during abnormal operational transients. Chapter 15 identifies and evaluates the threats to fuel integrity posed by abnormal operational events. In no case does the core exceed the thermal-hydraulic safety limit.

The scram initiated by nuclear system high pressure, in conjunction with the pressure relief system, is sufficient to prevent damage to the nuclear system process barrier as a result of internal pressure. For turbine-generator trips, the stop valve closure scram and turbine control valve fast closure scram provide a greater margin to the nuclear system pressure safety limit than does the high pressure scram. Chapter 15 identifies and evaluates accidents and abnormal operational events that result in nuclear system pressure increases. In no case does pressure exceed the nuclear system safety limit.

The scrams initiated by the main steam line MSIV closure, and RPV low water level satisfactorily limit the radiological consequences of gross failure of the fuel or nuclear system process barriers. Chapter 15 evaluates gross failures of the fuel and nuclear system process barriers. In no case does the release of radioactive material to the environs result in exposures that exceed the guideline values of applicable published regulations.

Neutron flux is the only essential variable of significant spatial dependence that provides inputs to the RPS. The basis for the number and locations of neutron flux detectors is discussed in Subsection 7.6.1.13. The other requirements are fulfilled through the combination of logic arrangement, channel redundancy, wiring scheme, physical isolation, power supply redundancy, and component environmental capabilities.

The RPS uses "one-out-of-two-taken-twice" logic. Theoretically, its reliability is slightly higher than a "two-out-of-three" system and slightly lower than a "one-out-of-two" system. The differences can be neglected in a practical sense, however, because they are slight. The dual trip system is advantageous because it can be thoroughly tested during reactor operation without causing a scram. This capability for a thorough testing program significantly increases reliability.

The use of a different channel for each logic input allows the system to sustain any channel failure without preventing other sensors that monitor the same variable from initiating a scram. Any maintenance operation, calibration operation, or test results in only a single trip system trip. This leaves at least two channels per monitored variable capable of initiating a scram. The resistance to spurious scrams contributes to plant safety because reduced cycling of the reactor through its operating modes decreases the probability of error or failure.

When an essential monitored variable exceeds its scram trip point, it is sensed by at least two independent sensors in each trip system. Only one channel must trip in each trip system to initiate a scram. Thus, the arrangement of two channels per trip system ensures that a scram will occur as a monitored variable exceeds its scram setting.

Each control rod is controlled as an individual unit. A failure of the controls for one rod would not affect other rods. The backup scram valves provide a second method of venting the air pressure from the scram valves, even if either scram pilot valve solenoid for any control rod fails to deenergize when a scram is required.

Sensors, channels, and logics of the RPS are not used for control of process systems. Therefore, failure in the instrumentation and control of process systems cannot induce failure of any portion of the protection system.

Failure of either RPS motor-generator set would result, at worst, in a single trip system trip. Alternative power is available to the RPS buses. A complete, sustained loss of electrical power to both buses would result in a scram, delayed by the motor-generator set flywheel inertia.

The environment in which the instruments and equipment of the RPS must operate was considered in setting the environmental specifications given in Tables 3.11-1, 3.11-3, and 3.11-4. The specifications for the instruments located in the reactor or turbine buildings are based on the worst expected ambient conditions.

Design of the system to comply with safety class requirements and the fail-safe characteristics of the system ensure safe shutdown of the reactor during earthquake ground motion. The system fails in a direction that causes a reactor scram only when subjected to extremes of vibration and shock.

To ensure that the RPS remains functional, the number of operable channels for the essential monitored variables is maintained at or above the minimum given in Tables 7.2-2 and 7.2-3. The minimum applies to any untripped trip system; a tripped trip system may have any number of inoperative channels. Because reactor protection requirements vary with the mode in which the reactor operates, the tables show different functional requirements for the

RUN and STARTUP modes. These are the only modes in which more than one control rod can be withdrawn from the fully inserted position.

In case of a LOCA, reactor shutdown occurs immediately following the accident, as one or more process variables exceed their specified setpoint. Operation verification that shutdown has occurred may be made by observing one or more of the following indications:

a. Control rod status lamps indicating each rod fully inserted

b. Control rod scram pilot valve status lamps indicating open valves

c. Neutron monitoring power range channels and recorders downscale

d. Annunciators for RPS variables and trip logic in the tripped state

e. Sequence-of-events recorder log of trips

f. IPCS control rod position log.

7.2.2.2.2 Conformance To Specific Regulatory Requirements

7.2.2.2.2.1 Industry Standards

IEEE 279-1971

IEEE 279-1971 is satisfied as follows (except for manual scram, which is addressed below):

NEDO-10139, "Compliance of Protection Systems to Industry Criteria: General Electric BWR Nuclear Steam Supply System," demonstrates compliance of the RPS with IEEE 279-1968. The following paragraphs address the differences between IEEE 279-1968 and IEEE 279-1971 standards:

a. Paragraph 4.7 - Control and Protection System Interaction. The RPS interlocks to control systems only through isolation devices such that no failure or combination of failures in the control system will have any effect on the RPS

b. Paragraph 4.22 - Identification of Protection System. Each system cabinet is marked with the words "Reactor Protection System" and the particular redundant portion is listed on a distinctively colored marker plate. Cabling outside the cabinets is identified by color coding (as discussed in Subsection 8.3.1).

Exact design comparisons with the testability requirements of IEEE 279-1971 4.9, 4.10, and 4.11 are given in NEDO-10139:

a.	Scram discharge volume	Pages 2-26, 2-27
b.	Main steam line isolation valve	Page 2-39
c.	Turbine stop valve	Pages 2-56, 2-57
d.	Turbine control valve	Pages 2-69, 2-70

e.	Reactor water level	Page 2-99
f.	Deleted	
g.	Neutron monitoring system	Page 2-125 (Plus NEDC-32410P-A, Pages 4-5, 4-6)
h.	Drywell pressure	Page 2-138
i.	Reactor pressure	Page 2-146
j.	Mode switch	Pages 2-164, 2-165
k.	Discharge volume bypass	Pages 2-170, 2-171
l.	Main steam line valve bypass	Page 2-178
m.	Turbine trip bypass	Page 2-186

The RPS manual scram function satisfies IEEE 279-1971 as follows:

a. Paragraph 4.2 - Single Failure Criterion

RPS manual controls comply with the single failure criterion. Four manual scram pushbuttons are arranged into two groups on one main control room Bench Board and the switches are provided with physical and electrical separation.

b. Paragraph 4.3 - Quality of Components and Modules

The RPS manual switches are selected to be of high quality and reliability.

c. Paragraph 4.4 - Equipment Qualification

Manual switches and trip logic components are certified by the vendor that they perform in accordance with the requirements listed on the purchase specification as well as in the intended application. This certification, in conjunction with the existing field experience with these components in this application, serves to qualify these components.

d. Paragraph 4.5 - Channel Integrity

The manual switches and components are specified to operate under normal and abnormal conditions of environment, energy supply, malfunctions, and accidents.

e. Paragraph 4.6 - Channel Independence

The manual scram pushbutton is a channel component. The trip channels are physically separated and electrically isolated to comply with this design requirement.

f. <u>Paragraph 4.7 - Control and Protection System Interaction</u>

The manual scram pushbutton has no control interaction.

g. <u>Paragraph 4.8 - Derivation of System Inputs</u>

Not applicable.

h. <u>Paragraph 4.9 - Capability for Sensor Checks</u>

Not applicable.

i. <u>Paragraph 4.10 - Capability for Test and Calibration</u>

A manual scram switch permits each individual trip logic, trip actuator, and trip actuator logic to be tested on a periodic basis.

j. <u>Paragraph 4.11 - Channel Bypass or Removal from Operation</u>

Since actuation of one manual scram pushbutton places its RPS trip system in a tripped condition, it is in compliance with this design requirement.

k. <u>Paragraph 4.12 - Operating Bypasses</u>

Not applicable.

l. <u>Paragraph 4.13 - Indication of Bypasses</u>

Not applicable.

m. <u>Paragraph 4.14 - Access to Means for Bypassing</u>

Not applicable.

n. <u>Paragraph 4.15 - Multiple Set Points</u>

Not applicable.

o. <u>Paragraph 4.16 - Completion of Protective Action Once It Is Initiated</u>

Once the manual scram push buttons are depressed, it is only necessary to maintain them in that condition until the scram contactors have de-energized and open their seal-in contacts. At this point, the trip actuator logic proceeds to initiate reactor scram regardless of the state of the manual scram push buttons.

p. <u>Paragraph 4.17 - Manual Actuation</u>

Four manual scram pushbutton controls are provided on one main control room Bench Board to permit manual initiation of reactor scram at the system level. The four manual scram pushbuttons (one in each of the four RPS trip logics) comply with this design requirement. The logic for the manual scram is one-out-of-two twice. No single failure in the manual or automatic portions of the RPS can prevent either a manual or automatic scram.

q. <u>Paragraph 4.18 - Access to Set Point Adjustments, Calibration, and Test Points</u>

Not applicable.

r. Paragraph 4.19 - Identification of Protective Actions

When any manual scram pushbutton is depressed, a control room annunciation is initiated and an IPCS alarm record is produced to identify the tripped RPS trip logic.

s. Paragraph 4.20 - Information Readout

The manual scram function complies with this requirement.

t. Paragraph 4.21 - System Repair

The manual scram function complies with this requirement.

The RPS is fail-safe and its power supplies are thus unnecessary for scram. A total loss of power causes a scram. A loss of one power source causes a trip system trip. IEEE 308-1971 does not apply to the RPS.

IEEE 323-1971

"General Guide for Qualifying Class I Electric Equipment" is satisfied by complete qualification testing and certification of all essential components. Records covering all essential components are maintained. For a complete summary of how the RPS complies with IEEE 323-1971, refer to NEDO-10698. See also Section 3.11.

IEEE 336-1971

"Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During Construction of Nuclear Power Generating Stations" is satisfied except as modified by the Edison Quality Assurance Procedures.

IEEE 338-1971

"Periodic Testing of Protection Systems" is complied with by being able to test the RPS from sensors to final actuators at any time during plant operation. The test must be performed in overlapping portions.

IEEE 344-1971

Conformance to IEEE 344-1971 is described in Section 3.10.

IEEE 379-1972

"Trial-Use Guide for the Application of the Single-Failure Criterion to Nuclear Power Generating Station Protection Systems" is judged to be satisfied by the RPS design criteria described in NEDO-10139.

7.2.2.2.2.2 Conformance To Regulatory Guides and 10 CFR 50

The RPS is designed so that it may be tested during plant operation from sensor device to final actuator device in compliance with Regulatory Guide 1.22. The test must be performed in overlapping portions so that an actual reactor scram does not occur as a result of the testing.

The RPS is judged to comply with Regulatory Guide 1.53 since all of the additional provisions of Regulatory Guide 1.53 as applied to IEEE 379 are met or exceeded by the actual design.

10 CFR 50, Appendix B

"Quality Assurance Criteria for Nuclear Power Plants." A Quality Assurance program has been established that includes quality control at the component vendor, at the nuclear steam supplier, at various stages of construction, and during installation at the nuclear power plant site. System design is continually checked for conformance to the applicable industry criteria. Periodic testing ensures that the system is available and adequate to perform its intended purpose. Quality assurance records are maintained by the nuclear steam supplier and Edison. For a complete description of the Quality Assurance Program, see Chapter 17.

General Design Criteria of 10 CFR 50, Appendix A

a. Criterion 13 - Each RPS input is monitored and annunciated

b. Criterion l9 - Instrumentation and control is provided in the main control room. The reactor can also be shut down from outside the main control room by opening breakers

c. Criterion 20 - The RPS constantly monitors the appropriate plant variables to maintain the fuel barrier and primary coolant pressure boundary. It automatically initiates a scram when the variables exceed the established setpoints

d. Criterion 2l - The RPS is designed with four independent and separated output channels. No single failure or operator action can prevent a scram. The system can be tested during plant operation to ensure its availability

e. Criterion 22 - The redundant portions of the RPS are separated such that no single failure or credible natural disaster can prevent a scram. Functional diversity is used by measuring flux, pressure, and level (all dependent variables) in the reactor vessel

f. Criterion 23 - The RPS is fail-safe. A loss of electrical power or air supply will not prevent a scram. Postulated adverse environments will not prevent a scram

g. Criterion 24 - The RPS has no control function

h. Criterion 29 - The RPS is highly reliable so that it is able to scram in the event of anticipated operational occurrences.

7.2.2.2.2.3 Instrument Ranges and Setpoints

The design criteria used in selecting instrument span and trip setpoints for safety-related applications consider the following factors:

a. The selection of instrument range is based on knowledge of the expected variation of the process variable being monitored. In all cases, the range selected is greater than the expected variable excursions

b. The accuracy of each trip setpoint is better than or equal to the accuracy assumed in the accident analysis performed for the Fermi 2 plant design

c. Trip setpoints are normally located in the portion of the instrument range of greatest accuracy. In all cases, the setpoint is located in the portion of the instrument's range that is consistent with the required accuracy

d. All of the safety-related trip setpoints are chosen to allow for the normal expected instrument setpoint drift without exceeding associated Technical Specifications

e. All setpoints are verified on a prescribed schedule as outlined in the Technical Specifications.

TABLE 7.2-1 REACTOR PROTECTION SYSTEM INSTRUMENTATION SPECIFICATIONS

Scram Function	Instrument	Trip Setting[a]
Nuclear system high pressure	Pressure transmitter	1080 psig
Primary containment high pressure	Pressure transmitter	1.68 psig
RPV low water level	Level transmitter	173.4 in. above top of active fuel
Scram discharge volume high water level	Level switch/ transmitter	50 gal
Turbine stop valve closure	Position switch	Before 10 percent valve closure
Turbine control valve fast closure	Valve fast closure initiation logic	Start of control valve fast closure
Main steam line isolation valve closure	Position switch	Before 10 percent valve closure
Neutron monitoring system scram	Neutron detector	(IRM) 120/125 divisions of FS APRM) Refer to UFSAR Table 7.6-9 for APRM system trip setpoints.

[a] Nominal values given for information. See Technical Specifications for actual operational settings.

TABLE 7.2-2 CHANNELS REQUIRED FOR FUNCTIONAL PERFORMANCE OF REACTOR PROTECTION SYSTEM: STARTUP MODE

This table shows the normal and minimum number of channels required for the functional performance of the RPS in the STARTUP mode. The "Normal" column lists the normal number of channels per trip system. The "Minimum" column lists the minimum number of channels per untripped trip system required to maintain functional performance.

Channel Description	Normal	Minimum[a,b]
Neutron monitoring system (APRM)[c]	2	2
Neutron monitoring system (IRM)	2	2
Nuclear system high pressure	2	2
Primary containment high pressure	2	2
RPV low water level	2	2
Scram discharge volume high water level	2	2
Manual scram	2	2
Each main steam line isolation valve position	0 (bypassed)	0

[a] During testing of sensors, the channel should be tripped when the initial state of the sensor is not essential to the test.

[b] Nominal values given for information. See Technical Specifications for operational requirements.

[c] Number of channels refers to final two-out-of-four voter channels for APRM. See Technical Specifications for more specific requirements related to APRM channels.

TABLE 7.2-3 CHANNELS REQUIRED FOR FUNCTIONAL PERFORMANCE OF REACTOR PROTECTION SYSTEM: RUN MODE

This table shows the normal and minimum number of channels required for the functional performance of the RPS in the RUN Mode. The "Normal" column lists the normal number of channels per trip system. The "Minimum" column lists the minimum number of channels per untripped trip system required to maintain functional performance.

Channel Description	Normal	Minimum[a,b]
Neutron monitoring system (APRM)[c]	2	2
Nuclear system high pressure	2	2
Primary containment high pressure	2	2
RPV low water level	2	2
Scram discharge volume high water level	2	2
Manual scram	2	2
Each main steam line isolation valve position	4	4
Each turbine stop valve position	4	4
Turbine control valve fast closure	2	2
Turbine first-stage pressure (bypass channel)	2	2

[a] During testing of sensors, a channel may be placed in an inoperable status for up to 6 hr for required surveillance without placing the trip system in the tripped condition, provided that at least one operable channel in the same trip system is monitoring that parameter.

[b] Nominal values given for information. See Technical Specifications for operational requirements.

[c] Number of channels refers to final two-out-of-four voter channels for APRM including the OPRM function. OPRM/APRM functions are independently voted in the two-out-of-four voters. See Technical Specifications for more specific requirements related to APRM channels.

TABLE 7.2-4 (TRM TABLE 3.3.1.1-1) REACTOR PROTECTION SYSTEM RESPONSE TIMES

The Reactor Protection System Response Times are listed in Technical Requirements Manual (TRM) Volume I Table 3.3.1.1-1. TRM Volume I is incorporated by reference into the UFSAR.

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Refer to Plant Drawing I-2156-03

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FIGURE 7.2-1, SHEET 1

REACTOR PROTECTION SYSTEM SCRAM FUNCTIONS

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Refer to Plant Drawing I-2156-04

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FIGURE 7.2-1, SHEET 2

REACTOR PROTECTION SYSTEM SCRAM FUNCTIONS

Figure Intentionally Removed
Refer to Plant Drawing I-2156-01

Figure Intentionally Removed
Refer to Plant Drawing I-2156-02

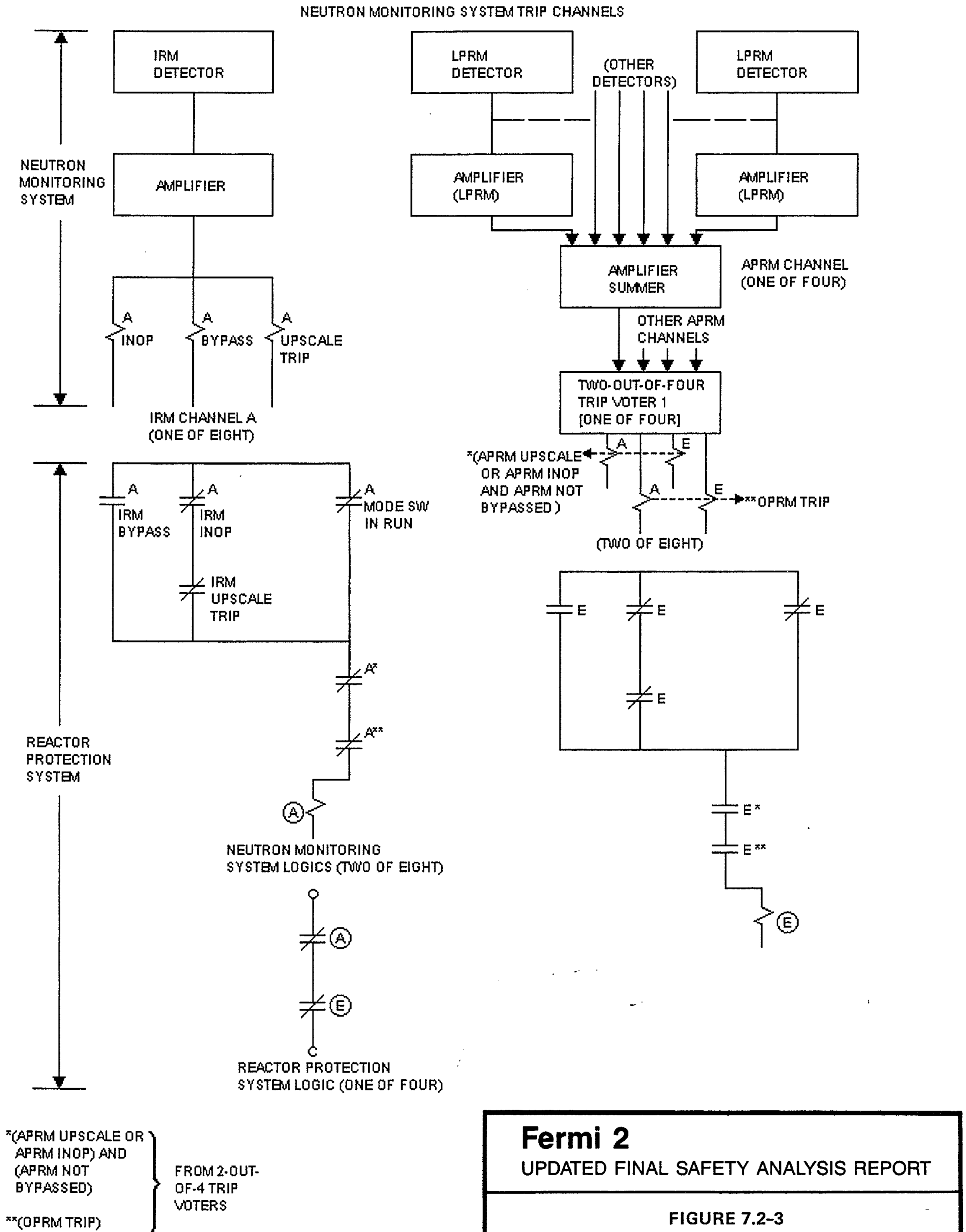

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FIGURE 7.2-3

RELATIONSHIP BETWEEN NEUTRON MONITORING SYSTEM AND REACTOR TRIP SYSTEM

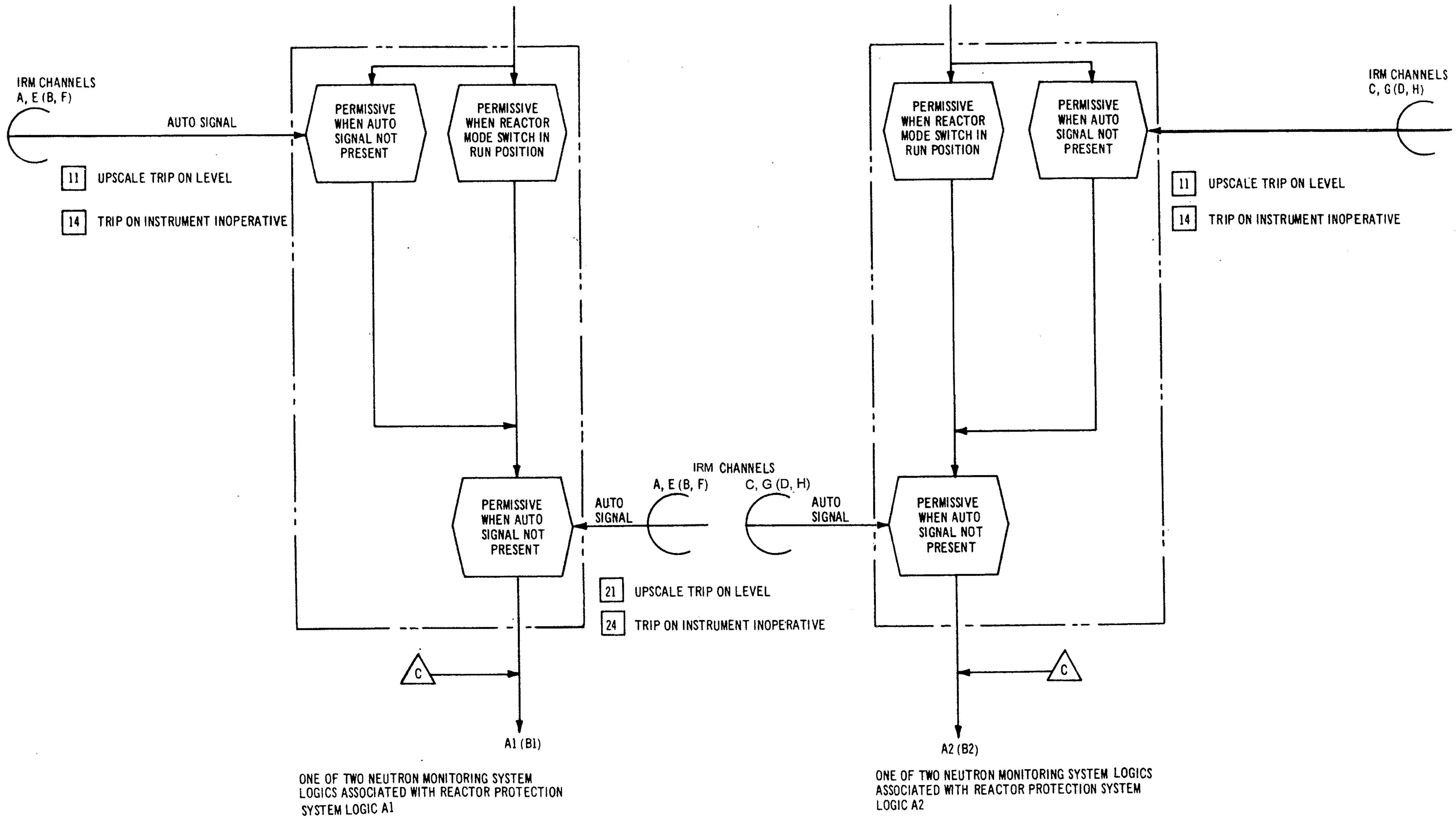

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FIGURE 7.2-4

NEUTRON MONITORING SYSTEM LOGICS

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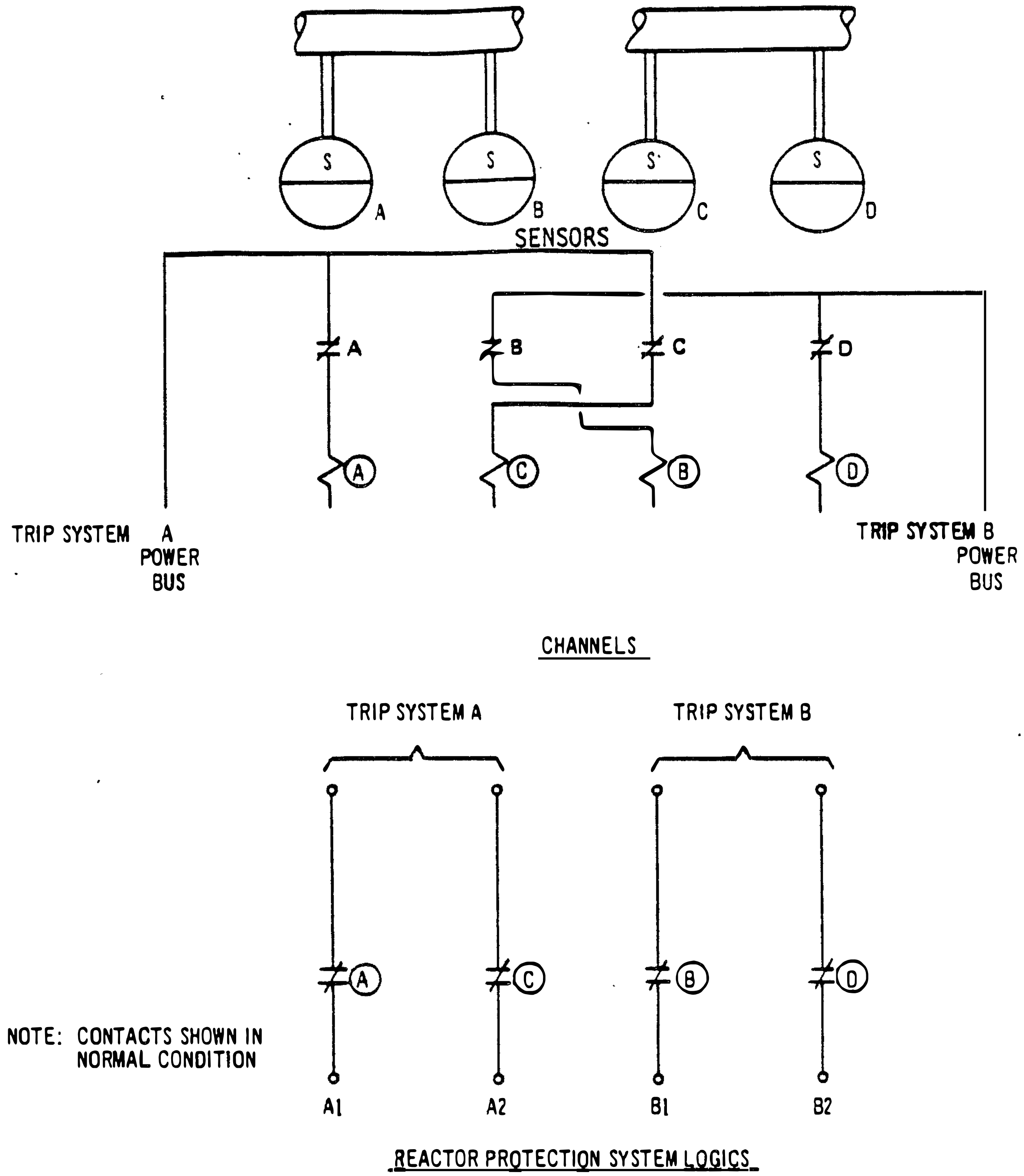

TYPICAL LOGIC & CHANNEL CONFIGURATION FOR:
SCRAM DISCHARGE VOLUME HIGH WATER LEVEL
TURBINE CONTROL VALVE FAST CLOSURE
REACTOR VESSEL LOW WATER LEVEL
PRIMARY CONTAINMENT HIGH PRESSURE
NUCLEAR SYSTEM HIGH PRESSURE

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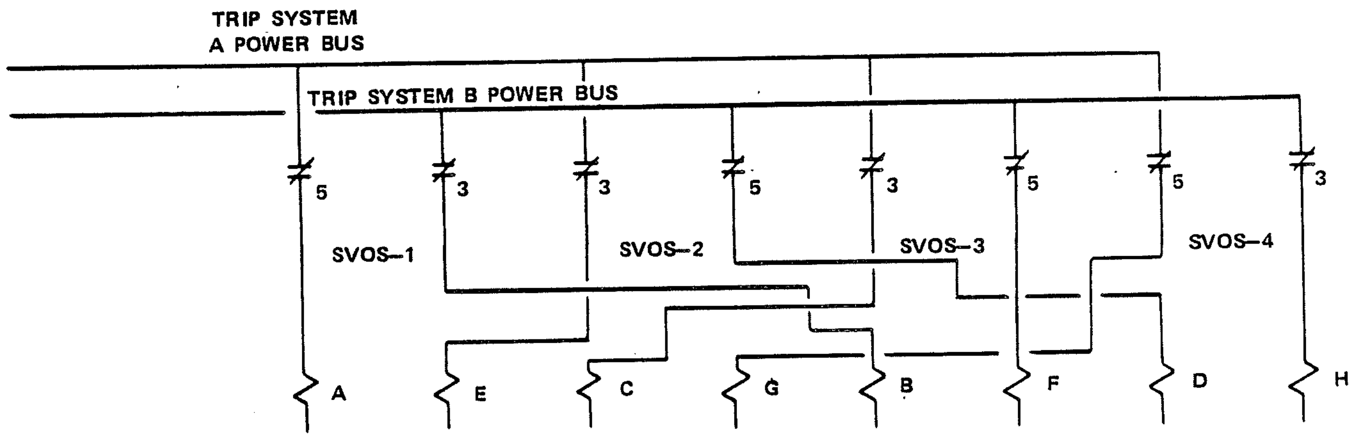
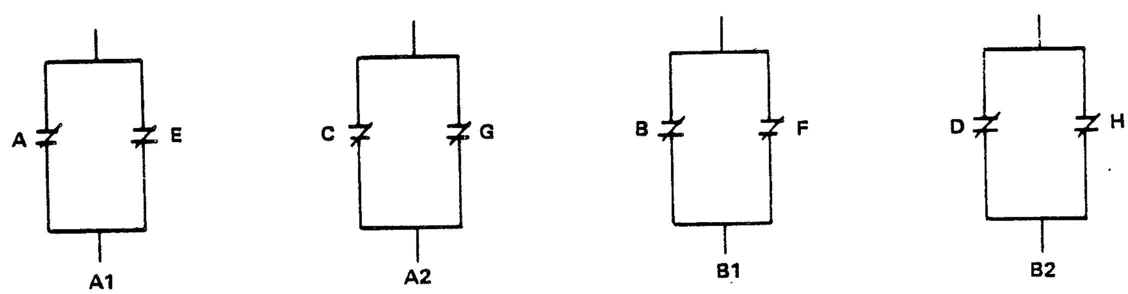
FIGURE 7.2-5

TYPICAL ARRANGEMENT OF CHANNELS AND LOGICS



TURBINE STOP VALVE CLOSURE CHANNELS



REACTOR PROTECTION SYSTEM LOGICS

NOTE: CONTACTS SHOWN IN NORMAL CONDITION

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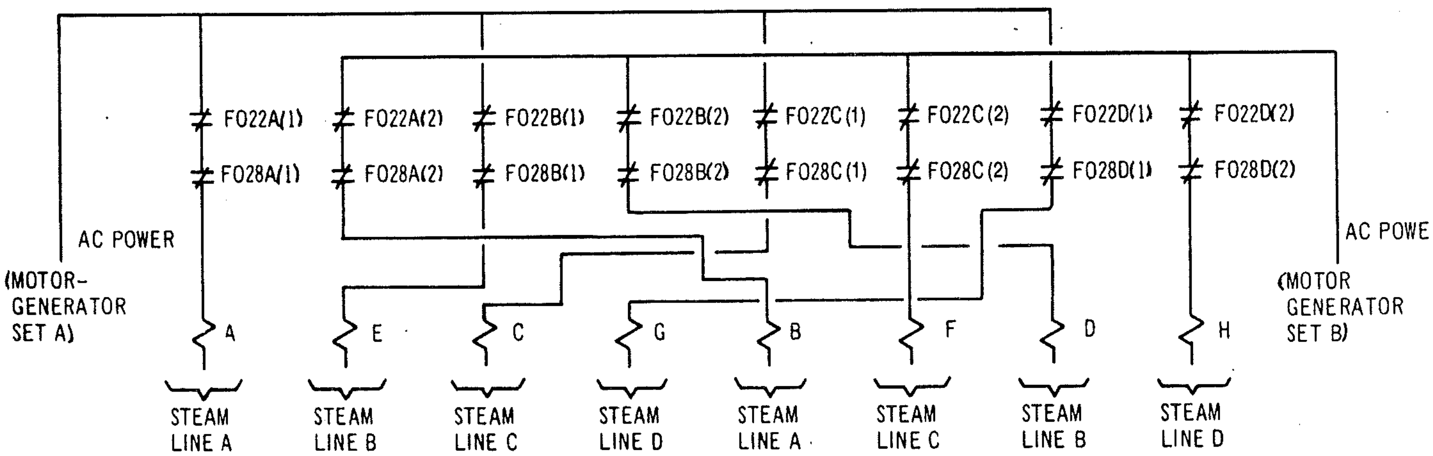
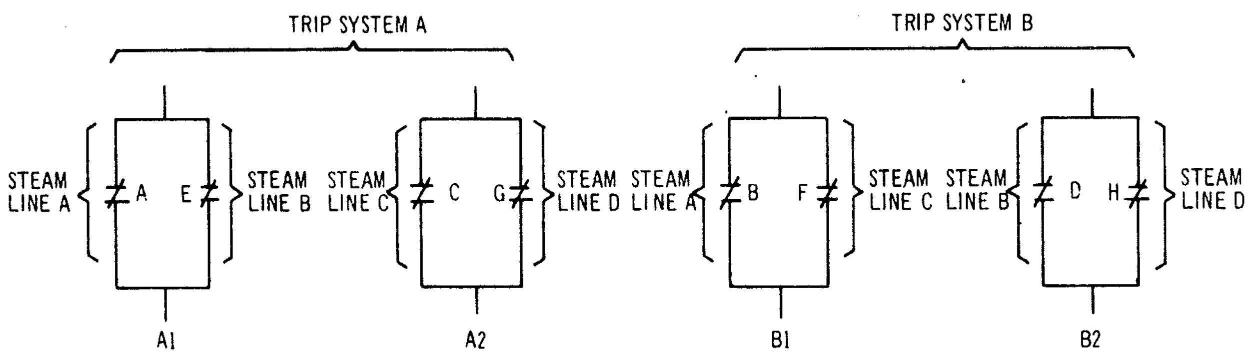
FIGURE 7.2-6

TYPICAL CONFIGURATION FOR TURBINE STOP CLOSURE REACTOR TRIP



MAIN STEAM LINE ISOLATION CHANNELS
(SWITCH CONTACTS SHOWN IN POSITIONS WHEN ISOLATION VALVES LESS THAN 10% CLOSED)



REACTOR PROTECTION SYSTEM LOGICS
(CONTACTS SHOWN IN NORMAL CONDITION)

KEY:
F022A - STEAM LINE A, INBOARD VALVE
F028A - STEAM LINE A, OUTBOARD VALVE
F022B - STEAM LINE B, INBOARD VALVE
F028B - STEAM LINE B, OUTBOARD VALVE
F022C - STEAM LINE C, INBOARD VALVE
F028C - STEAM LINE C, OUTBOARD VALVE
F022D - STEAM LINE D, INBOARD VALVE
F028D - STEAM LINE D, OUTBOARD VALVE

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FIGURE 7.2-7

TYPICAL CONFIGURATION FOR MAIN STEAM LINE ISOLATION REACTOR TRIP

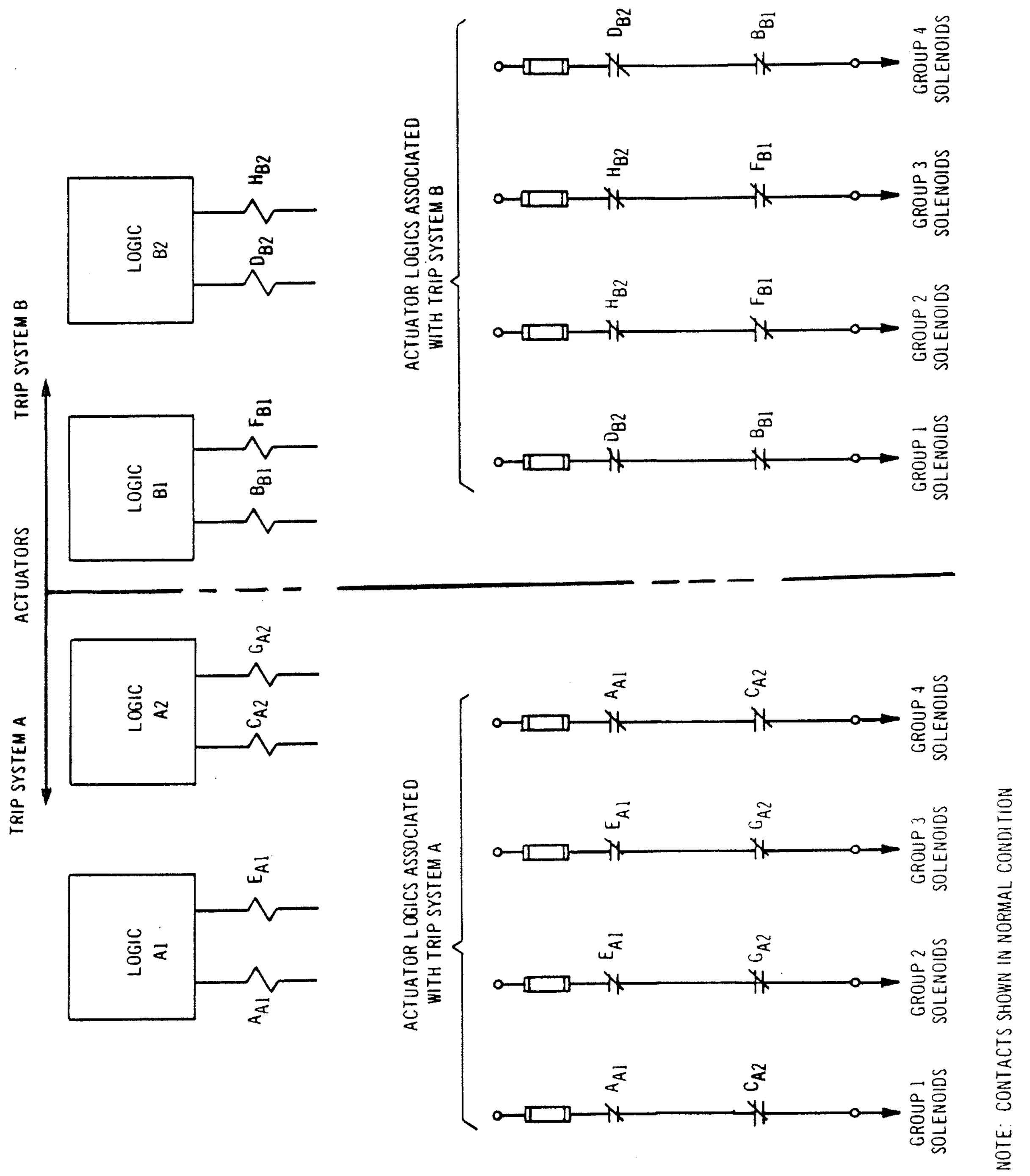

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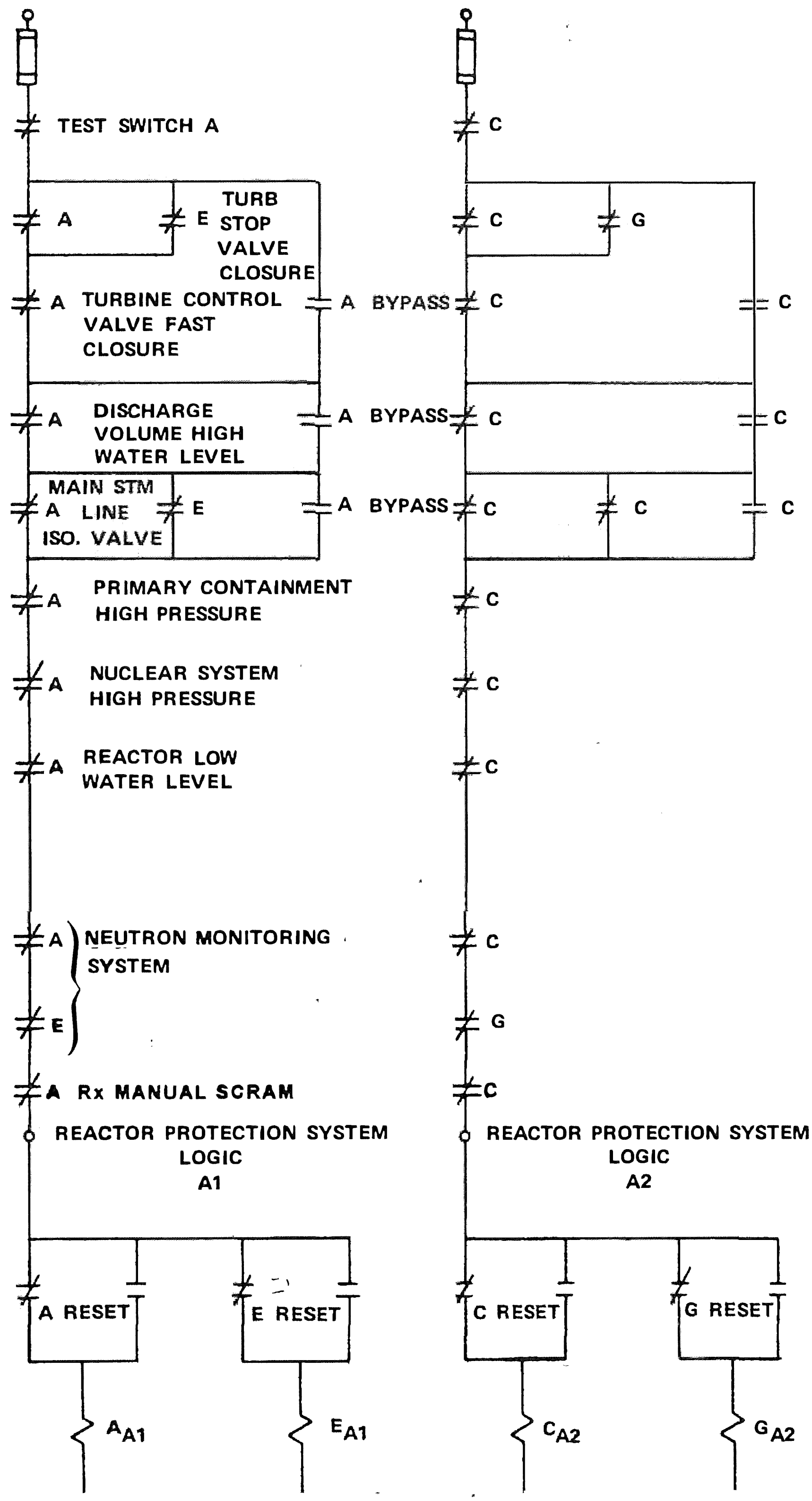
FIGURE 7.2-8

ACTUATORS AND ACTUATOR LOGIC



NOTE: CONTACTS SHOWN IN NORMAL OPERATING STATE

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FIGURE 7.2-9

LOGICS IN ONE TRIP SYSTEM

7.3 ENGINEERED SAFETY FEATURE SYSTEMS

Included in this section are descriptions and analyses of the instrumentation and controls for the following engineered safety feature (ESF) systems:

a. Emergency core cooling system (ECCS)

b. Primary containment and reactor vessel isolation control system

c. Emergency core cooling auxiliary system

d. Emergency equipment cooling water system

e. Main control room atmospheric control system

f. Standby gas treatment system

g. Standby power system

h. Deleted

The format of this section departs from the Regulatory Guide 1.70, Revision 2, Standard Format Guide in that the description and analysis are grouped together under each system heading rather than by descriptions and by analyses.

The main steam isolation valve leakage control system is discussed in Subsection 6.2.6.

7.3.1 Emergency Core Cooling System

7.3.1.1 Design-Basis Information

The design-basis information for the ECCS, required by Section 3 of IEEE 279-1971, is provided in Subsection 7.1.2.1.3.

7.3.1.2 System Description

The ECCS includes the following subsystems:

a. High-pressure coolant injection system (HPCI)

b. Automatic depressurization system (ADS)

c. Core spray system

d. Low-pressure coolant injection (LPCI) mode of the residual heat removal (RHR) system.

The purpose of ECCS instrumentation and control is to initiate appropriate responses from the ECCS to ensure that the fuel is adequately cooled in the event of a design-basis LOCA. The cooling provided by the system restricts the release of radioactive materials from the fuel by preventing or limiting the extent of fuel damage following situations in which reactor coolant is lost.

The equipment involved in the control of these systems includes automatic injection valves, steam turbine pump controls, electric pump controls, relief valve controls, and the switches, contacts, and relays that make up sensory logic channels. Testable check valves and certain automatic isolation valves are not included in this description since they are pertinent to the containment and reactor vessel isolation control system (CRVICS).

Power Sources

The instrumentation and control of the ECCS is powered by the 130-V dc and 120-V ac systems, and by the standby power system when required. The redundancy and separation of these power supply systems are consistent with the redundancy and separation of the ECCS instrumentation and control. Both of these power supply systems are described in detail in Chapter 8.

7.3.1.2.1 High Pressure Coolant Injection System Instrumentation and Control

When actuated, the HPCI system pumps water from either the condensate storage tank or the suppression chamber to the reactor pressure vessel (RPV) via the "A" feedwater pipeline. The HPCI system includes one turbine-driven pump, one dc motor-driven auxiliary oil pump, one barometric condenser dc condensate pump, one barometric condenser dc vacuum pump, other auxiliaries, automatic valves, control devices for this equipment, sensors, trip channels, and logic circuitry. The arrangement of equipment and control devices is shown in Figure 7.3-1.

Pressure and level transmitters used in the HPCI system are located on racks in the reactor building. The only operating component for the HPCI system that is located inside the primary containment is one of the two isolation valves in the HPCI turbine steam supply isolation valves. The rest of the HPCI system instrumentation and control components are located outside the primary containment. Cables connect the sensors to control circuitry in the main control room. The system is arranged to allow a full-flow functional test of the system during normal reactor power operation. The system will automatically return from the full-flow test mode to accident response operation.

The controls automatically initiate the HPCI system on receipt of either an RPV low water level signal or a primary containment high-pressure signal, and bring the system to its design flow rate, given in Section 6.3, within 60 sec. The controls then function to provide design makeup water flow to the RPV until the water level in the RPV reaches an upper limit. At this time the HPCI system shuts down until further need is indicated. The HPCI system would automatically restart on low water level and operate indefinitely without manual intervention. The controls are arranged to allow manual startup, operation, and shutdown from the main control room.

7.3.1.2.1.1 Initiating Circuits

The RPV low water level is monitored by four level transmitters that sense the differences between the pressure of a constant reference column of water and the pressure due to the actual height of water in the vessel. Two pipelines, attached to taps above and below the normal water level on the RPV, are required for the level transmitters. The lines are physically separated from each other and tap off the RPV at widely separated points. These same lines are also used for pressure and water level instruments for other systems.

A backfill system is installed on each level instrument reference leg. The system provides a metered flow of water from the control rod drive system to each leg. The flow is low enough to not affect the performance of the instrumentation. The backfill is designed to prevent the accumulation of dissolved noncondensable gases in the reference legs.

The level transmitters and primary containment high-pressure transmitters for the HPCI are arranged in pairs, with the transmitter contacts in a "one-out- of-two taken twice" electrical arrangement. This arrangement ensures that no single event can prevent HPCI initiation from RPV low water level or drywell high pressure. Cables from the level transmitters lead to the trip unit racks located in the fourth floor of the reactor building for logic and sequencing action.

The primary containment high-pressure initiation signal for the HPCI system uses output from the same trip unit that serves the RHR and core spray systems, as described in Subsection 7.3.1.2.3.

The HPCI system turbine is functionally controlled as shown in Figure 7.3-2. A speed governor limits the turbine speed to its maximum operating level. A control governor receives a pump flow signal and adjusts the turbine steam control valve so that design HPCI pump discharge flow rate is obtained. Manual control of the governor is possible in the test mode, but the governor automatically returns to automatic control on receipt of a HPCI initiation signal.

Figure 7.3-2 shows the various modes of turbine control. The flow signal used for automatic control of the turbine is derived from a differential pressure measurement across a flow element in the HPCI pump discharge line. The governor controls the pressure applied to the hydraulic operator of the turbine control valve, which in turn controls the steam flow to the turbine. Hydraulic pressure is supplied for both the turbine control valve and the turbine stop valve by the dc-powered oil pump during startup, and then by the shaft-driven hydraulic oil pump when the turbine reaches a certain speed.

On receipt of an initiation signal, the auxiliary oil pump starts, providing hydraulic pressure for the turbine stop valve and turbine control valve hydraulic operator. Since there is no flow at first in the HPCI system, the flow signal runs the control governor to the high speed stop. As hydraulic oil pressure is developed, the turbine stop valve and the turbine control valve open simultaneously, and the turbine accelerates toward the speed setting of either the control governor or the speed governor, whichever is lower. As HPCI flow increases, the flow signal adjusts the control governor setting so that rated flow is maintained. The turbine is automatically or manually shut down by tripping the turbine stop valve closed if any of the following signals are detected:

a. Turbine overspeed (automatic)

b. High turbine exhaust pressure (automatic)

c. Low pump suction pressure (automatic)

d. RPV high water level (automatic)

e. HPCI isolation signal (automatic)

f. Manual pushbutton

g. HPCI steam supply pressure low (automatic).

Turbine overspeed indicates a malfunction of the turbine control mechanism. High turbine exhaust pressure indicates a condition that threatens the physical integrity of the exhaust line. Low pump suction pressure warns that cavitation and lack of cooling can cause damage to the pump, which could place it out of service. A turbine trip is initiated for these conditions so that if the causes of the abnormal conditions can be found and corrected, the system can be quickly restored to service. The trip settings are selected far enough above or below normal values so that a spurious turbine trip is unlikely, but not too close to values that could cause damage before the turbine is shut down.

Turbine overspeed is detected by a standard turbine overspeed detection device. Two pressure transmitters are used to detect high turbine exhaust pressure; either transmitter can initiate turbine shutdown. One pressure switch is used to detect low HPCI pump suction pressure.

High water level in the RPV indicates that the HPCI system has performed satisfactorily in providing makeup water to the RPV. Further increase in level could result in HPCI turbine damage caused by gross carryover of moisture. The RPV high-water-level setting, which trips the turbine, is near the top of the steam separators and is sufficient to prevent gross moisture carryover to the turbine. Two level transmitters that sense differential pressure are arranged so that both transmitters are required to trip simultaneously to initiate a turbine shutdown.

UFSAR Section 7.5.1.4.2.1 describes that the wide-range water level system is uncompensated for variation in reactor water density and is calibrated to be most accurate at operational pressure and temperature conditions. At low reactor coolant temperatures and pressures, the higher water density causes the wide-range instruments to read higher than both the narrow-range instruments and the actual water level. Below approximately 550 psig, this phenomenon results in a wide-range level above the RPV high water level setting (Level 8) when the actual water level is normal (Reference 5). With wide-range level above Level 8, HPCI automatic initiation on the primary containment high-pressure signal and HPCI manual initiation are both inhibited by the Level 8 trip signal. HPCI automatic initiation on RPV low water level (Level 2) remains available since the Level 8 signal is automatically reset by the occurrence of a Level 2 actuation signal. For accidents occurring below 600 psig for which HPCI may be effective, analysis (Reference 5) has shown that HPCI automatic initiation at Level 2 is sufficient to perform the intended safety function and that the analyses of record from normal reactor pressure are bounding. Amendment 206 (Reference 6) revised the Technical Specifications to indicate that the HPCI functions of automatic initiation on primary containment high-pressure and manual initiation are not required to be operable below a reactor pressure of 550 psig.

The control scheme for the turbine auxiliary oil pump is shown in Figure 7.3-2. The controls are arranged for automatic manual control. On receipt of an HPCI initiation signal, the auxiliary oil pump starts and provides hydraulic pressure to open the turbine stop valve and the turbine control valve. As the turbine gains speed, the shaft-driven oil pump begins to supply hydraulic pressure. Should the shaft-driven oil pump malfunction, causing oil pressure to drop, the auxiliary oil pump restarts.

Operation of the barometric condenser components, which consist of the barometric condenser condensate pump (dc), the barometric condenser vacuum pump (dc), and the barometric condenser water level instrumentation, prevents outleakage from the turbine shaft seals. Operation of this equipment is automatic, as shown in Figure 7.3-2, and failure does not prevent the HPCI system from providing water to the RPV.

7.3.1.2.1.2 Logic and Sequencing

The RPV low water level and primary containment (drywell) high pressure are the two functions that can automatically start the HPCI system, as indicated in Figure 7.3-2 Sheet 1. The RPV low water level is an indication that reactor coolant is being lost and that the fuel is in danger of being overheated. Primary containment high pressure is an indication that a breach of the nuclear system process barrier has occurred inside the drywell.

The logic scheme used for the initiating functions is a "one-out-of-two taken twice" arrangement for both RPV low water level and high drywell pressure. Either one can initiate HPCI. The logic is powered from reliable dc buses. Level transmitters and drywell pressure transmitters are shared with core spray initiation.

Instrument settings for the HPCI system instrumentation and control are listed in Table 7.3-1. The RPV low water level (L2) setting for HPCI initiation is selected high enough above the active fuel to start the HPCI in time to prevent fuel clad failure and to prevent an unacceptable fraction of the core from reaching the temperature at which fuel fragmentation occurs (Section 6.3). The water level setting is far enough below normal levels that spurious HPCI system startups are avoided. The primary containment high-pressure setting is selected to be as low as possible without inducing spurious HPCI system startup.

To prevent the turbine pump from being damaged by overheating at reduced HPCI pump discharge flow, a pump discharge bypass is provided to route the water discharged from the pump to the suppression chamber. The bypass is controlled by an automatic, dc motor-operated valve whose control scheme is shown in Figure 7.3-2. At high HPCI flow, the valve is closed; at low flow, the valve is opened. Flow switches that measure the pressure difference across a flow element in the HPCI pump discharge line provide the signals used for flow indication.

The HPCI initially uses the condensate storage tank as the source of coolant to provide high-grade water to the reactor. A single failure of the condensate low-level switches or suppression pool high-level switches could cause a switchover of HPCI source water from the condensate storage tank to the suppression pool. A premature switchover has no adverse safety impact. The transfer to the suppression pool feature is to ensure an adequate long-term quantity of coolant or to control the pool level. The long-term source of water for the HPCI system is the suppression pool; thus a failure causes switchover to the desired suction source.

7.3.1.2.1.3 Bypasses and Interlocks

To prevent the HPCI steam supply line from filling up with water and cooling, a condensate drain pot, steam line drain, and appropriate valves are provided in a drain line arrangement just upstream of the turbine supply valve. The control scheme is shown in Figure 7.3-2. The controls position valves so that during normal operation, steam line drainage is routed to the main condenser. On receipt of an HPCI initiation signal, the drainage path is isolated. The water level in the steam line drain condensate pot is controlled by a level switch and a pilot air-operated solenoid valve that energizes to allow condensate to flow out of the pot.

During test operation, the HPCI pump discharge is routed to the condensate storage tank. Two valves, a dc motor operated valve (E4150F008) and an air operated valve (E41F011), are installed in the pump discharge to the condensate storage tank line. The piping arrangement is shown in Figure 7.3-1. The control scheme for the two valves is shown in Figure 7.3-2. On receipt of an HPCI system initiation signal, the two valves close and remain closed. The valves are interlocked to close if either of the suppression chamber suction valves are fully open. Valve E41F011 functions as a throttle valve while operating in the test mode. It is a fail-close globe valve with flow over the seat, capable of fast closure. It is credited for closure against pump shut off head. Valve E4150F008 is a slower motor operated valve which provides redundant isolation of the test line. If manual transfer from the test mode to vessel injection is desired, operator action is needed to close E41F011 prior to opening the HPCI injection valve. Numerous indications pertinent to the operation and condition of the HPCI system are available to the main control room operator. Figures 7.3-1 and 7.3-2 show the various indications provided.

7.3.1.2.1.4 Redundancy and Diversity

The HPCI system is actuated either by RPV low water level or by primary containment high pressure. Both of these conditions could result from a LOCA. The redundancy of the HPCI system initiating circuits is consistent with the design of the HPCI system. A single failure does not prevent activation.

7.3.1.2.1.5 Actuated Devices

All automatic valves in the HPCI system are equipped with remote manual test capability so that the entire system can be operated from the main control room. Motor-operated valves are provided with appropriate limit switches to turn off the motors when the fully open or fully closed positions are reached. Valves that are automatically closed upon isolation signals are equipped with manual reset devices so that they cannot be reopened without operator action. All essential components of the HPCI system controls operate independently of offsite ac power.

To ensure that the HPCI system can be brought to the design flow rate within 60 sec from the receipt of the initiation signal, the following operating times for essential HPCI system valves are provided by the valve operation mechanisms.

a. HPCI turbine steam supply valve - 50 sec

b. HPCI pump discharge valves - 40/50 sec

c. HPCI pump minimum flow bypass valve - 22.5 sec.

The operating time is the time required for the valve to travel from the fully closed to the fully open position, or vice versa. A HPCI steam supply line inboard isolation valve and the bypass valve around the HPCI outboard isolation valve are provided; they are intended to isolate the HPCI steam line in the event of a break in that line. A normally closed dc motor-operated isolation valve is located in the turbine steam supply line just upstream of the turbine stop valve. The piping and logic scheme for this valve is shown in Figures 7.3-1 and 7.3-2. On receipt of a HPCI system initiation signal, this valve opens and remains open until closed by operator action from the main control room.

Two isolation valves are provided in the steam supply line to the turbine. The valve inside the drywell is a Division I ac-powered valve that is normally open. The valve outside the drywell is a Division II dc-powered valve and is normally closed. A small bypass valve provides a warmup path around the closed valve to keep the turbine steam line free of water. The HPCI steam supply outboard isolation valve is signaled open on a HPCI initiation, and the HPCI steam supply inboard, and outboard isolation valves, and the bypass valve around the HPCI steam supply outboard isolation valve close automatically on a HPCI system isolation. The isolation signal takes precedence over the initiation signal. The control diagram is shown in Figure 7.3-2.

The primary element instrumentation for HPCI system isolation consists of the following:

a. Inside valve E41-F002

    1. Ambient temperature sensor - emergency area cooler high temperature. Isolation started as soon as activated

    2. Differential pressure transmitter - HPCI steam line high flow; a time delay has been added to this isolation to prevent spurious trips that could result from pressure spikes associated with pump startup

    3. Pressure transmitters - HPCI turbine exhaust diaphragm high pressure

    4. Pressure transmitters - HPCI steam supply pressure low.

b. Outside valve E41-F003 - Instrumentation similar to that described for the inside valve causes the outside valve to isolate if the conditions warrant isolation. Both valves can be individually actuated by manual pushbutton switches

    Three pump suction valves are provided in the HPCI system. One valve allows pump suction from the condensate storage tank while the other two series valves allow water to be taken from the suppression chamber. The condensate storage tank is the preferred source. All three valves are operated by dc motors. The control arrangement is shown in Figure 7.3-2

    On receipt of a HPCI system initiation signal, the condensate storage tank suction valve receives an open signal. If the water level in the condensate storage tank falls below a preselected level, the suppression chamber suction valves automatically open and the condensate storage tank suction valve automatically closes. Two level transmitters detect the condensate storage tank low-water-level condition. Either transmitter causes the suppression chamber suction valves to open and the condensate storage tank suction valve to close. The suppression chamber suction valves also automatically open if a high water level is detected in the chamber. Two level transmitters monitor the water level. Either transmitter can initiate opening of the suppression chamber suction valves. If open, the suppression chamber suction valves automatically close on receipt of the signals that initiate HPCI steam line isolation

    Two dc motor-operated HPCI pump discharge valves in the pump discharge pipeline are provided. The control schemes for these two valves are shown in

Figure 7.3-2. Both valves are arranged to open on receipt of either one of the HPCI system initiation signals. One of the pump discharge valves closes automatically on receipt of a turbine trip signal. The other valve remains open after HPCI system initiation until closed by the operator in the main control room.

7.3.1.2.1.6 Separation

General

Separation within the ECCS is such that no single failure can prevent core cooling. Instrumentation and control equipment and wiring are segregated into separate divisions designated Divisions I and II. Separate requirements are also maintained for the control and motive power for the ECCS. System separation is as follows:

Division I	Division II
Core spray pump A and pump C	Core spray pump B and pump D
Automatic depressurization	HPCI
RHR A and C	RHR B and D

Systems shown opposite each other are redundant. In addition, should HPCI fail to reduce RPV pressure through coolant makeup injection, the ADS will depressurize the RPV to allow LPCI and Core Spray to provide adequate core cooling. Control logic for all Division I systems is the 260/130-V dc Division I battery and for Division II systems is the 260/130-V dc Division II battery.

Specific

The HPCI system is a Division II system except for the HPCI main pump test line isolation valve E41F011, in which its motive force is fed from the interruptible air supply (note: the solenoid valves for E41F011 remain in Division II logic), and inside isolation valve E4150-F002, which is Division I ac powered. The E4150-F002 valve is controlled by logic operated from Division I 260/130-V dc battery so that no single failure can prevent the automatic closure of at least one valve of the pair of isolation valves. To maintain the required separation, HPCI system logic relays, instruments, and manual controls are mounted so that separation from Division I is maintained. Logic relays, instruments, and manual controls for outboard steam line isolation valve E41-F003 and bypass valve E41-F600 are separated from Division I equipment.

7.3.1.2.1.7 Testability

Instrumentation and control of the ECCS is designed to be completely testable during reactor operation. Specific test schedules for this and subsequent systems in this section (Section 7.3) are given in the Technical Specifications. Systems providing core cooling water are arranged with bypass valves so that pumps may be operated at design flow.

Instrumentation and control is designed to establish that the following functions are met:

a. Each instrument channel functions independently of all others

b. Sensing devices respond to process variables and provide channel trips at correct values

c. Sensors and associated instrument channels respond to both steady-state and transient changes in the process variable within specified accuracy and time limitations, and provide channel trips at correct values even when affected by process variations that may extend grossly beyond the expected trip setpoint

d. Paralleled circuit elements can perform their intended functions independently

e. Series circuit elements are free from shorts that can abrogate their function

f. Redundant instrument or logic channels are free from interconnecting shorts that could violate independence if a single malfunction should occur

g. No element of the system is omitted from the test if it could impair system operability in any way. (If the test is done in parts, then the parts must overlap sufficiently to ensure operability of the entire system)

h. Each monitoring alarm or indication function is operable.

The emergency core cooling system response times are shown in Technical Requirements Manual Volume I Table 3.3.5.1-1, which is referenced in UFSAR Table 7.3-11. Response time testing is required by the Technical Specifications. Technical Specification Table 3.3.3-3 was deleted from the Technical Specifications and added to the UFSAR as Table 7.3-11 (TRM Table 3.3.5.1-1) in agreement with NRC Generic Letter 93-08 and Amendment Number 100 to the Technical Specifications. The response times information of the UFSAR Table 7.3-11 was then relocated to the Technical Requirements Manual Volume I.

The periodic response time testing for the ECCS instrument channels has been eliminated. The BWROG Report NEDO-32291A provides the required analyses as briefly described in 7.2.1.1.3.8.1.

Specific

The HPCI system is provided with test jacks in each logic. The low reactor level or high drywell pressure "one-out-of-two taken twice" circuit can be tested completely by actuating only one instrument channel at a time. Insertion of the test plug at the logic relay panel actuates an annunciator in the main control room, indicating that the HPCI system is in test status.

7.3.1.2.1.8 Environmental Considerations

The control mechanism for the inboard isolation valve on the HPCI system turbine steam line is the only HPCI system control component located inside the primary containment that must remain functional in the environment resulting from a LOCA. The environmental capabilities of this valve are discussed in Subsection 7.3.2.2.9. The HPCI system instrumentation and control equipment located outside the primary containment is selected in consideration of the normal and accident environments in which it must operate. These conditions are listed in Table 3.11-3.

7.3.1.2.1.9 Operational Considerations

The HPCI system is not required for normal operations. Under the abnormal or accident conditions when it is required, initiation and control are provided automatically for at least 10 minutes. The automatic depressurization system (ADS) can also depressurize the reactor vessel to a point when the low pressure ECCS systems can be initiated to inject water into RPV. With the incorporation of the high drywell pressure signal bypass timer into the ADS automatic initiation logic, as discussed in Subsection 7.3.1.2.2.2, no operator actions are required to actuate ADS after any LOCA. When the bypass timer times out, the high drywell pressure initiation permissive signal is bypassed, and the ADS will be automatically initiated based on reactor vessel low water level signal alone. This is true even when the main steam line isolation valves (MSIV) line breaks outside the drywell and the break becomes isolated due to MSIV closure.

7.3.1.2.2 Automatic Depressurization System Instrumentation and Control

Automatically controlled relief valves are installed on the main steam lines inside the primary containment. The valves are dual purpose in that they relieve pressure either by normal mechanical action or by automatic action of an electric-pneumatic control system. Actuation is initiated on receipt of a signal indicating high drywell pressure, low RPV water level, and core spray and/or RHR pumps running. A time delay allows the operator to delay actuation if the HPCI system is in operation. The relief by normal mechanical action is intended to prevent overpressurization of the nuclear steam supply system (NSSS). If the HPCI system is not available during a small-break LOCA, the depressurization by automatic action of the ADS is intended to reduce NSSS pressure so that the core spray system or LPCI system can inject water into the RPV.

The automatic instrumentation and control equipment for the relief valves is described in this subsection. The instrumentation and control for one of the relief valves is discussed. Other relief valves equipped for automatic depressurization are identical.

The control system consists of pressure and water level sensors arranged in trip systems that control a solenoid-operated pilot air valve. The solenoid-operated pilot valve controls the pneumatic pressure applied to a bellows-actuator that operates the relief valve directly. An accumulator is included with the control equipment to store pneumatic energy for relief valve operation. The accumulator is sized to provide pneumatic pressure for five actuations of the pilot valve during interruptions if the pneumatic supply to the accumulator is switched from the normal to the emergency backup supply source.

Cables from the sensors lead to the trip unit racks located in the reactor building, where the logic arrangements are formed in cabinets. The electrical control circuitry is powered by dc power from the plant batteries. The power supplies for the redundant control circuits are selected and arranged to maintain tripping ability in the event of an electrical power circuit failure. Electrical elements in the control system energize to open the relief valve.

7.3.1.2.2.1 Initiating Circuits

The pressure and level transmitters used to initiate one ADS logic are separated from those used to initiate the redundant logic on the same ADS valve. Reactor pressure vessel low water level is detected by six transmitters that measure differential pressure. Primary containment high pressure is detected by four pressure transmitters. The primary containment high pressure signals are arranged to seal into the control circuitry. These signals must be manually reset to clear.

A timer is used in each ADS logic. The time delay setting before actuation of the ADS is long enough that the HPCI system has time to operate, yet not so long that the LPCI and core spray systems are unable to adequately cool the fuel if the HPCI system cannot. An alarm in the main control room is activated when either of the timers is timing. Resetting the ADS initiating signals recycles the timer. A display of the time remaining before the ADS actuates is available to the operator in the main control room.

7.3.1.2.2.2 Logic and Sequencing

The two initiating signals used for ADS are RPV low water level (level 1) and drywell high pressure. Simultaneous occurrences of RPV low water level and drywell high pressure conditions initiate a nominal 105 second time delay. After that time delay, ADS safety relief valves will operate if a sufficient number of low pressure ECCS pumps (RHR and/or core spray) are available for adequate core cooling. RPV low water level (level 1) signal also initiates a bypass timer which is set for a nominal 7 minutes. This time delay is provided to bypass the drywell high pressure permissive. If for some reason the drywell high pressure is not detected, the RPV low water level signal alone will actuate the ADS safety relief valves. The 7 minute bypass time delay, plus the original 105 second time delay and the permissive from appropriate ECCS pump discharge pressure will provide for ADS actuation. The instrument trip settings are given in Table 7.3-2.

Figure 7.3-6 shows the logic for ADS actuation, with the High Drywell Pressure Bypass Timer started on level 1. A nominal bypass timer time delay setpoint of 7 minutes was established for Fermi 2 from the unique analyses performed by General Electric, which is consistent with the analysis presented in NEDO-24708A (Figure Group 3.5.2.1-33). The results of these analyses demonstrate that adequate core cooling is ensured for isolation events, even with the ADS blowdown delayed after level 1 for an analytical time of 10 minutes. A subsequent confirmatory analysis established the adequacy of the bypass timer setpoint including increases in reactor rated thermal power to 3486 MWth (refer to Subsection 6.3.2.2 for analytical values).

Starting the bypass timer at level 1 allows the operator enough time to control the system manually and still ensure automatic depressurization in time to prevent excessive fuel heat-up, even under the worst-case conditions described above.

Primary containment high pressure indicates a breach in the nuclear system process barrier inside the drywell. For each logic train, a permissive signal indicating LPCI or core spray pump discharge pressure is also required. Discharge pressure on either of the two LPCI pumps or two of the core spray pumps (one discharge pressure sensor per pump) in the same division is sufficient to give the permissive signal. This signal prevents initiation of the ADS until the low-pressure ECCS is operating.

After receipt of the initiation signals and after a delay provided by timers, each of the solenoid pilot air valves is energized. This allows pneumatic pressure from the accumulator to act on the air cylinder operator. The air cylinder operator holds the relief valve open. Lights in the main control room indicate when the SRV is opened.

Manual reset switches are provided for the ADS initiation signal and primary containment high-pressure signals. By resetting these signals manually, the delay times are recycled. The operator can use the reset pushbuttons to delay or prevent automatic opening of the relief valves if such delay or prevention is prudent.

A manual inhibit switch is also provided for each ADS trip system. These switches allow the operator to inhibit ADS operation without repeatedly pressing the reset pushbuttons. Operation of the manual inhibit switch will activate a white indicating light and an annunciator to alert the operator of the inhibit action. Enabling the inhibit function will not terminate an ADS logic actuation after the 105 second time delay has elapsed. At this point, only the reset pushbutton can be used to affect the ADS operation. Refer to Subsection 6.3.2.17 for criteria in using the reset pushbutton switch.

Control switches are available in the main control room for each SRV associated with the ADS. The OPEN position is for manual SRV operation.

Two divisional ADS logic systems are provided: ADS "A,C" logic and ADS "B,D" logic (Figure 7.3-4). Division I sensors for low reactor water level and high drywell pressure initiate ADS "A,C" logic, Division II sensors initiate ADS "B,D" logic. Either ADS "A,C" logic or "B,D" logic actuates the solenoid pilot valve on each ADS valve.

The RPV low water level initiation setting for the ADS is selected to depressurize the RPV in time to allow adequate cooling of the fuel by the LPCI system or core spray system following a LOCA in which the HPCI system fails to perform its function adequately. The primary containment high-pressure setting is selected as low as possible without inducing spurious initiation of the ADS. This provides timely depressurization of the RPV if the HPCI system fails to start or fails after it successfully starts following a LOCA. Since the ADS is a backup for HPCI, different drywell pressure-sensing transmitters are used for ADS and HPCI.

The low-pressure pump discharge pressure setting used as a permissive for depressurization is selected to ensure that at least one of the four LPCI pumps or one of the core spray loops has received electrical power, has started, and is capable of delivering water into the RPV. The setting is high enough to ensure that the pump will deliver at near rated flow without being so low as to provide an erroneous signal indicating that the pump is actually running.

7.3.1.2.2.3 Bypasses and Interlocks

It is possible for the operator to manually delay the depressurizing action by depressing the timer reset pushbutton. The operator may also interrupt the depressurization at any time by the same action.

A manual switch is also provided to allow the operator to inhibit ADS operation (prior to its automatic initiation) instead of successively pressing the reset pushbuttons to reset the ADS timer.

The operator would make these decisions based on an assessment of other plant conditions.

7.3.1.2.2.4 Redundancy and Diversity

The ADS is initiated by a combination of high drywell pressure and low RPV water level. The initiating circuits for each of these parameters are redundant, as verified by the circuit description in this section.

7.3.1.2.2.5 Actuated Devices

All relief valves in the ADS are equipped with remote manual switches so that the ADS valves can be manually as well as automatically operated. The valves also relieve pressure by built-in mechanical action.

7.3.1.2.2.6 Separation

General

Refer to Subsection 7.3.1.2.1.6.

Specific

The ADS is a Division I system, but also makes use of Division II power and pneumatic supply. The "A,C" sensing and control logic is connected to the Section 1 half of the 260/130-V dc Division I battery. The "B,D" control logic is fed from the Section 2 half of the 260/130-V dc Division I battery, with automatic transfer to the Section 1 half. The "B,D" sensing and interposing relay circuitry (to the "B,D" control logic) is fed from the Division II battery.

Each valve is normally fed from the Section 1 half of the Division I battery, but each has a power monitor to automatically transfer to the Section 2 half of Division I battery on a power failure.

7.3.1.2.2.7 Testability

Refer to Subsection 7.3.1.2.1.7.

Specific

The ADS has two trip systems; either one can initiate automatic depressurization. Each trip system has two trip logics, both of which must trip to initiate depressurization. Four test jacks are provided, one in each trip logic. To prevent spurious actuation of the ADS during testing, only one trip logic is actuated at a time. An alarm is provided if a test plug is inserted on both trip logics. Operation of the test plug switch along with actuation of the ADS reactor level interlock and the ac interlock (RHR or core spray pumps running) closes one of the two series relay contacts in the valve-solenoid circuit. This causes a light to turn on, indicating proper trip logic operation. When the test is performed, continuity of the solenoid circuit is verified. Testing of the other trip logic and trip system is accomplished in a similar manner. Annunciation is provided in the main control room whenever a test plug is inserted to indicate ADS in test status.

7.3.1.2.2.8 Environmental Considerations

The signal cables, solenoid valves, pressure switches for indication, and SRV operators are the only instrumentation and control equipment for the ADS located inside the primary containment. They remain functional in the environment resulting from a LOCA. These items operate in the most severe environment resulting from a design-basis LOCA (Section 3.11). Gamma and neutron radiation is also considered in the selection of these items. Equipment located outside the drywell also operates in its normal and accident environments.

7.3.1.2.2.9 Operational Considerations

The instrumentation and control of the ADS is not required for normal plant operations. When automatic depressurization is required, it is initiated automatically by the circuits described in this section. No operator action is required for at least 10 minutes following initiation of the system.

A temperature element is installed on the SRV discharge piping several feet from the valve body. The temperature element is connected to a multipoint recorder in the main control room so that a means of detecting SRV leakage during plant operation is provided. When the temperature in any SRV discharge line exceeds a preset value, an alarm is sounded in the main control room. The alarm setting is enough above normal rated power temperatures to avoid spurious alarms, yet low enough to give early indication of SRV leakage.

7.3.1.2.3 Core Spray System Instrumentation and Control

The core spray system consists of two independent spray loops, as illustrated in Figure 7.3-7. The core spray system is capable of supplying sufficient cooling water to the RPV to adequately cool the core following a design-basis LOCA. The two spray loops are physically and electrically separated so that no single physical event makes both loops inoperable. Each loop includes two ac pumps, appropriate valves, and the piping to route water from the suppression chamber to the RPV.

The instrumentation and control for the core spray system includes the sensors, relays wiring, and valve-operating mechanisms used to start, operate, and test the system. Except for the testable check valve in each spray loop, which is inside the primary containment, the sensors and valve closing mechanisms for the core spray system are located in the reactor building.

Cables from the sensors are routed to the trip unit racks located in the auxiliary building, where the control circuitry is assembled in electrical panels. Each core spray pump is powered from a different ac bus which is capable of receiving standby power. The power supply for automatic valves in each loop is the same as that used for the core spray pump in that loop. Control power for each of the core spray loops comes from separate dc buses.

The electrical equipment for one core spray loop is located in a separate cabinet from that used for the electrical equipment for the other loop.

7.3.1.2.3.1 Initiating Circuits

Primary containment pressure is monitored by four pressure transmitters mounted on instrument racks outside the drywell, but inside the reactor building. Cables are routed from the transmitters to the relay logic cabinets. Each drywell high-pressure trip channel provides an input into the trip logic shown in Figure 7.3-8. Pipes that terminate in the reactor building allow the transmitters to communicate with the drywell interior.

Four drywell pressure transmitters are electrically connected to a "one-out-of-two taken twice" circuit as well as four water-level transmitters to both loops, so that no single event can prevent the initiation of the core spray system due to primary containment high pressure. Contacts from the primary containment high-pressure signal relays are also used in the HPCI, LPCI/RHR, and core spray systems.

Contacts from the RPV low water level (Level 1), initiation signal relays are used in the ADS, core spray, LPCI, and primary CRVICS systems.

7.3.1.2.3.2 Logic and Sequencing

The control scheme for the core spray system is illustrated in Figure 7.3-8. Trip settings are given in Table 7.3-3. The overall operation of the system following the receipt of an initiating signal is as follows:

a. Test bypass valves are closed and interlocked to prevent opening

b. If normal ac power is available, the core spray pumps in both spray loops start 5 sec after receiving the initiation signal

c. If normal ac power is not available, the core spray pumps in both spray loops start 5 sec after standby power becomes available to that particular pump

d. When the RPV pressure drops to a preselected value, valves open in the pump discharge lines, allowing water to be sprayed over the core.

The RPV low water level indicates that the core is in danger of being overheated due to loss of coolant. Drywell high pressure indicates that a breach of the nuclear system process barrier has occurred inside the drywell. The considerations used in establishing the RPV low water level and primary containment high-pressure settings and the instruments that provide the initiating signals are the same as those used for the HPCI system.

To prevent pump overheating at reduced core spray pump flow, a pump discharge bypass is provided from each loop. The bypass routes the discharge from both pumps in a loop back to the suppression chamber. The bypass is controlled by an automatic motor-operated valve whose control scheme is shown in Figure 7.3-8. At core spray high loop flow, the bypass valve is closed; at low flow, the bypass valve is opened. A flow switch measures the flow in each of the two loops.

7.3.1.2.3.3 Bypasses and Interlocks

During test operation, each core spray loop discharge can be routed to the suppression pool. Motor-operated valves are installed in the test lines. On receipt of a core spray initiation signal, the bypass valve closes and remains closed. The piping arrangement is shown in Figure 7.3-7; the control scheme for the two valves is shown in Figure 7.3-8.

7.3.1.2.3.4 Redundancy and Diversity

The core spray system is completely redundant with two independent spray loops. Initiation of the system is described in Subsection 7.3.1.2.3.1.

7.3.1.2.3.5 Actuated Devices

The control arrangements for the core spray pumps are shown in Figure 7.3-8. The circuitry provides for the detection of power available so that all pumps are automatically started. Each of the four pumps can be controlled by a main control room remote switch, or by the automatic control system. A pressure transducer on the discharge line from each core spray pump provides a signal in the main control room to indicate the successful startup of a pump. If a core spray initiation signal is received when normal ac power is not available, all core spray pumps start 5 sec after restoration of the particular bus voltage from which the pump motor receives power, and avoids overloading the source of standby power. The core spray pump motors are provided with overload protection. Overload relays are applied to maintain power as long as possible without immediate damage to the motors or emergency power system. Valve motors are protected by overload alarms and trips.

Flow measuring instrumentation is provided in each of the two core spray loop discharge lines. The instrumentation provides flow indication in the main control room.

Except where specified otherwise, the remainder of this description of the core spray system refers to one spray loop. The second core spray loop is identical. The control arrangements for the various automatic valves in the core spray system are indicated in Figure 7.3-8.

Each of the valves is equipped with limit switches to turn off the valve motor when the valve reaches the limits of movement. Appropriate interlocks prevent the incorrect positioning of the valves by manual action after the system has been automatically actuated. All motor-operated valves are equipped with limit switches that provide main control room indication of valve position. Each automatic valve can be operated from the main control room.

On receipt of an initiation signal, the test bypass valve is interlocked shut. Having received the initiation signal, the core spray pump discharge valves are automatically opened when NSSS pressure drops to a preselected value. The setting is selected low enough so that the low-pressure portions of the core spray system are not overpressurized, yet high enough to open the valves in time to provide adequate cooling for the fuel. Four pressure transmitters are used to monitor nuclear system pressure. The transmitters can initiate opening of the discharge valves on a "one-out-of-two taken twice" basis. The signal received on automatic core spray initiation overrides all other signals. The full-stroke operating times of the motor-operated pump discharge valves are selected to be rapid enough to ensure proper delivery of water to the RPV in a design-basis accident (DBA). The full stroke operation times are as follows:

a. Test bypass valve - 108 sec

b. Pump suction valve - 80 sec

c. Outboard pump discharge isolation valves - 13 sec

d. Inboard pump discharge isolation valves - 12 sec

7.3.1.2.3.6 Separation

General

Refer to Subsection 7.3.1.2.1.6.

Specific

The core spray system consists of independent Division I and II systems. Pumps A and C are in Division I and pumps B and D are in Division II. Two separate logics located in separate panels are used. Logic for the "A" loop is operated by the 260/130-V dc Division I battery and logic for the "B" loop is operated by the 260/130-V dc Division II battery.

7.3.1.2.3.7 Testability

General

Refer to Subsections 7.1.3.1 and 7.3.1.2.1.7.

Specific

The core spray system is provided with a test jack in both "A" and "B" logics. The low reactor level or high drywell pressure "one-out-of-two taken twice" circuit can be completely tested by only actuating one instrument channel at a time. Insertion of the test plug at either logic relay panel actuates an annunciator in the main control room, which indicates that the core spray system is in test status.

7.3.1.2.3.8 Environmental Considerations

The only control components pertinent to core spray system operation that are located inside the primary containment are those controlling the testable check valve on each of the two injection lines. Other equipment, located outside the drywell, is selected in consideration of the normal and accident environments in which it must operate (Table 3.11-3).

7.3.1.2.3.9 Operational Considerations

The core spray system is not required for normal operations. When it is required for accident conditions, it is initiated automatically by the circuitry described in this section. No operator action is required for at least 10 minutes following initiation. After this time, manual operation may be assumed by the operator.

Core spray system pressure between the two pump discharge valves is monitored by a pressure switch to permit detection of leakage from the nuclear system into the core spray system outside the primary containment. A detection system is provided to continuously confirm the integrity of the core spray piping between the inside of the RPV and the core shroud. A differential pressure switch measures the pressure difference between the bottom of the core and the inside of the core spray sparger pipe just outside the RPV. If the core spray sparger piping is sound, this pressure difference will be the pressure drop across the core. If integrity is lost, this pressure drop will include the core pressure drop and the steam separator pressure drop. An increase in the normal pressure drop initiates an alarm in the main control room. Pressure in the core spray pump suction line is monitored by a locally mounted pressure indicator to permit determination of suction head and pump performance.

7.3.1.2.4 Low-Pressure Coolant Injection Instrumentation and Control

Low-pressure coolant injection is an operating mode of the RHR system. The LPCI system is designed to provide water to the RPV following the design-basis LOCA.

Figure 5.5-13 shows the entire RHR system, including the equipment used for LPCI operation.

The instrumentation for LPCI system operation controls other valves in the RHR system. This ensures that the water pumped from the suppression chamber by the main system pumps is routed directly to the reactor. These interlocking features are described in this subsection.

Operation of the LPCI system uses four pumps and two loops, although only three out of four pumps are needed for LPCI cooling. Each loop injects into the reactor through the recirculation pump loop. Figure 5.5-13 shows the location of instruments, control equipment, and LPCI system components. Except for the LPCI system testable check valves, the components pertinent to LPCI system operation are located outside the primary containment.

Power for the LPCI system pumps is supplied from ac buses that can receive standby ac power. Each pump is powered from a separate bus. Motive power for the automatic valves comes from one of the lines that powers the pumps for that loop. Control power for the LPCI components comes from the dc buses.

The LPCI is arranged for automatic and remote manual operation from the main control room. Manual operation allows the operator to act independently of the automatic controls in the event of a LOCA.

7.3.1.2.4.1 Initiating Circuits

The two automatic initiation functions provided for the LPCI systems are RPV low water level and primary containment (drywell) high pressure. Either of these functions initiates the LPCI system.

The low level initiation signal for the LPCI system is a "one-out-of-two taken twice" circuit arrangement using relay contacts from the core spray system. It is used in conjunction with the primary containment high-pressure initiation signal. The high-pressure initiation signal uses pressure transmitters such as those described for the core spray system in Subsection 7.3.1.2.3. A discussion of the LPCI mode loop selection logic is provided in Subsection 6.3.2. Additional information can be found in Subsection 7.3.1.2.4.10.

7.3.1.2.4.2 Logic and Sequencing

The overall LPCI system operating sequence following the receipt of an initiation signal is as follows:

a. All four main system pumps start with no delay, taking suction from the suppression chamber. The valves in the suction paths from the suppression chamber are kept open so that no automatic action is required to line up suction, except when the system is lined up in shutdown cooling. For the loop in shutdown cooling, the suction path requires manual action to realign, and the operating pump(s) need to be reset after trip.

b. Valves used for other RHR operating modes (containment spray, RHR, etc.) are automatically positioned so that the water pumped from the suppression chamber is routed correctly

c. When nuclear system pressure has dropped to a value at which the LPCI system pumps are capable of injecting water into the vessel, the LPCI system injection valves automatically open. If a shutdown cooling isolation has occurred, then the logic needs to be manually reset to permit the LPCI system injection valves, F015A/B to open.

d. The LPCI loops then deliver water to the RPV until vessel water level is adequate to provide core cooling. Cooling water level is ensured since the pump is sealed in. The LPCI cannot be canceled for 5 minutes.

In the descriptions of the LPCI system instrumentation and control that follow, Figure 5.5-13 can be used to determine the physical location of sensors. Figure 7.3-9 can be used to determine the functional use of each sensor in the control circuitry for LPCI system components. Instrument characteristics and settings are given in Table 7.3-4. Actuation logic is shown in Figures 7.3-9 Sheets 1 and 2.

Additional information that provides a more detailed description of the differential pressure sensors used in the LPCI loop selection logic and additional clarification of the loop selection logic can be found in Subsection 7.3.1.2.4.10.

7.3.1.2.4.3 Bypasses and Interlocks

When an RHR loop is operating in the SDC mode, the loop is designed to isolate automatically on low reactor water level (i.e., Level 3) or high reactor pressure. If the system isolates on decreasing level before LPCI initiates (since Level 3 is higher than Level 1), the common SDC suction (E11F008 and 9) valves and the LPCI injection valves (E11F015A and B) in both divisions close, and pumps in the loop that is operating in the SDC mode trip on loss of suction path. The LPCI loop pumps that are lined up in standby mode are not affected. Under these circumstances, if LPCI injection is necessary, operator action would be necessary to align RHR to the LPCI mode. The LPCI injection valves' logic would have to be reset for both the loop in SDC and the loop in LPCI standby mode using the divisional push buttons in the control room. In the loop that was in SDC, the pump control logic would have to be reset before the pump could be started. The torus suction valves for the loop that was in SDC would have to be opened. All of these actions would be performed at the control room panels for the associated RHR loops.

As shown on Sheet 2 of Figure 7.3-9, there are three time-delay interlocks in the loop selection logic:

a. A 0.5-sec delay to determine if either recirculation loop is shut down (in which case, the other loop is also shut down)

b. A 2.0-sec delay to allow momentum effects to settle and system parameters to stabilize

c. A 0.5-sec delay while loop selection logic is being cycled.

Once the specific recirculation loop is selected for injection and the reactor pressure is below the RHR overpressure interlock setpoint, the RHR outboard and inboard valve circuits for that loop receive an OPEN permissive and a CLOSE block. The signal to the outboard valve is locked in for 5 minutes; this time is considered sufficient for the system to reflood the core to at least two-thirds of its height. Expiration of the 5-minute lock-in period does not initiate valve closure, but does give the operator the facility to throttle the flow.

The other loop, the loop not selected for LPCI injection, receives a CLOSE signal for 10 minutes when the loop selection is made. If the LPCI initiation signal remains, there is no capability in the logic to manually bypass the 10- and 5-minute delays in the loop selection logic. Once the loop is selected, the operator cannot change loops for 10 minutes.

To protect the main system pumps from overheating at low flow rates, a minimum flow bypass line is provided that routes water from the pump discharge to the suppression chamber. A motor- operated valve controls the flow in each bypass line. The minimum-flow bypass valve automatically opens on sensing low flow in the discharge line, and automatically closes when flow is above the low flow setting. Figure 5.5-13 shows the location of the flow sensors. The OPEN circuit contains a 25-sec delay permissive; this prevents loss of reactor vessel inventory to the suppression pool during shutdown cooling mode initiation.

The valves that divert water for containment cooling (F016, F021, F024, F027, F028) are signaled closed on receipt of an LPCI system initiation signal. These valves cannot be opened by manual action unless two conditions exist: the accident initiation signal indicating the need for containment cooling is present; and the RPV water level inside the core shroud is above the level equivalent to two-thirds the core height, which indicates that the pumps are not needed for the LPCI function.

Two differential-pressure transmitters are used to monitor water level inside the core shroud. Each is separately piped to the RPV. A keylock switch in the main control room allows manual override of the two-thirds core height and accident initiation signal permissives for the containment cooling valves.

The RHR heat exchanger bypass valve, F048, receives an OPEN and block CLOSE permissive from the LPCI initiation signal so maximum flow is available for injection. After 3 minutes, this permissive is blocked and the operator can manually close, throttle, or leave the valve in the open position.

7.3.1.2.4.4 Redundancy and Diversity

The LPCI system is redundant in that two separate loops are provided with pumps A and C feeding into loop A, and pumps B and D feeding into loop B. Loops A and B are tied together by means of a cross-header with a locked-open valve in the header. Initiation of the system is described in Subsection 7.3.1.2.4.

7.3.1.2.4.5 Actuated Devices

The functional control arrangement for the LPCI system pumps is shown in Figure 7.3-9. If ac power is available, all four LPCI system pumps start with no delay. Otherwise, they start as soon as the emergency power is available. The operator can manually control the pumps from the main control room. This permits him to use the pumps for other purposes such as containment cooling.

Two pressure-indicating transmitters are installed in each pump discharge line to verify that pumps are operating following an initiation signal. The pressure signal is used in the ADS to verify availability of low-pressure core cooling. The pressure transmitters are located upstream of the pump discharge check valves to prevent the operating pump discharge pressure from concealing a pump failure.

The main system pump motors are provided with overload protection. The overload relays maintain power on the motor as long as possible without harming the motor or jeopardizing the emergency power system.

All automatic valves used in the LPCI function are equipped with remote-manual test capability. The entire system can be operated from the main control room. Motor-operated valves have limit switches to turn off the motors when the fully open positions are reached. Torque switches are also provided to control valve motor forces when valves are closing. Thermal overload devices are used to trip motor-operated valves. Valves that have vessel and containment isolation requirements are described in Subsection 7.3.2.

The LPCI system pump suction valves from the suppression pool are normally open. To reposition the valves, a keylock switch must be turned in the main control room. On receipt of an LPCI initiation signal, certain reactor shutdown cooling system valves and the RHR test line valves are signaled to close, although they are normally closed, to ensure that the LPCI system pump discharge is correctly routed. Included in this set of valves are the valves that, if not closed, would permit the main system pumps to take suction from the reactor recirculation loops, a lineup used during normal shutdown cooling system operation.

A timer similar to that used in the LPCI system pump control circuitry cancels the LPCI open signal to the heat exchanger bypass valves after a 3-minute delay, which is time enough to permit satisfactory start of the LPCI system. The signal cancellation allows the operator to control the flow through the heat exchangers for other postaccident purposes. Canceling the open signal does not cause the bypass valves to close.

7.3.1.2.4.6 Separation

General

Refer to Subsection 7.3.1.2.1.6.

Specific

The LPCI system is a Division I and II system. Pumps A and C are in Division I, and pumps B and D are in Division II. Two separate logics located in separate panels are used. Logic for loop A (pumps A and C) is operated by the 260/130-V dc Division I battery and logic for loop B is operated by the 260/130-V dc Division II battery.

7.3.1.2.4.7 Testability

General

Refer to Subsection 7.3.1.2.1.7.

Specific

The LPCI system is provided with test jacks in each logic. The low reactor level or high drywell pressure "one-out-of-two taken twice" circuit can be completely tested by actuating only one instrument channel at a time. The other test jacks are used in the logic to facilitate testing as required. Insertion of the test plug in any jack actuates an annunciator in the main control room, indicating that LPCI is in test status.

7.3.1.2.4.8 Environmental Considerations

The only control components pertinent to LPCI system operation that are located inside the primary containment are those controlling the testable check valves on the injection lines. Other equipment, located outside the drywell, is selected in consideration of the normal and accident environments in which it must operate, as described in Table 3.11-3.

7.3.1.2.4.9 Operational Considerations

The LPCI system is a mode of the RHR system. The pumps, valves, piping, and other equipment used for the LPCI system are used for other modes of the RHR system. The LPCI mode is not required for normal operation.

7.3.1.2.4.10 Low-Pressure Coolant Injection Loop Selection Logic

Because the LPCI system injects water into the reactor through the discharge piping of one of the recirculation loops, it is necessary to make certain that the water is not injected into a broken recirculation loop. To satisfy this requirement, a break-detection system is provided to select the recirculation loop that is broken. This system then provides a signal that causes the LPCI water to be injected through the unbroken loop.

The location of the break in the recirculation system is determined by comparing the pressure of the two recirculation loops. The broken loop will indicate a lower pressure than the unbroken loop. The loop with the higher pressure is then used for LPCI injection or, if both pressures are the same, loop B is selected for injection. A diagram showing the relative physical location of the loop selection differential measurement can be found in Figure 5.5-2.

This logic system for break detection or loop selection is shown in Figure 7.3-9 and the details follow:

a. The entire LPCI system is activated by either high drywell pressure or reactor low water level. Each of these signals is of the one-out-of-two-twice type

b. The recirculation pump differential switches set up the network logic in the optimum arrangement depending on whether one pump or two pumps are operating. If only one pump is operating, the pressure difference due to the pump flow tends to mask the pressure difference due to the break. To avoid this, the loop selection time is delayed (0.5 sec) to determine if either recirculation pump is shut down and to allow proper selection of the unbroken loop. If only one pump is operating, the pump is tripped by the logic circuit

c. The reactor-vessel-pressure permissive delays the one- pump-operating side of the logic network until the reactor pressure has dropped to less than about 900 psig. The delay is added to provide time for the recirculation pump coastdown

d. After satisfaction of the reactor-pressure permissive mentioned above or if both recirculation pumps have indicated ΔP greater than the setpoint, the logic network is delayed about 2 sec to allow momentum effects to settle and system parameters to stabilize

e. Finally, the loop selection is made. If loop A pressure is greater than that of loop B, then loop B is broken and injection will occur in loop A. If the pressure at loop A is not greater than that at loop B, the 0.5-sec timer will run out, causing loop B to be selected. The 0.5-sec time delay allows the loop selection logic to function. The ΔP is measured from each recirculation loop riser pipe to the corresponding riser pipe on the other recirculation loop. The taps are located as close to the reactor vessel as possible. This arrangement provides a one-out-of-two-twice logic

   Loop selection differential pressure trip comparator set-points are adjusted to a value that gives the earliest valid indication of a break. The differential pressure comparator output contact is closed when the pressure in the recirculation pump A riser is approximately 1.0 psi higher than the pressure in the B recirculation pump riser

f. Once the specific recirculation loop is selected for injection and the reactor pressure is below about 500 psig, the RHR outboard and inboard valve circuits for that loop receive an "open" permissive and a "close" block.

Because of the design of the logic circuitry, all cases except when a loop B break is detected cause injection through loop B. The interconnecting line between both RHR loop discharge lines permits total injection to either recirculation loop. In the accident mode, the core is flooded to an adequate height and the level is maintained by the LPCI operating alone with three of four pumps operating. The design basis requires 30,000 gpm (three of four pumps). Injecting into both loops simultaneously would produce some loss of inventory due to a postulated break in one of the loops.

A complete description of the sensors and trip units is the main subject of NEDO-21617, Analog Transmitter/Trip Unit System for Engineered Safeguard Sensor Trip Inputs.

7.3.1.3 Analysis of the Emergency Core Cooling System

7.3.1.3.1 Conformance To General Functional Requirements

In Chapters 6 and 15, the individual and combined capabilities of the ECCS are evaluated. Consideration of failure in plant instrument air and loss of cooling water to vital equipment is presented in Chapter 15. The safety design bases mentioned below are given in Subsection

7.1.2.1.3. The control equipment characteristics and trip settings are described in Subsection 7.3.1.2 and were considered in the analysis of ECCS performance. For the entire range of nuclear process system break sizes, the cooling systems are effective both in preventing fuel-cladding failure and in preventing more than a small fraction of the reactor core from reaching the temperature at which a gross release of fission products can occur. This conclusion is valid even with significant failures in individual cooling systems because of the overlapping capabilities of the ECCS. The instrumentation and control for the ECCS satisfies the requirements of safety design basis Item a.

Safety design basis Item b. requires that instrumentation for the ECCS respond to the potential inadequacy of core cooling regardless of the location of a breach in the nuclear system process barrier. The RPV low water level initiating function, which alone can actuate HPCI, LPCI, and core spray, meets this safety design basis because a breach in the nuclear system process barrier inside or outside the primary containment is sensed by the low water level trip channels. Because of the isolation responses of the CRVICS to a breach of the nuclear system outside the primary containment, the use of the RPV low-water signal is satisfactory as the only emergency cooling system initiating function that is completely independent of breach location.

The other major initiating function, primary containment high pressure, is provided as a diverse backup to water level to ensure isolation of all NSSS breaches inside the primary containment. This second initiating function is independent of the physical location of the breach within the drywell. The method used to initiate the ADS, which employs RPV low water level and primary containment high pressure, requires that the nuclear system breach be inside the drywell because of the required primary containment high pressure signal. For breaks outside primary containment, or for breaks inside primary containment which do not result in primary containment high pressure, the primary containment high pressure permissive is bypassed after a time delay following a low reactor water signal. This control arrangement is satisfactory in view of the automatic isolation of the RPV by the CRVICS for breaches outside the primary containment, and because the ADS is required only if the HPCI fails. This meets Safety design basis Item b.

An evaluation of ECCS controls shows that no operator action is required to initiate the correct responses of the ECCS.

The alarms and indications provided to the operator in the main control room allow interpretation of any situation requiring ECCS operations, and verify the response of each system. Manual controls are illustrated on functional control diagrams. The main control room operator can manually initiate every essential operation of the ECCS.

The degree to which safety is dependent on operator judgment and response has been appropriately limited by the design of the ECCS control equipment. Therefore, safety design bases Items c.1., c.2., and d. of Subsection 7.1.2.1.3 are satisfied.

The redundancy provided in the design of the control equipment for the ECCS is consistent with the redundancy of the cooling systems themselves. The arrangement of the initiating signals for the ECCS which come from common sensors is the same as that provided by the dual trip system arrangement of the RPS. No failure of a single initiating trip channel can prevent the start of the cooling systems.

The numbers of control components provided in the design for individual cooling system components are consistent with the need for the controlled equipment. An evaluation of the control schemes for each ECCS component shows that no single control failure can prevent the combined cooling systems from providing the core with adequate cooling.

In performing this evaluation, the redundancy of components and cooling systems was considered. The functional control diagrams provided with the descriptions of cooling systems controls were used in assessing the functional effects of instrumentation failures. In the course of the evaluation, protection devices that can interrupt the planned operation of cooling system components were investigated for the results of their normal protective action as well as the effect of maloperation on core cooling effectiveness. The only protection devices that can act to interrupt planned ECCS operation are those that must act to prevent complete failure of the component or system. Examples of such devices are the HPCI turbine overspeed trip, HPCI steam line break isolation trip, pump trips on low suction pressure, and automatically controlled minimum flow bypass valves for pumps. In every case the action of a protective device cannot prevent other redundant cooling systems from providing adequate cooling to the core.

The minimum number of trip channels and sensors, as given in Tables 7.3-5 through 7.3-8, is sufficient to ensure correct functional performance of the ECCS. In determining the minimum number of trip channels needed to ensure functional performance, the use and redundancy of sensors in control circuitry and the redundancy of the controlled equipment in any individual cooling system were considered.

Where no redundancy of trip channels is available in the controls of a cooling system component required to function if the system is to operate, functional performance is not possible unless the trip channels are operable. Where two or more sensors of a monitored variable are arranged in parallel in control circuitry, inoperability of one parallel branch does not compromise performance of the system.

It should be noted that the various degrees of redundancy in control circuitry for the components of the ECCS reflect considerations for the integrated performance of the systems. The tables referenced in this subsection consider only the functional performance of each individual cooling system. To determine the proper state in which an inoperable sensor or trip channel should be placed, the functional effect of the channel and the proper action of the controlled equipment in a LOCA are considered. The condition given in the tables for inoperable sensors provides assurance that the essential functions of each individual ECCS are not degraded in a LOCA situation.

Because the control arrangement used for the ADS is designed to avoid spurious actuation, the information in Table 7.3-6 is worthy of special consideration. The relief valves are controlled by two trip systems, either one of which can initiate automatic depressurization. Each trip system has two trip logics, both of which must trip to initiate depressurization. Table 7.3-6 shows the minimum number of functional trip channels necessary for automatic depressurization.

The conditions indicated by Table 7.3-6 result in both trip systems always remaining capable of initiating automatic depressurization. If an inoperable sensor is in the tripped state or if a synthetic trip signal is inserted in the control circuitry, automatic depressurization can be initiated when the other initiation signals are received. The prohibition against simultaneously inoperative RPV low water level and primary containment high pressure trip channels in any one trip logic is necessary to prevent situations where a trip logic is continuously in the tripped condition. If the trip logics containing the timers are affected, the planned delay in automatic depressurization is eliminated. The trip channel conditions indicated in Table 7.3-6 avoid these undesirable situations.

The LPCI system logic arrangement for the injection valves and recirculation loop valves warrants special consideration in the evaluation of conditions affecting LPCI system performance. The LPCI system sensing circuit for break detection and valve selection is arranged so that failure of a single device or circuit to function on demand does not prevent correct selection of a loop for injection. The system is effective in providing the proper amount of coolant flow into the undamaged recirculation loop under all combinations of recirculation loop pumping conditions, break sizes, and break location.

The conditions represented by Tables 7.3-5 through 7.3-8 are the result of a functional analysis of each individual ECCS. Because of the redundancy in methods of supplying cooling water to the fuel in LOCA situation, and because it is the cooling of the fuel that must be ensured in such a situation, the minimum trip channel conditions in these tables are in excess of those required operationally to ensure core cooling capability. Operational requirements for the ECCS will be determined from the reliability aspects of the integrated performances of the systems when the specific characteristics of core cooling system components are known.

The locations of controls where operation of ECCS components can be adjusted or interrupted have been surveyed. Controls are located in areas under the surveillance of operations personnel.

The environmental capabilities of instrumentation for the ECCS are discussed in the descriptions of the individual systems. Components located inside the primary containment that are essential to ECCS performance are designed to operate in the environment resulting from a LOCA.

7.3.1.3.2 Conformance To Specific Regulatory Requirements

Conformance to Regulatory Guide 1.22 is discussed in Subsections 7.3.1.2.1 through 7.3.1.2.4. Conformance to the requirements of General Design Criteria (GDC) 13, 35, 36, and 37 of 10 CFR 50, Appendix A, is discussed in Subsections 7.3.1.2.1 through 7.3.1.2.4. The requirements of 10 CFR 50, Appendix B, are met as described in Chapter 17.

7.3.1.3.3 Conformance To IEEE 279-1971

The provisions of the HPCI, ADS, core spray, and LPCI systems design that fulfill the general requirements of IEEE 279-1971 are given, for the most part, in the GE Topical Report, Compliance of Protection Systems to Industry Criteria; General Electric BWR Nuclear Steam Supply System, NEDO-10139, Subsections 3.4.3, 3.5.2, 3.2.2, and 3.3.2, respectively.

The HPCI, ADS, core spray, and LPCI interlock no control systems; therefore, no failure or combination of failures in the control systems can have any effect on the HPCI, ADS, core spray, or LPCI system.

The ECCS equipment cabinets are identified by means of colored nameplates, in conformance with the 1971 identification requirements. Controls for each subsystem are grouped in one area of the control panel. Relays are located in separated panels for each division and subsystem.

7.3.1.3.4 Industry Standard IEEE 338-1971

The ECCS conforms to IEEE 338-1971.

7.3.1.3.5 Industry Standard IEEE 323-1971

Conformance to IEEE 323-1971 is described in NEDO-10698. See also Section 3.11.

7.3.1.3.6 Industry Standard IEEE 344-1971

Conformance to IEEE 344-1971 is described in NEDO-10678. See also Section 3.10.

7.3.2 Containment and Reactor Vessel Isolation Control System

7.3.2.1 Design-Basis Information

The design-basis information for the CRVICS, as required by Section 3 of IEEE 279-1971, is provided in Subsection 7.1.2.1.2 and is supplemented by the following:

a. To limit the uncontrolled release of radioactive materials to the environs, the CRVICS shall initiate, with precision and reliability, timely isolation of penetrations through the primary containment structure, which could otherwise allow the uncontrolled release of radioactive materials whenever the values of monitored variables exceed preselected operational limits

b. To provide assurance that important variables are monitored with a precision sufficient to fulfill safety design basis Item a., the CRVICS shall respond correctly to the sensed variables over the expected range of magnitudes and rates of change

c. To provide assurance that important variables are monitored with a precision sufficient to fulfill safety design basis Item a., an adequate number of spatially independent sensors are provided for monitoring essential variables that have spatial dependence

d. To provide assurance that conditions indicative of a gross failure of the nuclear system process barrier are detected with sufficient timeliness and precision to fulfill safety design basis Item a., CRVICS inputs shall be derived, to the extent feasible and practical, from variables that are true, direct measures of operational conditions

e. The time required for closure of the main steam isolation valves (MSIVs) shall be short, so that the release of radioactive material and the loss of coolant as a result of a breach of a steam line outside the primary containment are minimal

f. The time required for closure of the MSIVs shall not be so short that inadvertent isolation of steam lines causes a more severe transient than that resulting from closure of the turbine stop valves coincident with failure of the turbine bypass system. This basis ensures that the MSIV closure speed is compatible with the ability of the reactor protection system (RPS) to protect the fuel and nuclear system process barrier

g. To provide assurance that closure of Class A and Class B automatic isolation valves is initiated (Subsection 7.3.2.2.1) when required, with sufficient reliability to fulfill safety design basis Item a., the following safety design bases are specified for the systems controlling Class A and Class B automatic isolation valves:

    1. Any one failure, maintenance operation, calibration operation, or test to verify operational availability shall not impair the functional ability of the isolation control system to respond correctly to essential monitored variables, assuming no other single active failure

    2. The system shall be designed for a high probability that when any essential monitored variable exceeds the isolation setpoint, the event shall either result in automatic isolation or shall not impair the ability of the system to respond correctly as other monitored variables exceed their trip points

    3. Where a plant condition that requires isolation can be brought on by a failure or malfunction of a control or regulating system, and the same failure or malfunction prevents action by one or more isolation control system channels designed to provide protection against the unsafe condition, the remaining portions of the isolation control system shall meet the requirements of safety design bases Items a., b., c., and g.1.

    4. The power supplies for the CRVICS shall be arranged so that loss of one supply cannot prevent automatic isolation when required

    5. The system shall be designed so that, once initiated, automatic isolation action goes to completion. Return to normal operation after isolation action requires deliberate operator action

    6. There shall be sufficient electrical and physical separation between trip channels monitoring the same essential variable to prevent environmental factors, electrical faults, and physical events from impairing the ability of the system to respond correctly

    7. Earthquake ground motions shall not impair the ability of the CRVICS to initiate automatic isolation.

h. To ensure that the timely isolation of main steam lines is accomplished, when required, with extraordinary reliability, at least one of the isolation valves in each of the steam lines does not rely on continuity of any variety of electrical power for the motive force to achieve closure

i. To reduce the probability that the operational reliability and precision of the CRVICS are degraded by operator error, the following safety design bases are specified for Class A and Class B automatic isolation valves:

   1. Access to all trip settings, component calibration controls, test points, and other terminal points for equipment associated with essential monitored variables shall be under the physical control and supervision of the main control room operator

   2. The means for bypassing trip channels, trip logics, or system components is under the control of the main control room operator. If the ability to trip some essential part of the system has been bypassed, this fact shall be continuously indicated in the main control room.

j. To provide the operator with a means independent of the automatic isolation functions to take action in the event of a failure of the nuclear system process barrier, it shall be possible for the main control room operator to manually initiate isolation of the primary containment and RPV

k. The following bases are specified to provide the operator with the means to assess the condition of the CRVICS and to identify conditions indicative of a gross failure of the nuclear system process barrier

   1. The CRVICS is designed to provide the operator with information pertinent to the status of the system

   2. Means are provided for prompt identification of instrument channel and trip system responses.

l. It shall be possible to check the operational availability of each trip channel and trip logic during reactor operation.

7.3.2.2 System Description

7.3.2.2.1 Identification

Class A isolation valves are in lines that communicate directly with the RPV and penetrate the primary containment. These lines generally have two isolation valves in series, one inside the primary containment and the other outside the primary containment.

Class B isolation valves are in lines that do not communicate directly with the RPV, but penetrate the primary containment free space. These lines have two isolation valves in series, both of which are outside the primary containment.

Class C isolation valves are in lines that penetrate the primary containment, but do not communicate directly with the RPV, the primary containment free space, or the environs (closed systems). These lines require one isolation valve located outside the primary containment. The CRVICS includes the sensors, trip channels, switches, and remotely activated valve-closing mechanisms associated with the valves, which, when closed, effect isolation of the primary containment and/or the RPV.

It should be noted that the control systems for the Class A and Class B isolation valves, which close by automatic action pursuant to the safety design bases, are the main subjects of this section.

However, Class C remotely operated isolation valves are included because they add to the operator's ability to effect manual isolation. Testable check valves are also included because they provide the operator with the ability to ensure that the check valve disk can respond to reverse flow.

7.3.2.2.2 Power Supply

The two power supplies for the trip systems and trip logics are fed from the same two electrical buses that supply the RPS trip systems. Each of the buses has its own motor-generator set. Either bus can receive alternative power from a bus that can be energized by standby power. The buses cannot be simultaneously supplied from the same power source.

Isolation valves receive electrical power from buses that are reliable, in that power would be available from standby power sources except those isolation valves that are powered from the RPS. These valves automatically isolate on loss of offsite power. Power for the operation of the two valves in a line comes from different divisional sources. The MSIVs use ac, dc, and air or nitrogen pressure in the control scheme.

7.3.2.2.3 Physical Arrangement

Table 6.2-2 lists the lines that penetrate the primary containment and indicates the types and locations of the isolation valve(s) installed in each line. Lines that penetrate the primary containment and are in direct communication with the RPV generally have two Class A isolation valves, one inside the primary containment and one which is outside the primary containment. Lines that penetrate the primary containment and that communicate with the primary containment free space, but which do not communicate directly with the RPV, generally have two Class B isolation valves located outside the primary containment.

Class A and Class B automatic isolation valves are considered essential for protection against the gross release of radioactive material in the event of a breach in the nuclear system process barrier. Process lines that penetrate the primary containment but do not communicate directly with the RPV, the primary containment free space, or the environs, have at least one Class C isolation valve located outside the primary containment. This Class C valve may close either by process action (reverse flow) or by remote manual operation.

Table 6.2-2 presents information about all piping penetrations in the primary containment. Only the controls for the automatic isolation valves are discussed in this subsection. The valves that are the subject of this text are specially identified in the detailed descriptions that follow.

Power cables are run in conduits from appropriate electrical sources to the motor or solenoid involved in the operation of each isolation valve. Valve position switches are mounted on the valve for which position is to be indicated. Switches are enclosed in cases to protect them from environmental conditions.

The control arrangement for the MSIVs includes pneumatic piping and an accumulator for each valve. Pressure and water-level sensors are mounted on instrument racks in either the reactor building or the turbine building. Cables from each sensor are routed in conduits and cable trays to the trip unit racks located in the reactor building. All signals transmitted to the main control room are electrical; no pipe from the nuclear system or the primary containment penetrates the main control room. Pipes used to transmit level information from the RPV to sensing instruments terminate inside the secondary containment (reactor building). The sensor cables and power supply cables are routed to cabinets in the control center where the logic arrangements of the system are formed.

To ensure continued protection against the uncontrolled release of radioactive material during and after earthquake ground motions, the control system required for automatic closure of Class A and Class B valves is seismic designed as Category I equipment as described in Subsection 7.1.2.1.2. This meets safety design basis Item g.7.

7.3.2.2.4 Logic

The basic logic arrangement is one in which an automatic isolation valve is controlled by redundant trip systems. In cases where many isolation valves close on the same signal, two trip systems control the entire group. Where just one or two valves must close in response to a special signal, two trip systems may be formed from the instruments provided to sense the special condition. Valves that respond to the signals from common trip systems are identified in the detailed description of isolation functions.

Each trip system has two trip logics, each of which receives input signals from at least one trip channel for each monitored variable. Thus, two trip channels are required for each essential monitored variable to provide independent inputs to the trip logics of one trip system. A total of four trip channels for each essential monitored variable is required for the trip logics of each trip system. The trip actuators associated with one trip logic provide inputs into the trip actuator logics for either one or two isolation trip systems. The two automatic trip logics associated with each trip system can produce a redundant isolation valve closure. For main steam line isolation valves only, both trip systems are used to actuate closure of inboard and outboard isolation valves. The logic is "one-out-of-two taken twice" arrangement for each variable.

The basic logic arrangement described above does not apply to Class C isolation valves and testable check valves. Exceptions to the basic logic arrangement are made in several instances for certain Class A and Class B isolation valves. The reasons for this are explained in Subsection 7.3.2.1.

7.3.2.2.5 Operation

During normal operation of the isolation control system, when isolation is not required, sensor and trip contacts essential to safety are closed; trip channels, trip logics, and trip actuators are normally energized. Whenever a trip channel sensor contact opens, its auxiliary relay deenergizes, causing contacts in the trip logic to open. The opening of contacts in the trip logic deenergizes its trip actuators. When deenergized, the trip actuators open contacts in all the trip actuator logics for that trip system. If a trip then occurs in any of the trip logics of the other trip system, the trip actuator logics for the trip system are deenergized. With both trip systems tripped, appropriate contacts open or close in valve-control circuitry to actuate associated valve-closing mechanisms. Automatic isolation valves that are normally closed also receive the isolation signal.

The control system for each Class A isolation valve is designed to provide closure of the valve in time to prevent uncovering of the fuel as a result of a break in the pipeline which the valve isolates. The control systems for Class A and Class B isolation valves are designed to provide closure of the valves with sufficient rapidity to restrict the release of radioactive material to the environs below the guideline values of published regulations.

All automatic Class A and Class B valves and remotely operable Class C valves can be closed by manipulating switches in the main control room, thus providing the operator with a means independent of the automatic isolation functions to take action in the event of a failure of the nuclear system process barrier. This meets safety design basis Item j.

Once isolation is initiated, the valve continues to close, even if the condition that caused isolation is restored to normal. The operator must manually operate switches in the main control room to reopen a valve that has been automatically closed. Unless manual override features are provided in the manual control circuitry, the operator cannot reopen the valve until the conditions that initiated isolation have cleared. This is the equivalent of a manual reset and meets safety design basis Item g.5.

A trip of an isolation control system trip channel is annunciated in the main control room so that the operator is immediately informed of the condition. The response of isolation valves is indicated by "open-closed" lights. All motor-operated Class A and Class B isolation valves have a set of "open-closed" lights. The lights for each valve are located on the main control room panel at the manual control switches that control the valve. A second set of valve group displays that indicate status of the eighteen (18) containment isolation valve groups and individual valve status is available on the Integrated Plant Computer System (IPCS) as part of SPDS.

Inputs to annunciators, indicators, and the computer are arranged so that no malfunction of the annunciating, indicating, or computing equipment can functionally disable the system. Signals directly from the isolation control system sensors are not used as inputs to annunciating or data-logging equipment. Isolation is provided between the primary signal and the information output. The arrangement of indications pertinent to the status and response of the CRVICS satisfies safety design bases Items k.1. and k.2.

7.3.2.2.6 Isolation Valve Closing Devices

Table 6.2-2 itemizes the type of closing device provided for each isolation valve intended for use in automatic or remote manual isolation of the primary containment or RPV. In order that automatic Class A valves be fully closed in time to prevent the RPV water level from falling below the top of the active fuel as a result of a break of the line the valve isolates, the valve-closing mechanisms are designed to give the maximum closing times specified in the Technical Requirements Manual. In many cases a standard closing rate of 12 in./minute is adequate to meet isolation requirements. Using the standard rate, a 12-in. valve is closed in 60 sec. Because of the relatively long time required for fission products to reach the containment atmosphere following a break in the nuclear system process barrier inside the primary containment, a 1-minute closure time is adequate for the automatic closing devices on most Class B isolation valves.

Motor-operators for Class A and Class B isolation valves are selected with capabilities suitable to the physical and environmental requirements of service. The required valve-closing rates were considered in selecting motor-operators. Appropriate torque and limit switches are used to ensure proper valve seating. Handwheels, which are automatically disengaged from the motor-operator when the motor is energized, are provided for local-manual operation.

Direct solenoid-operated isolation valves and solenoid air-pilot valves are chosen with electrical and mechanical characteristics that make them suitable for their services. Appropriate water- tight or weather tight housing is used to ensure proper operation under accident conditions.

The pneumatic actuator used for testable check valves is designed to allow for the opening of the valve at near zero psi differential pressure across the valve. The actuator cannot close the valve against forward flow, or prevent the closing of the valve against reverse flow. Thus, the check valve will neither hinder forward fluid flow nor fail to stop reverse flow regardless of the condition of the actuator.

The MSIVs are spring-closing, pneumatic, piston-operated valves designed to close on loss of pneumatic pressure to the valve operator. This is a fail-safe design. The control arrangement is shown in Figure 7.3-10. Closure time for the valves is adjustable between 3 and 10 sec. Each valve is piloted by two, three-way, packless, direct-acting, solenoid-operated pilot valves, one of which is powered by ac and the other by dc. An accumulator is located close to each isolation valve to provide pneumatic pressure for valve closing in the event of failure of the normal gas supply system.

The valve pilot system and the pneumatic lines, as shown in Figure 7.3-11, are arranged so that when one or both solenoid-operated pilot valves are energized, normal gas supply provides pneumatic pressure to the gas-operated pilot valve to direct gas pressure to the main valve operator. This overcomes the closing force exerted by the spring and keeps the main valve open. When both pilots are deenergized, as would be the result when both trip systems trip, or when the manual switch is placed in the closed position, the path through which gas pressure acts is switched so that the opposite side of the valve operator is pressurized. This assists the spring in closing the valve. In the event of gas-supply failure, the loss of gas pressure causes the gas-operated pilot valve to move by spring force to the position resulting in main valve closure. Main valve closure is then effected by means of the gas stored in the accumulator and by the spring.

Gas pressure and the force exerted by the spring, acting together, are both required to close the valve. The isolation valves inside the primary containment (inboard) are designed to close with pneumatic pressure and spring force with the vented side of the piston operator at the containment peak accident pressure. The outboard valve is exactly the same design, although it will be subjected only to atmospheric pressures.

The accumulator volume holds reserve pneumatic pressure inventory to assist the springs in closing MSIVs when the pneumatic supply to the accumulator has failed. The supply line to the accumulator is large enough to make up pressure to the accumulator at a rate faster than the rate that the valve operation bleeds pressure from the accumulator during valve opening or closing.

A separate, single, solenoid-operated pilot valve with an independent test switch is included to allow manual testing of each isolation valve from the main control room. The testing arrangement is designed to give a slow closure of the isolation valve being tested so that rapid changes in steam flow and NSSS pressure are avoided. Slow closure of a valve during testing requires 50 to 60 sec.

7.3.2.2.7 Isolation Functions and Settings

The isolation trip settings of the CRVICS are listed in Table 7.3-9. The functions that initiate automatic isolation are itemized in Table 6.2-2 in terms of the lines that penetrate the primary containment. Table 6.2-2 includes all lines of concern for isolation purposes. Although this section is concerned with the electrical control systems that initiate isolation to prevent direct release of radioactive material from the primary containment or nuclear system process barrier, the additional information given in Table 6.2-2 can be used to assess the overall (electrical and mechanical) isolation effectiveness of each system having lines that penetrate the primary containment.

Isolation functions and trip settings used for the electrical control of isolation valves in fulfillment of the previously-stated safety design bases are discussed in the following subsection. The role each isolation function plays in initiating isolation of barrier valves or groups of valves is illustrated in the functional control diagrams of Figures 7.3-2, 7.3-12, 7.3-13, 7.3-14, and 7.4-1.

7.3.2.2.7.1 Reactor Vessel Low Water Level

A low-water level in the RPV could indicate that reactor coolant is being lost through a breach in the nuclear system process barrier and that the core is in danger of becoming overheated as the reactor coolant inventory diminishes. Reactor vessel low-water level initiates closure of various Class A valves and Class B valves. The closure of Class A valves is intended to either isolate a breach in any of the lines in which valves are closed, or to conserve reactor coolant by closing off process lines. The closure of Class B valves is intended to prevent the escape of radioactive materials from the primary containment through process lines that are in communication with the primary containment free space.

Three RPV low water-level isolation trip settings are used to completely isolate the RPV and the primary containment. The level signals are defined as follows and are shown in Figure 7.3-12:

a. Level 3 (L3) is the highest of the three and also initiates the level scram and isolates the RHR system

b. Level 2 (L2) is the initiation level for the reactor core isolation cooling (RCIC) and HPCI systems and is selected to be less than the volume resulting from a void collapse occurring in the event of a scram from full power. Level 2 also closes certain containment isolation valves

c. Level 1 (L1) is selected far enough above the top of the active fuel and is selected based on the time required for the RHR and core spray systems to function in the event of a large break. Level 1 also isolates the MSIVs.

Isolation of the following lines occurs when the level reaches L3, which is the highest or most conservative level (Table 6.2-2, signal C):

a. Drywell equipment drain sump discharge

b. Drywell floor drain sump discharge

c. RHR shutdown cooling

d. Traversing in-core probe (TIP) system withdrawal.

The second level (L2) isolates the majority of the nuclear pressure boundary lines and the primary and secondary containment paths. This is also the level that starts the HPCI and RCIC systems, and it has been selected to be lower than the level change resulting from a void collapse following a scram from full power. Specifically, isolation of the following lines is initiated on Level 2 (Table 6.2-2, signal B):

a. Reactor sample lines

b. Reactor water cleanup

c. Drywell air and nitrogen inlet

d. Suppression chamber exhaust

e. Suppression chamber air and nitrogen inlet

f. Drywell exhaust

g. Drywell pressure control

h. Suppression chamber pressure control

i. Purge to standby gas treatment

j. Control center heating, ventilation, and air conditioning (HVAC)

k. Reactor building ventilation

l. Recirculation pump seal purge

m. Torus water management

n. Primary containment radiation monitoring.

The final isolation level is Level 1 (L1). This level setting provides automatic isolation for the following lines, which penetrate the primary containment, if they are open (Table 6.2-2, signal A):

a. RHR containment spray

b. RHR test line

c. Core spray test line

d. Suppression chamber spray

e. Main steam

f. Main steam line drains.

7.3.2.2.7.2 Main Steam Line High Radiation

High radiation in the vicinity of the main steam lines could indicate a gross release of fission products from the fuel. High radiation near the main steam lines initiates isolation of the reactor water sample line (Table 6.2-2, signal D). In addition, main steam line high radiation trips the condenser mechanical vacuum pumps and gland seal exhausters (see Subsection 11.4.3.8.2.3).

The high-radiation trip setting is selected high enough above background radiation levels so that spurious isolation is avoided, yet low enough to promptly detect a gross release of fission products from the fuel. Further information regarding high-radiation setpoint is available in Section 11.4.

7.3.2.2.7.3 Main Steam Line Space High Temperature

High temperature in the space in which the main steam lines are located outside the primary containment could indicate a breach in a main steam line. The automatic closure of various Class A valves prevents both the excessive loss of reactor coolant and the release of significant amounts of radioactive material from the nuclear system process barrier. When high temperatures occur in the main steam line space, all four main steam lines and the main steam line drain are isolated.

The main steam line space high-temperature trip is set far enough above the temperature expected during operations at rated power so that spurious isolation is avoided, yet low enough to provide early indication of a steam line break.

7.3.2.2.7.4 Main Steam Line High Flow

Main steam line high flow could indicate a break in a main steam line. The automatic closure of various Class A valves prevents the excessive loss of reactor coolant and the release of significant amounts of radioactive material from the nuclear system process barrier. On detection of the main steam line high flow, all four main steam lines and the main steam line drain are isolated.

The main steam line high-flow-trip setting was selected high enough to permit the isolation of one main steam line for the test at rated power without causing an automatic isolation of the rest of the steam lines, yet low enough to permit early detection of a steam line break.

7.3.2.2.7.5 Low Steam Pressure at Turbine Inlet

Low steam pressure at the turbine inlet while the reactor is operating could indicate a malfunction of the nuclear system pressure regulator, at which time the turbine control valves or turbine bypass valves open fully. This action causes rapid depressurization of the nuclear system. From part-load operating conditions, the rate of decrease of nuclear system saturation temperature could exceed the allowable rate of change of vessel temperature. A rapid depressurization of the RPV while the reactor is near full power could result in undesirable differential pressure across the channels around some fuel bundles of sufficient magnitude to cause mechanical deformation of channel walls. Such depressurizations, without preventive action, could require thorough vessel analysis or core inspection prior to returning the reactor to power operation. To avoid the time-consuming requirements following a rapid depressurization, the steam pressure at the turbine inlet is monitored. On falling below a preselected value with the reactor in the RUN mode, isolation of all four main steam lines and the main steam drain line is initiated.

The low-steam-pressure isolation setting was selected far enough below normal turbine inlet pressures so that spurious isolation is avoided, yet high enough to provide timely detection of a pressure regulator malfunction. Although this isolation function is not required to satisfy any of the safety design bases for this system, this discussion is included here to make the listing of isolation functions complete.

7.3.2.2.7.6 Primary Containment (Drywell) High Pressure

High pressure in the drywell could indicate a breach of the nuclear system process barrier inside the drywell. The automatic closure of various Class B valves prevents the release of significant amounts of radioactive material from the primary containment. On detection of a high drywell pressure, the following pipelines are isolated:

a. Drywell equipment drain discharge
b. Drywell floor drain discharge
c. TIP tubes
d. Drywell air and nitrogen inlet
e. Suppression chamber exhaust valves
f. Suppression chamber air and nitrogen inlet
g. Drywell exhaust
h. Drywell pressure control
i. Suppression chamber pressure control
j. Purge to standby gas treatment
k. Control center HVAC recirculation mode
l. Reactor building ventilation system isolation
m. Torus water management
n. Primary containment radiation monitoring.
o. Reactor recirculation pumps seal purge supply lines
p. EECW Division 1 and 2 drywell cooling supply lines (Note: isolation signal from ECCS logic, not from RPS logic)

The primary containment high pressure isolation setting was selected to be as low as possible without inducing spurious isolation trips.

7.3.2.2.7.7 Reactor Core Isolation Cooling Turbine Steam Line Space High Temperature

High temperature in the vicinity of the RCIC turbine could indicate a break in the RCIC steam line. The automatic closure of certain Class A valves prevents the excessive loss of radioactive material from the nuclear system process barrier. When high temperature occurs in the RCIC area, the RCIC turbine steam line is isolated. The high-temperature isolation setting was selected far enough above anticipated normal RCIC system operational levels so that spurious operation is avoided, yet low enough to provide timely detection of an RCIC turbine steam line break.

7.3.2.2.7.8 Reactor Core Isolation Cooling Turbine High Steam Flow

Reactor core isolation cooling turbine high steam flow could indicate a break in the RCIC turbine steam line. The automatic closure of certain Class A valves prevents the excessive loss of reactor coolant and the release of significant amounts of radioactive materials from the nuclear system process barrier. The RCIC turbine high-steam-flow trip setting was selected high enough to avoid spurious isolation, yet low enough to provide timely detection of a RCIC turbine steam line break. An electrical time-delay circuit prevents spurious isolations on the turbine startup transient.

The logic arrangement used for this function is shown in Figure 7.4-1, and is an exception to the usual logic requirements since high steam flow is the second method of detecting a RCIC turbine steam line break.

7.3.2.2.7.9 Reactor Core Isolation Cooling Turbine Steam Line Low Pressure

The RCIC turbine steam line low pressure is used to automatically close the two isolation valves in the RCIC turbine steam line so that steam and radioactive gases do not escape from the RCIC turbine shaft seals into the reactor building after steam pressure has decreased to such a low value that the turbine cannot be operated. The isolation setpoint is chosen at a pressure below that at which the RCIC turbine can operate effectively.

7.3.2.2.7.10 High-Pressure Coolant Injection Turbine Steam Line Space High Temperature

High temperature in the vicinity of the HPCI turbine could indicate a break in the HPCI turbine steam line. The automatic closure of certain Class A valves prevents the excessive loss of reactor coolant and the release of significant amounts of radioactive material from the nuclear system process barrier. When high temperature occurs in the HPCI turbine area, the HPCI turbine steam supply line is isolated. The high-temperature isolation setting was selected far enough above anticipated normal HPCI system operational levels so that spurious isolation is avoided, yet low enough to provide timely detection of an HPCI turbine steam line break.

7.3.2.2.7.11 High-Pressure Coolant Injection Turbine High Steam Flow

The HPCI turbine high steam flow could indicate a break in the HPCI turbine steam line. The automatic closure of certain Class A valves prevents the excessive loss of reactor coolant and the release of significant amounts of radioactive materials from the nuclear system process barrier.

On detection of HPCI turbine high steam flow, the HPCI turbine steam line is isolated. The high-steam-flow trip setting was selected high enough to avoid spurious isolation, yet low enough to provide timely detection of an HPCI turbine steam line break. An electrical time-delay circuit prevents spurious isolations on the turbine startup transient.

The logic arrangement used for this function is shown in Figure 7.3-2, and is an exception to the usual logic requirement since high steam flow is the second method of detecting an HPCI turbine steam line break.

7.3.2.2.7.12 High-Pressure Coolant Injection Turbine Steam Line Low Pressure

The HPCI turbine steam line low pressure is used to automatically close the two isolation valves in the HPCI turbine steam line so that steam and radioactive gases do not escape from the HPCI turbine shaft seals into the reactor building after steam pressure has decreased to such a low value that the turbine cannot be operated. The isolation setpoint is chosen at a pressure below that at which the HPCI turbine can operate.

7.3.2.2.7.13 Reactor Building Ventilation Exhaust High Radiation

High radiation prior to the reactor building ventilation exhaust fans could indicate a breach of the nuclear system process barrier inside the primary containment, which would result in increased airborne radioactivity levels in the primary containment exhaust to the secondary containment. The automatic closure of certain Class B valves acts to close off release routes for radioactive material from the primary containment into the secondary containment (reactor building). Reactor building ventilation exhaust high radiation initiates isolation of the following pipelines:

a. Drywell air and nitrogen inlet
b. Suppression chamber exhaust
c. Suppression chamber air and nitrogen inlet
d. Drywell exhaust
e. Drywell pressure control
f. Suppression chamber pressure control
g. Purge to standby gas treatment
h. Reactor building supply and exhaust (vent)
i. Control center normal air intake and exhaust.

The high-radiation trip setting selected is far enough above background radiation levels to avoid spurious isolation, yet low enough to provide timely detection of nuclear system process barrier leaks inside the primary containment. Because the primary containment high pressure isolation function and the RPV low-water-level isolation function are adequate in effecting appropriate isolation of the above pipelines for gross breaks, the reactor building ventilation exhaust high-radiation isolation function is provided as a third redundant method of detecting breaks in the nuclear system process barrier significant enough to require automatic isolation.

7.3.2.2.8 Instrumentation

Sensors providing inputs to the CRVICS are not used for the automatic control of the process system. Thus, the functional controls of the protection and process systems are separated. Trip channels are physically and electrically separated to reduce the probability that a single physical event could prevent isolation. Trip channels for one monitored variable that are grouped near each other provide inputs to different isolation trip systems. The sensors are used functionally in the isolation control system, as illustrated in Figures 7.3-2, 7.3-9, 7.3-12, 7.3-13, and 7.4-1. Table 7.3-9 lists instrument characteristics. The sensors are described in the following paragraphs:

a. Reactor vessel low-water-level signals are initiated from eight level transmitters (differential pressure transmitters) that sense the difference between the pressure due to the constant reference column of water and the pressure due to the actual water level in the vessel.

   A backfill system is installed on each level instrument reference leg. The system provides a metered flow of water from the control rod drive system to each leg. The flow is low enough to not affect the performance of the instrumentation. The backfill is designed to prevent the accumulation of dissolved noncondensable gases in the reference legs.

   Four narrow-range transmitters provide an input to individual trip units that provide an isolation signal when the reactor water level drops to the first (highest) water level (L3) trip settings. Each of the four wide-range transmitters provides signals to two trip units. One trip unit provides the isolation signal for the second low water level (L2) trip setting. The other trip unit provides the isolation signal for the third and lowest (L1) trip setting

   Logic channel trips are arranged in one-out-of-two-twice logic. Channels A or C and B or D are required to initiate isolation for both inboard and outboard MSIVs. Two of the four transmitters for each trip level are connected to one pair of taps (A and B). The other two transmitters (C and D) are connected to taps that are 180^{o} around the RPV from the first pair. This physical separation ensures that no single physical event can prevent isolation if it were required. Cables from the transmitters are routed to the trip units in the auxiliary building

b. Main steam line radiation is monitored by four radiation monitors, which are described in Subsection 11.4.3.8.2.3

c. High temperature in the vicinity of the main steam lines is detected by 16 resistance temperature detectors (RTDs) located along the main steam lines between the drywell wall and the reactor building steam tunnel pressure relief doors. Eight additional RTDs sense high temperature in the turbine building steam tunnel. The detectors are located or shielded so that they are sensitive to air temperature and not to the radiated heat from hot equipment. The main steam line space temperature detection system is designed to detect leaks of from 1 percent to 10 percent of rated steam flow

d. High flow in each main steam line is sensed by four differential pressure transmitters that sense the pressure difference across the flow restrictor in that line. The logic is arranged as two trip systems with two trip logics in each system. Any two trip logics can trip the isolation valve. Each trip logic receives an input from a high-steam-flow trip channel for each steam line

e. Main steam line low pressure is sensed by four pressure transmitters that sense pressure downstream of the outboard MSIVs. The sensing point is located at the header that connects the four steam lines upstream of the turbine stop valves. The logic is arranged as two trip systems with two trip logics per system. Any two trip logics associated with each trip system can trip the isolation valves

f. Primary containment pressure is monitored by four pressure transmitters that are mounted on instrument racks outside the drywell. Pipes that terminate in the reactor building connect the transmitters to the drywell interior. Cables are routed from the transmitter to the main control room. The transmitters are grouped in pairs, physically separated, and electrically connected to the isolation control system so that no single event prevents isolation due to primary containment high pressure

g. High temperature in the vicinity of the RCIC turbine is sensed by two ambient and two differential temperature measurements. Only the ambient temperature sensors can initiate RCIC isolation

h. High flow in the RCIC turbine steam line is sensed by two differential pressure transmitters, which monitor the differential pressure across a mechanical flow element installed in the RCIC turbine steam supply pipeline. The tripping of either trip channel initiates isolation of the RCIC turbine steam line. This is an exception to the usual sensor requirement

i. Low pressure in the RCIC turbine steam line is sensed by four pressure transmitters from the RCIC turbine steam line upstream of the isolation valves. The transmitters are arranged as two trip systems, either of which must trip to initiate isolation of the RCIC turbine steam line. Each trip system receives inputs from two pressure transmitters, both of which must trip to trip the system

j. High temperature in the vicinity of the HPCI turbine is sensed by two ambient and two differential temperature measurements. Only the ambient temperature sensors can initiate isolation

k. High flow in the HPCI turbine steam line is sensed by two differential pressure transmitters which monitor the differential pressure across a mechanical flow element installed in the HPCI turbine steam line. The tripping of either transmitter initiates isolation of the HPCI turbine steam line

l. Low pressure in the HPCI turbine steam line is sensed by four pressure transmitters from the HPCI turbine steam line upstream of the isolation valves. The transmitters are arranged as two trip systems, either of which can initiate isolation of the HPCI turbine steam line. Each trip system receives inputs from two pressure transmitters, both of which must trip to trip the trip system

m. Reactor building ventilation exhaust radiation is monitored by two independent redundant monitors. Each monitoring trip channel provides the isolation function as described in Subsections 7.3.2.2.7.13 and 11.4.3.8.2.4. The primary containment high pressure isolation function and the RPV low water level isolation function are adequate in effecting the isolation of the pipelines that could release radioactivity due to breach of the nuclear system process barrier inside the primary containment. The reactor building ventilation exhaust radiation is provided as a third redundant method of detecting breaks in the nuclear system process barrier (significant enough to require automatic isolation).

   In addition to the above, the fuel pool ventilation exhaust radiation monitoring system is provided to detect a high radiation level in the ductwork that could be due to fission gases from a refueling accident. Four fuel pool ventilation exhaust detectors in a redundant "one out of two" logic provide the isolation function as described in Subsection 11.4.3.8.2.11.

n. High temperature in the spaces occupied by the reactor shutdown cooling system piping outside the primary containment is sensed by temperature switches that activate alarms only, indicating possible pipe breaks. Automatic isolation on high temperature is not required since the RPV low-water-level isolation function is adequate in preventing the release of significant amounts of radioactive material in the event that either of these two systems suffers a breach.

Sensor trip channel and trip logic relays are high reliability relays equal to type-HFA relays made by GE. Table 7.3-10 lists the minimum numbers of trip channels needed to ensure that the isolation control system retains its functional capabilities.

7.3.2.2.9 Environmental Capabilities

Special consideration has been given to isolation requirements during a LOCA inside the drywell. Components of the CRVICS that are located inside the primary containment and that must operate during a LOCA are the cables, control mechanism, and valve operators or isolation valves inside the drywell. These isolation components are required to be functional in a LOCA environment.

Electrical cables for isolation valves in the same lines are routed separately. Motor-operators for valves inside the primary containment are of the totally enclosed type; those outside the primary containment have weatherproof type enclosures. Solenoid valves, whether used for direct valve isolation or as an air or gas pilot, are provided with watertight enclosures. All cables and operators are capable of operation in the most unfavorable ambient conditions anticipated for design-basis accident (DBA) conditions. Temperature, pressure, humidity, and radiation are considered in the selection of equipment for the system. Cables used in high radiation areas have radiation-resistant insulation. Shielded cables are used whenever necessary to eliminate interference from magnetic fields. Electrical cables are selected with insulation designed for this service.

Closing mechanisms and valve operators are considered satisfactory for use in the isolation control system only after completion of environmental testing under LOCA conditions or after submission of evidence from the manufacturer describing the results of suitable prior tests.

Verification that the isolation equipment has been designed, built, and installed in conformance to the specified criteria is accomplished through the following series of tests in the vendor's shop or after installation at the plant before startup, during startup, and thereafter, where appropriate, during the service life of the equipment:

a. Material qualification tests
b. Weld qualification tests
c. Metallurgical tests
d. Hydrostatic tests
e. Leakage tests
f. Closing time tests
g. Preoperational tests
h. Startup tests
i. Periodic tests
j. Verification of type of materials used for insulation
k. Environmental testing of electrical equipment under simulated accident conditions.

Control is also exercised through review of equipment design during bid review and by approval of vendor's drawings during the fabrication stage. Purchase specifications require extensive control of materials and of the fabrication procedure.

7.3.2.3 Analysis

The CRVICS is described in Subsection 7.3.2.2. The safety design bases and specific regulatory requirements of this system are stated in Subsection 7.3.2.1. This analysis shows compliance with these requirements.

7.3.2.3.1 Safety Evaluation Analysis

The CRVICS, in conjunction with other safety systems, is designed to provide timely protection against the onset and consequences of accidents involving the gross release of radioactive materials from the fuel and nuclear system process barriers. It is the objective of Chapter 15 to identify and evaluate postulated events resulting in gross failure of the fuel barrier and the nuclear system process barrier. The consequences of such gross failures are described and evaluated in that section.

Design procedure has been to select tentative isolation trip settings that are far enough above or below normal operating levels that spurious isolation and operating inconvenience are avoided. It is then verified by analysis that the release of radioactive material following postulated gross failures of the fuel and nuclear system process barrier is kept within acceptable bounds. Trip-setting selection is based on operating experience and constrained by the safety design and the safety analyses.

Chapter 15 shows that the actions initiated by the CRVICS, in conjunction with other safety systems, are sufficient to prevent releases of radioactive material from exceeding the guide values of published regulations. Because the actions of the system are effective in restricting the uncontrolled release of radioactive materials under accident situations, the CRVICS meets the precision and timeliness requirements of safety design basis Item a.

The CRVICS meets the precision and timeliness requirements of safety design basis Item a. using instruments with the characteristics described in Table 7.3-9. Therefore, it is concluded that safety design basis Item b. is met.

Temperatures in the spaces occupied by various steam lines outside the primary containment are the only essential variables of significant spatial dependence that provide inputs to the CRVICS. The large number of temperature sensors and their dispersed arrangement near the steam lines requiring this type of break protection provide assurance that a significant break will be detected rapidly and accurately. The number of sensors provided for steam line break detection satisfies safety design basis Item c.

Because the CRVICS meets the timeliness and precision requirements of safety design basis Item a. by monitoring variables that are true, direct measures of operational conditions, it is concluded that safety design basis Item d. is satisfied.

Subsection 15.6.4 evaluates a gross breach in a main steam line outside the primary containment during operation at rated power. The evaluation shows that the main steam lines are automatically isolated in time to prevent both a release of radioactive material in excess of the guideline values of published regulations, and to prevent the loss of coolant from being great enough to allow uncovering of the core. The time required for automatic closure of the MSIVs meets the requirements of safety design basis Item e. The shortest closure time of which the MSIVs are capable is 3 sec. The transient resulting from a simultaneous closure of all MSIVs in 3 sec during reactor operation at rated power is considerably less severe than the transient resulting from inadvertent closure of the turbine stop valves (which occurs in a small fraction of 1 sec) coincident with failure of the turbine bypass system. This conclusion is substantiated in Subsection 15.2.3. This meets safety design basis Item f.

The safety design bases Items g., h., and i. must be fulfilled for the CRVICS to meet the design reliability requirements of safety design basis Item a. It has already been shown that safety design bases Items g.5. and g.7. have been met. The remainder of the reliability requirement is met by a combination of logic arrangement, sensor redundancy, wiring scheme, physical isolation, power supply arrangement, and environmental capabilities. These subjects are discussed in the following paragraphs.

Because essential variables are monitored by four trip channels arranged for physical and electrical independence, and because a dual trip system arrangement is used to initiate closure of automatic isolation valves, no single failure, maintenance operation, calibration operation, or test can prevent the system from initiating valve closure. An analysis of the isolation control system shows that the system does not fail to respond to essential variables as a result of single electrical failures such as short circuits, ground, and open circuits. A single trip system trip is the result of these failures. Isolation is initiated on a trip of the remaining trip system. For some of the exceptions to the usual logic arrangement, a single failure could result in inadvertent isolation of a pipeline. With respect to the release of radioactive material from the nuclear system process barrier, such inadvertent valve closures are in the safe direction and do not pose any safety problems. This meets safety design basis Item g.1.

The redundancy of trip channels for all essential variables provides a high probability that whenever an essential variable exceeds the isolation setting, the system initiates isolation. In the unlikely event that all trip channels for one essential variable in one trip system fail in such a way that a system trip does not occur, the system could still respond properly as other monitored variables exceed their isolation settings. This meets safety design basis Item g.2. The sensors, circuitry, and logic channels used in the CRVICS are not used in the control of any process system. Thus, malfunction and failures in the controls of process systems have no direct effect on the isolation control system. This meets safety design basis Item g.3.

The various power supplies used for the isolation control system logic circuitry and for valve operation provide assurance that the required isolation can be effected in spite of power failures. If ac power for valves inside the primary containment is lost, dc power is available for operation of valves outside the primary containment. The main steam isolation valve control arrangement is resistant to both ac and dc power failures. Because both solenoid-operated pilot valves must be deenergized, loss of a single power supply neither causes inadvertent isolation nor prevents isolation if required.

The logic circuitry for each channel is powered from the separate sources available from the RPS buses. A loss of power here results in a single trip system trip. In no case does a loss of a single power supply prevent isolation. This meets safety design basis Item g.4.

The isolation control system can operate under the most unfavorable environmental condition associated with normal operation. The discussion of the effects of rapid nuclear system depressurization on level measurement given in Subsection 7.2.1.1.3.1 is equally applicable to the RPV low-water-level transmitters used in the CRVICS. The temperature, pressure, differential pressure, and level transmitters, cables, and valve-closing mechanisms used were selected with ratings that make them suitable for use in the environment in which they must operate.

The special considerations made for the environmental conditions resulting from a LOCA inside the drywell are adequate to ensure operability of essential isolation components located inside the drywell.

The wall of the primary containment effectively separates adverse environmental conditions that might otherwise affect both isolation valves in a line. The location of isolation valves on either side of the wall decouples the effects of environmental factors with respect to the ability to isolate any given line. The previously discussed electrical isolation of control circuitry prevents failures in one part of the control system from propagating to another part. Electrical transients have no significant effect on the functioning of the isolation control system. Therefore, it is concluded that safety design basis Item g.6. is satisfied.

The design of the MSIVs meets the requirement of the safety design basis in that the motive force for closing each MSIV is derived from both a source of pneumatic or gas pressure, and the energy is stored in a spring. Both pneumatic and spring energy is required to close the valve. None of the valves rely on continuity of any sort of electrical power to achieve closure in response to essential safety signals. Total loss of the power used to control the valves would result in closure. This meets safety design basis Item h.

Calibration and test controls for pressure and level transmitters are located on the transmitters themselves. These transmitters are located in the turbine building and reactor building. To gain access to the setting controls on each transmitter, a cover plate, access plug, or sealing device must be removed by operations personnel before any adjustment in trip settings can be effected. The location of calibration and test controls in areas under the control of supervision or of the main control room operator reduces the probability that operational reliability will be degraded by operator error. This meets safety design basis Item i.1.

Because no manual bypasses (except for those used during a BDBEE) are provided in the isolation control system, safety design basis Item i.2. is met. Because safety design bases Items g., h., and i. have been met, it can be concluded that the CRVICS satisfies the reliability requirement of item safety design basis a. That the system satisfied safety design bases Items j., k.1., and k.2. was shown in the description of the system. The following subsection, covering inspection and testing of the system, demonstrates that safety design basis Item 1. is satisfied.

7.3.2.3.2 Inspection and Testing

All parts of the primary containment isolation control system are testable during reactor operation. Isolation valves can be tested to ensure that they are capable of closing by operating manual switches in the main control room and observing the position lights and any associated process effects. Testable check valves are arranged to verify that the valve disk is free to open and close. The trip channel and trip system responses can be functionally tested by applying test signals to each trip channel and observing the trip system response.

Functional testing and calibration schedules developed using available failure rate data, reliability analyses, and operating experience are presented in the Technical Specifications. The schedules represent an optimization of CRVICS reliability by considering, on one hand, the failure probabilities of individual components, and, on the other hand, the reliability effects during individual component testing on the portions of the system not undergoing tests.

The isolation actuation system instrumentation response times are shown in Technical Requirements Manual Volume I Table 3.3.6.1-1, which is referenced in UFSAR Table 7.3-12. Response time testing is required by the Technical Specifications. Technical Specification Table 3.3.2-3 was deleted from the Technical Specifications and added to the UFSAR as Table 7.3-12 (TRM Table 3.3.6.1-1) in agreement with NRC Generic Letter 93-08 and Amendment Number 100 to the Technical Specifications. The response times information of UFSAR Table 7.3-12 was then relocated to the Technical Requirements Manual Volume I.

The response time testing for the trip functions associated with the diesel start and sequencing of loads is eliminated in agreement with NRC Generic Letter 93-05 and Amendment Number 99 to the Technical Specifications.

The periodic sensors response time testing for the reactor vessel low water level-level 1 and the main steam line flow-high has been eliminated. The BWROG Report NEDO-32291A provides the required analyses as briefly described in 7.2.1.1.3.8.1.

7.3.2.3.3 Specific Regulatory Requirements Conformance

7.3.2.3.3.1 IEEE 279-1971

Conformance to IEEE 279-1971 is demonstrated in Topical Report NEDO-10139, Paragraph 4.2. The 21 subparagraphs of 4.2 cover the 21 subparagraphs of IEEE 279-1968. The following discussion is addressed to IEEE 279-1971, subparagraphs 4.7, 4.17, and 4.22, which are different from those in IEEE 279-1968:

a. Paragraph 4.7.1: Classification of Equipment - There is no control function in the system. It is strictly a protection system

b. Paragraph 4.7.2: Isolation Devices - Since there is no control function, no isolation devices are required

c. Paragraph 4.7.3: Single Random Failure - No single random failure of a control system can prevent proper action of the isolation system channel designed to protect against the condition

d. Paragraph 4.7.4 - Analysis of 4.7.3 applies directly

e. Paragraph 4.17: Manual Initiation - Manual initiation controls are provided and separated in such a manner as to prevent a single failure from inhibiting an isolation.

   The separation of devices is maintained in both the manual and automatic portions of the system so that no single failure in either the manual or automatic portions can prevent an isolation by either manual or automatic means. There are no areas of the system that are common to manual and automatic functions

f. Paragraph 4.2: Identification - Panels and racks that house isolation system equipment are identified with a distinctive color marker plate listing the system name and the designation of the particular redundant portion of the system. Instrument cables are identified in accordance with IEEE 279-1971.

In addition, NEDO-10139 demonstrated conformance with IEEE 279-1971, Paragraph 4.14, by the position that there are no manual controls that bypass the containment isolation control function. This conformance with IEEE 279-1971 is maintained but is modified to note the use of keylock switches added to allow operation of the Hardened Containment Vent System in support of the plant’s response to a BDBEE in accordance with NRC Order EA-13-109.

7.3.2.3.3.2 Industry Standard IEEE 323-1971

Compliance with this standard is discussed in Section 3.11 and NEDO-10698.

7.3.2.3.3.3 IEEE 338-1971

The system is testable during reactor operation. The tests that may be performed will cover the sensors through the final actuators, demonstrate independence of channels, and bare any credible failures while not negating any isolation.

7.3.2.3.3.4 Industry Standard IEEE 344-1971

Compliance with this standard is discussed in Section 3.10 and NEDO-10678.

7.3.2.3.3.5 Regulatory Guide 1.22

Regulatory Guide 1.22 requires periodic testing of protection system actuation functions. The MSIVs and associated logic and sensor devices may be tested from the sensor device to one of the two solenoids required for valve closure. The valve may be exercised closed with either a slow-acting test solenoid or the normal closing solenoid to verify that there are no obstructions to the valve stem at full power. A reduction in power is necessary before performing a valve closure. All the isolation valves, other than the MSIVs, may be tested from sensor to actuator during plant operation. The test may cause isolation of the process lines involved, but their isolation is tolerable.

7.3.2.3.3.6 10 CFR 50, Appendix A

General Design Criterion 13

The integrity of the reactor core and the reactor coolant pressure boundary (RCPB) is ensured by monitoring the appropriate plant variables and closing various isolation valves, as detailed in the various description sections.

7.3.2.3.3.7 10 CFR 50, Appendix B

The guidelines of 10 CFR 50, Appendix B, are met as described in Chapter 17.

7.3.3 Emergency Core Cooling System Auxiliary Systems Instrumentation and Control

7.3.3.1 Design-Basis Information

The design-basis information for the instrumentation and control of the reactor building closed cooling water (RBCCW) system, as required by Section 3 of IEEE 279-1971, is provided in Subsection 7.1.2.1.28.

7.3.3.2 System Description

7.3.3.2.1 Cooling System for Reactor Auxiliaries

The RBCCW system and its backup, the emergency equipment cooling water (EECW) system, provide cooling water for the ECCS auxiliary equipment and area air coolers, as described in Subsection 9.2.2. A discussion of the EECW system is contained in Subsection

7.3.4. A description of the RBCCW system, including instrumentation and control, is presented in Subsection 7.6.1.14.

7.3.3.2.2 Control Circuits

The RBCCW system operates and supplies services during normal operation of the plant. It continues to operate during an accident unless interrupted by some abnormal condition. The system is shut down by the head tank low-level signal using "one-out-of-two taken twice" logic. Each individual RBCCW pump (outside of the RBCCW supplemental cooling loops) shuts down on low pump suction, also using “one-out-of-two taken twice” logic.

In the event that the RBCCW system cannot maintain adequate flow to the EECW loops, the EECW system is automatically started by low differential pressure between the supply and return headers. Logic is "one-out-of-two." A loss of offsite power directly initiates the EECW system to anticipate the loss of power to the RBCCW system. The EECW system is also auto-initiated on high drywell pressure.

7.3.3.3 Analysis

Description of the analysis of the EECW system is found in Subsection 7.3.4.3.

7.3.4 Emergency Equipment Cooling Water System

7.3.4.1 Design-Basis Information

The design-basis information for the instrumentation and control of the EECW system, as required by Section 3 of IEEE 279-1971, is provided in Subsection 7.1.2.1.18.

7.3.4.2 System Description

The EECW system ensures cooling water to remove heat from emergency equipment on loss of offsite power, on high drywell pressure, or failure of the RBCCW system. Since this system is described in Subsection 9.2.2, the following discussion provides additional information on the EECW instrumentation and control. The EECW system is shown in Figures 9.2-3 and 9.2-4.

7.3.4.2.1 Power Sources

Instruments and controls for the EECW system receive electrical power from the redundant 120-V, 60-Hz instrument power systems described in Subsection 8.3.1 and from Division I and Division II 130 V dc Class IE batteries as described in Subsection 8.3.2.1.2. Those instruments and controls requiring pneumatic power receive plant instrument air as described in Subsection 9.3.1.

7.3.4.2.2 Equipment Design

Each of the two redundant and separate EECW loops has electrically and physically separate controls and instruments.

7.3.4.2.3 Initiation and Control Circuits

The EECW system can be started manually from the main control room. Low RBCCW flow to the EECW loops causes loss of EECW header differential pressure, which automatically isolates the RBCCW and starts the EECW loops. If EECW has already been initiated for the purposes of RBCCW heat exchanger cleaning, enhanced drywell cooling, testing, or RHR reservoir freeze protection, the location of the differential pressure sensors inside the EECW system envelope will not sense a RBCCW low flow condition and, therefore, will not cause EECW to automatically reinitiate and reisolate the nonessential loads. This action is not required since this is not a condition requiring protective action as described in Section 7.1.2.1. The EECW system is also automatically initiated by a loss of offsite power or on high drywell pressure. Automatic start of EECW makeup pump is achieved if makeup tank has low pressure or level and makeup tank isolation valve is open, and normal pump suction pressure.

7.3.4.2.4 Logic

The EECW system logic is shown in Figure 7.3-15. These logic schemes are identical for each of the two redundant EECW loops. Level switches are used to alarm when there is insufficient water inventory. If offsite power is available, the EECW pumps start nominally 1.5 seconds after receipt of the initiation signal. If offsite power is unavailable, the EECW pumps are sequenced on the EDG buses by the automatic load sequencer. See Table 8.3-5.

7.3.4.2.5 Testability

Control and logic circuitry can be tested by placing that loop in operation from the main control room. If an auto-initiate signal is received during a test, the manual signal is automatically overridden by the auto-initiate signal, and both loops will be placed into operation as required.

7.3.4.3 Analysis

7.3.4.3.1 Conformance To Specific Regulatory Requirements

The specific requirements of IEEE 279-1971, to which attention has been directed in the design of the EECW system, are itemized below by paragraph number as they appear in IEEE 279-1971.

a. Paragraph 4.1: Automatic Initiation - This requirement is met by incorporating capability in the design for automatic startup of the EECW system on loss of offsite power, on high drywell pressure, or on occurrence of low pressure across the supply and return headers of either cooling loop

b. Paragraph 4.2: Single Failure - The single-failure criterion is met by having an independently controlled EECW loop for each of the two RBCCW divisions

c. Paragraph 4.3: Quality Assurance - This requirement is met as described in Chapter 17

d. Paragraph 4.4: Equipment Qualification - This requirement is met as described in Chapter 3

e. Paragraph 4.5: Channel Integrity - This requirement is met by supplying electrical power to the EECW system from buses backed up by diesel generators. The routings of power, signal, and control circuits take separate paths. The EECW system is designed to withstand seismic accelerations

f. Paragraph 4.6: Channel Independence - This requirement is met by the independent instrumentation and controls provided in the EECW system and separate power feeds that are used

g. Paragraph 4.7: Control Interaction - The requirement of this criterion is met by the complete independence of controls of the two divisions of the EECW system

h. Paragraph 4.8: Direct Inputs - This requirement is met by the provision of separate and independent instrumentation to supply signal inputs for control of the two loops of the EECW system

i. Paragraph 4.9: Sensor Checks - This requirement is met by introducing a test signal (in one channel at a time) sufficient to verify that a logic trip is achievable when the parameter deviates beyond the setpoint. Correct response of each sensor is verified by observing that its output indicates a deviation of the parameter beyond the setpoint value

j. Paragraph 4.10: Testability - This requirement is satisfied by the automatic override of a manual control command if an emergency condition arises during testing

k. Paragraph 4.11: Channel Bypass - This requirement is met by the cooling adequacy of one loop, allowing one loop to be tested during operation without loss of protection

l. Paragraph 4.12: Operation of Bypasses - This requirement is met by the automatic override of manual control, which is provided to automatically initiate operation of the system if an emergency arises during a test

m. Paragraph 4.13: Bypass Indication - This requirement is met by the display provisions in the main control room, which indicate the operational or nonoperational state of the EECW system

n. Paragraph 4.14: Bypass Access - This requirement is met by the administrative control that is imposed on use of the operational controls of the EECW system

o. Paragraph 4.15: Multiple Setpoints - This requirement is not applicable to the EECW system

p. Paragraph 4.16: Action Completion - This requirement is satisfied by the functional characteristics of the automatic controls of the EECW system

q. Paragraph 4.17: Manual Access - This requirement is satisfied by the manual control provisions incorporated in the EECW system controls

r. Paragraph 4.18: Setpoint Access - This requirement is satisfied by the administrative control that is imposed on use of the setpoint adjustments

s. Paragraph 4.19: Identification - This requirement is satisfied by the indicating lamps and sequential recorders that the design incorporates to indicate the state of the EECW system and its valves and pumps

t. Paragraph 4.20: Information Readout - This requirement is satisfied by the readout instruments provided to display temperature, pressure, and flow parameters in the EECW system

   A sequential recorder is provided to register initiation of water pump operation and tripout of the pump motor circuit breaker

u. Paragraph 4.21: System Repair - This requirement is met by the readily identifiable modular design of the instrumentation and control components

v. Paragraph 4.22: Identification - This requirement is met by using appropriate tags and color schemes to enable easy identification of circuits and components that are part of the EECW safeguard system

The following additional IEEE criteria are met by the provisions outlined in the sections or chapters of this UFSAR that are indicated:

a. IEEE 323-( ): Section 3.11 (IEEE 323-1971 for equipment purchased before November 15, 1974; IEEE 323-l974 for equipment purchased on or after November 15, 1974)

b. IEEE 336-1971:Chapter 17

c. IEEE 338-1971:Subsection 7.3.1.3.4

d. IEEE 344-1971:Section 3.10.

The requirements of Regulatory Guide 1.22 are met on the basis of the manual test and control provisions that the EECW system design incorporates.

Evaluation of the EECW system against criteria of 10 CFR 50, Appendix A and Appendix B, is as follows:

a. Criterion 13 - This criterion is met by using qualified differential pressure sensors and operating them in a "one-out-of-two" logic arrangement

b. Criterion 20 - This criterion is met by providing the automatic mode of startup as stated in Subsection 7.1.2.1.18

c. Criterion 21 - The EECW system provides assurance that, through its standby redundancy, each loop has sufficient reliability to fulfill the single-failure criterion. No single component failure, maintenance operation, calibration operation, or test to verify operational availability impairs the ability of the system to perform its intended safety function. There is sufficient electrical and physical separation between channels and between trip logic circuits monitoring the same variable to prevent environmental factors, electrical transients, and physical events from impairing the ability to respond correctly

The EECW system includes design features that permit inservice testing. This enhances the functional reliability of the system by enabling early detection of malfunctioning components in the course of routine tests

d. Criterion 22 - Physical separation, separate power feeds, and separate controls are provided for the two cooling loops. This ensures that the EECW system of each loop, providing necessary cooling capacity, is available for the required safety function. Details of separation criteria and independence are contained in Section 3.12 and Subsection 9.2.2

e. Criterion 23 - Since the two loops are independent, failure of one loop will not affect operation of the other

f. Criterion 24 - Since no signals required for control of the reactor are used for control of the EECW system, this criterion is satisfied

g. Criterion 29 - High functional reliability of the EECW system is achieved through the combination of sensor redundancy, control logic arrangement, functional and physical separation of loops, operating power independence, fail-safe design, and inservice testability. These requirements are discussed in detail in Criteria 21 through 24.

   An extremely high probability of correct system response to anticipated operational occurrences is maintained by a thorough program of inservice testing and surveillance. Active components can be tested or removed from service for maintenance during reactor operation without compromising protective control functions, even in the event of a subsequent single failure. Components important to safety are tested during normal reactor operation. Functional testing and calibration schedules are developed using available failure rate data, reliability analyses, and operating experience. These schedules represent an optimization of system reliability by considering the failure probabilities of individual components, and also the reliability effects during individual component testing on the portion of the system not undergoing test. The capability for inservice testing ensures the high functional reliability of the system should a monitored parameter exceed the corrective action setpoint.

The guidelines of 10 CFR 50, Appendix B, are met as described in Chapter 17.

7.3.5 Control Center Atmospheric Control System Instrumentation and Control

7.3.5.1 Design-Basis Information

The design-basis information for the instrumentation and control of the control center atmospheric control system, as required by Section 3 of IEEE 279-1971, is provided in Subsection 7.1.2.1.

7.3.5.2 System Description

The instrumentation and control for the control center HVAC system functions to ensure the habitability of the control center under all plant operating conditions is described in Section 6.4 and Subsections 9.4.1 and 12.2.2.1.

7.3.5.2.1 Power Sources

Each redundant control center HVAC system is comprised of a supply air fan, return air fan, electric heating coil, and a refrigeration unit. Power supply for these components of each control center HVAC system is from separate essential ac buses that can receive standby ac power. Control power for isolation dampers, instrumentation, and controls comes from the bus that powers the corresponding equipment train.

7.3.5.2.2 Initiating Circuits, Logic, and Sequencing

Various components of each redundant control center HVAC system are initiated as follows:

a. The supply and return air fans are initiated manually by control switches at the main control board

b. The refrigeration unit is provided with a manual/ automatic selector switch on the main control board. While in automatic mode, the refrigeration unit is initiated by the demand signal from the thermostat in the chilled water piping

c. A subsystem of the process radiation monitoring system (PRMS) monitors radiation levels in the main control room air intake. High radiation indication by detectors in the main control room air intake duct downstream of the filter train activates an alarm within the control center. High-high level automatically places the control center HVAC system in full recirculation mode

d. If combustion products are detected in the control center by the smoke (ionization) detectors, one of the following manual actions is initiated via hand switches in the main control room at the discretion of the operator:

   1. The outside air intake and exhaust air damper can be fully opened and the recirculation air damper fully closed to purge the control center air (smoke purge mode)

   2. Route outside air and recirculation air mixture (approximately 7 percent of the total mixture) from the control center HVAC system through normally bypassed odor and smoke-removing filters.

e. If the control center HVAC system is operating in the normal mode and one of the automatic gaseous suppression systems is initiated automatically by the fire detection system, the smoke purge mode is automatically initiated. However, the smoke purge mode is overridden if the recirculation mode is signaled to start.

f. If an automatic isolation occurs due to detection of a potential breach of the primary reactor pressure boundary, as indicated by low reactor water level, high drywell pressure, high radiation level as monitored by the fuel pool ventilation exhaust, or the reactor building ventilation exhaust, the emergency makeup outside air is automatically provided to pressurize the main control room.

7.3.5.2.3 Bypasses and Interlocks

All of the isolation dampers in each control center HVAC system equipment are interlocked with the operation of corresponding supply air and return air fans. Operation of any of these fans opens all the corresponding isolation dampers. The supply-air and return-air fans are operated manually by hand switches.

To prevent short-cycling and a possible freeze-up of the evaporator, the refrigeration machine start is interlocked with the operation of the supply-air fan and corresponding return-air fans, condenser cooling water, and chilled water pump. The operation of the refrigeration machine is further interlocked with safety protection cutout; i.e., low-pressure and high-pressure cutout in refrigerant circuit, and oil failure switch in the compressor lubrication circuit. To guard against overheating, the electric heating coil is interlocked with supply-air fan operation and a thermal cutout switch. Low temperature of the chilled-water line is alarmed.

Zone mixing dampers are controlled by thermostats in each zone. The operation of the refrigeration machine is controlled by a thermostat in the chilled-water return pipe. The electric heating coil is controlled by a thermostat in the hot deck of the air handling unit.

All of the isolation dampers in the outside air intakes and the emergency-makeup-air filter train are appropriately interlocked to serve the required function. The electric heating coil for humidity control in the emergency-makeup-air filter train is interlocked with the emergency-makeup-air fans.

7.3.5.2.4 Redundancy and Diversity

Instrumentation and control equipment for each control center HVAC system is completely independent of one another.

7.3.5.2.5 Actuated Devices

The normal and emergency operation of each control center HVAC system involves the following actuated devices:

a. Supply-air fan

b. Return-air fan

c. Electric heating coil

d. Refrigeration unit

e. Emergency-makeup-air electric heating coil

f. Emergency-makeup-air fan

g. Corresponding isolation and control dampers

h. Chilled water pump.

7.3.5.2.6 Separation

The channels and logic circuits are physically and electrically separated to preclude the possibility that a single event would prevent operation of the control center HVAC system. Electrical cables for instrumentation and control on each control center HVAC system are routed separately.

7.3.5.2.7 Testability

Control and logic circuitry used in the controls for the control center HVAC system can be individually checked by applying test or calibration signals to the sensors and observing trip or control responses. Operation of each redundant HVAC system is periodically rotated to permit on-line checking and testing of performance of the complete system. The automatic control circuitry for the emergency equipment is designed to restore its normal function in response to initiation signals.

7.3.5.2.8 Environmental Considerations

Temperature, pressure, humidity, and radiation dosage are considered in selection of various equipment, instrumentation, and controls for the control center HVAC system. These are described in Section 3.ll and Subsection 9.4.l.

7.3.5.2.9 Operational Considerations

The control center HVAC system is required during normal and abnormal plant operating conditions. The automatic circuitry is designed to start the emergency equipment if the signal for its initiation is received, as described in this section.

7.3.5.3 Analysis

Conformance To General Functional Requirements

The control center HVAC system instrumentation and controls are designed to ensure the habitability of the main control room during and after all the normal and abnormal plant operating conditions. Certain components of the system are required during normal and abnormal plant operating conditions only. The controls for the system provide warning to the operator of any abnormal operating transients in the system, and automatically initiate action that provides protection against the consequences of the release of radioactive material to outdoor environs following any accident.

Chapter 15 identifies and evaluates postulated events that can result in release of fission products due to an accident. The consequences of such an accident are described and evaluated.

Because essential variables are monitored by channels arranged for physical and electrical independence, no single failure, maintenance operation, calibration operation, or test can prevent the system from performing its function. A single active failure in the Halon fire protection system will cause closure of smoke/Halon dampers to the relay room, cable spreading room or computer room. Manual actions are required to reopen these dampers to reestablish airflow.

The sensor circuitry and logic used in the control center HVAC system are not used in the control of any process system. Thus, malfunction and failures in the controls of the process systems have no direct effect on the control center HVAC system.

The power supplies used for the system logic circuitry and controls provide assurance that the required performance cannot be affected by a loss of offsite electric power or loss of instrument air. In no case does the loss of a single power supply prevent function of the control center HVAC system.

Portions of the system required to operate during and following the design basis accident to provide acceptable environments within the control center have been qualified both environmentally and seismically.

Inputs to annunciators and indicators are arranged so that no malfunction of the annunciating and indicating device can functionally disable the system. Direct signals from the control center HVAC system control system sensors are not used as inputs to annunciating or data-logging equipment.

All controls for interrupting any part of the system operation are located in the main control room. All controls and instrumentation essential to the operation of the control center HVAC system meet the IEEE 279-1971 criteria.

7.3.6 Standby Gas Treatment System Instrumentation and Control

7.3.6.1 Design-Basis Information

The design basis information for the instrumentation and control of the standby gas treatment system (SGTS), as required by Section 3 of IEEE 279-1971, is provided in Subsection 7.1.2.1.16.

7.3.6.2 System Description

The instrumentation and control of the SGTS are used to maintain, when necessary, a preset constant flow that will maintain the reactor building at a negative pressure and preclude leakage of radioactive particulates and gases directly to the outdoors. The SGTS is designed to reduce radioactive particulates and gaseous concentration in the exhaust air from the reactor building before exhausting to the outdoors.

The SGTS is described in detail in Subsection 6.2.3 and is shown schematically in Figure 6.2-20.

7.3.6.2.1 Power Sources

Each SGTS exhaust equipment train has an exhaust fan, a standby cooling fan, an electric heating coil, and associated air- operated isolation valves that require power. Power supply for various components of each SGTS equipment train and the instrument air compressor is from separate essential ac buses that can receive standby ac power. Motive power for isolation valves and the controls comes from the bus that powers the corresponding equipment train, except for the isolation valves in the reactor building ventilation system supply and exhaust duct headers. These valves are operated by air cylinders with instrument air being controlled by solenoid valves for each isolation valve. If either control air or electric control power were lost, the isolation valves would be closed by springs mounted on the valves.

7.3.6.2.2 Initiating Circuits

The system is automatically started in response to any one of the following signals:

a. High drywell pressure (Subsection 7.3.2.2.7.6)

b. Low reactor water level (Subsection 7.3.2.2.7.1)

c. High radiation in fuel pool ventilation exhaust (Subsection 11.4.3.8.2.11)

d. High radiation in the reactor building ventilation exhaust (Subsection 11.4.3.8.2.4)

e. Manual activation from the main control room

f. Downscale trip due to loss of offsite power to radiation monitors located in the Reactor Building and fuel pool ventilation exhaust system.

7.3.6.2.3 Logic and Sequencing

The following actions take place simultaneously on receipt of an initiation signal:

a. Closure trip of reactor building isolation valves

b. Trip of reactor building ventilation system

c. Opening of SGTS isolation valves

d. Startup of both SGTS equipment trains and annunciation of an alarm on the main control panel.

When both trains are automatically started, the audible and visual alarm on the main control panel warns the operator to shut down one of the trains. Individual hand switches located on the main control panel for each of the equipment trains permit manual operation.

7.3.6.2.4 Bypasses and Interlocks

All of the air-operated isolation valves pertinent to a SGTS equipment train are interlocked through a relay circuit with the operation of the SGTS unit.

The SGTS cooling fan is interlocked so as not to operate when the SGTS exhaust fan is in operation.

To protect against overheating, the electric heating coil for relative humidity control of the charcoal filters is interlocked with the SGTS exhaust fan operation, and high temperature is indicated by an alarm in the main control room.

Airflow through the SGTS is controlled automatically with a vortex damper on the exhaust fan valve, and flow is recorded on the main control panel. Low flow initiates an alarm to alert the operator to start the redundant SGTS equipment train.

To prevent fire in the charcoal bed, a source of CO_2 will purge air from the charcoal filters if the bed temperature exceeds 310°F. A pressure switch in the discharge line of the CO_2 unit will annunciate an alarm on the main control panel after the purge process begins.

On receipt of an initiation signal, the reactor building ventilation isolation valves close and remain closed unless a manual reset switch is activated.

7.3.6.2.5 Redundancy and Diversity

Each SGTS unit is automatically initiated by independent control systems.

7.3.6.2.6 Actuated Device

Initiation of the SGTS includes starting of the SGTS exhaust fan, energizing electric heating for preheating air, deenergizing charcoal bed heaters, and opening valves on the inlet and outlet sides of the SGTS equipment train.

7.3.6.2.7 Separation

The channels and logic circuits are physically and electrically separated to preclude the possibility that a single event would prevent operation of the SGTS. Electrical cables for instrumentation and control on each SGTS equipment train are routed separately.

7.3.6.2.8 Testability

Control and logic circuitry used in the controls for the SGTS can be individually checked by applying test or calibration signals to the sensors and observing trip or control responses. Operation of the isolation valves and fans from manual switches verifies the ability of breaker and damper mechanisms to operate.

7.3.6.2.9 Environmental Considerations

Temperature, pressure, humidity, and radiation dosage are considered in the selection of the various equipment, instrumentation, and controls for the SGTS described in Section 3.11 and Subsection 6.2.3.

7.3.6.2.10 Operational Considerations

The SGTS is available, if required, during normal plant operating conditions when any division is being tested. The other division is available for operation should it be needed.

7.3.6.3 Analysis

Conformance To General Functional Requirements

The SGTS control system is designed to initiate action that provides timely protection against the consequences of the release of radioactive materials inside the secondary containment following any accident. Chapter 15 identifies and evaluates postulated events that can result in release of fission products due to an accident. The consequences of such an accident are described and evaluated.

Because essential variables are monitored by channels arranged for physical and electrical independence, and because a dual trip system arrangement is used to initiate the SGTS, no single failure, maintenance operation, calibration operation, or test can prevent the system from operating when required. The sensor circuitry and logics used in the SGTS control system are not used in the control of any process system. Thus, malfunction and failures in the controls of process systems have no direct effect on the SGTS control system.

The various motive power supplies used for the SGTS logic circuitry and controls provide assurance that the required initiation can be effected in spite of loss of electric power or loss of instrument air. In no case does a loss of single power supply prevent initiation of the SGTS when required. Required instruments, isolation valve closing mechanisms, and cables of the SGTS can operate under the environmental conditions associated with postaccident operation. Active components of SGTS instrumentation and control can be tested and calibrated during plant operation.

All sensors and associated equipment are designed to meet Category I requirements, and are protected from fire, explosion, missiles, lightning, wind, and flood to preclude functional degradation of the system performance.

Inputs to annunciators and indicators are arranged so that no malfunction of the annunciating and indicating device can functionally disable the system. Direct signals from the SGTS control system sensors are not used as inputs to annunciating or data-logging equipment. Isolation is provided between primary signal and the information output.

7.3.7 Standby Power System

7.3.7.1 Design-Basis Information

The design-basis information for the instrumentation and control of the standby power system, as required by Section 3 of IEEE 279-1971, is provided in Subsection 7.1.2.1.

7.3.7.2 System Description

Four emergency diesel generators (EDGs) provide the power necessary for the ECCS during a loss of system power. A detailed explanation of this system and its corresponding instrumentation and control can be found in Subsection 8.3.1.

A battery system of redundant 130-V dc power-control batteries provides the dc power required during any ECCS function. Full- size battery chargers normally carry the load. However, the capability of the batteries is enough to handle the load for a sufficient amount of time should power to the chargers be lost. A detailed explanation of the battery system can be found in Subsection 8.3.2.

7.3.7.3 Analysis

Conformance To General Functional Requirements

The standby power systems are designed to provide electrical power availability to the ECCS and other safety-related systems at maximum reliability should normal offsite power not be available. Each supply has an independent redundant counterpart, thereby ensuring against single failure (IEEE 279-1971, Paragraph 4.2). The equipment, cabling interconnections, and circuit breakers are all qualified to Class 1E standards and housed in Category I structures.

An explanation of the EDGs and their conformance is found in Subsection 8.3.1. An explanation of the battery systems and their conformance is found in Subsection 8.3.2.

7.3.8 Post-LOCA Combustible Gas Control System

The NRC amended 10 CFR 50.44, “Standards for combustible gas control system in light-water-cooled power reactors” on October 16, 2003 to eliminate the requirements for hydrogen recombiners. The hydrogen recombiner Technical Specification requirements were subsequently removed by License Amendment 159, dated March 15, 2004. Regulatory Guide 1.7 was revised in March 2007 to reflect the amended 10 CFR 50.44. The Combustible Gas Control System (CGCS) has been retired in place with its electrical circuits de-energized and fluid process piping isolated from primary containment with redundant locked-closed isolation valves. Combustible gas control of the primary containment is provided by inerting the primary containment with nitrogen. Gas concentrations inside the primary containment are monitored by the Hydrogen/Oxygen analyzer subsystem of the primary containment monitoring system which is further discussed in Subsection 7.6.1.12.

7.3.9 Residual Heat Removal Service Water System Instrumentation and Control

7.3.9.1 Design-Basis Information

The design-basis information for the instrumentation and control of the residual heat removal service water (RHRSW) system, as required in Section 3 of IEEE 279-1971, is provided in Subsection 7.1.2.1.27.

7.3.9.2 System Description

The RHRSW system provides cooling water to remove heat from the RHR system. The RHRSW system includes a closed-cycle supply of water, pumps, and mechanical draft cooling towers to reject the heat to the environment. The system will operate with or without a loss of offsite power. The RHRSW system is described in Subsection 9.2.5 and the system diagram is provided in Figure 9.2-6. The following discussion provides additional information on the RHRSW instrumentation and control.

7.3.9.2.1 Power Sources

Instrumentation and controls for the RHRSW system receive electrical power from the redundant 120-V, 60-Hz instrument power systems described in Subsection 8.3.1. Part of the control logic is direct current, powered by the Class 1E direct current system described in Subsection 8.3.2. The pressure control valves requiring pneumatic power receive plant instrument air as described in Subsection 9.3.1.

7.3.9.2.2 Equipment Design

Each of the two separate, redundant RHRSW loops has electrically and physically separate controls and instruments.

7.3.9.2.3 Initiation and Control Circuits

The RHRSW pumps, valves, and cooling tower fans are all initiated manually from the main control room.

7.3.9.2.4 Logic

The RHRSW system is a manually initiated system; therefore, there is no automatic initiation logic. The RHRSW pumps automatically trip if they are operating and a LOCA signal is received, as indicated in Figure 7.3-9, Sheet 1. This trip is provided to allow the automatic loading of other emergency safety feature equipment on the emergency diesel generators if a loss of offsite power occurs. The interlock can be bypassed by a keylock switch so that the pumps can be started if there is a long-term LOCA signal present. The cooling tower fan motors automatically load-shed if a loss of offsite power occurs. The motors must be manually reset from the main control room before they will restart.

7.3.9.2.5 Testability

Each RHRSW loop can be tested from the control room by starting the RHRSW pumps and/or cooling tower fans. If an accident signal is received during a test, the system pumps trip off and remain off until the operator manually restarts.

7.3 ENGINEERED SAFETY FEATURE SYSTEMS

REFERENCES

1. U.S. Nuclear Regulatory Commission, NRC Action Plan Developed as a Result of the TMI-2 Accident, NUREG-0660, May 1980; Revision 1, August 1980.
2. U.S. Nuclear Regulatory Commission, Clarification of TMI Action Plan Requirements, NUREG-0737, October 1980.
3. Letter from W. H. Jens, Detroit Edison, to B. J. Youngblood, NRC, Subject: Modifications of ADS Logic (NUREG-0737, Item II.K.3.18), dated July 31, 1984 (EF2-66712).
4. Deleted
5. 004N0874, Revision 0, "HPCI/RCIC Unavailability – Wide Range Level Off-Calibration Level 8 Trip at Low Pressure – for the Enrico Fermi 2 Nuclear Power Plant," dated February 2017.
6. Letter from the USNRC to DTE Electric Company, "Fermi 2 – Issuance of Amendment to Revise High Pressure Coolant Injection System and Reactor Core Isolation Cooling System Actuation Instrumentation Technical Specifications (CAC No. MF9330)," dated April 14, 2017.

TABLE 7.3-1 HIGH PRESSURE COOLANT INJECTION SYSTEM INSTRUMENT SPECIFICATIONS

HPCI Function	Instrument	Trip Settings[a]	Instrument Range
RPV high water level turbine trip	Level transmitter	Level 8[b]	10 to 220 in.[c]
Turbine exhaust diaphragm high pressure	Pressure transmitter	10 psig	0 to 50 psig
Turbine exhaust high pressure	Pressure switch	140 psig	0 to 200 psig
HPCI system pump low suction pressure	Pressure switch	15 in. Hg V ac	30 in Hg to 0.5 psig
HPCI system pump high suction pressure	Pressure switch	70 psig	2 to 75 psig
RPV low water level	Level transmitter	Level 2[b]	10 to 220 in.[c]
Primary containment (drywell) high pressure[d]	Pressure transmitter	2 psig	0 to 5 psig
HPCI system steam supply low pressure	Pressure transmitter	100 psig	0 to 200 psig
Condensate storage lank low level	Level transmitter	45,000 gal	-10 in./0/+10 in. H_2O
Turbine overspeed	Centrifugal device	122 percent of turbine rated speed	

[a] Nominal values are given for information. See Technical Specifications for actual operational settings.

[b] Shown in Figure 7.3-12.

[c] Zero is at the top of the active fuel.

[d] Incident detection circuitry instrumentation.

TABLE 7.3-2 AUTOMATIC DEPRESSURIZATION SYSTEM INSTRUMENT TRIP SETTINGS

System Function	Instrument	Trip Settings[a]	Instrument Range
Reactor vessel low water level (permissive)[d]	Level transmitter	Level 3[b]	160 to 220 in.[c]
Reactor vessel low water level (permissive)[d]	Level transmitter	Level 1[b]	10 to 220 in.[c]
Primary containment (drywell) high pressure[d]	Pressure transmitter	1.68 psig	0 to 5 psig
Primary containment (drywell) high pressure bypass time delay[d]	Timer	7 min	1 to 30 min
Automatic depressurization time delay[d]	Timer	105 sec	10 to 300 sec
LPCI pump discharge pressure[d]	Pressure transmitter	118.5 psig	0 to 500 psig
Core spray pump discharge pressure[d]	Pressure transmitter	143.5 psig	0 to 500 psig

[a] Nominal values are given for information. See Technical Specifications for actual operational settings.

[b] Shown in Figure 7.3-12.

[c] Zero is at the top of the active fuel.

[d] Incident detection circuitry instrumentation.

TABLE 7.3-3 CORE SPRAY SYSTEM INSTRUMENT SPECIFICATIONS

Core Spray Function	Instrument	Trip Settings[a]	Instrument Range
RPV low water level[d]	Level Transmitter	Level 1[b]	10 to 220 in.[c]
Primary containment high pressure[d]	Pressure transmitter	1.68 psig	0 to 5 psig
RPV low pressure	Pressure transmitter	469 psig[e] Decreasing	0 to 1200 psig
Core spray sparger high differential pressure	Differential pressure switch	0.2 psid	-7 to +2 psid
Pump discharge flow	Flow indicator	--	0 to 10,000 gpm
Pump suction pressure	Pressure indicator	--	-30 in. Hg to 30 psig
Pump discharge pressure	Pressure transmitter	143.5 psig	0 to 50 psig

[a] Nominal values are given for information. See Technical Specifications for actual operational settings.

[b] Shown in Figure 7.3-12.

[c] Zero is at the top of the active fuel.

[d] Incident detection circuitry instrumentation.

[e] Approximate setting.

TABLE 7.3-4 LOW PRESSURE COOLANT INJECTION INSTRUMENT SPECIFICATIONS

LPCI FunctionF	Instrument	Trip Settings[a]	Instrument Range
RPV low water level (LPCI loop selection)[d]	Level transmitter	Level 2[b]	10 to 220 in.[c]
RPV water level (LPCI pump start signal)[d]	Level transmitter	Level 1[b]	10 to 220 in.[c]
Primary containment (drywell) high pressure(LPCI initiation)[d]	Pressure transmitter	1.68 psig	0 to 5 psig
RPV low water level (inside shroud)	Level transmitter	Level 0[b]	-150 to +50 in.
Recirculation loop break detection	Differential pressure transmitter	0.63 psid[e] Trip on upscale	0 to 2 psid
LPCI break detection circuit	Timer	1/2 sec	0.15 to 3 sec
LPCI break detection circuit	Timer	2 sec	0.15 to 3 sec
LPCI reactor vessel low pressure	Pressure transmitter	925 psig	0 to 1500 psig
LPCI valve initiation signal cancellation	Timer	10 minutes	3 to 30 minutes
LPCI pump low flow	Flow switch	5000 gpm	0 to 50 in. WC
RPV pressure permissive (loop selection)	Pressure transmitter	469.5 psig	0 to 1200 psig
Recirculation pumps differential pressure transmitter	Differential pressure transmitter	1.63 psid Trip on downscale	0 to 5 psid

[a] Nominal values are given for information. See Technical Specifications for actual operational settings.

[b] Shown in Figure 7.3-12.

[c] Zero is at the top of the active fuel.

[d] Incident detection circuitry instrumentation.

[e] Repeatability of ±0.5 percent on trip point. Return from overrange of 200 psi to 0 psi in 100 msec maximum.

TABLE 7.3-5 HIGH PRESSURE COOLANT INJECTION SYSTEM: MINIMUM NUMBERS OF TRIP CHANNELS REQUIRED FOR FUNCTIONAL PERFORMANCE

Component Affected	Trip Channel	Instrument Type	Number of Trip Channels Provided	Minimum Number of Trip Channels Required To Maintain Functional Performance[a]
HPCI system initiation	RPV low water level	Level transmitter	4	2 per untripped trip system
HPCI system initiation	Primary containment high pressure	Pressure transmitter	4	2 per untripped trip system
HPCI system turbine	HPCI system pump discharge flow	Flow indicator controller	1	1
HPCI system turbine	RPV high water level	Level transmitter	2	1 per untripped sytem
HPCI system turbine	Turbine exhaust diaphragm high pressure	Pressure transmitter	2	1[b]
HPCI system turbine	HPCI system pump low suction pressure	Pressure switch	1	1[b]
Minimum flow bypass valve	HPCI system pump flow	Flow switch	1	1
HPCIS steam supply valve and suppression chamber suction valve	HPCI system steam supply low pressure	Pressure transmitter	4	2 per untripped trip system
Suppression chamber suction valve	Condensate storage tank low level and suppression pool high level	Level transmitter	4[c]	2

[a] Nominal values are given for information. See Technical Specifications for operational requirements.

[b] An inoperable trip channel should be placed in the untripped state.

[c] Two each: condensate storage low, suppression pool high.

TABLE 7.3-6 AUTOMATIC DEPRESSURIZATION SYSTEM: MINIMUM NUMBERS OF TRIP CHANNELS REQUIRED FOR FUNCTIONAL PERFORMANCE

Initiating Function	Instrument Type	Number of Trip Channels Provided	Minimum Number of Trip Channels Required To Maintain Functional Performance[a,b]
RPV low water level (Level 1)	Level transmitter	2 per trip system	2 per untripped trip system
RPV low water level (Level 3)	Level transmitter	1 per trip system	1 per untripped trip system
Primary containment high pressure	Pressure transmitter	2 per trip system	2 per untripped trip system
Time delay (ADS timer)	Timer	1 per trip system	2 per untripped trip system
Time delay (ADS drywell high pressure bypass timer)	Timer	2 per trip system	2 per untripped trip system
ac interlock (RHR or core spray pump running)	Pressure transmitter	1 per pump	1 per pump

[a] One trip logic of each trip system must be fully operable. Both an RPV low water level trip channel and a primary containment high-pressure trip channel should not be inoperable in any one trip logic.

[b] Nominal values are given for information. See Technical Specifications for operational requirements.

TABLE 7.3-7 CORE SPRAY SYSTEM: MINIMUM NUMBERS OF TRIP CHANNELS REQUIRED FOR FUNCTIONAL PERFORMANCE

Component Affected	Trip Channel	Instrument Type	Number of Trip Channels Provided	Minimum Number of Trip Channels Required to Maintain Functional Performance[a]
Core spray system	RPV low water level	Level transmitter	4	2 per untripped trip system
Core spray system	Primary containment high pressure	Pressure transmitter	4	2 per untripped trip system
Core spray discharge valve	RPV low pressure	Pressure transmitter	4	2 per untripped trip system
Core spray sparger leak detection	Core pressure differential	Differential pressure switch	1 per sparger (alarm only)	1 per sparger (alarm only)

[a] Nominal values are given for information. See Technical Specifications for operational requirements.

TABLE 7.3-8 LOW-PRESSURE COOLANT INJECTION: MINIMUM NUMBERS OF TRIP CHANNELS REQUIRED FOR FUNCTIONAL PERFORMANCE

Component Affected	Trip Channel	Instrument Type	Number of Trip Channels Provided	Minimum Number of Trip Channels Required To Maintain Functional Performance[a]
LPCI initiation	RPV low water level	Level transmitter	4	2 per untripped trip system
LPCI initiation	Primary containment high pressure	Pressure transmitter	4	2 per untripped trip system
Containment spray valves	RPV low water level inside shroud	Level transmitter	1	1[b]
Minimum flow bypass valves	LPCI pumps discharge low flow	Flow switch	1, 2[c] (one per loop)	1, 2[c]
LPCI injection valves and recirculation loop valves	Recirculation loop break	Differential pressure transmitter	4	2
LPCI injection valves	RPV low pressure	Pressure transmitter	4	2
Reactor recirculation pumps	RPV low water level	Level transmitter	4	2
Containment cooling valves	Primary containment (drywell) high pressure	Pressure transmitter	4	2

[a] Nominal values are given for information. See Technical Specifications for operational requirements.

[b] An inoperable sensor should be placed in the untripped state.

[c] One channel to open, two channels to close.

TABLE7.3-9 PRIMARY CONTAINMENT AND REACTOR VESSEL ISOLATION CONTROL SYSTEM INSTRUMENTATION SPECIFICATIONS

Isolation Function	Sensor	Instrument Range	Trip Setting[a]
RPV low water level (L3)	Differential pressure transmitter	160 to 220 in.	L3[b]
Reactor vessel low water level (L2)	Differential pressure transmitter	10 to 220 in.	L2[b]
Reactor vessel low water level (L1)	Differential pressure transmitter	10 to 220 in.	L1[b]
Main steam line high radiation	Radiation monitor	0 to 10^6 mR/hr	3.0 x full power background
Main steam tunnel high temperature	Temperature sensor	50 to 350°F	140°F
Main steam line high flow	Differential pressure transmitter	0 to 150 psi	102 psid
Main steam line low pressure	Pressure transmitter	0 to 1200 psig	756 psig
Primary containment high pressure	Pressure transmitter	0 to 5 psig	1.68 psig
RCIC turbine area high temperature	Temperature sensor	50 to 350°F	154°F
RCIC turbine steam line high flow	Differential pressure transmitter	-300 to +300 in H_2O	+109 in. H_2O -109 in. H_2O
RCIC turbine steam line low pressure	Pressure transmitter	0 to 200 psig	62 psig
HPCI turbine area high temperature	Temperature sensor	50 to 350°F	154°F
HPCI turbine steam line high flow	Differential pressure transmitter	-500 to +500 in. H_2O	+425 in. H_2O -425 in. H_2O
HPCI turbine steam line low pressure	Pressure transmitter	0 to 200 psi	110 psig
Fuel pool ventilation exhaust high radiation	Radiation monitor	0.01 to 100 mR/hr	10 mR/hr
Reactor water cleanup system space high temperature	Temperature sensor	50 to 350°F	175°F

[a] Nominal values are given for information. See Technical Specifications and/or Technical Requirements Manual, Vol I for actual operational limits.

[b] See Figure 7.3-12 Sheet 3.

TABLE 7.3-10 PRIMARY CONTAINMENT AND REACTOR VESSEL ISOLATION CONTROL SYSTEM: MINIMUM NUMBERS OF TRIP CHANNELS REQUIRED FOR FUNCTIONAL PERFORMANCE[a]

Trip Channel Description	Normal Number of Trip Channels Per Trip System	Minimum Number of Trip Channels Required Per Untripped Trip System To Maintain Functional Performance[b]
RPV low water level (first setting) (level 3)	2	2
RPV low water level (second setting) (level 2)	2	2
RPV low water level (third setting) (level 1)	2	2
Main steam line high radiation	2	2
Main steam line space high temperature	4	4
Main steam line high flow	2/line	2/line
Main steam line low pressure	2	2
Primary containment high pressure	2	2
RCIC steam line space high temperature	1	1
RCIC steam line high flow	1	1
RCIC steam line low pressure	2	2
HPCI steam line space high temperature	1	1
HPCI steam line high flow	1	1
HPCI steam line low pressure	2	2
Fuel pool ventilation exhaust high radiation	2	2

[a] These data are derived from Technical Specifications.

[b] Nominal values are given for references only. See Technical Specifications for operational limits.

TABLE 7.3-11 (TRM – 3.3.5.1-1) EMERGENCY CORE COOLING SYSTEM RESPONSE TIMES

The Emergency Core Cooling System Response Times are listed in Technical Requirements Manual (TRM) Volume I Table 3.3.5.1-1. TRM Volume I is incorporated by reference into the UFSAR.

TABLE 7.3-12 (TRM TABLE 3.3.6.1-1) ISOLATION ACTUATION SYSTEM INSTRUMENTATION RESPONSE TIME

The Isolation Actuation System Instrumentation Response Times are listed in Technical Requirements Manual (TRM) Volume I Table 3.3.6.1-1. TRM Volume I is incorporated by reference into the UFSAR.

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FIGURE 7.3-1, SHEET 1

HIGH PRESSURE COOLANT INJECTION SYSTEM
P&ID

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FIGURE 7.3-1, SHEET 2

HIGH PRESSURE COOLANT INJECTION
SYSTEM P&ID

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FIGURE 7.3-2, SHEET 1

HIGH PRESSURE COOLANT INJECTION SYSTEM FCD

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FIGURE 7.3-2, SHEET 2

HIGH PRESSURE COOLANT INJECTION SYSTEM FCD

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FIGURE 7.3-2, SHEET 3

HIGH PRESSURE COOLANT INJECTION SYSTEM FCD

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FIGURE 7.3-2, SHEET 4

HIGH PRESSURE COOLANT INJECTION SYSTEM FCD

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FIGURE 7.3-2, SHEET 5

HIGH PRESSURE COOLANT INJECTION SYSTEM FCD

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FIGURE 7.3-2, SHEET 6

HIGH PRESSURE COOLANT INJECTION SYSTEM FCD

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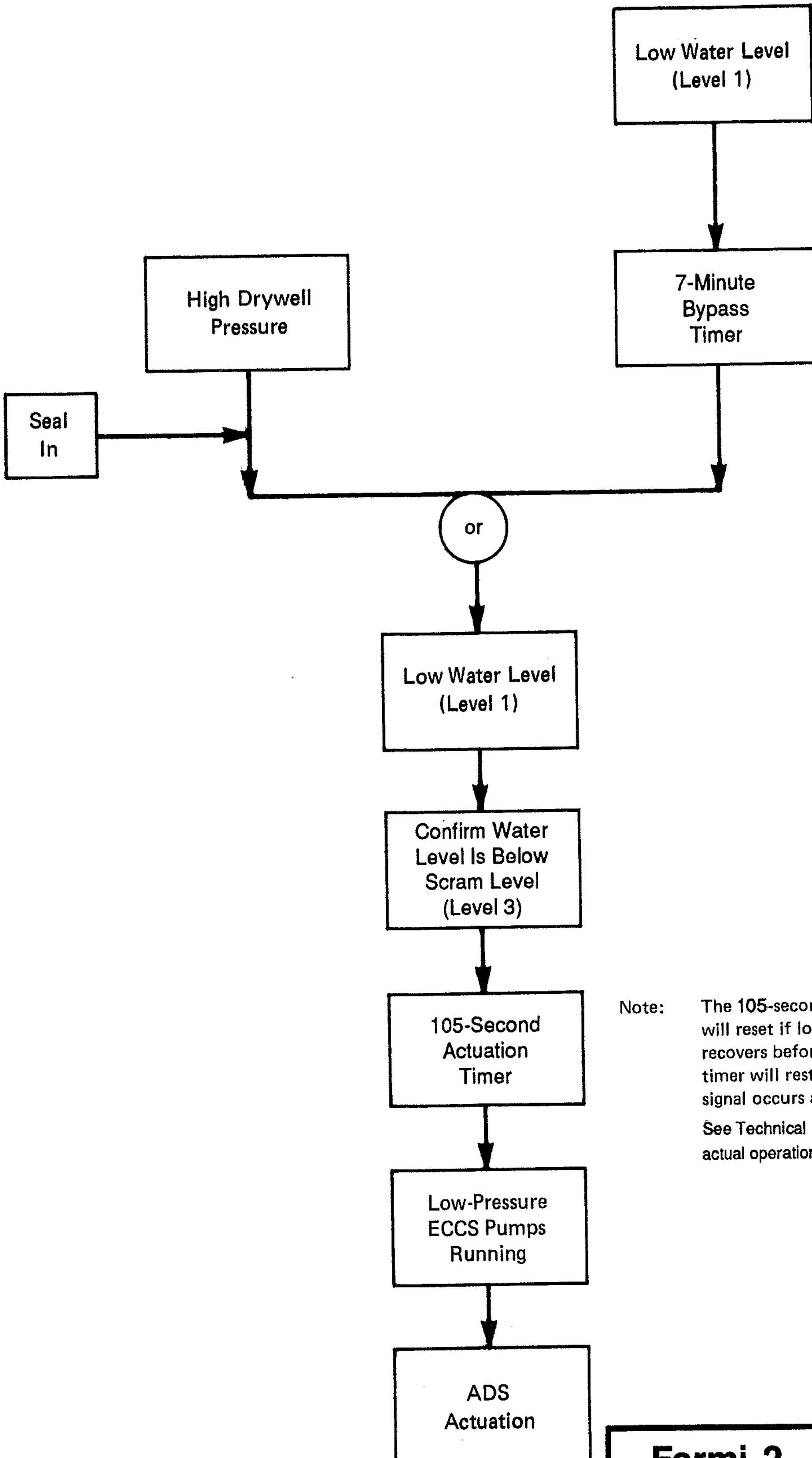
FIGURE 7.3-4

AUTOMATIC DEPRESSURIZATION SYSTEM FCD

FIGURE 7.3-5 INTENTIONALLY DELETED



Note: The 105-second actuation timer will reset if low-water-level trip recovers before it times out. The timer will restart if the low-level signal occurs again.

See Technical Specifications for actual operational settings.

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FIGURE 7.3-6

AUTOMATIC DEPRESSURIZATION SYSTEM DELAYED BYPASS OF DRYWELL PRESSURE TRIP WITH BYPASS TIMER STARTED AT LOW WATER LEVEL (LEVEL 1)

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Refer to Plant Drawing M-2034

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FIGURE 7.3-7

CORE SPRAY SYSTEM P&ID

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FIGURE 7.3-8, SHEET 1

CORE SPRAY SYSTEM FCD

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FIGURE 7.3-8, SHEET 2

CORE SPRAY SYSTEM FCD

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Figure Intentionally Removed
Refer to Plant Drawing I-2200-02

FIGURE 7.3-9, SHEET 2

RESIDUAL HEAT REMOVAL SYSTEM FCD

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Refer to Plant Drawing I-2200-03

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FIGURE 7.3-9, SHEET 3

RESIDUAL HEAT REMOVAL SYSTEM FCD

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FIGURE 7.3-9, SHEET 4

RESIDUAL HEAT REMOVAL SYSTEM FCD

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FIGURE 7.3-9, SHEET 5

RESIDUAL HEAT REMOVAL SYSTEM FCD

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FIGURE 7.3-9, SHEET 6

RESIDUAL HEAT REMOVAL SYSTEM FCD

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Figure Intentionally Removed
Refer to Plant Drawing I-2200-09

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FIGURE 7.3-9, SHEET 8

RESIDUAL HEAT REMOVAL SYSTEM FCD

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FIGURE 7.3-9, SHEET 9

RESIDUAL HEAT REMOVAL SYSTEM FCD

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FIGURE 7.3-9, SHEET 10

RESIDUAL HEAT REMOVAL SYSTEM FCD

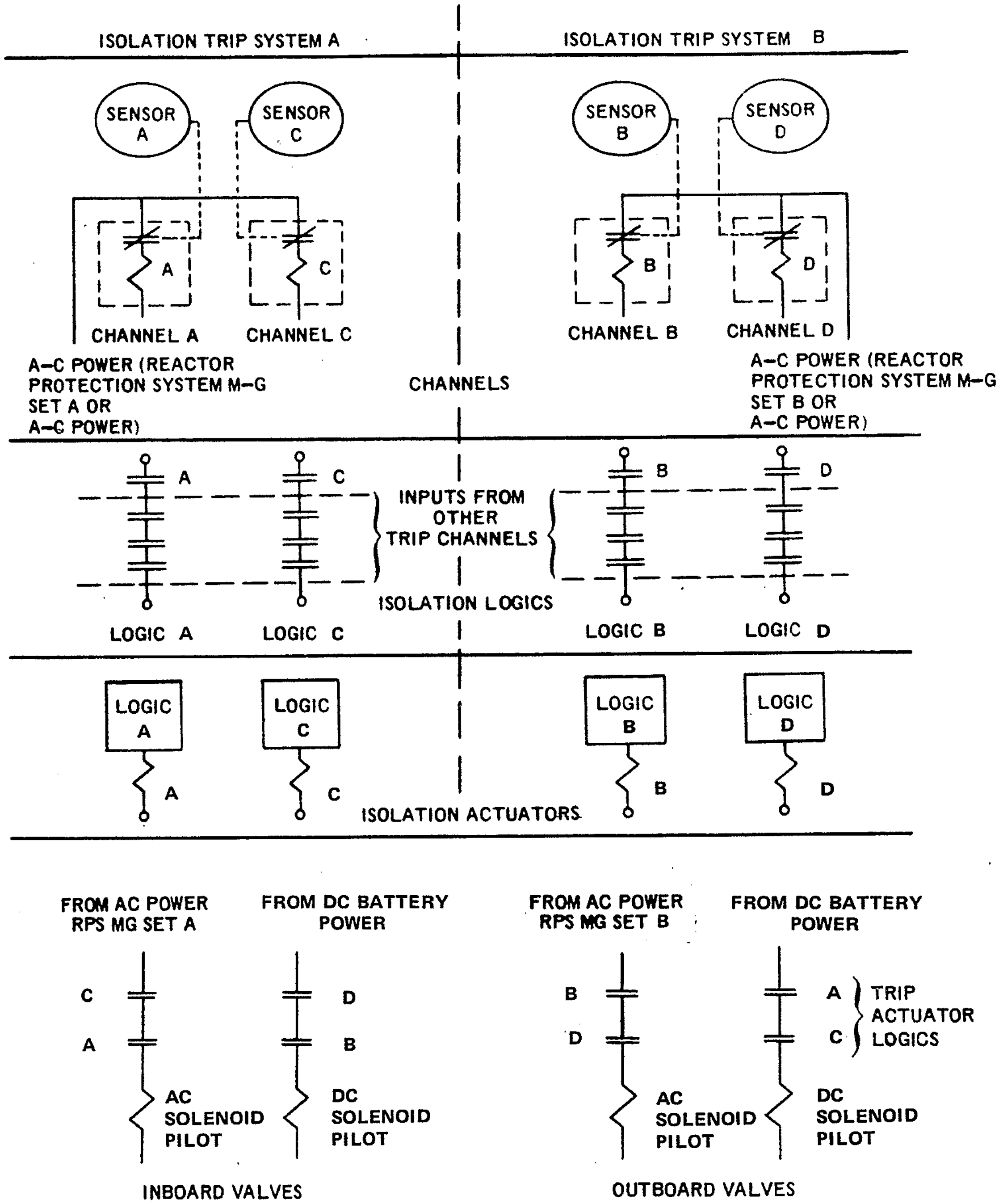

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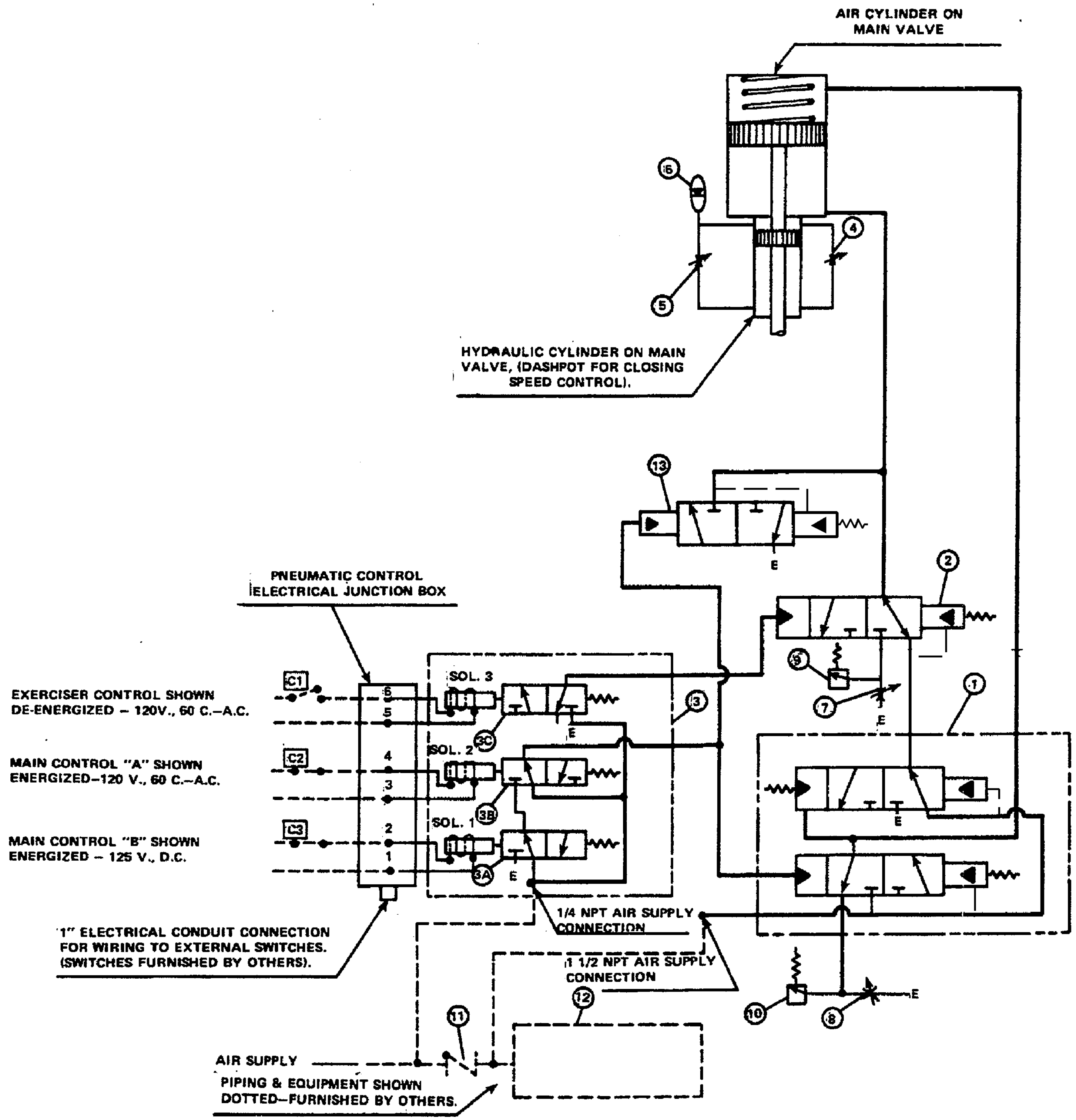
FIGURE 7.3-10

TYPICAL ISOLATION CONTROL SYSTEM FOR MAIN STEAM LINE ISOLATION VALVES



GENERAL ELECTRIC COMPANY DRAWING NO. 21217-H

SCHEMATIC CONTROL DIAGRAM

LEGEND

1. 1 1/4" FOUR-WAY, 5 PORTED, POPPET TYPE, AIR PILOT OPERATED VALVE (MAIN CONTROL VALVE).
2. 1 1/4" THREE-WAY AIR PILOT OPERATED VALVE (EXERCISER CONTROL VALVE).
3. 1/4" SOLENOID PILOT VALVE ASSEMBLY, CONSISTING OF:
   - 3A 1/4" THREE-WAY D.C. SOLENOID OPERATED VALVE (MAIN PILOT CONTROL VALVE).
   - 3B 1/4" THREE-WAY A.C. SOLENOID OPERATED VALVE (MAIN PILOT CONTROL VALVE).
   - 3C 1/4" THREE-WAY A.C. SOLENOID OPERATED VALVE (EXERCISER CONTROL VALVE).
4. 3/4" NEEDLE VALVE (FOR FINE ADJUSTMENT OF CLOSURE SPEED).
5. 3/4" NEEDLE VALVE (FOR COARSE ADJUSTMENT OF CLOSURE SPEED).
6. ACCUMULATOR (TO COMPENSATE FOR THERMAL EXPANSION OF OIL).
7. 1/2" AIR METERING VALVE (FOR ADJUSTMENT OF EXERCISER CLOSURE SPEED).
8. 3/4" AIR METERING VALVE (FOR ADJUSTMENT OF OPENING SPEED).
9. 3/4" RELIEF VALVE.
10. 1" RELIEF VALVE.
11. 1 1/2" CHECK VALVE (FURNISHED BY OTHERS).
12. AIR STORAGE TANK (FURNISHED BY OTHERS).
13. 1/2" TWO-WAY, POPPET TYPE, AIR PILOT OPERATED VALVE.

OPERATION

TO OPEN VALVE – CLOSE SWITCH C2 AND/OR SWITCH C3.

TO CLOSE VALVE – OPEN SWITCHES C2 AND C3.

TO EXERCISE VALVE CLOSED – CLOSE SWITCH C1 (SWITCHES C2 AND C3 CLOX

TO EXERCISE VALVE CLOSED – CLOSE SWITCH C1 (SWITCHES C2 AND C3 CLOSED).

TO OPEN AFTER EXERCISING – RETURN SWITCH C1 TO NORMAL OPEN POSITION.

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FIGURE 7.3-11

MAIN STEAM LINE ISOLATION SCHEMATIC

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FIGURE 7.3-12, SHEET 1

NUCLEAR STEAM SUPPLY SYSTEM
P&ID

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FIGURE 7.3-12 SHEET 2

NUCLEAR STEAM SUPPLY SYSTEM
P&ID

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FIGURE 7.3-12, SHEET 3

NUCLEAR STEAM SUPPLY SYSTEM P&ID

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FIGURE 7.3-13, SHEET 1

NUCLEAR BOILER SYSTEM FCD

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FIGURE 7.3-13, SHEET 2

NUCLEAR BOILER SYSTEM FCD

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FIGURE 7.3-13, SHEET 3

NUCLEAR BOILER SYSTEM FCD

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FIGURE 7.3-13, SHEET 4

NUCLEAR BOILER SYSTEM FCD

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FIGURE 7.3-13, SHEET 5

NUCLEAR BOILER SYSTEM FCD

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FIGURE 7.3-13, SHEET 6

NUCLEAR BOILER SYSTEM FCD

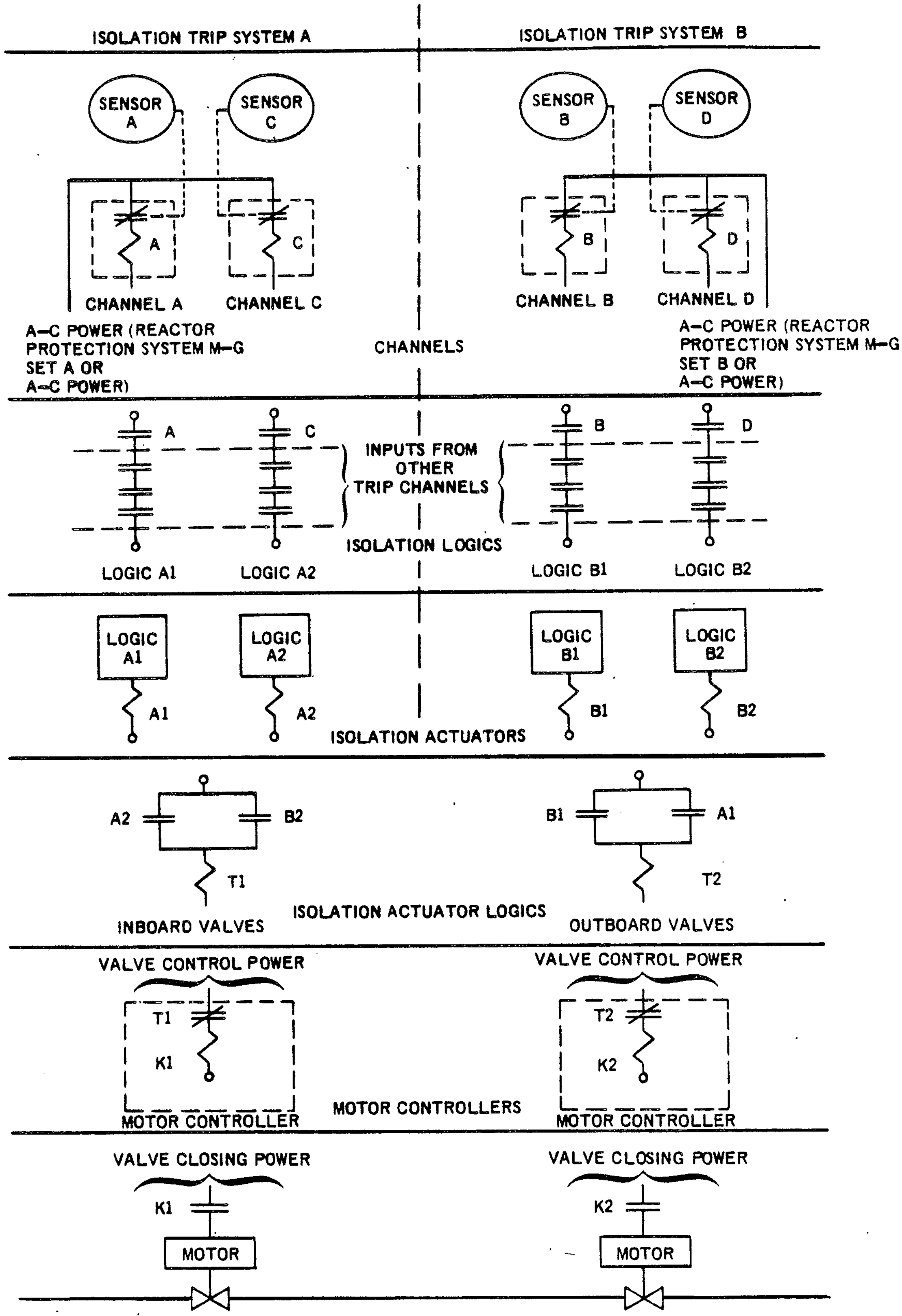

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FIGURE 7.3-14

TYPICAL ISOLATION CONTROL SYSTEM USING MOTOR-OPERATED VALVES

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Refer to Plant Drawing I-2440-01

FIGURE 7.3-15, SHEET 1

EMERGENCY EQUIPMENT COOLING
WATER LOGIC DIAGRAM

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Refer to Plant Drawing I-2440-03

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FIGURE 7.3-15, SHEET 2

**EMERGENCY EQUIPMENT COOLING
WATER LOGIC DIAGRAM**

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Refer to Plant Drawing I-2440-04

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FIGURE 7.3-15, SHEET 3

EMERGENCY EQUIPMENT COOLING WATER LOGIC DIAGRAM

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Refer to Plant Drawing I-2440-05

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FIGURE 7.3-15, SHEET 4

EMERGENCY EQUIPMENT COOLING WATER LOGIC DIAGRAM

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FIGURE 7.3-15, SHEET 5

EMERGENCY EQUIPMENT COOLING
WATER LOGIC DIAGRAM

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Refer to Plant Drawing I-2440-08

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FIGURE 7.3-15, SHEET 6

EMERGENCY EQUIPMENT COOLING
WATER LOGIC DIAGRAM

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Refer to Plant Drawing I-2440-09

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FIGURE 7.3-15, SHEET 7

EMERGENCY EQUIPMENT COOLING
WATER LOGIC DIAGRAM

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Refer to Plant Drawing I-2440-10

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FIGURE 7.3-15, SHEET 8

EMERGENCY EQUIPMENT COOLING
WATER LOGIC DIAGRAM

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Refer to Plant Drawing I-2440-06

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FIGURE 7.3-15, SHEET 9

EMERGENCY EQUIPMENT COOLING
WATER LOGIC DIAGRAM

7.4 SAFE-SHUTDOWN SYSTEMS

7.4.1 Description

7.4.1.1 Reactor Core Isolation Cooling System Instrumentation and Control

7.4.1.1.1 System Identification

7.4.1.1.1.1 Function

The reactor core isolation cooling (RCIC) system provides core cooling during reactor shutdown by pumping makeup water into the reactor pressure vessel (RPV) in case of a loss of flow from the main feedwater system. It is activated in time to preclude conditions that lead to inadequate core cooling.

7.4.1.1.1.2 Classification

Electrical modules for the RCIC system are classified as Safety Class 2 and Category I.

7.4.1.1.2 Power Sources

The RCIC pump is turbine driven and the RCIC trip system is powered by the Division I 260/130-V dc battery.

7.4.1.1.3 Equipment Design

When actuated, the RCIC system pumps water from either the condensate storage tank or the suppression chamber to the RPV via the feedwater lines. The RCIC system includes one turbine-driven pump, one barometric condenser dc vacuum pump, one vacuum dc condensate pump, automatic valves, control devices for this equipment, sensors, and logic circuitry. The arrangement of equipment and control devices is shown in Figure 5.5-7.

Pressure and level transmitters used in the RCIC system are located on racks in the reactor building. The only operating component of the RCIC system that is located inside the primary containment is one of the two RCIC system turbine steam supply isolation valves.

The rest of the RCIC system instrumentation and control components are located outside the primary containment. Cables connect the sensors to control circuitry in the main control room. The system is designed to allow a full flow functional test of the system during normal reactor power operation. The system will automatically return to normal system operation if called upon to do so during the test.

7.4.1.1.3.1 Initiating Circuits

Reactor pressure vessel low water level is monitored by four level transmitters which sense the difference between the pressure of a constant reference leg of water and the pressure resulting from the actual height of water in the vessel. Two pipelines, attached to taps above and below the water level on the RPV, are required for each of the two reference legs used with the RCIC. The lines are physically separated from each other and tap off the RPV at widely separated points. Two pairs of differential-pressure sensing lines from the two reference legs terminate outside the primary containment and inside the reactor building.

A backfill system is installed on each level instrument reference leg. The system provides a metered flow of water from the control rod drive system to each leg. The flow is low enough to not affect the performance of the instrumentation. The backfill is designed to prevent the accumulation of dissolved noncondensable gases in the reference legs.

The RCIC system is initiated only by low water level. The RCIC initiation circuit is arranged in a "one-out-of-two taken twice" logic.

The RCIC system is automatically initiated after the receipt of an RPV low water level signal, and produces the design flow rate within 50 sec. The controls then function to provide a flow of makeup water to the RPV until the amount of water delivered to the RPV is adequate to restore vessel level. At this time, the RCIC system automatically shuts down by closing the turbine steam supply valve and the steam warmup bypass valve, if it is still open. The system will automatically reinitiate if the water level returns to the low-level trip point. The controls are arranged to allow remote manual startup, operation, and shutdown.

The RCIC turbine is functionally controlled as shown in Figure 7.4-1. Minimizing initial peak speed of the turbine is accomplished by use of a warmup bypass valve. A speed governor limits the turbine speed to its maximum operating level. A control governor receives a RCIC system flow signal and adjusts the turbine steam control valve so that design pump discharge flow rate is obtained. Manual control of the governor is possible in the test mode; however, the governor automatically returns to automatic control on receipt of an RCIC system initiation signal. The flow signal used for automatic control of the turbine is derived from a differential pressure measurement across a flow element in the RCIC pump discharge line. The governor controls the position of the hydraulic operator on the turbine control valve, which in turn controls the steam flow to the turbine. Hydraulic pressure is supplied by the shaft-driven hydraulic oil pump.

The turbine is automatically shut down by tripping the turbine trip and throttle valve closed if any of the following conditions are detected

a. Turbine overspeed

b. High turbine exhaust pressure

c. An RCIC isolation signal from Logic A or B

d. Low pump suction pressure

e. Manual trip.

Turbine overspeed indicates a malfunction of the turbine control mechanism. High turbine exhaust pressure indicates a condition that threatens the physical integrity of the exhaust line. Low pump suction pressure warns that cavitation and lack of cooling can cause damage to the pump which could place it out of service. A turbine trip is initiated for these conditions so that the system can be quickly restored to service if the causes of the abnormal conditions can be found and corrected. The trip settings are selected far enough from normal values so that a spurious turbine trip is unlikely, but not so far that damage occurs before the turbine is shut down. Turbine overspeed is detected by a standard turbine overspeed mechanical device.

Two pressure switches are used to detect high turbine exhaust pressure; either switch can initiate turbine shutdown. One pressure switch is used to detect low RCIC system pump suction pressure.

High water level (Level 8) in the RPV indicates that the RCIC system has performed satisfactorily in providing makeup water to the RPV. Further increase in level could result in RCIC system turbine damage caused by gross carryover of moisture. The RPV high water level setting that closes the RCIC turbine steam supply valve is near the top of the steam separators and is sufficient to prevent gross moisture carryover to the turbine. Two level transmitters that sense differential pressure are arranged so that both transmitters are required to trip in order to halt RCIC operation.

UFSAR Section 7.5.1.4.2.1 describes that the wide-range water level system is uncompensated for variation in reactor water density and is calibrated to be most accurate at operational pressure and temperature conditions. At low reactor coolant temperatures and pressures, the higher water density causes the wide-range instruments to read higher than both the narrow-range instruments and the actual water level. Below approximately 550 psig, this phenomenon results in a wide-range level above the RPV high water level setting (Level 8) when the actual water level is normal. With wide-range level above Level 8, RCIC manual initiation is inhibited by the Level 8 trip signal. RCIC automatic initiation on RPV low water level (Level 2) remains available since the Level 8 signal is automatically reset by the occurrence of a Level 2 actuation signal. For accidents occurring below 600 psig for which RCIC may be effective, analysis has shown that RCIC automatic initiation at Level 2 is sufficient to perform the intended safety function and that the analyses of record from normal reactor pressure are bounding. Amendment 206 revised the Technical Specifications to indicate that the RCIC function of manual initiation is not required to be operable below a reactor pressure of 550 psig.

7.4.1.1.3.2 Logic and Sequencing

Reactor pressure vessel low water level automatically starts the RCIC system, as indicated in Figure 7.4-1.

The RCIC trip is powered by the Division I 260/130-V dc battery.

Instrument settings for the RCIC system instrumentation and control are listed in Table 7.4-1. The water level setting is far enough below normal levels that spurious RCIC system startups are avoided.

To prevent the turbine pump from being damaged by overheating at reduced RCIC pump discharge flow, a pump discharge bypass is provided to route the water discharged from the pump back to the suppression pool. The bypass is controlled by an automatic, dc motor-operated valve whose control scheme is shown in Figure 7.4-2. At RCIC high flow, the valve is closed; at low flow, the valve is opened. A flow switch that measures the pressure difference across a flow element in the RCIC pump discharge line provides the signals.

7.4.1.1.3.3 Bypasses and Interlocks

The RCIC steam supply line is maintained hot to prevent build-up of condensate by utilizing a condensate drain pot, steam line drain, and appropriate valves in a drain line arrangement just upstream of the turbine supply valve. The water level in the steam line drain condensate pot is controlled by a level switch and a solenoid piloted air operator, which energizes to allow condensate to bypass a manually controlled globe valve during periods of high condensate such as warming the steam line. The control scheme is shown in Figure 7.4-1. The controls position valves so that during normal operation, steam line drainage is routed to the main condenser. On receipt of a RCIC initiation signal and subsequent opening of RCIC turbine inlet valve E5150F045, the drainage path is isolated.

During test operation, the RCIC pump discharge is routed to the condensate storage tank. A dc motor-operated valve is installed in the pump-discharge-to-condensate-storage-tank line. The piping arrangement is shown in Figure 5.5-7. The control scheme for the valves is shown in Figure 7.4-1. On receipt of a RCIC system initiation signal, the valve closes and remains closed. The valve is interlocked closed if either of the suppression chamber suction valves is not fully opened. Numerous indications pertinent to the operation and condition of the RCIC system are available to the main control room operator. Figure 7.4-1 shows the various indications provided.

Keylock switches have been added to inboard and outboard steam isolation valve control circuitry, as shown in Figure 7.4-1, to ensure deliberate operator action to manually close these valves. Additionally, a control room annunciator alarms when the F007 and F008 valves are not in the fully open position. This prevents damage from water hammer caused by inadvertent valve reopening. Should either or both of these valves be closed, the outboard isolation valve can be slowly reopened to allow any moisture in the line to drain. Then line pressure across the inboard isolation valve is equalized, and the downstream line is warmed by slowly opening the inboard isolation valve.

7.4.1.1.3.4 Redundancy and Diversity

Four reactor water level sensors in a "one-out-of-two taken twice" circuit supply the signal which results from a loss-of-water inventory condition.

7.4.1.1.3.5 Actuated Devices

All automatic valves in the RCIC are equipped with remote manual test capability so that the entire system can be operated from the main control room. Motor-operated valves are provided with appropriate limit switches to turn off the motors when the fully open or fully closed positions are reached. Logic circuitry that controls valves which are automatically closed on isolation or turbine trip signals is equipped with manual reset devices so that the valves cannot be reopened without operator action. All required components of the RCIC controls operate independently of ac power.

To ensure that the RCIC system can be brought to design flow rate within 50 sec from the receipt of the initiation signal, the following maximum operating times for essential RCIC valves are provided by the valve operation mechanisms:

a. RCIC turbine steam supply valve - 45 sec

b. RCIC steam warmup bypass valve - 10 sec

c. RCIC pump discharge injection valves - 30 sec

d. RCIC pump minimum flow bypass valve - 25 sec

The operating time is the time required for the valve to travel from the fully closed to the fully open position, or vice versa. The two RCIC steam supply line isolation valves are normally open. They are intended to isolate the RCIC steam line in the event of a break in that line. A normally closed dc motor-operated isolation valve and a normally closed dc motor-operated warmup bypass valve are located in the turbine steam supply line just upstream of the turbine stop valve. The control schemes for these valves are shown in Figure 7.4-1. On receipt of a RCIC initiation signal, the valves open. The turbine steam supply valve remains open until closed by operator action or a level 8 trip. The warmup bypass valve remains open for 25 seconds then auto closes if a level 2 signal is not present.

Two normally open isolation valves are provided in the steam supply line to the turbine. The valve inside the drywell is controlled by an ac motor. The valve outside the drywell is controlled by a dc motor. The control diagram is shown in Figure 7.4-1. The valves automatically close on receipt of an RCIC isolation signal.

The instrumentation for RCIC isolation consists of the following:

a. Inside valve

   1. Ambient temperature sensor - emergency area cooler high temperature. Isolation is initiated immediately

   2. Differential pressure transmitter - RCIC steam line high flow or instrument line break. A time delay has been installed to prevent inadvertent system isolation due to pressure spikes associated with pump startup. The delay device setpoints (approximately 3 sec), along with the surveillance intervals, are included in the Technical Specifications

   3. Two pressure transmitters - RCIC turbine exhaust diaphragm high pressure. Both transmitters must activate to isolate

   4. Two pressure transmitters - RCIC steam supply pressure low. Both transmitters must activate to isolate.

b. Outside valve

   A similar set of instrumentation causes the outside valve to isolate with the addition of manual isolation if the low-level initiation signal is present.

Three pump suction valves are provided in the RCIC system. One valve lines up pump suction from the condensate storage tank, the other two from the suppression chamber. The condensate storage tank is the preferred source. All three valves are operated by dc motors. The control arrangement is shown in Figure 7.4-1. On receipt of an RCIC initiation signal, the condensate storage tank suction valve automatically opens. On receipt of a condensate storage tank low level signal, RCIC suction is automatically switched to the suppression pool. This is further discussed in Subsection 7.4.1.1.3.8.

Two dc motor-operated RCIC pump discharge valves are provided in the pump discharge line. The control schemes for these two valves are shown in Figure 7.4-1. Both valves are arranged to open on receipt of the RCIC initiation signal. One of the pump discharge valves closes automatically if a turbine trip occurs. The other valve remains open after RCIC initiation until closed by operator action in the main control room.

7.4.1.1.3.6 Separation

As in the emergency core cooling system (ECCS), the RCIC system is separated into divisions designated I and II (Subsection 7.3.1.2.1.6). The RCIC is a Division I system, but the inside steam line valve is in Division II: therefore, part of the RCIC logic is treated as Division II. The inside valve is an ac powered valve. The rest of the valves are dc-powered valves. Division I logic is powered by a 260/130-V dc Division I battery, and the Division II logic is powered by a 260/130-V dc Division II battery.

7.4.1.1.3.7 Testability

The RCIC may be tested to design flow during normal plant operation. Water is drawn from the condensate storage tank and discharged through a full flow test return line to the condensate storage tank. The discharge valve from the pump to the feedwater line remains closed during the test, and reactor operation remains undisturbed. Design of the control system is such that the RCIC system returns to the operating mode from the full flow test if system initiation is required.

7.4.1.1.3.8 Automatic Switchover of RCIC System Suction

In the original design, the switchover from the condensate storage tank to the suppression chamber as a source of water was to be manually controlled. However, as a result of discussions with the NRC, this was changed to automatically controlled. Automatic RCIC suction transfer occurs when the trip logic is deenergized. The trip logic is developed within the Division II HPCI system from redundant analog CST level transmitters and trip units. The HPCI level trip units provide redundant signals to the Division I RCIC suction transfer circuitry through auxiliary relay contacts. Either of these redundant low level signals will automatically open RCIC valves F029 and F031 (refer to Figures 5.5-7, 7.4-1, and 7.4-2). The RCIC suction transfer then uses the full-open position limit switches on F029 and F031 to initiate the closure of F010, the valve in the pump suction connection to the condensate storage tank. Panel status information is provided for the operator in the form of valve position indication.

The condensate storage tank level instrumentation is designed to meet the position of the NRC's Instrumentation and Controls System Branch with respect to freeze protection.

A single source connection penetrates the tank. This source connection is common to both the analog transmitters that monitor tank level for the purpose of transferring the RCIC/HPCI pump suction and the transmitter associated with the continuous wide- range tank level indication provided in the main control room. This equipment is contained within a large insulated steel cabinet (H21-P492) welded directly to the exterior of the condensate storage tank about 3 ft above ground level. The environment within the cabinet is maintained above freezing by a radiant strip heater and a local-control thermostat. A temperature-sensing device that is independent of the strip heater and its associated control thermostat is also located within the cabinet. This sensor produces a visual and audible alarm in the main control room whenever the temperature in the transmitter cabinet falls below 40°F. The cabinet temperature control and the low-temperature alarm are electrically independent and powered from completely independent and diverse power sources. A failure of either would not affect the ability of the other to perform its function. To guarantee the continued performance of the environmental control and monitoring systems, Edison will perform a yearly functional surveillance of the systems prior to the advent of freezing weather.

Edison has based its justification of the nonseismic location of the transmitters used in the suction transfer system primarily on the degree of conservatism in instrumentation seismic design. The level transmitters used in this transfer application were seismically qualified as described in the licensing topical report NEDO-21617.

Fermi site ground response spectra applicable to a transmitter mounting on the tank located at grade level would fall well below the values used for qualification of the transmitters in the reference document. As a result, the transmitters are expected to operate properly during and after a seismic event. As an added degree of conservatism, a failure of the tank which results in a loss of inventory and/or loss of the current signal from either transmitter will cause trip units (E41-N661 B and D) and associated trip relays to transfer the RCIC and HPCI suction valves to the suppression pool. These trip units and relays are located on the fourth floor of the reactor building in panel H21-P081. These devices and cabinet are located within the seismically qualified portion of the plant and meet the environmental and seismic qualification requirements for Class 1E electrical equipment.

All of the equipment that accomplishes the automatic suction valve transfer on low condensate tank level is classified as Quality Level 1. The transmitters were purchased as qualified instruments along with the balance of the transfer system and are included with the trip units and relays in the Technical Specifications because the surveillance requirement includes the entire measurement loop.

7.4.1.1.4 Environmental Considerations

The only RCIC control component located inside the primary containment that must remain functional in the environment resulting from a LOCA is the control mechanism for the inside isolation valve. The environmental capabilities of this valve are discussed in Subsection 7.3.2.2.9. The RCIC instrumentation and control equipment located outside the primary containment is selected in consideration of the normal and accident environments in which it must operate. Refer to Subsection 7.4.1.1.3.8 for information on the environmental considerations for the HPCI/RCIC instruments on the condensate storage tank.

Level sensing instrumentation used as inputs to the RCIC logic from residual heat removal (RHR) is discussed in Subsection 7.3.1.2.4.

7.4.1.1.5 Operational Considerations

7.4.1.1.5.1 General Information

Core cooling is required in the event that the reactor becomes isolated from the main condensers during normal operation by a closure of the main steam isolation valves (MSIVs). Cooling is necessary because of the core fission product decay heat. Steam is vented through the pressure safety/relief valves to the suppression pool. The RCIC system maintains reactor water level by providing the makeup water. Initiation and control are automatic.

The provisions taken in accordance with General Design Criterion (GDC) 19 of 10 CFR 50, Appendix A, to provide the required equipment outside the main control room for hot and cold shutdown, are described in Subsection 7.5.1.5.1.

7.4.1.1.5.2 Setpoints

A list of setpoints for the RCIC system can be found in Table 7.4-1.

7.4.1.2 Standby Liquid Control System Instrumentation and Control

7.4.1.2.1 System Identification

7.4.1.2.1.1 Function

The instrumentation and control system for the standby liquid control system (SLCS) is designed to inject water-soluble neutron-absorber solution well above saturation temperature.

7.4.1.2.1.2 Classification

The SLCS is a backup method of manually shutting down the reactor to cold subcritical independently from the control rod drive system. Thus, the system is considered a control system and not a safety system. The standby liquid control process equipment, instrumentation, and control essential for injection of the neutron-absorber solution into the reactor are designed to withstand Category I earthquake loads. Nonprocess equipment and instrumentation and control are designed as a nonseismic system. The SLCS has been reclassified to identify that it was not originally intended, procured, designed, or classified as safety related, but it will be maintained and tested as a safety-related system after completion of its preoperational tests.

7.4.1.2.2 Power Sources

The power supply to explosive valve F004A and injection pump C001A is from automatically restored MCC 72B-4C. The power supply to explosive valve F004B and injection pump C001B is from automatically restored MCC 72E-5B. The location of these pumps and valves is shown in Figure 7.4-3. The power supply to the tank heaters and heater controls can also be connected to an engineered safety feature (ESF) bus. The 120-V ac power supply to the main control room benchboard indicator lights is powered from an inductive BOP MPU, and the level and pressure transmitters are powered from restorable instrument MPU 1.

7.4.1.2.3 Equipment Design

7.4.1.2.3.1 Initiating Circuits

The standby liquid control is initiated in the main control room by turning a keylocking switch to either system A or system B. The key is removable in the center OFF position. When either system is initiated, both explosive valves (F004A and F004B) are fired, and the selected pump C001A or C001B is started. Should the selected pump fail to start, the key switch may be turned to the alternate pump.

7.4.1.2.3.2 Logic and Sequencing

When the SLCS is initiated, both the explosive valves fire and the pump that has been selected for injection starts.

7.4.1.2.3.3 Bypasses and Interlocks

There are no bypasses. When the SLCS is initiated to inject soluble neutron absorber into the reactor, the outboard isolation valve of the reactor water cleanup (RWCU) is automatically closed.

7.4.1.2.3.4 Redundancy and Diversity

The redundancy exists in duplicated pumps, explosive valves, and power supply as outlined in Subsection 7.4.1.2.2.

7.4.1.2.3.5 Actuated Devices

When the SLCS is initiated to inject soluble neutron absorber into the reactor, one of the two injection pumps and each of the two explosive valves are actuated.

7.4.1.2.3.6 Testability

The instrumentation and control system of the SLCS is tested when the system test is performed as outlined in Subsection 4.5.2.4.4.

7.4.1.2.4 Environmental Considerations

The environmental considerations for the instrumentation and control portions of the SLCS are the same as for the active mechanical components of the system. This is discussed in Section 3.11 and Subsection 4.5.2.4.3.

7.4.1.2.5 Operational Considerations

7.4.1.2.5.1 General Information

The control scheme for the SLCS can be found in Figure 7.4-3. The standby liquid control is manually initiated in the main control room by inserting the proper key into the keylocking switch and turning it to either system A or system B. The time it takes to complete the injection is between 50 and 125 minutes. When the injection is completed, the system is manually turned off by returning the keylocking switch to the OFF position.

7.4.1.2.5.2 Operator Information

The SLCS indicators are as follows:

a. The system pressure is indicated with an indicator that has a range of 0-1800 psig in the main control room

b. The storage tank level is indicated with an indicator that has a range of near empty to near full, calibrated to read in inches of liquid storage in the main control room

c. The continuity of the explosive valve dual primer ignition circuit is monitored by measuring a trickle current through the primers. If either of the dual primer or the primer ignition circuit becomes open-circuited, the continuity meter reads downscale

d. Indicator lights in the main control room show if either pump is running, stopped, or tripped

e. Indicator lights in the main control room show whether or not the explosive valve firing circuitry has continuity

f. Indicator lights in the main control room show if service valve F008 is open or closed, as shown in Figure 7.4-3

g. Indicator lights in the main control room show if the F006 check valve disk is open or closed

h. Indicator lights on the local panel show if the manually controlled high-power storage tank heater is on or off

i. Indicator lights on the local panel for the low-power storage tank heater have been de-energized and abandoned in place.

The SLCS main control room annunciators annunciate when

a. There is a loss of continuity of either explosive valve primers

b. The standby liquid storage temperature becomes too hot or too cold

c. The standby liquid tank level is too high or too low.

7.4.1.2.5.3 Setpoints

The SLCS has setpoints for the various instruments as follows:

a. The loss of continuity meter is set to activate the annunciator just below trickle current that is observed when the primers of the explosive valves are new

b. The high and low standby liquid temperature switch is set to activate the annunciator at temperatures of approximately 110°F and 48°F, respectively

c. The high and low standby liquid storage tank level switch is set to activate the annunciator when the volume is approximately 2975 gal net and 2618 gal net of the storage tank capacity, respectively

7.4.1.3 Reactor Shutdown Cooling System Instrumentation and Control

7.4.1.3.1 System Identification

The shutdown cooling mode is a function of the RHR system and is placed in operation during a normal shutdown and cooldown.

7.4.1.3.2 Power Sources

The power sources for the reactor shutdown cooling system instrumentation and control are as described in the ECCS discussion in Subsection 7.3.1.2.

7.4.1.3.3 Equipment Design

The reactor water is cooled by taking suction from one of the recirculation loops as shown in Figure 5.5-13. During the shutdown cooling mode, only one RHR system heat exchanger is required. This allows the remaining RHR system division to be held in standby for use in either the low-pressure coolant injection (LPCI) mode or containment cooling mode. One RHR division's valve alignment is shifted from the standby mode lineup (suction from the torus) needed for LPCI and containment cooling to the shutdown mode lineup (suction from reactor recirculation loop-B) after the reactor is depressurized. One RHR heat exchanger removes enough decay heat, even with declining reactor water approach temperature, so that the proper cooldown rate may be achieved.

If it is necessary to discharge a complete core load of reactor fuel to the spent fuel pool, the cooling capacity of the fuel pool cooling and cleanup system (FPCCS) heat exchangers may be exceeded. A means is provided for making a physical connection between the spent fuel pool and the RHR system. The RHR heat exchangers have greater cooling capacity than the FPCCS heat exchangers, and can maintain the spent fuel pool within its design temperature until the decay heat load is within the capacity of the FPCCS.

7.4.1.3.3.1 Initiating Circuits

The reactor shutdown cooling system is initiated only by manual action. The system cannot be actuated unless certain requirements, described in the following subsections, are met.

7.4.1.3.3.2 Bypasses and Interlocks

To prevent opening the shutdown cooling valves except under proper conditions, interlocks are provided as shown in Table 7.4-2.

The two RHR pumps used for shutdown cooling are interlocked to trip the pumps if the shutdown cooling valves and suction valves from the suppression pool are not properly positioned.

7.4.1.3.3.3 Actuating Devices

All motor-operated valves in the shutdown cooling system are equipped with remote manual switches in the main control room.

7.4.1.3.3.4 Testability

The shutdown cooling system pumps of the RHR system may be tested to full capacity during normal plant operation.

7.4.1.3.4 Environmental Considerations

The only shutdown cooling control component located inside the drywell that must remain functional in the environment is the control mechanism for the (inboard) isolation shutdown cooling suction valve. The environmental capabilities of this valve are discussed in Subsection 7.3.2.2.9. The instrumentation and control equipment located outside the drywell is selected in consideration of the normal and accident environments in which it must operate.

7.4.1.3.5 Operational Considerations

All controls for the shutdown cooling system are located in the main control room. Operator information is provided as described in the RHR discussion of the LPCI mode in Subsection 7.3.1.2.4.

The provisions taken in accordance with GDC 19 of 10 CFR 50, Appendix A, to provide the required equipment outside the main control room for hot and cold shutdown, are described in Subsection 7.5.1.5.1.

7.4.2 Analysis

7.4.2.1 General

Presented below are analyses that show how the safe shutdown systems satisfy their design bases listed in Section 7.1.

7.4.2.2 Reactor Core Isolation Cooling System Instrumentation and Control

7.4.2.2.1 Conformance To General Functional Requirements

For events other than pipe breaks, the RCIC system has a makeup capacity sufficient to prevent the RPV water level from decreasing to the level where the core is uncovered without using the ECCS.

To ensure to a high degree that the RCIC system operates when necessary and in time to provide adequate core cooling, the power supply for the system is taken from reliable sources that are immediately available. Evaluation of instrumentation configuration for the RCIC system shows that no failure of a single initiating sensor either prevents the starting or causes false starting of the system.

A design flow functional test of the RCIC system can be performed during plant operation by taking suction from the demineralized water in the condensate storage tank and discharging through the full flow test return line back to the condensate storage tank.

During the test, the discharge valve to the feed line remains closed and reactor operation is undisturbed. Control system design provides automatic return from the full flow test mode to the operating mode if system initiation is required during testing.

7.4.2.2.2 Conformance To Specific Regulatory Requirements of IEEE 279-1971

7.4.2.2.2.1 Single-Failure Criterion (IEEE 279-1971, Paragraph 4.2)

The RCIC system, by itself, is not required to meet the single- failure criterion. The control logic circuits for the RCIC system initiation and control are housed in a single relay cabinet, and the power supply for the control logic and other RCIC equipment is from a single dc power source.

The RCIC initiation sensors and wiring up to the RCIC relay logic cabinet do, however, meet the single-failure criterion. Physical separation of instrument lines is provided so that no single instrument rack destruction or single instrument line (pipe) failure can prevent RCIC initiation. Wiring separation between divisions also provides tolerance to single wireway destruction (including shorts, opens, and grounds) in the accident detection portion of the control logic. The single-failure criterion is not applied to the logic relay cabinet or to other equipment required to function for RCIC operation.

7.4.2.2.2.2 Quality Components (IEEE 279-1971, Paragraph 4.3)

This requirement is described in NEDO-10139, which applies equally to the core spray and RCIC systems.

7.4.2.2.2.3 Equipment Qualification (IEEE 279-1971, Paragraph 4.4)

Environmental

No components of the RCIC control system are required to operate in the drywell environment. The RCIC steam line isolation valve located inside the drywell is a normally open valve and is required to operate only to isolate the primary containment.

Other process sensor equipment for RCIC initiation is located in the reactor building and is capable of accurate operation in ambient temperature conditions that result from abnormal conditions.

Panels and relay cabinets are located in typical power station control room and/or auxiliary relay room environments. Therefore, environmental testing of components mounted in these enclosures is not warranted.

There are no components in the RCIC control system that have not demonstrated their reliable operability in previous applications in nuclear power plant protection systems or in extensive industrial use.

7.4.2.2.2.4 Channel Integrity (IEEE 279-1971, Paragraph 4.5)

The RCIC system instrument initiation channels meet the single- failure criterion as discussed in Subsection 7.4.2.2.2.1 above, and thus satisfy the channel integrity objective of this paragraph.

By definition (IEEE 279-1971, Paragraph 2.2), a channel loses its identity where single-action signals are combined. Therefore, since instrument channels are combined into a single trip system, this paragraph of IEEE 279-1971 does not strictly apply for the RCIC control system.

7.4.2.2.2.5 Channel Independence (IEEE 279-1971, Paragraph 4.6)

Channel independence for initiation sensors is provided by electrical and mechanical separation. The A and C sensors for RPV level, for instance, are located on one local instrument panel identified as Division I equipment, and the B and D sensors are located on a second instrument panel widely separated from the first and identified as Division II equipment.

The A and C sensors have a common pair of process taps that are widely separated from the corresponding taps for sensors B and D. Disabling of one or both sensors in one location does not disable the control for RCIC initiation.

7.4.2.2.2.6 Control and Protection Interaction (IEEE 279-1971, Paragraph 4.7)

The RCIC system is strictly an off-on system, and no signal whose failure could cause need of RCIC can also prevent RCIC from starting. Annunciator circuits using contacts of sensor relays and logic relays cannot impair the operability of the RCIC system control because of the electrical separation between controls. A short between the annunciator wiring and the RCIC control wiring could result in a single ground on the dc control circuit without affecting circuit operability.

7.4.2.2.2.7 Derivation of System Inputs (IEEE 279-1971, Paragraph 4.8)

The input that starts the RCIC system is a direct measure of the variable that indicates need for core cooling; e.g., RPV low water level.

7.4.2.2.2.8 Capability for Sensor Checks (IEEE 279-1971, Paragraph 4.9)

All sensors are of the pressure-sensing type and are installed with calibration taps and instrument valves so that testing during normal plant operation or during shutdown is permitted.

The reactor low-pressure transmitters can be easily checked for operability during plant operation by observing the analog output of respective transmitters. The RPV level transmitters are also checked for operability in a similar fashion. Refer to Subsection 7.1.3.1.

7.4.2.2.2.9 Capability for Test and Calibration (IEEE 279-1971, Paragraph 4.l0)

The RCIC control system is capable of being completely tested under normal plant operation to verify that each element of the system, active or passive, is capable of performing its intended function. Sensors can be exercised by applying test pressures.

The RCIC system can be manually started in the test mode by opening steam supply valves to the RCIC turbine to pump water from the condensate storage tank through the test return valves back to the condensate storage tank, while the reactor is at pressure.

Motor-operated valves can be exercised by the appropriate control relays and starters, and all indications and annunciations can be observed as the system is tested.

7.4.2.2.2.10 Channel Bypass or Removal From Operation (IEEE 279-1971, Paragraph 4.11)

Calibration of a sensor that introduces a single instrument channel trip will not cause a protective function without the coincident trip of a second channel. There are no instrument channel bypasses in the RCIC system. Removal of a sensor from operation during calibration does not prevent the redundant instrument channel from functioning.

7.4.2.2.2.11 Operating Bypasses (IEEE 279-1971, Paragraph 4.12)

The RCIC system design contains no operating bypasses.

7.4.2.2.2.12 Indication of Bypasses (IEEE 279-1971, Paragraph 4.13)

Indication of bypasses provided is as discussed in Subsection 7.4.2.2.2.11.

7.4.2.2.2.13 Access To Means for Bypassing (IEEE 279-1971, Paragraph 4.14)

Access to motor control centers and instrument valves is controlled. Access to other means of bypassing is located in the main control room and is therefore under the administrative control of the operators.

7.4.2.2.2.14 Multiple Setpoint (IEEE 279-1971, Paragraph 4.15)

This is not applicable because all setpoints are fixed.

7.4.2.2.2.15 Completion of Protective Action Once It Is Initiated (IEEE 279-1971, Paragraph 4.16)

The final control elements for the RCIC system are essentially bi-stable, i.e., motor-operated valves stay open or closed once they have reached their desired position, even though their starter may drop out (which they do when the limit switch is reached). In the case of pump starters, the automatic initiation signal is electrically sealed in.

Thus, once protection action is initiated (i.e., flow established), it must go to completion or continue until terminated by deliberate operator action or automatically stopped on high vessel water level or system malfunction trip signals.

7.4.2.2.2.16 Manual Actuation (IEEE 279-1971, Paragraph 4.17)

Each piece of RCIC actuation equipment required to operate (pumps and valves) is capable of manual initiation electrically from the control panel in the main control room. Failure of logic circuitry to initiate the RCIC system will not affect the manual control of equipment.

However, failures of active components or control circuit failure which produces a turbine trip may disable the manual actuation of the RCIC system. Failures of this type are continuously monitored by alarms.

7.4.2.2.2.17 Access To Setpoint Adjustment (IEEE 279-1971 Paragraph 4.18)

Setpoint adjustments for the RCIC system sensors are integral with the sensors on the local instrument racks and cannot be changed without the use of tools to remove covers over these adjustments. Control relay cabinets are capable of being locked to prevent unauthorized actuation. Because of these restrictions, compliance with this requirement of IEEE 279-1971 is considered complete.

7.4.2.2.2.18 Identification of Protective Actions (IEEE 279-1971, Paragraph 4.19)

Protective actions are directly indicated and identified by annunciator operation or action of the sensor relay, which has an identification tag and a clear glass window front that permits convenient visible verification of the relay position. This combination of annunciation and visible relay actuation is considered to fulfill the requirements of this criterion.

7.4.2.2.2.19 Information Readout (IEEE 279-1971, Paragraph 4.20)

The RCIC control system is designed to provide the operator with accurate and timely information pertinent to its status. It does not introduce signals into other systems that could cause anomalous indications confusing to the operator. Periodic testing is the means provided for verifying the operability of the RCIC components and, by proper selection of test periods, to be compatible with the historically established reliability of the components tested, complete and timely indications are made available. Sufficient information is provided on a continuous basis so that the operator can have a high degree of confidence that the RCIC function is available and/or operating properly.

In addition to the annunciator alarms shown on the functional control diagram in Figure 7.4-1, the following alarms are provided:

a. Failure of control power to the RCIC system

b. Valve overload alarm.

In addition to the annunciators, the other indications on the main control room panel are

a. Valve position lights

b. Pump monitor lights

c. Pump suction/discharge pressure indicator

d. RCIC pump flow indicator

e. Turbine exhaust line pressure indicator

f. Turbine steam inlet pressure indicator

g. Turbine speed indicator

h. Turbine supervisory indicators.

i. Barometric condenser vacuum pump current

j. Barometric condenser condensate pump current

7.4.2.2.2.20 System Repair (IEEE 279-1971, Paragraph 4.21)

The RCIC control system is designed to permit repair or replacement of components.

Recognition and location of a failed component will be accomplished during periodic testing. The simplicity of the logic will make the detection and location relatively easy, and components are mounted in such a way that they can be conveniently replaced in a short time. Sensors that are connected to the instrument piping cannot be changed so readily but are connected with separable screwed or bolted fittings.

7.4.2.2.2.21 Identification (IEEE 279-1971, Paragraph 4.22)

The RCIC system is identified uniquely as a Division I system. All controls and instruments are located in one area of the main control room panel and are clearly identified by nameplates.

Relays are located in one panel for RCIC use only. Relays and panels are identified by nameplates.

7.4.2.2.3 Conformance To Specific Regulatory Requirements

The RCIC system conforms to the following regulatory requirements:

a. IEEE 323-1971 - This is discussed in Section 3.11 and GE Topical Report NEDO-10698

b. IEEE 338-1971 - Only paragraphs of IEEE 338-1971 that apply to the design of the RCIC system will be covered

   Capability for Sensor Checks (IEEE 338-1971, 2.1) is discussed in Subsection 7.4.2.2.2.8. Capability for Test and Calibration (IEEE 338-1971, 2.2) is discussed in Subsection 7.4.2.2.2.9

c. IEEE 344-1971 - This is discussed in Topical Report NEDO-10678

d. 10 CFR 50, Appendix A requirements -

   1. Criterion 13 - Subsections 7.4.1.1.3.1, 7.4.1.1.3.2, 7.4.1.1.3.3

   2. Criterion 37 - Subsection 7.4.1.1.3.7.

e. 10 CFR 50, Appendix B requirements - The requirements of 10 CFR 50, Appendix B, are met as described in Chapter 17

f. Regulatory Guide 1.22 - Subsections 7.4.2.2.2.8 and 7.4.2.2.2.9.

7.4.2.3 Standby Liquid Control System Instrumentation and Control

7.4.2.3.1 Conformance To General Functional Requirements

Redundant positive displacement pumps, explosive valves, and control circuits for these components have been provided as described in Subsection 7.4.1.2. This constitutes all the active equipment required for injection of the sodium pentaborate solution. Continuity relays provide monitoring on the explosive valves, and indicator lights provide indication on the main reactor control panel of system status as described in Subsection 7.4.1.2.5.2. Testability is described in Subsection 7.4.1.2.3.6. Redundant power sources are described in Subsection 7.4.1.2.2.

7.4.2.3.2 Conformance To Specific Regulatory Requirements

Qualification of Class 1E electrical equipment in accordance with IEEE 323-1971 and seismic design of Class 1E electrical equipment in accordance with IEEE 344-1971 are covered in Topical Reports NEDO-10698 and NEDO-l0678, respectively, and Sections 3.11 and 3.10.

The requirements of 10 CFR 50, Appendix B, are described in Chapter 17.

7.4.2.4 Reactor Shutdown Cooling System Instrumentation and Control

7.4.2.4.1 Conformance To General Functional Requirements

The design of the reactor shutdown cooling system instrumentation and controls meets all the functional requirements of Subsection 7.1.2.1.27 as follows:

7.4.2.4.1.1 Valves

Manual controls and position indicators are provided in the main control room. Interlocks are provided to prevent opening of the valves if shutdown conditions are not met. Interlocks are also provided to close the valves if an isolation signal is present or if high reactor pressure exists.

Redundant sensors (N111A and B) are provided for the RHR shutdown cooling pressure interlocks. These sensing loops meet or exceed the EICSB-3 Branch Technical Position. The interlocks are designed as part of the testability option and, therefore, formal diversity of the sensors and trip units has not been provided. Formal test procedures are used to verify operability of the interlocks. It is Edison's position that the accuracy, reliability, testing, and inherent on-line status monitoring of the analog transmitter/trip unit design obviate the need for diverse instruments.

7.4.2.4.1.2 Instrumentation

Shutdown flow indicator is provided. The RHR cooling water and service water temperatures are provided. Head spray flow indication is no longer provided. A permanent modification has removed the head spray piping, disabling this flow path.

7.4.2.4.1.3 Annunciation

The following annunciators are provided:

a. Division I/Division II RHR valves thermal overload

b. RHR heat exchanger cooling water discharge temperature high

c. RHR system overpressure

d. RHR pump motor tripped.

7.4.2.4.1.4 Pumps

Manual controls and stop and start indicators are provided in the main control room. Interlocks are provided to trip the pumps if the shutdown cooling valves are not properly set up.

7.4.2.4.2 Conformance To Specific Regulatory Requirements

Conformances to regulatory requirements are the same as those specified for the ESF systems.

Consideration of failure of plant instrument air and loss of cooling water to safe-shutdown equipment is given in Chapter 15. These systems are not specifically designed for consideration of plant load rejection or turbine trip, but the plant is designed to handle those situations and shut down safely.

TABLE 7.4-1 REACTOR CORE ISOLATION COOLING INSTRUMENT SPECIFICATION

RCIC Function	Instrument	Trip Settings[a]	Range
RPV high water level turbine trip	Level transmitter	Level 8[b]	10 to 220 in.[c]
Turbine exhaust diaphragm high pressure	Pressure transmitter	10 psig	0 to 30 psi
RCIC system pump low suction pressure	Pressure switch	Low - 20 in. Hg vacuum[d]	30 in. Hg vacuum to 10 psig
RCIC system pump high suction pressure	Pressure switch	High - 70 psig	0.5 to 80 psig
RPV low water level[e]	Level transmitter	Level 2[b]	10 to 220 in.[c]
RCIC system steam supply low pressure	Pressure transmitter	50 psig	0 to 200 psig
Turbine overspeed	Centrifugal device	122.3 percent of rated speed	

[a] Nominal values are given for information. See the Technical Specifications for operational limits.

[b] Figure 7.3-12.

[c] Zero is at the top of the active fuel.

[d] Approximate setting.

[e] Incident detection circuitry instrumentation.

TABLE 7.4-2 REACTOR SHUTDOWN COOLING BYPASSES AND INTERLOCKS

Valve Function Manual Open	Reactor Pressure Exceeds Shutdown	Isolation Valve Closure Signal
Inboard suction isolation	Cannot open	Cannot open
Outboard suction isolation	Cannot open	Cannot open
Reactor injection	Can open	Cannot open
Head spray[c]	Cannot open	Cannot open

Valve function Automatic[a] close or Manual[b] close		
Inboard suction isolation	Closes A and M	Closes A and M
Reactor injection	Closes A and M	Closes A and M
Head spray[c]	Closes A and M	Closes A and M

[a] Automatic is abbreviated as "A."

[b] Manual is abbreviated as "M."

[c] Head spray piping attached to reactor pressure vessel (RPV) is removed. The remaining pipe in drywell is blanked off.

Figure Intentionally Removed
Refer to Plant Drawing I-2230-01

Fermi 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 7.4-1, SHEET 1

REACTOR CORE ISOLATION COOLING SYSTEM FCD

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Refer to Plant Drawing I-2230-02

Fermi 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 7.4-1, SHEET 2

REACTOR CORE ISOLATION COOLING SYSTEM FCD

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Refer to Plant Drawing I-2230-03

Fermi 2

UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 7.4-1, SHEET 3

REACTOR CORE ISOLATION COOLING SYSTEM FCD

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Refer to Plant Drawing I-2230-04

Fermi 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 7.4-1, SHEET 4

REACTOR CORE ISOLATION COOLING SYSTEM FCD

Figure Intentionally Removed
Refer to Plant Drawing I-2230-05

Fermi 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 7.4-1, SHEET 5

REACTOR CORE ISOLATION COOLING SYSTEM FCD

Figure Intentionally Removed
Refer to Plant Drawing I-2230-06

Fermi 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 7.4-1, SHEET 6

REACTOR CORE ISOLATION COOLING SYSTEM FCD

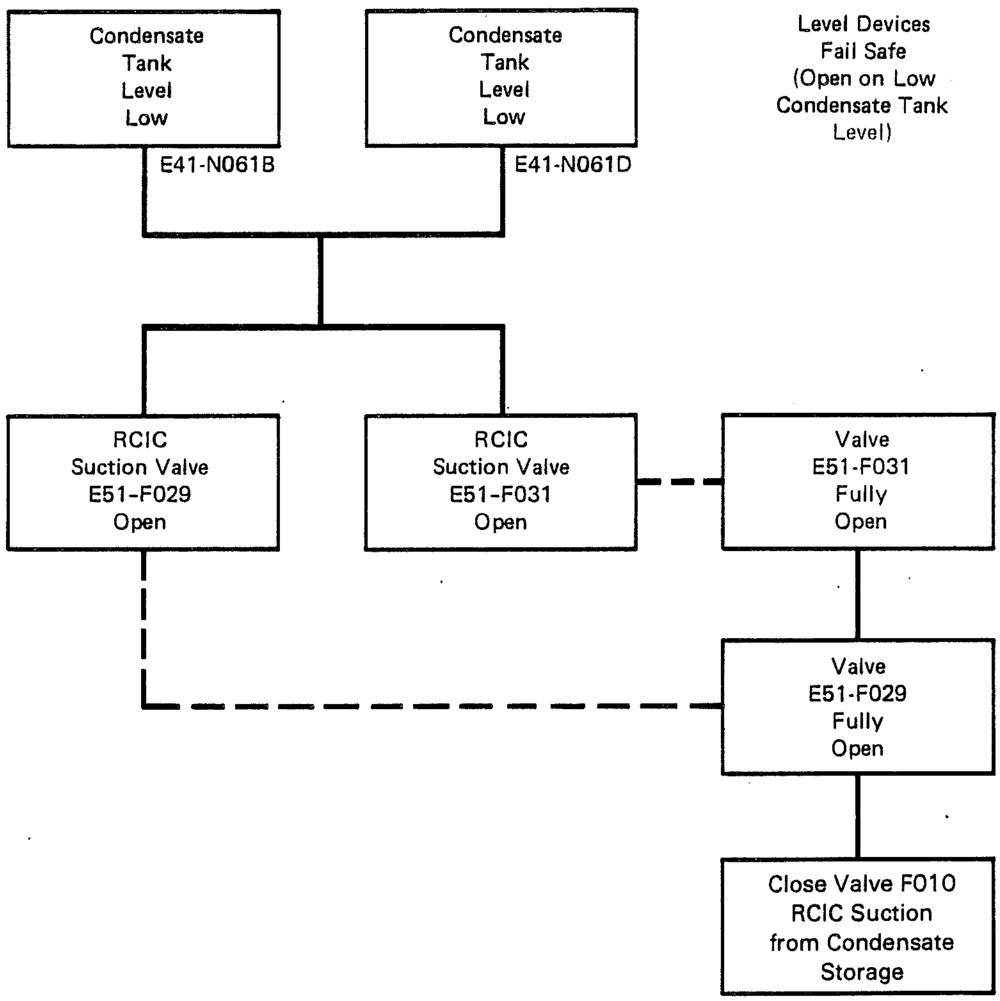

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FIGURE 7.4-2

SIMPLIFIED LOGIC DIAGRAM OF REACTOR CORE ISOLATION COOLING AUTOMATIC SUCTION SWITCHOVER

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Refer to Plant Drawing I-2130-01

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FIGURE 7.4-3

STANDBY LIQUID CONTROL SYSTEM FCD

7.5 SAFETY-RELATED AND POWER GENERATION DISPLAY INSTRUMENTATION

7.5.1 Description

7.5.1.1 General

A description of the instrumentation that provides information to the operator to enable him to perform required safety functions is provided in this subsection.

A Human Factors Engineering design review program was established to maintain control room and remote shutdown panel instrumentation in conformance with the general human factors conventions adapted from NRC Human Factors Criteria (NUREG-0700 “Guidelines for Control Room Design Reviews”) as well as plant specific conventions. This program was originally described in section 5.0 of Supplement 2 to the DCRDR “Summary Report for the Fermi 2 Control Room.”

7.5.1.2 Normal Operation

The normal plant process variable indicators and recorders are described in Section 7.6 and are shown on the piping and instrumentation diagrams for the various nuclear steam supply systems (NSSSs). Information channel ranges and indicators are selected on the basis of giving the operator the necessary information, during expected operational perturbations, to perform all the normal plant maneuvers and to be able to track all the process variables pertinent to safety. Description of the control rod position indicating system is given in Subsection 7.7.1.1.5.

7.5.1.3 Abnormal Transient Occurrences

The ranges of indicators and recorders provided are capable of covering the extremes of process variables and providing necessary information to enable the operator to perform required safety functions.

7.5.1.4 Accident Conditions

Information readouts are provided to accommodate events up to and including a LOCA. These readouts are designed from the standpoint of operator action, information, and event tracking requirements, providing assurance that requirements for all other credible events or incidents will be covered.

7.5.1.4.1 Initial Accident Event

The design basis of all engineered safety feature (ESF) systems to mitigate accident event conditions takes into consideration that no operator action or assistance is necessary for the first 10 minutes of the event. This requirement makes it mandatory that all protective action necessary in the first 10 minutes be automatic. Therefore, although continuous tracking of process variables is available, no operator action based on them is required or recommended.

7.5.1.4.2 Postaccident Tracking

After 10 minutes, operator action is optional, based on the information available. Within 30 minutes, however, containment cooling must be initiated.

The process instrumentation described in the following subsections provides information to the operator for his use in monitoring reactor conditions after a LOCA.

This instrumentation was designed to conform to the requirements of Regulatory Guide 1.97 [formerly, Branch Technical Position (BTP) ICSB-23]. A formal type-test seismic qualification based on IEEE Standard 344-1971 was obtained for the strip-chart recorders used in the systems.

Details of the tests performed are available in the General Electric Seismic Summary Report for panel H11-P602, dated December 1977.

7.5.1.4.2.1 Reactor Water Level

Appropriate vessel water level instrumentation described below is operable during and after postulated design-basis accidents.

The emergency core cooling system (ECCS) equipment and reactor protection and containment isolation system initiation is automatic. In addition, 11 level indicators are located in the control room. These instrument designations, their ranges, and control room location are presented in Table 7.5-1. Their ranges vary to cover the active fuel to the top of the reactor vessel so that the required range of the reactor vessel water level is monitored.

Two wide-range water level signals are transmitted from two nuclear boiler system independent differential pressure transmitters and are recorded on two, multi-point recorders in the main control room. One point records the wide-range level and the other point records the reactor pressure on each of the two recorders. The differential pressure transmitters have one side connected to a condensing-type chamber reference leg and the other side connected directly to a vessel nozzle for the variable leg. The water level system is uncompensated for variation in reactor water density and is calibrated to be most accurate at operational pressure and temperature conditions. The range of the recorded level is from the top of the feedwater control range (just above the high level turbine trip point) down to a point near the top of the active fuel. The power sources for the two channels are inverter-fed from the two divisional batteries. Both pressure and level recorders are equipped to automatically switch from a low (normal) speed to high speed when signal levels reach preset values as shown in Figure 7.3-12.

Two fuel-zone water level signals are transmitted from two nuclear boiler system independent differential-pressure transmitters. Signals go to water level recorders (programmable), one in each division. The differential-pressure transmitters have one side connected to a condensing-type chamber reference leg and the other side connected directly to the bottom tap of a calibrated jet pump for the variable leg. The water level system is uncompensated for variation in reactor water density and is calibrated to be most accurate at saturated atmospheric conditions. The programmable recorders perform mathematical conversion of the fuel-zone water level measurements to readings which account for the difference between calibration and off-calibration conditions expected during the accident.

The recorders use reactor vessel pressure signals to calculate the signal conversions. The level range is from near the bottom of the active fuel to over the top of the active fuel, as shown in Figure 7.3-12. The ranges of the wide-range level and the fuel-zone level overlap. Power sources are as stated in the previous paragraph. The feedwater control system has other reactor water level recorders/indicators in the main control room.

Fermi 2 is a BWR/4 design that uses only nonheated reference columns that are maintained full of condensate by the condensing chambers for all of the level measurements. A backfill system is installed on each level instrument reference leg. The system provides a metered flow of water from the control rod drive system to each leg. The flow is low enough to not affect the performance of the instrumentation. The backfill is designed to prevent the accumulation of dissolved noncondensable gases in the reference legs. Yarway reference columns are not used. Reactor vessel taps are divided into two separate divisions to maintain spatial diversity. Fermi 2 has three upper-steam-space taps (one on the head vent line), similar to the BWR/3 design. There are two intermediate (water zone) taps that sense the water variable leg inside the vessel annulus approximately 13 ft above the top of the active fuel. There are two lower taps that sense the water variable leg inside the vessel annulus outside the core shroud at approximately 10 in. above the top of the active fuel. Additionally, two lower taps that sense the water variable leg inside the jet pump above the pump diffuser tap similar to the BWR/3 are provided.

The power for the feedwater system level instrumentation is supplied from a vital instrument bus. Power is supplied to the reactor protection system (RPS) trip system level instruments from the RPS motor-generator sets. Power for the balance of the level instrumentation that is part of the ECCS is supplied by safety-grade inverter power supplies powered by the appropriate divisional battery.

With respect to drywell sensing line routing, Fermi 2 meets the requirements outlined in Figure 2.3.2.2-8 of NEDO 24708A, and, therefore, the level instruments are relatively independent of drywell temperature changes.

All of the level sensors are located on spatially separated divisional safety-grade instrument racks located in the reactor building approximately 15 ft from the drywell wall. All the level instrument channel response times are well within the design criteria.

In response to NRC requests for additional information on water level indication errors, Edison has provided information to further demonstrate the adequacy of the Fermi 2 water-level instrument design in response to high drywell temperatures that may lead to reference-leg flashing. In the unlikely case that flashing occurred, the expected error would be about 4 in. of indicated level. Even if the entire reference-leg portion in the drywell boiled off, the hypothetical error would not seriously impact adversely either manual or automatic actions to safely mitigate the worst-case transient identified.

7.5.1.4.2.2 Reactor Pressure

Two reactor pressure signals are transmitted from two independent pressure transmitters and are recorded on two, multi-point recorders in the main control room (same recorders described in Subsection 7.5.1.4.2.1 above). One point records pressure; the other records the wide-range level. The range of recorded pressure is from 0 to 1500 psig. Additionally, fuel-zone water level recorders (programmable) use reactor pressure signals to correct water level measurements for off-calibration pressure. The feedwater control system has other pressure signals recorded in the main control room. This range is sufficient to include the safety limit pressure.

7.5.1.4.2.3 Shutdown, Isolation, and Core Cooling Indication

The following information furnished to the main control room operator permits him to assess reactor shutdown, isolation, and availability of emergency core cooling following the postulated accidents.

a. Reactor shutdown occurs as one or more process variables exceed their specified setpoint. Operator verification that shutdown has occurred may be made by observing one or more of the following indications:

   1. Control rod status lamps indicating each rod fully inserted. Power source is a battery-powered inverter supply (Figure 7.5-1)

   2. Control rod scram valve status lamps indicating open valves. Power source is a battery-powered inverter supply (Figure 7.5-1)

   3. Neutron-monitoring power-range channels and recorders downscale. Power sources are the RPS motor-generator sets (Figure 7.5-1) and battery-powered inverters

   4. Annunciators for RPS variables and trip logic in the tripped state. Power source is dc from station battery (Figure 7.5-1)

   5. Logging of control rod positions on the Integrated Plant Computer System (IPCS). Power source is computer power supply from uninterruptible power supply (UPS) A and B

   6. Events recorder logging of trips. Power source is from station battery.

b. Reactor isolation occurs after the accident as various environmental and process variables exceed their setpoints. The operator may verify reactor isolation by observing one or more of the following indications:

   1. Isolation valve position lamps indicating valve closure. Power source is the same as for the associated motor operator

   2. Main steam line flow indication downscale. Power source is a battery-powered inverter supply (Figure 7.5-1)

   3. Annunciators for the primary RPS variables and trip logic in the tripped state. Power source is dc from station battery

   4. Events recorder logging of trips.

c. Operation of emergency core cooling following the LOCA may be verified by observing the following instrumentation:

1. Annunciators for high pressure coolant injection (HPCI), core spray, residual heat removal (RHR), and automatic depressurization system (ADS) sensor initiation logic trips. Power source is dc from a station battery
2. HPCI pump discharge pressure and flow indicators (Figure 7.3-1). Power for these instruments is derived from a battery-operated inverter supply
3. ADS valve position status (Figure 7.3-4). Position-indicator power is derived from battery powered inverters
4. Divisional core spray discharge pressure indicators, loop flow indicators, and pump motor ammeters (Figures 7.3-7 and 7.3-8). Power for the respective instruments is derived from the appropriate ESF bus
5. Divisional low pressure coolant injection (LPCI) (RHR) pump discharge header pressure indicators, loop flow indicators, loop flow recorders, and pump motor ammeters (Figure 7.3-9). Power for these instruments is derived from the associated ESF bus
6. Divisional RHR service water loop flow indicators and outlet temperature recorders (Figure 7.3-9). Power for these instruments is derived from the associated ESF bus
7. Injection valve position status. Power source is the same as for the valve motor
8. Events recorder logging of trips in the emergency core cooling network. Power source is the l30-V dc power system
9. Relief valve discharge pipe temperature monitors. Power source is 120-V ac supplied from a 120-V ac instrument bus.

d. Conditions of significant timed interlocks that restrict the flexibility of the ESF systems are indicated by the following devices:

   1. An indicating timer, which displays the amount of time remaining until manual ADS activation is permissive. This device is powered from the ADS logic supply
   2. Four timers, which indicate that the required time has elapsed and the RHR (LPCI) "failed" loop injection valves can be reopened. These devices are powered from their respective divisional logic supply
   3. Two timers, which indicate that the required time has elapsed and the RHR (LPCI) injection valves can be closed manually. These devices are powered from their respective divisional logic supply.

e. The following indicating devices are provided to permit rapid assessment of the standby power system status and to enhance the manual reconnection of loads:

   1. Each of the emergency diesel generator (EDG) automatic load sequencer systems provides visual indication of the exact state of the automatically sequenced loads. These devices are powered by the sequencer system power supply. Specific details of this system are described in Subsection 8.3.1.1.7.

   2. A digital meter that displays remaining generator capacity for each EDG is provided. Power is supplied to these instruments from the respective EDG bus. This system is described more fully in Subsection 8.3.1.1.11.

7.5.1.4.2.4 Primary Containment Indication

The following systems provide the control room operator with necessary information regarding the full range of environmental conditions possible within the primary containment following an accident or incident.

a. Drywell temperature in various locations within the drywell volume is recorded on redundant strip-chart recorders (Subsection 7.6.1.12.2). The power supply for these recorders is derived from the respective ESF bus

b. Drywell pressure is monitored by both narrow-range and wide-range pressure transmitters and recorded on redundant strip-chart recorders (Subsection 7.6.1.12.3). The power supply for these devices is derived from battery-powered inverters

c. Torus temperature is monitored by thermocouples located in both the torus air space and the suppression pool water. Continuous strip-chart recording of these temperatures is provided on redundant recorders (Subsection 7.6.1.12.2). The recorders are supplied with power from the appropriate ESF bus

d. Torus pressure is monitored by both narrow-range and wide-range pressure transmitters and recorded on redundant strip-chart recorders (Subsection 7.6.1.12.3). The power supply for these devices is derived from battery-powered inverters

e. Suppression pool water level is continuously recorded on redundant recorders (Subsection 7.6.1.12.4). Power for this instrumentation is supplied by the battery-powered inverters

f. Radiation level within the drywell is monitored and recorded (Section 11.4). The power for this instrumentation is derived from a 120-V ac instrument bus.

7.5.1.4.2.5 Bypassed and Inoperable Status Indication for Nuclear Safety Systems

In addition to administrative procedures for determining and indicating bypassed or inoperable status of systems, channel bypassed and inoperable status indication is provided for the RPS and ESF systems in accordance with the requirements of IEEE 279-1971, Section 4.13. As stated in Sections 7.1, 7.2 and 7.3, the RPS and ESF systems comply with

IEEE 279-1971, as supported by NEDO-10139, which has been incorporated into the UFSAR by reference. Refer to Sections 7.2 and 7.3 for descriptions of control room indication related to specific RPS and ESF functions.

7.5.1.4.3 Safety Parameter Display System (SPDS)

SPDS is a function of the Integrated Plant Computer System (IPCS) that provides a specific selection of emergency response information. SPDS uses data from selected plant data systems and processes the data for display on the IPCS. SPDS information can be displayed on any IPCS terminal, which includes those specifically located in the control room, the technical support center (TSC), and the emergency operations facility (EOF). The SPDS display in the control room is provided to assist the operators in assessing the safety status of the plant following an accident. The IPCS and SPDS are described in subsections 7.6.1.9.1 and 7.6.1.9.1.2.5.1 respectively.

7.5.1.5 Special Condition: Loss of Habitability of Main Control Room

7.5.1.5.1 Criteria

It is necessary to be able to carry out the reactor shutdown functions from outside the main control room and to bring the reactor to cold condition in an orderly fashion in compliance with General Design Criterion 19 of 10 CFR 50, Appendix A. This requirement applies when the main control room becomes uninhabitable for any reason and is accomplished using the remote shutdown panel discussed in this section.

Appendix R to 10 CFR 50 requires that the plant be safely shut down remote from the control room in the event of a fire in the main control room, relay room, cable spreading room, and other areas containing equipment or cabling of both divisions required for safe shutdown. This capability is provided by the alternative shutdown system described in Subsection 7.5.2.5.

7.5.1.5.2 Remote Shutdown Panel

The remote shutdown panel is located in the Division I switchgear room on the second floor of the reactor building. At this location it cannot be damaged by failure of any other equipment. The remote shutdown system panel is designed to comply with the requirements of Quality Assurance Level I, Seismic Category I. The following systems have instrumentation and controls on the remote panel, as shown in Figures 7.5-2 and 7.5-3.

a. Reactor core isolation cooling (RCIC) system

b. RHR system

c. Recirculation flow control system

d. Nuclear boiler system

e. Control rod drive (CRD) system

f. Residual heat removal service water (RHRSW) system

g. Primary containment monitoring system.

7.5.1.5.3 Conditions Assumed To Exist As the Main Control Room Becomes Inaccessible

a. The plant is operating normally at, or less than, design power

b. Loss of offsite ac power is considered unlikely, but credible. For shutdown outside the control room coincidental with the loss of offsite ac power, the instrumentation and controls of the alternative shutdown system, e.g., dedicated shutdown panel and its associated procedures, will be used as described in UFSAR Section 7.5.2.5.2.

c. No LOCA or transients shall be assumed; therefore, complete control of ESF systems from outside the main control room will not be required

d. Plant personnel evacuate the main control room

e. The main control room continues to be inaccessible during the entire shutdown procedure

f. The event that causes the main control room to become inaccessible is assumed to be such that the operator can manually scram the reactor before leaving the main control room. As a backup, the operator can manually scram the reactor, and if necessary, close the MSIVs from outside the Main Control Room.

g. The main turbine pressure regulators may be controlling reactor pressure via the bypass valves; however, in the interest of simplicity and safety, it is assumed that this function is lost. Therefore, main steam line isolation is assumed to occur, and reactor pressure is relieved through the relief valves to the suppression pool. The feedwater control system is also assumed to be unavailable due to reactor isolation

h. Reactor water is made up by the RCIC system

i. The dc services are supplied from at least one plant dc power system for each essential system or equipment item in the remote shutdown system.

7.5.1.5.4 Description

The system provides remote control for the reactor systems needed to carry out the shutdown function from outside the main control room and to bring the reactor to cold condition in an orderly fashion. This system also provides a variation to the normal system used in the main control room, permitting the shutdown of the reactor when feedwater is unavailable and the normal heat sinks (turbine and condenser) are lost.

Automatic activation of relief valves and the RCIC system brings the reactor to a hot shutdown condition. During this phase of shutdown, the suppression pool is cooled by operating the RHR system in the suppression pool cooling mode. Reactor pressure is controlled and core decay and sensible heat are rejected to the suppression pool by relieving steam pressure through the relief valves. Reactor water inventory is maintained by the RCIC system.

Manual operation of the relief valves cools the reactor and reduces its pressure at a controlled rate until reactor pressure becomes so low that the RCIC system discontinues operation. This condition is reached at 50 to 100 psig reactor pressure. The RHR system is then operated in the shutdown cooling mode wherein the RHR system heat exchanger is connected directly into the reactor water circuit to bring the reactor to the cold low-pressure condition.

7.5.1.5.5 Procedure for Reactor Shutdown From Outside the Main Control Room

a. If evacuation becomes necessary, the operator will scram the reactor by the manual scram switches or reactor mode switch at the main control room panel as he leaves the main control room

b. The main turbine pressure regulator will, under normal conditions, control the reactor pressure while rejecting heat (steam) through the turbine bypass valves. The feedwater control system will control water level

c. As a backup, the operator can manually scram the reactor and close the MSIVs from outside the Main Control Room

d. The remainder of the procedure as described assumes that the automatic pressure regulator is not available from time zero and the main steam isolation valves (MSIVs) are closed, but the actual procedure may be written to utilize any plant equipment that is available as long as this worse case condition is provided for

e. Key-controlled transfer switches at the remote panel are operated to transfer control to the remote shutdown panel

f. Relief valves open automatically and cycle to control reactor pressure. Reactor level starts to drop at a rate depending on prior power level and elapsed time from scram

g. The operator starts the RCIC system manually before Level 2 (Figure 7.3-12) is reached and monitors the water level thereafter. The water level will continue to fall

h. One relief valve opens and closes automatically, by the Low - Low Set Function

i. Reactor level reaches its lowest point at about 80 in. above top of active fuel if the RCIC system was initiated at low level. Level starts to rise as a result of RCIC system flow. Pressure relief is through one relief valve in automatic intermittent operation

j. Water level is returned to normal by operation of the RCIC system

k. One relief valve is still in automatic intermittent operation. The RCIC system turbine automatically shuts down when Level 8 is reached. It starts automatically when the level drops to the initiation level

l. Reduction of reactor pressure is started by manually actuating one relief valve. While activating relief valves, the operator observes the reactor level and suppression pool temperature

m. Relief valves are closed before level drops below Level 3. The reactor cooldown rate will be controlled to not exceed 100°F per hour. Reactor level varies between Level 3 and Level 8

n. The RHR system with one pump, one heat exchanger, and the RHRSW system is used to cool the suppression pool

o. The operator activates two relief valves to maintain reduction of pressure to 250 psig while observing pool temperature, which is not to exceed 140°F unless the reactor pressure decreases to less than 250 psig

p. Reactor pressure is reduced to 100 psig, allowing the suppression pool temperature to reach 170°F if necessary

q. The RHR system is placed in the shutdown cooling mode. The RHR operation continues until the reactor is in the cold/low-pressure condition

r. Normal reactor water level is maintained after being placed in the shutdown cooling mode.

7.5.2 Analysis

7.5.2.1 General

The safety-related and power-generation display instrumentation provides adequate information to allow operators to make correct decisions as bases for manual control actions permitted under normal, abnormal transient, and accident conditions.

Information instrumentation having no direct input to ESF systems, except through the operator as a link, is considered to be outside the scope of existing IEEE Standards. However, insofar as practical, instruments are selected from those types qualified under IEEE 279-1971 and IEEE 323-1971. Redundancy and independence or diversity are provided in all of the information systems used for the basis of operator-controlled safeguards action.

This instrumentation is designed to operate during normal operation, accident, and postaccident environmental conditions. The design criteria that the instrumentation must meet are discussed more fully in Subsection 7.1.2. The specific design qualifications of the instruments referenced in this section are tabulated in Table 7.5-2.

7.5.2.2 Normal Operation

Subsection 7.5.1.2 describes the basis for selecting ranges for instrumentation and, inasmuch as monitoring requirements for abnormal transient or accident conditions exceed those for normal operation, the normal ranges are covered adequately.

7.5.2.3 Abnormal Occurrences

These occurrences will result in conditions lesser in consequence than those defined to be accident conditions in Subsection 7.5.2.4. Proper accident tracking, therefore, qualifies abnormal occurrence tracking.

7.5.2.4 Accident Conditions

The LOCA is the most extreme operational event. Information readouts are designed to accommodate this event from the standpoint of operator action, information, and event tracking requirements, and therefore cover all other design-basis events or incidents requirements.

7.5.2.4.1 Initial Accident Event

The design bases of all ESF systems to mitigate accident event conditions take into consideration that no operator action or assistance is required or recommended for the first 10 minutes of the event. This requirement makes it mandatory that all protective action necessary in the first 10 minutes be automatic. Therefore, although continuous tracking of variables is available, no operator action based upon them is intended.

7.5.2.4.2 Postaccident Tracking

After 10 minutes, operator action is optional. The following process instrumentation provides information to the operator after a design-basis accident (DBA) for his use in monitoring reactor conditions within the primary containment.

7.5.2.4.2.1 Reactor Water Level

Vessel water-level instrumentation described in Subsection 7.5.1.4.2.1 is redundant, electrically independent, and is operable following all credible accident events. Subsection 15.6.2 discusses the postulated instrument line break scenarios. This instrumentation complies with independence and redundancy requirements of IEEE 279-1971.

7.5.2.4.2.2 Reactor Pressure

Pressure instrumentation described in Subsection 7.5.1.4.2.2 is redundant, electrically independent, and is operable following all credible accident events. This instrumentation complies with the independence and redundancy requirements of IEEE 279-1971.

7.5.2.4.2.3 Shutdown, Isolation, and Core Cooling Indication

This information instrumentation will have no direct input to the ESF systems and is considered to be outside the scope of existing 36IEEE Standards. However, insofar as practical, instruments will be selected from those types that are qualified under IEEE-279 and IEEE-323. Redundancy and independence or diversity will be provided in all systems which are used for operator control and ESF status information.

7.5.2.4.2.4 Primary Containment Indication

Primary containment instrumentation described in Subsection 7.5.1.4.2.4 is designed to be redundant, electrically independent, and remain operable following all credible accident events. The ranges have been selected to cover the design conditions of the containment.

7.5.2.4.3 Safety Parameter Display System

See Subsection 7.6.1.9.1.2.5.1 for a discussion of the design analysis of the SPDS.

7.5.2.5 Special Condition: Post-Fire Reactor Shutdown From Outside the Main Control Room

Analysis of reactor shutdown from outside the main control room is included in Subsection 7.5.1.5 for non-fire scenarios requiring control room evacuation. This section discusses the alternative shutdown system, which includes the dedicated shutdown panel, used for post-fire shutdown for fires in the main control room and selected other areas.

7.5.2.5.1 Design Bases

The alternative shutdown system was designed and installed to meet the requirements of 10 CFR 50, Appendix R, Section III, paragraphs G and L. The alternative shutdown system was designed to provide safe-shutdown capability separate and remote from the control center complex (control room, relay room, and cable spreading room, fire zones 03AB, 07AB and 09AB) and other selected auxiliary building fire zones 08AB, 11AB and 13AB when a fire in the complex or these zones is assumed to significantly damage the equipment/cabling in these zones. In the context of the discussion of alternative shutdown design basis, these six fire zones are referred to as the dedicated shutdown areas of concern. The above fire zones are described in UFSAR 9A.4. These zones are not the Fire Detection Zone numbers. UFSAR Figure 9A-1 provides a descriptive table cross-referencing the UFSAR Fire Zones and the Fire Detection Zones used in the abnormal operating procedure.

The objectives of the alternative shutdown system are to

a. Achieve and maintain subcritical reactivity conditions in the reactor

b. Maintain reactor coolant inventory

c. Achieve and maintain hot shutdown

d. Achieve cold shutdown conditions within 72 hr

e. Maintain cold shutdown conditions thereafter.

The reactor is shut down and maintained subcritical by control rod insertion. The portions of the CRD system necessary for reactor scram are designed to fail safely (actuate) if subjected to a fire. The core is kept covered by establishing standby feedwater flow to make up for loss of reactor vessel water inventory. Hot shutdown is achieved and maintained by establishing primary containment cooling and torus cooling. The primary containment fan and cooling unit operation (Subsection 9.4.5) and the torus cooling mode of the system (Subsection 5.5.7) are established prior to exceeding established drywell temperature and suppression pool water temperature design limits, respectively. Cold shutdown is achieved by the shutdown cooling mode of the RHR system.

The alternative shutdown system provides a dedicated shutdown panel located in the radwaste building, second floor*, from which an operator can monitor the reactor and keep the reactor core covered with water. The system design uses appropriate systems already installed, with installation of the panel and necessary control and transfer switches to make it functional.

NOTE:* In past correspondence with the NRC, the dedicated shutdown panel has also been called the 3L panel because it satisfies Paragraph III.L, of Appendix R to 10 CFR 50.

7.5.2.5.2 System Description

The alternative shutdown system consists of one of the four combustion turbine generators (CTGs), the standby feedwater (SBFW) system, a dedicated shutdown control panel and associated instrumentation, a Distributed Control System (DCS), and Division I portions of the following systems: RHR, RHRSW, emergency equipment cooling water (EECW), and emergency equipment service water (EESW). The dedicated shutdown panel is supplemented by local manual operator actions to achieve hot or cold shutdown.

The four CTGs (Subsection 8.2.1.2) are oil-fired turbine generators located onsite, remote from the fire areas of concern. The CTG 11-1 is used to provide emergency power when a fire occurs in the fire areas of concern, or on loss of offsite power should the EDGs be unavailable. CTG 11-1 has black start capability. The CTG starting diesel is located in an enclosed heated compartment and is equipped with a float tank, which provides an initial supply of warm fuel oil, to ensure its operability. Diesel fuel is maintained in the CTG Fuel Oil Tank with a fuel level maintained by plant procedures to ensure nominal fuel availability for 72 hours of operation for a single CTG unit at 10 MW load.

If CTG 11-1 is not available, either CTG 11-2, CTG 11-3 or CTG 11-4 (with AC starting motors) can be established on a standby basis as the black start power source for alternative shutdown power source using a standby starting diesel generator. Cold weather equipment preparation is addressed within the System Operating Procedure during the cold weather season.

The CTGs' control, instrumentation, and power cabling is located, isolated, and/or routed independent from the fire areas of concern, except for the CTG supervisory control circuit, which has transfer and lockout features that ensure that it is isolated from control room CTG circuitry.

Control of the breakers in the Fermi 120-kV switchyard and control of the CTGs is via a supervisory system. The essential elements of the system consist of a Distributed Control System panel (with local I/O) located at the 120-kV switchyard area, fiber optic communication lines, and actuating devices.

The Distributed Control System (DCS) functions as follows: field devices interface with the local DCS I/O panels and processors for 120-kV switchyard & CTGs process the signals and transmit the data via redundant fiber optic lines to a 3L Remote I/O panel in the Dedicated Shutdown Panel area in Fermi 2. The 3L Remote I/O panel interfaces with the Dedicated Shutdown panel for monitoring and control functions for the CTGs and 120-kV switchyard equipment. A block diagram of the CTG DCS control system is presented in Figure 7.5-4.

A dedicated shutdown system transfer pushbutton is provided in the control room, which, when activated, communicates with the DCS to initiate a start signal to CTG 11-1, arm the 120-kV switchyard undervoltage scheme, and inhibit control signals for the 120-kV

Switchyard and CTGs from the Fermi 2 control room. At the same time, 120-kV Switchyard and CTG 11-1 control is transferred to the Dedicated Shutdown Panel (H21-P623). If the control room is abandoned before the transfer pushbutton is activated, transfer can be accomplished at the Dedicated Shutdown Panel H21-P623 and the CTG 11-1 can be started manually after transfer. The possible fire induced spurious equipment actuations before transfer occurs are recoverable at the H21-P623 panel. The undervoltage scheme isolates 120-kV switchyard buses from offsite supplies and aligns breakers to provide power for Dedicated Shutdown from CTG 11-1.

The CTG power is supplied via peaker bus 1-2B through breaker A6 to the 4160-V Class 1E bus or via the main 120-kV bus through transformer SS64 (see Figure 8.3-1). The 4160-V bus provides power for the SBFW pumps; the Division I RHR, RHRSW, EECW, and EESW pumps and associated powered equipment through downstream electrical buses (Figure 7.5-5).

The SBFW system, Figure 7.5-6, described in Subsection 10.4.8, provides an alternative makeup water source for the reactor vessel. After transfer, the SBFW system is manually controlled and operated from the dedicated shutdown panel to maintain level above the top of the core. Control and transfer switches necessary for operating associated feedwater system valves and breakers are installed on the dedicated shutdown panel. Also, SBFW system flow is indicated on the dedicated shutdown panel. Power for the feedwater pump motors is from the CTGs or offsite power via the 4160-V electrical bus.

If the CTG is operating in parallel on the grid at the time offsite power is lost, the CTG output breaker is assumed to trip. However, the CTG turbine will not trip. The plant operator must take steps to isolate the grid, reclose the CTG output breaker and line up the two SBFW buses. If the CTG was not in operation, it could be started from the main control room before abandonment, but in the worst case, it would be started from the dedicated shutdown panel.

The RHR and RHRSW systems, described in Subsections 5.5.7 and 9.2.5, provide cooling capability for the reactor and torus water. The RHR system functional modes (1) torus cooling (Figure 7.5-7) and (2) shutdown cooling (Figure 7.5-8) modes, are described in Subsections 5.5.7.3.1 and 5.5.7.3.2.

The RHRSW system (Subsection 9.2.5) provides the heat sink for the reactor core by providing the cooling medium for the RHR heat exchanger. The EECW system functions as described in Subsection 9.2.2.1 to cool equipment required for reactor shutdown. The EECW is cooled by the EESW described in Subsection 9.2.5; a simplified flow diagram is shown in Figure 7.5-9.

The dedicated shutdown control panel is a local operation station, remote from the fire areas of concern, with instrumentation and control switches and transfer switches necessary for operating the SBFW shutdown system required to keep the reactor core covered with water. Instrumentation, control switches, and transfer switches on the panel are listed in Table 7.5-3.

Hot and cold shutdown can be achieved from the dedicated shutdown panel with manual operator action required locally in the reactor/auxiliary building and RHR complex. Local operation includes controlling equipment at local panels, switchgear, MCCs, distribution panels, and valves. Figures 7.5-7 and 7.5-8 show the flow paths involved for both hot and cold shutdown.

Auxiliary systems required to support the alternative shutdown system are listed below and are described in the sections identified.

The SBFW system requires no auxiliary support system. Both pump and motor have a forced-flow lube-oil system that is driven off the pump shaft. The lube-oil system is cooled by a portion of the pump discharge flow routed to an oil cooler. Motor windings are designed to take a 74°F rise in temperature over a continuous rating of 111°F, which results in a maximum temperature of 185°F in approximately 60 hr. Once in shutdown cooling, the SBFW system will be turned off; inventory makeup will no longer be required. Conditions required for entry into shutdown cooling will be established within 12.5 hours. Space cooler, heat exchanger, and pump/motor cooling for the other systems is supplied either by EECW, EESW, or RHRSW as specified in Subsections 9.2.2 and 9.2.5.

Auxiliary support systems (i.e., heating, ventilation, and air conditioning [HVAC], or other fluid systems) are not required for the EECW system, EESW system, or the Division I switchgear room. This is because of the small heat loads generated (under the scenario very little electric equipment is energized) and because the EECW and EESW pumps require no external cooling or seal water. The dedicated shutdown panel area in the second floor of the radwaste building is provided with a local area cooler as described in Section 9.4.3. The function of the Dedicated Shutdown Air Conditioning Unit is to provide cooling, if needed, to maintain habitability at the Dedicated Shutdown Panel location for the duration of a post-fire shutdown requiring the use of the panel. This cooler is manually restored to the 72M Bus which is powered by dedicated shutdown power sources, including CTG 11-1. Once started using a switch near the Dedicated Shutdown Panel, area temperature is automatically controlled by local thermostat.

The RHR pump requires the support of a room cooler and a pump bearing cooler. Both the bearing cooler and pump room cooler are supplied by the EECW system. The room cooler also requires operation of a fan unit.

Drywell cooling is accomplished by establishing EECW flow to the drywell cooling units and operation of their associated fan units.

If normal communications links are not available, communications between the operators at locations in the plant and the dedicated shutdown panel operator are via hand-held portable radios that operate by either radio-to-radio, or radio-to-portable, repeater-to-radio communication links. Communication between the Dedicated CTG operator and the Main Control Room or local Dedicated Shutdown Panel operator is achieved using the local telephone system.

Eight-hour emergency lighting for safe-shutdown capability is provided for all local operations and for access/egress routes to and from local safe-shutdown areas. Use of local emergency lighting for the CTG area is addressed within the System Operating Procedure.

To implement the alternative shutdown concept, it must be ensured that cabling and required devices are not in, or do not pass through, a fire zone for which the concept is being relied upon, or that an adequate level of protection is provided. To achieve this objective, transfer switches have been installed that completely isolate any cabling that passes through the fire zones of concern from their associated actuating devices. New cable that is required for instrumentation and CTG supervisory control is routed to ensure it does not pass through the fire areas of concern.

Interfaces between Class 1E and non-Class 1E components meet the electrical separation criteria for Section 8.3 and appropriate IEEE criteria for environmental and seismic qualification.

Table 7.5-5 lists the 4160-V switchgear and motor control center (MCC) positions that have the above-described transfer function.

7.5.2.5.3 Procedure

An Abnormal Operating Procedure provides procedural guidance to achieve and maintain safe shutdown in the event that a fire in any of the dedicated shutdown areas of concern warrants post-fire shutdown from outside the main control room using the dedicated shutdown panel. The procedure provides direction regarding conditions upon which the procedure should be entered, actions to be taken in the control room before it is abandoned, as well as immediate and longer-term manual actions at the dedicated shutdown panel and other plant locations. These actions, in the aggregate, assure that the plant is put in a known and analyzed configuration to support the performance of the design basis functions described in Section 7.5.2.5.1 consistent with the safe shutdown analysis described in Appendix 9A.

When the standby diesel generator is utilized, the system operating procedure addresses starting and maintaining the standby diesel generator to power the CTG 11-2, CTG 11-3, or CTG 11-4 480 volt starting motors and auxiliaries. An additional dedicated CTG operator is required at the CTG area whenever the standby diesel generator is used to provide power for the Dedicated Shutdown System.

7.5.2.5.4 Safety Evaluation

Post-fire shutdown outside the control room using the alternative shutdown system and dedicated shutdown panel has been analyzed as described in Section 9A.3. This analysis includes circuit faults including open circuits, shorts to ground and hot shorts that could directly affect safe shutdown systems as well as common shutdown functions, e.g., loss of RPV inventory or spurious SRV operation. The safe shutdown analysis demonstrates that the core will remain covered with the Standby Feedwater System delivering flow to the RPV within 24.4 minutes. The time studies for establishing SBFW flow include allowance for the power supply starting times, breaker and valve operating times and operator transit times. In addition, the analysis demonstrates that establishing suppression pool and drywell cooling functions within approximately 4 hours following reactor scram from full power, ensures operation within the containment design limits.

Therefore, the alternative shutdown system (including the instrumentation and controls located on the dedicated shutdown panel), in conjunction with proceduralized manual actions taken at the panel and at other plant locations, provides the capability required to achieve and maintain safe shutdown following a fire that requires shutdown from outside the control room.

A black start test of an alternate CTG demonstrated that use of an alternate CTG supported the performance goal of the alternative Dedicated Shutdown system which is Standby Feedwater system delivering flow to the RPV within 24.4 minutes.

7.5.2.5.5 Tests and Inspections

Except for where equipment directly interfaces with essential Class 1E components, the alternative shutdown system is considered a BOP system. Quality assurance requirements for the Class 1E portion of the alternative shutdown system will be the same as for the Class 1E equipment it is interfacing with. Quality assurance requirements applied to those portions of the system not interfacing directly with a Class 1E system will be appropriate for the use of that portion of that system. Periodic testing is described in Section 9A.6.

7.5.3 DELETED IN REVISION 20

TABLE 7.5-1 CONTROL ROOM LEVEL INDICATION

Instrument Name	Type and No.	Scale (in.)	Control Room Panel
Postaccident pressure/level recorder A	MRE-R623A	+10 to +220	601
Postaccident pressure/level recorder B	MRE-R623B	+10 to +220	602
Core level recorder	LR-R615		602
Core level recorder	LR-R610		601
Flood-up level indicator	LIE-R605	+160 to +560	603
Wide-range level indicator A	LI-R604A	+10 to +220	601
Wide-range level indicator B	LI-R604B	+10 to +220	602
Narrow-range level indicator A	LI-R606A	+160 to +220	603
Narrow-range level indicator B	LI-R606B	+160 to +220	603
Narrow-range level indicator C	LI-R606C	+160 to +220	603
Narrow-range level recorder A/B	LR-R614	+160 to +220	603

TABLE 7.5-2 SAFETY-RELATED AND POWER GENERATION DISPLAY INSTRUMENTATION

	Reactor Water Level Transmitter B21-N091A-D & B21-N085A-B[a]	Reactor Pressure Transmitter B21-N051A-B	Pressure/ Level Recorder B21-R623A-B	Neutron Monitoring Power Range Recorders C51-R603A-B
Design classes QA level/seismic category[i]	I/I	I/I	I/I	1M/II/I
Power supply	120-V ac Div. I/II inverter bus	120-V ac Div. I/II inverter bus	120-V ac Div. I/II inverter bus	120-V ac BOP inverter bus
Number of channels	6	2	2	4[b]
Alarm setpoint(s)[c]	173 in. decreasing for N091[d] – 42 in. for N085	NA[e]	Alarm on Auto-switchover to high chart speed	NA
Control logic	ECCS level logic	NA	NA	NA
Instrument range	N091[d] – 10 to 220 in. N085[d] - -150/0/50 in.	0-1500 psig	Compatible with inputs	0-125 percent
Instrument accuracy[f, j]	N091 - ±0.25 percent[f] N085 - ±0.25 percent	±0.25 percent	±0.5 percent	±0.5 percent

	Annuciators RPS Variables[l]	Integrated Plant Computer	Sequence-of-Events Recorder[l]	Main Steam Flow Recorder C32-R607[g]
Design classes QA level/seismic category[i]	NQ/II/I	NQ/II/I	NQ/II/I	NQ/II/I
Power supply	130-V dc BOP battery inverter supply	120 V ac from UPS A and B	130-V dc BOP battery inverter supply	120-V ac BOP inverter bus
Number of channels	2 per variable	1 per variable	2 per variable	1
Alarm setpoint(s)	NA	NA	NA	NA
Control logic	Open circuit to alarm	NA	Open circuit to alarm	NA
Instrument range	NA	NA	NA	0-17 x 10^6 lb/hr
Instrument accuracy[f, j]	NA	NA	NA	±0.5 percent

TABLE 7.5-2 SAFETY-RELATED AND POWER GENERATION DISPLAY INSTRUMENTATION

	HPCI Discharge Pressure Transmitter E41-N009	HPCI Discharge Pressure Indicator E41-R609	HPCI Discharge Flow Transmitter E41-N008	HPCI Discharge Flow Indicator E41-R613	ADS Valve Position Indicator Lamps
Design classes QA level/seismic category[i]	I/I	1M/II/I	I/I	I/I	I/I
Power supply	Inverter from Div. II Battery	Inverter from Div. II Battery	Inverter from Div. II Battery	Inverter from Div. II Battery	Div. I battery
Number of channels	1	1	1	1	1 per valve
Alarm setpoint(s)	NA	NA	NA	NA	NA
Control logic	NA	NA	NA	NA	NA
Instrument range	0-1500 psig	0-1500 psig	0-8000 gpm	0-8000 gpm	NA
Instrument accuracy[f,j]	±0.4percent	±0.5 percent	±0.25 percent	±.2 percent	NA

	Core Spray Discharge Pressure Transmitter E21-N001A-B	Core Spray Discharge Pressure Indicator E21-R600A-B	Core Spray Discharge Flow Transmitter E21-N003A-B	Core Spray Discharge Flow Indicator E21-R601A-B
Design classes QA level/seismic category[i]	I/I	1M/II/I	I/I	1M/II/I
Power supply	120-V ac Div. I/II	120-V ac Div. I/II	120-V ac Div. I/II	120-V ac Div. I/II
Number of channels	2	2	2	2
Alarm setpoint(s)	NA	NA	NA	NA
Control logic	NA	NA	NA	NA
Instrument range	0-600 psig	0-600 psig	0-10,000 gpm*	0-10,000 gpm*
Instrument accuracy[f,j]	±0.4 percent	±0.5 percent	±0.25 percent	±1 percent

*9150 to 10,000 gpm on the scale not used

	Core Spray Pump Motor Current	RHR (LPCI Mode) Pump Discharge Header Pressure Transmitter E11-N056A-D	RHR (LPCI Mode) Pump Discharge Header Pressure Indicator E11-R803/R804	RHR (LPCI Mode) Flow Transmitter E11-N015A-B
Design classes QA level/seismic category[1]	NQ/II/I	I/I	1M/II/I	I/I
Power Supply	Current transformer	120-V ac. Div. I/II inst. bus	120-V ac. Div. I/II inst. bus	120-V ac. Div. I/II inst. bus
Number of channels	4 (1 per motor)	4 (1 per motor)	4 (1 per motor)	4 (1 per motor)
Alarm setpoint(s)[c]	125 percent	NA	NA	NA
Control logic	NA	NA	NA	NA
Instrument range	0-200 percent	0-500 psig	0-500 psig	0-774.8” W.C.
Instrument accuracy[f,j]	±2 percent	±0.25 percent	±0.5 percent	±0.25 percent

TABLE 7.5-2 SAFETY-RELATED AND POWER GENERATION DISPLAY INSTRUMENTATION

	RHR (LPCI Mode) Flow Recorder E11-R608A-B	RHR Pump Motor Current	RHR Service Water Flow Transmitter E11-N007A-B	RHR Service Water Flow Indicator E11-R602A-B	RHR Service Water Thermocouples E11-N005A-B
Design classes QA level/seismic category[1]	1M/II/I	NQ/II/I	I/I	1M/II/I	NQ/II/I
Power Supply	120-V ac Div. I/II inst. bus	Current transformer	120-V ac Div. I/II inst. bus	120-V ac Div. I/II inst. bus	NA
Number of channels	2	4 (1 per motor)	2	2	2
Alarm setpoint(s)[c]	NA	289 amps	NA	NA	NA
Control logic	NA	NA	NA	NA	NA
Instrument range	0-28,000 gpm*	0-500 amps	0-10,000 gpm	0-10,000 gpm	0-400 °F
Instrument accuracy[f,j]	±0.5 percent	±2 percent	±0.4 percent	±1 percent	NA

* Due to zero suppression programming of the RHR Flow Recorder, zero flow will be displayed until a nominal flow of 1000 gpm is achieved.

	RHR Service Water Outlet Temperature Recorder E11-R601A-B	Relief Valve Discharge Thermocouples B21-N004A-H, J-N, P, R	Relief Valve Discharge Temperature Recorder B21-R614	Indicating Timer on ADS
Design classes QA level/seismic category[i]	NQ/II/I	NQ/II/I	1M/II/I	NQ/II/I
Power supply	120-V ac Div. I/II inst. Bus	NA	120-V ac BOP inst. Bus	120-V ac Div. I battery
Number of channels	2	15	15 (one recorder)	1
Alarm setpoint(s)[c]	175 °F	NA	220 °F	NA
Control logic	NA	NA	NA	Starts on energization of ADS timers
Instrument range	0-400 °F	0-600 °F	0-600 °F	105-0 sec (count down)
Instrument accuracy[f,j]	±0.5 percent	Per ANSI C96.1	±0.2 percent	±1 sec.

TABLE 7.5-2 SAFETY-RELATED AND POWER GENERATION DISPLAY INSTRUMENTATION

	Automatic Load Sequencer	Digital "Remaining Capacity" Meter	Drywell Thermocouples T50-N409B, - N412A	Drywell and Torus Temperature Recorder T50-R800A-B	Pressure Transmitter (Narrow Range) T50-N401A-B
Design classes QA level/seismic category[i]	I/I	NQ/II/I	I/I	I/I	I/I
Power supply	260-130-V dc Div. I&II battery	120-V ac inst. Buses Div. I&II	NA	120-V ac Div I: Instrument Bus Div II: Inverter Bus	Div. I: battery inverter on Div. I Div. II: battery inverter on Div. II
Number of channels	4	4	2	6 (2 – Drywell) (4 – Torus) page 7.5-33	2
Alarm setpoint(s)[c]	NA	NA	NA	NA	NA
Control logic	NA	NA	NA	NA	NA
Instrument range	NA	3000-0 kW	See recorder	0-400 °F	-5 to +5 psig
Instrument accuracy[f, j]	NA	±1 percent	Standard TC wire	±0.3 percent	±0.25 percent

	Drywell Pressure Transmitter (Wide Range) T50-N415A-B	Drywell Narrow Range, Wide Range and Torus Wide Range, Narrow Range Pressure Recorder T50-R802A-B
Design classes QA level/seismic category[i]	I/I	I/I
Power supply	CH A battery inverter on Div. I CH B battery inverter, Div. II	Div. I - battery inverter on Div. I Div. II – battery inverter on Div. II
Number of channels	2	2
Alarm setpoint(s)[c]	NA	NA
Control logic	NA	NA
Instrument range[k]	0-250 psig	-5 to +5 psig, 0 to 250 psig, 0-80 psig, -5 to +15 psig
Instrument accuracy[f, j]	±0.25 percent	±0.25 percent

TABLE 7.5-2 SAFETY-RELATED AND POWER GENERATION DISPLAY INSTRUMENTATION

	Torus Thermocouples T50-N402A, -N403B, -N405B, &N404A	Containment Radiation D11-K816 A-B	Torus Pressure Transmitters Wide-Range T50-N414A-B	Torus Pressure Transmitters Narrow-Range T50-N499 A-B
Design classes QA level/seismic category[i]	I/I	I/I	I/I	I/I
Power supply	NA	CH A-120-V ac inst. bus, Div. I CH B-120-V ac inst. bus, Div. II	CH A-battery – inverter on Div. I CH B-battery – inverter on Div. II	CH A-battery – inverter on Div. I CH B-battery – inverter on Div. II
Number of channels	4	2	2	2
Alarm setpoint(s)[c]	NA	NA	NA	NA
Control logic	NA	NA	NA	NA
Instrument range	NA See recorder	10^0 to 10^8 rad/hr	NA 0 to 80 psig	NA -5 to +15 psig
Instrument accuracy[f,j]	Standard TC wire	--	±0.25 percent	±0.25 percent

	Suppression Pool Water Level Transmitter T50-N406 A-B	Suppression Pool Water Level Recorder T50-R804 A-B	Drywell Radiation Instrument T50-N003	Drywell Radiation Recorder T50-R809
Design classes QA level/seismic category[i]	I/I	I/I	IM/II/I	1M/II/I
Power supply	Div. I-Battery inverter on Div. I Div. II-Battery inverter on Div. II	120-V ac inst. buses Div. 1 & II	120-V ac inst. buses BOP	120-V ac inst. buses BOP
Number of channels	2	2	1	1
Alarm setpoint(s)[c]	NA	NA	To be established after background is measured	To be established after background is measured
Control logic	NA	NA	NA	NA
Instrument range	-144 to +56 in.	-144 to +56 in.	Variable over suitable range	Compatible with radiation instrument recorder output
Instrument accuracy[f,j]	±0.25 percent	±0.25 percent	2 percent	±0.5 percent

[a] Wide range shutdown indication. Reads full scale when jet pumps are operating.

[b] Two recorders display two channels each.

[c] Nominal values are given for information. See Technical Specifications for operational limits.

[d] Measured from top of active fuel.

[e] NA = Not Applicable.

[f] Accuracy specified in percent of full scale unless otherwise noted.

[g] Recorder shared with feedwater flow signal.

[h] *May be obtained from analyzers or recorders or combination of the two depending on make selected.*

[i] The instrument seismic category and QA level information provided in the UFSAR tables may have been upgraded to meet the Pressure Boundary Integrity (PBI) or other requirements. The instrument seismic category and QA level information is available in the Fermi 2 Central Component Database.

[j] The instrument accuracy information provided in the UFSAR tables is a bounding value. For actual value see the Fermi 2 Central Component Database.

[k] Deleted

[l] The Visual Annunciator System (C9700) combines the annunciator and sequence-of-events recorder function using redundant hardware and application software.

TABLE 7.5-3 DEDICATED SHUTDOWN PANEL INSTRUMENTATION AND CONTROLS

Instrumentation

Reactor pressure

Reactor level

Condensate storage tank level

Torus temperature

Torus level

Primary containment temperature (drywell)

Standby feedwater flow

Bus voltage monitor for buses 101, 102, 1, 1-2, 64

Combustion turbine generator - voltage, frequency, watts, VARs

Undervoltage trip armed

Supervisory control transferred

Controls

120 - kV breaker control

1) breaker GM
2) breaker GK
3) breaker GH
4) breaker GD
5) breaker GL

CTG control

1) raise/lower voltage
2) raise/lower governor
3) power block control

13.8- kV breaker control

1) breaker A2
2) breaker A6
3) breaker A7
4) breaker B6

Standby feedwater system

1) SBFW pump A (4160-V breaker V2)
2) SBFW pump B (4160-V breaker W4)
3) SBFW discharge isolation valve (N2103 F001)
4) SBFW low flow discharge valve (N2103 F003)
5) SBFW high flow discharge valve (N2103 F002)

TABLE 7.5-3 DEDICATED SHUTDOWN PANEL INSTRUMENTATION AND CONTROLS

13.2 kV breaker control

1) breaker A
2) breaker B
3) breaker C
4) breaker D

4160-V breaker control

1) breaker V1
2) breaker V2
3) breaker V3
4) breaker W4
5) breaker W5

Safety/relief valve B21-F013G

Transfer switches

1) EF2 Supervisory Control
2) EF2 System Controls

TABLE 7.5-4 HAS BEEN INTENTIONALLY DELETED

TABLE 7.5-5 <u>4160-V SWITCHGEAR AND MOTOR CONTROL CENTERS WITH TRANSFER AND LOCAL CONTROL CAPABILITY</u>

Breaker V1, V2, V3, W4, W5, C5, C6, C8, C11, C9, C10
(no local control for C9 and C10, just transfer)

480-V MCC 72B-2A:

<u>Valve</u>

P4400F616 (EECW inboard containment isolation)

480-V MCC 72B-3A:

<u>Valve</u>

E1150F028A (RHR torus return)
E1150F024A (RHR torus return)
E1150F004A (RHR torus pump suction)
E1150F611A (RHR valve F017 bypass)

<u>Fan</u>

T4700C001

480-V MCC 72C-F:

<u>Valve</u>

B3105F031A (reactor recirculation pump discharge isolation)
E1150F010 (RHR Division II cross tie)
E1150F015A (RHR shutdown cooling return to vessel)
E1150F017A (RHR shutdown cooling return to vessel)

480-V MCC 72C-3A

<u>Valve</u>

E1150F009 (RHR shutdown cooling inboard suction)
P4400F606A (EECW supply - outboard containment isolation)
E1150F003A (RHR heat exchanger outlet)
E1150F004C (RHR torus pump suction)

TABLE 7.5-5 <u>4160-V SWITCHGEAR AND MOTOR CONTROL CENTERS WITH TRANSFER AND LOCAL CONTROL CAPABILITY</u>

E1150F047A (RHR heat exchanger inlet)

E1150F068A (RHR service water throttle)

E1150F048A (RHR heat exchanger bypass)

P4400F601A (EECW return to RBCCW)

P4400F602A (EECW make-up tank outlet)

P4400F603A (RBCCW supply to EECW)

E1150F006C (RHR pump suction isolation)

E1150F016A (RHR drywell spray line)

E41-F400 (torus water level isolation valve)

T50-F412A (torus water level isolation valve)

<u>Fan</u>

T4700C002 (containment cooling fan)

T4100B018 (RHR room cooler fan)

MCC 2PC 1

<u>Valve</u>

N2103F001 (SBFW discharge isolation)

N2103F002 (SBFW high flow discharge throttle valve)

N2103F003 (SBFW low flow discharge throttle valve)

MCC 72F-4A (with alternate supply from 72M-3B)

<u>Valve</u>

P4400F607A (EECW return - outboard containment isolation)

MCC 72M-3B, Compt 5BR

<u>Battery Charger</u>

R3200S022A (BOP Battery Charger 2C-1, DC power for SBFW valves)

TABLE 7.5-5 4160-V SWITCHGEAR AND MOTOR CONTROL CENTERS WITH TRANSFER AND LOCAL CONTROL CAPABILITY

MCC 72S-2A, Compt 5C

Battery Charger

R3200S022C (BOP Battery Charger 2C1-2, DC power for SBFW valves)

Figure Intentionally Removed
Refer to Plant Drawing I-2007-01

FIGURE 7.5-1, SHEET 1

REACTOR CONTROL BOARD

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Refer to Plant Drawing I-2007-02

Figure Intentionally Removed
Refer to Plant Drawing I-2007-02

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FIGURE 7.5-1, SHEET 3

REACTOR CONTROL BOARD

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FIGURE 7.5-1, SHEET 4

REACTOR CONTROL BOARD

Figure Intentionally Removed
Refer to Plant Drawing I-2007-02

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FIGURE 7.5-1, SHEET 5

REACTOR CONTROL BOARD

Figure Intentionally Removed
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FIGURE 7.5-1, SHEET 6

REACTOR CONTROL BOARD

Figure Intentionally Removed
Refer to Plant Drawing I-2007-03

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FIGURE 7.5-1, SHEET 7

REACTOR CONTROL BOARD

Figure Intentionally Removed
Refer to Plant Drawing I-2791-01

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FIGURE 7.5-2

INSTRUMENTATION AND CONTROL ON REMOTE SHUTDOWN PANEL

Figure Intentionally Removed
Refer to Plant Drawing I-2796-01

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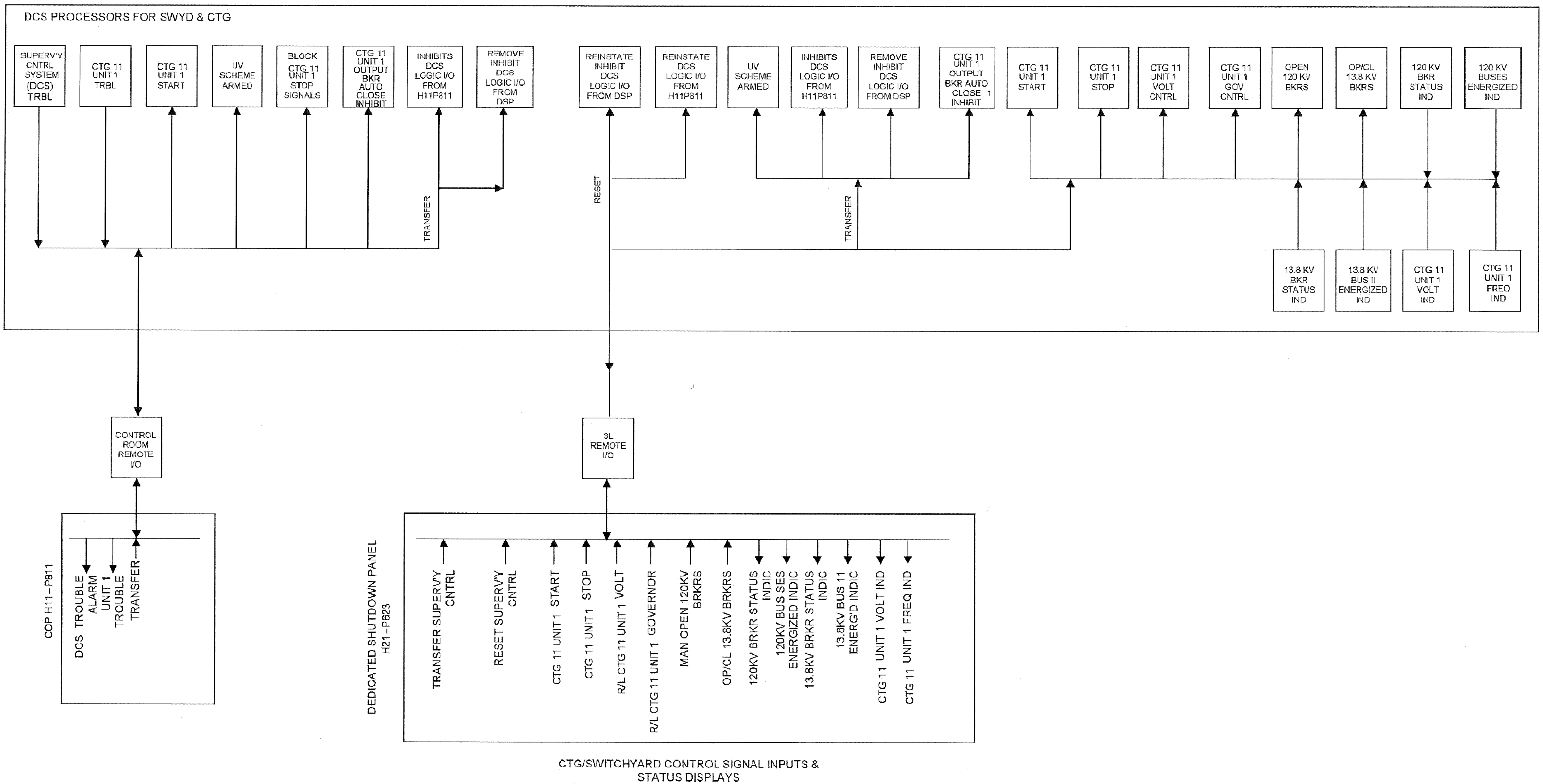
FIGURE 7.5-3

REMOTE SHUTDOWN SYSTEM



NOTE: DCS PROCESSORS FOR SWYD AND CTG ARE LINKED FOR DATA TRANSFER

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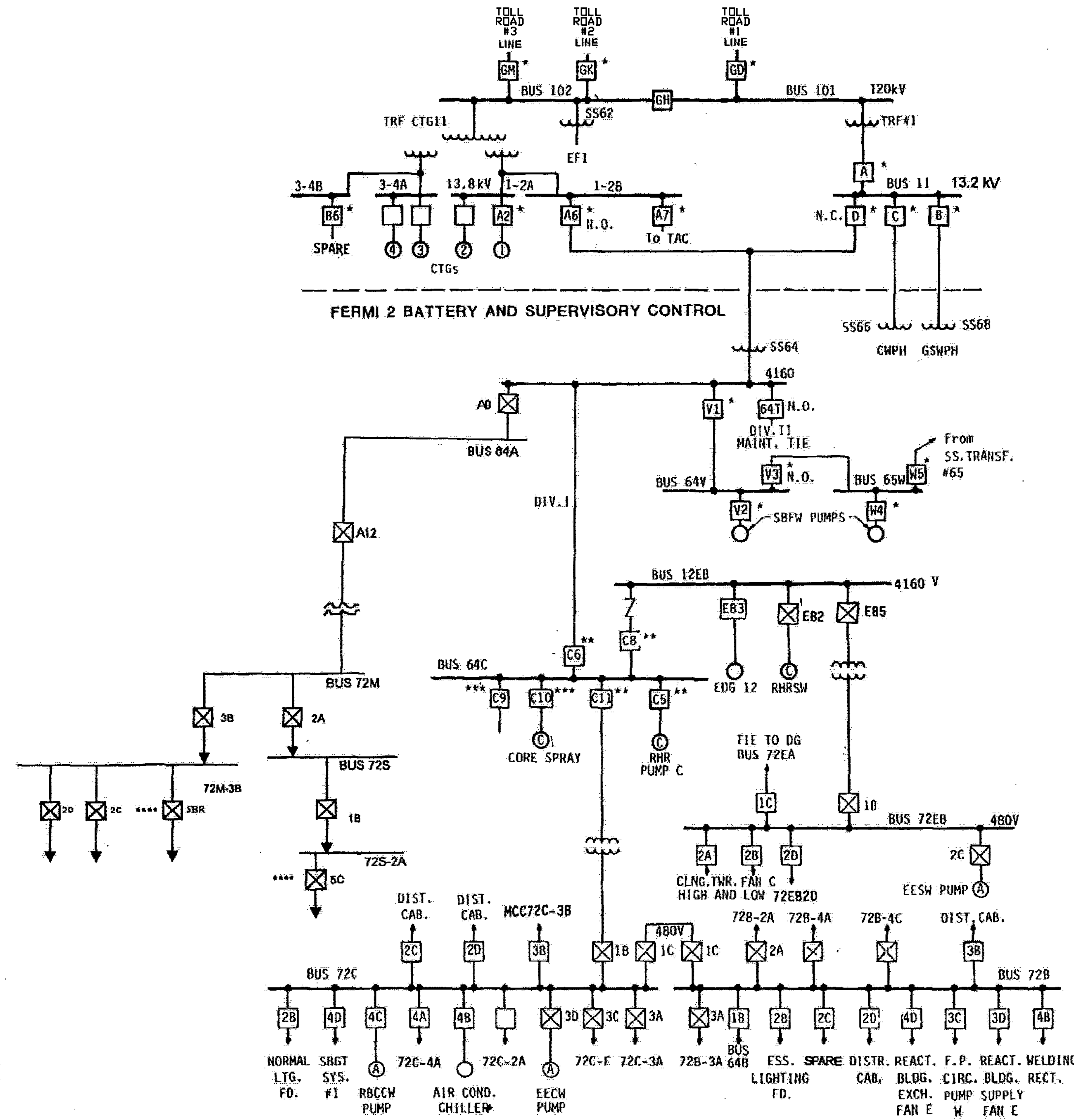
FIGURE 7.5-4

SUPERVISORY AND TELEMETERING CONTROL BLOCK DIAGRAM



* Transfer with control and indication at dedicated shutdown panel.

** Transfer with local control and indication in DIV. 1 SWGR room.

*** Transfer and control in DIV. 1 SWGR room (can take local control to disable only).

**** Transfer with local control at MCC compartment

☒ Breaker locally closed if open.

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FIGURE 7.5-5

ONE-LINE DIAGRAM - ALTERNATIVE SHUTDOWN SYSTEM

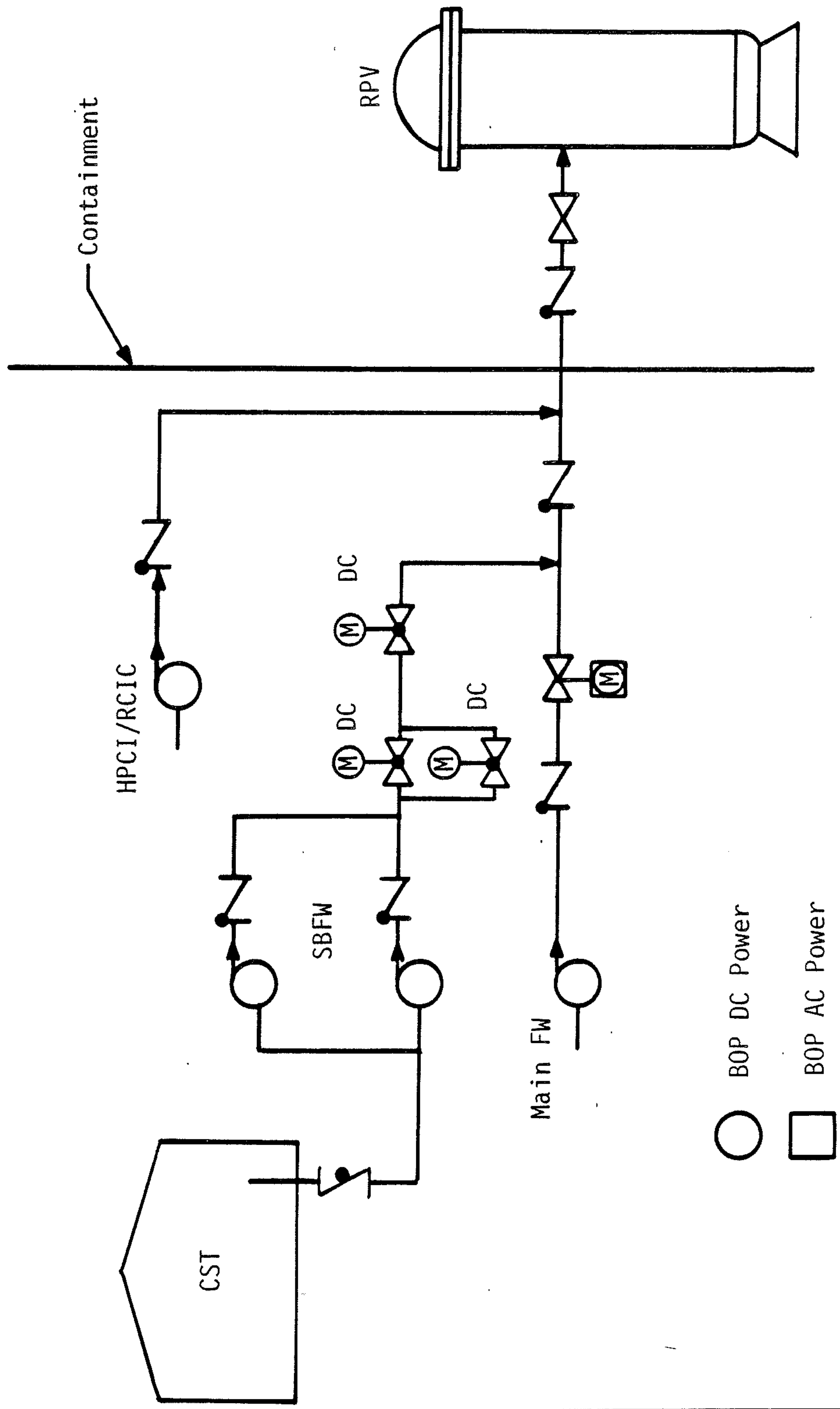

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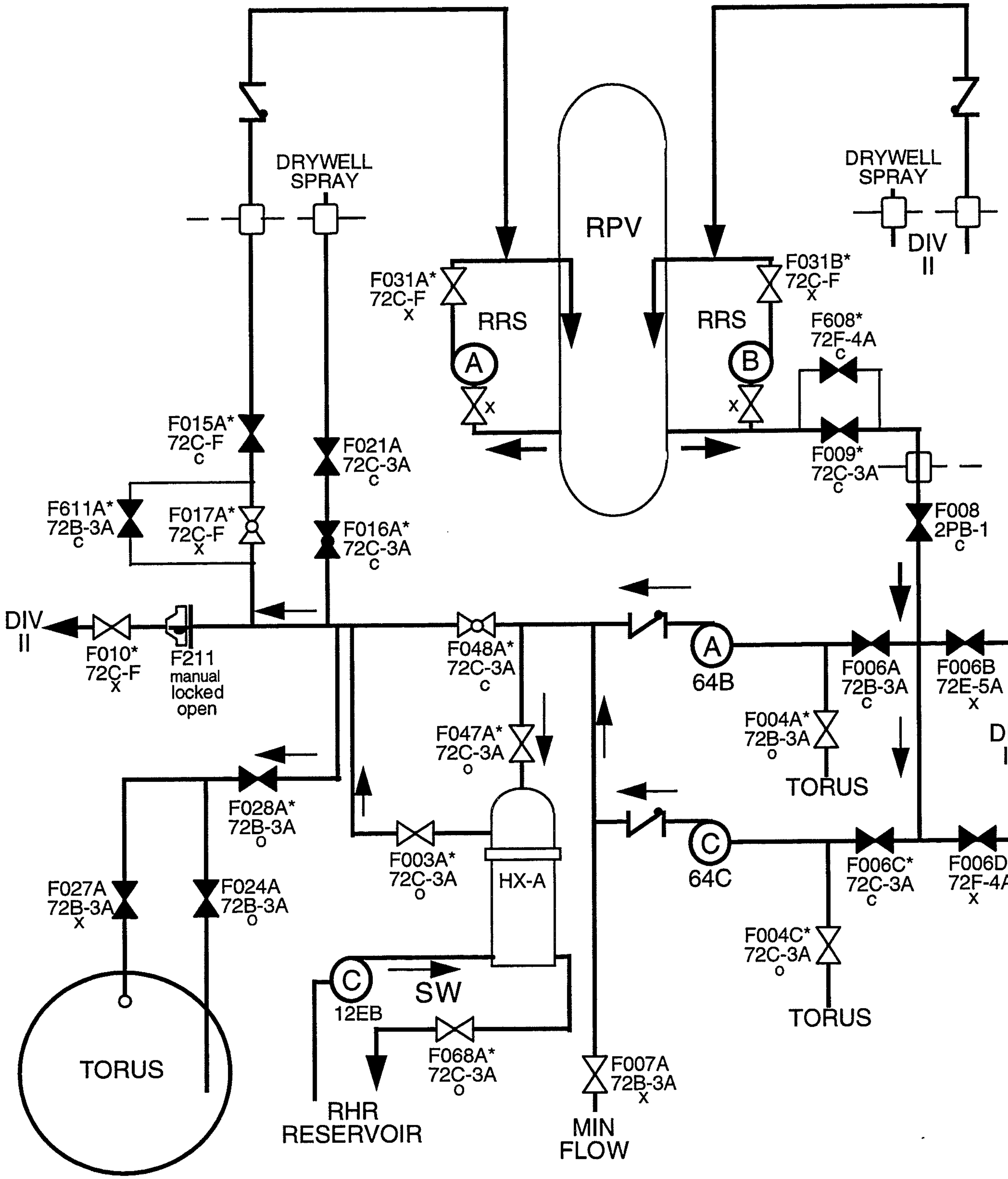
FIGURE 7.5-6

STANDBY FEEDWATER SYSTEM
SIMPLIFIED DIAGRAM



TORUS COOLING

1. Valves shown before loss of offsite power
2. Valve position required for torus cooling lineup:
   o - open
   c - closed
   x - either open or closed
3. Count: 8 valves need control outside control center
   * - Valve has transfer capability with control and indication (local control capability with appropriate indication at the motor control center isolable from the control center)

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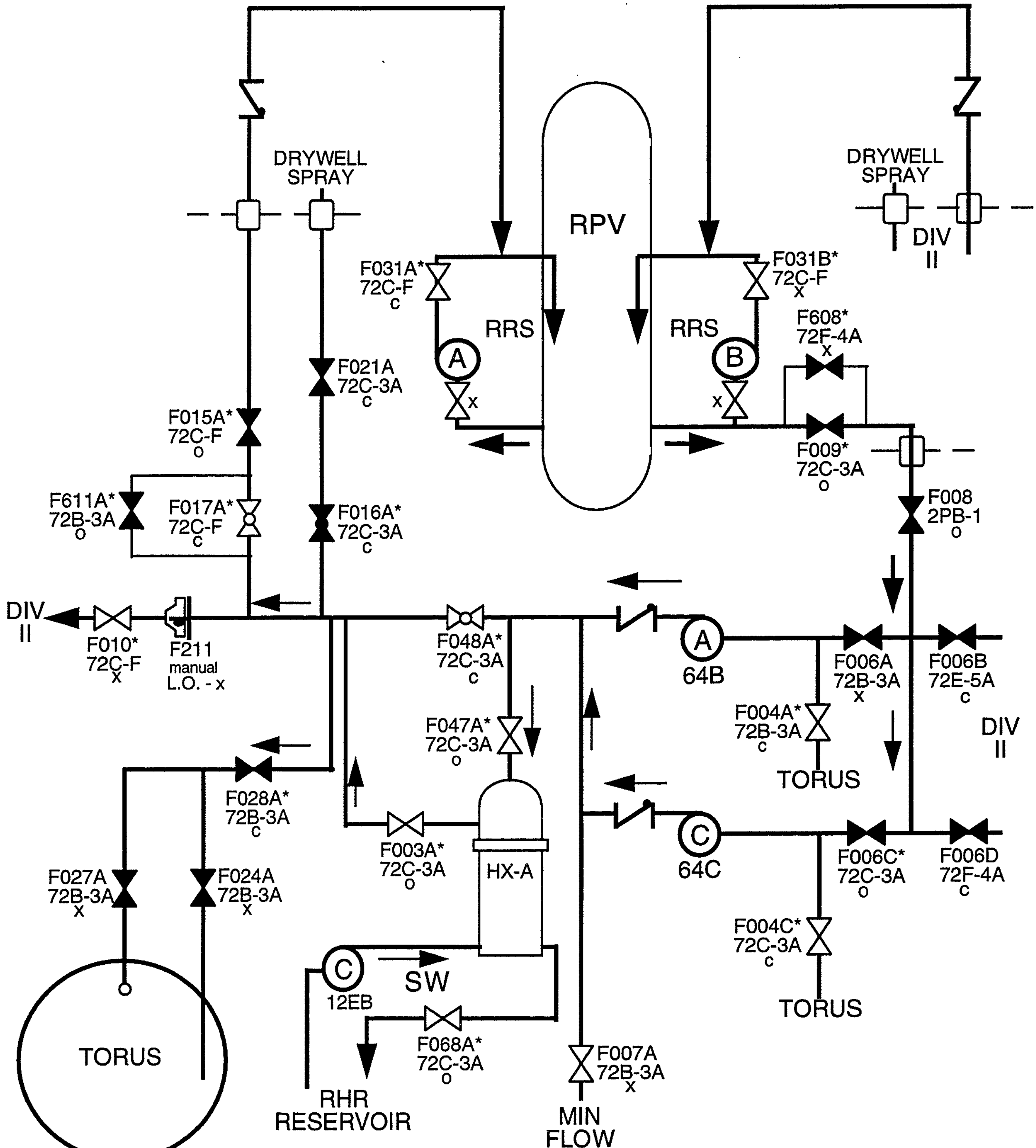
FIGURE 7.5-7

RESIDUAL HEAT REMOVAL SYSTEM TORUS COOLING MODE



SHUTDOWN COOLING

1. Valves shown before loss of offsite power unless previously aligned for torus cooling
2. Valve position required for shutdown cooling lineup:
   o - open
   c - closed
   x - either open or closed
3. Count: 11 valves need attention
   * - Valve has transfer capability with control and indication

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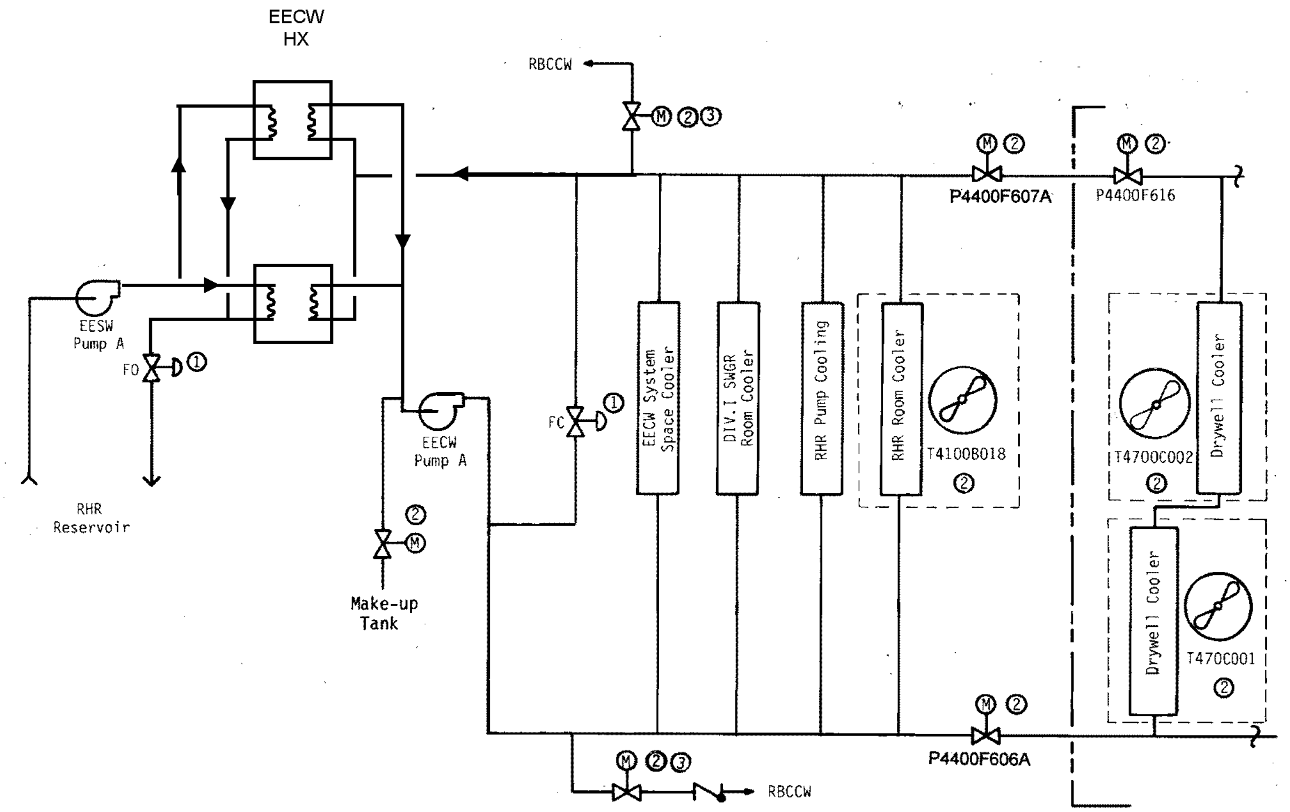
FIGURE 7.5-8

RESIDUAL HEAT REMOVAL SYSTEM SHUTDOWN COOLING MODE



① Position to which valve goes during electrical load stripping (FO = Fail Open, FC = Fail Closed).

② Transfer with local control and indiction at motor control center.

③ Because the RBCCW system is a hydraulically closed system, there will be no flow through these valves.

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FIGURE 7.5-9

EMERGENCY EQUIPMENT COOLING WATER SYSTEM SIMPLIFIED DIAGRAM

7.6 OTHER SYSTEMS REQUIRED FOR SAFETY AND POWER GENERATION

7.6.1 Description

7.6.1.1 Refueling Interlocks System

7.6.1.1.1 System Identification

The purpose of the refueling interlocks system is to restrict the movement of control rods and the operation of refueling equipment to reinforce operational procedures that prevent making the reactor critical during refueling operations.

7.6.1.1.2 Power Sources

Both channels are powered by the control rod drive (CRD) system power supply. A failure of this power supply will prevent any rod motion.

7.6.1.1.3 Equipment Design

7.6.1.1.3.1 Circuit Description

The refueling interlocks circuitry senses the condition of the refueling equipment and the control rods. Depending on the sensed condition, interlocks are actuated to prevent the movement of the refueling equipment or withdrawal of control rods (rod block). Dual channel Circuitry is provided to sense the following conditions:

a. All rods inserted

b. Refueling platform positioned near or near over the core

c. Refueling platform hoists fuel-loaded (fuel grapple, frame-mounted hoist, trolley-mounted hoist)

d. Fuel grapple not at full-up position.

The indicated conditions are combined in logic circuits to satisfy all restrictions on refueling equipment operations and control rod movement (Figure 7.7-1). A two-channel dc circuit indicates that all rods are in. The rod-in condition for each rod is established by the closure of a magnetically operated reed switch in the rod position indicator probe. The rod-in switch must be closed for each rod position indicator probe. The rod-in switch must be closed for each rod before the "all-rods-in" signal is generated. Both channels must register the "all-rods-in" signal for the refueling interlock circuitry to indicate the "all-rods-in" condition.

During refueling operations, no more than one control rod is permitted to be withdrawn. This restriction is enforced by a redundant logic circuit that uses the "all-rods-in" signal and a rod selection signal to prevent the selection of a second rod for movement with any other rod not fully inserted. The simultaneous selection of two control rods is prevented by the interconnection arrangement of the select pushbuttons. With the mode switch in the REFUEL position, the circuitry prevents the withdrawal of more than one control rod and the movement of the loaded refueling platform over the core with any control rod withdrawn.

Operation of refueling equipment is prevented by interrupting the power supply to the equipment. The refueling platform is provided with two mechanical switches attached to the platform, which are tripped open by a long, stationary ramp mounted adjacent to the platform rail. The switches open before the platform or any of its hoists are physically located over the reactor pressure vessel (RPV) to indicate the approach of the platform toward its position over the core.

The hoists on the refueling platform and the service platform are provided with switches that open when the hoists are fuel loaded.

This circuitry indicates when fuel is loaded on any hoist.

7.6.1.1.3.2 Bypasses and Interlocks

NOTE: Service platform and hoist equipment are permanently removed. However, bypass for the load interlock system will remain in place in order to provide original function.

A bypass for the service platform hoist load interlock is provided. When the service platform is no longer needed, its power plug is removed. This deenergizes the power supply to the hoist. The platform can then be moved away from the core. Deenergizing the hoist power supply opens the hoist load switches and gives a false indication that the hoist is loaded. This indication prevents control rod withdrawal with the mode switch in the STARTUP or REFUEL position. A bypass plug allows control rod movement in this situation. The bypass plug is physically arranged to prevent the connection of the service platform power plug unless the bypass plug is removed. The rod block interlocks and refueling platform interlocks provide two independent levels of interlock action. The interlocks that restrict operation of the platform hoist and grapple provide a third level of interlock action since they would be required only after a failure of a rod block and refueling platform interlock. It is pertinent to note that the strict procedural control exercised during refueling operations may be considered a fourth level of backup.

7.6.1.1.3.3 Redundancy and Diversity

The refueling interlocks are designed such that a single interlock failure will not cause an accident. These refueling interlocks are provided for use during planned refueling operations. Criticality is prevented during the insertion of fuel, provided control rods in the vicinity of the vacant fuel space are fully inserted during the fuel insertion. The refueling interlock system accomplishes this by:

a. Preventing operation of the fuel-loaded refueling equipment over the core whenever any control rod is withdrawn

b. Preventing control rod withdrawal whenever fuel-loading equipment is over the core

c. Preventing withdrawal of more than one control rod when the mode switch is in the REFUEL position.

The refueling interlocks have been carefully designed using redundancy of sensors and circuitry, to provide a high level of reliability and assurance that the stated design bases will be met. Each of the individual refueling interlocks discussed above need not meet the single-failure criterion of IEEE 279-1971 because the four essentially independent levels of protection provide assurance that the design basis is met. For any of the "situations" listed in Table 7.6-1, a single interlock failure will not cause an accident, result in potential physical damage to fuel, or result in radiation exposure to personnel during fuel-handling operations.

7.6.1.1.3.4 Testability

Complete functional testing of all refueling interlocks before refueling outages positively indicates that the interlocks operate in the situations for which they were designed. The interlocks are subjected to valid operational tests by loading each hoist with a suitable test weight, positioning the refueling platform, and withdrawing control rods.

7.6.1.1.4 Environmental Considerations

The refueling equipment is subject to conditions during normal operation that are less severe than those listed in Table 3.11-1. The refueling interlocks are not required to operate under the conditions listed in Table 3.11-1.

7.6.1.1.5 Operational Considerations

The refueling interlocks system is required only during refueling operations.

In the refueling mode, the main control room operator has an indicator light for “refuel mode one rod permissive” whenever all control rods are fully inserted. He can compare this indication with control rod position data from the computer as well as control rod in/out status display. Furthermore, whenever a control rod withdrawal block situation occurs, the operator receives annunciation and computer logging of the rod block. He can compare these outputs with the status of the variable providing the rod block condition.

Both channels of the control rod withdrawal interlocks must agree that permissive conditions exist in order to move control rods; otherwise, a control rod withdrawal block is placed into effect. Failure of one channel may initiate a rod withdrawal block, but does not prevent application of a valid control rod withdrawal block from the remaining operable channel.

In terms of refueling platform interlocks, the platform operator has indicators for the platform x-y position and z position of the fuel grapple. Pushbuttons and rotary control switches are provided for local control of the platform and its hoists. The platform operator can immediately determine whether the platform and hoists are responding to his local instructions. In conjunction with the main control room operator, the local operator can verify proper operation of each of the three categories of interlocks listed previously.

7.6.1.2 Reactor Pressure Vessel Instrumentation

Figure 7.3-12 shows the instrument numbers, arrangements of the sensors, and sensing equipment used to monitor the RPV conditions. Because the RPV sensors used for the reactor protection system (RPS), engineered safety feature (ESF) systems, and control systems have been described and evaluated in other portions of this document, only the sensors that are not required for those systems are described in this subsection.

7.6.1.2.1 System Identification

The purpose of the RPV instrumentation is to monitor the key RPV operating parameters during plant operation.

7.6.1.2.1.1 Function

These instruments and systems are used to provide the operator with information during normal plant operation, startup, and shutdown. They are monitoring devices only and provide no active power control or safety function.

7.6.1.2.1.2 Classification

The systems and instruments discussed in this subsection are designed to operate under normal and peak operating conditions of system pressures and ambient pressures and temperatures. However, no special industry classifications are imposed on these instruments.

7.6.1.2.2 Equipment Design

The instrument sensing lines to the various pressure and level sensors slope downward from the vessel to the instrument rack at a nominal 1/8 in./ft (including allowance for piping sag).

7.6.1.2.3 Circuit Description

Basic design information for this system is given in Table 7.6-2.

7.6.1.2.3.1 Reactor Pressure Vessel Temperature

The RPV temperature is determined on the basis of reactor coolant temperature. Temperatures needed for operation and for compliance with the Technical Specifications operating limits are obtained from one of several sources, depending on the operating condition. During normal operation, either reactor pressure and/or the inlet temperature of the coolant in the recirculation loops can be used to determine the vessel temperature. Below the operating span of the resistance temperature detectors in the recirculation loop, the vessel pressure is used for determining the temperature. Below 212°F the vessel coolant temperature, and thus the vessel temperature, is reasonably well shown by the reactor water cleanup (RWCU) system inlet temperature. These three sources of input are most conveniently available from the Integrated Plant Computer System (IPCS). During normal operation, vessel thermal transients are limited via operational constraints on parameters other than temperature.

Reactor pressure vessel thermocouples are provided as a means of observing vessel metal surface temperature behavior in response to changes in vessel coolant temperature during startup and during power-operation testing. Indications based on the thermocouples are not used for controlling the rate of heating or cooling or limiting the vessel thermal stresses.

7.6.1.2.3.2 Reactor Pressure Vessel Water Level

The reactor vessel water level instrumentation systems are discussed in other sections as follows:

a. Reactor water level instrumentation that initiates reactor scram is discussed in Subsection 7.2.1.1.3.1

b. Reactor water level is maintained by the feedwater control system (Subsection 7.7.1.3).

The reactor water level system that pertains to this section is used to monitor, in the main control room, the reactor water level during the shutdown condition when the reactor system is flooded for maintenance and head removal. The water level design is the condensate chamber reference leg type that is not compensated for change in density. The vessel condition that provides accurate water level information is 0 psig pressure and ambient temperature. The range of the instrument is from the bottom of the feedwater control operating range to a level over the top of the RPV head. Figure 7.3-12 shows specific values at which alarms and safety actions are initiated.

7.6.1.2.3.3 Reactor Core Hydraulics

Figure 7.3-12 shows the flow instruments, differential pressure instruments, and recorders provided so that the core coolant flow rates and the hydraulic performance of RPV internals can be determined.

The differential pressure between the throat of each jet pump and of the core inlet plenum is measured and indicated in the relay room. Four jet pumps, two associated with each recirculation loop, are specially calibrated. They are provided with pressure taps in the diffuser sections. The differential pressure measured between the diffuser tap and the throat tap allows precise flow calibration using the jet pump prototype test performance data for each of the calibrated jet pumps. The flow rates through the remaining jet pumps are calculated from the flows shown by the four calibrated jet pumps. The flow rates through the jet pumps associated with each recirculation loop are summed to provide main control room indication of the core flow rate associated with each recirculation loop (Figure 7.3-12). Total flows for both loops are summed and recorded in the main control room to indicate the total flow through the core. During the operation of a single recirculation loop, total core flow indication is derived by subtracting the reverse flow signal from the forward flow signal of the active jet pumps. This function is provided automatically any time a single recirculation pump is operating.

A differential pressure transmitter indicates core plate pressure drop by measuring the pressure difference between the core inlet plenum and the space just above the core support assembly. The instrument sensing line used to determine the pressure in the core inlet plenum is the same line used for the injection of the standby liquid from the standby liquid control system (SLCS). An instrument sensing line is provided for measuring pressure above the core support assembly. The differential pressure across the core plate is indicated and recorded in the main control room.

A differential pressure transmitter and control room indicator indicate the jet pump developed head by measuring the difference between the jet pump suction pressure (reactor annulus – between vessel wall and core shroud) and the jet pump discharge pressure (pressure below the core plate).

This instrumentation permits the determination of total core flow in two ways. The first method is the readout of the summed flow measurements from all the jet pumps as described in the preceding paragraphs. The second method involves establishing a correlation between drive loop flow rate and core flow rate with reactor power as a parameter. The correlation can then be used to convert the flow in the recirculation pump loops to core flow rate. This correlation is of a temporary nature because it changes with a fixed core arrangement over a period of time as a result of crud buildup on the fuel. The main control room flow rate readouts of the specially calibrated jet pumps can be used to cross check the flow rate readouts of all the other jet pumps. A discrepancy in the cross-checks is reason enough to check local flow indications.

7.6.1.2.3.4 Reactor Pressure Vessel Pressure

Pressure indicators and transmitters detect RPV internal pressure from the same instrument lines used for measuring RPV water level.

The following list shows the subsections in which the RPV pressure-measuring instruments are discussed:

a. Pressure transmitters for initiating scram or for bypassing main steam isolation valve (MSIV) closure are discussed in Subsection 7.2.1.1.3

b. Pressure transmitters used for high-pressure coolant injection (HPCI), core spray, low-pressure coolant injection (LPCI), and the automatic depressurization system (ADS) are discussed in Subsection 7.3.1.2

c. Pressure transmitters and recorders used for feedwater control are discussed in Subsection 7.7.1.4

d. Pressure transmitters used for wide range pressure recordings are discussed in Subsection 7.5.1.4.2.

7.6.1.2.3.5 Reactor Pressure Vessel Head Seal Leak Detection

The pressure between the inner and outer head-seal rings is sensed by a pressure switch. If the inner seal fails, the pressure at the pressure switch is the vessel pressure and the pressure switch trips, sounding an annunciator in the main control room. The plant continues to operate with the outer seal as a backup and the inner seal can be repaired at the next outage when the head is removed. If both the inner and outer head seals fail, the leak is detected by an increase in drywell temperature and pressure. This system is part of the leak detection system (LDS), which is described in Subsection 7.6.1.8.

7.6.1.2.3.6 Safety/Relief Valve Seat Leak Detection

Thermocouples are located near the discharge of the safety/relief valve seat. The temperature signal goes to a multipoint recorder with an alarm. The alarm will be activated by any temperature in excess of a set temperature, signaling that one of the safety/ relief valve seats has started to leak. This system is part of the LDS (Subsection 7.6.1.8).

7.6.1.2.3.7 Other Instruments

a. The steam temperature is measured at the steam manifold and is recorded in the main control room

b. The feedwater temperature is measured and transmitted to the main control room.

7.6.1.2.4 Testability

Pressure, differential pressure, water level, and flow instruments are located outside the drywell and are piped so that calibration and test signals can be applied during reactor operation.

7.6.1.2.5 Environmental Considerations

There are no special environmental considerations for the instruments described in this subsection.

7.6.1.2.6 Operational Considerations

7.6.1.2.6.1 Normal

The RPV instrumentation discussed in this subsection is designed to augment the existing information from the ESF such that the operator can start up, operate at power, shut down, and service the RPV in an efficient manner. None of this instrumentation is required to initiate any ESF.

7.6.1.2.6.2 Operator Information

The following information is available to the operator:

a. Selected RPV thermocouples are recorded on a multipoint recorder at a local rack

b. The shutdown flooding water level is indicated in the main control room

c. The flow for each of the four calibrated jet pumps is indicated in the main control room

d. The differential pressure for all the jet pumps (calibrated and uncalibrated) is indicated in the main control room and relay room

e. The recirculation core flow that is generated by each recirculation loop is indicated in the main control room

f. The total core flow is recorded by one pen of a two-pen recorder in the main control room. The other pen records the core plate differential pressure

g. The jet pump developed head is indicated in the main control room

h. The reactor head seal LDS activates an annunciator when the reactor head inner seal fails

i. The discharge temperatures of all the safety/relief valves (SRVs) are shown on a multipoint recorder in the relay room. Any temperature in excess of setpoint turns on an annunciator indicating that an SRV seat has started to leak.

7.6.1.2.7 Setpoints

The annunciator alarm setpoints for the reactor head seal leak detection, SRV seat leak detection, and feedwater corrosion product monitor are set so the sensitivity to the variable being measured provides adequate information.

Figure 7.3-12 includes a chart showing the relative indicated water levels at which various automatic alarms and safety actions are initiated. Specific level values are shown in Figure 7.3-12. Each of the listed actions is described and evaluated in the subsection of this report where the system involved is described. The following list tells where various level measuring components and their setpoints are discussed:

a. Level transmitters for initiating scram are discussed in Subsection 7.2.1.1

b. Level transmitters for initiating primary containment or vessel isolation are discussed in Subsection 7.3.2.2.8

c. Level transmitters used for initiating HPCI, LPCI, core spray, and ADS, and the level transmitters to shut down the HPCI pump drive turbine, are discussed in Subsection 7.3.1.2

d. Level transmitters to initiate reactor core isolation cooling (RCIC) and the level transmitters to shut down the RCIC pump drive turbine are discussed in Subsection 7.4.1.1

e. Level trips to initiate various alarms and trip the main turbine and the turbine-driven feed pumps are discussed in Subsection 7.7.1.3 and 7.7.1.4.

7.6.1.3 Process Radiation Monitor System

The Process Radiation Monitor system is described in Section 11.4.

7.6.1.4 Area Radiation Monitor System

The Area Radiation Monitor system is described in Subsection 12.1.4.

7.6.1.5 Offsite Environs Radiation Monitor Systems

These systems are described in the Offsite Dose Calculation Manual (ODCM).

7.6.1.6 Rad-Chem Radiation Monitoring Instruments

These systems are described in Section 12.3.

7.6.1.7 Reactor Water Cleanup System Instrumentation and Control

7.6.1.7.1 System Identification

The purpose of the RWCU system instrumentation and control is to provide protection for the system equipment from overheating and overpressurization and to provide the operator with information concerning the effectiveness of operation of the system.

This system is not safety related, and all instrumentation components in the system used only for RWCU operation are nonessential. The instrumentation is a standard industrial type for which performance has been proven by years of service throughout the industry.

7.6.1.7.2 Power Sources

The RWCU instrumentation is fed from the 120-V ac instrumentation bus. No backup power source is necessary since the RWCU system is not a safety-related system. The RWCU instrumentation is arranged in groups or circuits, and each such circuit is protected by a suitable fuse. Thus, a short-circuit within the system will have only a local effect that can be corrected easily without interrupting reactor operation.

7.6.1.7.3 Equipment Design

7.6.1.7.3.1 Circuit Description

The RWCU system is described in Subsection 5.5.8. This subsection describes the circuitry used to protect the resin and the filter-demineralizer. These circuits are shown in Figure 5.5-19 and the operating logic is shown in Figure 7.6-1.

To prevent resins from entering the reactor recirculation system in the event of a filter-demineralizer resin support failure, a strainer is installed on the outlet of each filter-demineralizer unit. Each strainer is provided with a local alarm energized by high differential pressure. A bypass line is provided around the filter-demineralizer units for bypassing the units when necessary.

Relief valves and instrumentation are provided to protect the equipment against overpressurization and the resins against overheating. The system is automatically isolated when signaled by any of the following occurrences:

a. High temperature downstream of the nonregenerative heat exchanger - to protect the ion exchange resins from deterioration due to high temperature (Table 7.6-2)

b. Reactor vessel low water level - to protect the core in case of a possible break in the RWCU system piping and equipment (Subsection 7.3.2.2.7.1)

c. SLCS actuation - to prevent removal of the boron by the RWCU system filter-demineralizers

d. Cleanup system equipment area high ambient temperatures - part of the plant LDS

e. High temperature increase across the system's ventilation ducts - part of the plant LDS

f. High change in system inlet flow in comparison to the system outlet flow - part of the plant LDS.

In the event of low flow or loss of flow in the system, flow is maintained through each filter-demineralizer by its own holding pump. Sample points are provided upstream of the RWCU system and downstream of each filter-demineralizer unit for continuous indication and recording of system conductivity. High conductivity is annunciated in the main control room. The influent sample point is also used as the normal source of reactor coolant samples. Samples analysis also indicates the effectiveness of the filter-demineralizer units.

7.6.1.7.3.2 Testability

Because the RWCU system is usually in service during plant operation, satisfactory performance is demonstrated without the need for any special inspection or testing.

7.6.1.7.4 Environmental Considerations

The RWCU system is not required for safety purposes, nor is it required to operate after the design-basis accident (DBA). The RWCU system is required to operate in the normal plant environment for power generation purposes only.

The RWCU control instrumentation located in the RWCU equipment area is subject to the environment described in Table 3.11-3.

7.6.1.7.5 Operational Considerations

The RWCU system instrumentation and control is not required for safe operation of the plant. It provides a means of monitoring parameters of the system and protecting the system.

7.6.1.8 Leak Detection System

7.6.1.8.1 System Identification

This subsection discusses the instrumentation and controls associated with the LDS. The system itself is discussed in Subsection 5.2.7.

The LDS serves to detect leakage from the nuclear boiler pressure boundary and auxiliary and ESF systems. It also generates isolation signals to systems that are leaking in excess of determined limits.

7.6.1.8.2 Power Sources

Power source separation is applicable to leak detection channels that are associated with the isolation valve system. Two power sources are used to comply with separation criteria so that redundant channels receive power from separate sources. Power is provided by dc/ac inverter A and dc/ac inverter B.

Inboard and outboard isolation valves in the same line are on separate power sources.

7.6.1.8.3 Systems and Components Provided With Leak Detection Systems

The following systems and components include leak detection instrumentation and control:

a. Main steam lines
b. Reactor core isolation cooling
c. High-pressure coolant injection
d. Recirculation pumps
e. Residual heat removal
f. Reactor water cleanup
g. Safety/relief automatic depressurization system valves
h. Reactor vessel head seal
i. Emergency core cooling system suction lines.

7.6.1.8.4 System Design

The LDS detects leaks by use of the following techniques:

a. Sensing excess flow in process piping systems
b. Sensing pressure and temperature changes in the primary containment
c. Monitoring temperatures in areas containing equipment and piping systems (Figure 7.6-2)
d. Monitoring activity of the drain sumps.

Detected leaks are annunciated in the main control room and, in certain cases, isolated from the nuclear steam supply system (NSSS) pressure boundary.

Leaks as small as 5 gpm are detected by either temperature and pressure changes or drain sump activities. Leaks greater than 5 gpm are also detected by changes in reactor water level and by change of flow in process lines.

Temperature detectors are located or shielded such that they are sensitive to air temperature only, and not to heat radiated from the equipment. Temperature sensors have individual alarm setpoints adjustable over a range of flow rates corresponding to leakage of up to 35 gpm.

Reactor coolant leakage of 5 gpm actuates an alarm in the main control room.

Specific information concerning the LDS is given in Table 7.6-2.

7.6.1.8.5 Leak Detection Within the Primary Containment

7.6.1.8.5.1 General

Leaks within the primary containment are detected by the following methods (Figure 7.6-3):

a. Monitoring pressure and temperature in the primary containment

b. Monitoring equipment drain and floor drain sump pump activity

c. Monitoring the drywell floor drain sump level

d. Monitoring the cooling water differential temperature of the closed cooling water system

e. Monitoring reactor water level.

In addition, a second method of leak detection uses recognition of increased containment atmosphere radioactivity as indicative of a system leak.

7.6.1.8.5.2 Pressure Measurement in Primary Containment

The primary containment is pressurized and maintained at a slightly positive pressure during reactor operation. The normal operating pressure is about 0.5 psig. The pressure may fluctuate as a result of barometric pressure changes and outleakages, but a pressure rise above the operating level indicates a process system leak.

Drywell pressure is monitored in the main control room as part of the primary containment monitoring system (Subsection 7.6.l.l2). High drywell pressure activates an alarm in the main control room and initiates automatic response of the RPS and ESF systems (Sections 7.2 and 7.3).

7.6.1.8.5.3 Temperature Measurement in Primary Containment

Drywell atmosphere temperature is maintained at approximately 135°F during reactor operation by heat exchangers of the drywell cooling system. An abnormal temperature rise significantly above 135°F indicates a high-energy process leak. A temperature rise will be detected by monitoring:

a. Drywell temperature at various elevations

b. Differential water temperature of closed cooling water system.

7.6.1.8.5.4 Primary Containment Sump Activity Monitoring

Equipment drain and floor drain sumps are provided with "fill-up" and "pump-out" rate measurements. Excessive rates are annunciated in the main control room.

The equipment drain sump collects only identified leakage and is equipped with high/low-level switches that control the sump drain. A sump filling/pump frequency in excess of the normal rate or excessive pumping time activates an annunciator in the main control room (Figure 7.6-4). Normal leakage (filling/pumping frequency) is to be determined during operational testing. The equipment drain sump receives drainage from pump seal leakoff, RPV head flange vent drain, and valve packing leakoff.

The floor drain sump is provided with the normal level switches for control of the pumps similar to the equipment drain sump. Additionally, an analog level transmitter is installed in the floor drain sump to provide a very sensitive level change measurement. A continuous analog display of sump level is derived from the transmitter and is located in the control center. An operator alarm is activated whenever the level measurement detects a sump inleakage greater than 1 gpm. This level monitor is designed and installed to remain functional following a seismic event and thereby meet the requirements of Regulatory Guide 1.45.

The floor drain sump collects unidentified leakage. This leakage is collected from CRDs, valve flanges, floor drains, the closed cooling water system, drywell cooling unit drains, and other potential sources not already identified. Leakage from the closed cooling water system is detected by decreased levels in the system surge tank.

The unidentified-leakage rate is that portion of the total leakage rate received in the drywell floor drain sump. A leakage rate of 150 gpm has been calculated to be the liquid leakage from a crack large enough to propagate rapidly. An allowance for reasonable leakage that does not compromise barrier integrity and is not identifiable is made for normal plant operation.

The unidentified-leakage rate limit is established at 5 gpm, which is far enough below the 150-gpm leakage rate to allow time for corrective action to be taken before the process barrier is significantly compromised. Normal background leakage will be determined during operational testing.

7.6.1.8.5.5 Reactor Vessel Head Seal Leak Detection

The RPV head is provided with double seals with a pressure switch sensing the pressure between the seals. High pressure (Table 7.6-2) is indicative of leakage past the inner seal and activates an annunciator in the main control room. The RPV head seal leak detection is also described in Subsection 7.6.1.2.3.5.

7.6.1.8.5.6 Recirculation Pump Seal Leak Detection

There are two recirculation pump LDSs, one for each of the pumps in the recirculation loop. Each LDS monitors the flow rate (leakage) past its associated pump's shaft by measuring the pressure within the seal cavity. There are two monitored seal cavities per pump.

The recirculation pump LDS consists of two types of monitoring circuits (Figure 7.6-5). The first of these monitors the pressure levels within the seal cavities, presenting the plant operator with a visual display of the pressure in each cavity. The second type of circuit monitors the rate of liquid flow from the seal cavities.

The pressure levels within seal cavity number 1 and seal cavity number 2 are measured with identical instrumentation (Table 7.6-2).

All condensate flowing past the recirculation pump seal packings and into the seal cavities is collected and sent by one of two drain systems to the drywell equipment sump for disposal. The first system drains the major portion of the condensate collected within the number 2 seal cavity. The condensate flow rate through the drain system is measured (high/low) by a flow switch. The point at which the microswitch closes can be adjusted so that switch actuation occurs only above or below certain flow rates (Table 7.6-2). Excessively high or low flow rates through this drain system activate the "Pump Seal Staging Flow" annunciator in the main control room.

7.6.1.8.5.7 Safety/Relief Valve Automatic Depressurization System Leak Detection

A temperature element (sensor) is used to detect leakage past each relief or safety valve. These temperatures are recorded on a multipoint recorder in the relay room. Normally, all relief and safety valves are in the shut-tight condition and remain at about the same temperature.

Steam passage through the valve elevates the sensed temperature at the exhaust, causing an "abnormal" temperature reading on the recorder. Microswitch contacts on the recorder close on high temperature (Table 7.6-2) to activate the "SRV Open" annunciator in the main control room.

7.6.1.8.6 Reactor Building Sump Activity Monitoring

Instrumentation for monitoring equipment drain sump and floor drain sump activities is the same in design as that described for drywell sump monitoring in Subsection 7.6.1.8.5.4.

7.6.1.8.7 Main Steam Line Leak Detection System

7.6.1.8.7.1 System Function

The main steam lines are continuously monitored for leaks by the main steam line LDS. Steam line leaks will cause changes in at least one of the following monitored operating parameters: sensed temperature, flow rate, or low water level in the RPV. If a leak is detected, the LDS responds by triggering an annunciator in the main control room and, depending upon the activating parameter, initiates steam line isolation action.

7.6.1.8.7.2 Physical Description

The main steam line LDS resistance temperature detectors (RTDs) are located throughout the main steam line tunnel, positioned such that they are screened from direct thermal radiation and yet are still able to respond to the temperature of the ambient air. The RTDs are used to trip the MSIVs closed.

The flow-rate monitoring components of the main steam line LDS consist of a set of four differential pressure transmitters and an associated flow element for each main steam line. The outputs of the differential pressure transmitters are connected to components of the nuclear steam supply shutoff system that give a coincidence signal for main steam line isolation at a flow of approximately 130 percent.

Reactor water level and main steam line tunnel area temperature are monitored by circuits associated with the containment and reactor vessel isolation system to indicate the presence of a steam leak. The coverage of this discussion extends only to the sensing instrumentation and not to circuit arrangement or response. Such information may be found in the description of the primary containment and reactor vessel isolation control system.

Under conditions of normal reactor operation at constant power, reactor water level should remain fairly constant since the rate of steam mass flow leaving the reactor is matched by the feedwater mass flow rate into the RPV. However, given a condition of continued steam leakage from the closed system, the condensate reservoir level and the reactor water level decrease.

Reactor water level is monitored by level transmitters of the containment and reactor vessel isolation control system in addition to the normal complement of process-monitoring instruments. Reactor water level falling below the predetermined minimum allowable level results in switch actuation and subsequent containment and reactor vessel isolation control system responses.

7.6.1.8.8 Reactor Water Cleanup System Leak Detection

Leakage in the high temperature process flow of the RWCU system external to the primary containment is detected by temperature- sensing elements. Temperature sensors are located in the inlet and outlet ventilation ducts to measure the temperature difference. Local ambient-temperature sensors are located in all compartments containing equipment for these systems. Alarms in the main control room annunciate a temperature rise corresponding to excessive leakage. In addition to annunciation, a high cleanup- room temperature rise actuates automatic isolation of the RWCU system.

In addition to the temperature-detection method, leakage is detected by means of a flow comparison between RWCU system inlet and outlet. If the inlet flow exceeds outlet flow by approximately 55 gpm, as governed by the Technical Specifications, an alarm is actuated and the RWCU system is isolated automatically.

7.6.1.8.9 Residual Heat Removal System Leak Detection

The residual heat removal (RHR) leak detection components are divided into two groups, one sensitive to RHR system leaks external to the primary containment, and the other sensitive to system leaks internal to the primary containment. Leak detection instruments of the first group use devices that are sensitive to temperature and that monitor area ambient and differential temperatures. The second group of instruments monitors the pressure level within the drywell. Additionally, liquid leakage from system components contained within the drywell is collected and the rate of accumulation measured. The ambient and differential temperature monitoring circuits consist of thermocouples, switch point modules, and meters.

The thermocouples are mounted in their individual holders which, in turn, are mounted in the RHR equipment area such that they are sensitive primarily to the air temperature. The switch-point modules and meters are mounted on the leak detection panel in the relay room. A high ambient temperature lights the point module alarm indicator on the leak detection panel and activates the high ambient temperature alarm.

7.6.1.8.10 Reactor Core Isolation Cooling and High-Pressure Coolant Injection Systems

Leaks in the RCIC or HPCI systems are detected by differential pressure transmitters and by local temperature detectors that are functionally the same as those described for main steam line leak detection (Subsection 7.6.1.8.7).

Downstream of the differential pressure elements, gross leaks in the system are detected by a set of two differential pressure transmitters sensing differential pressure across an orifice plate. Flow in excess of specified limits isolates the system and activates an alarm in the main control room. A 3-sec time delay has been installed to prevent inadvertent system isolation due to pressure spikes. Gross leaks upstream of the differential pressure elements may be detected by a set of four pressure transmitters. The primary function of these transmitters is to detect low reactor pressure and to provide HPCI or RCIC turbine isolation signal.

The turbine exhaust vent lines of the HPCI system and the RCIC system are monitored for pressure by means of four pressure transmitters. A high-pressure signal isolates the system and activates an alarm in the main control room. Temperature sensors are located in the inlet and outlet of the ventilation duct of the equipment area and in the inlet to emergency coolers for measuring temperature-difference rise and room ambient temperature in the event of steam leakage. High temperature and high temperature difference are annunciated in the main control room. A high area temperature will automatically isolate the respective system.

The power required to operate the logics associated with the RCIC and HPCI LDSs is continuously monitored. Loss of power is identified by the "RCIC LOGIC POWER FAILURE" or "HPCI LOGIC POWER FAILURE" annunciators in the main control room.

7.6.1.8.11 Leak Detection in the Emergency Core Cooling System Piping Routing Area Adjacent to Suppression Pool

Temperature elements are located in the inlet and outlet of the ventilation ducts of the suppression pool area. High temperature and high temperature differences are annunciated in the main control room.

7.6.1.8.12 Emergency Core Cooling System Suction Lines Leak Detection

The purpose of this LDS is to provide information that would allow the closing of the valve in a broken emergency core cooling system (ECCS) line before net positive suction head (NPSH) is lost to the redundant system.

A sump-level alarm contact notifies the operator that a significant leak exists in the torus area. This signal allows the operator to terminate the loss of torus water.

7.6.1.8.13 Feedwater Leak Detection

A separate feedwater LDS is not provided. Leaks from the feedwater lines will be detected by one or a combination of the following methods:

a. Primary containment sumps high flow rate
b. Differential water temperature of closed cooling water system
c. Primary containment high pressure
d. Primary containment high temperatures
e. Reactor building sump high flow rate.

7.6.1.8.14 Testability

The proper operation of the sensors and the logic associated with the LDS are verified for proper operation during the LDS preoperational test and during inspection tests that are provided for the various components as they apply during plant operation.

Each temperature switch, both ambient- and differential-type, is connected to dual thermocouple elements. Each temperature switch can be checked for operation by observing the ambient temperature or differential, and then turning the trip-point adjustment and verifying that the switch operates at the proper temperature. Each temperature switch contains a trip light that lights when temperature exceeds the setpoint. The setpoint is reset manually to its required value by adjusting the setpoint on the meter in the main control room. In addition, keylock test switches are provided so that logic can be tested without sending an isolation signal to the system involved. Thus, complete system check can be confirmed by checking activation of the isolation relay associated with each switch.

The containment drain monitor system can be tested by supplying makeup water to the sump at a sufficient flow rate to bring the water level above the sump high-level pump-actuation point in less than predetermined time.

The RWCU differential-flow leak detection is tested by inputting a mA signal to simulate a high differential flow. Alarm and indicator lights monitor the status of the trip circuit.

7.6.1.8.15 Environmental Considerations

The sensors, wiring, other equipment, and electronics associated with the isolation valve logic are designed to withstand the conditions that follow a LOCA.

7.6.1.9 Plant Computer Systems

7.6.1.9.1 Integrated Plant Computer System (IPCS)

7.6.1.9.1.1 System Description

The IPCS is a computer system that combines various functions of the legacy computer systems that it replaced. The IPCS provides the capability of monitoring, recording and displaying plant parameters via strategically located display devices. The IPCS is designed to be highly reliable and provide current information for selected plant variables. All real-time data displays will update the current field conditions in a timely manner.

The IPCS is not required for safe operation of the plant. Hardwired instrumentation and control allows the operator to safely operate the plant in all modes in the absence of the IPCS. There is no safety objective for the IPCS.

The IPCS consists of several computing nodes interconnected through a local area network (LAN) configuration. These computing nodes work in conjunction with each other to form a single cohesive system.

The IPCS computing nodes have self-checking provisions. It performs diagnostic checks to determine the functionality of certain portions of the system hardware and software. It also performs internal software checks to verify that input signals and selected program computations are within specific limits or reasonable bounds.

The IPCS consists of two redundant computers, operating in parallel, simultaneously monitoring the same field signals. Either of the computers can be designated as the main computer (Master), and the other will be designated as the backup computer (Slave). Under normal operating conditions, both the Master computer and Slave computer perform all the key functions; however, only the Master computer is allowed to output data and calculation results. In the event the Master computer fails, the Slave computer will become the Master computer, and automatically assume control of all functions. The operating personnel will be informed of the fail-over. If the Slave computer fails while the Master computer is operating normally, the operating personnel will be informed and the Master computer will continue to function normally.

The operating personnel use display consoles to enter information into the IPCS, and to request various functions. Diagnostic messages on the display consoles, together with printer outputs and annunciator outputs permit the IPCS to communicate plant and system status to the operating personnel.

The IPCS has the capability for on-line storage and retrieval of historical data, which are to be used for time-history displays and other data analysis functions. These analysis functions include, but are not limited to, determining the plant steady-state operating conditions prior to an initiating event and evaluating the transient conditions producing the event and the post-event equipment performance.

The IPCS has on-line storage for pre-event and post-event data. The declaration of an event is signaled to the system from the display consoles or automatically for a scram. Additional post-event data can be stored at the operator’s request. The historical data storage and recovery are performed by the IPCS without interrupting the other functions of the system, such as data acquisition and console display. The IPCS has the capability of transferring the historical data onto magnetic media.

The IPCS consolidates the following functions into a homogenous computer system. Separate legacy computers provided these functions during the initial licensing of the plant:

- a. Scan, Log and Alarm (SLA)
- b Man-Machine Interface (MMI)
- c. Nuclear Steam Supply System (NSSS) Function
- d. Balance of Plant (BOP) Function
- e. Emergency Response Functions
    - 1. Safety Parameter Display System (SPDS) Function
    - 2. Emergency Response Data System (ERDS) Function
- f. Meteorological (MET) Function
- g. Transient Recording and Analysis (TRA) Function
- h. Data Archival Function
- i. Special Functions

In addition to the function consolidation listed above, the IPCS provides external interfaces with the digital processor/computer equipment associated with each of the following systems, which are further described in Section 7.6.1.9.1.3:

GE 3D-Monicore Computer System (3DM) Interface

GE NUMAC LINK Interface (PRNM and RWM Interface)

Eberline SS-1 Radiation Monitor System

Radiological Dose Assessment Application Interface

Meterological Data Acquisition System (MDAS) Interface

Visual Annunciator System (VAS) Interface

7.6.1.9.1.2 System Functions

7.6.1.9.1.2.1 Scan, Log and Alarm (SLA) Functions

The SLA function gathers data from selected plant data systems, provides the signal conditioning for conversion to engineering units, provides out-of-scale checking of each data point, and keeps a live database of all the current values of the data points.

The IPCS has the capability to alarm the main control room annunciator system in the event of abnormal IPCS operation.

7.6.1.9.1.2.2 Man-Machine Interface (MMI)

The IPCS generates displays and data summaries for use in the control room, technical support center (TSC), and emergency operations facility (EOF). The IPCS also retains a history of each data point. The current value or the historical values of a data point are accessible from the display consoles.

The MMI, the display consoles, and the form of the display on these consoles are designed considering human factors engineering. The system has predesigned displays that are called onto the screen by the operator.

7.6.1.9.1.2.3 Nuclear Steam Supply System (NSSS) Function

The NSSS functions provided are based on Fermi 2 requirements and General Electric recommendations for BWR heat balance and interface support to core monitoring software 3DM.

MMI screens and reports are provided in support of the NSSS performance calculations.

7.6.1.9.1.2.4 Balance of Plant (BOP) Function

The BOP function provides calculations that are based on Fermi 2 requirements, General Electric recommendations, industry recognized practices, and an analysis of the Fermi 2 BOP cycle arrangement and operation.

Accumulation calculations are provided for the determination of BOP related accumulated data. These accumulated data values are primarily associated with the plant electrical generation data and require the determination of both daily and monthly accumulated totals.

7.6.1.9.1.2.5 Emergency Response Functions

The Emergency Response Functions include the Safety Parameter Display System (SPDS) and the Emergency Response Data System (ERDS). When the plant was originally licensed, various capabilities to support the Emergency Plan were implemented on a dedicated computer system called the Emergency Response Information System (ERIS). These capabilities have been incorporated into the IPCS and are referred to as the Emergency Response Function.

7.6.1.9.1.2.5.1 Safety Parameter Display System (SPDS) Function

Description

An IPCS display with continuous SPDS status indication is provided in the control room, the TSC, and the EOF.

The SPDS function of the IPCS was added to the Fermi 2 design to aid operating personnel in assessing the safety status of the plant. The SPDS function display is accessible and visible to operating personnel and is distinguishable from other displays. The SPDS function display does not inhibit physical or visual access to operator interfaces with other systems located in the control room.

The SPDS design provides for the validation of parameters associated with the function. Operating personnel are alerted to any unsuccessful validation.

Interfaces between the SPDS function and safety-related systems are through isolation means. Interfaces between the SPDS function and non-safety-related systems are designed to ensure the integrity of the SPDS function.

The SPDS functional design includes the consideration of the following human engineering criteria:

a. Presenting information in directly usable form
b. Designing displays for quick identification of unsafe conditions
c. Easy selection of the display required
d. Minimizing reflection and glare.

The SPDS function presents the value or status of the primary variables of the following safety parameters:

a. Core cooling
b. Fuel integrity
c. Reactivity
d. Reactor coolant system integrity
e. Containment integrity

f. Radioactivity effluent to the environment.

A primary variable is defined as the monitored variable that provides the most direct indication needed to assess the status or value of a safety parameter. Secondary variables are those monitored variables that provide additional information about the safety parameters.

The primary variable associated with each safety parameter is shown in Table 7.6-3 and is discussed below:

a. Core cooling. The primary method to assess adequate cooling in BWRs is by a direct measurement of the reactor water level. Natural circulation capability is an inherent BWR feature. There are no traps that might block the natural circulation. Steam and noncondensibles rise to the top during normal operation and during accident conditions. As long as there is adequate water level, there is assurance of adequate core cooling

b. Core and fuel integrity. When the containment is isolated, the presence of fuel damage is determined by taking a sample of reactor coolant and performing a spectral analysis of the sample. During normal operation, the presence of fuel damage is determined by offgas radiation readings

c. Reactivity. The neutron instrument is the primary variable for determining this parameter

d. Reactor coolant system integrity. This parameter is assessed by monitoring reactor pressure, drywell pressure, drywell sump collection rate, and RPV isolation

e. Containment integrity. This parameter is assessed by measuring drywell and torus pressure, containment isolation, combustible gas level, torus temperature, torus level, and drywell temperature

f. Radioactivity effluent to environment. This parameter is assessed by monitoring the radioactivity at planned plant release points.

The parameters associated with the SPDS displays are listed in Table 7.6-4.

Emergency procedure guidelines (EPGs) have been developed by the BWR Owners Group; they are symptom based and designed to improve the operator's ability to mitigate the consequences of a broad range of initiating events and subsequent multiple operator errors. The Fermi 2 Emergency Operating Procedures (EOPs) are based on the EPGs. The EOPs identify entry conditions and contain parameter versus parameter limit curves. The emergency response function includes the EOP limit curves and parameter information that is supportive of determining entry conditions.

The SPDS function displays are comprised of an overview display, critical safety function displays (generally a bar and/or trend), and the EOP limit curves.

Design Analysis

The graphics provided to the operator by the SPDS function are one of the man-machine interfaces to the IPCS. The IPCS acquires both digital and analog inputs from field sensors and computer data links with monitoring and control systems throughout the plant.

Existing signal loops of monitoring and control systems were tapped to provide inputs for the SPDS function. The isolation requirement for analog safety-related circuits was provided by using a qualified isolator for each circuit which provides input to the data acquisition system. Dry contact inputs were provided for digital inputs. Engineering was completed in accordance with applicable design criteria to ensure that the SPDS function cannot adversely affect safety-related systems.

Signals to the IPCS for the SPDS function are processed and validated to prevent misleading the operator. Redundant input signals are used for selected parameters and comparison limits are performed for validation. Additional information processing is performed for analog, digital, and derived parameters and includes the following:

a. Sensor range limit checks

b. Conversion to engineering units

c. Validation routine processing

d. On-line diagnostics for transmission

e. Time tagging of data.

The SPDS function incorporates human factors engineering guidance. The operator's interface with the displays and keyboard have been designed to provide easily accessed and readily understood displays. The BWR Owners Group Control Room Improvements Committee developed the initial Graphic Display System (GDS) in a program which had extensive human factors evaluation. The program included development and dynamic screening of the GDS and later a simulator evaluation of the displays by operators. The Fermi 2 SPDS function includes many features of the GDS, and has incorporated most of the recommendations from the findings of the simulator evaluation. Some of the human factors criteria that were considered in the SPDS function are listed in the Description subsection above.

The SPDS design requirements with regard to parameter selection, isolation, signal validation, and human factors engineering have been analyzed. The critical safety function based, and EOP-related, selected parameters are sufficient to assess the safety status of the identified functions for a wide range of events, which include symptoms of severe accidents.

7.6.1.9.1.2.5.2 Emergency Response Data System (ERDS) Function

The Fermi 2 ERDS function provides selected plant parameters from the IPCS computer to the NRC. The ERDS function was developed to provide the NRC accurate and timely data on four types of plant parameters, namely:

a. Core and coolant system conditions

b. Conditions inside the containment

c. Radioactivity release rates

d. Data from the plant's meteorological tower.

The ERDS function is for use during emergencies to transmit information to the NRC Operations Center. The ERDS function datalink will operate in conjunction with the

Emergency Notification System (ENS), and would be supplemented with voice transmission of essential data not available from the ERDS function.

7.6.1.9.1.2.6 Meteorological (MET) Function

Section 2.3.3.2 describes the Meteorological Data Acquisition System (MDAS) and its interface with the IPCS hardware that replaced the legacy MDAS computer system. The dual-processor IPCS hardware and associated peripherals support the Regulatory Guide 1.23 meteorological function requirements of the orignal system and provide a platform for performing calculations, providing meteorological data for display at various plant locations, and archiving meteorological data.

The following are examples of calculations (based on data obtained from MDAS) done as part of the IPCS meteorological function:

Sigma Phi (measure of wind stability based on the variability of the vertical component of wind direction and and horizontal wind speed)

Pasquill Stability Class

Lake Breeze Status.

In addition, the IPCS MET function uses a Best Value algorithm to determine which value to archive from either the primary or secondary MDAS instrument train data.

7.6.1.9.1.2.7 Transient Recording and Analysis (TRA) Function

The TRA function replaces the legacy General Electric GETARS computer system functionality. The TRA has the capability to process analog and digital points at a scan rate equal to or faster than 100 samples per second, continuously, without degradation of performance of any other IPCS function. The TRA supports auto archiving of data based on data triggers. The ability to utilize both digital states and analog alarm setpoints is provided.

The TRA function plot and report resolution is 10 milliseconds. The TRA function plot and report function provides summary statistics such as mean, minimum, maximum, and standard deviation.

7.6.1.9.1.2.8 Long Term Data Archive (LTA) Function

A computer that is separate from the Master/Slave computers performs the Long Term Data Archive (LTA) function of the IPCS. The LTA computer communicates with the Master computer to receive current plant process data, both analog and digital, at a predefined interval. The LTA computer contains specialized software and a separate I/O database.

Data for points that have been deleted from the IPCS computer database, are retained on the LTA computer, for later retrieval.

7.6.1.9.1.3 External Interfaces

7.6.1.9.1.3.1 GE 3D-Monicore Computer System (3DM) Interface

The 3DM operation requires periodic transmission of live and static plant data to and from the IPCS. All communications with the 3DM are initiated and monitored by the IPCS.

Live plant data transmitted from the IPCS to 3DM includes the following plant inputs and status (represented as individual points):

a. Heat balance input points

b. LPRM and APRM data

c. Control rod data

Live plant data transmitted from the 3DM to IPCS includes the following:

a. RWM messages

7.6.1.9.1.3.2 GE NUMAC LINK Interface

The NUMAC LINK is a data acquisition system interface to the GE NUMAC LINK Power Range Neutron Monitor (PRNM) and the Rod Worth Minimizer (RWM) NUMAC systems. The IPCS NUMAC LINK interface provides the necessary analog and digital points acquired by the PRNM and RWM in support of real-time plant monitoring and application functions. All data received by the NUMAC LINK from the PRNM and RWM is date and time stamped and is accessible by a two-way communication protocol interface.

The IPCS RWM acquired data, through the NUMAC LINK interface, consists of the following signals:

a. Control rod positions and status (including substitute)

b. Control rod movement messages

c. RBM digital points

d. RWM messages

The IPCS PRNM data consists of the following signals

a. LPRM flux and associated digital points

b. APRM flux and associated digital points

c. RBM flux and associated digital points

d. Recirculation flow

e. Oscillation Power Range Monitor Units (OPRM)

7.6.1.9.1.3.3 Eberline SS-1 Radiation Monitor System (SS1) Interface

The SS1 radiation monitor has replaced the legacy Eberline CT2B radiation monitor. The SS1 interface acquires current value/status and historical value/status of various radiation monitoring points and processes them for storage in the real-time and archive database, as appropriate.

The IPCS performs all necessary calculations in support of the SPDS function and Dose Assessment interface, including a complex, best channel selection algorithm.

7.6.1.9.1.3.4 Radiological Dose Assessment Application Interface

The Radiological Dose Assessment program calculates the off-site radiological doses based on meteorological and radiological data available in the IPCS. The Earth Tech Raddose V software has been selected to replace the legacy ERIS dose assessment program.

The Raddose V implementation method runs on IPCS MMI in the control room, EOF, and TSC in two separate modes:

a. Utilizing manually input data
b. Using selected partial (or total) meteorological and radiological data automatically acquired from the IPCS.

Data and control files, necessary for sharing information between multiple dose assessment nodes, reside in multiple locations within the IPCS.

7.6.1.9.1.4 Power Sources

The IPCS has a reliable AC UPS power source. In the event of a complete loss of offsite power, data will be retained by the IPCS during the outage for display once power is restored. Non-essential peripheral devices are supplied from a reliable AC source with an automatic throw-over switch between normal and standby sources.

7.6.1.9.1.5 Environmental Considerations

All the IPCS equipment are capable of withstanding the service conditions to which they will be subjected to with respect to temperature, humidity, precipitation, etc.

7.6.1.9.1.6 Human Factors Engineering

Industry-accepted human factors considerations are followed in designing the man-machine interface. These considerations include, but are not limited to, the following:

a. Simplicity of entering commands
b. Feedback recognition of operator commands
c. Operator input error prevention and error detection
d. Flexibility of display access
e. Flexibility of data entry

7.6.1.9.2 3D-Monicore Computer System (3DM)

7.6.1.9.2.1 System Description

The objectives of the 3DM are to provide a quick and accurate calculation of core thermal performance and to facilitate data reduction, accounting, and logging functions.

The 3DM is not required for safe operation of the plant. Hardwired instrumentation and control allows the operator to safely operate the plant in all modes in the absence of the 3DM. There is no safety objective for the 3DM.

The 3DM consists of two redundant computers. Either of the computers can be designated as the main computer (Normal), and the other will be designated as the backup computer (Standby). Under normal operating conditions, the Normal computer performs all the functions and outputs data and calculation results. The Normal computer also updates the Standby computer at predefined intervals. In the event the Normal computer fails, the Standby computer will become the Normal computer after manual intervention by operating personnel, and assume control of all functions. If the Standby computer fails while the Normal computer is operating normally, the Normal computer will continue to function normally. Either computer can be placed in Failover mode for off-line activities without affecting the operating computer.

3DM receives plant process data from the IPCS via a high speed datalink. The IPCS gathers, formats and transmits the plant process data at predefined intervals. In addition, LRPM calibration flux data is received directly from the TIP system via a fiber optic NUMAC link.

The key 3DM features and capabilities are:

a. Adaptation of 3D diffusion theory solution to measured TIP and LPRM data

b. Use of full or partial TIP measurements of LPRM calibration

c. PANACEA 11 diffusion theory based substitute for non-functional TIPs and LPRMs

d. Calculating core performance parameter distributions and supplying gain corrections for each of the 172 LPRMs based on TIP data measurements

e. Calculating core margins based on LPRM and thermo-hydraulic readings

f. Providing displays and printouts of core thermal margins and core performance parameters automatically and on demand

g. Providing predictive capability to study and evaluate potential impact of operational changes

h. Providing a digital interface between the Power Range Neutron Monitor (PRNM) system and the IPCS. The interface is provided by the GE NUMAC LINKs as described in Section 7.6.1.9.1.3.2. The NUMAC LINKs also transmits calibration data to the PRNM from 3DM

i. Receiving and displaying RWM messages.

7.6.1.9.2.2 Operational Considerations

The local power density of every 6-in segment for every fuel assembly is calculated, using plant inputs of pressure, temperature, flow, LPRM levels, control rod positions, and the calculated fuel exposure. Total core thermal power is calculated from a reactor heat balance. Iterative computational methods are used to establish a compatible relationship between the core coolant flow and core power distribution. The results are subsequently interpreted as local power at specified axial segments for each fuel bundle in the core.

The core power distribution calculation sequence may be completed periodically or on demand. The computer has the capability to automatically print a periodic log for record purposes.

Flux level and position data from the plant are processed and formatted by the TIP system Automatic TIP Control Units (ATCU) and subsequently transmitted to 3DM. 3DM evaluates the data and determines gain adjustment factors by which the LPRM amplifier gains can be altered to compensate for exposure-induced sensitivity loss. The LPRM amplifier gains are not physically altered except immediately prior to calibration of the affected LPRM using the traversing in-core probe (TIP) system. The gain adjustment factor computations help to indicate to the operator when such a calibration procedure is necessary.

Using the power distribution data, a distribution of fuel-exposure increments from the time of the previous power distribution calculation is determined and is used to update the distribution of cumulative fuel exposure. Each fuel bundle is identified by batch and location, and its exposure is stored for each of the axial segments used in the power distribution calculation.

Exposure increments are determined periodically for each section of each control rod. The corresponding percent boron depletions are periodically updated. The exposure increment of each LPRM is determined periodically and is used to update both the cumulative ion chamber exposures and the correction factors for exposure-dependent LPRM sensitivity loss.

3DM provides on-line capability to determine monthly isotopic composition for each fuel bundle in the core. This evaluation consists of computing the weight of one isotope of neptunium, three of uranium, and five of plutonium, as well as the total uranium and total plutonium content. The isotopic composition is calculated for each segment of each fuel bundle and summed accordingly by bundles and batches. The method of analysis consists of relating the computed fuel exposure and average void fraction for the fuel to computer-stored isotopic characteristics applicable to the specific fuel type.

All functions and reports can be executed on demand by the operating personnel.

7.6.1.9.2.3 Power Sources

The 3DM has a reliable AC source with an automatic throw-over switch between normal and standby sources.

7.6.1.9.2.4 Environmental Considerations

All the 3DM equipment are capable of withstanding the service conditions to which they will be subjected to with respect to temperature, humidity, precipitation, etc.

7.6.1.10 (Deleted)

7.6.1.11 Sequence of Events Recorder

The sequence of events recorder function provides the basic alarm detection management, reporting and real-time display of all sequence of events input signals to the annunciator system. The inputs include NSSS and balance-of-plant (BOP) data.

The input signals are independent of the IPCS and are electrically isolated from it. An outage of the computer would not affect operation or reliability of the sequence of events recorder.

The sequence of events recorder displays the time and alarm type of each event and can resolve the time of occurrence with a resolution approaching 1 msec.

7.6.1.12 Primary Containment Monitor System

The primary containment monitor system consists of the following five monitor subsystems:

a. Primary containment radiation monitor

b. Primary containment temperature monitor

c. Primary containment pressure monitor

d. Pressure suppression pool water level indicator

e. Hydrogen/oxygen monitor.

Division II AOVs T5000F420B and T5000F421B are designed to be reopened in the event of an extended AC power failure, using DC solenoid valves T50F459B and T50F468B respectively, as show in Figure 7.6-11.

The primary containment radiation monitor subsystem supplements the LDS. The primary containment radiation monitor is not designed to operate following the DBA. The radiation monitor designed to monitor post-DBA containment radiation is the containment area high range monitor discussed in Section 11.4. The other four primary containment monitor subsystems, namely, the primary containment temperature monitor, primary containment pressure monitor, the pressure suppression pool water-level indicator, and the hydrogen/oxygen monitor, are required to operate after a LOCA, and are designed to meet the redundancy and separation requirements listed in Subsection 7.6.2.12. Under normal plant operation, however, these subsystems provide display of the monitored parameters for additional information on the operating conditions of the plant.

Descriptions of the five subsystems that compose the primary containment monitor system are presented in Subsections 7.6.1.12.1 through 7.6.1.12.4.

7.6.1.12.1 Primary Containment Radiation and Hydrogen/Oxygen Monitor Subsystem

7.6.1.12.1.1 System Identification

The primary containment radiation monitor subsystem is incorporated for monitoring the radioactivity of the atmosphere within the primary containment to provide additional information related to primary coolant leak detection. This provision improves the total drywell leak-detection diversity and enhances the sensitivity of leak detection beyond that which is available with the drywell sump system. An alarm and annunciator are actuated when the radiation level reaches a predetermined setpoint level. This subsystem has no control function (Table 7.6-2).

The primary containment radiation monitor uses a beta scintillation detector viewing a sample flow of primary containment atmosphere as it passes through a gaseous detector chamber. The sample is drawn from the primary containment, through the filters, past the gaseous sample detector, and returned to the containment by a sample pump. The piping and valve arrangement for sample flow are illustrated in Figure 7.6-11. Remotely controlled valves are used to select either all the drywell atmosphere sampling points, selected locations within the drywell, or the suppression chamber atmosphere for radiation monitoring.

The main sample flow loop supplies both the primary containment radiation monitor subsystem and the hydrogen/oxygen monitor subsystem in parallel. The hydrogen/oxygen monitor subsystem operates continuously to provide indication in the main control room of the concentration of hydrogen/oxygen in the containment. Levels of hydrogen and oxygen in excess of preset limits are alarmed in the main control room (Table 7.6-2).

The total time lag from intake of drywell atmosphere sample loop manifold to the monitoring instrument sampling point is designed to be less than 5 minutes. Within the primary containment radiation monitor are particulate and halogen filters to collect integrated samples for subsequent analysis.

Associated with each beta scintillation detector is a logarithmic count rate circuit, power supply unit, and meter readout. A recorder is provided in the main control room for display of radiation level. A flowmeter is provided in the sample line, with local display of flow rate, and means for actuation of the alarm and annunciator associated with the primary containment radiation monitor on loss of sample flow.

7.6.1.12.1.2 Classification

The primary containment hydrogen/oxygen monitor subsystem is seismically and environmentally qualified to meet the requirements of Regulatory Guide 1.97, Rev 2, Category 3 and 2, respectively. The radiation monitor has not been qualified environmentally or seismically.

7.6.1.12.1.3 Supporting Systems

Electrical Power

The electrical power required for operation of the primary containment radiation and hydrogen/oxygen monitor subsystems is supplied from the 480-V ESF motor control centers (MCCs) and the 120-V ac instrument bus as described in Subsection 8.3.1.

Pneumatic Power

The pneumatic power required for operation of valves in the sample lines will be supplied by an uninterruptible air system for the primary containment monitoring system isolation valves and an interruptible air system for the primary containment radiation monitoring system isolation valves as described in Subsection 9.3.1.

7.6.1.12.1.4 Equipment Design

Initiating Circuits

Control of the primary containment radiation and hydrogen/oxygen monitor subsystems for normal operation, test, and calibration is manual. The hydrogen/oxygen monitor subsystem is normally operated continuously from plant startup to shutdown.

Logic

The primary containment radiation monitor subsystem incorporates trip logic circuits for alarm and annunciator operation. A low mode alarm trip is provided to indicate instrument failure on loss of normal background reading, and a high mode trip to indicate a radiation level exceeding a predetermined normal background level. The hydrogen/oxygen monitor has alarms as defined in Table 7.6-2.

Actuated Devices

The primary containment radiation monitor and hydrogen/oxygen monitor subsystems have no control function. Devices actuated by the primary containment radiation monitor are an alarm and an annunciator on high radiation and on loss of background signal, the latter being indicative of instrument failure.

Testability

The primary containment radiation monitor and the hydrogen/oxygen monitor subsystems are fully testable during normal plant operation.

7.6.1.12.1.5 Environmental Considerations

The primary containment hydrogen/oxygen monitor subsystem is designed to operate reliably under normal and postulated abnormal environmental conditions in the equipment area. The local environmental conditions are defined in Table 3.11-1.

The oxygen monitors provide verification of the status of the inerted atmosphere of containment and oxygen levels in the containment atmosphere following a significant beyond design-basis accident for combustible gas control and accident management, including emergency planning.

The hydrogen monitors provide diagnosis of the course of significant beyond-design-basis accidents for accident management, including emergency planning.

7.6.1.12.1.6 Operational Considerations

Normal

During power operation, startup, or hot shutdown of the reactor, the primary containment radiation monitor subsystem is in continuous operation to detect and alarm a high level of radiation in the monitored atmosphere. The hydrogen/oxygen monitor subsystem is normally operated continuously from plant startup to shutdown.

Safety Function

On occurrence of radiation above the alarm setpoint level, the abnormal condition will be alarmed and annunciated in the main control room. High levels of hydrogen and/or oxygen are alarmed in the main control room.

Operator Information

The primary containment radiation monitor subsystem has provisions in the main control room for indicating the radiation count rate per unit volume of sample, for checking the setpoint at which the high radiation alarm is actuated, and for alarming low sample flow rate. A chart recorder is provided to record the monitored radiation levels. By the actuation of an alarm and annunciator, the operator is informed of high radiation level, instrument failure as evidenced by loss of normal background reading, or loss of sample flow. A number of functional alarms are provided in the hydrogen/oxygen monitors to ensure proper system operation.

Setpoints

The setpoint for actuation of the alarm and annunciator on high radiation will be established after the normal background is determined. The setpoint is adjustable over the instrument range. The alarm setpoints for the hydrogen/oxygen monitors can be found in Table 7.6-2.

7.6.1.12.2 Primary Containment Temperature Monitoring Subsystem

7.6.1.12.2.1 System Identification

The primary containment temperature monitor subsystem uses thermocouple detectors to measure drywell atmosphere temperature, pressure suppression pool chamber atmospheric temperature, and pressure suppression pool water temperature. To achieve representative temperature measurements in the primary containment, 16 sensors in the drywell, four sensors for suppression pool atmosphere, and four sensors for suppression pool water are used. The monitored temperatures are continuously recorded on two stripchart recorders. The primary containment temperature monitor subsystem has no control function; its purpose is that of data acquisition. Because of the importance of securing these temperature data on postulated accident (LOCA) conditions and other abnormal plant conditions, two redundant temperature monitors are provided.

In parallel with the primary containment temperature monitor subsystem (PCTMS), and in response to additional design requirements, two additional temperature monitoring systems have been installed to monitor the drywell air temperature and the suppression pool temperature, during normal mode of plant operation and transient condition, as discussed below.

The additional drywell air temperature monitoring subsystem uses 28 thermocouples (which are independent of the PCTMS) installed at six elevations. The temperature information is recorded in the main control room and is used by the operators to compute the volumetric average temperature for determination of the Technical Specifications operating limit. The additional suppression pool temperature monitoring subsystem uses a recorder and eight thermocouples (which are all independent of the PCTMS). These eight thermocouples in the torus are used by operators to compute the suppression pool water bulk average temperature for determination of the Technical Specification operating limit. The thermocouples are placed so that each thermocouple monitors the discharge of two SRVs. The recorder is located in the main control room and will alarm on bulk average water temperature ≥95.0°F or detection of an open T/C. The technical specifications allow the maximum average temperature of the suppression pool to be 95°F during operational conditions 1 or 2 unless the thermal power is less than or equal to 1%, or a test is being performed which adds heat to the suppression chamber. To alert an operator of this limit, an alarm will be set at approximately 95.0°F (increasing).

The additional thermocouples in the drywell and torus and the associated recorders which are used during normal mode of operation to monitor the drywell volumetric average and suppression pool bulk average temperature are classified as quality assurance (QA) level 1M and seismic category II/I. This classification means that these components are maintained like a QA level 1 component, and they will maintain their structural and mounting integrity during a seismic event.

The torus water temperature recorder and Division I drywell air temperature recorder are powered from a non-class IE distribution cabinet that is fed by a bus which is automatically restored by the emergency diesel generators (EDG) on a loss-of-offsite power. Thus, in the event of loss-of-offsite power, these recorders can be powered from the EDGs by closing a breaker. The Division II drywell air temperature recorder is powered from a class IE power bus.

7.6.1.12.2.2 Classification

The primary containment temperature monitor subsystem is not a fully qualified system. The set of 24 primary containment monitoring thermocouples have been installed seismically. Two thermocouples in the drywell, two in the suppression pool air space, and two in the suppression pool water have also been qualified environmentally for postulated accident conditions.

7.6.1.12.2.3 Power Sources

Operating power for the two identical temperature monitors of the primary containment temperature monitor subsystem is supplied from separate 120-V ac instrument buses to prevent total loss of monitoring capability on interruption of an instrument bus.

7.6.1.12.2.4 Equipment Design

Initiating Circuits

Both monitors are in service when the reactor is operating in order to provide necessary backup monitoring.

Redundancy

Two identical monitors are provided in the primary containment temperature monitor subsystem.

Separation

Instrument control and power feed circuits of the two monitors comprising this subsystem are separate. Routing of thermocouple and power circuits by separate paths and penetrations precludes total loss of temperature monitoring capability by a single destructive event.

Testability

To facilitate test and calibration, the temperature detectors are removable from their working locations. The recorders are tested and checked for calibration by the standard technique of using a millivolt box after disconnection of the thermocouple circuits.

7.6.1.12.2.5 Environmental Considerations

The thermocouples, associated thermocouple lead circuits, and recording instrumentation are of a design that provides reliable operation under normal and postulated abnormal environmental conditions. The environmental conditions of specific plant areas are defined in Tables 3.11-1, 3.11-3, and 3.11-4.

7.6.1.12.2.6 Operational Considerations

Normal

The primary containment temperature monitor subsystem operates continuously during operation of the reactor, and secures recordings of the monitored temperatures. Should a LOCA occur, obtained recordings provide essential information about the temperatures monitored by the primary containment temperature monitor subsystem.

Operator Information

Monitored temperatures are displayed on the recorder chart in the main control room, making this information directly available to the operations personnel when the plant is in operation.

7.6.1.12.3 Primary Containment Pressure Monitor Subsystem

7.6.1.12.3.1 System Identification

The primary containment pressure monitor subsystem monitors the atmospheric pressure of the drywell and the pressure suppression chamber and records on redundant chart recorders in the main control room. The instrumentation for the drywell uses two pressure ranges, -5 to +5 psig and 0 to 250 psig. The instrumentation for the pressure suppression chamber uses two ranges also, -5 to +15 psig and 0 to 80 psig. The low range of the pressure monitoring instrumentation enables detection of a change in drywell and or pressure suppression chamber pressure resulting from a primary containment leak and containment sprays, and provides for sensitive monitoring during normal operation of the plant and during shutdown and LOCA conditions. In order to provide continued monitoring of the drywell pressure during an extended loss of AC power, T5000F420B can be reopened using the DC solenoid valve T50F459B, as shown in Figure 7.6.11. The low range pressure monitoring instrumentation may also provide a means of detecting degradation of the containment pressure boundary. The high pressure ranges provide the capability to measure a pressure transient arising from a LOCA. Pressure is displayed on a multipoint recorder. Two complete and independent pressure monitors comprise the primary containment pressure monitor system. This subsystem has no control function; its purpose is that of data acquisition and advisory information.

Pressure transmitters used to initiate ECCSs or to provide inputs to the RPS are described in Subsection 7.3.1 and Section 7.2.

7.6.1.12.3.2 Classification

The primary containment pressure monitor subsystem is designed and installed as Category I. The pressure transmitters incorporated in this subsystem are also environmentally qualified for postulated accident conditions.

7.6.1.12.3.3 Power Sources

The electrical power for the powered equipment of the two pressure monitors in this subsystem is supplied from separate battery-powered inverters.

7.6.1.12.3.4 Equipment Design

Initiating Circuits

Control of operation of the pressure detector equipment is manual. Operation of this monitoring subsystem is continuous when the reactor is in operation.

Redundancy

Two identical monitors are provided in the primary containment pressure monitor subsystem.

Separation

Electrical circuits of the two identical pressure monitors comprising this subsystem are routed separately to minimize vulnerability to total impairment of the monitor subsystem by a single destructive event.

Testability

To facilitate periodic checks of operation of this subsystem, provisions are incorporated to allow for in-place testing of the detectors and convenient removal for testing when the reactor is shut down.

7.6.1.12.3.5 Environmental Considerations

The equipment of the primary containment pressure monitor subsystem is designed to operate reliably under the normal and postulated abnormal conditions of the equipment areas. The environmental conditions of these areas are defined in Table 3.11-1.

7.6.1.12.3.6 Operational Considerations

Normal

The primary containment pressure monitor subsystem operates continuously during operation of the reactor, securing recordings of the pressures within the primary containment.

Safety Function

Should a LOCA occur, secured recordings provide information sought about transients in the pressures monitored by the primary containment pressure monitor subsystem.

Operator Information

Monitored pressures are displayed on the recorder chart in the main control room as they are being recorded, making this information directly available while the plant is in normal operation. The pressure may fluctuate for a variety of reasons including changes in barometric pressure. A pressure rise above normal could indicate a process system leak as described in Subsection 7.6.1.8.5.2. The low range pressure monitoring instrumentation may also provide a means of detecting degradation of the containment boundary depending on the magnitude of the degradation. Unexplained changes in pressure during normal operation would therefore result in an investigation to determine the cause using the Corrective Action program as appropriate. If the drywell pressure increases above the trip value, the chart recorder increases chart speed to obtain better transient resolution. Peak pressure is also obtained by a peak-pressure indicator.

7.6.1.12.4 Pressure Suppression Pool Water Level Indicator Subsystem

7.6.1.12.4.1 System Identification

The pressure suppression pool water-level indicator subsystem continuously monitors and records on a chart recorder in the main control room the water level in the pressure suppression chamber. The principal function of this monitor subsystem is to obtain data on water level in the pressure suppression chamber on occurrence of a LOCA. The subsystem also serves to indicate and record the water level in the course of normal operation of the plant and during shutdown and LOCA condition. In order to provide continued monitoring of the suppression pool level during an extended loss of AC power, T5000F421B can be reopened using the DC solenoid valve T50F468B, as shown in Figure 7.6.11. This is a supplementary function because the pressure suppression chamber water level is maintained, and the level indication is necessarily provided in the main control room as part of the torus water management system.

7.6.1.12.4.2 Classification

The pressure suppression pool water level indicator subsystem is designed and installed as Category I. The transmitters are qualified to meet the environmental conditions of postulated accidents.

7.6.1.12.4.3 Power Sources

Operating electrical power for the pressure suppression pool water level indicator subsystem is supplied from separate battery-powered inverters.

7.6.1.12.4.4 Equipment Design

Initiating Circuits

Control of operation of the pressure suppression pool water level indicator subsystem is manual. Operation of the subsystem is continuous during reactor operation and when the reactor is shut down.

Redundancy

Two identical level-indicator instrumentation provisions comprise the pressure suppression pool water level indicator system.

Separation

The two independent level-indicator provisions comprising this subsystem have signal and power lines routed separately to minimize vulnerability to impairment of both subsystems by a single destructive event.

Testability

The pressure suppression pool water level indicator subsystem incorporates means to allow for complete testing of the subsystem during periods when the reactor is shut down.

7.6.1.12.4.5 Environmental Considerations

The equipment of the pressure suppression pool water level indicator subsystem is designed to operate reliably under the normal and postulated abnormal conditions to which the equipment would be exposed. The environmental conditions of the equipment areas are defined in Tables 3.11-1, 3.11-3, and 3.11-4.

7.6.1.12.4.6 Operational Considerations

Normal

The pressure suppression pool water level indicator subsystem is in continuous operation during operation of the reactor as well as during periods of shutdown, unless the equipment is taken out of service for test or maintenance purposes.

Safety Function

Should a LOCA occur, the recordings obtained provide essential information about the pressure suppression chamber water level during the abnormal conditions.

Operator Information

The water level in the pressure suppression pool is continuously indicated as well as recorded on a chart in the main control room.

7.6.1.13 Neutron Monitoring System Instrumentation and Control

The neutron monitoring system (NMS) consists of six major subsystems which are

a. Source range monitor

b. Intermediate range monitor

c. Local power range monitor

d. Average power range monitor

e. Rod block monitor

f. Traversing in-core probe.

7.6.1.13.1 System Identification

The purpose of this system is to monitor neutron flux levels of the core over the range from shutdown to full power, and to provide signals to the RPS (Section 7.2). It also provides information for operation and control of the reactor. Basic system information is given in Table 7.6-2.

Certain portions of the intermediate range monitor (IRM) and average power range monitor (APRM) systems provide a safety function, and portions of the rod block monitor (RBM) have been designed to meet IEEE 279-1971. All other portions of the NMS have no safety function.

7.6.1.13.2 Power Sources

The power supplies for each system are discussed in the individual circuit description.

7.6.1.13.3 Source Range Monitor System

7.6.1.13.3.1 Equipment Design

Circuit Description

The source range monitor (SRM) provides neutron flux information during reactor startup and low-flux-level operations. There are four SRM channels. Each includes one detector that can be physically positioned in the core from the main control room (Figures 7.6-12 through 7.6-14). The detectors are inserted into the core for a reactor startup. They can be withdrawn if the indicated count rate is between preset limits or if the IRM is on the third range or above.

The power for the monitors is supplied from the two separate +24 V dc buses. Two monitors are powered from each bus. The detector drives are powered by a 208-V ac three-phase bus.

Each detector assembly consists of a miniature fission chamber and a low-loss, insulated transmission cable.

The sensitivity of the detector is 1.2 x 10^{-3} cps/nv nominal. The detector cable is connected underneath the RPV to shielded coaxial cable. This shielded cable carries the pulses to a pulse current preamplifier located outside the primary containment.

The detector and cable are located inside the RPV in a dry tube sealed against reactor vessel pressure. A remote-controlled detector drive system moves the detector along the dry tube.

Vertical positioning of the chamber is possible from above the centerline of the active length of fuel to approximately 2-1/2 ft below the reactor fuel region, as shown in Figure 7.6-13. When a detector arrives at a travel endpoint, detector motion is automatically stopped. The SRM/IRM drive control logic is presented in Sheet 6 of Figure 7.6-16. The electronics for the SRMs, their trips, and their bypasses are located in one cabinet. Source-range signal-conditioning equipment is designed so that it can be used for open-core experiments.

A charge-sensitive preamplifier provides amplification and impedance matching for the signal conditioning electronics (Figure 7.6-17). The signal conditioning equipment converts the current pulses to analog dc voltages that correspond to the logarithm of the count rate. The equipment also derives the period. The output is displayed on front panel meters and is provided to remote meters and recorders.

The logarithmic count rate meter displays the rate of occurrence of the input current pulses. The period meter displays the time in seconds for the count rate to change by a factor of 2.72. In addition, the equipment contains integral test and calibration circuits, trip circuits, power supplies, and selector circuits.

The trip outputs of the SRM operate in the fail-safe mode. Loss of power to the SRM causes the associated outputs to become tripped (Figure 7.6-16, Sheet 2).

The SRM provides signals indicating SRM upscale, downscale, inoperative, and incorrect detector position to the RMCS to block rod withdrawal under certain conditions. Any SRM channel can initiate a rod block. These rod blocking functions are discussed in Subsection 7.7.1.1.3.5. Appropriate lights and annunciators are also actuated to indicate the existence of these conditions (Table 7.6-5). One in one group of four SRM channels can be bypassed at any one time by the operation of a switch on the operator's console.

Testability

Each SRM channel is tested and calibrated. Inspection and testing are performed as required on the SRM detector drive mechanism. The mechanism can be checked for full insertion and retraction capability. The various combinations of SRM trips can be introduced to ensure the operability of the rod blocking functions.

7.6.1.13.3.2 Environmental Considerations

The wiring, cables, and connectors located within the drywell are designed for the environmental conditions identified in NEDO 31558A per References 7 and 8 in Appendix A.

7.6.1.13.4 Intermediate Range Monitor System

7.6.1.13.4.1 Equipment Design

Circuit Description

The IRM monitors neutron flux from the upper portion of the SRM range to the lower portion of the power range monitoring subsystems. The IRM system has eight IRM channels, each of which includes one detector that can be positioned in the core by remote control. The detectors are inserted into the core for a reactor startup and are withdrawn after the reactor mode selector switch is turned to the RUN position and the LPRM is operative.

Power Supply

Power is supplied separately from the two 24-V dc sources. The supplies are split according to their use so that loss of a power supply results in the loss of only one trip system of the RPS.

Physical Arrangement

Each detector assembly consists of a miniature fission chamber attached to a low-loss, insulated transmission cable. When coupled to the signal conditioning equipment, the detector produces a reading of approximately 30 percent on the most sensitive range with a neutron flux of 10^8 nv. The detector cable is connected underneath the RPV to a shielded cable that carries the pulses generated in the fission chamber through the primary containment to the preamplifier.

The detector and cable are located in the drywell. They are movable in the same manner as the SRM detectors and use the same type of mechanical arrangement (Reference 1) and power supply.

Signal Conditioning

A voltage amplifier unit located outside the primary containment serves as a preamplifier. This unit converts the current pulses to voltage pulses, modifies the voltage signal, and provides impedance matching. The preamplifier output signal is coupled by a cable to the IRM signal conditioning electronics as shown in Figure 7.6-18.

Each IRM channel receives its input signal from the preamplifier and operates on it with various combinations of preamplification gain and amplifier attenuation ratios. The amplification and attenuation ratios of the IRM and preamplifier are selected by an operator's console-mounted range switch that provides 10 ranges of increasing attenuation acting on the signal from the fission chamber (the first six ranges are called low range and the last four ranges are called high range). As the neutron flux of the reactor core increases from 1×10^8 nv to 1.5×10^{13} nv, the signal from the fission chamber is attenuated to keep the input signal to the inverter in the same range. The output signal, which is proportional to neutron flux at the detector, is amplified and supplied to a locally mounted meter. Outputs are also provided for a remote meter and recorder.

Trip Functions

The IRMs are arranged in the core as shown in Figure 7.6-12 and are divided into two groups of IRM channels. Each group is associated with one of the two trip systems of the RPS. Two IRM channels and their trip auxiliary are installed in each bay of a four-bay cabinet. Full-length side covers isolate the cabinet bays. The arrangement of IRM channels allows one IRM channel in each group to be bypassed without compromising intermediate range neutron monitoring.

Each IRM channel includes four trip circuits as standard equipment. One trip circuit is used as an instrument trouble trip. It operates on when the high voltage drops below a preset level, when one of the modules is not plugged in, or when the OPERATE-CALIBRATE switch is not in the OPERATE position. Each of the other trip circuits can be specified to trip when preset downscale or upscale levels are reached.

The trip functions actuated by the IRM trips are indicated in Table 7.6-6. The reactor mode switch determines whether IRM trips are effective in initiating a rod block or a reactor scram (Figure 7.6-16, Sheet 1). Subsection 7.7.1.1 describes the IRM rod block trips. With the reactor mode switch in REFUEL or STARTUP, an IRM upscale or inoperative trip signal actuates a NMS trip of the RPS. Only one of the IRM channels must trip to initiate an NMS trip of the associated trip system of the RPS.

Testability

Each IRM channel is tested and calibrated using the appropriate Checkout and Initial Operations, Preoperational, or Surveillance Procedures. The IRM detector drive mechanisms and the IRM rod blocking functions are checked in the same manner as for the SRM channels. Each IRM channel can be checked to ensure that the IRM high flux scram function is operable.

7.6.1.13.4.2 Environmental Considerations

The wiring, cables, and connectors located in the primary containment are designed for the environmental conditions identified in NEDO 31558A per References 7 and 8 in Appendix A.

7.6.1.13.5 Local Power Range Monitor System

7.6.1.13.5.1 Equipment Design

Description

The LPRM consists of fission chamber detectors, signal conditioning equipment, and trip functions. The LPRM also provides outputs to the APRM, RBM, and Integrated Plant Computer System (IPCS).

Power Supply

Detector polarizing voltage for the LPRMs is supplied by eight pairs of redundant-dc power supplies, adjustable from 75 to 200 V dc. The 75-200 V dc power supplies can supply up to 3 milliamperes for each LPRM detector which ensures that the chambers can be operated in the saturated region at the maximum specified neutron fluxes. Each dc power supply pair powers approximately one-eighth of the LPRMs. Power for the dc power supplies comes redundantly from the two 120 V ac Reactor Protection System buses via intermediate dc power supplies. These intermediate dc supplies also provide power for the LPRM amplifiers.

Physical Arrangement

The LPRMs include 43 LPRM detector strings having detectors located at different axial heights in the core. Each string contains four fission chambers. These assemblies are distributed to monitor four horizontal planes throughout the core. Figure 7.6-12 shows the LPRM detector radial layout scheme that provides a detector assembly at every fourth intersection of the water channels around the fuel bundles. Thus, every location has either an actual detector assembly or a symmetrically equivalent assembly in some other quadrant.

The detector assemblies (see Figure 7.6-19) are inserted in the core in spaces between the fuel assemblies. They are inserted through thimbles mounted permanently at the bottom of the core lattice and penetrate the bottom of the RPV. These thimbles are welded to the RPV at the penetration point. They extend down into the access area below the RPV where they terminate in a flange. The flange mates to the mounting flange on the in-core detector assembly. The detector assemblies are locked at the top end to the top fuel guide by means of a spring-loaded plunger. Special water-sealing caps are placed over the connection end of the assembly and over the penetration at the bottom of the vessel during installation or removal of an assembly. This prevents loss of reactor coolant water on removal of an assembly, and also prevents the connection end of the assembly from being immersed in the water during installation or removal.

Each LPRM detector assembly contains four miniature fission chambers with an associated solid sheath cable. The chambers are vertically spaced in the LPRM detector assemblies in a way that gives adequate axial coverage of the core, complementing the radial coverage given by the horizontal arrangement of the LPRM detector assemblies. Each fission chamber produces a current that is coupled with the LPRM signal conditioning equipment to provide the desired scale indications.

Each miniature chamber consists of two concentric cylinders that act as electrodes. The inner cylinder (the collector) is mounted on insulators and is separated from the outer cylinder by a small gap. The gas between the electrodes is ionized by the charged particles produced as a result of neutron fissioning of the uranium-coated outer electrode. The chamber is operated at a polarizing potential of approximately 100 V dc. The negative ions produced in the gas are accelerated to the collector by the potential difference maintained between the electrodes. In a given neutron flux, all the ions produced in the ion chamber can be collected if the polarizing voltage is high enough. When this situation exists, the ion chamber is considered to be saturated. Output current is then independent of operating voltage and is reasonably linear over the design operating range (Reference 1).

Each assembly also contains a calibration tube for a traversing in-core probe (TIP). The enclosing tube around the entire assembly contains holes that allow circulation of the reactor coolant water to cool the fission chambers. Numerous tests have been performed on the chamber assemblies, including tests of linearity, gamma sensitivity, and cable effects (Reference 1). These tests and experience in operating reactors provide confidence in the ability of the LPRM system to monitor neutron flux to the design accuracy throughout design lifetime.

Signal Conditioning

The current signals from the LPRM detectors are transmitted to the LPRM amplifiers in the main control room. The current signal from a chamber is transmitted directly to its amplifier through shielded cable. The amplifier is a linear current amplifier whose voltage output is proportional to the current input and therefore proportional to the magnitude of the neutron flux. The amplifier output is "read" by the digital processing electronics. The digital electronics applies hardware gain corrections, performs filtering and applies the LPRM gain factors. The digital electronics provides suitable output signals for the computer recorders, annunciators, etc. The LPRM amplifiers also isolate the detector signals from the rest of the processing so that individual faults in one LPRM signal path will not affect other LPRM signals.

The LPRM signals are indicated on the reactor console. When a central control rod is selected for movement, the LPRM values associated with the nearest 16 LPRM detectors are displayed on console readouts. Each of the four axially spaced LPRM detector signals from each of the four LPRM assemblies are displayed. The operator can readily obtain readings of all the LPRM amplifiers by selecting the control rods in the correct order or by selecting summary LPRM screens on digital operator displays. Subsection 7.7.1.1 describes in greater detail the indications on the reactor console.

Trip Functions

The trip functions for the LPRM provide trip signals to activate displays and annunciators. The outputs for the trip functions are designed to go to the "tripped" state on loss of power to the processing electronics. Table 7.6-7 indicates the trips.

The trip levels can be adjusted to within ±0.1 of full-scale deflection, and the expected error is approximately ±1 percent of full scale.

Testability

LPRM channels are calibrated using data from previous full power runs and TIP data and are tested.

7.6.1.13.5.2 Environmental Considerations

Each individual chamber of the assembly is a moisture-proof, pressure-sealed unit. The chambers are designed for the environmental conditions identified in NEDO 31558A per References 7 and 8 in Appendix A.

7.6.1.13.6 Average Power Range Monitor System

7.6.1.13.6.1 Equipment Design

Description

The APRM system has four APRM channels, each of which uses input signals from a number of LPRM channels. Each of the four APRM channels provide inputs to four two-out-of-four voter channels. Two of the voter channels are associated with each of the trip systems of the Reactor Protection System. All four APRM channels are associated with both of the Reactor Protection System trip systems in that they provide inputs to each of the four voter channels.

Each APRM also includes an Oscillation Power Range Monitor (OPRM) Upscale Function which monitors small groups of LPRM signals to detect thermal-hydraulic instabilities. The OPRM Upscale function is enabled in the intended region on the plant power/flow map. The OPRM Upscale Function receives input signals from the LPRMs within the reactor core, which are combined into cells for evaluation by the OPRM algorithms. An OPRM Upscale trip function is generated from an APRM channel when the period based detection algorithm (basis for the safety analysis) in that channel detects oscillatory changes in the neutron flux, indicated by the combined signals of the LPRM detectors in a cell, with the period confirmations and relative cell amplitude exceeding specific setpoints. One or more cells in a channel exceeding the trip conditions will result in a channel trip. An OPRM Upscale trip is also issued from any channel if either the growth rate or amplitude based algorithms detect growing oscillatory changes in the neutron flux for one or more cells in that channel.

Power Supply

The APRM channels receive power redundantly from the 120-V ac supplied RPS buses. Each APRM two-out-of-four voter channel receives power from the same 120 V ac power as the Reactor Protection System trip system with which it is associated.

Signal Conditioning

The APRM channel uses digital electronic equipment which averages the output signals from a selected set of LPRMs, generates trip outputs via the two-out-of-four voter channels, and provides signals to readout equipment. Each APRM channel can average the output signals from up to 43 LPRM channels. Assignment of LPRM channels to an APRM is shown in Figure 7.6-20. The letters at the detector locations in Figure 7.6-20 refer to the axial positions of the detectors in the LPRM detector assembly. Position A is the bottom position, position B and C are above position A, and position D is the topmost LPRM detector position. The pattern provides LPRM signals from all four core axial LPRM detector positions throughout the core. Some LPRM detectors may be bypassed, but the averaging logic automatically corrects for these by removing them from the average. The APRM value calculated from the LPRM inputs is adjusted by a digitally entered factor to allow calibration of the APRM.

Each APRM channel calculates a recirculation flow signal which is used to determine the APRM's flow-biased rod block and scram setpoints. Each signal is determined by summing the flow signals from the two recirculation loops (Figure 5.5-2). These signals are sensed from two flow elements, one in each recirculation loop. The differential pressure from each flow element is routed to four differential pressure transducers (eight total). The signals from two differential pressure transducers, one from each flow element, are routed to two inputs to the APRM digital electronics. Table 7.6-8 indicates the flow function trips.

The APRM Channel Check surveillance will include a step to confirm that an APRM self-test is still running. It will also include a step to confirm that the RBM self-test is still running since the RBM hardware performs the recirculation flow comparison checks, however, the alarm is bypassed when the reactor mode switch is not in the “RUN” position. A surveillance (channel check) finding that the self-test is not operating in both RBMs (means the recirculation flow comparison function is not available) will not automatically result in any APRM/OPRM channel being declared inoperable, but will result in an increased rate of "flow comparison" manual surveillances. The flow comparison surveillance will be performed at nominally hourly frequencies to correspond to the self-test frequencies assumed in the unavailability analysis for the PRNM system.

All APRM channels are powered redundantly, via intermediate low voltage dc power supplies, from both the "A" and "B" Reactor Protection System 120 V ac power buses. The LPRM signal processing equipment is powered by the same sources as their associated APRM channels.

Trip Function

The digital electronics for the APRM channel provides trip signals directly to the Reactor Manual Control System and via the APRM two-out-of-four voter channels to the Reactor Protection System (RPS). Any two unbypassed APRM channels, via the APRM two-out-of-four voter channels, can initiate an RPS trip in both RPS trip systems. Any one unbypassed APRM can initiate a rod block. Table 7.6-9 lists the APRM trip functions. A simplified circuit arrangement is shown in Figure 7.6-21.

The APRM simulated thermal power upscale rod block and scram trip setpoints are varied as a function of reactor recirculation flow. The slope of the upscale rod block and scram trip response curves is set to track the required trip setpoints with recirculation flow changes. Subsection 7.7.1.1.3.5 discusses the thermal power monitor and the APRM in greater detail.

At least two unbypassed APRM channels must be in the upscale or inoperative trip state to cause an RPS trip output from the APRM two-out-of-four voter channels. In that condition, all four voter channels will provide an RPS trip output, two to each RPS trip system. If only one unbypassed APRM channel is providing a trip output, each of the four APRM two-out-of-four voter channels will have a half-trip, but no trip signals will be sent to the RPS. The trips from one APRM can by bypassed by operator action in the control room. Trip outputs to the RPS are transmitted by removing voltage to a relay coil, so loss of power results in actuating the RPS trips. A simplified APRM/RPS interface circuit arrangement is shown in Figures 7.2-3a and 7.2-3b.

In the startup mode of operation, the APRM "fixed" upscale trip setpoint is set down to a low level. This trip function is provided in addition to the existing IRM upscale trip in the startup mode. The trip settings are listed in Table 7.6-9.

The trip functions are performed by digital comparisons in APRM electronics. The APRM flux value is developed by averaging the LPRM signals and then adjusting the average to be APRM power. The APRM power is processed through a first order filter with a six second time constant to calculate simulated thermal power. These calculations are all performed by the digital processor and result in a digital representation of APRM and simulated thermal power. For each RPS trip and rod block alarm, the APRM power or simulated thermal power, as applicable (see Table 7.5-4), is digitally compared to the setpoint (which was previously entered and stored). If the power value exceeds the setpoint, the applicable trip is issued.

Testability

The APRM channels are calibrated using data from previous fullpower runs and are tested by procedures in the applicable instruction manual. Each APRM channel can be tested individually for the operability of the APRM scram and rod blocking functions by introducing test signals.

7.6.1.13.6.2 Environmental Considerations

All APRM equipment is installed and operated in the main control room environment as described in Table 3.11-4.

7.6.1.13.7 Rod Block Monitor System

7.6.1.13.7.1 Equipment Design

Circuit Description

The RBM has two channels; each channel uses input signals from a number of LPRM channels. A trip signal from either RBM channel initiates a rod block. One RBM channel can be bypassed without loss of subsystem function. The minimum number of LPRM inputs required for each RBM channel to prevent an instrument inoperative alarm is four when using four LPRM assemblies, three when using three LPRM assemblies, and two when using two LPRM assemblies (Figures 7.6-22 and 7.6-22(a)).

Power Supply

The RBM power is supplied by two pairs of redundant dc power supplies, one pair for each RBM. Each dc supply in a pair is supplied by one of the two 120-V ac RPS buses, one RBM per bus.

Signal Conditioning

The RBM signal is generated by averaging a set of LPRM signals. The LPRM signals used depends on the control rod selected. Upon selection of a rod for withdrawal or insertion, the conditioned signals from the LPRMs around the rod will be automatically selected by the two RBM channels. (Figure 7.6-22 shows examples of the four possible LPRM/selected rod assignment combinations.) For a typical non-edge rod, each RBM channel averages LPRM inputs from two of the four B-position and D-position detectors, and all four of the C-position detectors. A-position LPRM detectors are not included in the RBM averages, but are displayed to the operator. When a rod near, but not at, the edge of the core is selected, where there are fewer than four, but at least two, LPRM strings around the rod, the number of detectors used by the RBM channels is either six or four depending on how many LPRM strings are available. If a detector has been bypassed in the LPRM system, that detector is automatically deleted from the RBM processing and the averaging logic is adjusted to average only the remaining detectors.

After selection of a control rod, each RBM channel calculates the average of the related LPRM detectors and calculates a gain factor that will adjust the average to 100. Thereafter, until another rod is selected, the gain factor is applied to the LPRM average to obtain the RBM signal value. The RBM signal value is compared to RBM trip setpoints.

When a peripheral rod is selected, or if the APRM value from the RBM’s associated APRM is below the automatic bypass level (approximately 30% power), the RBM function is automatically bypassed, the rod block outputs are set to "permissive", and the RBM average is set to zero.

Each RBM channel receives the total recirculation flow and status from all four APRMs using high-speed fiber optic communication links to provide circuit isolation. The RBM channel provides a trouble alarm (flow compare) when the difference between max and min values for total recirculation flow exceeds a user defined setpoint (typically 10%), however, the alarm is bypassed when the reactor mode switch is not in the “RUN” position.

A surveillance (channel check) finding that the self-test is not operating in both RBMs (means the recirculation flow comparison function is not available) will not automatically result in any APRM/OPRM channel being declared inoperable, but will result in an increased rate of "flow comparison" manual surveillances. The flow comparison surveillance will be performed at nominally hourly frequencies to correspond to the self-test frequencies assumed in the unavailability analysis for the PRNM system.

Trip Function

The RBM supplies a trip signal to the Reactor Manual Control System to inhibit control rod withdrawal. The trip is set whenever the RBM signal value exceeds the RBM setpoint.

There are three different setpoints, each a percentage above the RBM initial value of 100. Figure 7.6-22(b) illustrates the trip setpoints. The particular setpoint that is applied is selected based on the simulated thermal power value from the RBM's associated APRM channel (an alternate APRM channel is assigned and is automatically used for inputs if the primary APRM channel is bypassed or inoperative). Higher APRM simulated thermal power values select a lower setpoint. That is, at higher power levels, the percentage increase in the RBM value allowed is less than at lower power levels.

Below 30 percent power, fuel damage cannot occur for any single rod withdrawal; hence, the RBM system is automatically bypassed. The low trip setpoint (LTSP) is enforced between 30 percent and 65 percent power, the intermediate trip setpoint (ITSP) is enforced between 65 percent and 85 percent power, and the high trip setpoint (HTSP) is enforced between 85 percent and 100 percent power. The core power input used to automatically select the applicable RBM trip is provided by the APRM. The RBM system is automatically bypassed if the control rod has one or more adjacent fuel bundles comprising the outer boundary of the core. The operator can bypass one of the two RBMs at any time. Either RBM can inhibit control rod withdrawal (Figure 7.6-16, Sheet 1). Table 7.6-10 indicates the trips.

Isolation Separation and Redundancy - The RBM channels A and B are redundant, separate, and isolated. The only exception is the sharing of LPRM C level detectors by both RBM channels. The impact on the availability of the RBM system due to the sharing of the C level detectors is small (Reference 9) and the benefits of the improved signal response far outweigh any perceived loss in signal redundancy; some other salient features are:

a. Redundant, separate, isolated rod selection information (including isolated contacts for each rod selection push button) provided directly to each RBM channel.

b. Independent, isolated RBM level readouts and status displays from the RBM channels.

c. Independent, isolated rod block signals from RBM to the RMCS circuitry.

Testability

The RBM channels are tested and calibrated. The RBMs are functionally tested by introducing test signals into the RBM's channels.

7.6.1.13.7.2 Environmental Considerations

See the description for the APRM.

7.6.1.13.8 Traversing In-Core Probe System

7.6.1.13.8.1 Equipment Design

Circuit Description

The TIP system includes five TIP machines. Each TIP machine includes the following components:

a. One TIP

b. One drive mechanism

c. One indexing mechanism

d. Up to 10 in-core guide tubes

e. One chamber shield

f. One guide tube valve.

The subsystem allows calibration of LPRM signals by correlating TIP signals to LPRM signals as the TIP is positioned in various radial and axial locations in the core. The guide tubes inside the reactor are divided into groups. Each group has its own associated TIP machine.

Physical Arrangement

A TIP drive mechanism uses a fission chamber attached to a flexible drive cable. The cable is driven from outside the drywell by a gearbox assembly. The flexible cable is contained by guide tubes that penetrate the reactor core. The guide tubes are a part of the LPRM detector assembly. The indexing mechanism allows the use of a single detector in any one of ten different tube paths. The tenth tube is used for TIP cross-calibration with the other TIP machines.

The control system provides both manual and semiautomatic operation. Electronics on the TIP panel amplifies and displays the TIP signal. Core position versus neutron flux is provided to the computer. A block diagram of the drive system is shown in Figure 7.6-23.

The heart of each TIP machine is the probe (Figure 7.6-24). It consists of a detector (fission chamber) and the associated signal drive cable. The body of the fission chamber is made of titanium with a neutron-sensitive inner coating of uranium-235. The chamber can operate in a neutron flux level of greater than 10^{14} nv. The saturation voltage is approximately 150 V dc (Reference 1).

The signal current from the detector is transmitted from the TIP to amplifiers and readout equipment by means of signal cable, which is an integral part of the mechanical drive cable. The cable drive mechanism contains the drive motor, the cable takeup reel, a mechanical counter, and an absolute encoder. The absolute encoder provides digital pulses to the control unit for positioning the TIP at specific locations along the guide tube.

The drive mechanism inserts and withdraws the TIP and its cable from the reactor and provides detector position indication signals. The drive mechanism consists of a motor and drive gearbox that drives the cable in the manner of a rack and pinion. A two-speed motor provides a high speed for insertion and withdrawal (approximately 60 fpm) and a low speed for scanning the reactor core (approximately 7.5 fpm). A takeup reel is included in the cable drive mechanism to coil the drive cable as it is withdrawn from the reactor. This reel makes it possible to connect the TIP and its cable to the amplifier through a connector rather than slip rings. This reduces possible noise and maintenance problems.

The absolute encoder and mechanical counter are driven directly from the output shaft of the cable drive motor. The absolute encoder position signal and a flux amplifier output are used to plot neutron flux versus TIP position. The TIP position signal is also available to the 3D-Monicore Computer System (3DM). The absolute encoder is used to position the TIP in the guide tube with a linear position accuracy of ±1 in. The absolute encoder can control TIP positions at the top of the core for initiation of scan and at the bottom of the core for changing to fast withdrawal speed.

A circular transfer machine with 10 indexing points functions as an indexing mechanism. One of the 10 locations is available for access to the guide tube common to all the TIP machines. Indexing to a particular tube location is accomplished manually at the control panel by means of a position selector switch that energizes the electrically actuated rotating mechanism.

The tube transfer mechanism is part of the indexing mechanism and consists of a fixed circular plate containing 10 holes on the reactor side that mate to a rotating single-hole plate. The rotating plate aligns and mechanically locks with each fixed-hole position in succession. The indexing mechanism is actuated by a motor-operated rotating drive. Electrical interlocks prevent the indexing mechanism from changing positions until the probe cable has been completely retracted beyond the transfer point. Additional electrical interlocks prevent the cable drive motor from moving the cable until the probe cable has been completely retracted beyond the transfer point. Additional electrical interlocks prevent the cable drive motor from moving the cable until the transfer mechanisms have indexed to the preselected guide tube location (Figure 7.6-16, Sheet 7).

A valve system is provided with a valve on each guide tube entering the primary containment. These valves are closed except when the TIP system is in operation. A ball valve and a cable shearing valve are mounted in the guide tubing just outside the primary containment. They prevent the loss of containment integrity. A guide tube ball valve is opened manually prior to TIP insertion. The shear valve is used only if containment isolation is required when the TIP is beyond the ball valve and when power to the TIP system fails. The shear valve, which is controlled by a manually operated keylock switch, can cut the cable and close off the guide tube. The shear valves are actuated by detonation squibs. The continuity of the squib circuits is monitored by indicator lights in the main control room.

A guide tube ball valve is normally deenergized and is in the closed position. When the ball valve is manually opened, it actuates a set of contacts which gives a signal light indication at the TIP control panel (Figure 7.6-16).

Signal Conditioning

The readout instruments and electrical controls for the TIP machines are mounted in a cabinet in the relay room. Because there are several groups of guide tubes, each with an associated TIP machine, there are also several groups of readout equipment controls mounted in the cabinet. Each set of readout equipment consists of a dc amplifier and a dc power supply for the TIP polarizing voltage. Each TIP control unit records the flux variations of each scan and provides the results to 3DM for operations.

Testability

The TIP system equipment is tested and calibrated using heat balance data and by use of the common channel.

7.6.1.13.8.2 Environmental Considerations

The equipment and cabling located in the primary containment are designed for the environmental conditions identified in NEDO 31558A per References 7 and 8 in Appendix A.

7.6.1.13.9 Thermal Power Monitor (TPM)

The thermal power monitor (TPM) typically involves the flow-weighted APRM scram in conjunction with a 6-sec time constant circuit.

The APRM has two output signals. The APRM neutron flux signal is representative of the core average neutron flux. The APRM-simulated thermal power (STP) signal represents the fuel surface heat flux. This signal is obtained by passing the neutron flux signal through a nonadjustable, 6-sec first order ("RC") filter to represent the fuel dynamics. A scram signal occurs when

a. The APRM neutron flux signal exceeds a setpoint that is independent of the recirculation flow rate or

b. The APRM STP signal exceeds a setpoint that is dependent on the recirculation flow rate.

If the time constant, which affects scram initiation by the TPM, is less than the effective time constant for the fuel for this type of transient, the TPM should provide a conservative measure of the time variation in surface heat flux. However, if the time constant is appreciably larger than that for the fuel, the fixed APRM trip without a time constant would provide the scram protection. The resulting maximum critical power ratio (MCPR) would then be less than that predicted for the TPM scram, which has a lower setpoint.

A General Electric analysis reported in the Supplemental Reload Licensing Report indicates that with a 6-sec time constant, the TPM scram occurs before the high-neutron-flux scram, because of its lower setpoint of 117 percent nuclear boiler rated (NBR). Therefore, it was appropriate to take credit for TPM scram for the loss of feedwater heater event. Assuming the APRM neutron-flux scram occurs first, the surface heat flux will be below the 117 percent setpoint, and the result will be even less severe.

The TPM used in Fermi 2 is safety grade and is designed to be single-failure proof.

7.6.1.14 Plant Cooling Water Systems Instrumentation and Control

7.6.1.14.1 System Identification

7.6.1.14.1.1 Reactor Building Closed Cooling Water System

The reactor building closed cooling water system (RBCCW) contains three 50 percent-capacity water pumps, two 50 percent-capacity heat exchangers, a makeup tank, a bypass valve for regulating the differential pressure across the supply and return water headers, motorized isolation valves, and a service water supply for discharge of heat from the heat exchangers. During normal operation(with or without RBCCW supplemental cooling in operation), two heat exchangers and two pumps are in service, and one pump is retained in standby. Automatic controls are provided in the RBCCWS to maintain within their operational range the demin water level in the makeup tank, the water temperature at the outlet of the heat exchanger, and the differential pressure between the supply and return water headers.

When the GSW temperature is 60°F or greater, operators have the option of placing the RBCCW supplemental cooling loops in service. Each loop is furnished with two 100 percent-capacity pumps and a plate and frame heat exchanger. Each RBCCW-SC loop takes suction from the RBCCW return header downstream of the RBCCW/EECW system interface, passes this water through a plate and frame heat exchanger in that loop to cool the RBCCW supplemental cooling water with chilled water from the supplemental cooling chilled water (SCCW) system, and discharges the cooled water to the RBCCW supply header just upstream of the RBCCW/EECW interface. When the RBCCW supplemental cooling pumps are in operation, each RBCCW supplemental cooling loop alone provides RBCCW flow to its respective division of EECW; thus the RBCCW supplemental cooling loops operate in parallel with the two 50 percent-capacity RBCCW pumps that service the nonessential loads outside of the EECW loops. Further details of the RBCCW supplemental cooling loops are described under Section 9.2.2.2.

7.6.1.14.1.2 Turbine Building Closed Cooling Water Systems

The TBCCWS contains three 50 percent-capacity water pumps, two 100 percent-capacity heat exchangers, a makeup tank, a bypass valve for regulating the differential pressure across the supply and return headers, and a service water supply for discharge of heat from the heat exchangers. One pump and one heat exchanger are retained on standby. Automatic controls are provided to maintain condensate level in the makeup tank and the water temperature at the outlet of the heat exchanger outlet to the supply header, and to regulate the differential pressure across the supply and return headers.

7.6.1.14.1.3 Classification

The RBCCWS is classified by regions, as indicated in Subsection 9.2.2. In the regions of the RBCCWS pumps, heat exchangers, makeup tank, and service water system, (including the RBCCW supplemental cooling loops), the classification is Quality Group D. In the regions of the drywell and the emergency equipment cooling water system (EECWS) components, the classification is Category I, Quality Group B and C, respectively. Elsewhere the classification is Quality Group D. The turbine building closed cooling water system (TBCCWS) and the supplemental cooling chilled water (SCCW) system are classified Quality Group D.

7.6.1.14.2 Supporting Systems

7.6.1.14.2.1 Electrical Power

The electrical power for the instrumentation and control of the RBCCWS and TBCCWS is from the 120-V ac circuit which is stepped down from the 480 bus supplying power to the pumps. Power for operating the coils of the pump circuit breakers and associated condition-indicating lights is 130 V dc. A detailed description of the ac and dc power system is contained in Subsection 8.3.1.

7.6.1.14.2.2 Pneumatic Power

In the RBCCWS and TBCCWS, pneumatic power is used for operation of the makeup tank level controller, heat exchanger outlet temperature controller, and water header differential pressure controller. In the RBCCW supplemental cooling loop, pneumatic power is used for operation of the temperature control valves. The pneumatic power is supplied by the air system described in Subsection 9.3.1.

7.6.1.14.2.3 Service Water

Cooling water for the RBCCWS and TBCCWS heat exchangers is taken from the general service water (GSW) system of the plant. Details of the GSW system are contained in Subsection 9.2.1.

GSW also provides the source of condenser cooling water for the supplemental cooling chilled water auxilliary support system to the RBCCW supplemental cooling loops. Details of the SCCW system are contained in Subsection 9.2.9.

7.6.1.14.3 Equipment Design

7.6.1.14.3.1 Initiating Circuits

Normal initiation of pump operation and shutdown in the RBCCWS and TBCCWS is by manual control. Selection of one or two pumps to be operational is made by the operator in response to bypass-valve position indications that are activated by two position switches, one closing at the 10 percent valve open position and the other at the 85 percent open position. Auxiliary controllers within the RBCCWS and TBCCWS function automatically to regulate the demin water level in the makeup tank, temperature at the process outlet of the heat exchanger, and the differential pressure across the supply and return headers.

Separate controls automatically regulate the bypass of RBCCW flow around the RBCCW supplemental cooling plate-and-frame heat exchangers to regulate the temperature of the water supplied by the RBCCW supplemental cooling loops when they are in operation. Manual operation of the temperature control valve is described in section 9.2.2.2. When RBCCW supplemental cooling is not in service, the RBCCW differential pressure controller functions to maintain EECW differential header pressure. With RBCCW supplemental cooling in operation, EECW differential header pressure is maintained by operation of the RBCCW supplemental cooling pumps themselves. In this mode of operation, the RBCCW differential pressure controller does not function to maintain EECW header differential pressure; however, it functions to allow two RBCCW pump operation outside of the RBCCW supplemental cooling loops.

7.6.1.14.3.2 Logic and Sequencing

The control logic diagrams for the RBCCWS and TBCCWS pumps are illustrated in Figures 7.6-25(1) (excluding RBCCW Supplemental Cooling) and 7.6-26, respectively. Operation of the pumps is prevented if the level in the associated makeup tank or the suction pressure at the pump inlet is at or below the lower limit of the established control range (Table 7.6-2). The control logic diagram for the RBCCW supplemental cooling loops is illustrated in Figure 7.6-25(2). RBCCW supplemental cooling pump operation is prevented on the same RBCCW makeup tank low level level signal. The RBCCW supplemental cooling pumps are not equipped with low pump suction trips. Equipment protection is provided instead with low flow trips. An EECW start signal initiates closure of the RBCCW/EECW system isolation valves; a low flow condition in the RBCCW supplemental cooling loops results, which trips the RBCCW supplemental cooling pumps. The low flow trip is not required to assure the operation of the EECW during or after receipt of the initiation signal.

Four sensors for each of the two parameters (demin water level and suction pressure) supply inputs to a "one-out-of-two taken twice" logic arrangement to inhibit pump operation if these parameters are below normal. Activation of the logic for low suction pressure trips only the pump at which the low pressure is sensed.

Activation of the logic for low demin water level in the makeup tank trips all the pumps in that system.

7.6.1.14.3.3 Bypasses and Interlocks

Loss of offsite power, high drywell pressure, or drop in differential pressure across the supply and return headers of the RBCCWS results in isolation of coolant circuits that are not essential in an emergency and in automatic initiation of EECWS operation.

Restoration of RBCCWS operation after power becomes available is by manual control. On loss of offsite power, the TBCCWS is deactivated. Initiation of system operation after power becomes available is by manual control.

7.6.1.14.3.4 Redundancy and Diversity

The RBCCWS contains two divisions of flow, one of which is a redundant division. Under normal conditions both divisions are operational. On loss of offsite power, high drywell pressure, or drop in differential pressure across the supply and return headers, the EECWS automatically takes over the function of supplying cooling water to vital equipment served by the two divisions (Section 7.3).

7.6.1.14.3.5 Testability

The controls of the RBCCWS and TBCCWS are fully testable during normal operation of the plant as well as during shutdown periods.

7.6.1.14.4 Environmental Considerations

The instrumentation and control of the RBCCWS and TBCCWS is designed to function with reliability under the environmental conditions that would be encountered under normal or postulated abnormal conditions. These conditions are defined in Tables 3.11-3 and 3.11-4.

7.6.1.14.5 Operational Considerations

7.6.1.14.5.1 Normal

Under normal plant conditions, the RBCCWS and TBCCWS are operated with one or two pumps, initiated manually, to meet the cooling needs as they arise. In the event of a malfunction of a pump or heat exchanger, operation of the standby unit is manually initiated, and the malfunctioning unit is deactivated by manual action or by automatic trip. When the GSW supply temperature exceeds 60°F, the operators have the option of initiating the RBCCW supplemental cooling loop(s) to provide additional RBCCW cooling capacity.

7.6.1.14.5.2 Operator Information

Attention of the operator is secured when the need arises for an increase or decrease of pumping capacity in the RBCCWS or TBCCWS by control room annunciators which indicate the near-open or near-closed positions of the bypass valve. Readout instruments are provided locally to display the demin water level and gas pressure in the makeup tanks and the pumps discharge pressure. Control room annunciators also alert operators to abnormal demin water level or gas pressure in the makeup tanks Readout instruments provided in the main control room display process outlet temperature of the heat exchangers and supply/return header pressure. With the RBCCW supplemental cooling loops in operation, the supply temperature to the EECW loops is indicated by the EECW divisional supply temperatures to the drywell. High and low demin water level, low gas pressure in the makeup tanks, and drop in differential pressure or in the supply and return headers of either EECW division are alarmed. Recorders register the initiation, shutdown, or tripout of the pumps in each system.

7.6.1.15 Fuel Pool Cooling and Cleanup System Instrumentation and Control

7.6.1.15.1 System Identification

7.6.1.15.1.1 Function

The purpose of the fuel pool cooling and cleanup system (FPCCS) instrumentation and control is to provide protection for the system from overheating and to provide the operator with information concerning the effectiveness of operation of the system.

7.6.1.15.1.2 Instrumentation Classification

The FPCCS is not a safety-related system. Therefore, the instrumentation is classified as nonessential. The instrumentation is a standard industrial type for which performance has been proven by years of service throughout the industry.

7.6.1.15.2 Power Sources

The FPCCS instrumentation is fed from the plant instrumentation bus. No backup power source is necessary since the FPCCS is not a safety-related system. The system wiring is protected against short circuit by appropriate fuses. Thus, a short circuit within the FPCCS wiring has only a local effect, which can be corrected without shutting down the FPCCS.

7.6.1.15.3 Equipment Design

The equipment for the FPCCS system is comprised of circulating pumps, heat exchangers, filters, surge tanks, and required piping, valves, instrumentation and controls. The spent fuel pool water is continually circulated in a closed loop except when the FPCCS is used to drain the reactor well and dryer-separator pit. The FPCCS functions and description are explained in Section 9.1.3.

The operating configurations for the FPCCS are obtained by means of manually operated valves and weir gates. The system operation is monitored by instrumentation that provides the operator with a means of evaluating system performance and also provides alarms in the event of a malfunction.

Irradiated components and spent fuel require cooling in addition to the shielding provided by the spent fuel pool. The cooling is provided on a continuous basis during normal operation of the FPCCS. The instrumentation of the FPCCS measures conductivity, temperature, system flow rate, level, and leakage. Indications of the system performance are furnished to the plant operators.

7.6.1.15.3.1 Conductivity

The ionic concentration in the water leaving each demineralizer unit is monitored by a conductivity-measuring system consisting of a conductivity cell, indicating transmitter, and a recorder.

7.6.1.15.3.2 Pump Discharge Pressure

The discharge pressure of each FPCCS pump is monitored by its pressure-indicating switch. If the pump discharge pressure falls below the switch setpoint, a contact set of the switch actuates a local indicator lamp. Another flow switch contact set opens in the actuating path of the alarm annunciator “Fuel Pool Cooling Trouble.”

7.6.1.15.3.3 Temperature

The temperature of the liquid in the piping system associated with the FPCCS pumps, heat exchangers, and valves is monitored by individual temperature elements, and the observed temperatures are recorded by a multipoint recorder. Temperature elements monitor the operation of the FPCCS. In each instance, the temperature levels observed by the temperature monitoring circuits are recorded on a multipoint recorder in the main control room.

7.6.1.15.3.4 Leakage

The leakage rates past the refueling bellows and the gate seal or drywell-to-reactor-well seal are monitored by circuit arrangements consisting of a flow switch and alarm annunciator (Figure 9.1-23). Liquid leakage past the refueling bellows is caught and routed past the flow switch before being piped to the drywell equipment drain sump. When the leakage liquid flow rate through the flow switch exceeds the high flow setpoint, flow switch contact sets energize an indicator lamp and initiate the alarm annunciator, "Fuel Pool Cooling Trouble."

7.6.1.15.3.5 Level

The water levels in both the spent fuel pool and the skimmer surge tank are monitored by alarm annunciator circuits. The spent fuel pool water level is monitored by a level sensor switch assembly that trips if the water level rises above the high level setpoint. On the high-level trip, the alarm annunciator activates and a local indicator lamp lights. Lowered water level automatically resets the level-sensing alarm circuitry.

The skimmer surge tank water level is monitored for both high and low water level. A high-water condition trips a level switch, which activates the alarm annunciator and lights a white indicator lamp. Subsequent lowering of the water level below the high trip setpoint automatically resets the alarm circuitry. Excessively low water levels in the skimmer surge tank cause a trip in the low water level sensor level switch. An alarm annunciator actuates and a white indicator lamp lights on the trip. The alarm circuit automatically resets with normal water level restored in the tank.

All annunciator alarms are located in the main control room panel with their attendant instrumentation located at local panels. The sensors are located at their respective monitoring positions. Specific alarm points are listed in Table 7.6-11.

To comply with NRC Order EA 12-051, spent fuel pool levels are monitored by Primary and Backup instrument channels. Each channel consists of a seismically installed level probe in the spent fuel pool, a signal processor with battery backup, and a remote level indicator. Primary and backup indicators are located in the main control room and reactor building second floor which are capable of supporting the following spent fuel pool actual water levels:

Level 1: Level that is adequate to support operation of the normal fuel pool cooling system, i.e. the surface of the water is maintained at Elevation 683’6” by scuppers that act as skimmers and wave suppressors.

Level 2: Level that is adequate to provide substantial radiation shielding for a person standing on the spent fuel pool operating deck, i.e. 18’ above the top of the fuel in the storage racks (el. 679’ 1/8”)

Level 3: Level where fuel remains covered and actions to implement make-up water addition should no longer be deferred, i.e. <12 in. above the top of the fuel in the storage racks (el. 661’ 1/8”)

7.6.1.15.4 Testability

Because the FPCCS is usually in service during plant operation, satisfactory performance is demonstrated without the need for any special inspection or testing beyond that specified in the manufacturer's instructions.

7.6.1.15.5 Environmental Considerations

The FPCCS is not required for safety purposes, nor is it required to operate after the DBA. The FPCCS is required to operate in normal plant environment only.

7.6.1.15.6 Operational Considerations

The FPCCS instrumentation and control is not required for safe operation of the plant. It provides a means of monitoring parameters of the system and protecting the system.

7.6.1.16 Deleted

7.6.1.17 Control Air System

7.6.1.17.1 System Function

The station air system normally provides control air for operation and control of various plant systems that are safety related as well as those that are nonsafety related. If the control air system pressure drops to 85 psig, indicating an abnormal loss of air pressure, the control air compressors will automatically start for the purpose of supply to its associated division and the control air system will be isolated from the station air system and also the nonsafety related plant systems. See Subsection 9.3.1 for a more detailed discussion of the control air system.

7.6.1.17.2 Classification

The noninterruptible portion of the control air system, including the compressors, filters, dryers, afterfilters, and receivers, is classified as Category I. The interruptible portion of the control air system, including its filter, dryer, afterfilter, and receiver, is classified as nonseismic.

7.6.1.17.3 Supporting Systems

7.6.1.17.3.1 Electrical Power

The electrical power required for operation of the control air system is supplied from the 480-V ac bus as described in Subsection 8.3.1.

7.6.1.17.3.2 Service Water

The cooling water required for operation of the control air system is supplied from the RBCCW or EECW system as described in Subsection 9.2.2.

7.6.1.17.4 Equipment Design

7.6.1.17.4.1 Initiating Circuits

Initiation of the noninterruptible control air system compressors occurs automatically on detection of low control air header pressure (85 psig), loss of offsite power, or a level 2 LOCA signal. In addition, isolation of the noninterruptible control air system from the station air and interruptible control air systems occurs automatically on detection of low noninterruptible control air header pressure (85 psig) or a loss of offsite power. Normally, the interties between the station air system and control air systems are open and the noninterruptible control air compressors are in auto standby.

7.6.1.17.4.2 Logic and Sequencing

Pressure sensors are provided to detect low control air system pressure. Activation of the logic for low control air header pressure causes isolation of the control air system and startup of the control air compressor.

7.6.1.17.4.3 Bypasses and Interlocks

A drop in control air header pressure results in isolation to prevent the use of noninterruptible control air by nonessential control air users. If offsite power is available, the control air compressors start prior to system isolation. On loss of offsite power, the control air compressors are started by the automatic load sequencer when diesel generator power becomes available. See Subsection 8.3.1.1.7 for a more detailed discussion of the automatic load sequencer.

7.6.1.17.4.4 Redundancy and Diversity

The noninterruptible control air system consists of two divisions for redundancy. Under normal operating conditions both divisions are supplied from the station air system. On loss of noninterruptible control air pressure, the control air compressors automatically take over the function of supplying control air to the vital equipment served by the two divisions of the control system. The interruptible control air system is supplied separately from the station air system. A normally closed tie from this system can be opened to provide air supply (if available) to the Division II noninterruptible control air system in the event of loss of its normal and control air compressor supply.

7.6.1.17.4.5 Testability

The controls for the control air system are fully testable during normal plant operation as well as during shutdown periods.

7.6.1.17.5 Environmental Considerations

The instrumentation and control of the control air system is designed to function with reliability under the environmental conditions that would be encountered under normal or postulated accident conditions. These conditions are defined in Table 3.11-4.

7.6.1.17.6 Operational Considerations

7.6.1.17.6.1 Normal

Under normal operating conditions, station air is the supply to both control air systems through their respective dryers. Under these conditions, the noninterruptible control compressors are normally in standby. In the event of low control air header pressure, the noninterruptible control air system divisions are isolated from the interruptible air users. The control air compressors will start automatically at the isolation setpoint.

7.6.1.17.6.2 Operator Information

Readout instruments are provided in the main control room to display and record the Division I and II control air pressures.

Recorders register the automatic initiation of the control air system compressors.

7.6.1.18 Alternate Rod Insertion

7.6.1.18.1 Equipment Identification

The alternate rod insertion (ARI) components of the CRD system are designed to mitigate the potential consequences of an anticipated transient without scram (ATWS) event. The ARI components are redundant to the RPS.

7.6.1.18.2 Equipment Design

7.6.1.18.2.1 Initiating Circuits

There are three initiating signals used for the ARI logics, namely:

a. Reactor dome high pressure

b. Reactor low water level 2

c. Manual initiation in the main control room

Any one of the above signals can initiate the divisional ARI logics as shown in Figure 7.7-3, Sheet 4. Additional immediate response to the initiation signals includes the recirculation pump motor generator field breaker trip (see Subsection 7.7.1.2.3.1).

7.6.1.18.2.2 Logic

Two divisional ARI logic systems are provided: Division I, consisting of logic channels A and C, and Division II for logic channels B and D. The signal to insert the control rods is generated in two separate divisions on two-out-of-two logic channels in a given division.

The ARI logic receives reactor dome pressure and water level signals from the nuclear boiler system. The logic causes automatic energization of the ARI solenoid valves when either the reactor high-pressure trip set point or low-water level 2 set point is reached. The ARI logic can also be initiated manually from the main control room. Each ARI logic channel is provided with a disarmed/armed pushbutton switch. Both pushbutton switches in a given division must be depressed to energize the ARI logic and initiate control rod insertion. The ARI initiation signals are designed to seal in the initiation logic to ensure completion of the ARI function until it is reset manually. A reset pushbutton per division is provided in the main control room to clear the ARI logic. A timer is used in each of the ARI logic channels to inhibit the reset function for approximately 30 seconds after the initiation signal is received. A 30-second time delay is selected to ensure completion of the ARI function before the logic can be reset.

The initiation of the two separate ARI logics results in the energization of eight Class 1E dc solenoid valves (four per division). Two of these, F160A and B, vent the scram air supply line just downstream of the F110A and B backup scram valves. (Refer to Figure 7.6-36). These ARI valves also act to block the supply of air to the scram header. Check valves F161A and B provide an air-flow path around the F160 valves in the event one or more of them fails. Four additional ARI valves, F162A, B, C, and D, vent the A and B scram header to the atmosphere. As the header depressurizes, the scram valves at each hydraulic control unit will spring open scramming the rods. Two ARI valves, F163A and B, vent the scram air header to the scram discharge volume drain and vent valves, closing these valves and isolating the scram discharge volume. All eight ARI valves are normally deenergized.

7.6.1.18.2.3 Annunciation and Indication

The manual initiation pushbutton switch in the main control room activates an annunciator window whenever it is placed in armed position. A separate annunciator window is activated upon initiation of the ARI logic circuits. The open and close position of the ARI solenoid valves are also indicated in the main control room.

7.6.1.18.2.4 Testability

Four separate ARI initiation logic channels are provided to permit maintenance, repair, test, or calibration of all circuit devices (at power) up to but not including the final trip devices (ARI solenoid valves). Each ARI logic channel is provided with a test jack and indicating lights to verify logic activation in any given division.

7.6.1.19 Safety/Relief Valves

7.6.1.19.1 System Identification

The nuclear pressure relief system is designed to prevent over-pressurization of the nuclear system that could lead to the failure of the reactor coolant pressure boundary.

7.6.1.19.2 Safety/Relief Valve Equipment Design

Safety/relief valves (SRVs) are dual-functioning types: automatic self-actuating and solenoid operated. The valves are self-actuated when reactor pressure exceeds spring set pressures that are adjustable in range. The SRVs are divided into three spring-set-pressure groups. The first group consists of five valves set to open when vessel pressure exceeds 1135 psig, the second group consists of five valves set to open when vessel pressure exceeds 1145 psig, and the third group consists of five valves set to open when vessel pressure exceeds 1155 psig. The solenoid-operated air pilot valves permit remote manual or automatic opening. The pilot valve controls the pneumatic pressure applied to an air cylinder operator that controls valve opening and closing. Each valve associated with ADS has an accumulator to store pneumatic energy with sufficient capacity for several relief valve operations. The valves are capable of remote manual opening at any pressure above 100 psig and staying open, once opened, until pressure decreases to 50 psig. Five of the SRVs are used for ADS (Subsection 7.3.1.2.2). Two SRVs are used for low-low setpoint relief (Subsection 7.6.1.19.9).

7.6.1.19.3 Initiating Circuits

Reactor pressure exceeding the setpoint actuates the SRV. The SRV can also be manually actuated (by remote manual switch) or automatically by the ADS and low-low setpoint relief logic.

7.6.1.19.4 Logic and Sequencing

No automatic logic is involved in the overpressure safety function of the SRVs. (See Subsection 7.6.1.19.9 for low-low setpoint relief logic and Subsection 7.3.1.2.2 for the ADS logic.)

7.6.1.19.5 Bypasses and Interlocks

Bypasses are not used in the normal SRV function. An arming circuit is used as an interlock to prevent the low-low setpoint valves from prematurely actuating during normal plant operation. The interlock is required because the reopening setpoint of the low valve is near the normal reactor operating range.

7.6.1.19.6 Redundancy and Diversity

Seven of the SRVs and their respective monitoring system pressure switches are powered by Division I. The other eight SRVs and their respective monitoring system pressure switches are powered by Division II. The SRVs are designed to meet ASME Boiler and Pressure Vessel Code Section III, and therefore diversity is not provided.

7.6.1.19.7 Actuated Devices

Relief valves are actuated by the following two means:

a. Self-actuation by reactor pressure exceeding the spring set pressure setpoint

b. Solenoid pilot operation by remote manual control or automatically by ADS (Subsection 7.3.1.2.2) or low-low set relief logic.

7.6.1.19.8 Separation

Logic circuitry, controls, and instrumentation are designed to maintain physical and electrical separation between Division 1 and Division II.

7.6.1.19.9 Low-Low Setpoint Relief Logic

Two of the 15 SRVs are provided with lower opening and closing setpoints that override the normal setpoints following initial opening of one or more SRVs using the normal setpoint. Logic for this low-low setpoint consists of reactor pressure transmitters that are enabled (armed) by a separate reactor high-pressure (scram) signal and a signal that one or more

SRVs are open. The two low-low set SRVs have slightly different opening and closing setpoints, thus ensuring that only one SRV at a time will reopen on increasing pressure after initial SRV actuation and closure. This arrangement serves to damp reactor pressure surges.

The low-low set logic automatically seals itself into control of the two selected valves and actuates an annunciator in the control room. This logic remains sealed in until manually reset by the operator.

Since the two valves will already have opened when reactor pressure exceeded the original (normal) overpressure safety setpoint, the low-low set logic acts to hold the valves open past their normal reclose points until the pressure decreases to a predetermined "low-low" setpoint. Thus, the valves remain open longer than the other SRVs.

The low-low set logic is designed with redundancy and single-failure criteria; that is, no single electrical failure will(1) prevent any low-low set function from operating, and (2) cause inadvertent seal-in of low-low set logic.

The two valves associated with low-low set are arranged in two independent secondary setpoint groups or ranges (low and high). The low- and high-pressure groups consist of one valve each, having both reopen and reclose setpoints independently and uniquely adjustable. These are set considerably lower than their normal SRV setpoints.

Each SRV valve has its own set of two tailpipe pressure switches. These pressure switches are arranged in two divisions for each low-low set valve so that opening of a single SRV will result in arming of both divisions of low-low set logic. The single-failure criterion is thus met for this function.

The operability of the low-low function is dependent on the operability of the instrumentation channels providing inputs to the low-low set logic. Besides the reactor steam dome pressure-high and low-low set pressure setpoint signals, each division of the low-low set logic normally receives at least five SRV pressure switch inputs from one group of SRVs with the same pressure setpoint. The low-low set logic is capable of performing its function (i.e., preventing multiple actuations of the SRVs) even if both pressure switches associated with one SRV tailpipe become inoperable. The loss of SRV position indication in this case will not challenge the assumptions of the safety analyses for a stuck-open SRV event (see Section 15.1.4).

7.6.1.19.10 Low-Low Setpoint Relief Logic Testability

The SRV system has two low-low setpoint logics, one in Division I and one in Division II. Either one can perform the low-low set function. Each valve has its own set of pressure switches. The sensors are arranged in two separate channels per each division and two-out-of-two logic is used to open the valves. Thus, the sensors and logic of each channel can be tested separately without actually actuating the valves. Indicator lights are provided to facilitate logic testing.

7.6.1.19.11 Environmental Considerations

The solenoid valves and their cables, pressure switches for indication, and the SRV operators are the only SRV controls located inside the drywell. All equipment will meet applicable environmental requirements.

7.6.1.19.12 Operator Information

A temperature element is installed on the SRV discharge piping several feet from the valve body. The temperature element is connected to a multipoint recorder in the control center to provide a means of detecting SRV leakage during plant operation. When the temperature in any SRV discharge piping exceeds a preset value, an alarm is sounded in the control room. The alarm setting is far enough above normal (rated power) drywell ambient temperatures to avoid spurious alarms, yet low enough to give early indication of significant SRV leakage.

Valve actuation is monitored by the SRV open/closed monitoring system (SRVOCMS) pressure switches connected to the SRV discharge line. An open SRV pressurizes the discharge line, which actuates the pressure switch that provides the input to the SRV monitor circuit. The monitor circuit provides inputs to SRV annunciators in the control room, to the Integrated Plant Computer System (IPCS), to the open-close indicators in the control room, and to the low-low setpoint relief logic. The SRVOCMS setpoint is selected so the pressure switch will actuate when the SRV opens in the expected operating range but will not respond to a leaking SRV. The expected operating range of the SRVOCMS is from 200 psig to the SRV safety function actuation point. The SRVOCMS uses Class 1E power and has a power supply monitor with annunciation upon loss of power. If a pressure switch becomes inoperable, SRV position indication relies on monitoring the SRV tail-pipe temperature recorder in the relay room as a backup means for determination of an open SRV.

7.6.1.20 Rod Worth Minimizer (RWM)

7.6.1.20.1 System Identification

7.6.1.20.1.1 Function

The objective of RWM is to provide backup to the operator for control rod pattern control in reactor startup and for control rod manipulation during low power operations. The nuclear measurement analysis and control RWM function is described in Reference 7.

7.6.1.20.1.2 Classification

The RWM is used for power generation only.

7.6.1.20.2 Power Source

The RWM receives its power from the 120V AC uninterruptible power supply.

7.6.1.20.3 Description

The RWM microcomputer system is a stand-alone microcomputer-based system with an RWM operator display and a continuous operating self-test feature that enforces adherence to established startup, shutdown, and low power level control rod procedures. The RWM microprocessor prevents the operator from establishing control rod patterns that are not consistent with prestored RWM sequences by initiating appropriate rod withdrawal block and rod insert block signals to the reactor manual control system rod block circuitry. The RWM sequences stored in the microprocessor memory are based on control rod worth at acceptable levels as determined by the design basis rod drop accident analyses.

7.6.1.20.3.1 RWM Inputs

Sequence

Up to four sequences are simultaneously stored for sequence control operation.

The operator is permitted to switch between sequences when all rods are in or when above the low power alarm point (LPAP).

The operator is permitted to switch between sequences at any power level, when both sequences conform to the present rod configuration within a single insert or withdraw error, not exceeding two notches.

Sequence selection is accomplished under keylock control with insert and withdraw blocks applied.

Bypass/Operate/Test

A keylock switch is provided for selection of operate or alternately bypass during sequence control operation.

During reactor shutdown, the test mode provides a single rod permissive function and a shutdown margin test facility.

Control Rod Selected

The input is a binary coded identification of the control rod selected by the operator.

Control Rod Position

The input is a binary coded identification of all rod positions.

Control Rod Drive Selected and Driving

The RWM uses the rod selected and driving input to identify the envelope of rod motion for the selected rod.

Control Rod Bypass

A maximum of eight control rods can be bypassed under keylock control.

Reactor Power Level

Feedwater system signals are used to implement two digital inputs to permit automatic bypass of the RWM function.

The low power set point (LPSP) identifies the power level at which the RWM is automatically bypassed on reactor startup and automatically initiated on reactor shutdown.

The low power alarm point (LPAP) identifies the approach to the LPSP on reactor shutdown.

Select Insert and Select Withdraw

The select insert and select withdraw inputs identify the direction of intended rod motion to permit termination of insert or withdraw motion at the respective insert or withdraw limit.

Insert Bus and Withdraw Bus

The reactor manual control system insert and withdraw bus is monitored to permit timing of rod drive motion.

7.6.1.20.3.2 RWM Outputs

Isolated contact outputs provide RWM Block and Annunciator functions.

RWM insert block and withdraw block are applied for each rod selection to inhibit rod motions which would result in insert or withdraw error.

RWM rod drive block and settle functions are used to terminate continuous rod motion at the respective insert or withdraw limit or if the RWM senses Multiple Rod Motion (See Section 7.6.1.20.3.4).

RWM annunciation draws operator attention to the RWM message log which identifies the reason for the action taken. RWM Annunciation is not systematically applied with insert or withdraw block since these are routinely applied to limit and inhibit rod motion.

7.6.1.20.3.3 RWM Indications

The RWM operator display panel provides indications of operating status including

a. Selected Rod

   Identification of the coordinate of the selected rod along with

   Position of the selected rod

   Select error status

   Insert block status

   Withdraw block status

b. Insert Error

   Identification of control rod coordinate and rod position for up to three insert error rods. Insert error is corrected as the next rod motion.

c. Withdraw Error

   Identification of control rod coordinate and position identification for one withdraw error. Withdraw error is corrected as the next rod motion.

d. Latched Step

   Identification of the current RWM sequence step number.

e. Selected Sequence

   Identification of the selected sequence.

f. Power Level

   Identification of power level is identified as "Below LPSP", "Transition Region", "Above LPAP", or "Unknown". When power level is indicated to be below LPSP and above LPAP, the power level is identified as "Unknown" and the RWM defaults to below LPSP operation.

7.6.1.20.3.4 Additional Functions

In addition to enforcing adherence to established control rod sequences, the RWM performs additional functions. These additional functions, with the exception of the multiple rod motion (MRM) rod drive block and display, are “utilities” which are used to record and display rod position/time data.

a. Single Rod Scram Timing

Single rod scram timing is selected by the operator to record rod position/time data during single rod scram testing.

b. Full Core Scram Timing

Full core scram timing is automatically initiated by a reactor scram signal and records the rod position/time data during a reactor scram.

c. Rod Drive Timing

Rod drive timing is selected by the operator to record rod position/time data for the rod being driven/tested.

d. Single Rod Scram Data Display

Single rod scram data display is selected by the operator during single rod scram testing to display the actual scram time for the rod under test, the average Technical Specification scram time, and margin of the scram time of the tested rod to the Technical Specification time. The display is available at the RWM operators display and RWM computer.

e. Shutdown Verification Display

The Shutdown Verification display is automatically initiated by a reactor scram signal and immediately displays if all rods are full-in, if all rods are inserted to or beyond the shutdown margin limit, and how many rods are not full-in. The shutdown verification screen is displayed at the RWM operators display.

f. Multiple Rod Motion (MRM) Rod Drive Block and Display

The multiple rod motion (MRM) rod drive block and display are initiated when the RWM senses that a rod (or rods) other than the selected rod is moving. MRM is defined as a movement of an unselected rod (or rods) that has resulted from a failure in the reactor manual control system (RMCS) when a valid rod is selected and being moved by the operator. The purpose of the MRM rod drive block is to terminate and limit rod motion of both the selected and any unselected rods to one notch, if an MRM were to occur. The MRM firmware will actuate the existing RWM rod drive block and settle relays to the RMCS and automatically initiate the MRM display at the RWM operator display if the RWM senses that an unselected rod (or rods) is moving. If the RWM is bypassed (keylock switch on the operator display), the MRM screen is automatically selected, but the MRM rod drive block is inhibited by the RWM bypass relay.

7.6.1.20.4 Environmental Considerations

The RWM is not used for credit in the safety analysis, nor is it required to operate during or after any design basis accidents. The RWM is employed to operate in the normal plant environment for power operation.

7.6.1.20.5 Operational Considerations

The RWM function does not interface with normal reactor operation, and in the event of its failure does not cause new rod patterns. The RWM function may be bypassed and its rod block function disables only by specific procedural control initiated by the operator, in accordance with the Technical Specifications.

With the RWM inoperable, a second licensed operator or other technically qualified member of the unit technical staff who is present at the reactor control console verifies the control rod movement compliance with the prescribed control rod pattern. The requirements for a rod motion verifier and the specified actions expected of the operator and verifier are proceduralized including:

Procedural guidance for control of Rod Pull Sheets to ensure correct pullsheets are used

Explicit instructions to the operator and verifier are contained in a Rod Pull Cover Sheet

Each operator and verifier reviews the cover sheet prior to pulling rods.

Explicit instructions are included to the verifier as to how and where to verify proper rod selection and positioning.

7.6.2 Analysis

7.6.2.1 Refueling Interlock System Instrumentation and Control

7.6.2.1.1 Conformance To General Functional Requirements

a. Safety Evaluation

The refueling interlocks, in combination with core nuclear design and refueling procedures, limit the probability of an inadvertent criticality. The nuclear characteristics of the core ensure that the reactor is subcritical even when the highest-worth control rod is fully withdrawn. Also, refueling procedures are written to avoid situations in which inadvertent criticality is possible. The combination of refueling interlocks for control rods and the refueling platform provides redundant methods of preventing inadvertent criticality even after procedural violations. The interlocks on hoists provide yet another method of avoiding inadvertent criticality.

Table 7.6-1 illustrates the effectiveness of the refueling interlocks. This table considers various operational situations involving rod movement, hoist load conditions, refueling platform movement and position, and mode switch manipulation. The initial conditions in situations 4 and 5 appear to contradict the action of refueling interlocks, because the initial conditions indicate that more than one control rod is withdrawn, yet the mode switch is in REFUEL. Such initial conditions are possible if the rods are withdrawn when the mode switch is in STARTUP and then turned to REFUEL. In all cases, correct operation of the refueling interlock prevents either the operation of loaded refueling equipment over the core when any control rod is withdrawn or the withdrawal of any control rod when fuel-loaded refueling equipment is operating over the core. In addition, when the mode switch is in REFUEL, only one rod can be withdrawn; selection of a second rod initiates a rod block.

7.6.2.1.2 Conformance To Specific Regulatory Requirements

No specific regulatory requirements apply to refueling interlocks. The refueling interlocks are designed to be normally energized (fail-safe).

IEEE standards do not apply because the refueling interlocks are not required for any postulated DBA or for safe shutdown. Furthermore, the interlocks are required only for the refueling mode of plant operation.

The requirements of 10 CFR 50, Appendix B, are met in the manner set forth in Chapter 17.

7.6.2.2 Reactor Pressure Vessel Instrumentation and Control

7.6.2.2.1 Conformance To General Functional Requirements

The RPV instrumentation and systems are designed to augment the existing information from the ESF systems such that the operator can start up, operate at power, shut down, and service the reactor systems in an efficient manner. None of this instrumentation is required to initiate an RPS or ESF system.

7.6.2.2.2 Conformance To Specific Regulatory Requirements

There are no specific regulatory requirements imposed on the RPV instruments and subsystems discussed in Subsection 7.6.1.2 because of the reasons stated in Subsection 7.6.2.2.1 above.

The requirements of 10 CFR 50, Appendix B, are met in the manner set forth in Chapter 17.

7.6.2.3 Process Radiation Monitor Systems

The process radiation monitor systems are described in Section 11.4.

7.6.2.4 Area Radiation Monitor System Instrumentation and Control

See Subsection 12.1.4.

7.6.2.5 Offsite Environs Radiation Monitor Systems

See the Offsite Dose Calculation Manual (ODCM).

7.6.2.6 Rad-Chem Radiation Monitoring Instruments

See Section 12.3.

7.6.2.7 Reactor Water Cleanup System Instrumentation and Control

7.6.2.7.1 General

The RWCU system is not a safety-related system. Therefore, the instrumentation supplied is for the plant equipment protection only.

7.6.2.7.2 Conformance To General Functional Requirements

The RWCU system is protected against overpressurization by relief valves. The ion exchange resin is protected from high temperature by temperature switches upstream of the filter-demineralizer unit. One switch activates an alarm when the water temperature reaches 130°F. A second switch provides a signal at 140ºF to close a motor-operated valve in the suction line to the RWCU pumps, which subsequently trips the pumps on low discharge flow.

Three motor-operated isolation valves close automatically on a reactor low water level signal. The outermost isolation valves G33F004 and G33F220 also close automatically when the standby liquid control system is activated. The isolation valves provide a pump trip when the valves close.

A high differential pressure across the filter-demineralizer or its discharge strainer automatically closes the unit's outlet valve after sounding an alarm. The holding pump starts whenever there is low flow through a filter-demineralizer. The precoat pump does not start when the level in the precoat tank is low.

Sampling stations are provided to obtain reactor water samples from the entrance and exit of both filter-demineralizers.

The system instrumentation and control for flow, pressure, temperature, and conductivity is recorded and/or indicated on a panel in the main control room. Instrumentation and control for backwashing and precoating the filter-demineralizers is on a local panel in the reactor building. Alarms are sounded in the main control room to alert the operator to abnormal conditions.

The RWCU system is controlled by the operator from the main control room.

A list of the RWCU system annunciators is given in Table 7.6-14.

7.6.2.7.3 Conformance To Specific Regulatory Requirements

Since the RWCU system is not a safety-related system, no specific regulatory requirement is applicable.

7.6.2.8 Leak Detection System Instrumentation and Control

7.6.2.8.1 General

The part of LDS instrumentation that is related to the system isolation circuitry is designed to meet requirements of the ESF system.

7.6.2.8.2 Conformance To General Functional Requirements

There are at least two different methods of detecting abnormal leakage from each system within the nuclear system process barrier and in each area as shown in Table 5.2-11. The instrumentation is designed so that it may be set to provide alarms at established leakage rate limits and isolate the affected system,if necessary. The alarm points are determined analytically based on design data and on measurements of appropriate parameters made during startup and preoperational tests. This satisfies the power generation design basis and safety design basis.

The unidentified leakage rate limit is based, with an adequate margin for contingencies, on the crack size large enough to propagate rapidly. The established limit is sufficiently low so that even if the entire unidentified leakage rate were coming from a single crack in the nuclear system process barrier, corrective action could be taken before the integrity of the barrier is threatened with significant compromise.

The limit on total leakage rate is established so that in the absence of normal ac power and feedwater, and without using the ECCSs, the leakage loss from the nuclear system could be replaced. The limit on total leakage also allows a reasonable margin below the discharge capability of either the floor drain or equipment drain sump pumps. Thus, the established total leakage rate limit allows sufficient time for corrective action to be taken before either the nuclear system coolant makeup or the drywell sump removal capabilities are exceeded.

7.6.2.8.3 Conformance To Specific Regulatory Requirements

Compliance With Regulatory Guide 1.22

The portion of the LDS that provides outputs to the system isolation logic is designed so that complete periodic testing of the isolation system actuation function is provided. This is accomplished by tripping the LDS one channel at a time from the leak detection panel in the main control room. An indicator lamp is provided to show that the particular channel is tripped.

Compliance With General Design Criteria 13 and 19-24 of 10 CFR 50

The leak detection sensors and associated electronics are designed to monitor the reactor coolant leakage over all expected ranges required for the safety of the plant. Automatic initiation of the system isolation action, reliability, testability, independence, and separation have been factored into leak detection design as required for isolation systems.

Compliance With IEEE 279-1971

Compliance of the LDS with IEEE 279-1971 is included in the IEEE 279-1971 compliance discussion of the CRVICS (Subsection 7.3.2.3.3.1) for which this system provides logic trip signals.

Compliance With IEEE 323-1971 - Leak detection compliance is shown in Topical Report NEDO-l0698. See also Section 3.11.

Compliance With IEEE 338-1971 - Leak detection compliance with IEEE 338-1971 is shown. All active components of the LDS associated with the isolation signal can be tested during plant operation.

Compliance With IEEE 344-1971 - Leak detection compliance with IEEE 344-1971 is shown in Topical Report NEDO-10678. See also Section 3.10.

7.6.2.9 Integrated Plant Computer System (IPCS)

The IPCS, exclusive of the meteorological and emergency response functions, is designed to provide the operator with certain information as defined in the equipment description in Subsection 7.6.1.9. The system augments existing information from other systems such that the operator can start up, operate at power, and shut down in an efficient manner. There are no specific regulatory requirements associated with this portion of the IPCS capabilities.

See Subsection 7.6.1.9.1.2.5.1 for a discussion of the design analysis of the IPCS Safety Parameter Display System (SPDS) function. NRC guidance on safety parameter systems is contained in Supplement 1 to NUREG-0737.

The IPCS, inclusive of all its functions, is not required to initiate any ESF or safety-related system.

7.6.2.10 (Deleted)

7.6.2.11 Sequence Recorder

The sequence recorder is designed to provide the necessary data and information systems to permit diagnosing the causes of unscheduled reactor shutdowns and determine the proper functioning of safety-related equipment. The requirements of generic letter 83-28 are met for post-trip review. The power source is reliable and non-interruptible. The system meets the requirements to record, recall, and display data and information to permit post-trip review.

7.6.2.12 Primary Containment Monitor Systems

7.6.2.12.1 Primary Containment Radiation and Hydrogen/Oxygen Monitor System

Conformance To Specific Regulatory Requirements

The primary containment radiation monitor subsystem is designed to monitor the primary containment for determination of radiation level during reactor operation or shutdown periods. The rate of flow of drywell atmosphere sample is sufficiently high to provide readings representative of the radiation level in the drywell in less than 5 minutes. Filters are provided in the sample supply line to the primary containment radiation monitor to collect particulates and halogens, on separate filters, for analysis. Monitored radiation level above a predetermined level is alarmed and annunciated in the main control room.

The diversity requirement of Regulatory Guide 1.45 is met by the noble gas activity monitor alarm; activity (cpm) is not required to be correlated with leak rate (gpm) per an exemption granted in NUREG 0798, Section 5.2.5.

The requirements of General Design Criterion (GDC) 30 of 10 CFR 50, Appendix A, are met in that the primary containment radiation monitor system provides means, as required, for monitoring the reactor primary containment atmosphere radioactivity.

In addition, the primary containment is monitored for hydrogen/oxygen with indication and high alarms in the main control room in compliance with Regulatory Guide 1.7 and Regulatory Guide 1.97, Rev 2, Category 3 and 2 requirements, respectively.

The design of the primary containment radiation monitor system incorporates provisions for indicating activity level of noble gases, and collecting particulates and halogens on filter papers for laboratory analysis. Also provided are trip logic provisions for actuating an alarm and an annunciator to inform operations personnel of low-scale conditions that would be indicative of instrument failure.

7.6.2.12.2 Primary Containment Temperature Monitor Subsystem

7.6.2.12.2.1 Conformance To General Functional Requirements

The primary containment temperature monitor subsystem is designed to fulfill the safety and power generation design bases and industry standards that are stated under Subsection 7.1.2.1.22.

7.6.2.12.2.2 Conformance To Specific Regulatory Requirements

The primary containment temperature monitor subsystem is designed to monitor continuously the temperature of the drywell atmosphere, drywell walls, drywell cap atmosphere, pressure suppression chamber atmosphere, and pressure suppression chamber water pool.

The requirements of GDC 13 of 10 CFR 50, Appendix A, are met in that the primary containment temperature monitor system provides instrumentation to obtain temperature measurements in the designated areas during normal operation, as well as postulated abnormal conditions of a LOCA.

The requirements of 10 CFR 50, Appendix B, are met in the manner set forth in Chapter 17.

The design of the primary containment temperature monitor subsystem includes multipoint recorders in the main control room, on which the temperatures monitored by the subsystem are continuously recorded and displayed.

7.6.2.12.3 Primary Containment Pressure Monitor Subsystem

7.6.2.12.3.1 Conformance To General Functional Requirements

The primary containment pressure monitor subsystem is designed to fulfill the safety and power generation design bases and industry standards stated in Subsection 7.1.2.1.22.

7.6.2.12.3.2 Conformance To Specific Regulatory Requirements

The primary containment pressure monitor system is designed to continuously monitor atmospheric pressure in the drywell and in the pressure suppression chamber.

The requirements of GDC 13 of 10 CFR 50, Appendix A, are met in that the primary containment pressure monitor subsystem has instrumentation that is provided, as required, for measurement and recording of pressure during normal operation, as well as postulated abnormal conditions of a LOCA.

The requirements of 10 CFR 50, Appendix B, are met in the manner set forth in Chapter 17.

The design of the primary containment pressure monitor subsystem includes chart recorders in the main control room, on which the pressure monitored by the subsystem is continuously recorded and displayed.

7.6.2.12.4 Pressure Suppression Pool Water Level Indicator Subsystem

7.6.2.12.4.1 Conformance To General Functional Requirements

This system is designed to fulfill the safety and power generation design bases and industry standards stated in Subsection 7.1.2.1.22.

7.6.2.12.4.2 Conformance To Specific Regulatory Requirements

The design of the pressure suppression pool water level indicator subsystem provides continuous monitoring of the water level in the pressure suppression chamber.

The requirements of GDC 13 of 10 CFR 50, Appendix A, are met in that the pressure suppression pool water level indicator system constitutes instrumentation that is provided, as required, to monitor the pool water level during normal operation as well as postulated abnormal conditions of a LOCA.

The requirements of 10 CFR 50, Appendix B, are met in the manner set forth in Chapter 17.

The pressure suppression pool water level indicator subsystem design includes chart recorders in the main control room on which the monitored level of the water pool is continuously recorded and displayed.

7.6.2.13 Neutron Monitoring System Instrumentation and Control

7.6.2.13.1 Source Range Monitor System

7.6.2.13.1.1 Conformance To General Functional Requirements

The arrangement of the source range monitors (SRM) in the reactor is shown in Figure 7.6-12. This arrangement and irradiated fuel produce at least three counts per second in the SRM using the sensitivity noted in Subsection 7.6.1.13.3. If the discriminator setting is adjusted to produce the specified sensitivity, the signal-to-noise count ratio is well above the 2:1 design basis for cold startup.

If the multiplication of one section of the core increases to put that section of the reactor on a 20-sec period, the nearest SRM chamber shows an increase in count rate. In general, at least one detector indicates the change in multiplications.

Normal startup procedures ensure that withdrawal of control rods is distributed about the core to prevent excessive multiplication in any one section of the core. Hence, each SRM chamber can respond in some degree during the initial rod withdrawal.

Examination of the sensitivity of the SRM detectors and their operating ranges of 10^6 counts per second indicates that the IRM is on scale before the SRM reaches full scale (Figure 7.6-15). Further overlap is provided by partial retraction of the SRM chambers. Such retraction is possible only if the indicated SRM count rate remains above the rod block trip level (approximately 100 counts per second), or if the IRM has been set to the third or any less sensitive (higher) IRM range.

7.6.2.13.1.2 Conformance To Specific Regulatory Requirements

There are no specific regulatory requirements of the SRM system.

7.6.2.13.2 Intermediate Range Monitor System

7.6.2.13.2.1 Conformance To General Functional Requirements

Subsection 7.2.1.1 evaluates the arrangement of redundant input signals to the RPS. The NMS trip input to the RPS and the trip channels used in actuating a NMS trip are of equivalent independence and redundancy to other RPS inputs.

The number and locations of the IRM detectors have been analytically and experimentally determined to provide sufficient intermediate range flux level information under the worst permitted bypass or detector failure conditions. To verify this, a range of rod withdrawal accidents has been analyzed. The most severe case assumes that the reactor is barely subcritical. One-fourth of the control rods plus one more rod have been removed in the normal operating sequence (Figure 7.6-37). The error or malfunction is removal of the control rod adjacent to the last rod withdrawn. This rod has been chosen to maximize the distance to the second nearest detector for each trip system. It is assumed that the nearest detector in each RPS trip system is bypassed.

A scram signal is initiated when one IRM detector in each RPS trip system reaches its scram trip level. The neutron flux versus distance resulting from this withdrawal is shown in Figure 7.6-38. Note that the second nearest detector in trip system B is farther away than the second nearest detector in trip system A. The ratio of the neutron flux at this point to the peak flux is l:4l00. This detector reaches its high scram trip setting of 95 percent of full scale at a local flux approximately 3.3 x 10^8 nv. At that time the peak flux in the core is 1.35 x 10^{12} nv or 2.7 percent rated average flux. The core average power is 0.07 percent when scram occurs. For this scram point to be valid, the IRM must be on the correct range. To ensure that each IRM is on the correct range, a rod block is initiated any time the IRM is both downscale and not on the most sensitive (lowest) scale. A rod block is initiated if the IRM detectors are not fully inserted in the core unless the reactor mode switch is in the RUN position.

The IRM scram trips and the IRM rod block trips are automatically bypassed when the reactor mode switch is in the RUN position.

The IRM detectors and electronics have been tested under operating conditions and verified to have the operational characteristics described. They provide the level of precision and reliability required by the RPS safety design bases.

The IRM is the primary source of information as the reactor approaches the power range. Its linear steps (approximately a half decade) and the rod blocking features on both high flux level and low flux level require that all the IRM'S are on the correct range as core reactivity is increased by rod withdrawal. The SRM overlaps the IRM. The sensitivity of the IRM is such that the IRM is on scale on the least sensitive (highest) range with approximately 15 percent reactor power.

7.6.2.13.2.2 Conformance To Specific Regulatory Requirements

Compliance With Regulatory Guide 1.22

The portion of the IRM system that provides outputs to the RPS is designed to provide complete periodic testing of protection system actuation function as desired. This provision is accomplished by initiating an output trip on one IRM channel at any given time, which will result in tripping one of the two RPS trip systems. Details are provided in Topical Report NEDO-10139, Subsection 2.2.8 (Reference 8).

Operator indication of IRM bypass is provided by indicator lamps as described in NEDO-10139, Subsection 2.2.8.13 (Reference 8).

Compliance With General Design Criteria 13 and 22-24 of 10 CFR 50

The IRM detectors and associated electronics are designed to monitor the in-core flux over all expected ranges required for safety of the plant.

Automatic initiation of RPS action, reliability, stability, independence, and separation has been factored into the IRM design as required for protection systems.

Compliance With IEEE 279-1971 - The IRM design is shown to comply with the design requirements of IEEE 279-1971 in Subsection 2.2.8 of Reference 8.

Compliance With IEEE 323-1971 - IRM compliance is shown in Topical Report NEDO-10698. See also FSAR Section 3.11.

Compliance with IEEE 338-1971 - IRM compliance with IEEE 338-1971 is shown in Subsections 2.2.8.9 and 2.2.8.10 of Reference 8.

Compliance With IEEE 344-1971 - IRM compliance is shown in Topical Report NEDO-10678. See also FSAR Section 3.10.

Compliance with 10 CFR 50, Appendix B - The requirements of 10 CFR 50, Appendix B, are met in the manner set forth in Chapter 17.

7.6.2.13.3 Local Power Range Monitor System

7.6.2.13.3.1 Conformance To General Functional Requirements

The LPRM provides detailed information about neutron flux throughout the reactor core. The number of LPRM assemblies and their distribution is determined by extensive calculational and experimental procedures. The division of the LPRM into various groups for ac power supply allows operation with one ac power supply failed or in service without limiting reactor operation.

Individual failed chambers can be bypassed. Neutron flux information for a failed chamber location can be interpolated from nearby chambers. Also, a substitute reading for a failed chamber can be derived from an octant-symmetric chamber, or an actual flux indication can be obtained by inserting a TIP to the failed chamber position. Each output is electrically isolated so that an event (grounding the signal or applying a stray voltage) on the reception end does not destroy the validity of the LPRM signal. Tests and experience attest to the ability of the detector to respond proportionately to the local neutron flux changes (Reference 1).

7.6.2.13.3.2 Conformance To Specific Regulatory Requirements

There are no specific regulatory requirements of the LPRM subsystem. Because they form inputs to the APRM system, however, a minimum number of LPRMs must be operable for each APRM as defined in the APRM safety design basis.

7.6.2.13.4 Average Power Range Monitor System

7.6.2.13.4.1 Conformance To General Functional Requirements

Each APRM derives its signal from LPRM information. The assignment, power separation, cabinet separation, and LPRM signal isolation are in accord with the safety design bases of the RPS. There are four APRM channels with the Reactor Protection System trip outputs from each routed to each of four APRM two-out-of-four voter channels. Two voter channels are associated with each Reactor Protection System trip system. This configuration allows one APRM channel to be bypassed plus one failure while still meeting the Reactor Protection System safety design basis.

Above a plant power level defined by Technical Specifications, the APRM power (and simulated thermal power) is adjusted periodically based on heat balance to match true reactor power. This adjustment is made regularly at a rate sufficient to compensate for LPRM burnup and the related change in APRM values. However, coolant flow changes, control rod movements, and failed or bypassed LPRM inputs can also affect the relationship between APRM measured flux and true reactor power. These predictable APRM variations are included in the analysis performed to determine minimum number of LPRM inputs required to be operable in order for the APRM channel to be operable. The analysis is performed considering worst case combinations of failed LPRM inputs, at rated conditions by assuming both continuous withdrawal of the maximum worth control rod and reduction of recirculation flow to 40% of rated flow. The minimum number of LPRM inputs for an APRM is determined such that the average of the remaining operable LPRM inputs still allows the APRM to track power excursions within the acceptance criteria assumed in plant safety analysis. If the number of operable LPRMs is less than the required minimum, the APRM channel is declared inoperable.

The flow-referenced APRM scram setpoint is adequate to prevent fuel damage during an abnormal operational transient, as demonstrated in Chapter 15.

The APRM also includes an OPRM Upscale function to provide compliance with GDCs 10 and 12, thereby providing protection from exceeding the fuel MCPR safety limit due to anticipated thermal hydraulic induced power oscillations. The OPRM utilizes three algorithms for detecting thermal-hydraulic instability related neutron flux oscillations: the period based detection, the amplitude based, and the growth rate based algorithms. All three are implemented in the OPRM Upscale function, but the safety analysis takes credit for the period based algorithm. The remaining algorithms provide defense in depth and additional protection against unanticipated oscillations. The OPRM Upscale function receives input signals from the LPRMs within the reactor core, which are combined into cells for evaluation by the OPRM algorithms. The OPRM Upscale function is enabled in the intended region on the plant power/flow map. The plant power level and recirculation drive flow conditions are defined by Technical Specifications.

7.6.2.13.4.2 Conformance To Specific Regulatory Requirements

a. Compliance With Regulatory Guide 1.22

The portion of the APRM subsystem that provides outputs to the RPS is designed to provide complete periodic testing of protection system actuation functions as desired. This provision is accomplished by initiating an output trip of one APRM channel at any given time, which will result in tripping one of the two RPS trip systems. Details are provided in Subsection 2.2.8 of Reference 8.

Compliance With General Design Criteria 10 and 12

The OPRM Upscale Function provides compliance with GDC 10 and GDC 12 by providing a hardware/software system that detects and acts to suppress thermal-hydraulic instabilities, thereby providing protection from exceeding the fuel MCPR safety limit due to thermal hydraulic induced power oscillations.

Compliance With General Design Criteria 13 and 20-24 of 10 CFR 50

The APRM detection and associated electronics are designed to monitor the in-core flux over all expected ranges required for safety of the plant.

Automatic initiation of protection system action, reliability, testability, independence, and separation has been factored into the APRM design as required for protection systems.

The requirements of 10 CFR 50, Appendix B, are met in the manner set forth in Chapter 17.

Compliance With IEEE 279-1971 - The APRM design is shown to comply with the design requirements of IEEE 279-1971 in Subsection 2.2.8 of Reference 8 and Subsection 4.4.1.1 of Reference 10.

Compliance With IEEE 323-1971 - APRM compliance is shown in Topical Reports NEDO-10698 and NEDC 32410P-A. See also FSAR Section 3.11.

Compliance With IEEE 338-1971 - APRM compliance with IEEE 338-1971 is shown in Subsections 2.2.8.9 and 2.2.8.10 of Reference 8.

Compliance with IEEE 344-1971 - APRM compliance is shown in Topical Reports NEDO-10678 and NEDC 32410P-A. See also FSAR Section 3.10.

7.6.2.13.5 Rod Block Monitor System

7.6.2.13.5.1 Conformance To General Functional Requirements

Motion of a control rod causes the LPRMs adjacent to the control rod to respond strongly to the change in power in the region of the rod in motion. Figure 7.6-41 illustrates the calculated responses of the two RBMs to the withdrawal of a selected control rod. The RBM setpoints may be selected such that the rod withdrawal error (RWE) is not the limiting transient. Figure 7.6-42 shows the relationship between MCPR and the RBM setpoint. It also shows that for an example operating limit MCPR (OLMCPR) requirement of 1.28, there is a 0.08 margin with 108 percent RBM setpoint (0.03 for 111 percent RBM setpoint). These margins are more than adequate to protect against any RWE events. The RBM setpoints conservatively assume a probability of 15 percent that any given LPRM has failed. The RBM setpoints are also valid for peripheral cells with less than four LPRM strings (the RBM cells near the core periphery may possess fewer than four control rods and have one, two, or three LPRM strings). In some peripheral cases, the responses are actually improved because the missing strings are the weaker signal inputs in a standard RBM cell.

7.6.2.13.5.2 Conformance To Specific Regulatory Requirements

Compliance With General Design Criterion 24 of 10 CFR 50, Appendix A

The RBM provides an interlocking function in the control rod withdrawal portion of the CRD RMCS. This design is separated from the protective functions in the plant to ensure their independence.

The RBM is designed to prevent control rod withdrawal error, given an imposed single failure within the RBM. One of the two RBM channels is sufficient to provide an appropriate control rod withdrawal block.

Compliance with 10 CFR 50, Appendix B

The requirements of 10 CFR 50, Appendix B, are met in the manner set forth in Chapter 17.

7.6.2.13.6 Traversing In-Core Probe Subsystem

7.6.2.13.6.1 Conformance To General Functional Requirements

An adequate number of TIP machines is supplied to ensure that each LPRM assembly can be probed by a TIP and that one LPRM assembly (the central one) can be probed by every TIP to allow intercalibration. Typical TIPs have been tested to prove linearity (Reference 1). The system has been field tested in an operating reactor to ensure reproducibility for repetitive measurements. The mechanical equipment has undergone life testing under simulated operating conditions to ensure that all specifications can be met. The system design allows semiautomatic operation for LPRM calibration and 3DM TIP processing function use. The TIP machines can be operated manually to allow pointwise flux mapping.

7.6.2.13.6.2 Conformance To Specific Regulatory Requirements

There are no specific regulatory requirements of the TIP subsystem.

7.6.2.14 Plant Cooling Water Systems Instrumentation and Control

Conformance To General Functional Requirements

The instrumentation and control of the RBCCWS and TBCCWS is designed to permit reliable operation and testing for each instrument loop or subsystem. Controls for the essential portion of the RBCCWS are described in Subsection 7.3.4

The nonessential portions of the RBCCWS and the TBCCWS are designed to shut down upon loss of offsite ac power. These systems can be restarted manually from the main control room. These systems are designed for manual startup, shutdown, and testing. Automatic controls are provided for maintaining condensate level in the makeup tank, gas pressure in the makeup tank, heat exchanger outlet temperature, and differential pressure across the supply and return headers. Indications, alarms, and/or warning lights for these variables are provided in the main control room. Deviations from normal conditions are thereby brought to the attention of the main control room operator who subsequently can take the appropriate action.

7.6.2.15 Fuel Pool Cleanup System Instrumentation and Control

7.6.2.15.1 General

The FPCCS is not a safety-related system. Therefore, the instrumentation supplied is for the plant equipment protection and for operator information about the system.

7.6.2.15.2 Conformance To General Functional Requirements

The FPCCS is monitored for conductivity, temperature, pool level, flow rate, and leakage.

The conductivity measurement provides the operator with information required to ensure that impurities in the water are limited to acceptable levels.

The low flow (pump discharge pressure) and temperature monitoring provide the operator with information required to ensure that the desired temperature is not exceeded and that filtering is maintained. Pool level and leakage monitoring provide the operator with information assuring the maintenance of adequate shielding and cooling.

Interface

The FPCCS is an independent system during normal operations. Evaporative losses in the system are replaced by the condensate storage system. If the heat load should become excessive, the shutdown cooling portion of the RHR system is operated in parallel with the FPCCS to remove the excess heat load.

7.6.2.15.3 Conformance To Specific Regulatory Requirements

System analysis shows that none of the regulatory requirements are applicable to the FPCCS.

7.6.2.17 Control Air System

Conformance To General Functional Requirements

The instrumentation and control of the control air system is designed to permit reliable operation and testing of each divisional loop of the control air system. The control air system is designed to fulfill the safety and power generation design bases stated in Subsection 7.1.2.1.31.

7.6.2.18 Alternate Rod Insertion

Conformance To General Functional Requirements

The sensors, transmitters, trip units, associated logic, and ARI valves are Class 1E, redundant to and diverse from the reactor protection system, are seismically and environmentally qualified to meet IEEE 323-1974 and IEEE 344-1975, and are supplied with Class 1E dc power.

The ARI equipment is physically separated into two redundant divisions. Either division will be automatically energized to actuate and scram the reactor upon receipt of high reactor pressure or vessel low-water-level 2 signals. The ARI logic may also be initiated manually from the main control room. (See Subsection 7.6.1.18.2 for further details).

7.6.2.19 Safety/Relief Valves Analysis

7.6.2.19.1 Conformance To General Functional Requirements

The SRVs furnished meet requirements of the ASME Boiler and Pressure Vessel Code Section III, Article 9. The valves are operable in two modes: self-actuated or power-actuated solenoid pressure relieving mode. The automatic mode is independent of the power-actuated mode. Failure of the power-actuated mode does not affect the self-actuated mode.

7.6.2.19.2 Conformance To Specific Regulatory Requirements

Compliance With Regulatory Guide 1.22

The logic channels up to the SRV solenoid operators are designed to enhance periodic testing.

Compliance With IEEE 279-1971

A demonstration of the single-failure withstand capability of the generic low-low set design was presented in the BWR Owners Group letter to the NRC, D. B. Vassallo, dated November 19, 1982, titled "Low-Low Set Logic/Lowered MSIV for Mark I Plants."

Compliance With IEEE 323-1974

System components are environmentally qualified as described in Section 3.11.

Compliance With IEEE 344-1975

System components are seismically qualified as described in Section 3.10.

7.6.2.20 Rod Worth Minimizer System

7.6.2.20.1 Conformance to General Functional Requirements

The RWM protects against the existence of a rod worth which could result in the damage to the reactor coolant pressure boundary in the unlikely event of a control rod drop accident.

7.6.2.20.2 Conformance to Specific Regulatory Requirements

There are no specific regulatory requirements for the RWM. The Fermi 2 RWM has been designed to enforce operator adherence to the predetermined sequence of control rod motions during operation at low power levels.

7.6 ALL OTER INSTRUMENTATION SYSTEMS REQUIRED FOR SAFETY

REFERENCES

1. W. R. Morgan, In-Core Neutron Monitoring System for General Electric Boiling Water Reactors, General Electric Co., APED-5706, Nov. 1968, revised April 1969.
2. General Electic Co., "Licensing Summary, The Nuclear Measurement Analysis and Control Rod Worth Minimizer (NUMACRWM) Enhanced RPCS Application," NEDO-31146, June 1986.
3. General Electic Co., "Compliance of Protection Systems to Industry Criteria: General Electric BWR Nuclear Steam Supply System," NEDO-10139, June 1970.
4. GE Nuclear Energy, Maximum Extended Operating Domain Analysis for Detroit Edison Company Enrico Fermi Energy Center Unit 2, NEDC-31843P, July 1990
5. GE Nuclear Energy, Licensing Topical Report, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC-PRNM) Retrofit Plus Option III Stability Trip Function," NEDC-32410P-A, Volumes 1 and 2, October 1995, Including Supplement 1, November 1997.

TABLE 7.6-1 REFUELING INTERLOCK EFFECTIVENESS

Situation	Refueling Platform Position	Refueling TMH[a]	Platform FMH[b]	Hoists FG[c]	Service Platform Hoist	Control Rods	Mode Switch	Attempt	Result
1.	Not near core	UL[d]	UL	UL	UL	All rods in	Refuel	Move refueling platform over core	No restrictions
2.	Not near core	UL	UL	UL	UL	All rods in	Refuel	Withdraw rods	Cannot withdraw more than one rod
3.	Not near core	UL	UL	UL	UL	One rod withdrawn	Refuel	Move refueling platform over core	No restrictions
4.	Not near core	Any hoist loaded or FG not fully up			UL	One or more rods withdrawn	Refuel	Move refueling platform over core	Platform stopped before over core
5.	Not near core	UL	UL	UL	UL	More than one rod withdrawn	Refuel	Move refueling platform over core	Platform stopped before over core
6.	Over core	UL	UL	UL	UL	All rods in	Refuel	Withdraw rods	Cannot withdraw more than one rod
7.	Over core	Any hoist loaded or FG not fully up				All rods in	Refuel	Withdraw rods	Rod block
8.	Not near core	UL	UL	UL	L[e]	All rods in	Refuel	Withdraw rods	Rod block
9.	Not near core	UL	UL	UL	L	All rods in	Refuel	Operate service platform hoist	No restrictions
10.	Not near core	UL	UL	UL	L	One rod withdrawn	Refuel	Operate service platform hoist	Hoist operation prevented
11.	Not near core	UL	UL	UL	UL	All rods in	Startup	Move refueling platform over core	Platform stopped before over core
12.	Not near core	UL	UL	UL	L	All rods in	Startup	Operate service platform hoist	No restrictions
13.	Not near core	UL	UL	UL	L	One rod withdrawn	Startup	Operate service platform hoist	Hoist operation prevented
14.	Not near core	UL	UL	UL	L	All rods in	Startup	Withdraw rods	Rod block

TABLE 7.6-1 REFUELING INTERLOCK EFFECTIVENESS

Situation	Refueling Platform Position	Refueling TMH[a]	Platform FMH[b]	Hoists FG[c]	Service Platform Hoist	Control Rods	Mode Switch	Attempt	Result
15.	Not near core	UL	UL	UL	UL	All rods in	Startup	Withdraw rods	No restrictions
16.	Over core	UL	UL	UL	UL	All rods in	Startup	Withdraw rods	Rod block
17.	Any	UL	Any condition	UL	Any condition	Any condition reactor not at power	Startup	Turn mode switch to run	Scram

[a] THM – trolley mounted hoist.
[b] FMH – frame mounted hoist.
[c] FG – fuel grapple.
[d] UL – unloaded
[e] L – fuel loaded

TABLE 7.6-2 GENERAL INSTRUMENTATION INFORMATION

	Reactor Pressure Vessel Temperature	Reactor Pressure Vessel Level Wide Range During Shutdown	Reactor Core Hydraulics Flow	Reactor Core Hydraulics Differential Pressure
Design classes quality/seismic category[b]	III/NA[a]	III/NA	III/NA	III/NA
Power supply	120-V ac inst. bus	120-V ac inst. bus	120-V ac inst. bus	120-V ac inst. bus
No. of channels	12	1	20	1
Alarm setpoint(s)[c]	NA	NA	NA	NA
Control logic	NA	NA	NA	NA
Instrument range	0 to 600°	160 to 560 in. H_2O	0 to 80 x 10^6 pph	0-30 psid
Instrument accuracy[c]	±6 °F	±0.2 percent	±2 percent	±2 percent

[a] NA = Not Applicable

[b] The instrument seismic category and QA level information provided in the UFSAR tables may have been upgraded to meet the Pressure Boundary Integrity (PBI) or other requirements. The instrument seismic category and QA level information is available in the Fermi 2 Central Component Database.

[c] The instrument accuracy information provided in the UFSAR tables is a bounding value.

	Reactor Pressure Vessel Pressure	Reactor Pressure Vessel Steam Temperature	Reactor Pressure Vessel Feedwater Temperature	RBCCW System Radiation Monitoring Subsystem
Design classes quality/seismic category[c]	I/I	III/NA[a]	III/NA	III/NA
Power supply	120-V ac invert. bus	120-V ac inst. bus	120-V ac inst. bus	24-V dc and 120-V ac inst. bus
No. of channels	2	2	6; 4 computer input 1-2 flow correctors	1
Alarm setpoint(s)[b]	NA	NA	NA	(b)
Control logic	NA	NA	NA for computer input 1/1 temp. correction mass flow meter	NA
Instrument range	0 to 1500 psig	400 to 550 °F	300 to 450 °F	10^{-1} to 10^6 cps gamma
Instrument accuracy[d] sensitivity[e]	±30 psig	±0.3 °F	±0.35 °F	1 x 10^{-4} µCi/ml estimated

TABLE 7.6-2 GENERAL INSTRUMENTATION INFORMATION

[a] NA = Not Applicable.

[b] Variable to be set periodically in the field.

[c] The instrument seismic category and the QA level information provided in the UFSAR tables may have been upgraded to meet the Pressure Boundary Integrity (PBI) or other requirements. The instrument seismic category and QA level information is available in the Fermi 2 Central Component Database.

[d] The instrument accuracy information provided in the UFSAR tables is a bounding value.

[e] Instrument sensitivity is provided to be consistent with other radiation monitors.

	EECW Radiation Monitoring Subsystem	RHR System Water Radiation Monitoring Subsystem	General Service Water Radiation Monitoring Subsystem	Radwaste Effluent Radiation Monitoring Subsystem
Design classes quality/seismic category[d]	III/NA[a]	III/NA	III/NA	III/NA
Power supply	120-V ac inst. buses	120-V ac inst. buses	24-V dc and 120-V ac inst. bus	24-V dc and 120-V ac inst. bus
No. of channels	2	2	1	1
Alarm setpoint(s)	([b])	([b])	([b])	([c])
Control logic	NA	NA	NA	1/1
Instrument range	10^1 to 10^7 cpm gamma	10^1 to 10^7 cpm gamma	10^1 to 10^6 cps gamma	10^1 to 10^6 cps gamma
Instrument sensitivity	5 cpm Cs-137	8 cpm Cs-137	5×10^{-9} µCi/cm^3 estimated	1×10^{-4} µCi/ml estimated

[a] NA = Not Applicable.

[b] Variable; to be set periodically in the field. REV 10 11/00

[c] Alarm setpoints to be field determined such that discharge concentration in decant line is less than 10 CFR 20 Table II, Column 2 limits.

[d] The instrument seismic category and QA level information provided in the UFSAR tables may have been upgraded to meet the Pressure Boundary Integrity (PBI) or other requirements. The instrument seismic category and QA level information is available in the Fermi 2 Central Component Database.

	Circulating Water Decant Line, Radiation Monitoring Subsystem	Main Steam Line Radiation Monitoring Subsystem	Off-Gas Radiation Monitoring Subsystem	Reactor Building Exhaust Plenum Radiation Monitoring Subsystem
Design classes quality/seismic category[c]	III/NA[a]	I/I	III/NA	III/NA
Power supply	120-V ac inst. buses	120-V ac RPS buses 120-V ac inst. buses	RPS buses A & B 24-V dc bus A	120-V ac inst. bus
No. of channels	1	4	3 (2 log, 1 linear)	1

TABLE 7.6-2 GENERAL INSTRUMENTATION INFORMATION

Alarm setpoint(s)	([b])	[b]3 x background	([b])	([b])
Control logic	NA	½ twice	NA	NA
Instrument range	10^{-1} to 10^{7} cpm gamma	10^{0} to 10^{6} mR/h	10^{0} to 10^{6} mR/h	See Table 11.4-1
Instrument sensitivity	8 cpm Cs-137	3.7 x 10^{-10} amp/R/h	3 x 10^{-10} amp/R/hr	80 cpm/mR/hr

[a] NA = Not Applicable.

[b] Variable; to be set periodically in the field.

[c] The instrument seismic category and QA level information provided in the UFSAR tables may have been upgraded to meet the Pressure Boundary Integrity (PBI) or other requirements. The instrument seismic category and QA level information is available in the Fermi 2 Central Component Database.

	Offgas Vent Pipe Radiation Monitoring Subsystem[e]	Fuel Pool Ventilation Exhaust Radiation Monitoring Subsystem	Turbine Building Ventilation Exhaust Radiation Monitoring Subsystem
Design classes quality/seismic category[d]	III/NA[a]	I/I	III/NA
Power supply	N/A	24-V dc bus A&B RPS buses A&B 120 V ac inst. bus	120-V ac inst. buses
No. of channels	N/A	4	1
Alarm setpoint(s)	N/A	([c])	([b])
Control logic	N/A	1/4	1/1
Instrument range	N/A	10^{-2} to 10^{2} mR/h (G-M)	See Table 11.4-2
Instrument sensitivity	N/A	0.01 mR/hr	80 cpm/mR/hr

[a] NA = Not Applicable.

[b] Variable; to be set periodically in the field.

[c] Refer to Technical Specifications

[d] The instrument seismic category and QA level information provided in the UFSAR tables may have been upgraded to meet the Pressure Boundary Integrity (PBI) or other requirements. The instrument seismic category and QA level information is available in the Fermi 2 Central Component Database.

[e] Ratemeters D11K600A/B are removed and all other supported components are abandoned in place.

	Radwaste Building Ventilation Exhaust Radiation Monitoring Subsystem	Reactor Building Ventilation Exhaust Radiation Monitoring Subsystem	Control Center Makeup Air Manifold Radiation Monitoring Subsystem	Standby Gas Treatment System, Vent Exhaust Radiation Monitoring Subsystem
Design classes quality/seismic category[c]	III/NA[a]	III/NA	III/NA	III/NA
Power supply	120-V ac inst. buses	120-V ac inst. buses	120-V ac inst. buses	120-V ac inst. buses
No. of channels	1	2	2	2, 1 per vent
Alarm setpoint(s)	([b])	([b])	([b])	([b])

TABLE 7.6-2 GENERAL INSTRUMENTATION INFORMATION

Control logic	1/1	1/2	1/2	NA
Instrument range	See Table 11.4-2	10^1 to 10^7 cpm (Beta)	10^1 to 10^7 cpm (Beta)	See Table 11.4-2
Instrument sensitivity	80 cpm/mR/hr	8 cpm Xe-133	8 cpm Xe-133	80 cpm/mR/hr

[a] NA = Not Applicable.

[b] Variable; to be set periodically in the field.

[c] The instrument seismic category and QA level information provided in the UFSAR tables may have been upgraded to meet the Pressure Boundary Integrity (PBI) or other requirements. The instrument seismic category and QA level information is available in the Fermi 2 Central Component Database.

	Two-Minute Holdup Pipe Radiation Monitoring Subsystem	Area Radiation Monitoring System	Reactor Water Cleanup Non-Regenerative Heat Exchanger Downstream Temperature	Drywell Leak Detection System Pressure
Design classes quality/seismic category[d]	III/NA[a]	III/NA	III/NA	I/I
Power supply	120-V ac inst. buses	120-V inst. local 120-V ac power bus	120-V ac RPS bus	120-V ac invert. and/or inst. buses
No. of channels	2	48	1	8 4 drywell 4 suppr. Pool
Alarm setpoint(s)[c]	([b])	Varies with location	130°	NA
Control logic	1/2	NA	1/1	NA
Instrument range	10^1 to 10^7 cpm gamma	Varies 10^{-2} to 10^2 up to 10^2 to 10^6 mR/h	75° to 205°	0 to 250 psig -5 to +5 paig 0 to 80 psig -5 to +15 psig
Instrument accuracy[e]	10 cpm (sensitivity)	±20 percent	±3 °F	±0.25 percent span

[a] NA = Not Applicable.

[b] Variable; to be set periodically in the field.

[c] Nominal value or refer to technical specification for setpoint information (as applicable).

[d] The instrument seismic category and QA level information provided in the UFSAR tables may have been upgraded to meet the Pressure Boundary Integrity (PBI) or other requirements. The instrument seismic category and QA level information is available in the Fermi 2 Central Component Database.

[e] The instrument accuracy information provided in the UFSAR tables is a bounding value.

TABLE 7.6-2 GENERAL INSTRUMENTATION INFORMATION

	Control Center Emergency Air South Inlet Radiation Monitor	Control Center Emergency Air North Inlet Radiation Monitor
Design classes quality/seismic category[c]	I/I	I/I
Power supply	120-V ac inst buses	120-V ac inst buses
No. of channels	2	2
Alarm setpoint(s)	(b)	(b)
Control logic	1/2	1/2
Instrument range	10^{-1} to 10^{7} cpm (Beta)	10^{-1} to 10^{7} cpm (Beta)
Instrument sensitivity	8 cpm/pci/cm^3	8 cpm/pci/cm^3

[a] NA = Not Applicable.

[b] Variable; to be set periodically in the field.

[c] The instrument seismic category and QA level information provided in the UFSAR tables may have been upgraded to meet the Pressure Boundary Integrity (PBI) or other requirements. The instrument seismic category and QA level information is available in the Fermi 2 Central Component Database.

	Drywell Leak Detection System Area Temperature	Drywell Leak Detection System Closed Cooling Water Differential Temperature from Atmospheric Coolers	Drywell sump Level Monitors Leak Detection System Sump Pumpout Rate	Drywell Sump Level Monitors Leak Detection System Sump Fill Rate
Design classes Quality/seismic category[d]	III/I[a]	III/NA[b]	III/NA	III/NA
Power supply	120-V ac inst. bus	120-V ac inst. bus	120-V ac inst. bus	120-V ac inst. bus
No. of channels	29	2	2	2
Alarm setpoint(s)[c]	4 to 115, 135, 145, 180 °F	35 °F Diff	5.1 min. 6.8 min	80.4 min. (Floor drain) 20.1 min. (Equip. drain)
Control logic	NA	NA	NA	NA
Instrument range	0 to 360 °F	95 to 150 °F	NA	NA
Instrument accuracy[e]	±1.6 °F	±0.1 percent	±9 sec ±45 sec.	±45 sec. (Floor drain) ±45 sec. (Equip. drain)

[a] Seismic installation.

[b] NA = Not Applicable.

[c] Nominal value or refer to technical specification for setpoint information (as applicable).

[d] The instrument seismic category and QA level information provided in the UFSAR tables may have been upgraded to meet the Pressure Boundary Integrity (PBI) or other requirements. The instrument seismic category and QA level information is available in the Fermi 2 Central Component Database.

[e] The instrument accuracy information provided in the UFSAR tables is a bounding value.

TABLE 7.6-2 GENERAL INSTRUMENTATION INFORMATION

	Reactor Pressure Vessel Head Seal Leak Detection (Inter-seal Pressure)	Recirculation Pump Leak Detection System Seal Cavity Pressure	Recirculation Pump Detection System Seal Leakage Rate	Safety Relief Valve Leak Detection System Discharge Pipe Temperature
Design classes quality/seismic category[c]	III/NA[a]	III/NA	III/NA	III/NA
Power supply	120-V ac inst. bus	120-V ac inst. bus	120-V ac inst. bus	120-V ac inst. bus
No. of channels	1	1 per cavity to 2 cavity per pump	1 per pump	15
Alarm setpoint(s)[b]	600 psig	NA	0.1 gpm	220 °F
Control logic	NA	NA	NA	NA
Instrument range	0 to 1500 psig	0 to 1250 psig	0 to 0.55 gpm(A) 0 to 1.25 gpm(B)	0 to 600°
Instrument accuracy[d]	±30 psig	±2 percent	±2percent	±6 °F

[a] NA = Not Applicable.[b] Nominal value or refer to technical specification for setpoint information (as applicable).

[c] The instrument seismic category and QA level information provided in the UFSAR tables may have been upgraded to meet the Pressure Boundary Integrity (PBI) or other requirements. The instrument seismic category and QA level information is available in the Fermi 2 Central Component Database.

[d] The instrument accuracy information provided in the UFSAR tables is a bounding value.

	Main Steam Line Leak Detection Area Temperature	Main Steam Line Leak Detection System Flow	Main Steam Line Tunnel Detection System Differential Temperature	Main Steam Line Tunnel Leak Detection System Temperature
Design classes quality/seismic category[d]	III/NA[a]	I/I	III/NA	I/I
Power supply	120-V ac invt. bus	120-V ac RPS buses	120-V ac invt. bus	120-V ac RPS bus
No. of channels	2	16	2	16
Alarm setpoint(s)[c]	160 °F increasing	NA[b]	70 °F increasing	NA[a,b]
Control logic	NA	1/4 isolates monitored steam line	NA	1/4 isolates monitored steam line
Instrument range	50° to 350°	0 to 150 psid	0 to 150° ΔT (50 to 350 °F)	50 to 350 °
Instrument accuracy[e]	±6 °F	psi	±3 °F	±2 °F

[a] NA = Not Applicable.

[b] See Technical Specifications for trip setpoint.

[c] Nominal value or refer to technical specification for setpoint information (as applicable).

[d] The instrument seismic category and QA level information provided in the UFSAR tables may have been upgraded to meet the Pressure Boundary Integrity (PBI) or other requirements. The instrument seismic category and QA level information is available in the Fermi 2 Central Component Database.

[e] The instrument accuracy information provided in the UFSAR tables is a bounding value.

TABLE 7.6-2 GENERAL INSTRUMENTATION INFORMATION

	RWCU System Leak Detection System Area Temperature Monitor	RWCU System Leak Detection System High Flow Rate	RWCU Differential Temperature Trip	RHR Leak Detection System Area Temperature
Design classes quality/seismic category[d]	I/I	I/I	I/I	III/NA[a]
Power supply	120-V ac invt. bus	120-V ac inst. bus	120-V ac invt. bus	120-V ac invt. bus
No. of channels	12	2	4	2
Alarm setpoint(s)[c]	175 °F[b]	NA[a,b]	NA[a,b]	148 °F
Control logic	1/5 per valve	1 per valve	1/5 per valve	NA
Instrument range	50 to 350 °F	0 to 400 gpm	0 to 150° ΔT	50 to 350°
Instrument accuracy[e]	±6 °F	±2.5 percent	±1 percent span	±6 percent

[a] NA = Not Applicable.

[b] See Technical Specifications for trip setpoint.

[c] Nominal value or refer to technical specification or Technical Requirements Manual for setpoint information (as applicable).

[d] The instrument seismic category and QA level information provided in the UFSAR tables may have been upgraded to meet the Pressure Boundary Integrity (PBI) or other requirements. The instrument seismic category and QA level information is available in the Fermi 2 Central Component Database.

[e] The instrument accuracy information provided in the UFSAR tables is a bounding value.

	RHR Leak Detection System Area Differential Temperature	RCIC Leak Detection System Steam Line Low Pressure	RCIC Leak Detection System Area Temperature	RCIC Leak Detection System Vent Differential Temperature
Design classes quality/seismic category[d]	III/NA[a]	I/I	I/I	I/I
Power supply	120-V ac invt. bus	120-V ac invt. bus	120-V ac invt. bus	120-V ac invt. bus
No. of channels	2	4	3	2
Alarm setpoint(s)[c]	50 °F ΔT	NA[b]	NA[b]	50 °F ΔT
Control logic	NA	2/2 (Redundant)	1/2	NA
Instrument range	0 to 150 ° ΔT	0 to 200 psig	50 to 350°	0 to 150 ° ΔT
Instrument accuracy[e]	±3 °F	±0.25 percent	±6 °F	±3 °F

[a] NA = Not Applicable.

[b] See Technical Specifications for trip setpoint.

[c] Nominal value or refer to technical specification for setpoint information (as applicable).

[d] The instrument seismic category and QA level information provided in the UFSAR tables may have been upgraded to meet the Pressure Boundary Integrity (PBI) or other requirements. The instrument seismic category and QA level information is available in the Fermi 2 Central Component Database.

[e] The instrument accuracy information provided in the UFSAR tables is a bounding value.

TABLE 7.6-2 GENERAL INSTRUMENTATION INFORMATION

	RCIC Leak Detection Steam Flow Rate (‘P)	HPCI Leak Detection System Steam Line Low Pressure	HPCI Leak Detection System Area Temperature	HPCI Leak Detection System Area Differential Temperature
Design classes quality/seismic category[d]	I/I	I/I	I/I	I/I
Power supply	120-V ac invt. bus	120-V ac inst. bus 120-V ac invt. bus	120-V ac invt. bus	120-V ac invt. bus
No. of channels	2	4	3	2
Alarm setpoint(s)	NA[a,b]	NA[a,b]	NA[a,b]	50 °F ΔT[c]
Control logic	1/2	2/2 redundant	1/2	NA
Instrument range	±300 inch H_2O	0 to 200 psig	50° to 350°	0 to 150° ΔT
Instrument accuracy[e]	±0.25 percent	±0.25 percent	±6 °F	±3 °F

[a] NA = Not Applicable.

[b] See Technical Specifications for trip setpoint.

[c] Nominal value or refer to technical specification for setpoint information (as applicable).

[d] The instrument seismic category and QA level information provided in the UFSAR tables may have been upgraded to meet the Pressure Boundary Integrity (PBI) or other requirements. The instrument seismic category and QA level information is available in the Fermi 2 Central Component Database.

[e] The instrument accuracy information provided in the UFSAR tables is a bounding value.

	HPCI Leak Detection System Steam Flow (Differential Pressure)	Suppression Pool Leak Detection System Area Temperature	Suppression Pool Leak Detection System Area Differential Temperature
Design classes quality/seismic category[d]	I/I[a]	I/I	I/I
Power supply	120-V invt. bus	120-V ac invt. bus	120-V ac inst. bus 120-V ac invt. bus
No. of channels	2	4	4
Alarm setpoint(s)[c]	NA[b]	90 °F > ambient	50 °F ‘T
Control logic	1/2	NA	NA
Instrument range	±500 in. H_2O	50° to 350 °F	0 to 150° ‘T
Instrument accuracy[e]	±0.25 percent	±6 °F	±3 °F

[a] NA = Not Applicable.

[b] See Technical Specifications for trip setpoint.

[c] Nominal value or refer to technical specification for setpoint information (as applicable).

[d] The instrument seismic category and QA level information provided in the UFSAR tables may have been upgraded to meet the Pressure Boundary Integrity (PBI) or other requirements. The instrument seismic category and QA level information is available in the Fermi 2 Central Component Database.

[e] The instrument accuracy information provided in the UFSAR tables is a bounding value.

TABLE 7.6-2 GENERAL INSTRUMENTATION INFORMATION

	ECCS Suction Lines Leak Detection System Sump Level Fill Rate	Sequence of Events Recorder, Nuclear Steam Supply / Balance-of- Plant	Primary Containment Radiation Monitor
Design classes quality/seismic category[b]	III/II/I	III/NA[a]	III/NA
Power supply	130-V dc inst. bus	130-V dc BOP battery inverter supply	120-V ac inst. bus
No. of channels	1	2560 inputs	1 each for gas and particulates (particulates is installed spare)
Alarm setpoint(s)	Field set during startup	NA	
Control logic	Sump fill rate	NA	NA
Instrument range	Timer (0 to 30 min)	NA	
Instrument accuracy[c]	±2 percent	Records inputs with a 1 msec resolution	

[a] NA = Not Applicable.

[b] The instrument seismic category and QA level information provided in the UFSAR tables may have been upgraded to meet the Pressure Boundary Integrity (PBI) or other requirements. The instrument seismic category and QA level information is available in the Fermi 2 Central Component Database.

[c] The instrument accuracy information provided in the UFSAR tables is a bounding value.

TABLE 7.6-2 GENERAL INSTRUMENTATION INFORMATION

	Primary Containment Hydrogen Analyzer[f]	Primary Containment Oxygen Analyzer[g]	Suppression Pool Water Level	Neutron Monitor System, Source Range Monitor	Neutron Monitor System, Intermediate Range Monitors
Design classes quality/seismic category[c]	I/I	I/I	I/I	III/NA[a]	I/I
Power supply	120-V ac inst. bus	120-V ac inst. bus	120-V ac invert. Bus 120-V ac invert	±24-V dc buses	±24-V dc buses
No. of channels	2	2	2	4	8
Alarm setpoint(s)[b]	High H_2 1.0 percent 3.5 percent	High O_2 3.5 percent 4.5 percent	NA	3 c/s down 10^5 c/s up	
Control logic	NA	NA	NA	1/4 for rod block	1/8 trips RPS; 1 channel isolatable
Instrument range[e]	0 to 30 percent H_2	0 to 10 percent O_2 0 to 30 percent O_2	+56 to -144 in. referenced to normal H_2O level	$1x10^3$ to $1x10^9$ nv	10^8 to $1.5x10^{13}$nv
Instrument accuracy[d]	±2.0 percent full scale	±3.0 percent full scale	±0.025 percent	±10 percent linear 1.2×10^{-3} cps/nv (nominal sensitivity)	±15 percent

[a] NA = Not Applicable.

[b] Nominal value or refer to technical specification for setpoint information (as applicable).

[c] The instrument seismic category and QA level information provided in the UFSAR tables may have been upgraded to meet the Pressure Boundary Integrity (PBI) or other requirements. The instrument seismic category and QA level information is available in the Fermi 2 Central Component Database.

[d] The instrument accuracy information provided in the UFSAR tables is a bounding value.

[e] The oxygen analyzer instrument range of 0 to 10% oxygen is provided to meet Regulatory Guide 1.97 Rev 2 requirements and 0 to 30% oxygen is provided for information only.

[f] The hydrogen analyzer is required to meet Regulatory Guide 1.97, Rev 2 Category 3 requirements.

[g] The oxygen analyzer is required to meet Regulatory Guide 1.97, Rev 2 Category 2 requirements.

TABLE 7.6-2 GENERAL INSTRUMENTATION INFORMATION

	Neutron Monitor System Local Power Range Monitor	Neutron Monitor System Average Power Range Monitor	Neutron Monitor System Transversing In-Core Probe	Neutron Monitor System Rod Block Monitor
Design classes quality/seismic category[b]	I/I	I/I	III/NA[a]	1M/II/I
Power supply	RPS buses	120-V ac RPS buses	120-V ac local power	120-V ac RPS buses
No. of channels	172	4	5	2
Setpoint(s)	See Table 7.6-7	See Table 7.6-9	NA	See Table 7.6-10
Control logic	Loss of power causes APRM to trip RPS	See Table 7.6-9	NA[a]	1/2
Instrument range	to 10^{14} nv	0 to 125 percent full power	2.8 x 10^{12} to 2.8 x 10^{14} nv	0 to 125 percent power/flow
Instrument accuracy[c]	±1 percent full scale	±1 percent full scale	Position ±1 in flux ±1.0 percent full scale	±1.5 percent

[a] NA = Not Applicable.

[b] The instrument seismic category and QA level information provided in the UFSAR tables may have been upgraded to meet the Pressure Boundary Integrity (PBI) or other requirements. The instrument seismic category and QA level information is available in the Fermi 2 Central Component Database.

[c] The instrument accuracy information provided in the UFSAR tables is a bounding value.

	RBCCW Makeup Tank Level Trip	RBCCW Low Suction Pressure Trip	TBCCW Makeup Tank Condensate Level Trip	TBCCW Low Suction Pressure Trip
Design classes quality/seismic category[c]	III/NA[a]	III/NA	III/NA[a]	III/NA
Power supply	120-V ac from power to pump	120-V ac from power to pumps	120-V ac from power to pumps	120-V ac from power to pumps
No. of channels	4	4	4	4
Alarm setpoint(s)[b]	6 in. decreasing	< 6 psig	6 in decreasing	< 7 psig
Control logic	1/2 twice	1/2 twice	1/2 twice	1/2 twice
Instrument range	0 to 48 in. WCD	30 HG to 20 psig	0 to 48 in. WCD	0 to 20 psig
Instrument accuracy[d]	±1/2 percent	±1/2 percent	±1/2 percent	±0.25 percent

[a] NA = Not Applicable.

[b] Nominal value or refer to technical specification for setpoint information (as applicable).

[c] The instrument seismic category and QA level information provided in the UFSAR tables may have been upgraded to meet the Pressure Boundary Integrity (PBI) or other requirements. The instrument seismic category and QA level information is available in the Fermi 2 Central Component Database.

[d] The instrument accuracy information provided in the UFSAR tables is a bounding value.

TABLE 7.6-2 GENERAL INSTRUMENTATION INFORMATION

	FPCC Conductivity	FPCC Pump Discharge Pressure	FPCC Pump Low Suction Pressure	FPCC Refueling Bellows Leakage Rate
Design classes quality/seismic category[c]	III/NA[a]	III/NA	III/NA	III/NA
Power supply	120-V ac inst. bus	120-V ac local power bus	130-V dc @ SWGR	120-V ac local power bus
No. of channels	2	2	2	1
	1 per demineralizer	1 per pump	1 per pump	
Alarm setpoint(s)[b]		90 psig	-10 ft H_2O	5 gpm
		decreasing = low		
Control logic	NA	NA	1/1	NA
Instrument range	0 to 10 micromhos/cm	0 to 200 psig	0.908 - 34.05 ft H_2O_g	2 to 20 gpm
Instrument accuracy[d]		±4 psig	±3 ft H_2O_g	±1 gpm

[a] NA = Not Applicable.

[b] Nominal value or refer to technical specification for setpoint information (as applicable).

[c] The instrument seismic category and QA level information provided in the UFSAR tables may have been upgraded to meet the Pressure Boundary Integrity (PBI) or other requirements. The instrument seismic category and QA level information is available in the Fermi 2 Central Component Database.

[d] The instrument accuracy information provided in the UFSAR tables is a bounding value.

	FPCC Gate Seal Level	FPCC Pool Water Level	FPCC Surge Tank Level
Design classes quality/seismic category[c]	III/NA[a]	III/NA	III/NA
Power supply	120-V ac local power bus	120-V ac local power bus	120-V ac local power bus
No. of channels	1	1	3; High, Low and Low-Low level switches
Alarm setpoint(s)[b]	5 gpm	High + 3 in. Low, 4 in. (normal = 0 in.)	High = 250 ft^3
			Low = 100 ft^3
Control logic	NA	NA	1/1
Instrument range	2 to 20 gpm	8 in. H_2O	NA
Instrument accuracy[d]	±1 gpm	±1/2 in. H_2O	±1/2 in. H_2O

[a] NA = Not Applicable.

[b] Nominal value or refer to technical specification for setpoint information (as applicable).

[c] The instrument seismic category and QA level information provided in the UFSAR tables may have been upgraded to meet the Pressure Boundary Integrity (PBI) or other requirements. The instrument seismic category and QA level information is available in the Fermi 2 Central Component Database.

[d] The instrument accuracy information provided in the UFSAR tables is a bounding value.

TABLE 7.6-3 SPDS SAFETY PARAMETERS AND ASSOCIATED PRIMARY VARIABLES

Safety Parameter	Primary Variable
Core cooling	Reactor water level
Fuel integrity	Reactor coolant sample analysis, offgas pretreatment radiation
Reactivity	Startup range monitor log count rate
Reactor coolant system integrity	Reactor pressure, drywell pressure, drywell sump collection rate, RPV isolation, safety/relief valve position
Containment integrity	Containment pressure, containment isolation valve positions, containment oxygen concentration, suppression pool/wetwell/torus level, drywell temperature
Radioactivity effluent to environment	Radiation level at plant release points

TABLE 7.6-4 PARAMETERS ASSOCIATED WITH SPDS DISPLAYS

Reactor Water Level
- Wide Range Div I
- Wide Range Div II
- Narrow Range Div I
- Narrow Range Div II
- Fuel Zone Range Div I
- Fuel Zone Range Div II
- Shutdown Range

Reactor Pressure
- Wide Range Div I
- Wide Range Div II
- Dome Pressure Wide Range
- Dome Pressure Narrow Range

Neutron Monitoring

APRM 1	SRM A
APRM 2	SRM B
APRM 3	SRM C
APRM 4	SRM D

Main Steam Line Radiation

Containment High Range Rad Mon Div I

Containment High Range Rad Mon Div II

Drywell Pressure
- Wide Range Div I
- Wide Range Div II
- Narrow Range Div I
- Narrow Range Div II

Primary Containment 02 Level Div I

Primary Containment 02 Level Div II

Primary Containment Water Level
- (Elevation 545 feet to 650 feet)

Torus Water Level Wide Range (-156 in. to +44 in.)

Torus Water Level Narrow Range (-10 in. to +10 in.)

Channels B and D

Torus Pressure Div I

TABLE 7.6-4 PARAMETERS ASSOCIATED WITH SPDS DISPLAYS

Suppression Pool Temperature
Drywell Temperature
Fuel Pool Div I Rad Mon A
Fuel Pool Div I Rad Mon C
SJAE Radiation Mon A
SJAE Radiation Mon B
Drywell Floor Drain Sump Level
Primary Containment Isolation Valves/Signal Status
Safety Relief Valve Status
SGTS Exhaust Fan Div I Status
SGTS Exhaust Fan Div II Status
Turbine Bldg Exhaust Fan Status
Radwaste Bldg Exhaust Fan Status
Reactor Bldg Exhaust Fan Status
Gaseous Effluent Radiation Monitors
SGTS Div I Exhaust
SGTS Div II Exhaust
Reactor Bldg Exhaust
Radwaste Bldg Exhaust
Turbine Bldg Exhaust

TABLE 7.6-5 SRM SYSTEM TRIPS

Trip Function	Nominal[a] Setpoint	Trip Action[b]
SRM Upscale (high)	10^5c/s	Rod block, amber light display, annunciator
SRM Instrument Inoperative	(c)	Rod block, amber light display, annunciator
Detector Retraction Permissive (SRM downscale)		Bypass detector full-in-limit switch when above present limit, annunciator, green light display, rod block when below preset limit with IBM range switches on first two ranges
SRM Period	50	Annunciator, amber light display
SRM Downscale	3c/s	White light display, annunciator, rod block
SRM Bypassed		White light display

[a] Nominal setpoints are included for reference only. See Technical Specifications for actual operational values.

[b] Also refer to Figure 7.6-17.

[c] Operate-Calibrate Switch not in Operate, module interlocks open, detector-polarizing voltage below 300 V.

TABLE 7.6-6 IRM SYSTEM TRIPS

Trip Function	Nominal[a] Setpoint	Trip Action[b]
IRM Upscale (High-High)	120/125 fs	Scram, annunciator, red light display
IRM Instrument Inoperative	(c)	Scram, annunciator, red light display
IRM Upscale (High)	108/125 fs	Rod block, annunciator, amber light display
IRM Downscale	5/125 fs	Rod block (exception on most sensitive scale), annunciator, white light display
IRM Bypassed	NA	White light display

[a] Nominal setpoints are included for references. See Technical Specifications for actual operational values.

[b] Also refer to Figure 7.6-17.

[c] Operate-Calibrate Switch not in Operate, module interlocks open, detector-polarizing voltage below 80 V.

TABLE 7.6-7 LPRM SYSTEM TRIPS

Trip Function	Trip Range	Trip** Setpoint	Trip Action
LPRM Downscale	0 percent to full scale	3 fs	APRM ODA* indication and annunciator
LPRM Upscale	0 percent to full scale	100 fs	APRM ODA* indication and annunciator
LPRM Bypass	Manual selection	NA	APRM ODA* indication and APRM averaging compensation

* Digital Operator Display Assembly

** Nominal Setpoints are included for reference only

TABLE 7.6-8 APRM FLOW FUNCTIONAL TRIPS

Trip Function	Nominal[a] Setpoint	Trip Action
Upscale	108 fs	Rod block, APRM ODA* indication and annunciator

* Digital Operator Display Assembly

[a] Nominal values are included for reference only.

TABLE 7.6-9 APRM SYSTEM TRIP

Trip Function	Trip Point Range	Nominal[a] Value	Action[b]
APRM Downscale	0 percent to full scale	5 percent of rated thermal power	Rod block, annunciator, APRM ODA*
APRM Upscale (Rod block) (two recirc loops)	Varied with flow, intercept and slope adjustable	($0.62W^c$ +54.5 percent with a clamp of 108 percent) 12 percent of rated thermal power in startup mode	Rod block, annunciator, APRM ODA*
APRM Upscale (thermal) (two recirc loops)	Varied with flow, intercept and slope adjustable	($0.62W^c$ +60.2 percent) with max of 113.5 percent of rated thermal power	Scram, annunciator, APRM ODA*
APRM Inoperative	OPER-INOP switch, module interlocks open, or self-test	Not in OPER mode or critical self-test fault	Scram, rod block, annunciator, APRM ODA*
APRM Bypass	Manual switch	--	White light
APRM Upscale (neutron)	0 percent to full scale	118 percent of rated thermal power 15 percent of rated thermal power in startup mode	Scram annunciator, APRM ODA*
OPRM Upscale Trip	Growth: 1.00-1.50 Amplitude: 1.05-1.50 Period: Confirmation count: 2-25 Amplitude: 1.00-1.30	Growth: 1.30 Amplitude: 1.30 Period: Confirmation Count: 14 Amplitude: 1.11	Scram, Annunciator, APRM ODA*
OPRM Upscale Alarm	Growth: 1.00-1.50 Amplitude: 1.05-1.50 Period: Confirmation Count: 1-20	Growth: 1.20 Amplitude: 1.20 Period: Confirmation Count: 12	Annunciator, APRM ODA*
OPRM Inoperative	0-44 (Min. OPRM Cells required)	<21 OPRM Cells operable	Annunciator, APRM ODA*
OPRM Enable	STP: 10-40% Flow: 50-100%	≥27.5% STP <60% drive flow	Annunciator, APRM ODA*

* Digital Operator Display Assembly

[a] See Technical Specifications and Technical Requirements Manual for actual operational values

[b] Also see Figure 7.6-16.

[c] W is recirculation loop flow.

TABLE 7.6-10 RBM SYSTEM TRIPS

Trip Function	Nominal Setpoint[a]	Trip Action
RBM Downscale RBM ODA*	94%	Rod block, annunciator,
RBM Inoperative	(b)	Rod block, annunciator, RBM ODA*
RBM Upscale[c]	LTSP = 114.0;	Rod block, annunciator,
	ITSP = 118.2;	RBM ODA*
	HTSP = 104.4	
RBM Bypassed	Manual switch	RBM ODA*, White light Display

* Digital Operator Display Assembly

(a) Nominal setpoints for reference only. See Core Operating Limits Report (COLR) for actual operational values.

(b) OPER - INOP switch not in OPER, module interlocks open, too few inputs, failure to adjust gain or more than one rod selected.

(c) These setpoints are in percent of reference level (Refer to Figure 7.6-22(b) for additional information).

TABLE 7.6-11 SPENT FUEL POOL LEAKAGE ALARMS IN CONTROL ROOM

Condition	Setpoint (nominal)
Fuel pool system temperature high	130 °F
Fuel pool water level low	4 in. below normal level
Fuel pool system trouble	Any alarm contacts from surge tank high or low, gate leakage, refueling bellows leakage, pump A or pump B discharge pressure low.
Fuel pool water level high	3 in. above normal level

TABLE 7.6-12 HAS BEEN INTENTIONALLY DELETED

TABLE 7.6-13 HAS BEEN INTENTIONALLY DELETED

TABLE 7.6-14 REACTOR WATER CLEANUP ANNUNCIATORS

Function	Trip Point
Reactor Water Cleanup Pump Low Flow	70 gpm
Reactor Water Cleanup Pump Seal Gland Plate Temperature High	250 °F
Reactor Water Filter-Demineralizer Inlet High Temperature	130 °F
Reactor Water Cleanup/Blowdown Line Pressure High	140 psi
Reactor Water Cleanup/Blowdown Line Pressure Low	5 psi
Reactor Water Cleanup Steam Leakage High Area Temperature	175 °F[a]
Reactor Water Cleanup Filter Demineralizer Trouble	Any alarm on load operated
Reactor Water Cleanup Valves Thermal Overload	Any valve over-load operated
Reactor Water Cleanup Differential High	55.1 gpm[a]
Reactor Water Conductivity High	Multiple setpoints

[a] Nominal value - refer to Technical Specifications for setpoint information.

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Refer to Plant Drawing I-2260-13

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FIGURE 7.6-1

REACTOR WATER CLEANUP SYSTEM FCD

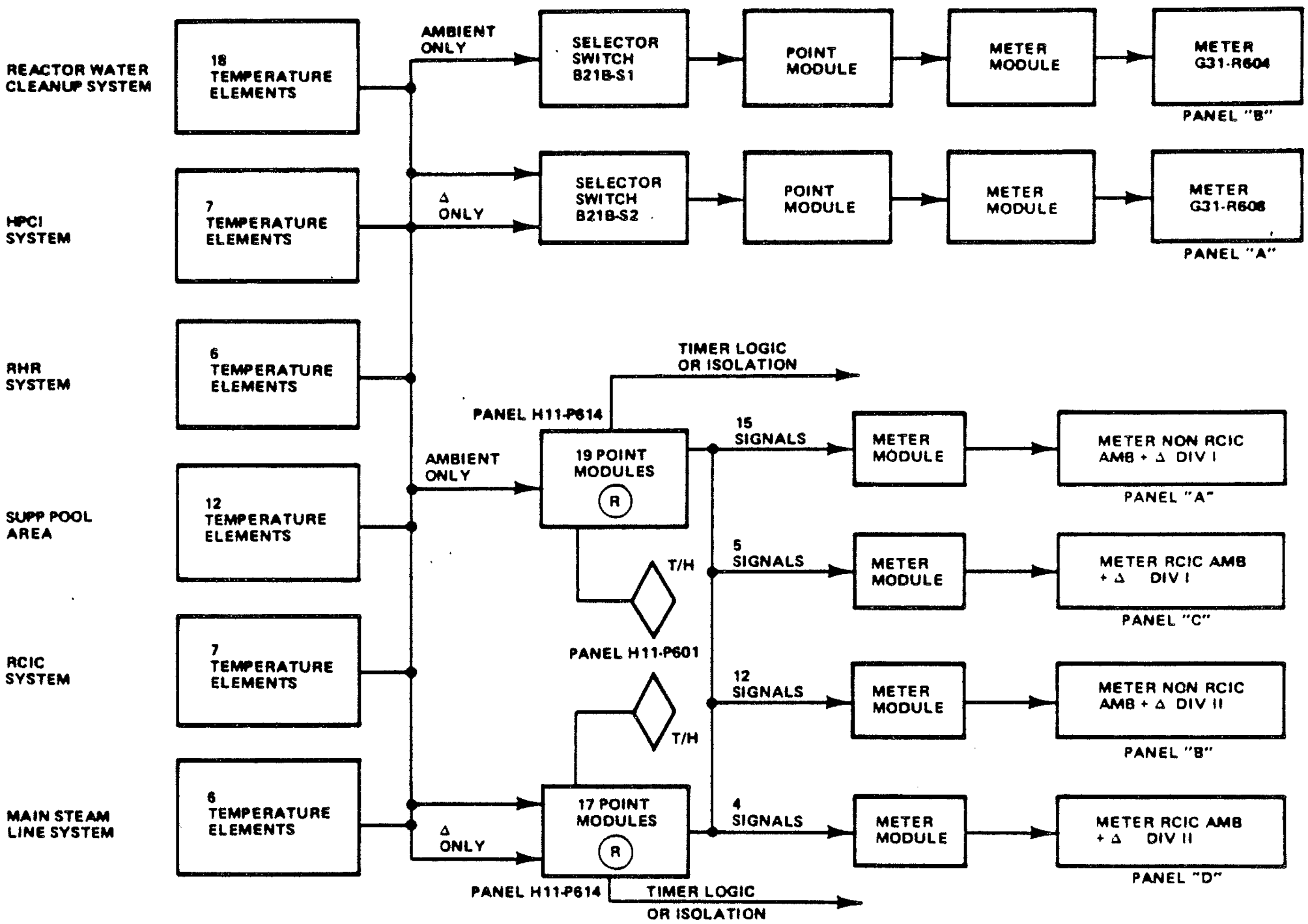

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FIGURE 7.6-2

AREA TEMPERATURE MONITORING SYSTEM BLOCK DIAGRAM

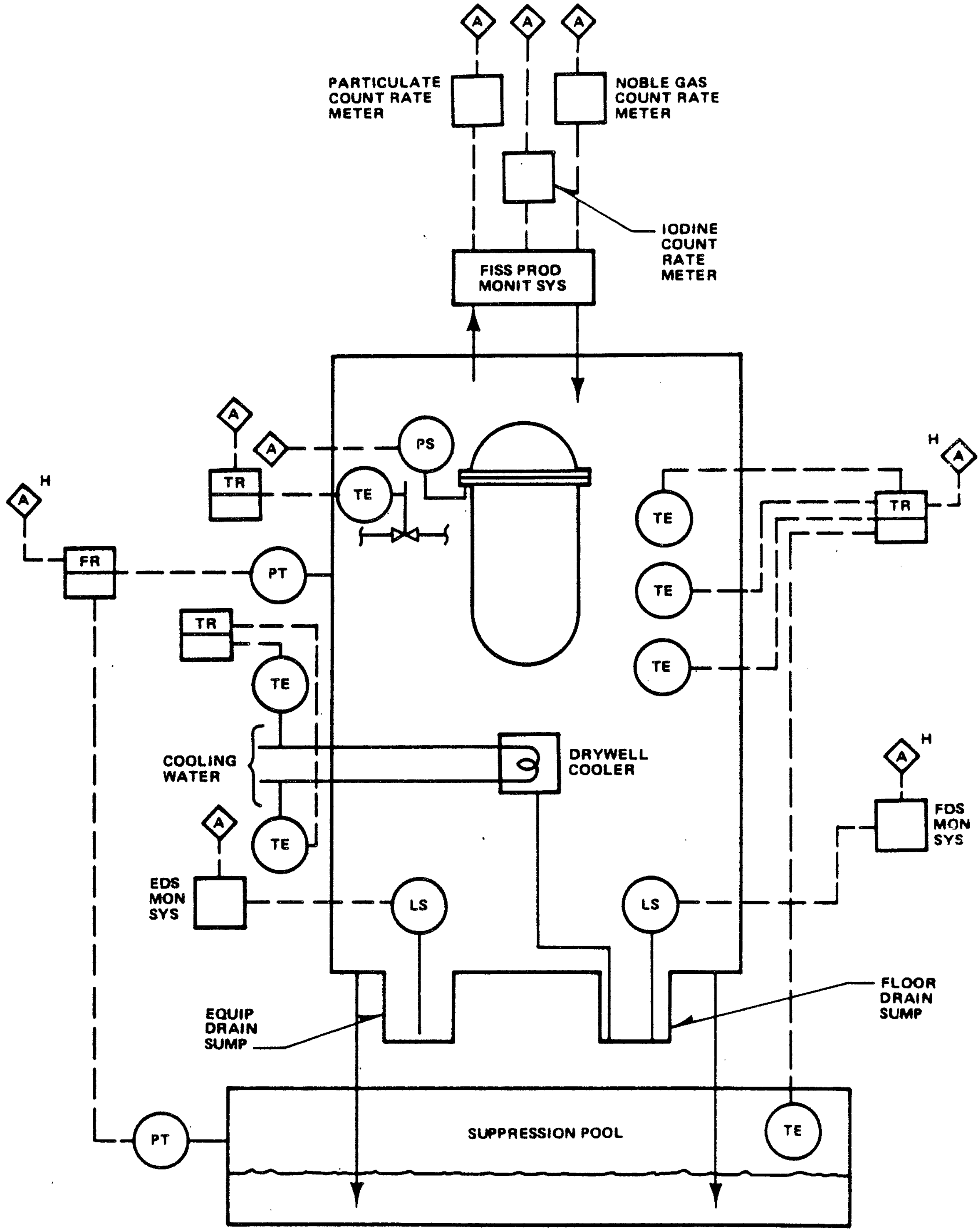

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FIGURE 7.6-3

CONTAINMENT LEAK DETECTION SYSTEM

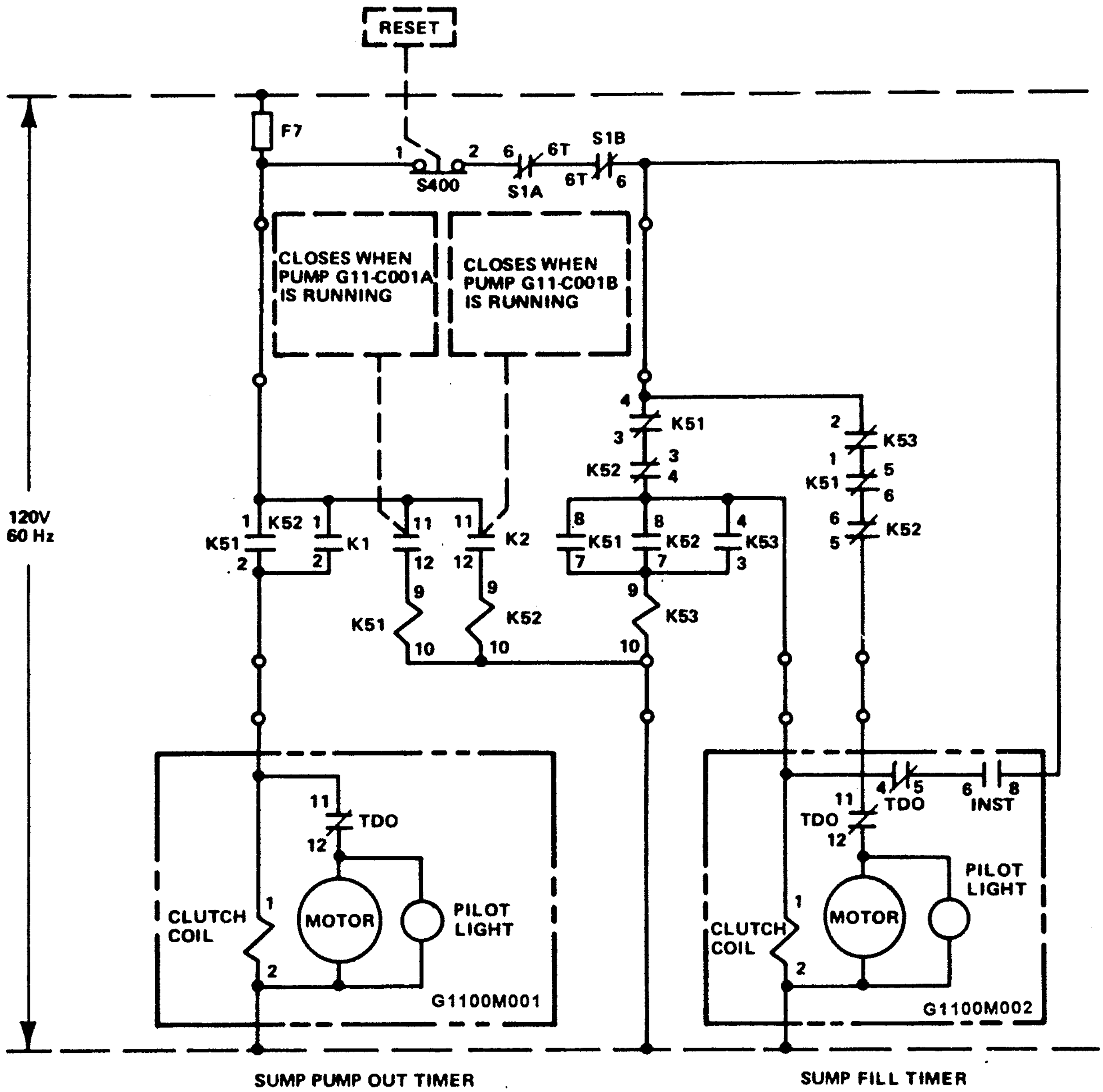

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FIGURE 7.6-4

EQUIPMENT AREA LEAK DETECTION SYSTEM TYPICAL

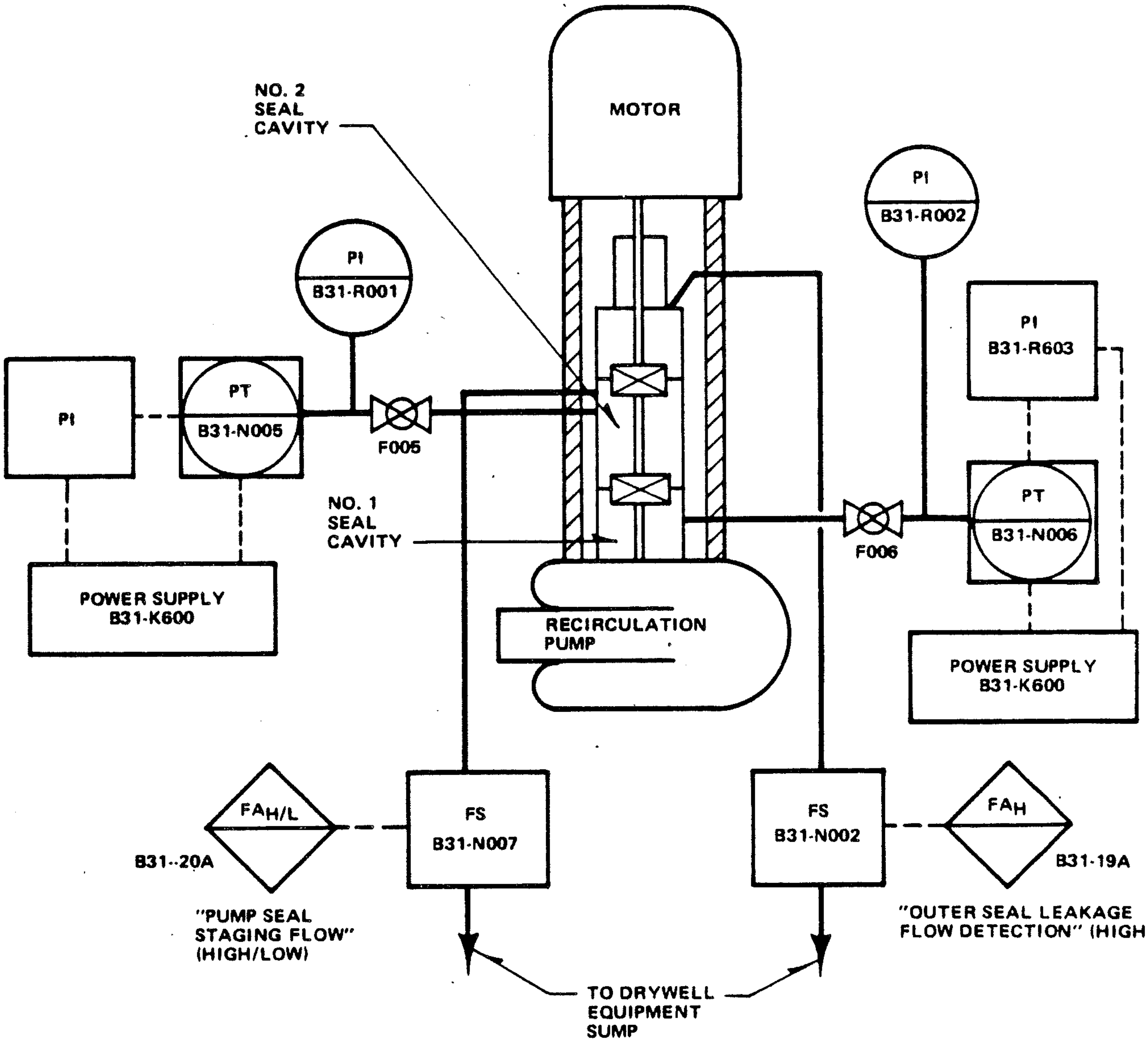

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FIGURE 7.6-5

RECIRCULATION PUMP LEAK DETECTION
BLOCK DIAGRAM

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FIGURE 7.6-10 HAS BEEN DELETED

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Refer to Plant Drawing I-2679-01

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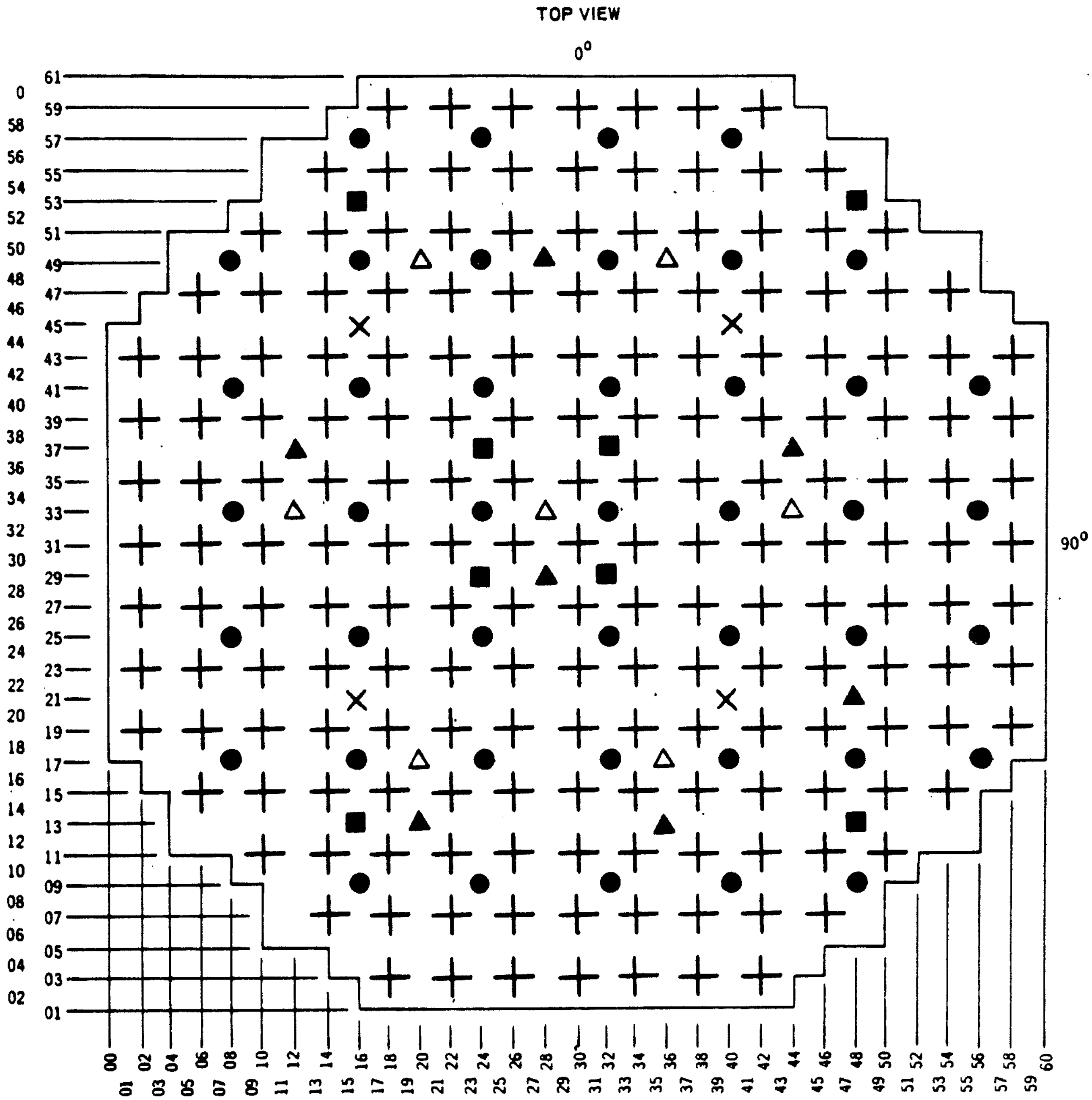
FIGURE 7.6-11

PRIMARY CONTAINMENT MONITORING SYSTEM



●	LOCAL POWER RANGE MONITORING SYSTEM (LPRM)	43
X	SOURCE RANGE MONITORING SYSTEM (SRM)	4
■	INTERMEDIATE RANGE MONITORING SYSTEM (IRM)	8
▲	DESIGN NEUTRON SOURCE LOCATIONS	7
△	SPARE NEUTRON SOURCE LOCATIONS	7

Note: All neutron sources removed from core during first refueling outage.

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FIGURE 7.6-12

NEUTRON MONITORING SYSTEM CORE LOCATION

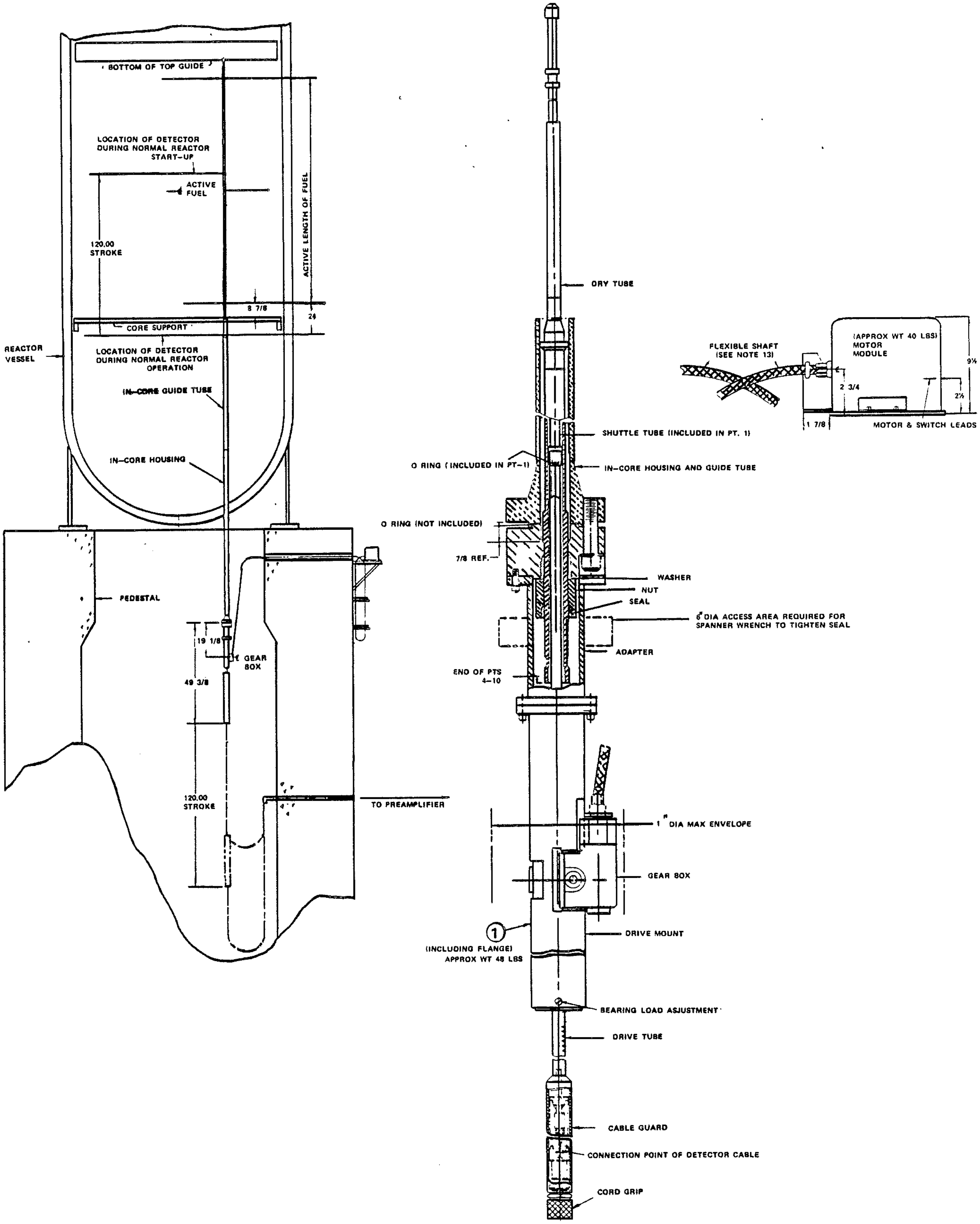

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FIGURE 7.6-13

SOURCE/INTERMEDIATE RANGE MONITOR NEUTRON MONITORING UNIT

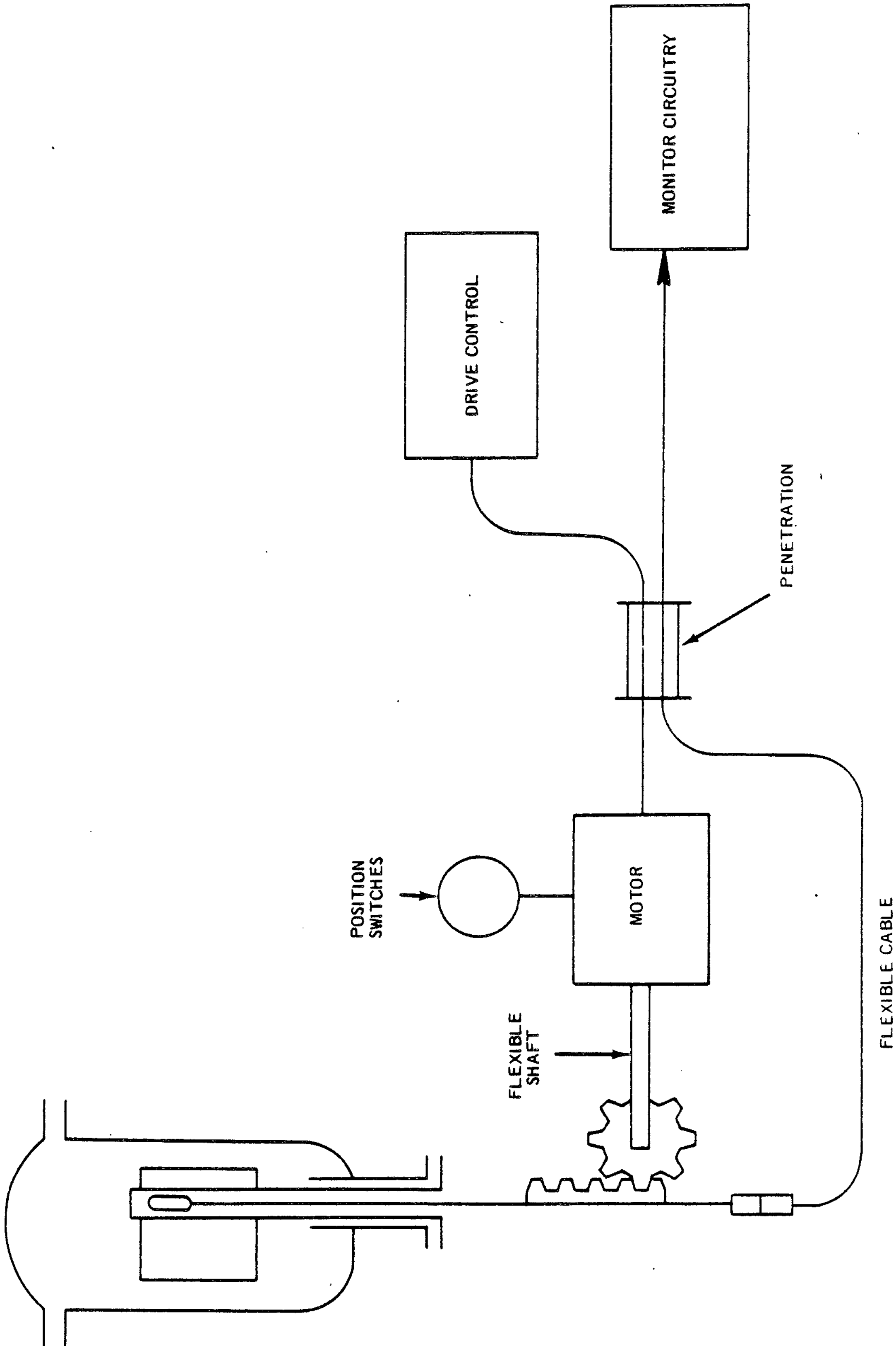

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FIGURE 7.6-14

DETECTOR DRIVE SYSTEM SCHEMATIC

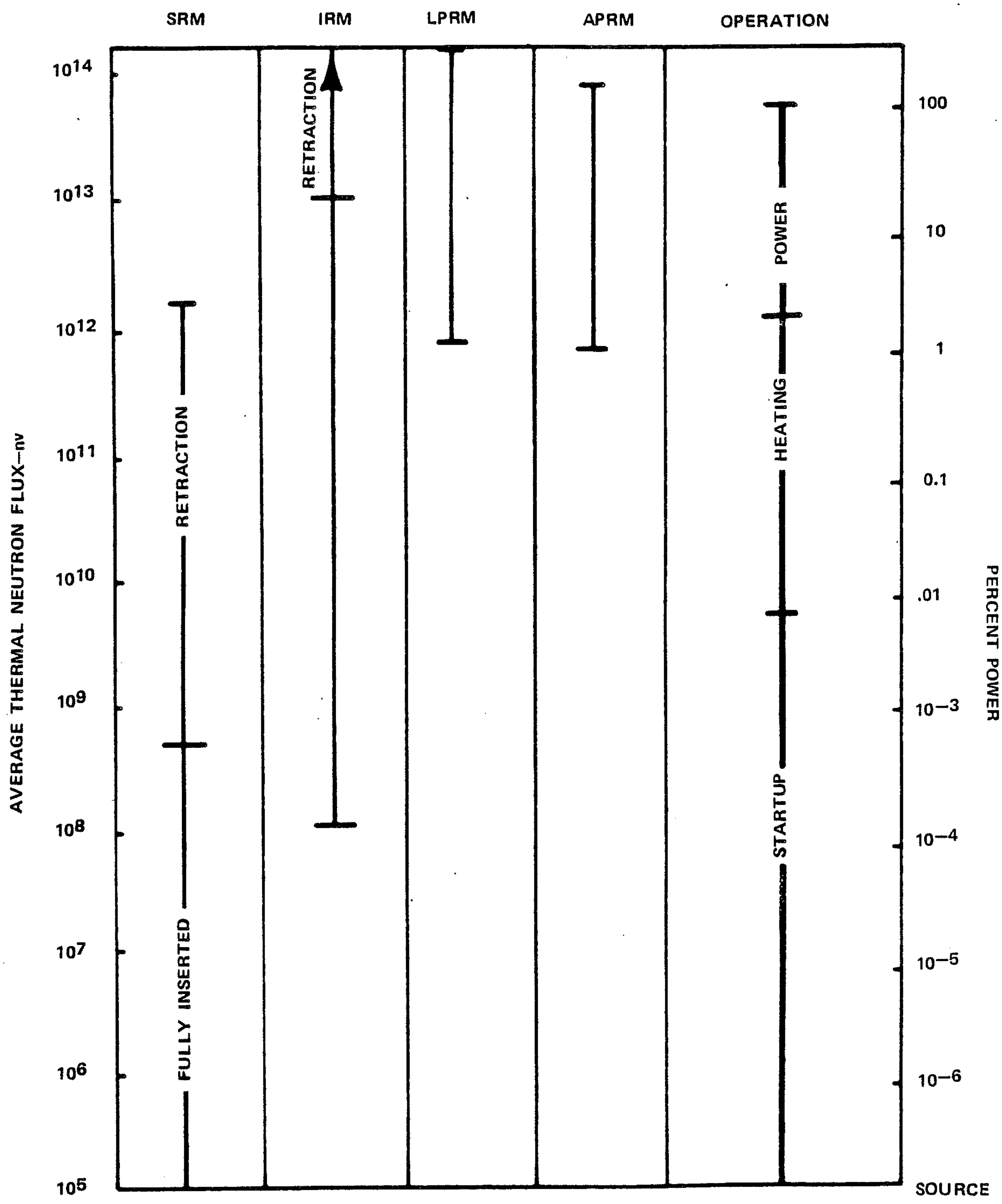

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FIGURE 7.6-15

RANGES OF NEUTRON MONITORING SYSTEM

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Refer to Plant Drawing I-2140-01

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FIGURE 7.6-16, SHEET 1

NEUTRON MONITORING SYSTEM FCD

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Refer to Plant Drawing I-2140-02

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FIGURE 7.6-16, SHEET 2

NEUTRON MONITORING SYSTEM FCD

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Refer to Plant Drawing I-2140-03

Figure Intentionally Removed
Refer to Plant Drawing I-2140-04

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FIGURE 7.6-16, SHEET 4

NEUTRON MONITORING SYSTEM FCD

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Refer to Plant Drawing I-2140-05

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FIGURE 7.6-16, SHEET 5

NEUTRON MONITORING SYSTEM FCD

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FIGURE 7.6-16, SHEET 6

NEUTRON MONITORING SYSTEM FCD

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Refer to Plant Drawing I-2140-07

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FIGURE 7.6-16, SHEET 7

NEUTRON MONITORING SYSTEM FCD

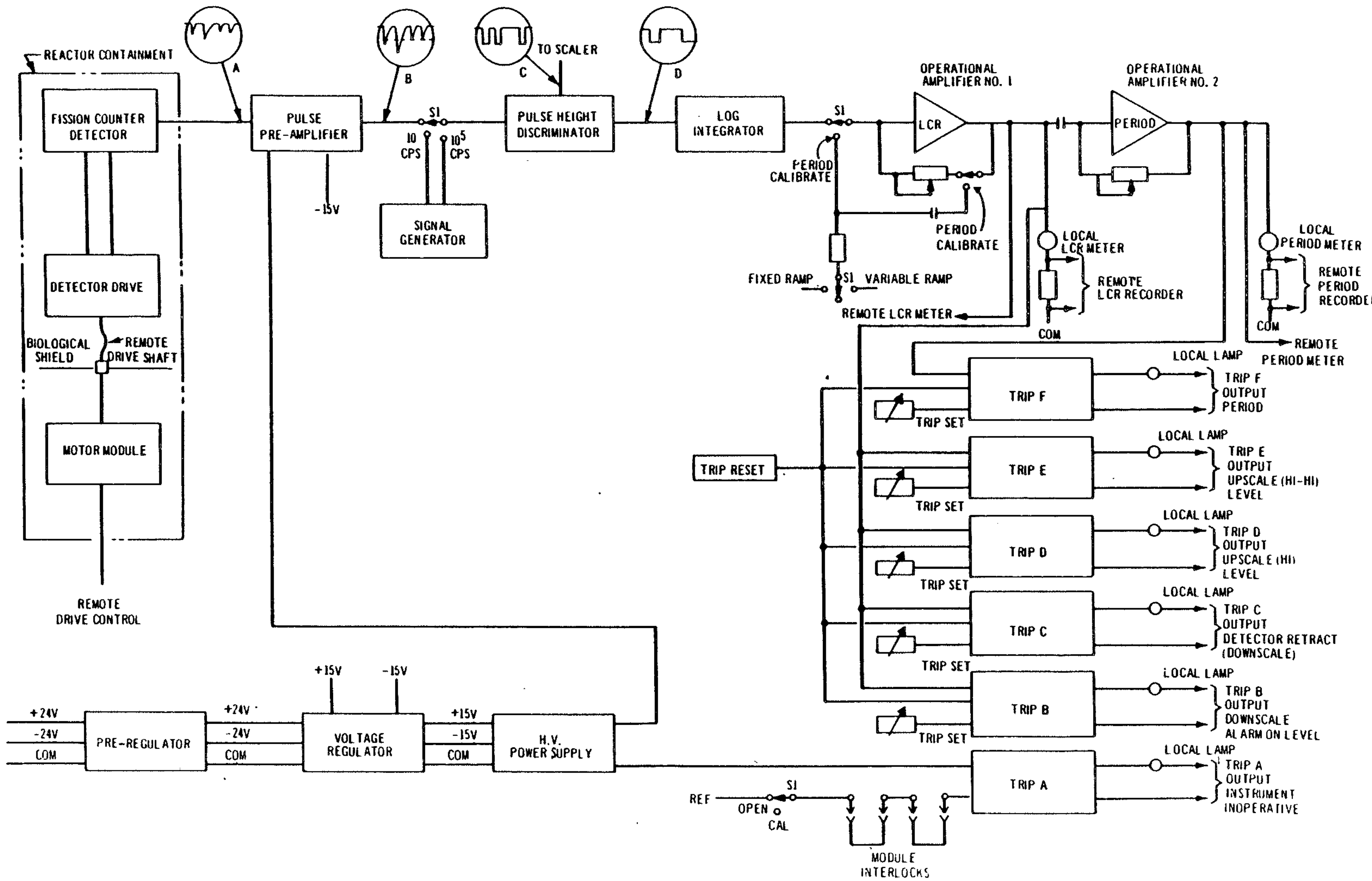

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FIGURE 7.6-17

FUNCTIONAL BLOCK DIAGRAM OF SOURCE RANGE MONITOR CHANNEL

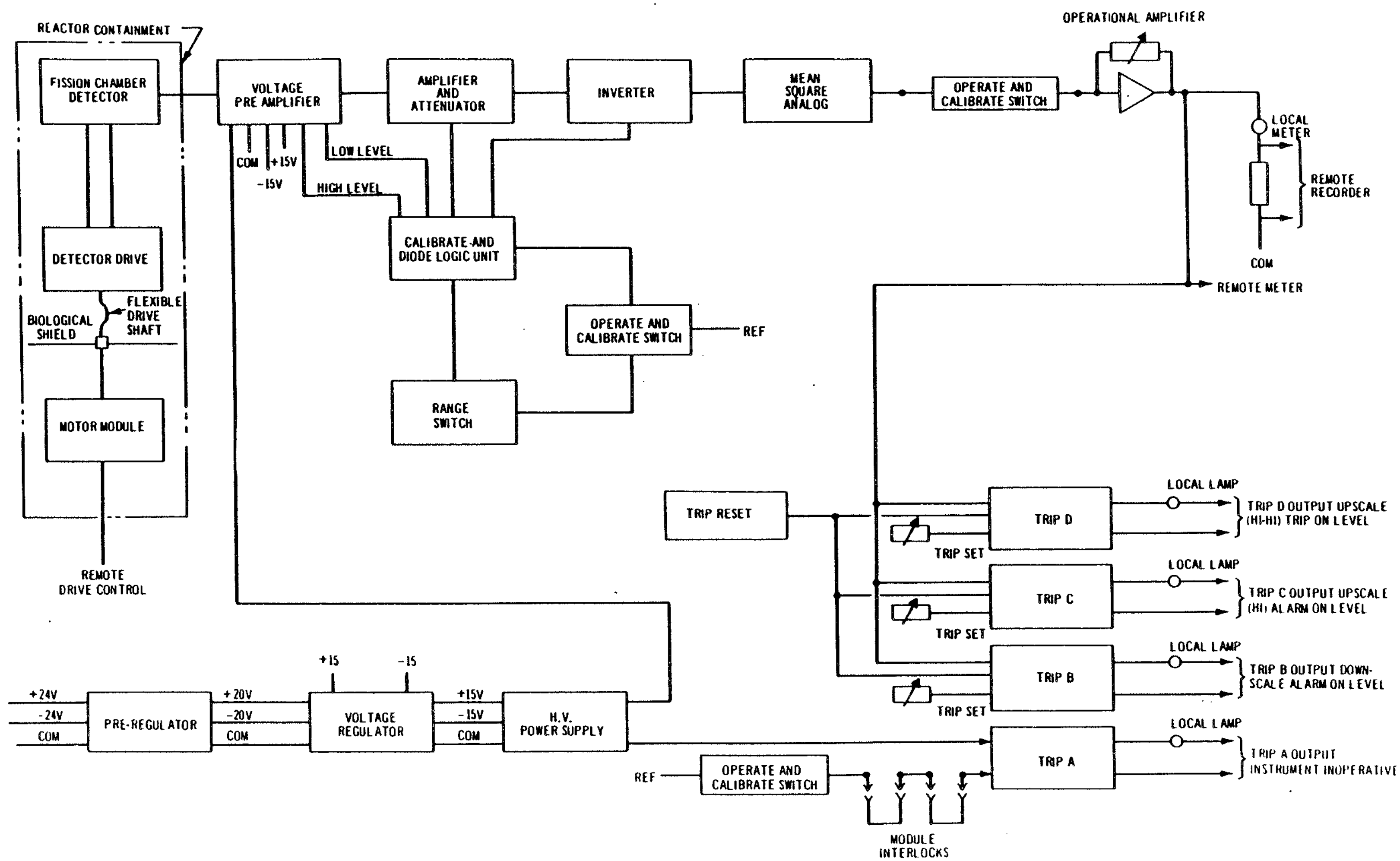

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FIGURE 7.6-18

FUNCTIONAL BLOCK DIAGRAM OF INTERMEDIATE RANGE MONITOR CHANNEL

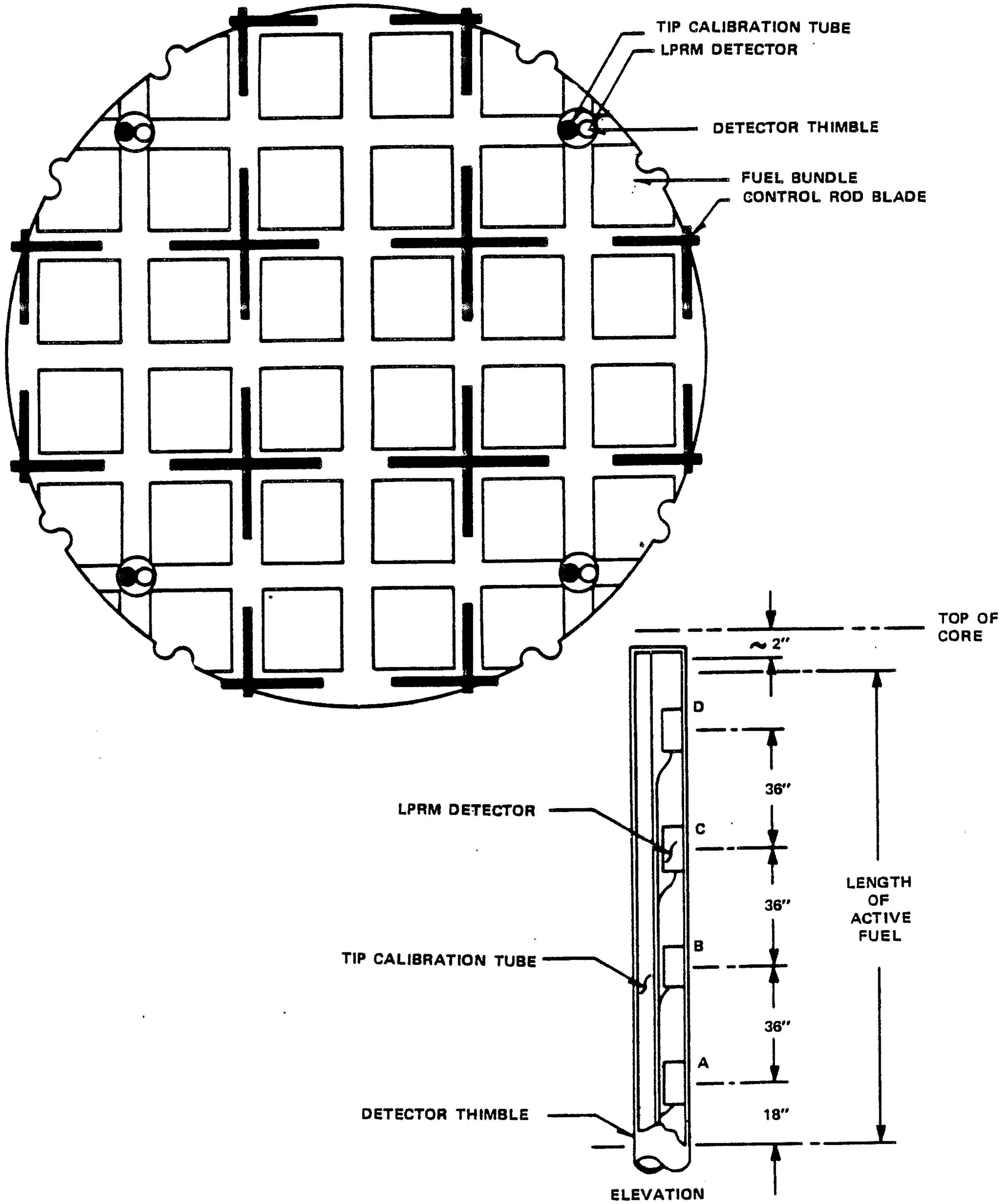

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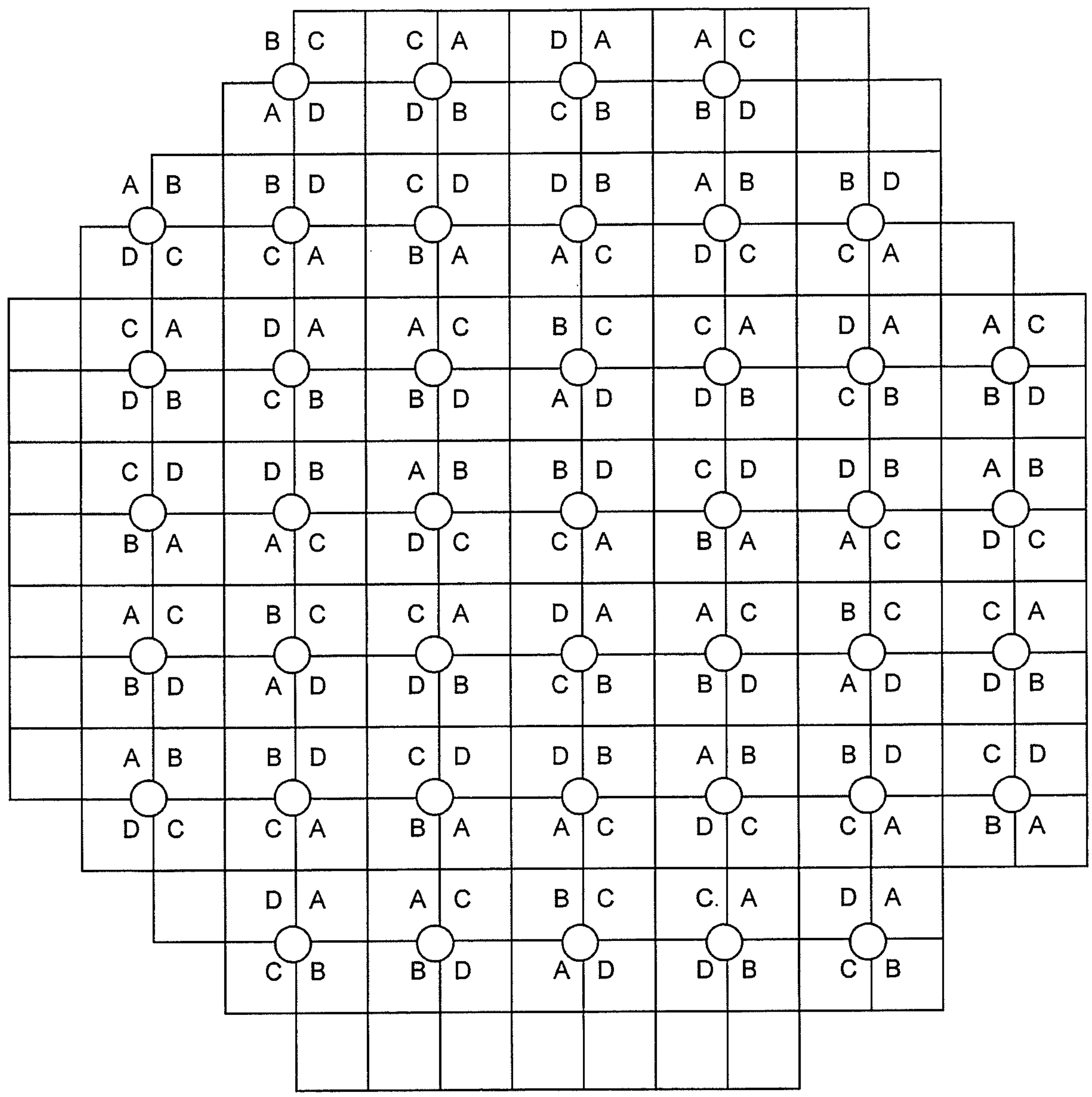
FIGURE 7.6-19

POWER RANGE MONITOR DETECTOR ASSEMBLY LOCATION



☐ CENTRAL CONTROL ROD

UPPER LEFT LETTER IS LPRM CHAMBER ASSIGNED TO APRM 1

UPPER RIGHT LETTER IS LPRM CHAMBER ASSIGNED TO APRM 2

LOWER RIGHT LETTER IS LPRM CHAMBER ASSIGNED TO APRM 3

LOWER LEFT LETTER IS LPRM CHAMBER ASSIGNED TO APRM 4

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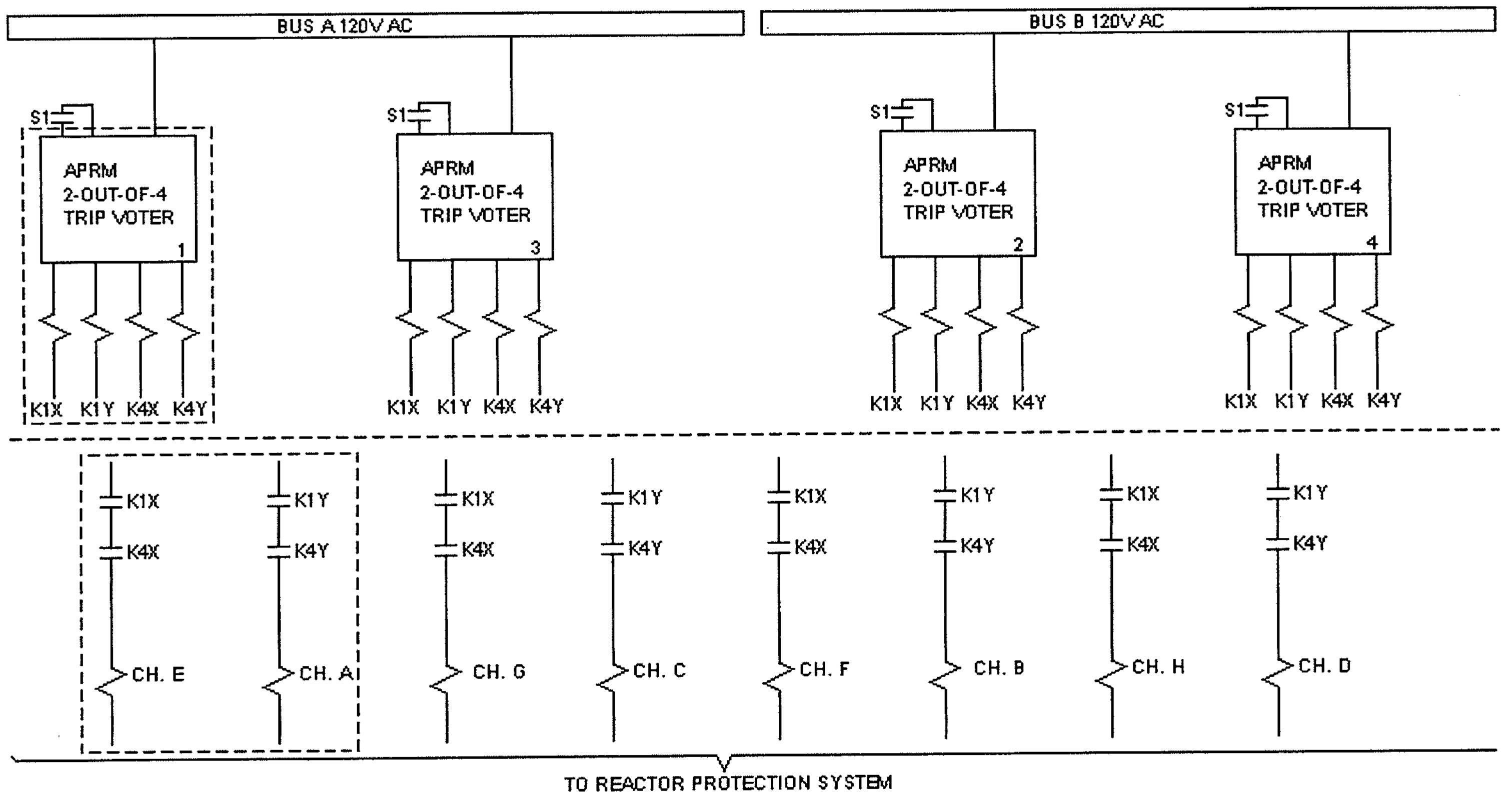
FIGURE 7.6-20

LOCAL POWER RANGE MONITOR TO AVERAGE POWER RANGE MONITOR ASSIGNMENT SCHEME

REV 9 04/99



LEGEND:

K1X & K1Y -- UPSCALE NEUTRON TRIP OR UPSCALE THERMAL TRIP OR INOP AND NOT BYPASSED

K4X & K4Y -- OPRM TRIP AND NOT BYPASSED

S1 -- REACTOR MODE SWITCH (CONTACT CLOSES IN RUN MODE)

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FIGURE 7.6-21

TYPICAL AVERAGE POWER RANGE MONITOR CIRCUIT ARRANGEMENT FOR REACTOR PROTECTION SYSTEM INPUT

REV 10 11/00

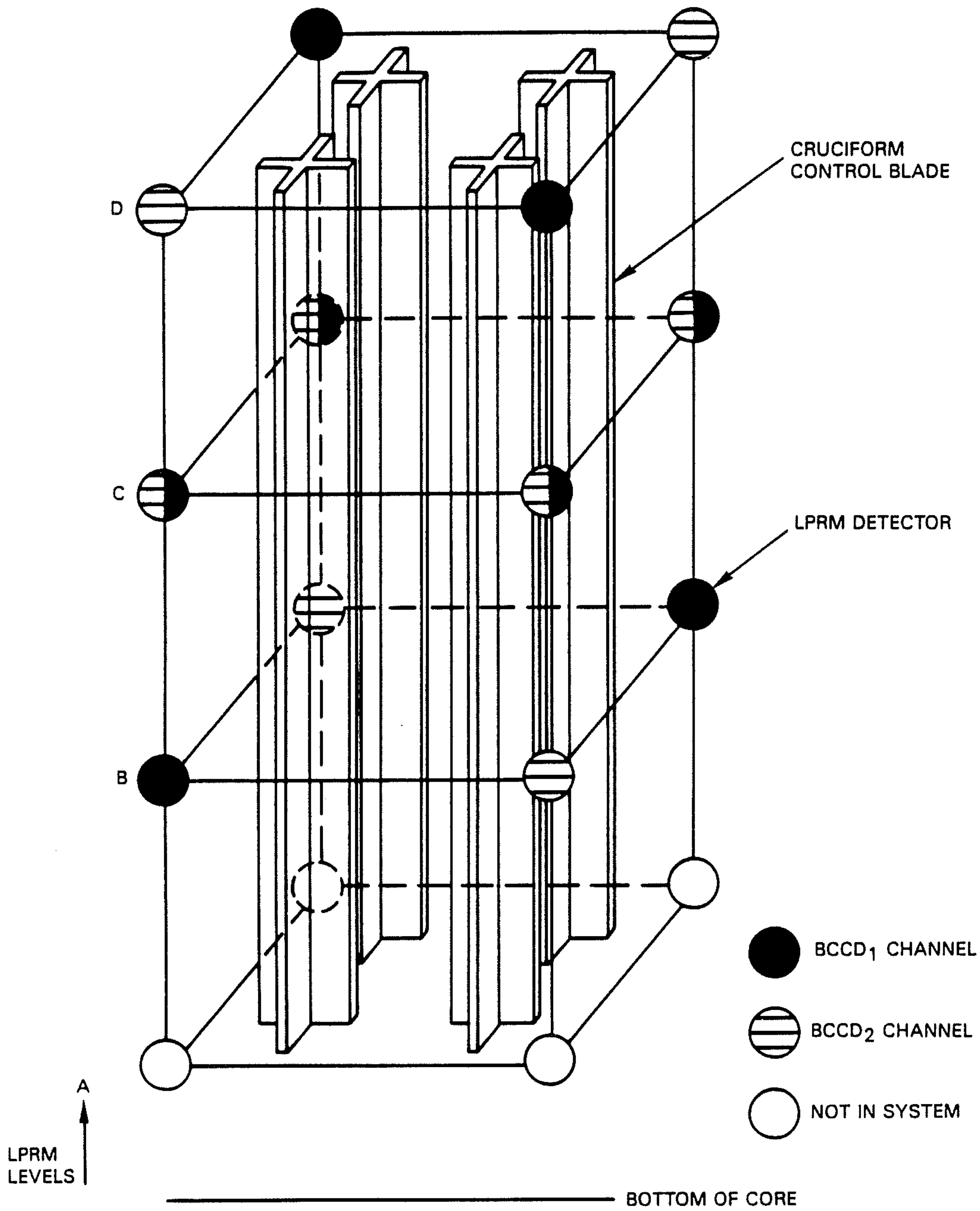

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FIGURE 7.6-22(a)

RBM $BCCD_1$/$BCCD_2$ LPRM ASSIGNMENT

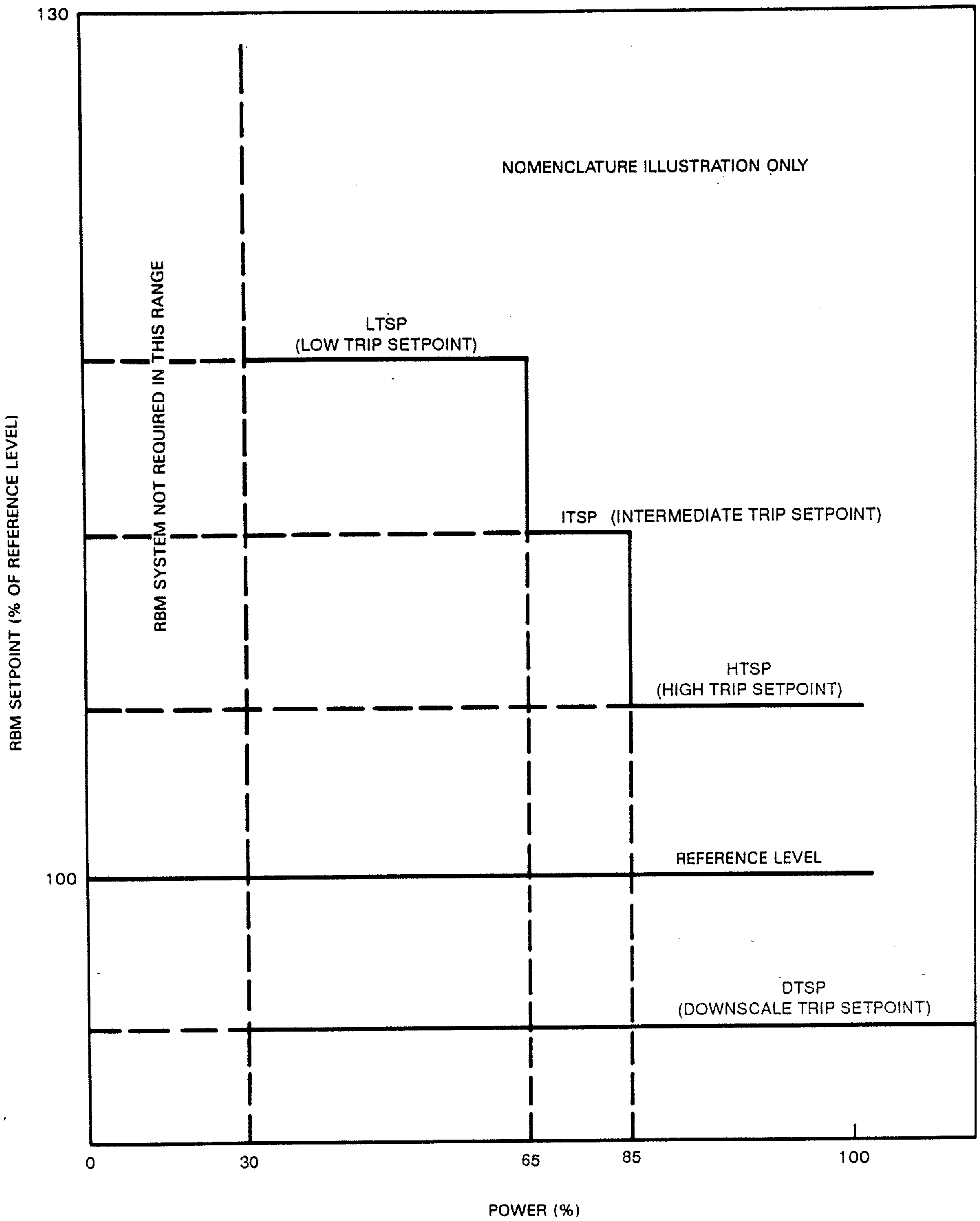

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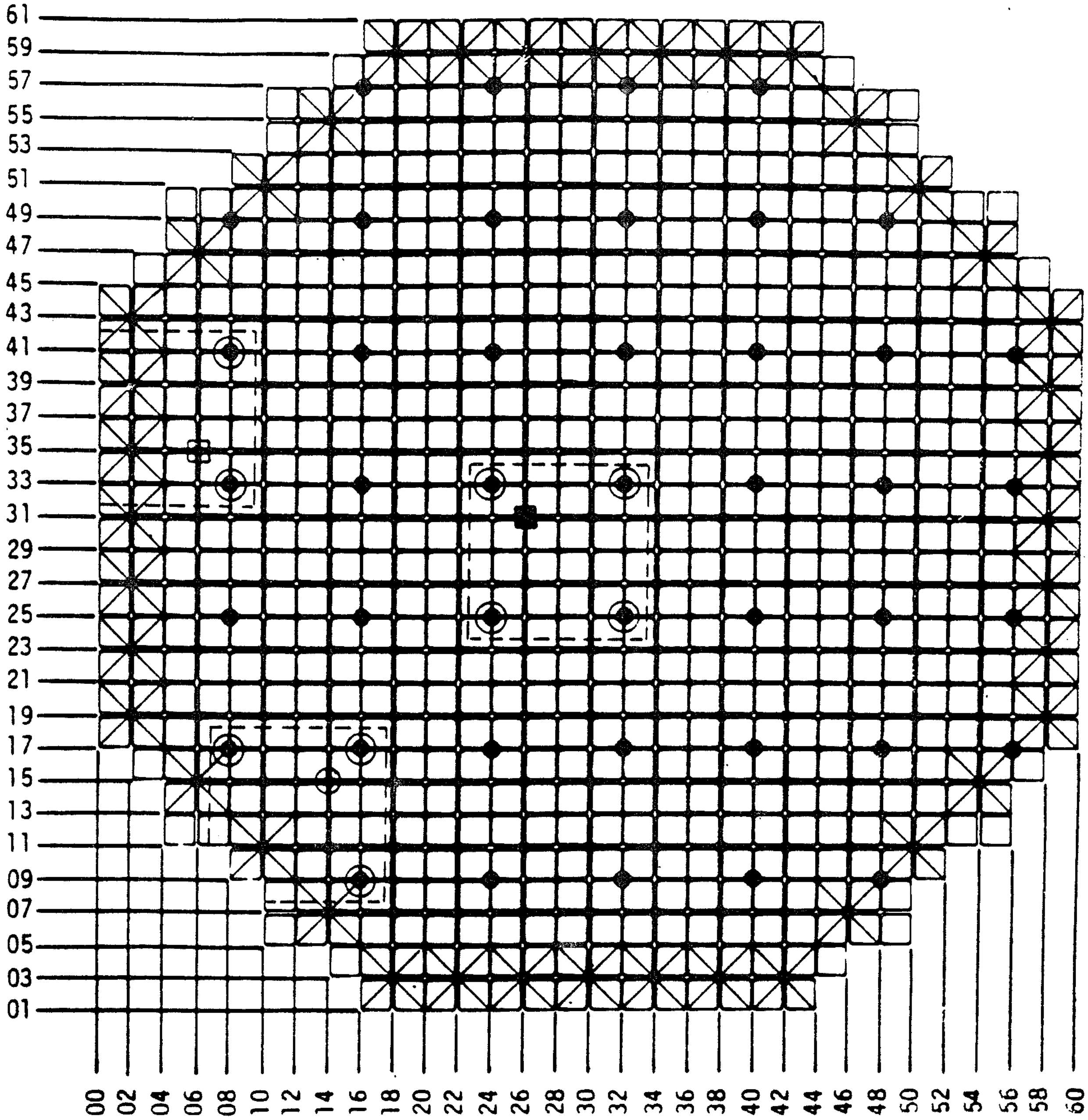
FIGURE 7.6-22(b)

TYPICAL POWER DEPENDENT RBM TRIP NOMENCLATURE



LPRM ASSEMBLY ASSIGNED TO RBM

ROD SELECTION RESULTING IN TWO-ASSEMBLY ASSIGNMENT

ROD SELECTION RESULTING IN THREE-ASSEMBLY ASSIGNMENT

ROD SELECTION RESULTING IN FOUR-ASSEMBLY ASSIGNMENT

RBM AUTOMATICALLY BYPASSED (READING ZEROED)

NOTE: ASSIGNMENT IS AUTOMATICALLY INITIATED ON ROD SELECTION.

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FIGURE 7.6-22

ASSIGNMENT OF LOCAL POWER RANGE MONITOR ASSEMBLIES TO ROD BLOCK MONITORS

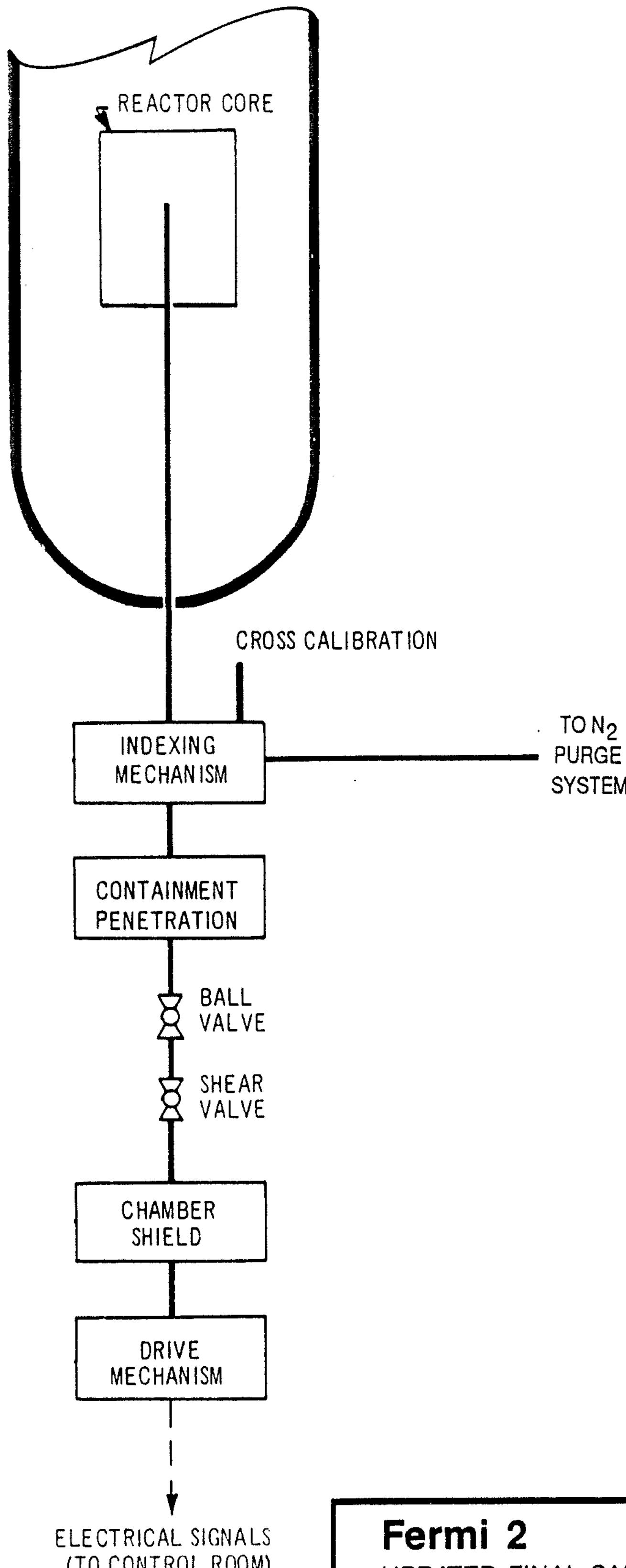

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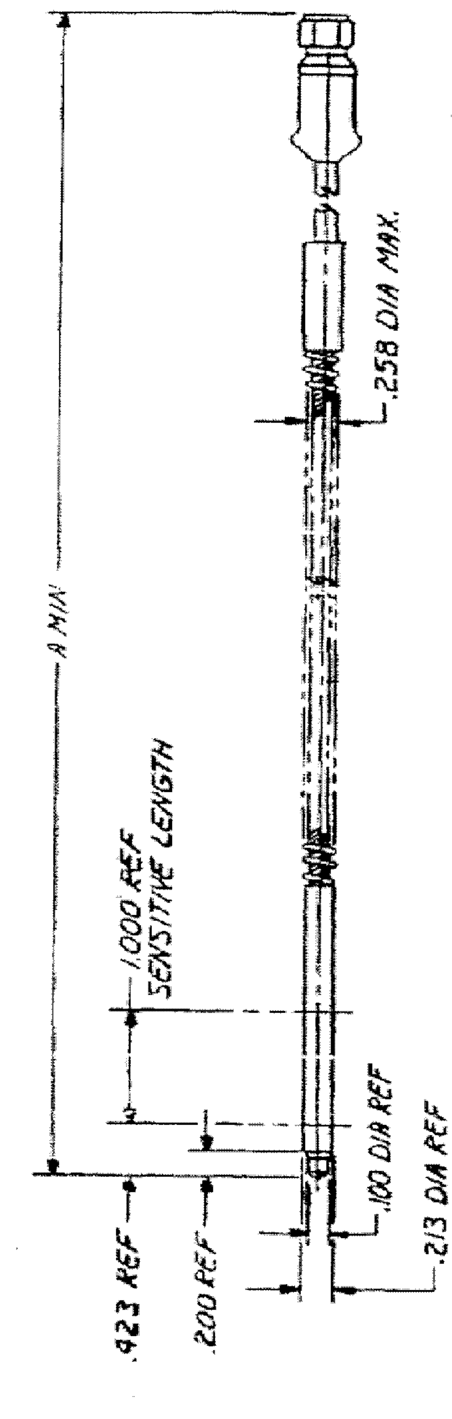
FIGURE 7.6-23

TRAVERSING IN-CORE PROBE SUBSYSTEM
BLOCK DIAGRAM



PART	CAT. NO.	A - FEET
1	169C8901G001	130
2	169C8904G002	150
3	169C8904G003	170

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FIGURE 7.6-24

TRAVERSING IN-CORE PROBE ASSEMBLY

Figure Intentionally Removed
Refer to Plant Drawing I-2420-01

Figure Intentionally Removed
Refer to Plant Drawing I-2420-02

Figure Intentionally Removed
Refer to Plant Drawing I-2430-01

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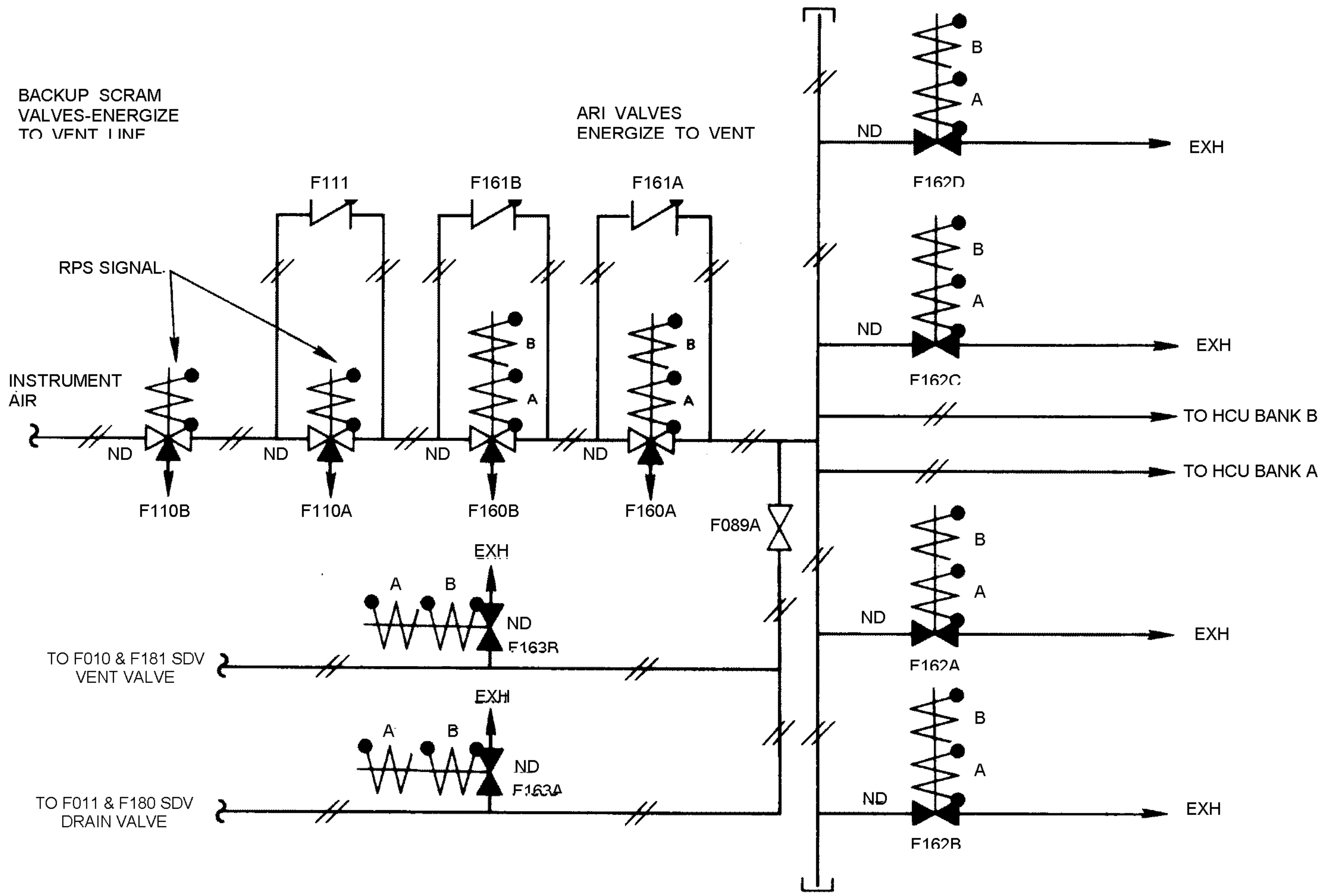
FIGURE 7.6-26

TURBINE BUILDING CLOSED COOLING WATER
PUMP NORTH, CENTER, AND SOUTH LOGIC DIAGRAM

FIGURES 7.6-27 THROUGH 7.6-35

ARE INTENTIONALLY DELETED

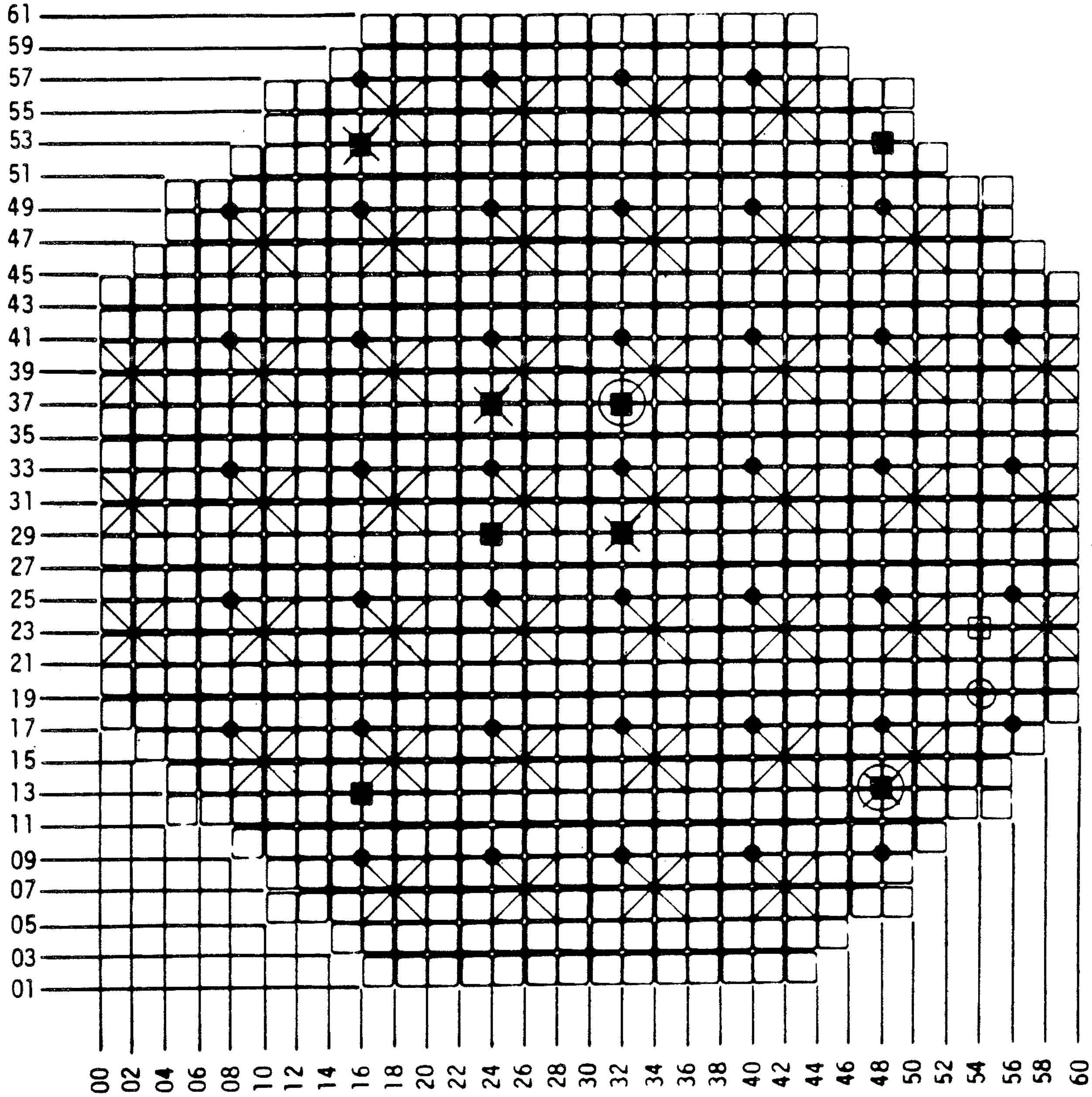


Fermi 2

UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 7.6-36

ALTERNATE ROD INSERTION VALVE ARRANGEMENT



IRM DETECTOR TRIP SYSTEM A

IRM DETECTOR TRIP SYSTEM B

CONTROL ROD WITHDRAWN

NEXT CONTROL ROD WITHDRAWN IN SEQUENCE

CONTROL ROD WITHDRAWN OUT OF SEQUENCE

IRM DETECTOR BYPASSED

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FIGURE 7.6-37

CONTROL ROD WITHDRAWAL ERROR

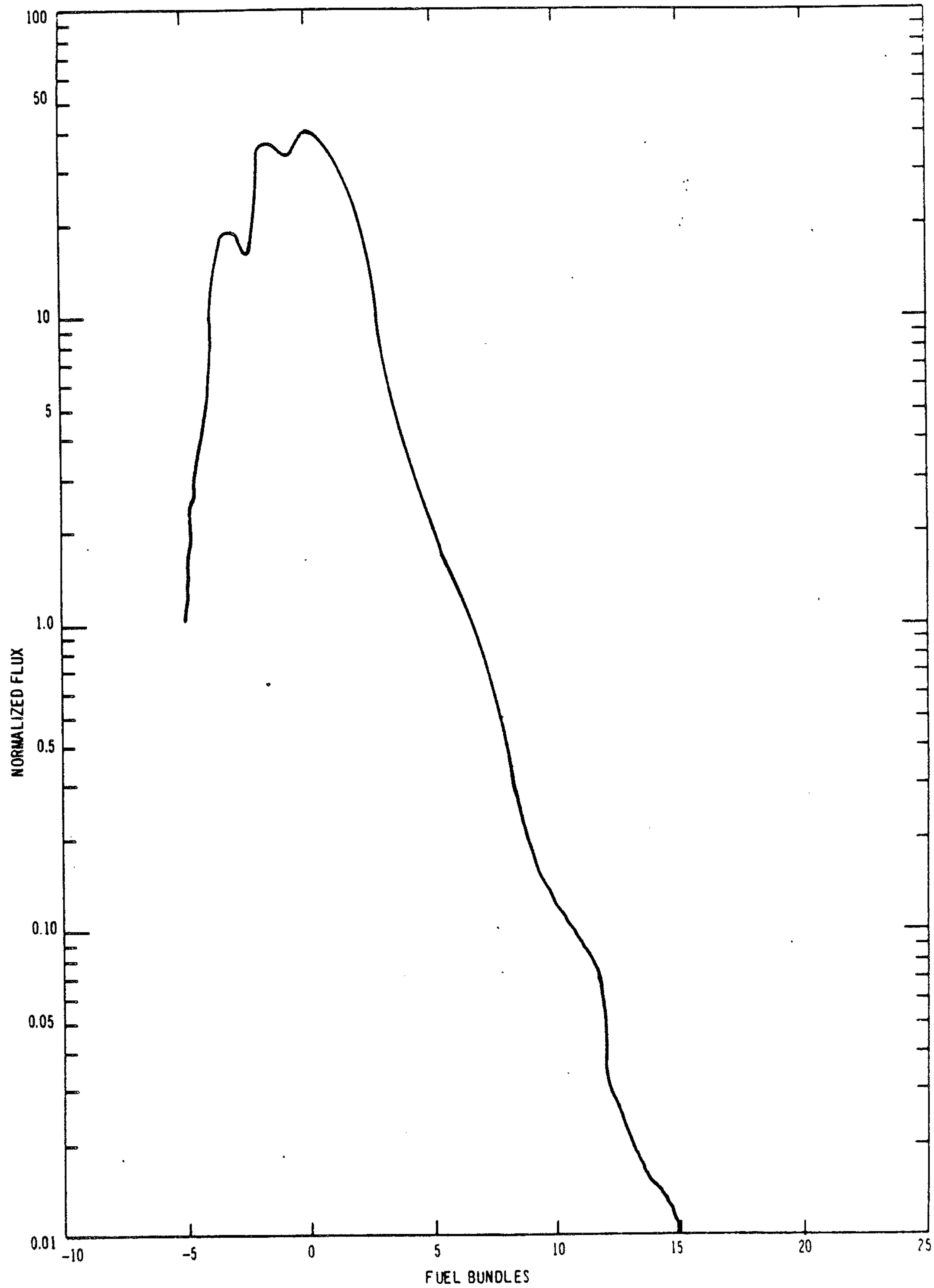

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FIGURE 7.6-38

NORMALIZED FLUX DISTRIBUTION FOR ROD WITHDRAWAL ERROR

FIGURES 7.6-39 THROUGH 7.6-40
ARE INTENTIONALLY DELETED

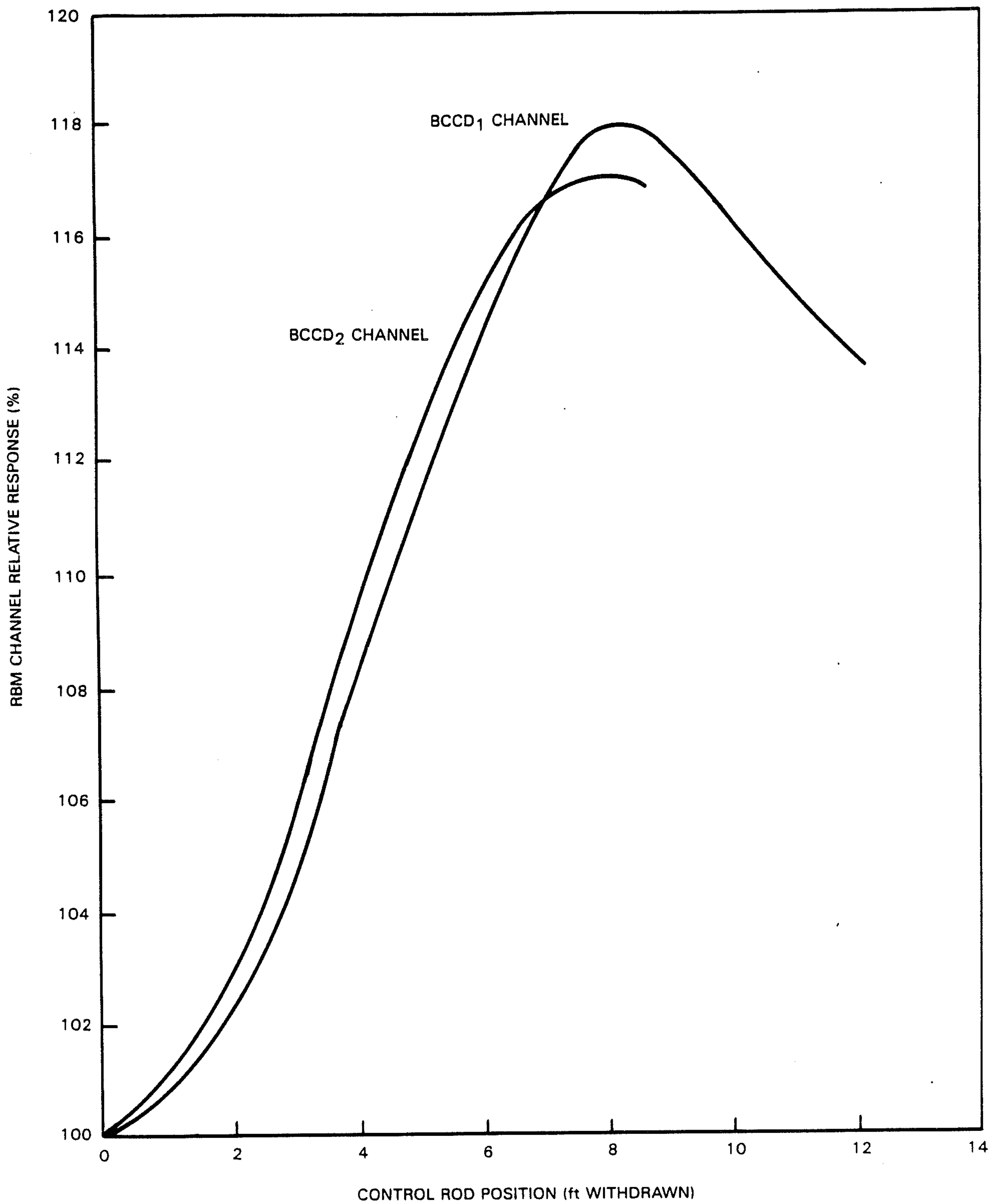

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FIGURE 7.6-41

TYPICAL RBM CHANNEL RESPONSES, LPRM ASSIGNMENT, NO FAILED LPRMs

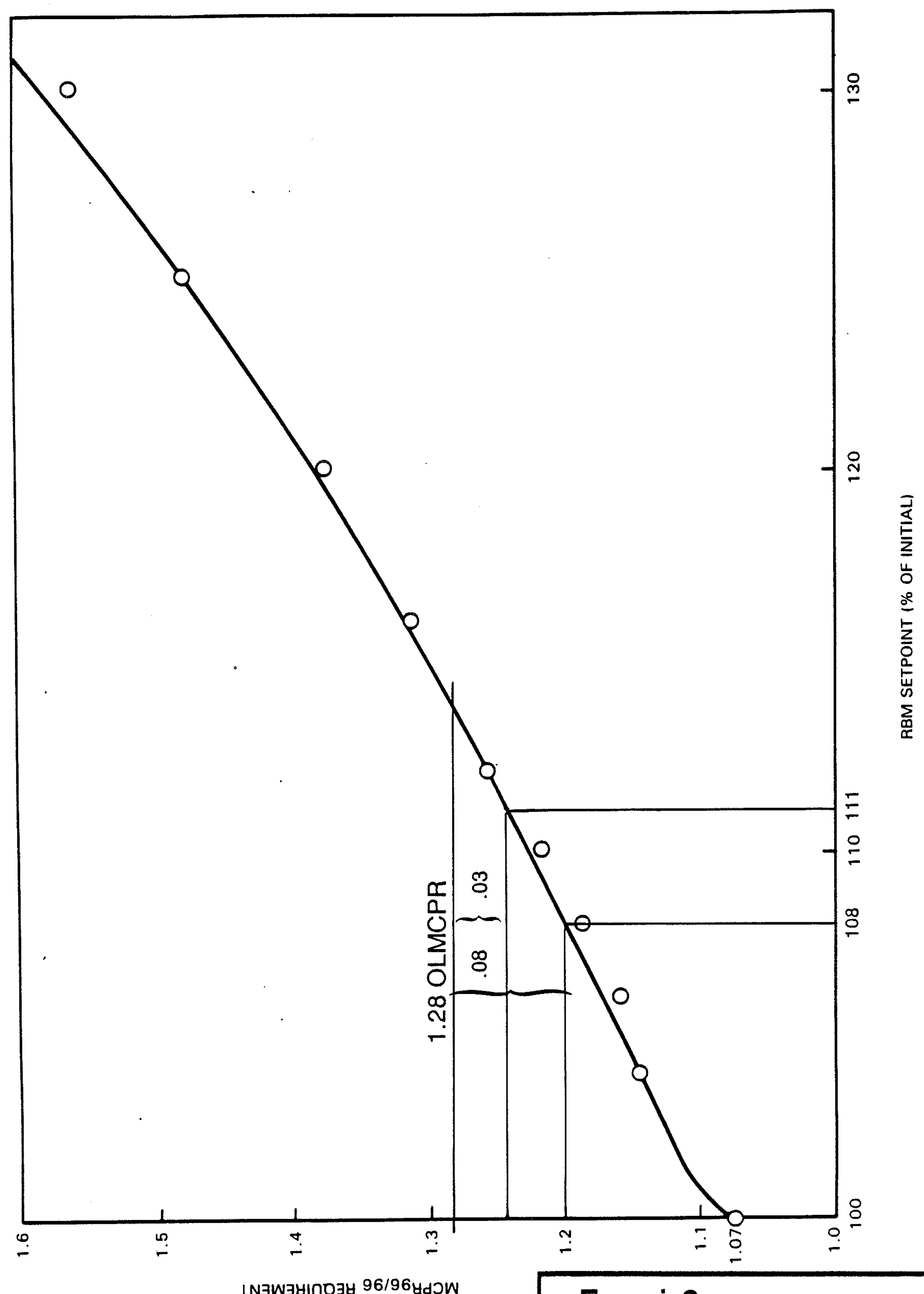

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FIGURE 7.6-42

TYPICAL DESIGN BASIS RWE MCPR REQUIREMENT VERSUS RBM SETPOINT

7.7 CONTROL SYSTEMS NOT REQUIRED FOR SAFETY

7.7.1 Description

This subsection discusses control systems whose functions are not essential for the safety of the plant. These systems are the reactor manual control system (RMCS), recirculation flow control system (RFCS), feedwater control system, pressure regulator and turbine-generator controls, and the radwaste processing system controls.

7.7.1.1 Reactor Manual Control System Instrumentation and Control

7.7.1.1.1 Identification

The RMCS instrumentation and control consists of the electrical circuitry, switches, indicators, and alarm devices provided for operational manipulation of the control rods and the surveillance of associated equipment. This system includes the interlocks that inhibit rod movement (rod block) under certain conditions. The RMCS does not include any of the circuitry or devices used to automatically or manually scram the reactor; these devices are discussed in Sections 7.2 and 7.6. In addition, the mechanical devices of the control rod drive (CRD) and the CRD hydraulic system are not included in the RMCS. The latter mechanical components are described in Subsection 4.5.2.

7.7.1.1.1.1 Function

The objective of the RMCS is to provide the operator with the means for changing reactor power by manipulating the control rods.

7.7.1.1.1.2 Classification

This system is a power generation system, nonessential for safety, and is classified in Chapter 3.

7.7.1.1.2 Power Sources

7.7.1.1.2.1 Normal

The RMCS receives its power from the 120-V ac instrumentation and control power buses, either bus A or bus B. Each of these buses receives its normal power supply from the appropriate 480-V ac engineered safety feature (ESF) bus as described in Subsection 8.3.1. One subsystem, the control rod position indication system, is powered by the 120-V ac instrument bus, as described in Subsection 8.3.1.

7.7.1.1.2.2 Alternate

On loss of normal auxiliary power, the station diesel generator provides backup power to the 480-V ac ESF bus and the 120-V ac instrument bus.

7.7.1.1.3 Equipment Design

7.7.1.1.3.1 General

Figure 4.5-15 shows the layout of the CRD hydraulic system. Figure 7.7-1 shows the functional arrangement of devices for the control of components in the CRD hydraulic system. Although the figures also show the arrangement of scram devices, these devices are not part of the RMCS.

Control rods are moved by admitting water, under pressure, from a CRD water pump into the appropriate end of the CRD cylinder. The pressurized water forces the piston, which is attached by a connecting rod to a control rod, to move.

Three modes of control rod operation are used: insert, withdraw, and settle. Four solenoid-operated valves are associated with each control rod to accomplish the actions required for the operational modes. The valves control the path the CRD water takes to the cylinder. The RMCS controls the valves.

The settle mode of control rod operation is provided to decelerate the control rod at the end of either an insert cycle or a withdraw cycle. The settle action smooths out the control rod movement and prolongs the life of the CRD hydraulic system components. During the settle mode, the withdraw valve associated with the settle operation is opened or remains open while the other three solenoid-operated valves are closed. During an insert cycle, the settle action vents the pressure from the insert drive water supply line to the exhaust header, thus gradually reducing the differential pressure across the drive piston of the selected rod. During a withdraw cycle, the settle action holds open the discharge path for withdraw water while the withdraw drive water supply is shut off. This also allows for a gradual reduction in the differential pressure across the control drive piston. After the control rod has slowed down, the collet fingers engage the index tube and lock the rod in position.

The arrangement of control rod selection pushbuttons and circuitry permits the selection of only one control rod at a time for movement. A rod is selected for movement by depressing a button for the desired rod on the reactor control benchboard in the main control room (Figure 7.5-1).

The direction in which the selected rod moves is determined by the position of a switch, called the "rod movement" switch, which is also located on the reactor control benchboard. This switch has "rod-in" and "rod-out-notch" positions and returns by spring action to the "off" position. The rod selection circuitry is arranged so that a rod selection is sustained until the movement cycle of the selected rod has been completed. Reversion to the no-rod-selected condition is not possible, except for loss of control-circuit power until any moving rod has completed the movement cycle.

7.7.1.1.3.2 Insert Cycle

The following is a description of the detailed operation of the RMCS during an insert cycle. The response of a selected rod when the various commands are transmitted has been explained in Subsection 7.7.1.1.3.1. Figure 7.7-1 can be used to follow the sequence of an insert cycle.

A three-position rod movement switch is provided on the reactor control benchboard. The switch has a "rod-in" position, a "rod-out-notch" position, and an "off" position. The switch returns by spring action to the "off" position. When a control rod is selected for movement, the operator places the rod movement switch in the "rod-in" position and then releases the switch. This action energizes the insert command for a limited time. Just before the insert command is removed, the settle command is automatically energized for a limited time. The insert command time setting and the rate of drive water flow provided by the CRD hydraulic system determine the distance traveled by a rod. The time setting results in a one-notch (6 in.) insertion of the selected rod for each momentary application of a "rod-in" signal from the rod movement switch. Continuous insertion of a selected control rod is possible by holding the rod movement switch in the "rod-in" position.

A second switch can be used to initiate insertion of a selected control rod. This switch is the "rod-out-notch-override" switch and is called the RONOR switch. The RONOR switch has three positions: "emergency-in," "notch override," and "off." The switch returns to the "off" position by spring action. By holding the RONOR switch in the "emergency-in" position, the logic maintains the insert command in a continuously energized state to cause continuous insertion of the selected control rod.

7.7.1.1.3.3 Withdraw Cycle

This subsection describes the detailed operation of the RMCS during a withdraw cycle. The response of a selected rod when the various commands are transmitted has been explained in Subsection 7.7.1.1.3.1. Figure 7.7-1 can be used to follow the sequence of a withdraw cycle.

When a control rod is selected for movement, the operator places the rod movement switch in the "rod-out-notch" position, which energizes the insert commands for a short time. Energizing the insert command at the beginning of the withdraw cycle is necessary to allow the collet fingers to disengage the index tube.

When the insert command is deenergized, the withdraw and settle commands are energized for a controlled period of time. The withdraw command is deenergized before the settle command; this tends to decelerate the selected rod. When the settle command is deenergized, the withdraw cycle is complete. This withdraw cycle is the same whether the rod movement switch is held continuously in the "rod-out-notch" position or is released. The timer that controls the withdraw cycle is set so that the rod travels one notch (6 in.) per cycle. Provisions are included to prevent further control rod motion in the event of timer failure.

A selected control rod can be continuously withdrawn if the rod movement switch is held in the "rod-out-notch" position at the same time that the RONOR switch is held in the "notch-override" position. When both switches are held in these positions, the withdraw and settle commands are continuously energized.

7.7.1.1.3.4 Control Rod Drive Hydraulic System Control

A motor-operated pressure control valve, two air-operated flow control valves, and four solenoid-operated stabilizer valves are included in the CRD hydraulic system to maintain smooth and regulated system operation. These devices are shown in Figure 4.5-15. The motor-operated pressure-control valve is positioned by manipulating a pushbutton in the main control room. The pushbuttons for this valve are located close to the pressure indicator that responds to the pressure changes caused by the movements of the valve. The air-operated flow control valves are automatically positioned in response to signals from an upstream flow measuring device. The stabilizer valves are automatically controlled by the energization of the insert and withdraw commands. The control scheme is shown in Figure 7.7-1.

There are two drive-water pumps, one of which is a spare. They are controlled by switches in the main control room. Each pump automatically stops on indication of low suction pressure.

7.7.1.1.3.5 Rod Block Interlocks

General

Figure 7.7-1 shows the general functional arrangement of the rod block interlocks used in the RMCS.

To achieve an operationally desirable performance objective where most failures of individual components would be easily detected or would not disable the rod movement inhibiting functions, the rod block logic circuitry is arranged as two similar logic circuits. These circuits are energized when control rod movement is allowed. Each logic circuit receives input trip signals from a number of trip channels, and each logic circuit can provide a separate rod block signal to inhibit rod withdrawal.

The rod block circuitry is effective in preventing rod withdrawal, if required, during both normal (notch) withdrawal and continuous withdrawal. If a rod block signal is received during a rod withdrawal, the control rod is automatically stopped at the next notch position, even during a continuous rod withdrawal.

The components used to initiate rod blocks in combination with refueling operations provide rod block trip signals to these same rod block circuits. These refueling rod blocks are described in Subsection 7.6.1.1.

Rod Block Functions

The following discussion describes the various rod block functions and explains the intent of each function. The instruments used to sense the conditions for which a rod block is provided are discussed in Subsection 7.6.1.13. The rod block functions provided specifically for refueling situations are described in Subsection 7.6.1.1.

With the mode switch in the SHUTDOWN position, no control rod can be withdrawn. This enforces compliance with the intent of the shutdown mode.

The circuitry is arranged to initiate a rod block, regardless of the position of the mode switch, for the following conditions:

a. Any average power range monitor (APRM) upscale rod block alarm. The purpose of this rod block function is to avoid conditions that would require reactor protection system (RPS) action if allowed to proceed. The APRM upscale rod block alarm setting is selected to initiate a rod block before the APRM high neutron flux scram setting is reached

b. Any APRM inoperative alarm. This ensures that no control rod is withdrawn unless the average power range neutron monitoring channels are either in service or are correctly bypassed

c. Either rod block monitor (RBM) upscale alarm. This function is provided to stop the erroneous withdrawal of a control rod so that local fuel damage does not result. Although local fuel damage poses no significant threat in terms of radioactive material released from the nuclear system, the trip setting is selected so that no local fuel damage results from a single control rod withdrawal error during power range operation

d. Either RBM inoperative alarm. This ensures that no control rod is withdrawn unless the RBM channels are in service or are correctly bypassed

e. Any APRM indicating recirculation flow upscale. This ensures that no control rod is withdrawn unless the recirculation flow functions, which are necessary for the proper operation of APRM rod block function, are operable

f. Deleted

g. Scram discharge volume high water level. This ensures that no control rod is withdrawn unless enough capacity is available in the scram discharge volume to accommodate a scram. The setting is selected to initiate a rod block earlier than the scram that is initiated on scram discharge volume high water level

h. Scram discharge volume high water level scram trip bypassed. This ensures that no control rod is withdrawn while the scram discharge volume high water level scram function is out of service

i. The rod worth minimizer (RWM) can initiate a rod insert block and a rod withdrawal block. The RWM limits the worth of any control rod that could be dropped by regulating the withdrawal sequence. This system prevents the movement of an out-of-sequence rod in the 100 percent control rod density to the preset low power level, the RWM will allow only BPWS mode withdrawals or insertions. The rod block trip settings are based on the allowable control rod worth limits established for the design-basis control rod drop accident. Additional information on the RWM function is available in Subsection 7.6.1.20

j. Rod position information system malfunction. This ensures that no control rod can be withdrawn unless the rod position information system is in service

k. Rod movement timer malfunction during withdrawal. This ensures that continuous withdrawal of a control rod does not result from failure of the normal rod timer during the withdrawal portion of the timing sequence.

With the mode switch in the RUN position, any of the following conditions initiates a rod block:

a. Any APRM downscale alarm. This ensures that no control rod will be withdrawn during power range operation unless the average power range neutron monitoring channels are operating correctly or are correctly bypassed. All unbypassed APRMs must be on scale during reactor operations in the RUN mode

b. Either RBM downscale alarm. This ensures that no control rod is withdrawn during power range operation unless the RBM channels are operating correctly or are correctly bypassed. An RBM which reads downscale (downscale alarm) and not automatically bypassed by the APRM low power feature is considered to have failed. This results in the rod withdrawal permissive not being given unless this RBM is bypassed.

With the mode switch in the STARTUP or REFUEL position, any of the following conditions initiates a rod block:

a. Any source range monitor (SRM) detector not fully inserted into the core when the SRM count level is below the retract permit level and any IRM range switch is on either of the two lowest ranges. This ensures that no control rod is withdrawn unless all SRM detectors are correctly inserted when they must be relied on to provide the operator with neutron flux level information

b. Any SRM upscale level alarm. This ensures that no control rod is withdrawn unless the SRM detectors are correctly retracted during a reactor startup. The rod block setting is selected at the upper end of the range over which the SRM is designed to detect and measure neutron flux

c. Any SRM downscale alarm. This ensures that no control rod is withdrawn unless the SRM count rate is above the minimum rate prescribed for low neutron flux level monitoring

d. Any SRM inoperative alarm. This ensures that no control rod is withdrawn during low neutron flux level operations unless neutron monitoring capability is available in that all SRM channels are in service or are correctly bypassed

e. Any intermediate range monitor (IRM) detector not fully inserted into the core. This ensures that no control rod is withdrawn during low neutron flux level operations unless proper neutron monitoring capability is available in that all IRM detectors are correctly located

f. Any IRM upscale alarm. This ensures that no control rod is withdrawn unless the intermediate range neutron monitoring equipment is correctly upranged during a reactor startup. This rod block also provides a means to stop rod withdrawal in time to avoid conditions requiring RPS action (scram) in the event that a rod withdrawal error is made during low neutron flux level operations

g. Any IRM downscale alarm except when range switch is on the lowest range. This ensures that no control rod is withdrawn during low neutron flux level operations unless the neutron flux is being correctly monitored. This rod block prevents the continuation of a reactor startup if the operator upranges the IRM too far for the existing flux level. Thus, the rod block ensures that the IRM is on scale if control rods are to be withdrawn

h. Any IRM inoperative alarm. This ensures that no control rod is withdrawn during low neutron flux level operations unless neutron monitoring capability is available in that all IRM channels are in service or are correctly bypassed.

Rod Block Bypasses

To permit continued power operation during repair or calibration of equipment for selected functions that provide rod block interlocks, the limited number of manual bypasses that are permitted are:

a. One SRM channel

b. Two IRM channels (one on bus A and one on bus B)

c. One APRM channel

d. One RBM channel.

The permissible IRM bypasses are arranged in two groups, each having an equal number of channels. One manual bypass is allowed in each group. The groups are chosen so that adequate monitoring of the core is maintained when one channel is bypassed in each group. The arrangement allows the bypassing of one IRM in each rod block logic circuit.

These bypasses are effected by positioning switches in the main control room. A light in the main control room indicates the bypassed condition.

An automatic bypass of the SRM detector position rod block is effected as the neutron flux increases beyond a preset low level on the SRM instrumentation. The bypass allows the detectors to be partially or completely withdrawn as a reactor startup is continued.

An automatic bypass of the RBM rod block occurs when the power level is below a preselected level or when a peripheral control rod is selected. Either condition indicates that local fuel damage is not threatened and that RBM action is not required.

The RWM rod block function is automatically bypassed when reactor power increases above a preselected value in the power range.

Arrangement of Rod Block Trip Channels

Half of the total neutron monitoring equipment (SRM, IRM, APRM, RBM) provides input to one of the two rod block logic circuits and the other half provides input to the other logic circuit. Two of the flow functions from each of the two recirculation loops provides a rod block signal to one logic circuit and the other two flow functions for each recirculation loop provides an input to the other logic circuit. Scram discharge volume high water level signals are provided as inputs into both of the two rod block logic circuits. Both rod block logic circuits sense when the high water level scram trip for the scram discharge volume is bypassed. The rod withdrawal block from the RWM trip affects both rod block logic circuits. The rod insert block from the RWM function prevents energizing the insert bus for both notch insertion and continuous insertion.

The APRM rod block settings are varied as a function of recirculation flow. The RBM rod block settings are power dependent. Analyses show that the selected settings are sufficient to avoid both RPS action and local fuel damage as a result of a single control rod withdrawal error. Mechanical switches in the SRM and IRM detector drive systems provide the position signals used to indicate that a detector is not fully inserted. Additional detail on all the neutron monitoring system (NMS) trip channels is available in Subsection 7.6.1.13.

The rod block from scram discharge volume high water level uses one nonindicating float switch installed on the scram discharge volume. A second float switch provides a main control room annunciation of increasing level.

7.7.1.1.3.6 Inspection and Testing

The RMCS can be routinely checked for correct operation by manipulating control rods using the various methods of control. Detailed testing and calibration can be performed by using standard test and calibration procedures for the various components of the reactor manual control circuitry.

7.7.1.1.4 Environmental Considerations

The RMCS is not required for safety functions, nor is it required to operate after the design-basis accident (DBA). The RMCS is required to operate in the normal plant environments for power generation purposes only.

The hydraulic control units are located in the reactor building. The logic, control units, and instrumentation readouts are located in the main control room. The control rod position detectors are located beneath the reactor pressure vessel (RPV) in Zone 3 of the primary containment. The normal design environments encountered in these areas are listed in Table 3.11-5.

7.7.1.1.5 Operational Consideration

7.7.1.1.5.1 Normal

The RMCS is totally operable from the main control room. Manual operation of individual control rods is possible with a jog switch to effect control rod insertion, withdrawal, or settle. Rod position indicators, described in Subsection 7.7.1.1.5.2, provide the necessary information to ascertain the operating state and position of all control rods. Conditions that prohibit control rod insertion are alarmed by the rod block annunciator.

7.7.1.1.5.2 Operator Information

Instrumentation

Table 7.7-1 gives information on instruments for the RMCS. A large rod information display on the vertical portion of the reactor control benchboard is patterned after a top view of the reactor core, as shown in Figure 7.5-1. The display allows the operator to acquire information rapidly by scanning. Colored windows provide an overall indication of rod pattern and allow the operator to quickly identify an abnormal indication. The following information for each control rod is presented in the display:

a. Rod fully inserted (green)

b. Rod fully withdrawn (red)

c. Rod identification (coordinate position, white)

d. Accumulator trouble (amber)

e. Rod scram (blue)

f. Rod drift (red).

Also available on digital operator display assemblies (ODAs), one for each two APRM channels, are local power range monitor (LPRM) readings as well as indications of LPRM low flux level and LPRM high flux level.

A separate, smaller display is located just below the large display on the vertical part of the benchboard. This display shows the positions of the control rod selected for movement and the positions of the other rods in the rod group. For display purposes, the control rods are considered in groups of four adjacent rods centered around a common core volume monitored by four LPRM strings. Rod groups at the periphery of the core may have less than four rods. The small rod display shows the positions, in digital form, of the rods in the group to which the selected rod belongs. A white light indicates which of the four rods is selected for movement. On either side of the four-rod position display are indicated (on RBM ODAs - one for each RBM) the readings of the 16 LPRM channels (four LPRM strings) surrounding the core volume common to the four rods of the group. The four-rod display allows the operator to easily focus his attention on the core volume of concern during rod movements. This arrangement eliminates the problems inherent in larger, full core displays where the operator must concentrate his attention on a small portion of a large display. The four-rod display also allows the operator to quickly investigate any volume of the core by simply selecting a control rod located in that volume.

The position signals of selected control rods, together with a rod identification signal, are provided as hardwired digital signals to the rod worth minimizer (RWM). These signals are then provided by the RWM as digital data to the Integrated Plant Computer System (IPCS) via a GE NUMAC LINK component of the 3D-Monicore Computer System (3DM).

Control rod position information is obtained from reed switches in the CRD that open or close as a magnet attached to the rod drive piston passes during rod movement. Reed switches are provided at each 3-in. increment of piston travel. Because a notch is 6 in. long, indication is available for each half-notch of rod travel. The reed switches located at the half-notch positions for each rod are used to indicate rod drift. Both the rod selected for movement and the rods not selected for movement are monitored for drift. A drifting rod is indicated by an alarm and red light in the main control room.

The rod drift condition is also monitored by the IPCS. Reed switches are provided at locations that are beyond the limits of normal rod movement. If the rod drive piston moves to these overtravel positions, an alarm is sounded in the main control room. The overtravel alarm provides a means to verify that the drive-to-rod coupling is intact because the drive cannot be physically withdrawn to the overtravel position when the coupling is in its normal condition. Coupling integrity can be checked by attempting to withdraw the drive to the overtravel position.

The following main control room lights are provided to enable the operator to be aware of the conditions of the control rod drive hydraulic system and the control circuitry:

a. Stabilizer valve selector switch position

b. Insert command energized

c. Withdraw command energized

d. Settle command energized

e. Withdrawal not permissive

f. Notch override

g. Pressure control valve position

h. Flow control valve position

i. Drive water pump low suction pressure (alarm only)

j. Drive water filter high differential pressure (alarm only)

k. High pressure of charging water to accumulator (alarm only)

l. CRD temperature

m. Scram discharge volume not drained (alarm only)

n. Scram valve pilot air heater high/low pressure (alarm only).

7.7.1.2 Recirculating Flow Control System Instrumentation and Control

7.7.1.2.1 System Identification

7.7.1.2.1.1 Function

The objective of the RFCS is to control reactor power level, over a limited range, by controlling the flow rate of the reactor recirculating water (Figure 5.5-2). The control involves varying the speed of the recirculation pumps by varying the voltage and frequency of the ac supply to each pump motor. The ac supply is provided by a motor-generator set for each pump. Each motor-generator set consists of a squirrel-cage induction motor driving a variable-frequency generator through a variable-speed converter. The generator output is varied by varying the slip within the converter. Since flow rate is directly proportional to pump speed which is proportional to generator speed, generator speed is considered the controlled variable of the system. Manual input to the individual loop controllers is the reference input to the system.

The RFCS is also designed to limit the range and rate of change of pump speed, and to otherwise ensure proper operation and equipment protection.

7.7.1.2.1.2 Classification

This system is a power generation system, nonessential for safety, and is classified in Chapter 3.

7.7.1.2.2 Power Sources

The RFCS consists of Remote Distributed Control System – Reactor Recirculation (Remote DCS-RR) and Remote Input/Output – Reactor Recirculation (Remote I/O-RR). The RFCS has redundant power supplies and redundant processing units. Both the flow loops A and B are controlled by Remote DCS-RR. The Remote DCS-RR is powered by 120 V ac instrument and control bus and 125 V dc power and Remote I/O-RR is powered by 120 V ac Bus A and Bus B for redundancy.

7.7.1.2.3 Equipment Design

7.7.1.2.3.1 General

Reactor recirculation flow is changed by adjusting the speed of the two reactor recirculating pumps by adjusting the frequency and voltage of the electrical power supplied to the recirculation pump motors.

Control of pump speed, and thus core flow, is such that at various control rod patterns, different power level changes can be accommodated. Refer to Section 4.4.3.5 for a discussion of BWR operation with recirculation flow control.

An increase in recirculation flow temporarily reduces the void content of the moderator by increasing the flow of coolant through the core. The additional neutron moderation increases the reactivity of the core, causing the reactor power level to increase. The increased steam generation rate increases the steam volume in the core with a consequent negative reactivity effect, and a new steady-state power level is established. When recirculation flow is reduced, the power level is reduced in the reverse manner.

Figure 7.7-2 is a simplified illustration of the RFCS. Figure 7.7-3 shows the system functional control diagram (FCD).

Each recirculation pump motor has its own motor-generator set for a power supply. A variable-speed converter is provided between the motor and generator of the motor-generator set. To change the speed of the reactor recirculation pump, the variable-speed converter varies the generator speed, which changes the frequency and magnitude of the voltage supplied to the pump motor so that the desired pump speed is attained. The RFCS uses a demand signal from the operator.

The RFCS is a digital microprocessor based distributed control system (DCS). The DCS features modular design consisting of input/output, redundant processor and communication. The DCS equipment is located in the relay room, control room and reactor building 4th floor.

The operator interface consists of manual/automatic (M/A) controllers, bar graph indicators, recorders, pushbuttons, control switches, indicating lights and video display. The controls permit the operator to operate in manual or automatic mode. An individual, independent M/A controller will provide speed control for each reactor recirculation pump. The manual mode of operation bypasses closed loop speed control. The M/A controller is placed in AUTO for control loop regulation by the feedback signal of generator speed, subject to the limiters. A manual runback indicating pushbutton is provided in the control room to manually runback the recirculation pumps. The M/A controller display includes speed setpoint, generator speed, and speed demand signal. A flat panel display with a touch screen is provided in the control room to access various system parameter data.

The system locks up the scoop tube on fault conditions. The system has the capability to monitor the initiation and clearance of the fault condition.

Each MG set has three magnetic pick-up speed sensors for redundancy, which provide speed feedback inputs into the Remote DCS-RR. The system transfers the M/A controller to MANUAL mode on either loss of two speed signals or communication failure with DCS processors.

A provision has been included in the Fermi 2 design to trip the recirculation pump motor-generator field breakers and drive motor breakers on receipt of ATWS initiation signals. The Fermi 2 RPT design employs two trip coils in each recirculation system motor generator set field breaker and drive motor breaker. This design provides redundant trips of both motor-generator sets following the transient and failure-to-scram. To minimize the possibility of breakers being tripped inadvertently, the automatic trip signals are arranged in two-out-of-two logic.

The breaker automatic trip signal is a combined ARI/RPT logic. That is, a low reactor vessel water level (level 2) or high reactor vessel pressure signal will initiate the trip of both sets of field breakers. (Refer to Figure 7.7-3, sheet 4).

The RPT may be manually initiated by the same two pushbuttons in the control room (on a divisional basis) as ARI, the difference being that initiation of one division will trip both sets of breakers.

The RPT logic delays MG set field breaker trip on low reactor vessel water level for 9 seconds. This time delay was provided to account for the difference in the pump coastdown time if the field breaker is tripped rather than the motor-generator set drive motor, as was assumed in the LOCA analysis. The manual reset of the generator field breaker trip seal-in circuit does not have any time delay due to the rapid operation of the circuit breaker. The manual reset of the drive motor breakers will have a time delay because the reset logic is ARI logic.

7.7.1.2.3.2 <u>Motor-Generator Sets</u>

Each of the two motor-generator sets and its controls are identical; therefore, only one description is given of the motor-generator set. Figure 5.5-2 shows the general arrangement and rating of the motor-generator set. The motor-generator set can continuously supply power to the pump motor at any speed between approximately 19 percent and 96 percent of the drive motor speed. The motor-generator set is capable of starting the pump and accelerating it from standstill to the desired operating speed when the pump motor thrust bearing is fully loaded by reactor pressure acting on the pump shaft.

The main components of the motor-generator set are

a. <u>Drive motor</u> - The drive motor is an ac induction motor that drives the input shaft of the variable speed converter

b. <u>Generator</u> - The variable-frequency generator is driven by the output shaft of the variable-speed converter. During normal operation, the generator exciter is powered by the drive motor. The excitation of the generator is provided from an auxiliary source during pump startup

c. <u>Variable-speed converter and actuation device</u> - The variable-speed converter transfers power from the drive motor to the generator. The variable-speed converter actuator automatically adjusts the slip between the converter input shaft and output shaft as a function of the signal from the speed controller. If the speed controller signal is lost, the actuator causes the speed converter slip to remain "as is." Manual reset of the actuation device is required to return the speed converter to normal operation.

7.7.1.2.3.3 Speed Control Configuration

The speed control system (Figure 5.5-2) controls the variable speed converters of both motor-generator sets. The micro-processor-based scoop tube positioner directly interfaces with the speed control system. The motor-generator sets can be manually controlled individually. The control system configuration for each motor-generator set consists of a manual automatic transfer station, a speed control function, a signal failure alarm, a startup mode function and a speed limiter. Components in the new speed control system contain I/O modules feeding the redundant main processing units. The control system is comprised of an arrangement of discrete modules which run the main processing unit. The operator interface is manual/automatic setpoint stations.

Speed Control

There is one speed control for each motor-generator set. The speed control system transmits the signal that adjusts the motor-generator set variable-speed converter. The speed control for each motor-generator set compares the setpoint signal from the operator station to the feedback signal from triple redundant magnetic speed sensors for each motor-generator set. The control system adjusts its output to the speed converter so that the speed feedback signal is made to equal the setpoint signal. The speed controller setpoint signal is received during automatic operation and during motor-generator set manual operation or during pump startup from the startup signal generator.

System Trouble Alarm

There is one system trouble alarm for each motor-generator set. The system trouble alarm actuates an alarm in the main control room and acts to prevent any change of slip within the variable-speed converter.

Startup Mode

There are triple redundant magnetic speed sensors for each motor-generator set. The triple redundant speed sensors supply the setpoint signal to the speed control system. This function sets the motor-generator set variable speed converter for approximately 50 percent recirculation pump speed.

Speed Limiter

There are four speed limiter functions for each motor-generator set. Number 1 limiter is an adjustable high limit. The speed control setpoint signal is automatically limited by the Number 1 limiter if the recirculation pump main discharge valve is not fully open or if the feedwater flow is less than 20 percent of rated flow. Number 2 or 3 limiter acts on the position demand to the scoop tube positioner and is actuated when a feedwater pump is tripped and level is below the low alarm setpoint (Number 2 limiter) or when both heater drain pumps are not pumping forward to the suction of the feed pumps (Number 3 limiter).

A manual defeat of runback 2 and 3 logic is used during startups, shutdowns and single loop operation. Number 4 limiter limits speed controller setpoint signal of operating pump following a trip of a single recirculation pump. The limiters are enabled during manual operation of the operator station. A manual runback indicating pushbutton is provided in the control room to manually runback the recirculation pumps.

7.7.1.2.3.4 Recirculation Loop Starting Sequence

Each recirculation loop is independently put into operation by operating the controls of each recirculation loop as follows:

a. Whenever the generator field breaker is open, the control system is automatically placed in startup mode. Startup mode bypasses the normal speed control circuits to position the variable-speed converter for startup. The minimum speed of the recirculation pumps is 20 percent as established by the mechanical stops. Startup operations of the plant are normally carried out with the recirculation pumps operating at approximately 30 percent speed. The power-versus-flow operating state for the reactor follows the 30 percent speed line for the normal control rod withdrawal sequence. (See Section 4.4.3.3.1 and Figure 4.4-3)

b. The starting sequence is manually initiated by placing the drive motor control switch for one motor-generator set in the start position.

c. Once the variable-speed converter has achieved its startup position, the following events occur:

    1. The auxiliary source of field excitation is engaged after a time delay

    2. The generator field breaker is closed after a time delay.

d. When the generator field breaker is closed, the manual/automatic setpoint station is automatically transferred to give the desired initial generator speed (typically <30 percent of rated speed) after the startup sequence is complete.

e. Deleted

f. After recirculation pump start is sensed by a combination of field breaker position and generator output current, the generator is automatically transferred to self-excitation

g. Recirculation flow is increased during startup by manually increasing recirculation pump speed

h. Deleted

7.7.1.2.3.5 Inspection and Testing

The motor-generator set, and the speed control system are functioning during normal power operation. Any abnormal operation of these components can be detected during operation. The components that do not continually function during normal operation can be tested and inspected for calibration and operability during scheduled plant shutdowns. All the RFCS components are tested and inspected according to the component manufacturer's recommendations. This can be done during scheduled shutdowns.

7.7.1.2.4 Environmental Considerations

The RFCS is not required for safety purposes, nor is it required to operate after the DBA. The system is required to operate in the normal plant environment for power generation purposes only. The following normal design environments are encountered by parts of the RFCS. The recirculation flow-control equipment in Zone 4 of the primary containment is the pump motor, which is subject to the environment specified in Table 3.11-5 under environmental conditions.

The control system hardware, operator controls, and instrumentation terminals are located in the main control room, relay room and reactor building (remote I/O) and are subject to the normal environments of these areas.

7.7.1.2.5 Operational Considerations

Indicators and alarms are provided to keep the operator informed of the status of the system so that he may quickly determine the location of malfunctioning equipment.

Temperature monitoring of equipment is recorded and alarmed if safe levels are exceeded. Indicators are provided to show pumping power requirements, motor-generator set speed, recirculation loop flow, valve positions, and analog control signal, all of which determine system status. Alarms are provided to alert the operator of malfunctioning control signals, excessive cooling water temperatures, inability to change pump speed, and the status of the motor-generator circulating lube-oil supply.

7.7.1.3 Feedwater Control System Instrumentation and Control

7.7.1.3.1 System Identification

7.7.1.3.1.1 Function

The feedwater control system automatically controls the flow of feedwater into the RPV so that the water in the vessel is maintained within predetermined levels during all modes of plant operation. The range of water level is based on the requirements of the steam separators, including limiting carryover and carryunder, which affects turbine performance and recirculation pump operation. The range of water level is also based on the need to prevent exposure of the reactor core. The feedwater control system uses water level, steam flow, and feedwater flow as a three-element control. Single-element control, based on water level only, is also available.

Normally, the signal from the feedwater flow is equal to the steam flow signal; thus, if a change in the steam flow occurs, the feedwater flow follows. The steam flow signal provides anticipation of the change in water level that would result from change in load. The level signal provides a correction for any mismatch between the steam and feedwater flow, which causes the level of the water in the RPV to rise or fall accordingly. Figure 7.7-4 shows the system IED.

7.7.1.3.1.2 Classification

This system is a power generation system, nonessential for safety, and is classified in Chapter 3.

7.7.1.3.2 Power Sources

The feedwater control system power is supplied by two (2) redundant uninterruptible power supplies. Interruptible instrument air and power is supplied to certain feedwater system (N21) control valves and operators.

7.7.1.3.3 Equipment Design

7.7.1.3.3.1 General

During normal plant operation, the feedwater control system automatically regulates feedwater flow into the RPV. The system is a distributed control system (DCS) using redundant processors and communication links. This system can be manually operated from the main control room.

The feedwater flow control instrumentation measures the water level in the RPV, the feedwater flow rate into the RPV, and the steam flow rate from the RPV. During automatic three-element operation, these measurements are used for controlling feedwater flow.

The optimum RPV water level is determined by the requirements of the steam separators. The separators limit water carryover in the steam going to the turbines and limit steam carryunder in water returning to the core. The water level in the RPV is maintained within ±2 in. of the setpoint level. This control capability is achieved during plant load changes by balancing the mass flow rate of feedwater to the RPV with the steam flow from the RPV. The feedwater flow is regulated by adjusting the speed of the turbine-driven feedwater pumps to deliver the required flow to the RPV.

7.7.1.3.3.2 Reactor Pressure Vessel Water Level Measurement

Reactor pressure vessel water level is measured by two independent sensing systems. Two (2) redundant differential pressure transmitters in each system sense the difference between the pressure caused by a constant reference column of water and the pressure caused by the variable height of water in the RPV. A backfill system is installed on each reactor water level instrument reference leg in compliance with the requirements of USNRC Generic Letter 92-04 and Bulletin 93-03. The system provides a metered flow of water from the control rod drive system (CRD) to each leg to prevent the accumulation of the noncondensable gases in the reference legs and assure a high reliability of the water level indication. The backfill flow rate is low enough to not affect the performance of the instrumentation. The differential pressure transmitters are installed on lines that serve other systems (Subsection 7.6.1.2). The differential pressure signals are used for level indication and control. The amplifier transmits the level signal for indication and control. The RPV water level signals from each sensing system are indicated in the main control room. The level signal from either sensing system can be manually selected by the operator as the signal to be used for feedwater flow control.

The redundant level signals in the operator selected sensing system and both level signals from the nonselected sensing system are applied to a median signal selector. The median signal is compared against the operator selected level and will automatically assume the lead level control signal if the operator selected sensing system fails. The water level for control is continuously recorded in the main control room.

7.7.1.3.3.3 Steam Flow Measurement

Steam flow is sensed at each main steam line flow restrictor by differential pressure transmitter. These steam flow signals are indicated in the main control room. The signals are summed to produce a total steam flow signal for indication and feedwater flow control. The total steam flow signal is recorded in the main control room.

7.7.1.3.3.4 Feedwater Flow Measurement

Feedwater flow is sensed at a flow element in each feedwater line by differential pressure transmitters. Each feedwater signal is summed to provide a total mass flow signal for the feedwater control system. The total feedwater flow signal is also recorded and integrated in the main control room. In addition, feedwater flow is sensed by an ultrasonic flow meter in each feedwater line and processed in the associated central processing unit to provide mass flows to the Integrated Plant Computer System (IPCS) for the sole purpose of the IPCS heat balance calculation and is not used for any direct control function.

7.7.1.3.3.5 Feedwater Control Signal

The level control system produces the feedwater control signal through digital control logic, the master level controller and the reactor feed pump manual/automatic control stations. The signal can be controlled either manually or automatically.

The master level control and the reactor feed pump manual/automatic stations contain a setpoint meter, level indicator, and a manual output control indicator.

The master manual/automatic setpoint station contains a setpoint meter, level indicator and a manual output control with an indicator. Input to the control system is derived from either the single-element signal (level only) or the three-element signal. The three-element signal is the summation of steam flow, feedwater flow, and the selected reactor water level. Single-element or three-element level control is manually selected by the operator. When three-element level control is selected, automatic transfer to single-element level control will occur if one of the feedwater flow signals or two of the steam flow signals should fail. Manual level control is automatically initiated if the control system cannot provide automatic level control. During automatic operation of the feedwater control system, the level control system output is proportional to the level error in the system. During manual operation, output is set and indicated at the manual/automatic setpoint station.

The level demand signal from the master control is applied to the input of two manual/automatic stations that have capabilities to add or subtract a bias signal from the master level demand, when in automatic. The bias capabilities allow independent adjustment of the speed demand signals to the turbine-driven feedwater pumps during automatic operation. During manual operation of the bias stations, the speed demand signal is manually adjusted by the operator.

Selection of automatic or manual control is made by the operator at a master manual/automatic setpoint station.

Normal Automatic Operation

The feedwater control system provides function block through the I/O modules to compute the three-element control signal to maintain RPV water level within a small margin of optimum water level during plant load changes. The total steam flow signal and the total feedwater flow signal are subtracted from each other to derive a flow error signal. When steam flow exceeds feedwater flow, the error signal is positive in polarity from its normal zero value. The flow error signal is multiplied by a gain factor referred to as mismatch gain. The mismatch gain determines how much level effect the flow error signal has when the error is 100 percent. The mismatch gain is used as a dynamic control system adjustment. The flow error signal is limited for +/-20 percent multiplied by the mismatch gain. The flow error signal is then subtracted from the selected level signal to provide the three-element control signal. When feedwater flow exceeds steam flow, the error signal is negative polarity. The three-element signal is modified further by a lead/lag function before being used for level control. The control system compares this signal against the level setpoint adjusted by the operator.

Following a reactor scram, the RPV water level controller setpoint is capable of being automatically lowered so that the Reactor Feed Pump Turbines do not overfill the reactor vessel. On receipt of a scram signal via a contact of an RPS auxiliary relay, the Post-Scram Reactor Water Level Setdown Logic lowers the level controller setpoint after the time delay. A momentary actuated switch in the control room allows the operator to reset the Post-Scram Reactor Water Level Setdown Logic after the scram signal is cleared.

Optional Automatic Operation

A single-element control signal (RPV water level) can be used to replace the above three-element signal. The operator manually transfers the level controller input to the "1 element control" signal. In the event of failure of the three-element signal, the control system will automatically transfer to single element. Reactor water level is then controlled in accordance with the controller setpoint.

Auxiliary Functions

The level control system also provides interlocks and control functions to other systems. When one of the reactor feed pumps is lost and coincident or subsequent low water level exists, reactor recirculation flow is reduced to within the power capabilities of the remaining reactor feed pumps. This reduction aids in avoiding a low-level scram by reducing the steaming rate.

Reactor recirculation flow is also reduced on sustained low feedwater flow to ensure that adequate net positive suction head (NPSH) is provided for the recirculation system.

Interlocks from steam flow and feedwater flow are used to initiate insertion of the RWM block. An alarm on low steam flow indicates that the RWM insertion interlock setpoint is being approached. The same steam flow and feedwater flow interlocks are used to bypass the gland seal exhauster trip on main steam line high radiation above the low power setpoint. Alarms from the control system are also provided for high and low water level, reactor high pressure and failures. High reactor water level (L-8) from the nuclear boiler system trips the turbine driven feedwater pumps, see subsection 7.6.1.2.7.

7.7.1.3.3.6 Turbine-Driven Feedwater Pump Control

Feedwater is delivered to the RPV through turbine-driven feedwater pumps arranged in parallel. The turbines are driven by steam from the RPV. During normal operation, the feedwater control signal from the level controller is fed to the turbine control mechanisms. The turbine control mechanisms adjust the speed of their associated turbines so that feedwater flow is proportional to the feedwater control signal. Each turbine can be controlled by its manual/automatic transfer station. The master manual/automatic setpoint station and the manual/automatic station associated with each turbine speed controller are configured to have "bumpless transfer". The turbine-driven feedwater pump control has speed limiters to restrain maximum feedwater flow to 117 percent.

7.7.1.3.3.7 Inspection and Testing

All feedwater control system components can be tested and inspected according to the manufacturers' recommendations. This can be done prior to plant operation and during scheduled shutdowns. Reactor pressure vessel water level indications from the two water level sensing systems are compared during normal operation to detect instrument malfunctions. Steam mass flow rate and feedwater mass flow rate can be compared during constant load operation to detect inconsistencies in their signals.

7.7.1.3.4 Environmental Considerations

The feedwater control system is not required for safety purposes, nor is it required to operate after the DBA. This system is required to operate in the normal plant environment for power generation purposes only. The reactor feed pumps in the turbine building experience the normal design environments listed in Table 3.11-5.

7.7.1.3.5 Operational Considerations

7.7.1.3.5.1 Normal

All control stations are located in the main control room where, at the operator's discretion, the feedwater control system can be operated either manually or automatically. Manual control of the individual turbine-driven feedwater pumps is available to the operator in the main control room. Manual control of the individual turbine-driven feedwater pumps is used during control of the startup level control valve. The startup level control valve is used to supply feedwater during periods of low reactor pressure and/or flow demand. The startup control system will automatically hold reactor water level to an operator selected setpoint as a single-element unmodified control system. It can also be operated manually.

Subsequent to a scram, the feedwater flow demand is very low. To ensure adequate control at this low flow, the feedwater control system automatically diverts feedwater flow through the startup control valve when a scram occurs. A minimum flow recirculation line valve automatically opens to maintain flow through each feedwater pump so that the pump is protected from overheating.

7.7.1.3.5.2 Operator Information

Indicators and alarms, provided to keep the operator informed of the status of the system, are discussed in Subsection 7.7.1.3.3.

7.7.1.4 Pressure Regulator and Turbine-Generator Instrumentation and Control

7.7.1.4.1 System Identification

7.7.1.4.1.1 Function

Power Generation - The pressure regulator system maintains constant main turbine inlet steam pressure.

7.7.1.4.1.2 Classification

The main turbine pressure regulator and bypass system is a conventional analog/hydraulic control system and is classified in Chapter 3.

7.7.1.4.2 Normal Power Sources

The main turbine pressure regulator control system is supplied by two independent 120-V ac instrument buses.

7.7.1.4.3 Equipment Design

7.7.1.4.3.1 System Description

Control and supervisory equipment for the turbine generator is conventional and arranged for remote operation from the main control room. Normally, the initial pressure regulator controls steam throttle valve position to maintain constant reactor pressure. The ability of the plant to follow system load demands is accomplished by adjusting reactor power level, either by changing flow in the reactor recirculation system (manually) or moving control rods (manually). However, the turbine speed governor, which is supplied by the turbine supplier, can override the initial pressure regulator. The steam valves close when an increase in system frequency or a loss of generator load causes the speed of the turbine to increase. In the event that the reactor is delivering more steam than the admission valves pass, the excess steam is automatically and directly bypassed to the main condenser by pressure-controlled bypass valves. Figure 7.7-5 is a simplified control diagram.

7.7.1.4.3.2 Steam Pressure Control

During normal plant operation, steam pressure is controlled by the turbine control valves. These control valves are positioned in response to either the pressure regulation signal or the turbine speed-load signal as selected by a "low value gate" circuit in the BOP turbine control system. The change in steam production is sensed by the pressure regulator, which signals the turbine control valves to adjust position to accept the change in steam flow, thereby regulating steam pressure.

A main steam line resonance filter is included in the pressure regulator circuits to prevent cycling from false pressure signals. These false pressure signals could be caused by sonic resonances in the main steam lines.

7.7.1.4.3.3 Steam Bypass System

The steam bypass equipment is designed to control steam pressure when reactor steam generation exceeds turbine requirements such as during startup (speed raising and synchronizing), sudden load reduction, and cooldown. Capacity of the system is 23.5 percent of 105 percent of nuclear steam supply system (NSSS) rated steam flow, and sudden load reductions of up to 25 percent of rated power can be accommodated without reactor scram.

Normally, the bypass system valves are held closed while the pressure regulator controls the turbine control valves, directing all steam flow to the turbine. If the speed governor or the load limiter restricts steam flow to the turbine, the regulator controls system pressure by opening the bypass valves. If the capacity of the bypass valves is exceeded while the turbine cannot accept an increase in steam flow, the system pressure rise and RPS action causes shutdown of the reactor.

The bypass valves are the automatically operated, regulating type. They are proportionately controlled by the NSSS pressure regulator which compares the steam pressure signal with the turbine control valve signal to bypass excess steam to the main condenser.

Bypass valves and controls are designed so the valves close on loss of control system electric power or hydraulic pressure.

7.7.1.4.3.4 Turbine Speed/Load Control System

The turbine control system is discussed in Chapter 10.

7.7.1.4.3.5 Turbine Generator to Reactor Protection System Interface

The RPS initiates reactor scram when it is required by the particular monitored plant conditions (Section 7.2). Two such conditions are turbine stop valve closure and turbine control valve fast closure when reactor power is above 29.5 percent.

The turbine stop valve closure signal is generated before the turbine stop valves have closed more than 10 percent (opened less than 90 percent). This signal originates from position switches that sense stop-valve motion away from fully open. The switches are closed when the stop valves are fully open, and the switches open within 10 msec after the setpoint is reached. The switches are electrically isolated from each other and from other turbine plant equipment.

The control-valve-fast-closure signal is generated by the relay logic that initiates the fast control valve closure. Separate circuits are associated with each of the control valves. Relay contacts are closed whenever the control valves are not being closed in the fast mode, and these relay contacts open when the fast closure mode is initiated.

To avoid reactor scram due to turbine stop or control valve fast closure when power is below 29.5 percent of rated power, two independent sensing lines are provided from the turbine first-stage pressure transmitter/trip units, which supply power level logic contacts to the RPS. The pressure taps are located to provide a pressure signal proportional to turbine steam flow. The pressure taps are shared with other instrumentation sensors. All sensors have individual isolation or root valves.

7.7.1.4.3.6 Inspection and Testing

Testing controls for testing the turbine valve RPS interface signal switches are provided to:

a. Actuate each stop valve individually to the 10 percent closed point with no interaction with other valves
b. Actuate one stop valve to the ten percent closure point and simulate another stop valve at the 10 percent closure point in the following combinations: valves 1 and 2; valves 1 and 3; valves 2 and 4; valves 3 and 4
c. Actuate one control valve at a time in the fast closure mode with no interaction with other valves.

7.7.1.4.4 Environmental Considerations

The pressure regulator and turbine-generator control system is not required for safety nor is it required to operate after the DBA. This system is required to operate in the normal plant environment for power generation purposes only.

Instrumentation and control on the turbines that experience the turbine building normal design environment is listed in Table 3.11-1. The logic, remote control units, and instrument terminals located in the main control room experience the environment listed in Table 3.11-1.

7.7.1.4.5 Operational Considerations

7.7.1.4.5.1 Normal

Two pressure control channels (A and B), operating redundantly, receive inputs from the pressure reference unit and from independent pressure transducers in the main steam lines upstream of the main steam stop valves. Main steam pressure is indicated on meters on the turbine control panel.

The pressure setpoints for the pressure reference circuit are produced by tandem potentiometers driven by a common motor. The motor is controlled by use of pushbuttons on the PRESSURE SETPOINT SELECTOR section of the main control panel. Desired setpoints for Channels A and B are indicated on meters on the main control panel. Pressure setpoint adjustment is limited to a maximum of 1 psi/sec by motor speed. In the event of failure of both regulators, alarm communication is provided in the main control room. Pushbutton operation is provided to remove the system from operation.

7.7.1.4.5.2 Operator Information

Nuclear Steam Supply System Control and Display

The NSSS pressure regulator has the following controls and information displayed in the main control room:

a. Main steam pressure regulator setpoint A

b. Main steam pressure regulator setpoint B

c. Individual bypass valve position indicators

d. Bypass valve test controls

e. Pressure regulator selection control.

Balance of Plant Control and Display

A list of the conventional turbine-generator control and supervisory instrumentation provided for operational analysis and malfunction diagnosis is described in Section 10.2.

7.7.1.5 Gaseous Radwaste System Instrumentation and Control

7.7.1.5.1 System Identification

7.7.1.5.1.1 Function

The objective of the gaseous radwaste system is to process and control the release of gaseous radioactive wastes to the site environs so that the total radiation exposure to persons outside the controlled area is as low as practicable, and does not exceed applicable regulations.

7.7.1.5.1.2 Classification

This system is required for power generation only.

7.7.1.5.2 Power Sources

The 120-V ac instrument bus normally provides power for the gaseous radwaste system instrumentation.

7.7.1.5.3 Equipment Design

7.7.1.5.3.1 General

The radiation levels at the offgas delay pipe and at the discharge of the offgas system are continuously monitored by detectors described in Section 11.4. This system is also monitored by flow and temperature instrumentation and by a hydrogen analyzer to ensure correct operation and control and to ensure that hydrogen concentration is maintained below the flammable limit. Table 7.7-2 lists process instruments that cause alarms and whether or not they are indicated or recorded in the main control room.

7.7.1.5.3.2 Catalytic Recombiner Instrumentation

The catalytic recombiner vessel temperatures are monitored by thermocouples and are then recorded. High or low temperature is annunciated in the main control room. The standby recombiner is temperature controlled, maintained, monitored, and recorded. Any low temperature is annunciated in the main control room. Inlet process gas is monitored for pressure and temperature. If abnormal measurements are obtained, they are annunciated in the main control room.

7.7.1.5.3.3 Offgas Condenser Condensate Level Control

The offgas condenser condensate level is maintained at a given level within the condenser shell. A level control system is used to provide drainage of condensate from the condenser shell. High level is annunciated in the main control room.

7.7.1.5.3.4 Offgas System Flow Measurements

Offgas system flow measurements are made between the charcoal adsorbers and the absolute filter downstream of the ring water buffer tanks before discharge into the reactor building ventilation stack.

7.7.1.5.3.5 Hydrogen Analyzer Measurement System

One hydrogen analyzer is used to measure the hydrogen content of the offgas process stream in the delay pipe. The hydrogen concentration percentage output from the analyzer is indicated and recorded in the main control room along with alarm annunciation for high hydrogen concentration percentage in the offgas process stream.

The hydrogen analyzer system continuously withdraws a sample of the process offgas, analyzes the hydrogen content, and returns the sample gas to the delay pipe. A loss of ac power to the analyzer system stops the analyzer.

7.7.1.5.3.6 Charcoal Vessel and Vault Temperature and Flow Monitoring and Control

Each charcoal vessel is temperature monitored. High vessel temperature is alarmed and annunciated at 100°F in the main control room. The charcoal vessel vault is also temperature monitored and recorded in the main control room along with high temperature alarm and annunciation. Three refrigeration units maintain the vault at a nominal temperature of 70°F.

The charcoal vessel train is flow monitored at the outlet and is indicated and recorded in the main control room along with highflow alarm and annunciation.

7.7.1.5.3.7 Differential Pressure Measurements

Differential pressure measurements are made across the precoolers, the sandfilter, the chillers, the charcoal vessel train, and the absolute filters. High differential pressure is annunciated in the main control room.

7.7.1.5.4 Environmental Considerations

The offgas control system is not required for safety purposes, nor is it required to operate after the DBA. The offgas control systems are required to operate in the normal plant environment for power generation purposes only.

Radwaste instrumentation and controls located in the offgas equipment area are subject to the environment under design conditions listed in Table 3.11-5. The control circuitry, remote control units, and instrument terminals in the main control room experience the normal design environment also listed in Table 3.11-5.

7.7.1.5.5 Operational Considerations

7.7.1.5.5.1 General

No operator action is required on the equipment described unless an alarmed condition occurs. The offgas signal to trip the HWC System is taken from the relay room panel H11-P913. Employing contact-to-coil separation prevents HWC System operation from affecting the Offgas system. Operator indicators and alarms are described in Subsection 7.7.1.5.3.

7.7.1.5.5.2 Setpoints

Hydrogen Analyzer

A hydrogen level of ~1.5 percent alarms and annunciates in the main control room.

Flow

A high flow of approximately 70 scfm alarms and annunciates in the main control room.

7.7.1.6 Liquid Radwaste System Instrumentation and Control

7.7.1.6.1 System Identification

7.7.1.6.1.1 Function

The objective of the liquid radwaste system is to control the release of liquid radioactive waste material to the environs and to package these wastes in suitable containers for offsite shipment and burial.

7.7.1.6.1.2 Classification

Since this system is required for power generation only, it does not include any Quality Class 1 or Category I components with the exception of the drywell drain isolation valve controls. The closure of these valves is necessary for sealing the primary containment under postulated accident conditions. The initiating signal is from the containment and reactor isolation control system (Subsection 7.3.2.2).

7.7.1.6.2 Power Sources

The 120-V ac instrument power is used for the liquid radwaste system.

7.7.1.6.3 Equipment Design

7.7.1.6.3.1 General

The liquid radwaste system is designed to process liquid waste water to remove particulates, impurities, and other materials, and to return the processed water for plant usage. The resulting solid wastes are then packaged in suitable containers for offsite burial.

Only those portions of the liquid radwaste system related to safety are described herein.

7.7.1.6.3.2 Instrumentation and Control

The radiation levels of the waste materials packaged for burial are monitored by plant personnel and are not part of this control system. Wastewater is collected in various sumps throughout the plant and is pumped into the radwaste collection tanks where it is processed. Excess processed liquids that are discharged from the plant are radiation monitored, flow controlled, and recorded. The instrumentation and control system of the radwaste process is typical of a standard chemical and water treatment process. Tank levels are indicated and recorded in the radwaste control room and high tank levels are annunciated in the radwaste control room.

Radiation from the liquid releases is monitored and recorded with high and low/inoperative alarms in the radwaste control room and alarms only in the main control room.

7.7.1.6.3.3 Drywell Sumps Control

There are two sumps within the containment that collect waste water which is pumped out to the liquid radwaste system collector tanks. Each sump is equipped with two pumps that automatically start and stop on high and low sump levels, respectively. The pumps are alternately started on each high level signal. Each pump is equipped with a separate float switch in a separate float well and is electrically connected to provide level backup for the other pump if one float device should fail. A high-high level is provided by each float switch which will start both pumps and annunciate an alarm in the main control room. The liquid discharge lines to the radwaste collector tanks are provided with two isolation valves. When either isolation valve is closed, the sump pumps are interlocked to prevent their operation. The sumps are automatically isolated on high drywell pressure or low reactor water level (L3).

7.7.1.6.3.4 Reactor and Turbine Building Sumps

These sumps collect waste water from their respective areas and automatically pump out the sumps on level control. These are not safety systems. An alarm and annunciation in the radwaste control room will occur on a high-high sump level to allow the operator to take corrective action.

7.7.1.6.3.5 Tank Level and Process Control

All tanks containing waste liquids throughout the radwaste liquid processing system are provided with liquid level indicators or recorders and alarms, and annunciators in the radwaste control room for high liquid level to inform the operator that corrective action is to be taken. The process control is by an operator from the radwaste control room panel. The control system is designed for manual startup and automatic stop when a process is completed (i.e., tank liquid contents have been emptied to next process). Since this is a batch system, the operator has full control and responsibility for the system control process.

The Side Stream Liquid Radwaste Processing System (SSLRPS) operation is controlled from the local control panel in the Radwaste Building Basement. Tank liquid level indicators, recorders and alarms are provided in the local control panel. Radwaste Control Room is provided with a trouble indicating alarm, as a backup, to alert the Radwaste Control Room Operators when the system operation drifts from the normal range.

7.7.1.6.4 Environmental Considerations

The radwaste control systems are not required for safety purposes, nor are they required to operate after the DBA. The radwaste control systems are required to operate in the normal plant environment for power generation purposes only. This environment is listed in Table 3.11-1.

7.7.1.6.5 Operational Considerations

7.7.1.6.5.1 General

The operator is in full control of the process system batches. Indicators and recorders are provided for all liquid tanks to inform the operator of the status of the system. Alarms and annunciation are provided to inform the operator either that a tank must be emptied or processed, or that a particular piece of equipment has malfunctioned so that corrective action may be taken.

7.7.1.6.5.2 Setpoints

All tank levels are set to alarm and annunciate in a timely manner in order to avoid overflow. This allows sufficient time for the operator to take corrective action in the process control.

7.7.2 Analysis

7.7.2.1 General

This subsection demonstrates that the protection systems are capable of coping with all failure modes of the control system.

7.7.2.2 Reactor Manual Control System Instrumentation and Control

7.7.2.2.1 Conformance To General Functional Requirements

The circuitry used in the RMCS is completely independent of the circuitry controlling the scram valves. This separation of the scram and normal rod control functions prevents failures in the reactor manual control circuitry from affecting the scram circuitry. The scram circuitry is discussed in Section 7.2. Because each control rod is controlled as an individual unit, a failure that results in the energizing of any of the insert or withdraw solenoid valves can affect only one control rod. The effectiveness of a reactor scram is not impaired by the malfunctioning of any one control rod. Therefore, no single failure in the RMCS can result in the prevention of a reactor scram. Repair, adjustment, or maintenance of RMCS components does not affect the scram circuitry.

The RMCS is an operational system used for regulating power level and power distribution. This system is self-monitoring with the automatic rod blocks, operator annunciators, and operating status lights (such as the rod position indicators) as part of the system design. The rod blocks are an internal subsystem of this nonsafety system. As such they are designed to be single- failure-proof, but are not designed to stringent safety standards.

The RMCS receives rod block signals from the NMS to prevent improper rod motion that could result in reactor scram. Common LPRM, IRM, and SRM detectors are used, but the signal is physically and electrically isolated before use in the RMCS. This isolation is achieved through two separate relay trip units that prevent any feedback from the RMCS to the RPS. Subsections 7.6.l and 7.6.2 describe this interface.

The performance of the RMCS is monitored by the RPS. If a variable, such as the neutron flux, which is controlled by the RMCS, exceeds specific limits, the RPS takes independent action to cause reactor shutdown.

It is thus seen that the RMCS is not required for safety nor for reactor shutdown, but only for changing plant power.

Accident analyses in Chapter l5 show that failures in the RMCS, such as continuous withdrawal of a control rod, do not result in any fuel damage. No fuel damage results from any single operator error or single equipment malfunction.

7.7.2.2.2 Conformance To Specific Regulatory Requirements

The RMCS meets the requirements of GDC 24 of l0 CFR 50, Appendix A.

No part of the RMCS is required for scram. The rod block functions provided by the NMS and the scram discharge volume high water level trip bypass signal interlocks are the only instances where the RMCS uses any instruments or devices used by the RPS. This includes relay contacts to the reactor mode switch and the scram discharge volume high level bypass switch. The rod block signals received from the NMS prevent improper rod motion before limits causing reactor scram are reached. Common LPRM, IRM, and SRM detectors are used, but physically and electrically separate trip signals are supplied to the RMCS and RPS systems. A description of this interface is contained in Subsections 7.6.l and 7.6.2. The scram discharge volume high water level trip bypass signal interlocks with the RMCS to initiate a rod block. The interlock is performed using isolating relay contacts so that no failure in the control system can prevent a scram.

7.7.2.3 Recirculating Flow Control System Instrumentation and Control

7.7.2.3.1 Conformance To General Functional Requirements

The RFCS is designed so that coupling is maintained between a motor-generator set drive motor and its generator even if the ac power or a speed controller signal fails. This ensures that the drive motor inertia contributes to power supplied to the recirculation pump during the coastdown of the motor-generator set after loss of ac power, and also ensures that the generator continues to be driven if the speed controller signal is lost.

Transient analyses described in Chapter l5 show that no malfunction in the RFCS can cause a transient sufficient to either damage the fuel barrier or exceed the nuclear system pressure limits as required by the safety design basis.

7.7.2.3.2 Conformance To Specific Regulatory Requirements

Except for the recirculation pump trip function, there are no specific regulatory requirements for the RFCS. The RFCS is not a safety-related system and is not required for safe shutdown of the plant, nor is it required during or after accident conditions. The recirculation pump trip function meets the requirements of IEEE 323-1974 and IEEE 344-1975.

7.7.2.4 Feedwater Control System (Turbine-Driven Pumps) Instrumentation and Control

7.7.2.4.1 Conformance To General Functional Requirements

The feedwater is a power generation system for the purposes of maintaining proper RPV water level. Should the RPV water level rise too high, the feedwater pumps and plant main turbine would be tripped. This is an equipment protective action which would result in reactor shutdown by the RPS as outlined in Section 7.2. Lowering of the RPV water level would also result in action of the RPS to shut down the reactor. Further decrease would actuate the emergency core cooling system (ECCS). Loss of feedwater is analyzed in Chapter 15.

7.7.2.4.2 Conformance To Specific Regulatory Requirements

The feedwater control system is not a safety-related system and is not required for safe shutdown of the plant, nor is it required during or after accident conditions. The Feedwater Control System Contains QA Level 1 transmitters classified as NUREG-0588 Category 2B (mechanical) for pressure boundary integrity and Category 2C (electrical).

There is no interface with safety-related systems, with the exception of the Reactor Protection System which provides a Post Scram Signal to the Feedwater Control System.

7.7.2.5 Pressure Regulator and Turbine-Generator Instrumentation and Control

7.7.2.5.1 Conformance To General Functional Requirements

The pressure regulator and turbine-generator instrumentation and control is designed to maintain constant reactor pressure, to follow system load demand fluctuations, and to control turbine speed. Excessive reactor pressure swings caused by failure of this system would be dealt with by the RPS (Section 7.2) and/or the safety/relief valves.

7.7.2.5.2 Conformance To Specific Regulatory Requirements

The pressure regulator and turbine-generator instrumentation and control is neither safety-related nor required for the safe shutdown of the plant. It is also not required during or after accident conditions.

7.7.2.6 Gaseous Radwaste System Instrumentation and Control

7.7.2.6.1 Conformance To General Functional Requirements

The objectives of the gaseous radwaste system instrumentation and control are to indicate and alarm the level of radioactivity within offgas process lines, to provide a record of all radioactive plant site releases, and to initiate appropriate action that would prevent the release of radioactive materials to the environs that exceed the operational limits established in 10 CFR 20 and Regulatory Guide 1.21.

The flow recorder is provided to keep a record of all discharge volumes. The flow measurements and recording accuracies are within 5 percent of indication for the flows measured.

7.7.2.6.2 Conformance To Specific Regulatory Requirements

The gaseous radwaste system instrumentation and control is neither safety-related nor required for the safe shutdown of the plant. It is not required to operate after a DBA. The gaseous radwaste system instrumentation and control is required to operate in the normal plant environment for power generation purposes only.

7.7.2.7 Liquid Radwaste System Instrumentation and Control

7.7.2.7.1 Conformance To General Functional Requirements

The liquid radwaste effluent for discharge to the circulating water blowdown is flow controlled and monitored for activity level. The discharge flow shutoff valve is operated by a keylock switch that requires plant supervisory control of any releases. The flow is recorded in the radwaste control room.

The packaged wastes are stored in the plant in a storage area set aside for this purpose. The radioactivity and quantity is the responsibility of plant supervisory personnel. This complies with Regulatory Guide 1.21, Revision 0.

7.7.2.7.2 Conformance To Specific Regulatory Requirements

Section 11.2 discusses the conformance of the liquid radwaste system to specific regulatory requirements.

TABLE 7.7-1 REACTOR MANUAL CONTROL SYSTEM INSTRUMENT SPECIFICATIONS

Measured Variable	Instrument Type	Instrument Range	Accuracy[d]	Trip Setting[a]
Drive water header pressure	Pressure indicator	0 to 2000 psig	±1/2 percent full scale	-
Drive water pump discharge pressure	Pressure indicator	0 to 2000 psig	±1/2 percent full scale	-
Drive water pump suction pressure	Pressure indicator	30 in. Hg to 60 psig	±1.5 percent full scale	-
Drive water filter differential pressure	Differential pressure switch (indicating)	0 to 75 psig	±1/2 percent full scale	25 psid, increasing
Cooling water header pressure	Pressure indicator	0 to 2000 psig	±1/2 percent full scale	-
Exhaust water header pressure	Pressure indicator	0 to 2000 psig	±1/2 percent full scale	-
Charging water accumulator header pressure	Pressure indicator	0 to 2000 psig	±1/2 percent full scale	-
Charging water header pressure	Pressure indicator	0 to 1800 psig	±1 percent full scale	-
Drive water pump suction Pressure	Pressure switch	30 in. Hg to 10 psig	±1 percent full scale	25 in. Hg, decreasing
Drive water system flow rate	Flow indicator	0 to 100 gpm	±1 percent full scale	-
Drive water header flow rate	Flow indicator	0 to 8 gpm	±2 percent full scale	-
Cooling water header flow rate	Flow indicator	0 to 80 gpm	±2 percent full scale	-
Stabilizing flow rate	Flow indicator	0 to 8 gpm	±0. 5 percent full scale	-

TABLE 7.7-1 REACTOR MANUAL CONTROL SYSTEM INSTRUMENT SPECIFICATIONS

Measured Variable	Instrument Type	Instrument Range	Accuracy[d]	Trip Setting[a]
Control rod drive Temperature	Temperature switch and monitor	0 to 500°F	±1 percent full scale	250°F
Control rod position (normal range)	Reed switches	Full in to full out every 3 in.	NA[b]	-
Control rod drive overtravel (withdraw direction)	Reed switches	NA	NA	2 in. beyond full out position
Insert bus time energized (for rod insertion)	Timer	-	-	2.8 sec
Insert bus time energized (for rod withdrawal)	Timer	-	-	0.62 sec
Withdraw bus time energized (for rod withdrawal)	Timer	-	-	1.5 sec
Settle bus time energized (for rod insertion)	Timer	-	-	4.4 sec
Settle bus time energized (for rod withdrawal)	Timer	-	-	5.8 sec
Rod block scram discharge volume high water level	Level switch		±3 in.	25 gal[c]
Rod block neutron monitoring system trip channels	Section 7.1.2.1.4, Neutron Monitoring System			
Rod block rod worth minimizer	Subsection 7.6.1.20, Rod Worth Minimizer System			
Rod block flow upscale	Section 7.1.2.1.4, Neutron Monitoring System			

TABLE 7.7-1 REACTOR MANUAL CONTROL SYSTEM INSTRUMENT SPECIFICATIONS

Measured Variable	Instrument Type	Instrument Range	Accuracy[d]	Trip Setting[a]

[a] Nominal setting - see Technical Specifications for setpoint and allowable values.

[b] NA = not applicable.

[c] For 1/2 total instrument volume.

[d] The instrument accuracy information provided in the UFSAR tables is a bounding value.

TABLE 7.7-2 PROCESS INSTRUMENT ALARMS OFFGAS SYSTEM

	Main Control Room	
Parameter	Indicated	Recorded
Preheater discharge temperature – low		X
Recombiner catalyst temperature – high/low		X
Offgas condenser drain well level – high	X	
Offgas condenser gas discharge temperature – high		X
H_2 analyzer – high		X
Precooler temperature – high		X
Chiller pressure[a] – high	X	
Charcoal bed temperature – high		X
Absolute filter pressure[a] – high	X	
Delay pipe pressure – high		X
Sandfilter pressure[a] – high	X	
Offgas system flow – high		X

[a] Differential pressure.

Figure Intentionally Removed
Refer to Plant Drawing I-2110-01

FIGURE 7.7-1, SHEET 1

CONTROL ROD DRIVE HYDRAULIC SYSTEM FCD

Figure Intentionally Removed
Refer to Plant Drawing I-2110-02

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FIGURE 7.7-1, SHEET 2

CONTROL ROD DRIVE HYDRAULIC SYSTEM FCD

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Refer to Plant Drawing I-2110-03

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FIGURE 7.7-1, SHEET 3

CONTROL ROD DRIVE HYDRAULIC SYSTEM FCD

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Refer to Plant Drawing I-2110-04

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FIGURE 7.7-1, SHEET 4

CONTROL ROD DRIVE HYDRAULIC SYSTEM FCD

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Refer to Plant Drawing I-2110-05

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FIGURE 7.7-1, SHEET 5

CONTROL ROD DRIVE HYDRAULIC SYSTEM FCD

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Refer to Plant Drawing I-2110-06

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FIGURE 7.7-1, SHEET 6

CONTROL ROD DRIVE HYDRAULIC SYSTEM FCD

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Refer to Plant Drawing I-2110-07

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FIGURE 7.7-1, SHEET 7

CONTROL ROD DRIVE HYDRAULIC SYSTEM FCD

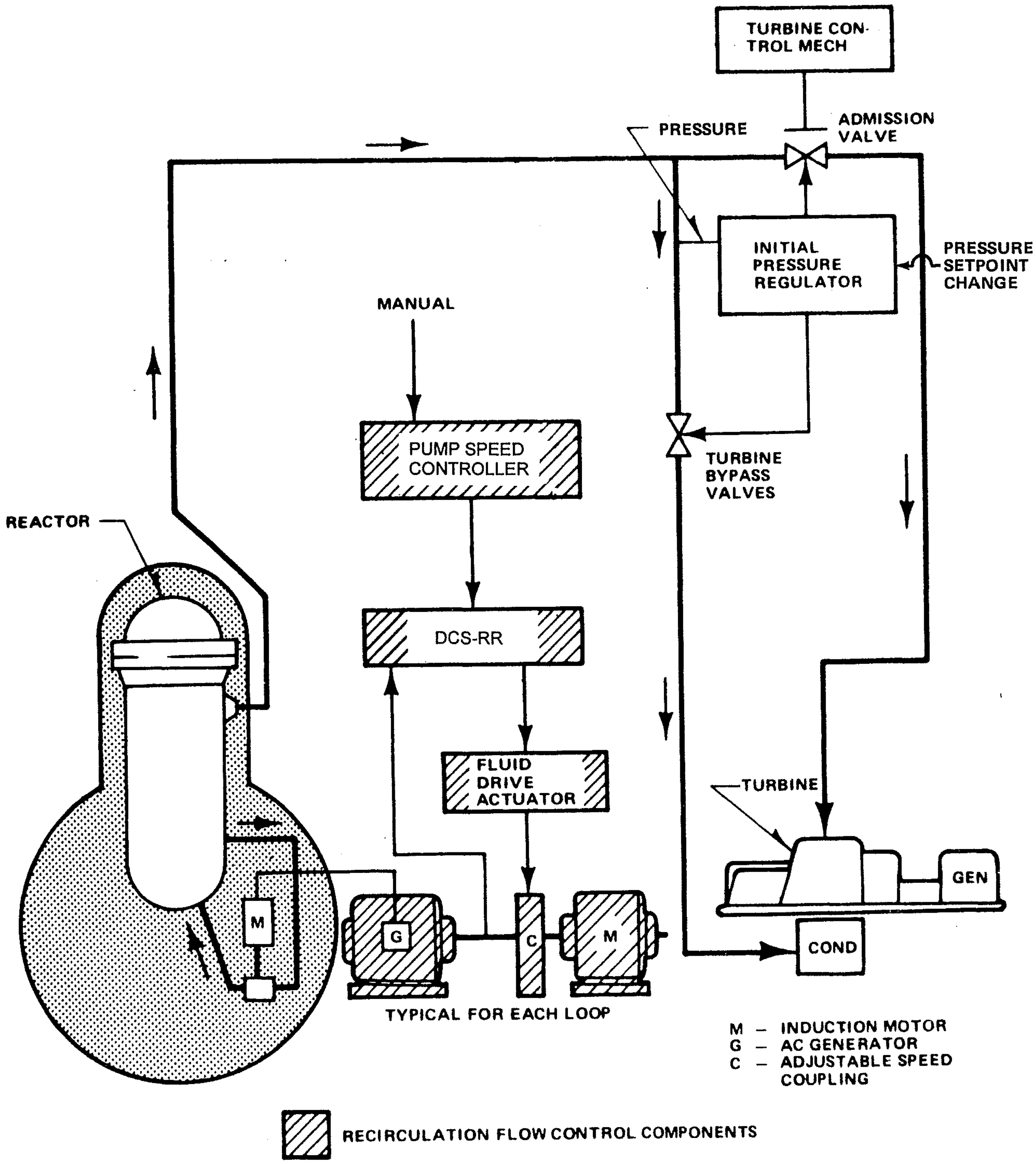

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FIGURE 7.7-2

RECIRCULATION FLOW CONTROL ILLUSTRATION

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Refer to Plant Drawing I-2100-01

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FIGURE 7.7-3, SHEET 1

REACTOR RECIRCULATION SYSTEM FCD

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FIGURE 7.7-3, SHEET 2

REACTOR RECIRCULATION SYSTEM FCD

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FIGURE 7.7-3, SHEET 3

REACTOR RECIRCULATION SYSTEM FCD

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FIGURE 7.7-3, SHEET 4

REACTOR RECIRCULATION SYSTEM FCD

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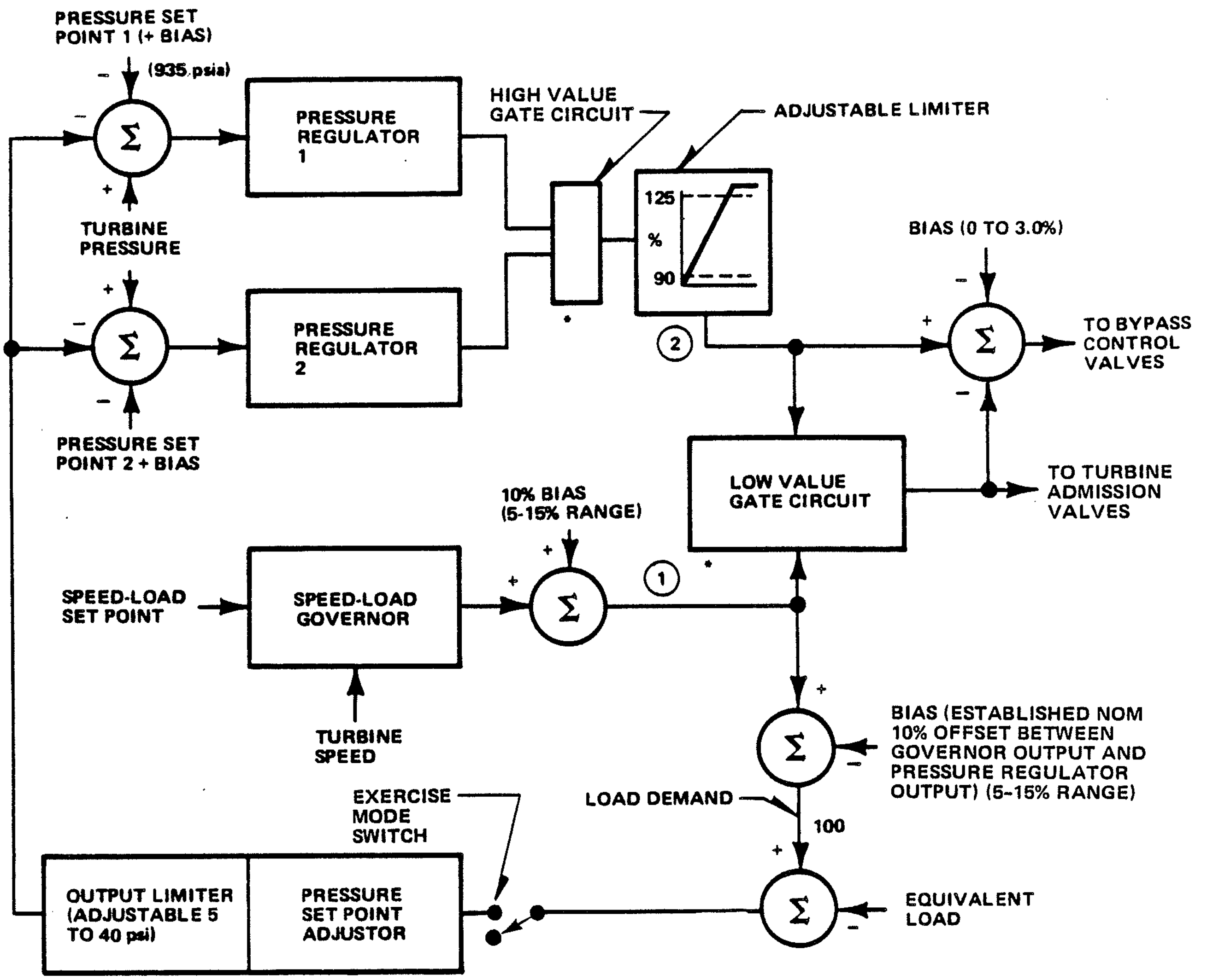
FIGURE 7.7-4

FEEDWATER CONTROL SYSTEM IED



*NOTE: HIGH AND LOW VALUE GATE TERMINOLOGY IS WITH REFERENCE TO THE MAGNITUDE OF THE INPUT SIGNAL TO THE GATE CIRCUIT UNDER NORMAL OPERATING CONDITIONS

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FIGURE 7.7-5

SIMPLIFIED DIAGRAM OF TURBINE PRESSURE AND SPEED LOAD CONTROL REQUIREMENTS

7.8 EMERGENCY RESPONSE FACILITIES

7.8.1 Introduction

DTE has a technical support center (TSC), an operational support center (OSC), and an emergency operations facility (EOF) onsite; an alternative EOF is located offsite. The TSC is in the office building annex. The command and control area of the primary OSC is an area within the TSC ventilation boundary. Additional areas adjacent or remote to this location are used for support, briefings, and for personnel musters. An alternate OSC is in the machine shop. The EOF is in the basement of the nuclear operations center approximately 6000 ft southwest of the reactor building outside the protected area. The alternative EOF is at the DTE Western Wayne Center, 22 miles northwest of the Fermi 2 site. See Figure 7.8-1 for the location of the facilities within the owner controlled area.

7.8.2 Technical Support Center

7.8.2.1 General

The TSC has been established to provide the capability to display and transmit plant status information to individuals knowledgeable and responsible for engineering and management support of reactor operations in the event of an emergency condition. The TSC building is sited inside the protected area to lessen the time needed by personnel working in the plant to reach the building during an emergency condition. Other key factors considered in the selection of the TSC location included (1) the time needed by personnel working in the control room, in other plant areas, and at offsite locations to reach the TSC; (2) the availability of shielding to minimize exposure to direct radiation from the primary containment for personnel traveling to the TSC from the control room and other plant areas; and (3) the radiation protection (shielding) provided by existing plant structures to personnel arriving from offsite locations. The site chosen for the TSC also supports the efficient routine staffing of the building by plant operations and support groups who will provide added assurance that the systems and equipment necessary for TSC functioning will be maintained in a state of readiness.

The TSC is the emergency operations work area for designated DTE technical, engineering, and management personnel; other DTE personnel required to provide any needed technical support; and a small staff of NRC personnel. The TSC personnel will provide guidance and technical support for the Shift Manager in the control room. However, all control operations will be performed by licensed operators.

7.8.2.2 Design Basis

Information on plant status is provided to the TSC for use by technical and management personnel in support of command and control functions executed from the control room. The TSC does not affect the reliability or availability of the power plant and its safety systems.

The design bases for the TSC are as follows:

a. Function. The onsite TSC will have the following functions:

1. Provide plant management and technical support to plant operations personnel during emergency conditions
2. Relieve the reactor operators of peripheral duties and communications not directly related to reactor system manipulations
3. Prevent congestion in the control room
4. Perform EOF functions until the EOF is activated.

b. Activation time. The TSC is activated according to the RERP Plan and is made functional within prescribed times

c. Information availability. The TSC is equipped with Integrated Plant Computer System (IPCS) displays that provide information on plant status to support control room operations and emergency management. The IPCS also provides sufficient data for the assessment of offsite radiological and meteorological conditions. See Subsection 7.6.1.9.1.2.5.

d. Communications. The TSC is provided with the capability to communicate with all emergency facilities and locations to implement the Radiological Emergency Response Preparedness Plan

e. Habitability. The TSC is habitable during postulated radiological emergencies to the same degree as the main control room. Special shielding and heating, ventilation, and air conditioning (HVAC) systems are provided to minimize personal exposure and to ensure that NRC limits for whole-body exposure and airborne concentrations are satisfied

f. Size and layout. Adequate space is provided for proper functioning of the TSC emergency organization. Adequate space is also provided for equipment necessary for operation of the TSC. (See Figure 7.8-2)

g. Security. Normal plant security measures are maintained during the activation of the TSC

h. Access. The TSC is readily accessible to members of the TSC emergency organization arriving from both onsite and offsite locations. The exposure of personnel manning the TSC to potential direct radiation from the primary containment has been minimized by the selection of an appropriate TSC site and of appropriate access routes to the TSC

i. Fire protection. The TSC construction minimizes the use of combustible materials. Appropriate portable and permanent fire-extinguishing equipment is provided for the TSC and for the HVAC system. Fire-detection instrumentation is provided for automatic shutdown of the building's HVAC system

j. Record storage. Adequate space is provided within the TSC for permanent storage of records, diagrams, and design drawings that are considered necessary to support the functioning of the TSC during emergency conditions

k. Protection against natural phenomena. The TSC is sited and constructed to withstand the maximum postulated 100-year winds and 100-year floods.

7.8.2.3 Codes and Standards

The TSC building is designed and constructed according to the following codes and standards:

a. ACI-318-77 - American Concrete Institute, Building Code Requirements for Reinforced Concrete

b. AISC-1978 - American Institute of Steel Construction, Specification for the Design Fabrication and Erection of Structural Steel for Buildings

c. ANSI A58.1-72 - American National Standards Institute, Building Code Requirements for Minimum Design Loads in Buildings and Other Structures, with

   1. Seismic Loadings conforming to Uniform Building Code (UBC) requirements for Zone 1

   2. Wind loads based on 100-year mean recurrence intervals for exposure type C.

d. UBC-79 - Michigan Uniform Building Code, Seismic Zone 1

e. ACI-531-79 - American Concrete Institute, Building Code Requirements for Concrete Masonry Structures.

The TSC is not classified as a nuclear safety-related facility. Its mechanical and electrical design bases are as follows:

a. Mechanical systems: Quality Group D (includes mechanical system supports) design governed by the codes listed in Tables 7.8-1 and 7.8-2

b. Electrical systems: Non-Class 1E.

7.8.2.4 Description

The TSC is located within the protected area of the Fermi 2 site, approximately 3-1/2 minutes walking time from the control room, as shown in Figure 7.8-3. It is located on the ground floor of the two-story office building annex, partially steel framed, with a 12-in.-thick reinforced-concrete ceiling slab on metal decking. The exterior walls, including labyrinths, are 12-in.- thick reinforced hollow-core concrete block filled with grout. The foundation incorporates spread footing under columns and strip footing under concrete block walls. There is a forced-air supply system, but no forced-air exhaust system; therefore, under normal operating conditions, the TSC will be under slight positive pressure with all entrance doors closed.

The site for the TSC was chosen to optimize the trade-off between travel time from the control room to the TSC and the radiation exposure of personnel enroute from onsite and offsite locations to the TSC. The Fermi 2 plant design was essentially completed at the time of TSC site selection, with the location of the primary containment and control room on the northwest side of the plant, as shown in Figure 7.8-3. To satisfy the NRC guidelines for a 2-minute transit time from the control room to the TSC, it would have been necessary to locate the TSC to the north or west of the plant, which would increase the exposure of personnel traveling to the facility to radiation from the primary containment. Because the TSC could be activated at any time of day, the final site was selected so that members of the TSC emergency organization have access to the TSC from several locations, including the control room, offsite locations, and the plant supervisory offices located in the office building annex. The structures adjacent to the site offer the advantage of maximum shielding to the TSC and its access routes, thus providing acceptable, safe travel time from the control room, should this route have to be traveled.

The TSC, as shown in Figure 7.8-2, covers about 5000 ft^2 including an area devoted to the primary OSC command and control function. Approximately 2075 ft^2 of this area is devoted to occupancy by TSC and designated OSC personnel. The remaining space consists of rooms for records storage, toilets, HVAC equipment, telephone and communications equipment, and electrical equipment. Status boards and marking boards are conveniently located within the monitor room. Telephone jacks and electrical outlets are in the floor.

The NRC has defined four emergency action levels (see Subsection 7.8.2.13) to categorize the severity of various operational emergencies. Additional guidance is published in NUREG-0654, Appendix 1 (Reference 1). The TSC will be activated for events at or beyond the "alert" level. Upon activation, the TSC will be placed in operation after occupancy by a specified number and type of personnel (staffing of the TSC is described in the Fermi 2 Radiological Emergency Response Preparedness Plan) and after TSC communication, monitoring, and occupancy support systems have been energized.

7.8.2.5 Habitability

The TSC occupants are protected from radiological hazards, including exposure to direct radiation and airborne contaminants. Specific design features and administrative procedures ensure that the radiation dose received by TSC personnel does not exceed the limits and guidelines of General Design Criterion (GDC) 19 of 10 CFR 50, and NRC Standard Review Plan, Section 6.4 (Reference 2).

The contributions of several radiation sources are considered in calculating the dose equivalent to TSC personnel. Radiation exposure may derive from immersion in or inhalation of radioactivity in the TSC atmosphere as well as direct shine from sources outside the TSC shield envelope (e.g., reactor building, standby gas treatment system [SGTS] exhaust plume, TSC makeup filters). Shielding is used to reduce the dose equivalent from any single external source to a negligible level; that is, less than one-tenth of the allowable dose equivalent. The radiation shield design considers all shield penetrations, as well as potential radiation sources within the habitable area.

The HVAC system has been designed to facilitate the occupation of all necessary personnel for winter and summer environmental and radiological accident conditions. It is designed to maintain a habitable environment of the same quality as the control room, even though it is not rated safety related, seismic, or redundant. The HVAC system is capable of the following:

a. Maintaining room temperature by removing all heat released by equipment, lights, occupants, and thermal transmission

b. Maintaining room temperature by replacing all heat loss due to thermal transmission, with no credit for lighting, occupants, or equipment

c. Limiting the thyroid radioiodine dose received by personnel inside the TSC

d. Introducing outside air into the TSC envelope will result in a slight positive pressure with respect to the outdoors.

Simplified process flow diagrams for the TSC HVAC system are provided as Figures 7.8-5, 7.8-6, and 7.8-7. The HVAC equipment consists of the following:

a. Air-handling unit: a three-zone, multizone air-handling unit with an air delivery of 5500 cfm. The unit is equipped with a direct-expansion cooling coil with a cooling capacity of 15 tons. Pressure-equalizing baffles are provided in the hot deck, as each zone shall have its own electric heating coil

b. Supply air filter: bag filters that are 80 to 85 percent efficient. The filter-element efficiency is based on the National Bureau of Standards' dust spot test

c. Purge fan: a ceiling-mounted, vane-axial, 4900-cfm purge fan

d. Steam generator: a self-contained, all-electric steam generator. The unit is capable of generating 20 lb/hr of steam for humidification

e. Steam humidifiers: Each zone is provided with a steam humidifier. The steam for humidification is provided from the steam generator

f. Air-cooled condensing unit: a floor-mounted, air-cooled condensing unit with a cooling capacity of 15 tons

g. Electric heating coils: Duct-mounted heating coils for each zone are provided and are rated for their respective zones

h. Toilet room exhaust fan: an air-line, duct-mounted exhaust fan with a 400-cfm capacity

i. HVAC and electric equipment room air-handling unit: This unit has a capacity of 3600 cfm

j. Duct-mounted electric heating coils and unit heaters are also provided for HVAC and electric equipment rooms.

The HVAC system for the TSC has an emergency makeup air system to filter a combination of outside makeup air and recirculation air for pressurization and to maintain the TSC dose within allowable limits. The emergency makeup air system consists of the following components:

a. Prefilters capable of no less than 85 percent filtration efficiency based on the ASHRAE dust spot test

b. A single-stage electric heating coil, capable of raising the air temperature and reducing the relative humidity of the airstream to 70 percent, or less, for the worst inlet condition

c. High-efficiency particulate air (HEPA) filters capable of removing 99.97 percent of particulate matter 0.3 μm and larger in size based on a hot dioctyl phthalate (DOP) test. The HEPA filters are provided upstream and downstream of the charcoal adsorber. The HEPA filters need not be tested as specified in Regulatory Guide 1.52 and need not meet the quality assurance requirements of 10 CFR 50, Appendix B

d. Two charcoal adsorbers (total charcoal thickness of 4 in.) that are capable of removing radioactive and nonradioactive forms of iodine are provided. The charcoal adsorbers are of the drawer type, filled with impregnated coconut shell where the depth of charcoal is 2 in. These adsorbers together have the iodine removal efficiency of not less than 99 percent. The charcoal adsorbers meet the requirements of Regulatory Guide 1.52, and of Table 7.8-3

e. A belt-driven centrifugal fan located upstream of the filter unit is provided to maintain the filter unit at a positive pressure

f. Each charcoal adsorber bank is provided with a two-stage continuous thermistor located across the discharge air path from each adsorber

g. Each charcoal adsorber bank includes a fire protection system for extinguishing a charcoal fire

h. The makeup air unit is provided with instrumentation as required in Table 4.2 of ANSI N509

i. The makeup air unit is provided with drain connections for each compartment of the housing, which are piped to the side of the unit, valved, and drain to the sanitary sewer.

The filter train for the emergency makeup air system is designed to remove radioactive particulates and absorb radioactive iodine. Circulated air consists of a mixture of recirculated air and sufficient outside air to maintain the TSC at a positive pressure of ≥ 1/8-in. water gage. TSC doses will be maintained within allowable limits provided the introduction of outside air does not exceed 1000 cfm.

An area radiation monitor is provided to continuously measure and indicate the general area radiation levels in the TSC. Friskers are available at the entrance to the TSC to provide radiological access control of persons entering the TSC. The TSC has provisions for monitoring iodine by using specific cartridges that can detect iodine levels as low as 1×10^{-7} $\mu Ci/cm^3$. The TSC radiation monitoring equipment is calibrated according to Health Physics procedures and to manufacturers' recommendations.

Sufficient protective clothing is stored in the TSC for personnel. If additional clothing is required, it is available from various designated locations in the plant.

Stationery supplies and duplicating equipment are also available in the TSC.

7.8.2.6 Staffing

Staffing of the TSC is described in the Fermi 2 Radiological Emergency Response Preparedness Plan. The TSC emergency organization is activated for conditions involving an alert, site area emergency, and general emergency.

7.8.2.7 Communications

The communications system is discussed in detail in the Radiological Emergency Response Preparedness Plan.

The plant intercom (HiCom) system used for general plant operations also has extensions in the TSC and other site emergency facilities. There is a public address system within the TSC for general announcements to all TSC personnel.

The communications systems have been tested and their performance evaluated during practice drills and a full-scale exercise. The systems have been found satisfactory for implementing the emergency plan.

7.8.2.8 Instrumentation and Power Supplies

Electric power is furnished to the TSC via two independent non-Class 1E 480-V ac feeders derived from separate offsite sources, each sized to carry the entire TSC load. The feeders are connected to the TSC power distribution system through an automatic transfer switch. On complete loss of offsite power, combustion turbine generators (not associated with the emergency diesel generators) located at the site are capable of providing power. Since the TSC is powered from non-Class 1E sources, TSC loads or faults in the TSC power distribution system will not affect the plant's safety-related power distribution system.

The TSC power distribution system consists of a single motor control center that provides power to the HVAC equipment, lighting and instrumentation power supply transformers, and other TSC auxiliary loads, such as copying machines and microfilm viewers. A separate instrumentation power supply transformer protects the solid-state TSC IPCS data display equipment from power-line disturbances.

Lighting for the TSC consists of recessed ceiling fixtures. Emergency battery-pack lighting is also furnished.

7.8.2.9 Information Systems

The TSC data display system, documentation, plant drawings, control room records, plant chemistry data, plant historical data, analytical data, verbal and recorded information provided by plant operations personnel, radiological assessment and other analyses available from offsite sources, and data provided by the radiological monitoring teams enable the TSC staff to determine the following:

a. The plant status and dynamics before and during the accident

b. The performance of accident mitigation functions

c. The nature and trend of the accident

d. The damage to the plant and equipment

e. The status of the operation (including personnel activity in the plant)

f. The amount of radioactive release to the environment

g. The prevailing meteorological conditions

h. The radiation and radioactivity level of the environs

i. The offsite dose assessment.

A computer-based data handling system, IPCS (see Subsection 7.6.1.9.1), is provided to supply emergency response information for display in the TSC. The IPCS is of high quality and reliability, and is non-Class 1E and nonseismic.

The IPCS displays emergency response information in the control room, TSC, and EOF. Recording, trending, and time-history plotting capabilities are provided within the system. In the event of a complete loss of offsite power, data will be retained by the IPCS during the outage for display once TSC power is restored.

Six workstations for data display are located in the TSC.

7.8.2.10 Records Storage

A file of copies of the following documents is maintained for use in the TSC:

a. General arrangements

b. Process and instrumentation diagrams

c. Piping drawings

d. Logic diagrams

e. Electrical schematics

f. Operating procedures

g. Emergency procedures

h. Technical Specifications

i. Master instrument lists (retrieval by computer)

j. Updated Final Safety Analysis Report

k. Plant operating records

l. Radiological Emergency Response Preparedness Plan and its implementing procedures

m. Radiation exposure histories (retrieval by computer)

n. Other documents sufficient to diagnose potential plant operating problems at the system level.

Other plant documents, or copies, are available for use by the TSC as needed during the course of an emergency. Such documents include those normally stored in other locations at the plant site, such as in the technical staff offices or in the records storage center next to the

TSC. A conventional office copy machine and microfilm viewing and copying devices are located in the TSC for the purpose of copying documents likely to be used during an emergency.

7.8.2.11 Fire Protection

The TSC is constructed using the following noncombustible materials:

a. Exterior: reinforced concrete block walls, reinforced concrete roof, and hollow metal doors. Exposed structural steel has been fireproofed

b. Interior: stud drywall-type partitions and suspended acoustical ceiling. All floor areas except the electrical equipment room, the HVAC room, and the monitor and rest rooms are carpeted. The monitor area has a computer floor with vinyl asbestos tile.

The following fire-protection equipment is provided:

a. Portable carbon dioxide units

b. A water deluge system for the charcoal filters in the emergency makeup filter unit

c. Smoke detectors in the fresh air intake and in the return-air duct of the TSC HVAC system.

7.8.2.12 Evaluation

DTE has provided for a TSC separate from but near the control room. The location in the office building annex ensures operating personnel familiarity with the facility. The TSC has the capability to display and transmit plant status to individuals knowledgeable of and responsible for engineering and management support of plant operations in the event of an accident.

The overall data handling system is the IPCS. The emergency response capability of the IPCS includes measurements that permit assessment of reactivity control, reactor core cooling, reactor coolant system integrity, containment integrity, meteorology, and dose assessment. The IPCS incorporates features and recommendations from NUREG-0696 (Reference 3).

Upon activation, the TSC will provide the initial main communications link between the plant, the OSC, the NRC, and the offsite emergency response organizations until the EOF is available. The TSC will be habitable to the same degree as the control room during postulated accident conditions in accordance with the requirements of NUREG-0578 (Reference 4).

Records pertaining to as-built conditions and layout of structures, systems, and components are available to personnel in the TSC.

In summary, the TSC provides the integrated emergency response capability required by the NRC.

7.8.2.13 Emergency Action Levels

a. Notification of unusual event: Events are in process or have occurred that indicate a potential degradation of the level of the safety of the plant

b. Alert: Events are in process or have occurred that involve an actual or potential substantial degradation of the level of the safety of the plant

c. Site area emergency: Events are in process or have occurred that involve actual or likely major failures of plant functions needed for the protection of the public

d. General emergency: Events are in process or have occurred that involve actual or imminent substantial core degradation or melting with imminent potential for loss of containment integrity.

7.8.3 Operational Support Center

The function of the OSC is to provide an onsite area where licensee operations support personnel will assemble in an emergency. The OSC will:

a. Provide locations where plant logistic support can be coordinated during an emergency

b. Restrict control room access to those support personnel specifically requested by the Shift Manager.

The OSC is an area within the TSC ventilation boundary. Additional areas adjacent or remote to this location can be used for support, briefings, and for personnel musters. These areas can include:

- A designated assembly point near the Control Room (Turbine Building 3rd floor)
- Normal work areas near the TSC
- The machine shop are in the Office Services Building
- Additional areas that may be used when directed by the Emergency Director

The OSC provides areas for the coordination of shift and maintenance personnel to support emergency response operations without causing congestion in the Control Room. Personnel reporting to the OSC include the Fire Brigade, Damage Control and Rescue Teams, Onsite Radiological Emergency Teams, Chemistry personnel, instrument control technicians, and general maintenance personnel.

The OSC is activated for an alert, site area emergency, or general emergency condition. The emergency organization is described in the Radiological Emergency Response Preparedness Plan. The machine shop is an alternate OSC, but any or all the designated OSC areas may serve as an alternate OSC. The designated assembly point near the control room and the area designated in the machine shop are equipped as necessary with supplies and equipment to ensure continued support of the OSC emergency organization. These areas are located such that it would be highly improbable that the different locations would not be habitable at the same time.

The OSC areas are equipped with communications systems and supplies, including protective clothing and equipment. Portable Health Physics equipment is provided to monitor radiological conditions in the OSC. Procedures have been established for control and for periodic inventories, recalibrations, and replenishments of perishable items. Communication to the OSC is via the emergency telephone communications network, radio communications using hand-held radio transmitters, and the plant intercom system.

The OSC also has radiation monitoring capabilities, though its habitability requirements are not the same as those of the control room. The monitoring equipment consists of friskers, dose rate meters, and high range dosimeters. The OSC personnel also have available the use of self-contained breathing apparatus and partial sets of protective clothing. At the direction of the Emergency Director, the OSC leadership shall relocate the command and control of the OSC to the alternate OSC as warranted. Additional muster and staging areas can be established as needed based on plant conditions.

The OSC emergency organization, equipment, and communications systems have been evaluated during a full-scale exercise and have been found acceptable.

7.8.4 Emergency Operations Facility

7.8.4.1 General

The EOF functions as an operational support center with capabilities for the following:

a. Management of overall licensee emergency response

b. Coordination of radiological and environmental assessment

c. Determination of recommended public protective actions

d. Coordination of emergency response activities with federal, state, and local agencies

Facilities are provided in the EOF for the acquisition, display, and evaluation of radiological, meteorological, and plant system data pertinent to determining offsite protective measures. These facilities are used to evaluate the magnitude and effects of actual or potential radioactive releases from the plant and to determine offsite dose projections. The EOF is used to coordinate emergency response activities with those of local, state, and federal agencies, including the NRC. DTE personnel in the EOF will make protective action recommendations for the public to the state emergency response organization.

The EOF is located in the basement of the nuclear operations center (NOC), approximately 6000 ft southwest of the Fermi 2 reactor building, and has been designed for habitability in the event of a postulated accidental radioactive release from Fermi 2. Shielding and HVAC system design ensure that NRC regulations for personnel exposure are satisfied.

The EOF is activated for conditions involving an Alert or higher emergency classification. Emergency plan implementing procedures define the transition of responsibility from the control room to the TSC and the EOF until the latter facilities become functional. The NOC also provides space for managing recovery operations and media briefings.

An alternative EOF is located at the Western Wayne Center, 22 miles northwest of the Fermi 2 site. The facility has adequate communications equipment and sufficient space to accommodate the additional personnel required for continuity of dose projection and decisionmaking capability, including coordination of the offsite teams. Portable equipment is provided for the personnel to perform their assigned functions.

7.8.4.2 Description

The primary EOF is located in the NOC building. Besides housing the EOF, the NOC provides room for supporting personnel required for assistance to Fermi 2 operations. This includes licensing, data control, administrative support, and training personnel. Also contained in the NOC will be the recovery center, a media briefing area, and a food processing and service area. Over 60,000 ft^2 of space will be provided in the NOC for these support personnel. Detailed information about staffing and the emergency organization is contained in the Fermi 2 Radiological Emergency Response Preparedness Plan.

The EOF is located about 6000 ft southwest of the power plant, just west of Quarry Lakes, within the DTE-controlled property boundary (see Figure 7.8-1). The facility can be reached from two directions via roads under the control of DTE. Electrical power is available from either one of two major power substations. An emergency generator is also available to automatically restore power in the improbable event of the loss of both power supplies.

The NOC building has been designed for the following:

a. Roof snow load: 40 lb/ft^2 minimum, plus provisions for drifted snow

b. Floors: 150 lb/ft^2 for entire second floor and for first floor at EOF

c. Stairs: 100 lb/ft^2

d. Wind load: conforms to ANSI A58.1-72, based on 100-year mean recurrence interval for exposure type C

e. Seismic: conforms to UBC for Zone 1.

The construction is standard except for special concrete shield walls surrounding the EOF that provide a protection factor of approximately 20. The internal layout of the EOF is shown in Figure 7.8-10 and consists of space allocated for records, counting facilities, offices, NRC office space, communications equipment, and emergency power (batteries) for communications equipment.

Habitability of the EOF is provided by an HVAC system, which includes a HEPA filter.

Radiation detection alarms are set at approximately three times the background levels to provide an early visual and audible warning to the EOF occupants. Air sampling capability is also provided in the EOF, with the capability to detect iodine concentrations as low as 1×10^{-7} $\mu Ci/cm^3$.

The EOF also has available friskers, dose rate meters, dosimeters of legal record (DLRs), iodine air sampler/detectors, and dosimeters to monitor radiation levels. The quality and quantity of this instrumentation has been determined by surveys, data research, and professional experience. The radiation monitoring equipment used in the EOF is calibrated according to Health Physics procedures and to manufacturers' instructions.

The EOF backup laboratory is equipped with a high-resolution gamma spectroscopy system and other equipment required to perform chemistry and radiochemistry.

Emergency supplies and equipment are stored and maintained in the EOF in accordance with the implementing procedures for the Radiological Emergency Response Preparedness Plan. These are periodically inventoried and calibrated to ensure their availability if needed. These supplies include protective clothing, stationery supplies, and duplicating equipment.

The EOF communication network is described in detail in the Radiological Emergency Response Preparedness Plan.

7.8.4.3 Information Systems

The EOF information systems are commensurate with the EOF functions of:

a. Coordination of offsite response

b. Coordination of radiological, meteorological, and environmental assessment

c. Recommendations for protective actions.

The information required to perform the above functions includes:

a. Assessment of plant status

b. Radiation releases

c. Meteorological data

d. Atmospheric dispersion models

e. Field monitoring for offsite radioactivity.

In addition to the information included in Subsections 7.8.2.9 and 7.8.2.10 for the TSC, the following are available for use in the EOF:

a. Offsite population data

b. Environmental radiological monitoring records

c. State and local emergency response plans

d. Evacuation plans.

7.8.4.4 Staffing

Staffing of the EOF is described in the Radiological Emergency Response Preparedness Plan.

7.8.4.5 Emergency Response Facilities Integration

During emergency conditions, it is essential that there be a continuous high level of interaction and communication among key personnel in the control room, emergency response facilities, and the NRC to ensure that all emergency actions are fully understood and coordinated.

The emergency response facilities are developed to function as an integrated system. DTE's emergency response facilities are designed to provide coordinated support to the control room during emergency operating conditions. These facilities are integrated into the Radiological Emergency Response Preparedness Plan to facilitate coordination with state and local emergency response facilities.

The system design of the emergency response facilities has the following functional criteria:

a. The operation of any system or subsystem within the emergency response facilities does not degrade the performance or reliability of any reactor safety or control system or of any safety-related displays in the control room

b. The operation of any system or subsystem in the emergency response facilities does not degrade or interfere with the functional operation of other systems in those facilities

c. The data acquisition hardware and software are protected against unauthorized manipulation or interference with input signals, data processing, data storage, and data output.

The emergency response function of the IPCS provides a fully integrated data processing system serving all emergency response facilities and systems.

The equipment to be used in the control room during an emergency is identified in Subsection 7.6.1.9. Subsection 7.6.1.9 also addresses the primary variables to be displayed.

7.8 EMERGENCY RESPONSE FACILITIES

REFERENCES

1. U.S. Nuclear Regulatory Commission, Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants, NUREG-0654, Revision 1, November 1980.
2. U.S. Nuclear Regulatory Commission, Standard Review Plan, Section 6.4, "Habitability Systems," NUREG-75/087, Revision 1.
3. U.S. Nuclear Regulatory Commission, Functional Criteria for Emergency Response Facilities, for Interim Use and Comment, Draft NUREG-0696, July 1980.
4. U.S. Nuclear Regulatory Commission, TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendations, NUREG-0578, July 1979; Revised August 1979 by NRC letter, enclosure 6.

TABLE 7.8-1 GOVERNING CODES AND STANDARDS FOR HVAC SYSTEM COMPONENTS

Components	Codes and Standards
Fans	AMCA 210-74: Laboratory Methods of Testing Fans for Rating
	AMCA 211A-74: Certified Rating Program Air Performance
	AMCA 300-67: Test Code for Sound Rating
Motors	NEMA MG 1-74: Motors and Generators
Cooling coils	ARI 410-72: Standard for Forced Circulation Air-Cooling and Air-Heating Coils (nuclear safety related and nonnuclear safety related)
Isolation, modulation dampers, and damper operators	AMCA 500: Test Method for Louvers, Dampers and Shutters
Supply filter units	Applicable portions of ANSI N509-76: Nuclear Power Plant Air Cleaning Units and Components
	ASHRAE 52-68: Air Cleaning Devices Used in General Ventilation for Removing Particulate Matter, Method of Testing
	Regulatory Guide 1.52 (Revision 2, March 1978): Design Testing and Maintenance Criteria for Engineered-Safety-Feature Atmosphere Cleanup System Air Filtration and Absorption Units of Light-Water-Cooled Nuclear Power Plants, including S&L Standard Position and excepting testing and quality assurance requirements.
Energy loads	ASHRAE Handbook and Product Directory, Fundamentals

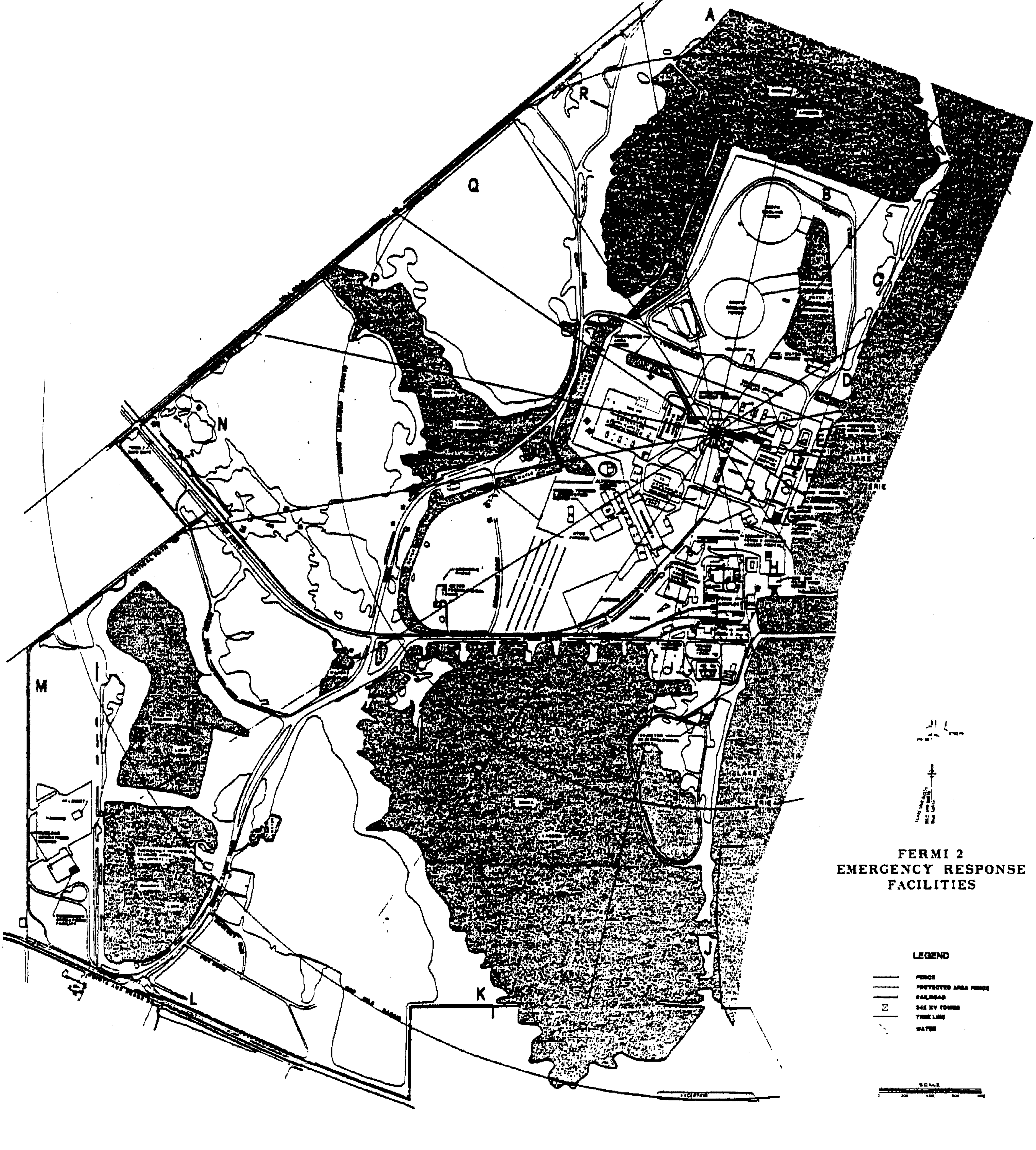
TABLE 7.8-2 GOVERNING CODES AND STANDARDS FOR MECHANICAL SYSTEM COMPONENTS

Components	Codes and Standards
Pressure vessel	ASME Boiler and Pressure Vessel (B&PV) Code, Section VIII, Division I
Heat exchangers	TEMA C and ASME B&PV Code, Section VIII, Division I
Piping	ANSI B31.1.0
Valves	ANSI B31.1.0
Pumps	Manufacturer's standards
Atmospheric storage tank	API-650, AWWA-D100, or ANSI B96.1
Storage tanks, 0 to 15 psig	API-620
Filter package	ANSI N509 and N510

TABLE 7.8-3 PERFORMANCE REQUIREMENT AND PHYSICAL PROPERTIES OF (UNUSED) ACTIVATED CARBON

Test	Method	Acceptance Value
	Performance Requirements	
Molecular iodine, 30 °C, 95 percent RH[a]	ASTM D3803	0.1 percent penetration, maximum
Molecular iodine, 180 °C		99.5 percent retentivity, minimum
Methyl iodine, 30 °C, 95 percent RH		3 percent penetration, maximum
Methyl iodine, 80 °C, 95 percent RH[a]		1 percent penetration, maximum
	Physical Properties	
Particle-size distribution	ASTM D2862	8 x 16 U.S. mesh Retained on No. 6 sieve: 0.1 percent maximum Retained on No. 8 sieve: 5.0 percent maximum Through No. 8, on No. 12 sieve: 60 percent maximum Through No. 12 on No. 16 sieve: 40 percent maximum Through No. 16 sieve: 5.0 percent maximum Through No. 18 sieve: 1.0 percent maximum
Ball pan hardness	ASTM D3802	92 minimum
C Cl_4 activity (onbase)	ASTM D3467	60 minimum
Apparent density	ASTM D2854	0.38 g/cm^3 minimum
Ash content (onbase)	ASTM D2866	State value
Ignition temperature	ASTM D3466	330 °C minimum
Moisture content	ASTM D2867	State value
pH of water extract	Appendix D	State value

[a] Tests shall be performed for qualification purposes only.



Fermi 2

UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 7.8-1

EMERGENCY RESPONSE FACILITIES

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Refer to Plant Drawing A-TS-2002

Fermi 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 7.8-2

TECHNICAL SUPPORT CENTER FLOOR PLAN

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Refer to Plant Drawing TSC PROPERTY PLAN

Fermi 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 7.8-3

PROPERTY PLAN – TECHNICAL SUPPORT CENTER

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Refer to Plant Drawing M-TS-2002-1

Fermi 2

UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 7.8-5

TECHNICAL SUPPORT CENTER HVAC SYSTEM
2VV01S AND 2VV02S

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Refer to Plant Drawing M-TS-2002-2

Fermi 2

UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 7.8-6

TECHNICAL SUPPORT CENTER HVAC SYSTEM
2VV02S

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Refer to Plant Drawing M-TS-2002-3

Fermi 2

UPDATED FINAL SAFETY ANALYSIS REPORT

7.8-7

TECHNICAL SUPPORT CENTER HVAC SYSTEM
2VV03S AND 2VV04S

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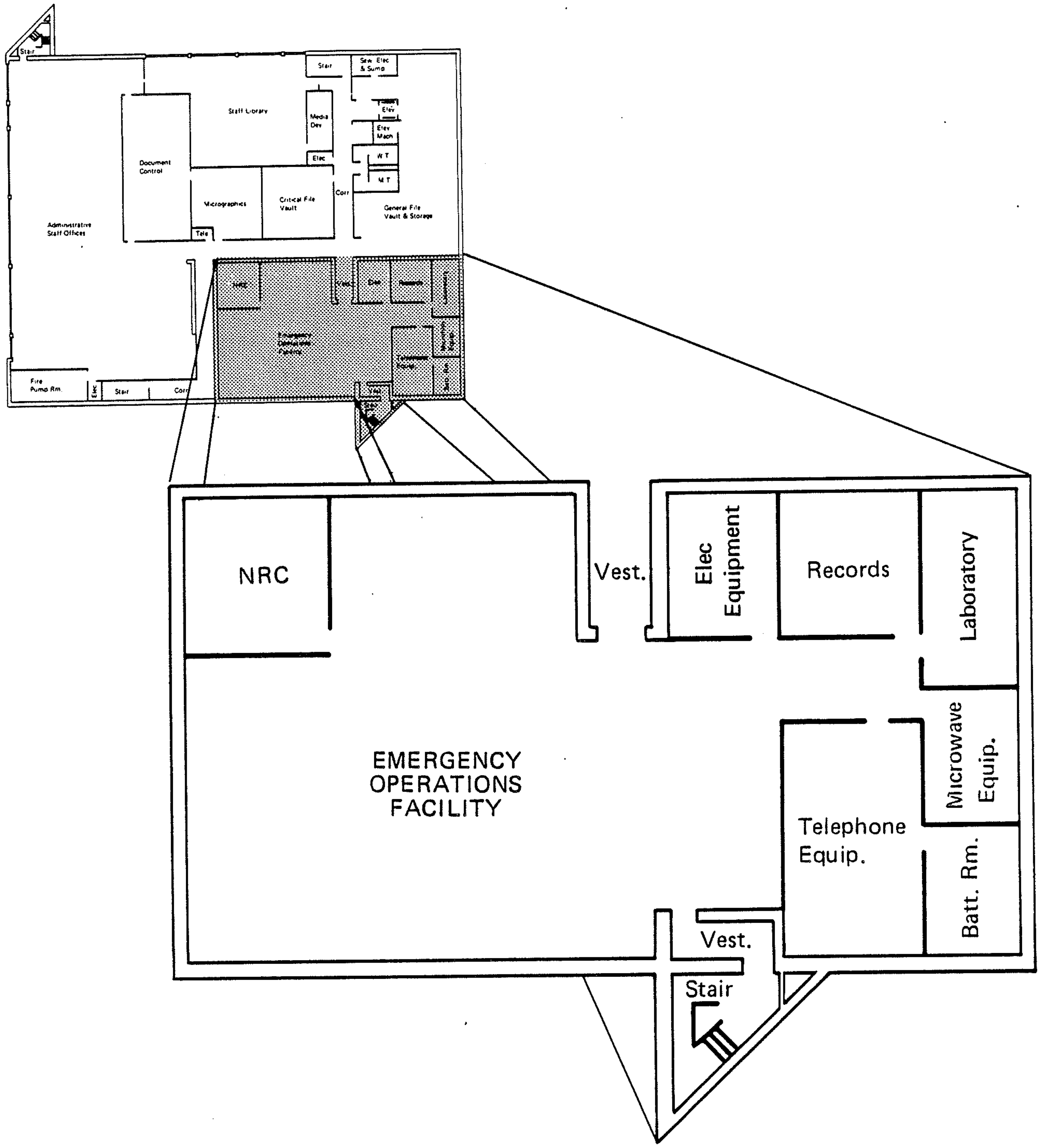


Fermi 2

UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 7.8-10

FLOOR PLAN – EMERGENCY OPERATIONS FACILITY

CHAPTER 8: ELECTRIC POWER

8.1 INTRODUCTION

Fermi 2 has a net electrical capacity of approximately 1170 MWe generated by a single turbine generator at 22 kV, and stepped up to 345 kV by two parallel transformers. These transformers are connected on the high side to the Fermi 2 345-kV station. This station is interconnected by two double circuit 345-kV lines to the Edison system (Figure 8.2-1). When Fermi 2 becomes operational at full power, the total capacity of the Edison system will be approximately 10,429 MW. When operating in conjunction with the Consumers Power Company, with whom a coordinated system has been established having four interconnections at 345 kV, the total integrated system capacity will be approximately 16,709 MW. Edison also has strong 345-kV interconnections with Ontario Hydro (two interconnections) and Toledo Edison (three interconnections).

Also on the Fermi site is the permanently shutdown Enrico Fermi Atomic Power Plant, Unit 1 (Fermi 1).

Fermi 1 also includes four gas turbine peaking units, each generator having a name plate capacity of 18.8 MVA. These units, as limited by turbine design ratings, have a net electrical output of 62.2 MW (summer) and 75.9 MW (winter). One of these units has the ability to be started by a diesel without the need for an external source of power.

The output of the gas turbine peaking units is connected to the 120-kV station, and this station is connected to the Edison system by three 120-kV lines (Figure 8.2-2).

All lines at both 120 kV and 345 kV are run on a common right-of-way; however, the right-of-way is of such a width that a 345-kV tower falling cannot interrupt all the lines on the right-of-way. The 120-kV and 345-kV transmission lines leave the plant in a common right of way for approximately 5 miles before diverging into different rights-of-way to the final termination at individual stations. Auxiliary power for Fermi 2 comes from both the 120-kV and 345-kV systems. Each system supplies half of the balance-of-plant (BOP) loads and one of the two redundant safety divisions.

Plant auxiliary power for engineered safety feature (ESF) loads for Division I of the two divisions is derived from a 15/20-MVA, 13.2/4.16-kV transformer connected to the secondary of a 120/13.2-kV transformer on bus 101, with an alternate feed from the secondary of the 120/13.8/13.8-kV gas turbine peaking unit transformer. The other division's power is supplied by one secondary winding, 45.32 / 27.99 / 17.33 MVA (ONAF (Oil Natural Air Forced cooling system)), of the 345/4.16/4.16-kV transformer. It should be noted that Fermi 2 has no unit auxiliary transformer. All plant auxiliaries are fed in normal operation from the 120-kV and 345-kV systems indicated above.

The principal voltage for auxiliary power is 4.16 kV, with smaller loads being supplied from 480-V ac load centers and motor control centers (MCCs).

In case of a total loss of offsite power, the unit requirements for power for safe shutdown are supplied by four 2850-kW diesel generators, two per division. Within a division, the two diesel generators are not run in parallel; each supplies a load group comprising about half of the division's emergency power requirements.

The dc power is supplied from three 260-V batteries, two batteries for ESF loads and one battery for BOP loads, to supply dc motors and motor-operated valves. Each battery is center tapped to provide 130-V dc power for control functions (Figures 8.3-9 and 8.3-11). There are two 48-V center-tapped batteries to supply source and intermediate range nuclear instrumentation and radiation monitoring equipment (Figure 8.3-10).

The ESF loads that require electric power to perform their safety function, the function that is performed, and the type of power that is required (ac/dc) are listed in Tables 8.1-1 and 8.1-2.

The design of the Fermi 2 electric power system is up to date with respect to the state of the art for nuclear plants and takes into account all NRC regulations, guides, and design criteria, including General Design Criteria 17 and 18. Regulatory Guides 1.6, 1.9, 1.30, 1.32, and 1.63, and IEEE Standards 308-1971, 279-1971, 323-1971, 317-1972, and 334-1971 are followed, except as noted in Subsection 8.3.1.2.2.2 and Appendix A.1.9. IEEE 323-1974 was taken into account on equipment for which the purchase specification was executed on or after November 15, 1974.

TABLE 8.1-1 ENGINEERED SAFETY FEATURE, AC LOADS

Engineered Safety Feature, AC Loads	Safety Function Performed
Core spray system (including pump motors, controls, and supporting devices)	Provides emergency core cooling by spraying water directly on the core
Residual heat removal (RHR) system (including pump motors, controls, and supporting devices)	Provides emergency core cooling by restoring and maintaining the water level in the reactor core at an adequate height; provides containment cooling using the containment spray mode of operation; removes residual heat from the reactor core during shutdown for refueling or servicing
RHR service water system and ultimate heat sink (including pumps, motors, fans, controls, and supporting devices)	Provides cooling to the essential features of the RHR complex, backup core flooding, and ultimate heat sink for all vital cooling systems
Main steam line monitoring system	Provides indication of gross fuel failure
Containment inboard isolation valves	Isolates the primary containment
Emergency equipment closed cooling water system (including pump motors, controls, and supporting devices)	Provides cooling water to the equipment needed for emergency shutdown
Diesel generator cooling water pumps, vent fans, and associated devices necessary for the operation of the standby power supply	Allows operation of the standby power supply
Main control room ventilation and air conditioning system	Ensures operation of safety-related control and instrumentation devices within their rated temperature
Standby gas treatment system	Reduces the consequences of off-site radiation doses resulting from a postulated accident
Engineered safety feature ventilation cooling system	Ensures operation of safety-related equipment

TABLE 8.1-2 ENGINEERED SAFETY FEATURE, DC LOADS

Engineered Safety Feature, DC Loads	Safety Function Performed
Automatic depressurization system	Relieves the pressure of the reactor pressure vessel to the containment pressure suppression pool
High-pressure coolant injection system accessories only (valves, pumps)	Maintains sufficient reactor water inventory for a small-break area LOCA
Containment outboard isolation valves	Isolates the primary containment
Control power for Class 1E switchgear and other devices included in the safety systems	Provides reliable control of the safety equipment

8.2 OFFSITE POWER SYSTEM

8.2.1 Description

8.2.1.1 Offsite Power Sources

Offsite power is available for the auxiliary power requirements of Fermi 2 at two different voltage levels, 345 kV and 120 kV.

Fermi 2 exports its net generation capability of approximately 1170 MWe at 345 kV after transformation by two parallel transformers from the generation level of 22 kV. The unit is interconnected with the 345-kV transmission system by two circuits or lines with one line per single tower, as shown in Figure 8.2-1. Each circuit is installed on a single tower and the two lines run to the Brownstown Station located about 16 miles away. These lines run over generally flat farmland. Each 345 kV line is protected by two identical and independent line differential schemes (A and B) using digital relays and fiber optic communication paths to provide high speed fault clearing. Each of these digital relays also provides additional time coordinated line protection, as a supplement to the differential schemes. Breaker failure protection is provided as part of the Backup (B) relaying and provides input to the (A) and (B) transfer trip logic. There are two independent fiber optic paths that link Fermi 2 to Brownstown Station. Each digital relay receives a fiber pair from each path as a normal and hot standby input. All four line protection schemes (A and B for each line) provide transfer tripping to Brownstown Station using the fiber optic communication paths as part of the breaker failure protection scheme. Both lines are equipped with time delayed automatic breaker reclosing to restore service to the line in the event of a momentary line fault (e.g., lightning).

The Fermi 2 to Brownstown lines leave the plant on opposite sides of a 500-ft right-of-way with three 120-kV lines routed between them. A plan view of the transmission corridor is shown in Figure 8.2-2; a sectional view of the transmission corridor appears in Figure 8.2-3. The spacing of the lines is such that collapse of either of the 345-kV towers would not interrupt the other 345-kV line, although it can interrupt two of the three 120-kV lines. The Fermi-Brownstown circuits will run to Brownstown Station via 345-kV towers located on the 500 ft out-of-plant transmission corridor to the east side of the Detroit-Toledo Expressway (I-75) and then via 345-kV towers on the Monroe-Brownstown corridor. Angle towers are used for all turns. The towers and lines have been designed for a simultaneous wind loading of 8 lb/ft^2 with a 1/2-in. ice load or, equivalently, a 1-in. ice load without wind load.

Although Fermi 2 does not generate power at 120 kV, it has strong interconnections with the 120-kV system (Figure 8.2-4). There are three 120-kV lines on separate towers running into the plant along the same right-of-way as the 345-kV lines. One line terminates at the Custer substation 13.9 miles away passing through the Shoal substation, the second at Radka 21.7 miles away, and the third at Brownstown 16.3 miles away after passing through the Swan Creek Substation and the Berlin Substation. (These line lengths are historical data and may not reflect the current line lengths.) These lines all terminate at the Toll Road substation located outside of the Fermi 2 owner controlled area. From the substation, the power enters the Fermi 2 120 kV switchyard on lines designated as Toll Road #1, #2, and #3. The 120-kV lines separate from the 345-kV Brownstown line at various points of the right of way and therefore do not follow the 345-kV lines the entire distance to the Brownstown Station but may share right of ways with additional lines (see Figure 8.2-2). These lines run through generally flat farmland with no unusual terrain features. These lines are protected with current differential and timed step distance first-line relaying, with redundant current differential and timed step distance relay backup. All three lines have automatic reclosing after a time delay to restore service in case of transient faults.

The 120-kV switchyard at Fermi 2 is tied to the 120-kV system through the Toll Road substation with three lines. The 120-kV Toll Road-Swan Creek line to the Brownstown station has a strong 345/120-kV source at Brownstown, in addition to two other 120-kV lines. The line to Custer Station ultimately ties to the Consumers Power Company's 120-kV system (Whiting A-1). The Radka line is ultimately tied to Superior Station, which has five additional lines at 120 kV, including two strong ties to the 345-kV transmission system at Wayne.

In March 2003, ownership of the Edison transmission system, including both switchyards, transferred to an independent purchaser, ITC Holdings. Edison and ITC Holdings are members of the East Central Area Reliability Council (ECAR), which also includes other utilities located in the midwestern region of the United States. The total peak load served by ECAR members is about 100,000 MW, and the ECAR members have about 108,000 MW of installed generating capacity.

ECAR members are required to maintain a minimum level of contingency reserves totaling 3 percent of their daily peak load projection, to protect against the unexpected loss of generating sources or other contingencies. An additional 1 percent of the daily peak load projection for each day is required to be maintained by the ECAR members as Load and Frequency Regulation Reserve, for load and frequency regulation. Some of the reserves are available immediately upon request, to meet the contingencies like unit trip and all reserves are required to be available within 10 minutes.

ECAR members are also required to share their reserves in the event of a unit trip, or some other type of system emergency that jeopardizes firm load, under a process referred to as Automatic Reserve Sharing. Thus, there will always be sufficient reserves available to maintain reliability for customers on the Detroit Edison system, even in the event of a trip of the largest unit.

The interconnection capability of Michigan Electric Coordinated System (MECS) study area, which includes Detroit Edison, will conservatively be approximately 3000 MW. ECAR studies show that adverse conditions outside the MECS study area may at times limit the capability to 2500 MW. This capability is sufficient to allow the forced outage of Edison's largest unit while its second largest unit is out of service.

Edison has the following interconnections with other utilities:

a.	Consumers Power	four 345-kV circuits five 120/138-kV circuits
b.	Ontario Hydro	two 345/230-kV circuits* two 230-kV circuits

c. Toledo Edison three 345-kV circuits

* The 230-kV portion of these circuits is located in Ontario.

8.2.1.2 Switchyards

The 345-kV switchyard is located approximately 150 yards from the plant. Its physical configuration is shown in Figure 8.2-5 and its electrical configuration is shown in Figure 8.3-1. The 345-kV switchyard is arranged in a nominal double breaker-double bus configuration. Transformer SS65, the auxiliary transformer serving Division II engineered safety feature (ESF) buses, is fed from the east bus (bus 301) of the switchyard. Switchyard circuit breakers are opened automatically by the associated line or bus relaying. Each breaker has two independent trip coils. The switchyard circuit breakers CM and CF are controlled in the Fermi 2 main control room. Switchyard circuit breakers BT, BM, DM and DF are controlled by transmission company, ITC Holdings. The switchyard has two control batteries, one for each of the two channels of protection (including trip coils) so that a battery or associated protection system failure will not prevent tripping and resultant isolation of faults. Transfer tripping of backup or remote terminal circuit breakers is accomplished through redundant fiber optic links.

The only switchyard fault that could lead to a sustained loss of power to transformer SS65 is a fault affecting bus 301 or transformer SS65 or an open phase condition on the SS65 high voltage side. In this case, the feed from the 120-kV switchyard to transformer SS64 will still be available for Division I power and safe shutdown. Failure of circuit breakers CF, DF or BM will cause a shutdown of bus 301.

If circuit breaker CF should fail, service to bus 301 can be restored in the following manner. Bus 301 would be deenergized with circuit breakers DF, BM and CM open due to backup protective relaying operation which isolated the faulted breaker. Visual inspection of relaying operation indicators would be made along with visual breaker inspection. If it is determined that a breaker failure caused the backup protective relaying to operate, permission would be obtained from the Central System Supervisor to restore service.

The defective circuit breaker CF would be isolated by opening the two sets of manual disconnects associated with circuit breaker CF. This is done at the control pedestal located at the base of the disconnects. Once the disconnects have been opened and tagged for safety purposes, circuit breaker DF and/or BM may be closed to energize bus 301, restoring service to system service transformer 65. The circuit breaker operations required to complete such an alignment is controlled by ITC Holdings. The time required to complete such an operation could vary from a minimum of 1 hr to a maximum of 8 hr.

Similarly, if circuit breaker DF should fail, bus 301 would be deenergized with circuit breakers DM, BM and CF open due to backup protective relaying operation which isolated the faulted breaker. Circuit breaker CM would be opened due to loss of the main machine on loss of system service transformer 65. The defective circuit breaker DF would be isolated by opening the manual disconnects associated with circuit breaker DF. Once the disconnects have been opened, the circuit breaker BM can be closed to energize bus 301, restoring service to system service transformer 65. Alternatively, circuit breakers CF and CM can be closed to energize bus 301, restoring service to system service transformer 65, after opening the intermediate switchyard motor-operated disconnect switches to disconnect the main unit transformers from the circuit breakers CF and CM. The time required to complete such an operation could vary from a minimum of 1 hr to a maximum of 8 hr.

Similarly, if circuit breaker BM should fail, bus 301 would be deenergized with circuit breakers DF, BT and CF open due to backup protective relaying operation which isolated the faulted breaker. Circuit breaker CM would be opened due to loss of the main machine on loss of system service transformer 65. The defective circuit breaker BM would be isolated by opening the manual disconnects associated with circuit breaker BM. Once the disconnects have been opened, the circuit breaker DF can be closed to energize bus 301, restoring service to system service transformer 65. Alternatively, circuit breakers CF and CM can be closed to energize bus 301, restoring service to system service transformer 65, after opening the intermediate switchyard motor-operated disconnect switches to disconnect the main unit transformers from the circuit breakers CF and CM. The time required to complete such an operation could vary from a minimum of 1 hr to a maximum of 8 hr.

The 120-kV switchyard, located at Fermi l about 1/4 mile from Fermi 2, is arranged as a radial-fed double bus as shown in Figure 8.3-1. The switchyard is arranged in such a way that any line fault will not interfere with the ability to energize transformer 1 and, therefore, Division I power. The only circumstance that could result in a sustained loss of power to transformer 1 is a fault affecting the 120-kV switchyard bus 101 or an open phase condition on the transformer 1 high voltage side. In this case, offsite power would be available from the 345-kV switchyard to Division II, which meets minimum safety-feature power requirements. Failure of circuit breakers GH or GD to interrupt a fault will cause a loss of bus 101. However, the power to Division I can be restored by one of two alternatives: the defective breaker can be isolated by use of disconnect switches and the bus reenergized or the source to Division I can be transferred to transformer CTG-11 secondary, thus feeding from 120-kV switchyard bus 102 (Figure 8.3-1).

The l20-kV switchyard was originally built to service the Fermi 1 liquid metal fast breeder reactor which has been permanently shut down. Four 18.8-MW gas turbine peaking units are installed near Fermi l on the Fermi site. Peaking units are of GE heavy-duty industrial design, rated at 18.8 MVA each.

These units may be started individually from the local panels in the combustion turbine generator control rooms. They may also be started from the Fermi 2 control room by a supervisory control system.

The peaker units are located approximately 200 ft south of the 120-kV switchyard, and are enclosed in a separate, fenced-in area. Electrically, there are two units to a peaker bus (buses 1-2A and 3-4A). These buses in turn are connected to the CTG-11 transformer via direct, buried, 25-kV insulated cables. These units operate at 13.8 kV, but the cables to the CTG-11 transformer were replaced with more conservatively rated 25-kV cables to improve the overall reliability of the CTG-11 transformer and the peaking unit block. However, any one of them has sufficient capacity to supply all plant ESF loads connected to Division I buses. One of the gas turbine peaking units is diesel-cranked and can be started without offsite power. The output of this generator can be used to start the other three.

8.2.1.3 Offsite Power Supply to the Plant from the Switchyards

There are five transformers supplying offsite power to Fermi 2. Two of the transformers, SS66 and SS68, provide power to the circulating water pump house and the general service water pump house, respectively, and both are located near their respective pump houses. The third transformer, SS69, provides power to both the circulating water pump house and the general service water pump house. See Subsection 8.3.1.1.1.

The other two transformers, SS64 and SS65, are located on the west side of the turbine building. Transformer SS65 is a three winding 345/4.16/4.16-kV, 34 / 21 / 13 MVA (ONAN (Oil Natural Air Natural cooling system)) 45.32 / 27.99 / 17.33 MVA (ONAF) cooled, outdoor transformer. One secondary winding supplies power to the recirculation pump motor-generator sets. The other winding supplies approximately half of the balance-of-plant (BOP) loads and all of the Division II Class 1E loads. Transformer 65 is equipped with an automatic online load tap changer on each of the 4.16 kV windings to accommodate a maximum switchyard voltage of 105% on down to a minimum switchyard voltage of 92% following a single grid contingency. Transformer SS65 is connected to bus 301 of the 345-kV switchyard via overhead lines.

Transformer SS64 is a 13.2/4.16-kV, 15/20-MVA, OA/FA outdoor transformer. It supplies Division I Class 1E power requirements and BOP loads. It receives its power from the 13.2-kV bus 11 via a buried bus duct. Bus 11 in turn receives its power from transformer 1, a nominal 120/13.2-kV, 24/32-MVA, oil-cooled outdoor transformer. Transformer SS64 is equipped with a +/- 15 percent automatic acting Load Tap Changer and a fixed tap setting of -5 percent which maintains adequate Division 1 voltages with 120 kV voltage variations between -10 percent and +20 percent which envelopes the +5 percent to -6.7 percent range. Without action from the Load Tap Changer, the Division 1 voltages would not remain adequate for the entire range of 120 kV voltages. The Load Tap Changer has a 20 second delay before movement and is set to maintain 121.8 V ac +/1 V ac. After the 20 second time delay the Load Tap Changer is capable of moving one tap approximately every two seconds resulting in a voltage change of approximately 0.9375 percent for each movement. Transformer 1 is located within the 120-kV switchyard and is connected to bus 101 of that switchyard. An alternate feed has been supplied to transformer SS64 from bus 1-2B. Bus 1-2B in turn receives power via an overhead enclosed bus duct from transformer CTG-11, a 120-kV to 13.8-kV, three winding, 60/68-MVA, oil-filled transformer. This transformer also serves as the step-up transformer for the four gas turbine peaking units located near Fermi 1. Transformer CTG-11 is located within the 120-kV switchyard and is connected to bus 102 of that switchyard.

CTG 11-1 is utilized as the alternate ac source for a Station Blackout event and to support response by the Dedicated Shutdown Panel to an Appendix R fire. An alternate CTG started with the standby diesel generator can also be utilized as an alternate source of this ac power.

The feeders from transformers SS64 and SS65 are run into the plant in completely separated systems to preserve the independence of the two offsite supplies. Transformer SS64 is run in underground ducts and in nonsegregated cable bus. Transformer SS65 is run in nonsegregated cable bus only.

Fermi 2 has installed open phase detection and isolation systems on the high voltage side for the system service transformer 1 and SS65 that powers Division I & II ESF and BOP buses to ensure that plant safety-related structures, systems and components perform their intended functions under postulated open phase conditions.

8.2.1.4 Design Capabilities for Periodic Inspection and Testing

The protective equipment on the 345-kV offsite power system is in itself redundant. Each of the two 345 kV lines have two identical and independent relay schemes utilizing fiber optic communications. There are two independent fiber communication paths between Fermi 2 and Brownstown Station, which serve each relay. The redundant relay schemes for each line operate from separate ac current and potential sources and the dc control is fed from separate batteries. The control for each line relay scheme operates separate redundant trip coils at each breaker. Breaker failure protection is provided as part of the backup (B) line relaying and provides input to (A) and (B) relaying schemes as available, to provide tripping of adjacent breakers and transfer trip for remote breakers.

The use of two relaying schemes with the redundant batteries and trip coils, along with current shorting switches and potential throwover switches, allows for the inservice shutdown of any one relay and control scheme for testing while maintaining one relaying scheme in service. The use of the double breaker-double bus scheme allows for the shutdown of one breaker without shutdown of the line itself. The breaker may then be tested with the relaying schemes as desired.

The 345-kV bus 301 has two protective bus differential relaying schemes, either one of which may be shut down for testing while maintaining the other in service. All control operations except actual tripping of the breakers can be done while maintaining bus 301 in service. Associated breaker operations may be completed one at a time to maintain service to the bus.

The 120-kV offsite system allows for periodic testing in the following manner. In addition to the combustion turbine generators, the 120-kV switchyard, which ultimately supplies Division I ESF buses, has three sources of power, composed of three 120-kV lines. Any of the lines may be shut down for complete periodic testing and still maintain two sources of power to the switchyard.

The design of the Edison system and the excellent reliability and percentage of correct operations are a result of this design and the effort to give maximum service and reliability. This design is in full conformance with General Design Criterion 18.

8.2.1.5 Conclusions

It is concluded that the design and configuration of the offsite power system conform to the requirements of IEEE 308-1971, Regulatory Guide 1.32, except for Parts 1d, 1e, and 2b, and General Design Criteria 17 and 18 of 10 CFR 50, Appendix A. These sections required compliance with Regulatory Guides 1.75 and 1.93. For discussions of those guides, see the applicable sections of Appendix A of this UFSAR.

8.2.2 Analysis

8.2.2.1 Loss of Fermi 2

Analysis of the Edison grid and surrounding systems was conducted, assuming the sudden loss of Fermi 2 during a period of maximum system demand and heavy power import. System stability is generally more critical during periods of heavy power import. A study was conducted using a digital computer program that models the Edison power system and those systems with which it has strong interconnections. The model treats large generators in both the Edison system and surrounding systems as discrete entities.

The analysis of the Edison offsite power grid stability, assuming a sudden trip of Fermi 2, indicates that the grid is stable.

The studies also indicate that the grid is capable of supplying the necessary offsite power if Fermi 2 is lost. This conclusion is based on the following analysis of the studies:

a. There is no evidence of cascading resulting from either high circuit loadings or depressed network voltages, because:

    1. Transient and steady-state postfault network voltages are at or near prefault conditions

    2. Transient and steady-state postfault network line flows are within emergency ratings.

b. Based on generator rotor angle changes, no machines tend toward instability

c. Transient and steady-state postfault Fermi auxiliary supply voltages are near prefault conditions.

A series of studies that consider a large Edison import have been made to examine the consequence of a system fault combined with a circuit breaker failure. This study assumed that:

a. The system modeled was that planned by Edison for early 1979 assuming Fermi 2 operational

b. System load was at the peak expected value for that period

c. Edison was importing 1300 MW of power, approximately 15 percent of net demand and roughly half of the system's net import capability

d. One 800-MW unit at the Monroe plant, the large fossil station nearest the Fermi site, was not operating

e. Only the Fermi 2 generator was in service at the Fermi plant

f. The postulated contingency was a three-phase fault on the Fermi-Brownstown 345-kV #3 circuit adjacent to Fermi 2

g. In addition, a circuit breaker failure at the Fermi 345-kV switchyard was assumed, which actuates backup relaying, resulting in disconnection of Fermi 2 from the grid.

The stability evaluation consisted of a prefault load flow, a transient stability study of the fault and immediate postfault system conditions, and a postfault steady-state load flow simulating system conditions after transients have subsided.

The prefault load flow study, which provided the initial conditions for the transient and the posttransient studies, included a detailed representation of the Edison, Consumers Power, Ontario Hydro, and Toledo Edison systems. Other interconnected systems were represented either to a lesser degree, or by an equivalent of the system.

The transient stability study showed the first 2 sec after the contingency occurs. The contingency considered involves a three-phase fault adjacent to the Fermi 345-kV bus on the Fermi-Brownstown #3 circuit and subsequently, backup protection operates in 12 cycles to isolate the faulty circuit breakers BM and BT at the Fermi station. Simulation of generators of 500 MW or greater capacity, which are electrically close to the Fermi plant, included transient saliency and excitation response.

The postfault load flow portrayed system conditions after transients have subsided and prior to automatic tieline and frequency control actuation to recover the Edison generation loss. During this period, the loss of generation is assumed offset by discrete load and generation changes that result from the drop in system frequency.

The transient stability and postfault load flow studies indicated that both the grids at 345 kV and 120 kV are stable and that Edison and its interconnected systems are capable of supplying the necessary offsite power. This conclusion was reached since there was no evidence of cascading, which could have resulted from either high circuit loadings or depressed network voltages. Steady-state postfault network voltages were at or near prefault conditions, and steady-state postfault network line flows were within emergency ratings. There was no apparent reaction of network protective relaying to transient network line currents and voltages. System transient studies are periodically updated, as system loads and configurations change, to verify that Edison's stability criteria are being met.

8.2.2.2 Outages of Transmission Lines Into Fermi

To demonstrate the reliability of the lines supplying the Fermi site, a historical study of unscheduled line outages on the existing 120-kV system was made. The following outages are an actual record of the outages of the 120-kV lines and buses at the Fermi plant. These interruptions are of the unscheduled variety and were recorded anytime the through current was interrupted. A number of these interruptions were of a momentary nature; that is, the current was automatically restored within seconds.

Unscheduled Outages[a]
Lines, 120 kV into Fermi Plant

Line	Length (Miles)[e]	1968	1969	1970	1971	1972	1973	Interruptions Average/Year
Fermi-Custer[b]	9.5	2	2	2	3	2	1	2.16
Fermi-Luzon[c]	21.5	0	0	0	2	1	2	0.83
Fermi-Brownstown[d]	16.1	2	0	1	4	3	3	1.66

a For additional, more current information on outages, see Table 8.2-1

b Line renamed in 1995 to Fermi-Shoal and Shoal-Custer lines. The Fermi-Shoal segment was revised to Fermi-Toll Road and Toll Road-Shoal in 2018.

c Line renamed in late 2003 to Fermi-Radka and Radka-Luzon. The Fermi-Radka segment was revised to Fermi-Toll Road and Toll Road-Radka in 2018.

d Line re-named in 1989 to Fermi-Swan Creek and Swan Creek-Brownstown lines and renamed in 1996 to Fermi-Swan Creek, Swan Creek-Berlin and Berlin-Brownstown lines. The Fermi-Swan Creek segment was revised to Fermi-Toll Road and Toll Road-Swan Creek in 2018.

e These line lengths are historical data and may not reflect the current line lengths.

Buses, 120 kV at Fermi

Bus	1968	1969	1970	1971	1972	1973	Interruptions Average/Year
101	0	0	0	1	0	0	0.166
102	0	0	0	1	0	1[f]	0.33

f This outage was due to a gas turbine peaking unit cable failure, which directly affects the 120-kV system. These cables have been replaced with extra-insulated cables (25 kV) to increase reliability.

A similar historical analysis of the actual 345-kV system was not possible since the lines are relatively new into Fermi 2. Past outages in this region most often have been the result of lightning strikes; however, outages due to gunshots, train derailments, galloping conductors, equipment failure, and unknown causes have also occurred. The average occurrence rate for thunderstorms is 35 per year. Circuit failures causing outages for 5 minutes or longer have occurred at a frequency of 1.0 per 100 circuit-miles per year. Failures causing outages for less than 5 minutes have occurred at a rate of 4.0 per 100 circuit-miles per year.

To achieve a base for viewing reliability of the 345-kV system, transmission performance data published by ECAR and MAIN reliability regions were used to yield estimated circuit unavailabilities for both the 345-kV and 120-kV transmission systems. This outage rate includes both scheduled and unscheduled outages.

Out-of-plant transmission availability can be measured by circuit outage rates and restoration time following an outage. The data are statistical in nature and are, therefore, subject to the number of circuit miles and geographical area for which historical performance data were available to compile the outage rate. Data for 120-kV circuits should be fairly representative because of the considerable number of circuit miles and years for which operating records are available. The data base available for evaluation of 345-kV circuit outage rates is not extensive, and is, therefore, more subject to change. The outage rate and restoration time data in Table 8.2-2 are for this reason based on a mixture of judgment and operating experience.

The stability studies in Subsection 8.2.2.1 lead to the conclusion that the two systems are electrically independent.

Another area of possible susceptibility to common failure is transmission line crossovers. The two Fermi-Brownstown 345-kV circuits are on separate tower lines. The crossovers that exist are

a. Fermi to Brownstown #3, south 345-kV circuit <u>crosses over</u> the Toll Road #1, Toll Road #2, and Toll Road #3 120-kV circuits (three 120-kV Fermi circuits) near the Fermi power plant at Toll Road and again when 345-kV circuit turns north at Highway I-75 at Mentel Road crossing over the Toll Road-Shoal, Toll Road-Radka, and Toll Road-Swan Creek lines

b. Monroe to Brownstown 345-kV (2) circuits <u>cross over</u>

    l. Fermi to Brownstown #3 north of Post Road at I-75

    2. Three 120-kV Toll Road circuits at I-75.

c. Monroe to Wayne and Monroe to Coventry circuits <u>cross</u> <u>over</u>

    1. Toll Road-Shoal 120-kV circuit near I-75

    2. Toll Road-Radka 120-kV circuit near War Road.

d. Majestic to Monroe-Allen Junction tap and the Majestic to Lemoyne circuits near Covell Road <u>cross over</u> the Toll Road-Radka 120-kV circuit

e. Fermi to Brownstown #3 north 345-kV circuit crosses over all three 120-kV lines twice at the Toll Road substation.

Based on the above, the most critical failure would be the collapse of the Fermi-Brownstown 345-kV north or south circuit out of Fermi as they pass over the 120-kV circuits as described in a. or e. above. Although this could cause the loss of all 120-kV circuits, the remaining Fermi-Brownstown 345-kV circuit out of Fermi would remain in service.

Based on this information, it is concluded that even in the case of a major earthquake, tornado, or similar cataclysmic event, the simultaneous loss of all offsite power transmission is improbable. However, should a complete loss of offsite power occur, the ESF buses will be supplied from the standby emergency diesel generators (EDGs).

8.2.2.3 <u>Switchyard Outages</u>

The primary defense against a total loss of offsite power is the complete independence of the two switchyards. The 345-kV and 120-kV switchyards are physically separated by more than a quarter of a mile and have no electrical interties. Therefore, other than a major natural disaster, such as a tornado or an earthquake of unexpected magnitude, no single event could precipitate the simultaneous loss of both switchyards.

The 345-kV switchyard double breaker-double bus design maximizes circuit, unit, and system service transformer availability by allowing terminal equipment maintenance without a complete shutdown of the associated circuit, unit, or system service transformer. On occurrence of a line fault, the provided protective relay schemes will:

a. Open the affected breaker

b. Initiate the breaker failure scheme.

In case the breaker called on to open fails to function or interrupt the fault within a predetermined time, the breaker failure scheme will:

a. Initiate transfer trip to open the breakers at the remote terminal of the line

b. Open all local breakers necessary to isolate the fault and defective breaker.

With the exception of a breaker failure-scheme operation resulting in tripping of all bus 301 breakers, no 345-kV line fault will cause the interruption of power transformer SS65.

Any defective breaker in the switchyard can be isolated with disconnect switches and power restored. The only failures that could cause a sustained outage of power to transformer SS65 are

a. A fault on bus 301 or associated equipment

b. A fault on either transformer SS65, or its feeder on the secondary side, detected by the transformer phase and neutral overcurrent or differential protection relays

c. A sudden pressure rise in the transformer oil

d. An open phase condition on transformer SS65 high voltage side.

As shown in Figure 8.3-1, the 120-kV switchyard is arranged with two buses tied together by a normally closed circuit breaker. On occurrence of a l20-kV line fault, the provided first-line or backup relay schemes will open the affected breaker to isolate the faulted line without interrupting power to transformer SS64. The only failures that could cause a sustained interruption of power to transformer SS64 are

a. When fed from bus 11 (normal feed)

 1. A fault on bus 101 or its associated equipment

 2. A failure of transformer 1 and its associated bus 11

 3. A failure of transformer SS64, its associated feeder cable, or primary breaker

 4. A fault on 120-kV bus 102 with a breaker failure of section breaker GH

 5. An open phase condition on transformer 1 high voltage side.

b. When fed from transformer CTG-11 (alternate feed)

 1. A fault on bus 102 or its associated equipment

 2. A failure of circuit switcher ‘GL’, transformer CTG-11 and its associated buses

3. A fault on circuit switcher ‘GJ’, 13.8-kV transformer SS62 and its associated buses (Fermi 1 equipment)
4. A failure of transformer SS64 or its primary breaker
5. A fault on the 120-kV bus 101 with a breaker failure of section breaker GH.

If an event should occur causing loss of power through transformer 1 and bus 11, transformer SS64 can be immediately restored by closing the feed from transformer CTG-11 via bus 1-2B. The controls for these breakers are on panel H11-P809 in the Fermi 2 control room.

8.2.2.4 Conclusions

Since the feeder to transformer SS64 is run in underground bus ducts and the feeder to transformer SS65 is run overhead, it is evident that no single occurrence except a major earthquake would cause the simultaneous loss of the feeders to both transformers.

It is concluded that the offsite power system is in conformance with General Design Criterion 17 of 10 CFR 50, Appendix A, and complies with the applicable sections of IEEE 308-1971 and Regulatory Guide 1.32, except for Parts 1d, 1e, and 2b. These sections required compliance with Regulatory Guides 1.75 and 1.93. For discussions of those guides, see Subsections A.1.75 and A.1.93.

8.2.2.5 Operation With Degraded Grid

8.2.2.5.1 Analysis

Based on the 1991 Edison grid configuration, generation capability, and predicted load, electrical equipment operating requirement limits were identified for Fermi 2 offsite power sources. These limits ensure satisfactory operability of all electrical equipment during all modes of plant operation, and are listed in the Nuclear Plant Operating Agreement (NPOA) for the Fermi 2 Nuclear Power Plant. The NPOA contains the detailed operating requirements for Fermi 2. The NPOA Transmission System Operating Criteria section contains nominal offsite source voltages, minimum continuous voltage, maximum continuous voltage, minimum frequency and maximum frequency.

These figures are based on results of load flow and stability analyses that calculated the grid response to contingencies designed to be the worst possible and to limitations for operating requirements of Fermi 2 auxiliaries and safety-related equipment.

At the conditions defined above, the voltage limits during continuous operation were calculated for all safety-related buses.

At the voltages specified, all safety-related loads are capable of performing their safety functions. Further load flow and stability analyses were run for a simulated loss of Fermi 2 or a loss of the largest grid load while operating at the limits identified previously.

The Ludington pumped storage plant constitutes the largest single grid load that could be lost at once. Based on the analysis for either situation, the following conclusions were evident:

a. Grid system stability is maintained

b. System frequency fluctuations that occur are insignificant

c. Voltage fluctuations are short lived and, allowing for normal grid voltage operating adjustment, do not exceed the limits previously stated.

No grid operating restrictions for spinning reserve, either real or reactive, within a designated distance from the plant site are required to maintain the offsite power sources within the limits specified.

In the course of the various voltage analyses, all previous transformer tap settings were verified. For the loads fed from the 120-kV system, the voltage regulation setpoint for the +20, -10 percent load tap changer of SS64 transformer was determined. Voltage regulation setpoints were also verified for the 480-V bus ±10 percent induction regulators fed from the 345-kV system via transformer SS65. Operational setpoints were chosen to optimize voltage levels for all modes of plant operation and to ensure that all electrical equipment can function as required when called on.

8.2.2.5.2 Identification of Degraded Grid Condition

Each of the Fermi 2 offsite sources is monitored by indicating voltmeters. In addition to the offsite source voltmeters, a low voltage alarm sensor and an indicating voltmeter are provided for monitoring the Division I 4160-V buses 64B, 64C, 11EA, and 12EB, since they are all at a common bus voltage. Another indicating voltmeter and a low voltage alarm sensor are provided for monitoring the Division II buses 65E, 65F, 13EC, and 14ED. In both cases, the low voltage alarm sensor will initiate alarms in the control room through the annunciator if the voltage on the buses drops below normal. The alarms will actuate at approximately 4.08 kV for the 120-kV source and 4.09 kV for the 345-kV source. These alarms would consist of both audio and visual indication to attract operator attention.

Supplementing the indicating voltmeters are recording voltmeters for each of the reactor building safety-related 4160-V buses. These could be used also to evaluate voltage at the corresponding bus in the residual heat removal complex since the voltage is essentially the same.

Safety-related 480-V buses use one indicating voltmeter per division. The voltmeter may be switched to read the desired bus voltage. Similarly, one 480-V bus within a division may be placed on a recording voltmeter as required. Since continued plant operation is directly dependent on the offsite source voltage, only those voltages would be alarmed.

8.2.2.5.3 Response To Degraded Grid Condition

Under certain unlikely operating conditions, the 120-kV bus voltage could drop below the limit specified in Subsection 8.2.2.5.1. For both the 345-kV and the 120-kV systems, two methods exist to maintain the proper voltage at the safety-related buses.

On receipt of the ESF bus voltage alarm but before the voltage has fallen below the minimum specified in Subsection 8.2.2.5.1, the plant operator, in conjunction with the System Supervisor, will take corrective action to prevent the grid voltage from decaying further. These actions may include, but are not limited to, initiation of the offsite peaking units or offsite switching.

Should the voltage continue to decay, undervoltage relays offer further protection. Two levels of undervoltage protection exist at the 4160-V safety-related buses. The primary undervoltage relays detect complete loss of offsite power and will be set below the allowable motor-starting transient with a brief time delay. The second level of undervoltage protection will prevent the voltage at the safety-related buses from slipping below the minimum required voltage for safety related loads. A moderate time delay provides immunity to grid and starting transients. A more conservative, time delay duration is applied for a degraded grid condition concurrent with a LOCA. Specific features of the second level of undervoltage protection are described below:

a. The undervoltage relays are set in accordance with design calculations to preclude damage to Class 1E equipment. A time-delay setting was chosen to avoid the operation of the relay for motor-starting conditions. The relays are qualified to Class 1E requirements and located in, and connected to, the Class 1E switchgear and fed from bus potential transformers that are also qualified to Class 1E requirements

b. Alarm relaying has been provided to alert the operators that a low-voltage condition exists. The setpoint of the alarm relay is above that of the degraded grid trip setting. This was done to give the operators advanced indication of system degradation. It also eliminates any possibility that setpoint drift would permit the trip function to be actuated ahead of an alarm. It does not in any way affect the time delay of the degraded grid relaying

c. The time delay for the actuation of the degraded grid undervoltage relay has been selected to be as short as possible, without encountering spurious trips from motor starting

d. A second, shorter time delay exists for the actuation of the degraded grid undervoltage relay with a concurrent LOCA. This second time delay was established to support Branch Technical Position (BTP) PSB1 Position B.1.b.1

e. The degraded grid voltage protection system at Fermi 2 meets all applicable requirements of IEEE Standard 279-1971, "Criteria for Protection Systems for Nuclear Power Generating Stations," as outlined in Branch Technical Position (BTP) PSB1

f. If offsite power is lost, the degraded grid relay output is inhibited upon opening of the associated offsite power supply breaker. The emergency diesel generators would start, and, when synchronous speed is achieved, the automatic sequencer would begin to add loads as required. If a safety injection actuation signal is received, the sequencer would automatically shed all loads from the emergency diesel generators. The sequencer would then begin adding ESF equipment as needed to mitigate the consequences of the accident. The degraded grid relaying is not designed to operate during sequencer operation. The diesel generator bus load-shedding feature is automatically bypassed once the diesel generator is supplying power to the bus. This is required so that the voltage drops encountered during load sequencing on the diesel generators will not interact with the load-shedding feature and negate the load sequencing

g. The Class 1E buses have been analyzed for all anticipated operating situations. Section 8.3 provides a description of the Class 1E distribution system

h. Measurements have been made during the preoperational test program to verify the Class 1E bus analysis techniques.

An independent scheme is provided for each division of emergency power. Within a division, both types of undervoltage relays can automatically trip the offsite feeder breaker and initiate load shedding. Upon start of the EDG and the subsequent EDG breaker closure, the diesels would be loaded by the automatic load sequencer.

Limiting conditions for operation, surveillance requirements, and trip setpoints are included in the Technical Specifications.

8.2.2.5.4 Periodic Verification of Grid Adequacy

To ensure that grid configuration changes do not adversely affect the present analyses, Edison constantly reviews the transmission grid system stability and voltage levels. On a yearly basis, an official company 5-year load and generation forecast is made. Based on these forecasts, base grid systems for a 5-year period are established. These base grid systems are tested via computer simulations to meet voltage and stability criteria. From the results of these tests, any grid configuration modification or operating restrictions required to maintain required grid operation are initiated. Verification of voltmeter accuracy and alarm setpoints for the low voltage alarm sensor will be made periodically, either at unit shutdown or at least once every 4 years.

In addition, during preoperational testing, the plant auxiliary system response was determined from actual measurements and these results were compared to the computer-simulated results to confirm the adequacy of the computer program.

Degraded grid voltage adequacy is ensured by the Fermi 2 electrical design basis calculations along with the yearly performed grid analyses.

TABLE 8.2-1 SUPPLEMENTAL INFORMATION ON UNSCHEDULED OUTAGES

Bus	Length (miles)[f]	Year 1978	1979	1980	1981	1982	Interruptions (average/yr)
120-kV lines:							
Brownstown-Berlin Berlin-Swan Creek Swan Creek-Toll Road Toll Road-Fermi[c]	16.10	1-Lightning	-0-	1-Lightning 1-Wind	2-Lightning 1-Unknown	2-Unknown	1.60
Custer-Shoal Shoal-Toll Road Toll Road-Fermi[d]	9.5	-0-	-0-	-0-	-0-	-0-	-0-
Fermi-Toll Road Toll Road-Radka (includes Seville Tap)[b] Radka-Luzon[e]	24.05	3-Wind	2-Wind	-0-	-0-	-0-	1.00
Kentucky-Luzon[b]	7.54	-0-	-0-	1-Lightning	-0-	1-Equipment breakdown 113 min. out (TRF 1-Kentucky)	0.40
Kentucky-Pioneer[b]	16.74	-0-	-0-	2-Wind	1-Lightning	-0-	0.60
Pioneer-Superior[b]	6.93	-0-	-0-	-0-	-0-	1-Contamination	0.20
345-kV lines:							
Brownstown-Fermi 2 (in 9/16/82)	15.43	--	--	--	--	-0-	--
Brownstown-Fermi 3 (in 10/18/82)	16.18	--	--	--	--	-0-	--
120 kV:							
101 (120 kV)	--	-0-	-0-	-0-	-0-	-0-	-0-
102 (120 kV)	--	-0-	-0-	1-Equipment failure 148 minutes	-0-	-0-	0.20
Fermi 2:							
301 (345 kV)	--	--	--	--	--	-0-	--
302 (345 kV)	--	--	--	--	--	-0-	--

TABLE 8.2-1 SUPPLEMENTAL INFORMATION ON UNSCHEDULED OUTAGES

[a] All momentary interruptions on lines unless otherwise indicated.

[b] These four lines are in series (one on one), and an interruption of any one of them would remove the Radka source to Fermi.

[c] Fermi-Brownstown line revised to Brownstown-Swan Creek and Swan Creek-Fermi lines in 1989 and revised to Brownstown-Berlin, Berlin-Swan Creek and Swan Creek-Fermi lines in 1996. It was subsequently updated to include the Toll Road substation in 2018.

[d] Custer-Fermi line revised to Custer-Shoal and Shoal-Fermi lines in 1995. The Shoal-Fermi segment was revised to Shoal-Toll Road and Toll Road-Fermi in 2018.

[e] Fermi-Luzon line revised to Fermi-Radka-Luzon in late 2003. Fermi-Radka-Luzon line revised to Fermi-Toll Road-Radka-Luzon in 2018.

[f] These line lengths are historical data and may not reflect the current line lengths.

TABLE 8.2-2 TRANSMISSION CIRCUIT OUTAGE RATES AND RESTORATION TIMES

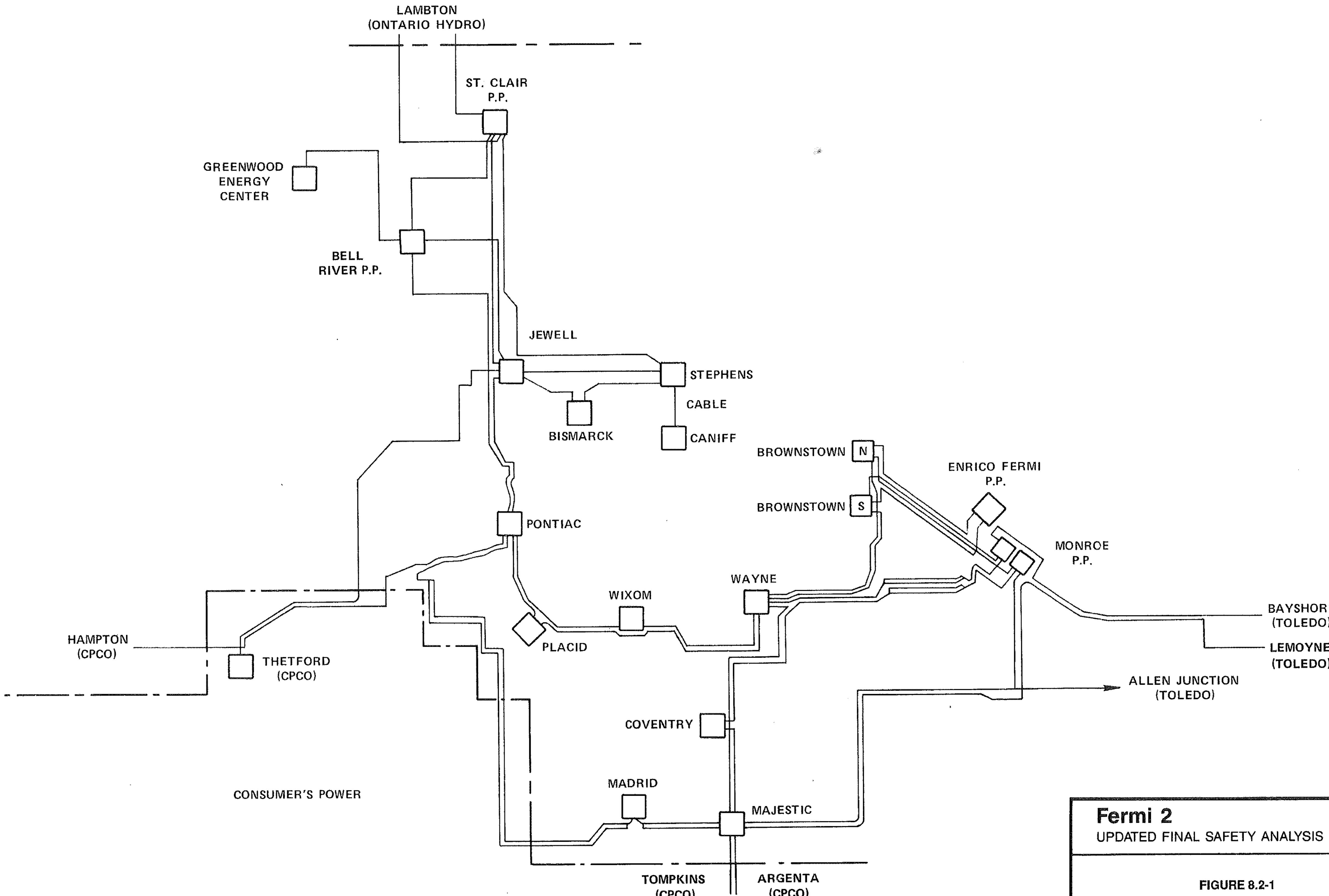
Designation	Circuit Length (miles)[c]	Average Circuit Outage Rate (outages per circuit per year)	Average Outage Duration (hr per outage)	Circuit Unavailability (year/year)
		345-kV Transmission		
Fermi-Brownstown 2	15.4	5.8[a]	12	7.9×10^{-3}
Fermi-Brownstown 3	16.2	5.9[a]	12	8.1×10^{-3}
		120-kV Transmission		
Fermi-Toll Road Toll Road-Swan Creek Swan Creek-Berlin Berlin-Brownstown	16.3	3.6[b]	12	4.9×10^{-3}
Fermi-Toll Road Toll Road-Shoal Shoal-Custer	13.9	3.5[b]	12	4.8×10^{-3}
Fermi-Toll Road Toll Road-Radka Radka-Luzon	21.9	3.7[b]	12	5.1×10^{-3}

[a] Based on MAIN and ECAR data, there can be 5.6 scheduled outages per line (circuit) per year plus 1.6 forced outages per 100 circuit miles per year.

[b] 3.2 scheduled outages per line (circuit) per year plus 2.2 forced outages per 100 circuit miles per year.

[c] These line lengths are historical data and may not reflect the current line lengths.

Note: The above forced outage rates do not include momentary interruptions where the circuit is automatically restored within seconds.



Fermi 2
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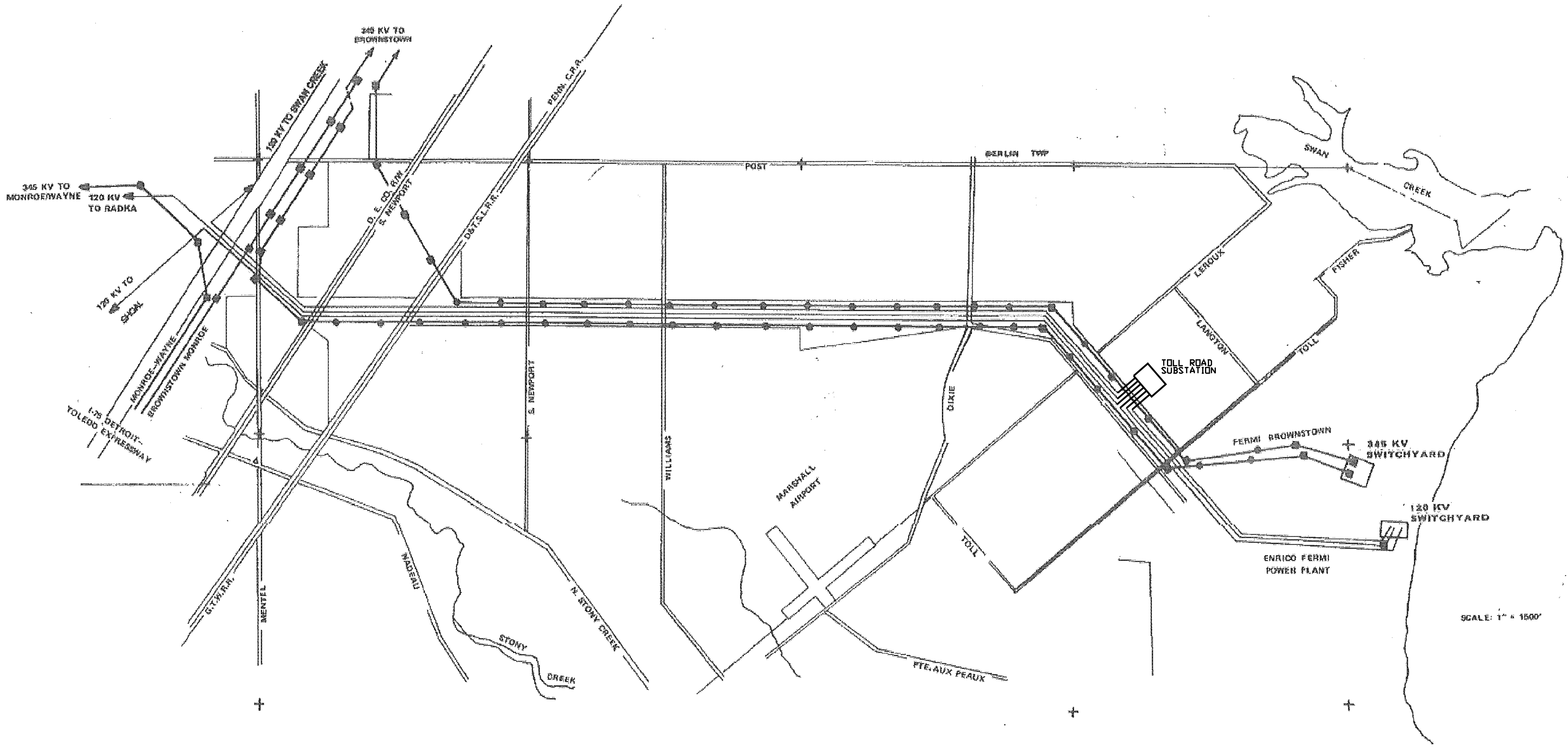
FIGURE 8.2-1

345-KV TRANSMISSION LINES IN 1988

REV 3 3/90



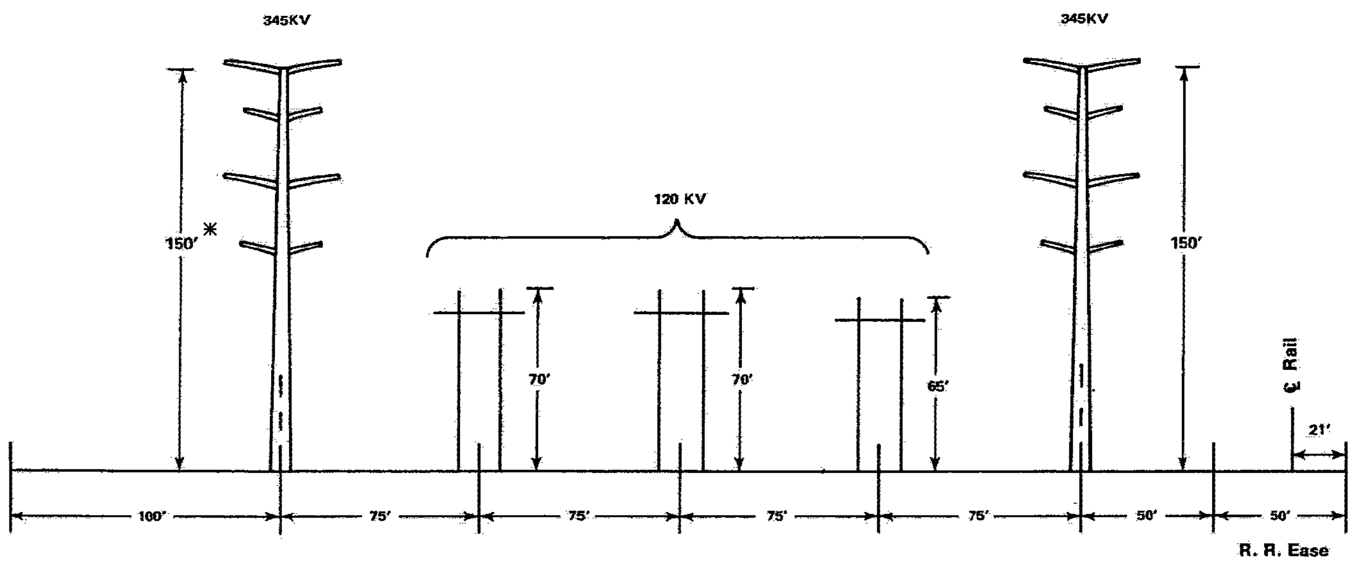
NOTE: The 120-kV and 345-kV transmission lines leave the plant in a common right of way for approximately 5 miles before diverging into different rights of way to the final termination at individiual stations,

Fermi 2

UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 8.2-2

FERMI TRANSMISSION CORRIDOR PLAN VIEW



Note: This illustration shall be considered typical tower arrangement.
Tower construction is determined by ITC Holdings (Section 8.2.1.1)

* The north 345kV towers in the vicinity of the Toll Road substation, on either side, are 170 feet in height to provide increased distance between the 345 kV line and the 120 kV substation.

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FIGURE 8.2-3

FERMI TRANSMISSION CORRIDOR
SECTIONAL VIEW

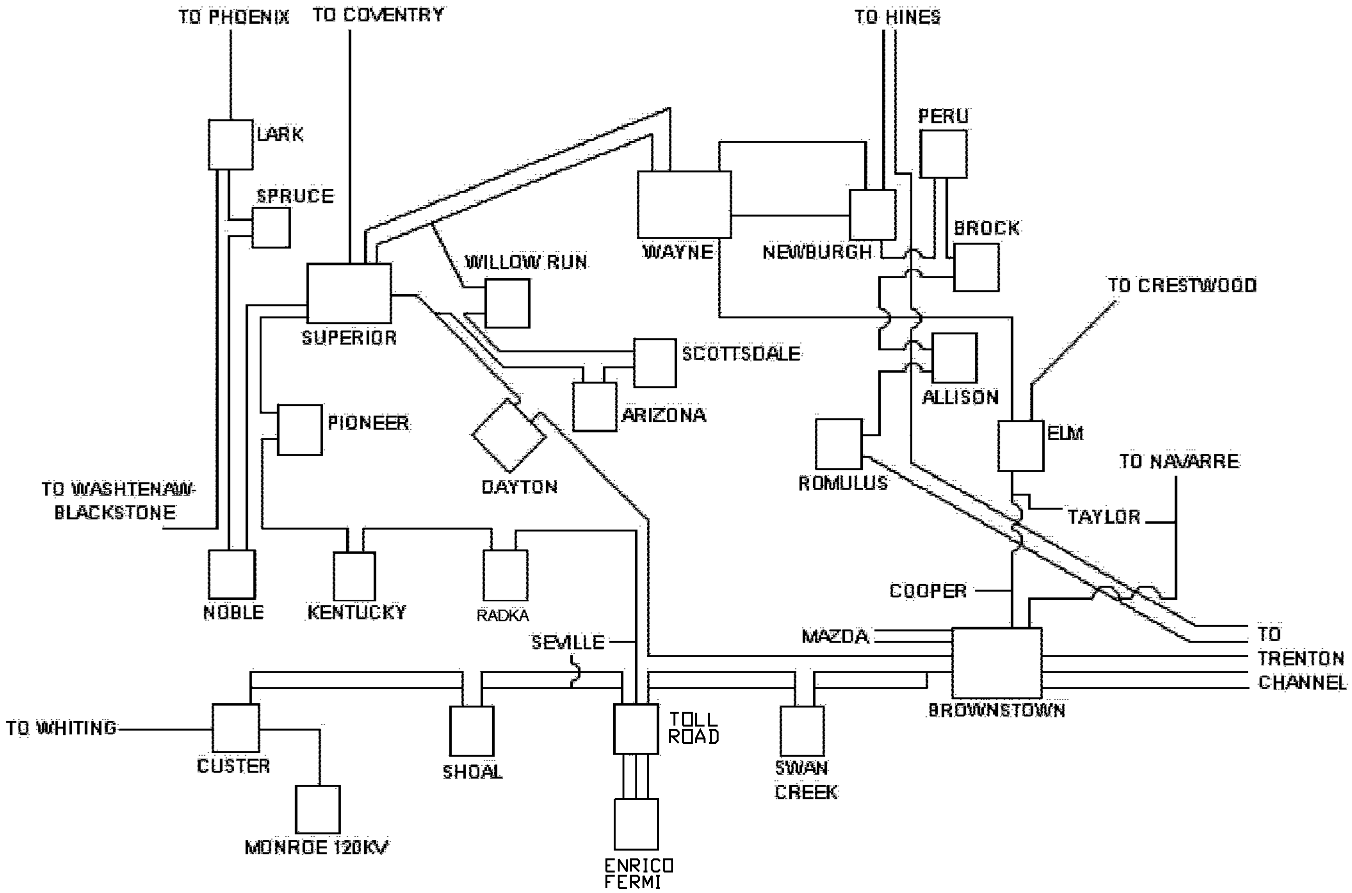

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FIGURE 8.2-4

120-KV TRANSMISSION LINES

Figure Intentionally Removed
Refer to Plant Drawing 6E721M 0001

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FIGURE 8.2-5
345KV SWITCHYARD PLAN

8.3 ONSITE POWER SYSTEMS

8.3.1 AC Power Systems

8.3.1.1 Description

Figure 8.3-1 shows the auxiliary ac power systems for Fermi 2. The offsite or preferred power for the ac power systems is supplied from the 120-kV and 345-kV transmission system through stepdown transformers. Alternate power for the engineered safety feature (ESF) systems is available through tie breakers that can tie the ESF bus to the opposite system transformer, for maintenance only. The main and tie breakers are interlocked in such a way that in no case can the two offsite power sources be tied together. Transfer to and from a maintenance tie source without interruption is possible, but the emergency diesel generator (EDG) of that particular bus must be used to make the transfer. This is accomplished by paralleling the EDG with the source, removing the source, paralleling with the alternate source, and then securing the EDG. Standby or onsite power originates at the EDGs housed in a physically separate Category I structure near the reactor building, known as the residual heat removal (RHR) complex.

Also available is CTG 11-1 or an alternate CTG 11-2, 11-3, or 11-4 which can be aligned to the 120-kV switchyard to act as the alternate ac source for a Station Blackout event and as a power source for the Dedicated Shutdown Panel.

The ac auxiliary power system as used in the plant has the following voltage levels:

a. 4160 V for loads above approximately 300 KVA

b. 480/277 V for loads below approximately 300 KVA.

8.3.1.1.1 Power Supply Feeders

Power supply feeders are of proven electrical, physical, and thermal qualities. They are sized to carry the load currents, with conductor temperatures remaining within the limits established by IPCEA and IEEE to obtain full expected cable life. The feeders are connected to their respective buses through air circuit breakers which are specified and constructed according to the applicable standards of ANSI, NEMA, and IEEE. These 4160-V circuit breakers are capable of an interruption capacity of 350 MVA. The 480-V breakers are of the following ratings:

	Symmetrical Interrupting Rating	
Breaker Type	Instantaneous amps	Delay amps
K600S	30,000	30,000
K1600S	50,000	50,000
K3000S	65,000	65,000

The calculated phase short circuit current for all feeders is always below the interrupting capacity of the breakers.

The preferred power for Division II is supplied from the system service transformer SS65 to the 4.16-kV buses through a nonsegregated cable bus system. A separate feeder bus section services each of the two 4.16-kV windings of transformer SS65. One feeder bus services switchgear bus 65G, which feeds only the two reactor recirculation pump motor-generator set drives. The other feeder bus is routed independently to Division II ESF buses 65F and 65E in the reactor building and balance-of-plant (BOP) buses 65D and 65W in the radwaste building, as shown in Figure 8.3-1.

Preferred power for Division I ESF buses is supplied from transformer SS64, through a feeder bus consisting in part of underground cable and ducts and nonsegregated cable bus coming off the 4.16-kV winding. In addition to Division I ESF buses 64B and 64C in the reactor building, BOP bus 64A and 64V in the radwaste building is also served by this feed.

A third feeder bus serves BOP loads in the circulating water pump house from transformer SS66. A fourth feeder bus supplies loads located in the general service water pump house, and is fed from transformer SS68.

A fifth feeder from the 345-kV transmission system via transformer SS69 provides an alternate feed to the BOP loads in the general service water pump house and the circulating water pump house. Transformer SS69 is fed from 345-kV bus 302. The feeds to the circulating water pump house BOP loads are split between transformers SS66 and SS69, with manual transfer of the feeds to the buses from the main control room. The feed to the general service water pump house BOP loads are split between transformers SS68 and SS69, with manual transfer of the feeds to the buses from the main control room (refer to Figure 8.3-1).

Bus feeders to and from the system service transformers are not classified Class 1E as defined by IEEE 308-1971. However, those feeder buses that service Class 1E switchgear buses are separate and independent of each other, so that any failure on one bus cannot affect the other.

The four feeders from the four EDG buses are contained in Class 1E underground concrete ducts. This onsite power supply is used as the standby supply to the ESF system buses in the event of the loss of offsite power.

8.3.1.1.2 Busing Arrangements

Switchgear buses are arranged and located to maintain electrical and physical independence between divisions of the safety systems. Separate switchgear rooms ensure the physical independence of safety divisions.

The two redundant ESF divisions include four 4.16-kV buses each. Two buses of each division are located in the RHR complex, and two are located in the auxiliary building (Figures 8.3-2 through 8.3-6). These buses service all 4.l6-kV safety loads, as well as provide a power bus source for lower voltage subdivisions at 480-V ac (Figures 8.3-5 and 8.3-6) and l20-V ac for ESF equipment (Figure 8.3-7). Except as noted below, the two divisions have no interconnections.

Within a division, ac loads are divided into two groups, each supplied by the common system service transformer. A diesel generator is assigned to power each group, when required. The EDGs are connected to a dedicated bus in the RHR complex rather than directly to the ESF buses in the reactor building, so that the cabling is minimized. The ESF bus located in the

RHR complex, the cable between the equivalent 4160-V ac bus in the reactor building, and the feeder breaker are included in a total differential protection scheme, avoiding the problems associated with the use of an overcurrent scheme on a feeder where full load currents are different when the feed direction reverses.

Several BOP loads in the reactor building are serviced by the safety buses. In case of a loss of offsite power, a load- shedding scheme initiates tripping of all breakers on 4160 V and 480 V, except 4160/480-V transformers and ESF-motor control center feeders. After the onsite power source (EDG) reaches normal voltage and frequency, sequential loading follows, in compliance with IEEE 308-1971. Once the diesel generator is supplying power to the bus, the bus load-shedding feature is automatically bypassed.

Figure 8.3-1 shows the overall bus arrangement. A functional logic diagram (Figure 8.3-8) describes the various conditions of operation. A description of the operation of the system is given in Subsection 8.3.1.1.14.

8.3.1.1.3 Loads Supplied From Engineered Safety Feature Buses

Loads supplied from ESF buses of each division are comprised of that equipment pertinent to the division and selected BOP loads. The one-line diagram of the ESF buses is shown in Figures 8.3-1 through 8.3-6. A tabulation of the overall ESF loads by system is listed in Table 8.3-2.

Motors are sized so that they have adequate torque to start with the pump discharge open, accelerate within the time allowed by the plant design, and run with maximum pump load. Torque calculations include voltage dips of the motor's rated terminal voltage.

When running at rated speed and maximum load, the motors have adequate torque to prevent stalling during voltage dips caused by starting other large motors on the same power source.

In general, the motor horsepower rating determines the voltage and the source of the motor feed as follows.

a. 1/2 to 49 hp at 480 V, from a 480-V motor control center (MCC)

b. 50 to 249 hp at 480 V, from 480-V bus switchgear

c. 250 and larger hp at 4160 V, from 4160-V bus switchgear.

Voltage regulation for the buses and equipment fed from the 120-kV system is provided by the +20, -10 percent load tap-changing facilities on the secondary windings of transformers SS64, SS66, and SS68.

Voltage regulation is provided for the 480-V buses fed from the 345-kV system through transformer SS65, which is equipped with an automatic online load tap changer on each of the secondary windings to accommodate a maximum switchyard voltage of 105% on down to a minimum switchyard voltage of 92% following a single grid contingency. The 345 kV system voltage can vary +5, -2 percent for normal operation. Voltage regulation is provided for the BOP buses at bus 65L at 4160 V. Bus 65L voltage is regulated by a ±5 percent, oil-filled, 300-kVA regulator. The 480-V ESF buses (buses 72 EC, ED, E, and F) are regulated by 480-V ±10 percent dry-type induction regulators that are part of the 480-V switchgear-unit substations.

8.3.1.1.4 Engineered Safety Feature Bus Interconnections

A manual bus tie connects the Division I buses to the alternate division transformer SS65, and a manual tie connects the Division II buses to the alternate division transformer SS64. The tie is made through two breakers, one at each end of the bus tie with both breakers normally open and racked out.

If power were not available to an ESF bus through its normal offsite source or through its emergency onsite source, it could be manually energized through the alternate offsite power source, for maintenance use only. The affected breakers are interlocked so that the two divisional transformers SS64 and SS65 cannot be operated in parallel on a common load. Nevertheless, this tie can be used as an alternate source for either one of the ESF buses through manual operation.

There is one area where loads can be powered from either redundant system by automatic throwover. This area involves MCC 72 CF, serving certain RHR valves, operation of which is necessary to the operation of the RHR system in the postaccident core cooling mode. This MCC has feeds from both divisions. Division I is the normal feed with an automatic throwover to the Division II feeder. Each feeder has a breaker and contactor at the source and a contactor at the MCC.

According to Regulatory Guide 1.6, Paragraph 4.C, no automatic load transfers are to be performed between redundant divisions. However, in the AEC Safety Analysis of Brunswick FSAR, Section 8.3, Docket No. 50-324, a throwover for certain RHR-related loads was accepted.

However, due to the special nature of the above auto transfer, all feeds to and from the MCC are run in conduit to maintain divisional integrity. This automatic throwover is provided with positive interlocks, breakers, and series contactors to satisfy the "no single failure" criterion.

Division I 480-V breaker 72C-3C is the normally closed feeder breaker. Division II 480-V breaker 72F-5C is the normally open standby breaker. The contactors will either close or open automatically as a result of the operated status of the associated breaker. This solution provides an open break on both ends of the standby feeder to prevent having both sides or contacts of the standby circuit breaker energized from the two redundant divisions.

The 120-V ac control buses and instrument buses have no direct ties between redundant safety divisions. The buses of each division are energized through three 480/120/120-V ac, single- phase transformers with an automatic throwover switch between the 480-V buses of the same division (Figure 8.3-7).

Engineered safety feature inductive loads such as relays and solenoids are connected to the "inductive load" buses, and signal devices such as transmitters and electronic systems are connected to the "instrument" buses.

8.3.1.1.5 Redundant Bus Separation

The 4160-V switchgear, 480-V switchgear, MCCs, and other load centers of one safety system are physically and electrically separated from the load centers of the other safety system. Separate and independent switchgear rooms are provided for each division. The

Division I switchgear is located generally to the south of the reactor centerline on the second floor, and the Division II switchgear is located in the same location on the third floor. Battery rooms are located on the third floor and separated by a 12-in. concrete wall.

The MCCs, distribution panels, and other load centers, except as described previously, are not necessarily located in a specific room. They are separated from similar safety equipment of the opposite division by a horizontal distance of 20 ft or more. If this distance cannot be achieved, a 6-in.-thick reinforced- concrete wall is placed between the redundant buses.

8.3.1.1.6 Equipment Capacities

The ac power system has its related equipment provided with adequate capacity to meet its intended function under all design conditions. All Class 1E 4.l6-kV switchgear is rated at 350 MVA to ensure proper operation and circuit interruption under the most adverse fault current conditions. Auxiliary load transformers and EDGs have been sized for the worst-case conditions of auxiliary or shutdown loading. Cables are properly sized in accordance with the latest IPCEA requirements.

8.3.1.1.7 Automatic Loading and Load Shedding of Buses

Should a loss of offsite power occur on any ESF bus, the degraded grid relay output to the associated load shed scheme is inhibited. This bus is stripped of loads by a double load-shedding scheme, as indicated on the functional logic diagram (Figure 8.3-8). Automatic load shedding of the buses begins and the associated EDG receives a start signal and accelerates to rated voltage and frequency. The EDG breaker closes and loads are sequenced on. These loads are specified in Table 8.3-3. Conditions imposed after an automatic loading interval may warrant further manual loading for an extended shutdown. These loads are shown in Table 8.3-4.

A LOCA without loss of offsite power will start the diesels without closing the EDG breaker. The EDGs will idle and remain in standby until manually stopped.

Although there are no mechanical limitations on running the diesel generator at full-speed no-load conditions, running in an unloaded condition can result in an accumulation of unburned oil residue in the engine exhaust system. If load is suddenly applied, it could result in a "stack fire." Therefore, the manufacturer has recommended that the engine be loaded with 50 to 75 percent of rated continuous load for 1 hr after any 8-hr period of unloaded operation.

If diesels are operating in an unloaded condition, normal operating procedures ensure that the engine is loaded after extended periods of no-load operation. In the event of an emergency start from a LOCA without a loss of offsite power, such a procedure would be used for running the diesels. Because there are four diesels, the first diesel would be loaded after four (4) hours and run for an hour, after which the next diesel would be loaded. This method would be applicable during initial recovery. A keylock switch to defeat the LOCA start signal is provided to permit the diesels to be shutdown and placed in standby for a possible long term recovery period without a loss of offsite power.

After a postulated design-basis LOCA, the water level is maintained at two-thirds core height by the core spray pumps. This level is below Level 1, or the LOCA initiating level. Also, containment pressure could remain above the LOCA initiating signal level for extended periods until the temperature is reduced. Thus, either LOCA signal could be present for weeks after an accident. With the keylock switch and administrative control, the EDG would still be operable for automatic startup on an undervoltage signal, but an extended period of light-load operation would be avoided.

Should the LOCA occur with or during a loss of offsite power, the buses are first stripped of all loads, except for selected feeds for motor-operated valves, and isolated from the offsite power sources before the loading time sequence begins (Table 8.3-5). Loads that are automatically initiated appear in Table 8.3-3. Conditions imposed after an automatic loading interval may warrant further manual loading for an extended shutdown. These loads are listed in Table 8.3-4. The EDG automatic load sequencing system consists, with the exception of the input and output electromechanical relays, of solid-state components. These automatically initiate the closing of selected circuit breakers or contactors in MCCs.

The automatic load sequencing system consists of two redundant, physically separated, and electrically isolated subsystems, one for each of the two divisions.

Each subsystem functions independently and is associated with the sensors and safety equipment of a particular division. Each EDG has its own automatic load sequencing equipment to load the generator in its own independent time interval. Contained in the control cabinet are an input signal conditioning module, initiation logic, a system clock, counter-decoder and delay logic, output drive, and relay modules.

Devices to provide reset control and test capability and indicators to monitor the system status are provided.

The logic and operating components in this system are manufactured using industrial and military-approved quality materials, discrete components (resistors and capacitors), solid-state semiconductors, and integrated circuits. The equipment is rated Class 1E. Printed circuit (PC) cards are flame retardant and are also keyed to prevent insertion of an incorrect card in the PC card file. Digital integrated circuits used on the PC cards are high-threshold logic.

The automatic load sequencing equipment system is designed to function continuously at ambient temperatures and under humidity conditions much more severe than can be expected in the Fermi 2 control area.

On receiving a signal indicating an emergency situation, the system will commence operation. It will delay output for a preselected time period to permit the shedding of the affected bus load and, if required, for the EDG to start and the EDG breaker to close.

After this delay, the automatic load sequencing equipment will generate an output, in the predetermined time and sequence, to initiate bus loading as per Table 8.3-5.

The automatic load sequencing equipment is periodically tested to ensure availability and correct functioning of this system.

8.3.1.1.8 Standby AC Power System

8.3.1.1.8.1 Description

The standby ac power system for Fermi 2 consists of four diesel-generator units. These units are Colt Industries, Fairbanks-Morse, 38TD8-1/8, 12-cylinder, opposed piston, 3967-hp, 900-rpm diesels, each driving a 4160-V ac, 3250-kW salient pole generator, using a solid-state excitation system and fast-response electrohydraulic governors. The total unit is rated at 2850 kW continuous. The basic unit has a long history of successful use in commercial and marine application and as a standby power source for nuclear power plants. At the time it was purchased it was the largest unit with proven reliability available for this service. Of the units for which bids were received, the model selected showed the best performance in starting the 2000-hp RHR pumps required for postaccident service at Fermi 2.

Each EDG is started automatically on loss of voltage to its respective bus, on low reactor water level, or on high drywell pressure.

The units are capable of being started or stopped (for non-emergency starts) manually from local control stations near the engines as well as from the main control room. For testing purposes, units are started manually, brought to speed, synchronized to the power plant system, and loaded. Normally, voltage is regulated automatically with capability to adjust the set point both locally and in the main control room. Manual speed control is also provided locally and in the main control room. Each unit is capable of operating in parallel with the power plant electrical system.

If offsite power is lost during parallel operation with the electrical system, the diesel breaker will be opened automatically via underfrequency relaying. It was determined that this would be the quickest method of tripping the EDG while it was trying to maintain the system loads. The operation of the underfrequency relaying will open the EDG breaker only, and is interlocked to operate only when the EDG is in parallel operation with the offsite system.

The opening of the EDG breaker causes an undervoltage condition on the affected bus. The EDG breaker will reclose automatically as soon as all designated loads are removed from the bus.

On occurrence of a LOCA and on receipt of an automatic signal from the power plant relays, each unit automatically "fast-starts," comes to rated voltage and synchronous speed, and is capable of operating as an isolated source to start the loads sequentially. Table 8.3-5 shows the loading sequence. If a loss of system power has occurred, the EDG is automatically connected to the bus. If bus voltage is normal, the EDG stands by at synchronous speed and rated voltage.

The EDGs are capable of being started or of being restarted from a hot shutdown condition without outside auxiliary service, except the 130-V dc control source from divisional batteries. They reach rated voltage and synchronous speed (unloaded) within 10 sec after initiation of a starting signal.

The individual rating of each EDG is

a. Continuous 2850 kW

b. Short time (2 hr) 3135 kW

c. 2000 hr 3100 kW

d. 300 hr 3250 kW

e. 30 minute 3500 kW

Inlet and exhaust system pressure drops are considered for determining these ratings. Losses attributable to continuously driven electrical auxiliaries are deducted from the gross output of the EDGs, except for the EDG service water pump. Each generator is designed to operate as an isolated source or, for testing purposes, in parallel with a 4160-V, three-phase, three-wire, 60-Hz, resistor-grounded, 350-MVA electrical system. The system also operates with a high impedance ground system, isolated from the offsite system.

The generators are air-cooled, 80 percent power factor, 4l60 V, 60 Hz, Class F insulated, with a rating of 4063 kVA at a temperature rise not exceeding ANSI Standard MG-I (1972) at ambient temperature of 140°F. The EDG rooms of the RHR complex are designed for 122°F ambient. The generator stator coils are vacuum-pressure impregnated to provide resistance to moisture and contaminants.

The generators and original excitation systems were designed to limit bus voltage dips during sequential starting of motors. Two different system analyses, one by Colt and the other by Detroit Edison, produced results close to the recommended limit of 75% in Regulatory Guide 1.9. As a result, pre-operational testing was utilized to ensure successful operation in lieu of analytical comparison to the Regulatory Guide 1.9 recommended limit. The pre-operational test results, shown in Table 8.3-8, identified that the first voltage dip associated with the RHR pump start did decrease below the Regulatory Guide 1.9 value, but subsequent voltage dips, such as for the CS pump start, did not. Following replacement of the original excitation systems (Portec) with new excitation systems (Basler), voltage dips associated with the RHR pump start have sometimes been below those from the pre-operational test results. Similarly, the voltage dip associated with the CS pump start has at times decreased below the Regulatory Guide 1.9 value. In addition to the older pre-operational test data, Table 8.3-8 also identifies the voltage dips since the excitation system replacements. Continued successful testing during refueling outages with the identified voltage dips ensures the adequacy of the EDG performance during large-motor starting transients. Voltage dips, while not an acceptance criteria, are monitored to identify potential for EDG or other equipment degradation. See Appendix A.1.9 for additional discussion of Regulatory Guide 1.9 conformance.

During preoperational testing, each diesel generator was started and loaded in the desired sequence, thus verifying their capabilities. In addition, the motor and pump torque curves were reviewed to ensure that the motor torque curve did not dip below the pump torque curve.

The EDGs are housed in reinforced-concrete, Category I structures. Each unit is completely enclosed in its own concrete cell and is isolated from the other units.

The units are connected to their respective 4.16-kV switchgear and control equipment by cables in underground ducts. There are two sets of Category I ductbanks between the RHR complex and the Reactor/Auxiliary building, with a Division I and Division II ductbank in each set. These cable duct runs meet necessary seismic design and Class 1E criteria, as explained in the following paragraphs. In each case, the buried cable ducts between the RHR complex and the Reactor/Auxiliary building provide adequate cable separation to maintain independence of redundant circuits.

The first set of ductbanks was installed during plant construction. The physical separation of the two redundant, below-grade circuits is 30 ft at the point the cable ducts leave the southeast corner of the reactor building. The ducts make a sweeping bend with a minimum separation of 20 ft between them. After the bend, the ducts parallel the reactor building in a westerly direction with 24 ft separation. This separation is constant until the ducts pass under the rail car air lock where the separation widens until the ducts enter (still below grade) the RHR complex.

Because of the separation provided, the redundant cables will not be subject to a common mode failure from a tornado missile, or a redundant division cable causing failure in the surviving divisional cable. (See Section 3.5 for a discussion of missile protection.)

Each circuit is separately housed in a cast-in-place rectangular shaped reinforced-concrete duct. The duct is then covered by placing successive layers of compacted-rock fill up to the finished site grade of 583.0 ft. The duct runs vary in elevation from 573.0 ft minimum to 580.0 ft maximum. Since maximum groundwater elevation is 576.0 ft, the cables are not specifically designed for continuous underwater service. For low voltage power, control and instrumentation cables, there is no long term mechanism for water related insulation degradation due to lack of voltage stressor or a credible common mode failure mechanism. Therefore, low voltage cables perform their design functions while their external surface remains continuously wetted due to surrounding water. 4160-V essential power circuits are not routed within these ductbanks.

The minimum elevation for cable termination in either the RHR complex or reactor building is 588.7 ft, which is above the site probable stillwater elevation of 586.9 ft.

The cable duct runs are designed to meet Category I requirements.

The physical separation of the redundant cable duct run provides adequate protection against all of the defined missiles since any single missile could fall within the zone of influence of only one cable at a time. The defined tornado missiles, i.e., the 4-in. by 12-in. by 12-ft-long plank or the 4000-lb passenger automobile, cannot physically impact the zone around both cable duct runs at the same time. Additional protection is provided as the entire cable duct run is buried beneath a layer of compacted rock that varies in depth from 3 ft 0 in. to 10 ft 0 in., placed in layers up to the final site grade elevation.

The second set of ductbanks and associated manholes is installed above the maximum ground water elevation of 576.0 ft with ducts sloped to the manholes, such that circuits contained are not subject to continuous wetting. 4160-V essential power circuits are routed within these ductbanks. These are also cast-in-place, rectangular reinforced concrete ductbanks, but are located with the ductbank top approximately six inches below the surface and manhole covers at grade level. The ductbanks rise above grade at the entrance to the RHR complex and the Reactor/Auxiliary building. The Division I and Division II ductbanks are separated by approximately 25 feet at the Auxiliary building entrance. The separation narrows to approximately 10’-6” at the closest point as they make a sweeping turn and widens to approximately 20 feet at the entrance to manholes 16946A and 16947A. The ductbank separation again narrows to approximately 7’-8” at a top elevation of approximately 580'-6" (three feet below grade) and runs underneath the ISFSI Transfer Pad to manholes 16946B and 16947B. The ductbanks exit manholes 16946B and 16947B with a separation of approximately 15 feet that increases to a separation of greater than 20 feet after approximately 30 feet from the manholes. The separation increases to approximately 115 feet during the run from manholes 16946 B and 16947B to manholes 16946C and 16947C, located near the RHR building. Ductbank separation for the ductbank run between manholes 16946C and 16947C and the RHR building cable vaults is greater than 80 feet.

The 4160-V RHR cable vaults and the manholes and ductbanks between these cable vaults and the Reactor/Auxiliary building cable vaults are designed as tornado missile barriers per the requirements of Regulatory Guide 1.76 Revision 1. Because of the tornado missile barrier design, the redundant cables will not be subject to a common mode failure from a tornado missile and, due to separation provided, a redundant division cable will not cause a failure in the surviving divisional cable. (See Sections 3.5, 3.12.3.2.3, and 9A.4.7.7 for a discussion of tornado missiles, separation, and fire protection, respectively.)

8.3.1.1.8.2 Location

Each diesel generator and its associated excitation system and switchgear are located within separate rooms in the RHR complex. The separating walls between units meet the same requirements as does the exterior of the building. The RHR complex structure serves to contain, protect, house, and support the equipment of the EDG system and protect it from the outdoor environment. In addition, the building is designed to the following requirements:

a. Each EDG is located in a separate compartment, with its own separate fuel-oil day tank and storage tank housed in a separate room

b. The EDGs are at Elevation 590 ft (New York Mean Tide, 1935), about 7 ft above the grade level of 583 ft. The associated switchgear and controls are located in separate rooms above the EDGs. The exciter-voltage regulator panel for each EDG is located in the EDG room

c. The building is protected against flood damage to Elevation 590 ft (New York Mean Tide, 1935)

d. The RHR complex structure is designed so that a turbine missile will not result in the failure of more than one system division

e. The total wind load pressures include positive and negative pressures, gust factor, and shape factor

f. The building is designed for a maximum roof live load of 70 lb/ft^2

g. Sufficient openings are provided in the structure for the combustion air inlet and exhaust piping and for the interior ventilation air

h. The generator end of the EDG is located to permit access to and removal of the generator

i. The EDG system is designed to be operable during and after a design-basis tornado that has the following characteristics:

NOTE: Effects of items i1., i2., and i5. are to be considered as acting simultaneously.

1. External wind forces resulting from the tornado funnel, which have a horizontal peripheral velocity of 300 mph and a transient horizontal velocity of 60 mph
2. Differential pressure between inside and outside of fully enclosed areas - 3 lb/in.^{2}
3. The ability to generate a missile equivalent to a 4-in. by 12-in. by 12-ft-long wood plank traveling end-on at 225 mph or a passenger auto (4000 lb) flying through the air at 50 mph and at not more than 25 ft above ground with a contact area of 20 ft^2
4. For torsional design the structures were considered engulfed in a tornado of a diameter equal to the diagonal dimension of the complex. Positive and negative pressures were applied to each wall proportional to the normal component of the tangential wind velocity
5. All building structures housing equipment necessary for safe shutdown are designed to withstand a tornado-induced depressurization rate of l lb/in.^{2}/sec for 3 sec. The Category I 4160-V RHR cable vaults and the manholes and ductbanks between these cable vaults and the Reactor/Auxiliary building cable vaults are designed to withstand a tornado-induced depressurization rate of 0.5 lb/in.^{2}/sec for 2.4 seconds, in accordance with Regulatory Guide 1.76 Revision 1 (March 2007). (See section 3.3.2.1 for a discussion of tornado protection.)

j. The complex is a Category I structure

k. It is impossible to recirculate the diesel generator exhaust to the diesel generator combustion air intake except under extremely adverse meteorological conditions. The diesel generator exhaust is 25 ft higher than and 50 ft horizontally away from the ventilation and combustion air intakes for the RHR building. Only a small fraction of the exhaust could recirculate to these intakes under extremely adverse conditions. Each ventilation and air intake is approximately 89,000 cfm, of which about 14,000 cfm (16 percent) is combustion air for the diesel generators. The small amount of exhaust that could be recirculated would be thoroughly mixed in the combustion and ventilation air intake system. Therefore, the amount of combustion products in the combustion air intake would be a fraction of the fraction of recirculated exhaust. Recirculation of exhaust products has been used to reduce NOX emissions, and tests have been performed in which there was no deleterious effect on engine capacity and performance for exhaust recirculation over 12 percent. There is no possibility that the diesel generator exhaust could dilute even nearly this much. Therefore, there is no possibility that the diesel generator could not develop full rated power due to exhaust recirculation

l. Abnormal climatic conditions such as heavy rain, freezing rain, dust storms, ice, and snow will not affect the diesel combustion air intake or exhaust

The diesel engine combustion air inlet filter is located inside the RHR complex structure. Combustion air is 14,000 cfm of the 89,000 cfm total (combustion plus ventilation) admitted through a louvered wall opening and a missile shield. Abnormal climatic conditions will not affect the diesel engine combustion air intake

The diesel engine exhaust silencer is located on the roof of the RHR complex and is surrounded by a missile shield enclosure. The exhaust silencer is provided with an open drain to relieve any condensate that may collect through the exhaust pipe

m. All of the critical electrical equipment required for operation of the EDGs, including switchgear, MCCs, and diesel generator control panels, is located within that diesel generator's separate heating, ventilation, and air conditioning (HVAC) system. These independent HVAC systems for each EDG use filtered outside air and maintain the rooms at positive pressure to preclude the infiltration of unfiltered outside air. The HVAC inlet takes air from the upper level of the RHR building at an elevation of 617 ft, while the grade level of the building is 583 ft. The diesel air combustion system, including the inlet and exhaust, is completely separate from the HVAC systems. These features protect the electrical equipment from dust particles

In addition, the diesel generators and the starting systems of associated electrical equipment are inspected and tested periodically to ensure the availability of the diesel generator on demand

The control cabinets are located in the switchgear room. The control voltage on the diesel generators is 130 V dc; this voltage level reduces problems of dust on contacts in the diesel generators control circuits.

All the above features provide protection to the electrical equipment from dust particles.

8.3.1.1.8.3 Emergency Diesel Generator Rating and Sizing

The following general sizing parameters were applied to the EDG:

a. Each unit shall be at rated voltage and frequency within 10 sec

b. Each unit shall be sized to carry the full requirement of postaccident loads

c. Each unit shall be capable of sequentially starting the large RHR pumps (2000-hp motors for pumps A, B, and C and 2250-hp for pump D) and the 800-hp core spray pump motors while maintaining a voltage and frequency as close as possible to Regulatory Guide l.9 recommended limits and still maintain parameter a of this list (See Table 8.3-8).

The Colt Industries Fairbanks-Morse units chosen were extensively tested to prove their ability to achieve rated speed and voltage in less than 10 sec.

Before delivery, each engine was given a wear-in run during which operation was gradually increased from idle speed, no load, to full speed and full-load. Between each step in the wear-in run, the unit was shut down and inspected. The unit was then given a full-load test run, with necessary temperature and pressure measurements to verify performance. After completion of the test run, the unit was given a post-trial inspection. After post-trial reassembly, a final check run was conducted. The generators were given tests in accordance with ASA-C-50. Further testing of the EDGs to start rapidly, accept load, and provide proper voltage response (using actual or simulated Fermi 2 emergency loads) was performed during the preoperational testing program, as described in Subsection 8.3.1.2.2.2.

Colt Industries has demonstrated the ability of the 38TD8-1/8 engine to withstand repeated starts and load pickups (see Reference 1). The engine successfully started, loaded, stopped, cooled down, and repeated the cycle l00 times without adjustment, failure, or excessive engine wear. Further discussion of this test is found in IEEE Conference Paper 69 CP 177-PWR (Reference 2).

Fifteen large-size Colt units had been qualified and were providing standby service at seven operating nuclear plants, as shown in Table 8.3-9. Included in this list is the Duane Arnold Energy Center. The Colt Industries EDGs at this plant have a continuous rating of 2850 kW, the same rating as Fermi 2.

Branch Technical Position EICSB 2 states that the diesel generator reliability qualification is needed for (1) larger capacity machines than previously used, or (2) nonstandard diesel generator arrangements. Since the Fermi 2 Colt EDGs have been qualified previously, since a previous nuclear standby unit of the same size is considered qualified, and since the Fermi 2 onsite power system is a standard design in compliance with Regulatory Guide 1.6, the Fermi 2 EDGs are in full compliance with the reliability qualification requirements of Branch Technical Position EICSB 2.

A demonstration test program, developed and implemented by Edison, confirmed the reliability of the EDGs. This program simulated the number of slow and fast starts that would be expected of an EDG over an 18-month fuel cycle and run time that might be needed to assure safe shutdown of the plant if EDG operation were required following a LOCA. This translated into 20 prelubed slow starts and 10 prelubed fast starts, and included a 7-day continuous run. After each start, the EDG was run under load for a minimum of 2 hr, including 1 hr at a load of 2500- 2600 kW. After each run, the EDG upper crankshaft main bearings were gap checked. The EDGs 11 and 13 were selected for the demonstration test program on the basis of their operating and maintenance histories and because they are in separate divisions. All aspects of the demonstration test were successfully completed on both EDGs and therefore it was concluded that the Fermi 2 EDGs could reliably perform their intended function.

The total loads on each diesel generator are shown in Tables 8.3-3 and 8.3-4. These tables show load requirements for loss of offsite power and LOCA. For all conditions calculated, the loads are within the short-time rating of the diesel generator in compliance with paragraph C.2 of Regulatory Guide 1.9, Revision 2.

The ability to recover voltage and frequency over load increments was the most critical parameter in the selection process for the EDG. The response of the units to the load sequence shown in Table 8.3-5 was analyzed using simulations by Colt Industries and by Detroit Edison. The analysis results shown in Table 8.3-8 were close to the recommended limit of 75% in Regulatory Guide 1.9. As a result, pre-operational testing was utilized to ensure successful operation in lieu of analytical comparison to the Regulatory Guide 1.9

recommended limit. The pre-operational test results, shown in Table 8.3-8, identified that the first voltage dip associated with the RHR pump start did decrease below the Regulatory Guide 1.9 value, but subsequent voltage dips, such as for the CS pump start, did not. Following replacement of the original excitation systems (Portec) with new excitation systems (Basler), voltage dips associated with the RHR pump start have sometimes been below those from the pre-operational test results. Similarly, the voltage dip associated with the CS pump start has at times decreased below the Regulatory Guide 1.9 value. In addition to the older pre-operational test data, Table 8.3-8 also identifies the voltage dips since the excitation system replacements. Continued successful testing during refueling outages with the identified voltage dips ensures the adequacy of the EDG performance during large-motor starting transients. Voltage dips, while not an acceptance criteria, are monitored to identify potential for EDG or other equipment degradation. See Appendix A.1.9 for additional discussion of Regulatory Guide 1.9 conformance.

8.3.1.1.8.4 Emergency Diesel-Generator Fuel System

For a detailed description of the EDG fuel system, refer to Subsection 9.5.4.

8.3.1.1.8.5 Emergency Diesel-Generator Cooling and Heating System

Each diesel unit has a self-contained, jacket-closed cooling water system that consists of an engine-driven pump, a heat exchanger using the RHR service water (RHRSW) as the heat sink, a l5-kW standby heater, and a standby coolant circulating pump. The standby heater and pump maintain a constant water temperature to ensure uniformly fast starts.

Lube oil is maintained at a constant temperature by a 15-kW heater and a standby lube-oil circulating pump to enable the machine to start reliably.

A separate service water pump and separate service water piping system are provided for each diesel engine (Subsection 9.5.5).

8.3.1.1.8.6 Emergency Diesel-Generator Starting System

Two air-operated starting subsystems are furnished for each EDG. Each starting subsystem is of the air- over-piston type supplied from one accumulator. Periodic tests verify the operability of the air start system and its components.

Each starting subsystem includes a separate air header, accumulator, piping, and air start distributor and can independently start the EDG. The fast start feature is ensured by utilizing both starting air subsystems.

Two accumulators are furnished for each unit, and they have the capability to start the unit a minimum of five times without recharging. Each accumulator is furnished with a shutoff cock, pressure gage, drain valve, safety valve, check valve, and sensing element for low-pressure alarm.

One 460-V ac, three-phase, motor-driven air compressor is furnished for each EDG. The compressor recharges the accumulators to normal operating pressure; recharging, when required, is automatic.

Redundant starting solenoid valves with continuous-duty coils are used. All solenoid valves have manual bypass valves for use in case of failure of the solenoid valve.

8.3.1.1.8.7 Emergency Diesel-Generator Control System

Each EDG has a local control panel and annunciator, as well as control and annunciator alarms in the main control room. The control functions provided are listed in Table 8.3-10. The provided metering is given in Table 8.3-11.

Control power for each diesel comes from a highly reliable Class 1E battery. The two diesels providing power for the safety system of Division I receive their control source from the two 130-V dc batteries of that division. The two diesels of the other divisions are supplied, in like manner, by the Division II control batteries.

Table 8.3-12 lists the parameters annunciated at the local EDG control panel. Table 8.3-13 provides a list of the EDG parameters monitored in the main control room.

The diesel generator air intake and exhaust systems do not require the alarming of any parameter except for the differential pressure across the intake filter. An indicator and switch are installed to locally monitor the air intake filter and alarm in the main control room. The combustion air intake and exhaust systems have no interlocks.

Controls and monitoring instrumentation critical to the continued operation of the EDG are protected from engine vibration. The annunciator and other control equipment are mounted on freestanding electric control panels. The engine gage boards are mounted in a cradle on vibration isolation springs. The relays pertaining to operation of skid equipment that were in a skid-mounted relay box have been moved to a wall-mounted panel.

8.3.1.1.8.8 Other Plants Utilizing Colt Emergency Diesel Generators

Table 8.3-9 lists other nuclear plants that use Colt Industries' EDGs of the same type as Fermi 2 for their standby power source.

8.3.1.1.9 Class 1E Instrument 120-V AC Power Supply

The 120-V ac power supply provides power for both Class 1E instrumentation and control and for certain ac control valves and solenoids. The system is shown in Figure 8.3-7 and the loads are tabulated in Table 8.3-14.

There are two Class 1E 120-V ac nominal power supplies, one per division. Each supply is a separate modular power supply unit rated at 45 kVA. A modular power unit consists of an automatic transfer switch with appropriate sensing devices, three single-phase transformers, and two line voltage regulators. Each modular power supply unit has two power sources at 480 V ac, each fed from a different MCC in the same division, which improves reliability. Power is selected from one of the two feeds and will transfer to the other feed on an undervoltage condition of 83 to 85 percent if maintained for 1 sec (nominal), provided that the alternate source is above 90 percent rated voltage and frequency.

The modular power supply unit has three distribution cabinets providing outputs, each 120 V ac nominal, 15 kVA. One is for inductive loads such as solenoid valves and similar applications where minor variations of voltage can be tolerated. Two outputs are 120 V ac nominal, 15 kVA, regulated power for instrumentation loads, the regulated outputs of MPU 1 and MPU 2 are bounded by the electrical design calculations to ensure that the regulated output voltage variations are within the tolerances for proper operation of the instrumentation loads. During the period when the common offsite power for both divisional MCCs is lost, these units will be powered by the respective division EDG within approximately 18 sec after loss of power.

Important, but not safety-related, loads such as feedwater control and the Integrated Plant Computer System (IPCS) are fed from a BOP uninterruptible power supply.

The instrument loads are such that they can tolerate a short power outage without unacceptably degrading plant safety.

8.3.1.1.10 Reactor Protection System 120-V AC Power System

A separate power system is provided for the reactor protection system (RPS) and certain other instrumentation, as described in Subsection 7.2.1.1.2.

The power feeds to the RPS 120-V ac power system are

a.	Motor-generator set A:	480-V MCC72B-4C pos 2C.
b.	Alternate A:	Distribution Cabinet 72C-2D pos 2 via a 480/120-V single-phase transformer feeding a 120-V regulator.
c.	Motor-generator set B:	480-V MCC 72E-5B, pos 1C-R.
d.	Alternate B:	Distribution Cabinet 72F-4B, pos 2 via a 480/120-V single-phase transformer feeding a 120-V regulator.

The alternate RPS feeds serve primarily as maintenance ties. No automatic transfer occurs between the normal and alternate sources because the loss of one motor-generator set will not cause a scram.

8.3.1.1.11 Instrumentation and Control Systems

The instrumentation and control required for the ESFs listed in Tables 8.1-1 and 8.1-2 are powered by the ac control and instrument buses shown in Figure 8.3-7, and by the dc buses shown in Figure 8.3-9. These buses provide the same reliability for control and instrumentation as is afforded by the equipment power supply. The instrumentation provides the operator with complete information on plant conditions. He receives all the information required to base a decision on adjusting loads or manually initiating loads, particularly when shutting down the emergency power supply.

Manual controls necessary for emergency equipment are all located in the main control room. The EDGs and their accessories have local control and instrumentation, in addition to that provided remotely in the main control room. On loss of offsite power and subsequent transfer to the emergency power supply (diesel generator), the following information is presented to the operator:

a. Load on the EDGs as well as the remaining EDG capacity is displayed in the main control room

   A digital "EDG remaining loading capability" instrument is provided for each EDG. With the EDG unloaded, this instrument will indicate the full rated loading capability in kilowatts. As soon as load is applied (automatic or manual), this digital instrument will display the remaining capability of the EDG. This information enables the operator to take appropriate action to avoid the remote possibility of the affected EDG becoming overloaded

b. Emergency core cooling system (ECCS) conditions are indicated as follows:

   1. High-pressure coolant injection - There is main control room indication of pump discharge flow and pressure, and local indication of steam flow

   2. Core spray - There is main control room indication of pump discharge flow and pressure plus current to the motors

   3. RHR - There is main control room indication of pump discharge flow and pressure plus current to the motors

   4. Automatic depressurization system (ADS) - There is main control room indication of valve position

   5. RHRSW - There is main control room indication of RHRSW flow and discharge temperature from the heat exchanger and the current to the pump motors.

c. Automatically initiated loads are connected as outlined in Table 8.3-3. They are adjusted manually for the conditions listed in Table 8.3-4.

8.3.1.1.12 Circuit Protection

8.3.1.1.12.1 Grounding

The general plant ground mass is formed by ringing each structure of the plant with bare copper cables and interconnecting the ground masses of the individual buildings. All connections are made by the cadweld process.

Separate cadwelded risers are used for the following ground systems:

a. Equipment ground system

b. Main turbine generator ground system

c. Instrument ground system.

The equipment ground system consists of multiple bare copper conductors with taps on each floor for equipment grounding. All motors, equipment cabinets, and ground buses are to be connected directly to the risers. The cable tray system is intended to be electrically continuous and is connected to the equipment ground risers.

Each tray or tray run is provided with a copper conductor connected to each section of tray and to the ground mass. All instrument grounds and case grounds are normally connected to the equipment ground. Local instruments are grounded using the equipment ground provided by the cable tray system.

The turbine-generator ground system consists of a double ring of 1/4- by 4-in. copper ground bars linked to the generator by two 500 MCM bare copper cables.

The instrument ground system is designed using an insulated cable connected directly to the station ground mass. This ground system is designed to provide a low noise ground for the computer system. One isolated riser is terminated on a ground bus bar in the relay room area to accommodate unusual field grounding problems.

All stairs and piping systems are grounded.

The 4.16-kV system is normally connected to neutral ground via 4-ohm resistors at the service transformers to limit ground fault current. When the vital system is fed from the EDGs, this ground is removed and the 4.16-kV system is operated as a high impedance ground system, with grounding accomplished through an impedance at the EDG neutral. The EDG high resistance grounding system allows continued operation of the EDG in the presence of a ground fault by limiting the ground fault current to a very low value, thus permitting operation of both the EDG and 4.16 kV loads. This feature provides the Operators with additional flexibility and enhanced equipment availability until an orderly transfer or equipment shutdown can be accomplished. All other power systems are directly grounded through the transformer neutrals..

8.3.1.1.12.2 Circuit Protection

The 4160-V bus feeder circuits have three phases of inverse time overcurrent plus inverse time neutral (ground) fault relay protection. The inverse time ground overcurrent relays, for the most part, monitor the neutral of the current transformers used for the phase overcurrent relays. The protective relays are GE-type IAC. These relays meet the seismic qualifications necessary for Class 1E equipment.

Motors, feeders, and other loads on the 4160-V buses have two phases of inverse time overcurrent relaying plus instantaneous ground fault protection using the ground fault sensor principle. The ground fault sensor is essentially a CT-like device that surrounds the three load conductors and detects any imbalance that occurs. The relays used with the ground fault sensors are GE-type PJC instantaneous overcurrent.

All protective relays are calibrated to provide the proper sequence of operation, which ensures that selective tripping will occur. The feeder circuit phase relays are calibrated to give at least 30 cycles of margin at the associated branch circuit relay calibration trip point. The feeder neutral or ground relays are calibrated to provide a 0.4-sec margin above the branch circuit neutral relay setting.

Devices fed from 480-V ac switchgear have time overcurrent protection that is applied in accordance with the latest industry standards. At Fermi 2 this protection is provided by solid-state devices known as "Power Shield." These devices are supplied as an integral part of the 480-V circuit breakers. The long time, short time, and instantaneous trip elements perform essentially the same protective functions as provided by the electromechanical trip devices, but with greater accuracy and repeatability due primarily to the absence of mechanical moving parts. These devices, being solid state, easily meet the seismic qualifications for the Class 1E equipment. Motor feeders are equipped with phase-instantaneous and time-delay overcurrent relaying, with a neutral solid-state instantaneous ground sensor device.

Each ESF bus located in the RHR complex, the feeder cable to the ESF bus in the reactor building, and the feeder breaker are protected by an overall differential relay scheme. In addition to the superior ability of a differential to detect bus faults, the use of such a scheme avoids the problems associated with an overcurrent relay scheme on a feeder where full load currents are different when the feed direction reverses.

When the EDGs are operating in parallel with offsite power, several protective relay functions are used to protect both the generator and engine. These trips are listed in Table 8.3-12 for both the test condition and emergency condition.

Under conditions that cause pickup of the emergency start relays, all of the trip circuits are blocked, with the exception of overspeed trip, generator differential, low lube-oil pressure, crank-case overpressure, and start failure trip. The low lube-oil pressure and crankcase overpressure trips are each connected in a two-out-of-three logic (one out of three causes an alarm only). Although there is one start failure relay, once the engine is started, either the low speed or running speed relays will inhibit initiation of the start failure relay.

There are two emergency start relays: either of these relays will initiate EDG starting as well as bypass the unnecessary trips. All of the bypassed trip circuits still retain their alarm function to alert the operator to an abnormal condition. Since the trip bypass is achieved with the emergency start relays, the bypass circuitry is directly monitored by the annunciator position "EDG - Auto Start." Surveillance tests on the emergency start relays will also test the status and operability of the bypass circuits. The EDG logic is designed so that the nonemergency trip relay is automatically reset by the emergency start signal. (Nonemergency trips are those other than the emergency-mode trips described above.) This feature prevents the inadvertent lockout of an EDG during standby by a false or real nonemergency-mode trip.

Devices such as motors fed from MCCs are protected by fused disconnect switches and thermal overloads. Non-motor-type loads are protected by circuit breakers. Overload settings are 125 percent or greater of full load current for nonessential items and 140 percent or greater of full load current for ESF loads.

At Fermi 2, the thermal overload devices on the ESF system motor-operated valves (MOVs) were selected to allow at least four times the valve stroke time at full load current and at least one time the valve stroke time at motor current associated with twice running torque. These criteria were used because it is felt that operation of the valve motors when needed supersedes any concern with degradation or failure of the motor due to excess heating.

Additional protection against premature operation is afforded by the thermal overload devices' being located at the MCCs and not at the motors themselves. All thermal overload devices are temperature compensated.

Branch short-circuit protection is provided by dual-element fuses (fusetrons) sized to override starting currents, yet maintain coordination with the thermal overload devices.

Preoperational testing ensured that thermal overload setpoints were calibrated properly. As necessary, full load current measurements were made to verify adequacy of the thermal overload device settings. Periodic tests will serve as verification of the drift of the trip setpoints for the thermal overload devices.

All circuits of the ESF buses are tripped on undervoltage, except feeds to the 4160/480-V transformers and selected MCCs with small load requirements. This allows each bus to be cleared when bringing up the EDG.

8.3.1.1.13 Maintenance and Testing

8.3.1.1.13.1 Auxiliary Electrical Power Systems

The 4160-V ac circuit breaker and associated equipment can be tested by jacking out the breaker to the test position. (The testing of certain systems is not possible during operation.)

The breaker opening and closing circuits can be operated without energizing the circuit in this test position. Test stations are provided for each ESF switchgear room, with the exception of the EDGs, because of the small number of breakers.

The 480-V ac circuit breakers for motor circuits and associated equipment can be tested if they are jacked to the test position. This allows breaker operation checks without energizing the circuit.

Incidents involving the inadvertent disabling of a component by racking out the circuit breaker of its redundant counterpart have occurred in nuclear power plants. At Fermi 2 several steps have been taken to preclude such an occurrence.

The 4160-V and 480-V switchgear (ESF and BOP) incorporate 52H auxiliary switches as applicable as part of the design. These individual cell-mounted auxiliary switches are actuated by the location of the circuit breaker. When the breaker is in either the test or disconnected position, the 52H/a contacts are open and the 52H/b contacts are closed, and vice versa when the breaker is fully racked in and connected. These contacts are wired to bypass the breaker-operated auxiliary contacts, as necessary, when the circuit breakers are in the disconnected or test position. Their specific purpose is to eliminate undesired signals and avoid disabling other equipment due to testing or removal of a circuit breaker.

All systems were checked during design for the presence of disabling interlocks. If an interlock had been inadvertently wired in even after design review was complete, construction testing procedures should have detected this condition. The preoperational tests served as the final test for the presence of disabling interlocks.

The 4160-V and 480-V breaker operating and protective relay tests were performed initially by performing checkout and initial operating (CAIO) tests. These tests were performed after the construction phase and consisted of initial equipment energizing, calibration, and functional testing of components.

Preoperational or acceptance tests and protective relay tests were performed before fuel load.

a. Preoperational or acceptance tests were system operating tests, which verified adequacy of individual components, instruments, interlocks, alarms, etc., to function as a system

b. Protective relay final verification and required retesting were also performed because construction and CAIO testing could and sometimes did alter the required final relay settings.

For CAIO and preoperational testing, instructions meeting the requirements of IEEE 336-1971, IEEE 279-1971, and others as applicable were written to ensure the adequacy of tests to be made on the electrical equipment.

The test package for a particular component included a test procedure, test forms, a check-off list to ensure completion, and an overlay test sheet to indicate, among other things, test equipment certification and approval by a responsible individual.

The test instructions described and indicated the purpose and scope of the tests, the equipment to be tested, the specifications and drawings to be used, the test equipment required, the precautions to be taken, and the prerequisites. Also included were the test procedure itself and the method of handling deviations or variances.

The personnel who performed this testing were engineers or technicians from several divisions of Edison who were qualified with respect to the concerned equipment, the test equipment to be used, and the procedures and precautions to be followed.

Subsequent tests will be performed in accordance with the Preventive Maintenance Program and surveillance program. Scheduled inspections of circuit breakers, contactors, and associated equipment to ensure adequacy of installation, mechanical and electrical clearances, cleanliness, and operability are conducted as specified in approved instructions and the Preventive Maintenance Program.

8.3.1.1.13.2 Standby AC Power System

Because the EDGs are used as standby units, readiness is of prime importance. The testing program is designed to test both the ability to start the system and the ability to run under load long enough to demonstrate that cooling and lubrication are adequate and that auxiliary system functions are satisfactory for an extended period of operation.

Each generator unit is capable of being synchronized manually for parallel operation with the normal plant ac power buses for load test runs. To ensure availability of the systems, one EDG at a time is routinely started and loaded in parallel with the offsite power systems. Tests of the automatic EDG functions are conducted as required to demonstrate proper operation. Details are contained in the Technical Specifications.

Plant operating procedures require application of approximately 30 percent load immediately after synchronization, with subsequent testing performed at loads of 50 percent or greater. To preclude formation of gum and varnish deposits in engine components, extended operation at less than 25 percent load is not required.

An initial system test was performed to demonstrate that the standby power supply can be started and can accept design load within the design-basis time, and that the standby power supply is independent of the offsite power supply.

The surveillance testing of the EDGs is scheduled in accordance with the Technical Specifications.

Component failures of the EDGs are addressed in the plant preventive maintenance program and are identified in the equipment performance evaluation analysis. Component failures are analyzed with respect to frequency, application, design, and manufacturing defects. Component failures are thereby corrected by problem analysis and engineering judgment.

Postmaintenance functional checks, before postmaintenance operability testing, of the individual EDG subsystems and components are specified in the plant procedures. These procedures verify the status of temporary modifications, that is, lifted leads or jumpers; electrical power feeds and switch lineups; valve lineups; and support system operability. The postmaintenance testing verifies the Technical Specifications operability requirements, and the updating of the equipment status board ensures the placement of the EDG in the automatic standby mode by the control room operator.

8.3.1.1.14 Operation of Breakers Associated With Bus 64B

In the following description, only ESF bus 64B will be considered. Breakers on buses 64C, 65E, and 65F operate in a similar manner. The description is typical of any of the vital load groups shown in Figure 8.3-1. Various relays will be referenced by their standard device function identification number as follows:

a. 51 - Time overcurrent relays

b. N51 - Time overcurrent neutral relay

c. 87B - Bus differential relays

d. 27 - Under/voltage relays.

8.3.1.1.14.1 Feed to Bus 64B

Bus 64B normally receives power from transformer SS64 via breaker B6, but it can also receive power from alternate sources, as discussed in Subsection 8.3.1.1.14.3.

8.3.1.1.14.2 Loss of Power to Bus 64B

In an emergency situation, such as loss of power to transformer SS64, EDG ll automatically starts, and the affected buses are cleared of loads. After the EDG reaches rated voltage and speed, EDG breaker EA3 will close automatically, and EDG ll will provide power to bus 64B, via breaker B8.

8.3.1.1.14.3 Maintenance Tie for Bus 64B

During maintenance operations, power can be supplied to bus 64B via breakers 65T and B9. If it is desired to have uninterrupted power to bus 64B during maintenance, EDG ll must be manually started and synchronized with bus 64B via breaker EA3. All of the load on 64B would be manually transferred to EDG-11, breaker B6 would be opened, breaker 65T would be closed, and Division I would be paralleled with Division II via breaker B9. The load would be manually transferred from EDG 11 to Division II, breaker EA3 would be opened and EDG 11 shut down. The reverse of the above would be followed to return bus 64B from a maintenance feed to its normal supply from transformer SS64.

8.3.1.1.14.4 Limitations on Use of Maintenance Tie

The design limitations on the use of the maintenance ties are as follows:

a. When power is provided to Division I from Division II via maintenance tie breaker 65T, the sum of the current through breakers 65T and C9 or B9 should not exceed 1200 amp

b. When power is provided to Division II from Division I via maintenance tie breaker 64T, the sum of the current through breakers E9 or F9 and 64T should not exceed 1200 amps.

8.3.1.1.14.5 Breaker Operation

For operation of breakers B9, B6, B8, EA5, 65T, EA3, and buses 64B and 11EA, refer to the logic diagram in Figure 8.3-8.

8.3.1.2 Analysis

8.3.1.2.1 Auxiliary Electrical Power Systems

8.3.1.2.1.1 Safety Design Basis

The auxiliary electrical power system provides adequate power to operate all auxiliary loads necessary for plant operation and safe shutdown of the reactor. The number of power sources for the plant auxiliary electrical power system is sufficient, and of such electrical and physical independence, that no single event would interrupt all auxiliary power at one time.

The ESF buses may be connected, by appropriate switching operations, to alternative sources of offsite power for maintenance purposes only. In the event of a total loss of external power sources, emergency auxiliary power is supplied from the plant EDG system located on the site. The EDG system sources are physically independent of any normal offsite power system. Each power source, up to the point of its connection to the auxiliary power bus, is capable of complete and rapid electrical isolation to prevent paralleling of power sources.

Duplicate electrical loads are diversified among auxiliary power buses. Plant layout criteria include the separation of switchgear sections, motor feeders, and similar equipment groups, so that no single postulated accident causes total loss of power to critical loads.

The auxiliary electrical power system takes into account General Design Criteria 17 and 18, and is designed accordingly.

8.3.1.2.1.2 Safety Evaluation

Normal power for ESF buses is from the 345-kv and 120-kV transmission systems by means of two system service transformers. One transformer is from the 345-kV station bus 301. The other is from the 120-kV bus 101 via transformer 1. All 345-kV and 120-kV buses have more than one offsite power source.

Redundancy of buses within the plant and the division of critical loads between buses yield a system that has a high degree of reliability and integrity.

Segregation of buses and components limits or localizes the consequences of electrical faults or mechanical accidents occurring at any point in the system.

All breakers and transformers are rated according to standard electrical industry practices and applicable IEEE, NEMA, and ANSI standards.

8.3.1.2.2 Standby AC Power Supply System

8.3.1.2.2.1 Safety Design Basis

The design of the onsite standby ac power supply system is a one ESF bus/one-EDG arrangement (two such arrangements per ESF division) with the redundant loads of each division split among four buses. Each EDG is of sufficient capacity to carry the essential loads of its respective bus. A single failure that could cause the loss of a division pair of EDGs would not prevent safe reactor shutdown.

The EDGs start automatically and reach rated frequency and voltage within a maximum of 10 sec. They either automatically close into the bus and load, if offsite power is lost, or they stand by at rated speed and voltage, if offsite power is still available. The EDG fuel-oil storage tanks are of sufficient capacity to meet the EDG fuel requirements for at least 7 days. The EDG fuel-oil storage tanks are located inside the RHR complex in separate enclosed rooms. Refer to Subsection 9.5.4 for details. Two fuel pumps are provided for each EDG. Either pump is adequate to maintain the proper level in the fuel day tank, thus providing 100 percent redundancy. The EDGs are equipped for manual periodic starting, synchronizing, and loading to permit readiness testing without interrupting normal plant operation.

8.3.1.2.2.2 Compliance With Design Criteria

The design of the standby ac power supply system is based on the requirements of Regulatory Guide 1.6 and IEEE 308-1971, and complies with General Design Criteria 17 and 18. The two redundant ac systems are completely independent except for the one swing bus which has double safety interlocks to ensure against tying divisions together at the bus (Subsection 8.3.1.4). The loads on this bus are the low pressure coolant injection (LPCI) system injection valves and recirculation pump suction and discharge valves.

The standby ac power supply system meets the requirements of Regulatory Guide 1.9 except for certain voltage and frequency requirements. Table 8.3-8 gives an analysis of large-motor starting ability. The two motors considered were the RHR pump motors (2000-hp motors for pumps A,B, and C and 2250-hp for pump D) and the 800-hp core spray pump motor. Depending on the analysis used, the voltage dip when starting the RHR pump and the recovery time when starting the core spray pump exceed the stated limits. A detailed test program has been conducted to ensure the adequacy of the EDG. Continued surveillance testing also ensures the adequacy of the EDG performance during large-motor starting transients. Additional discussion of conformance with Regulatory Guide 1.9 is provided in Appendix A.1.9.

Field tests were performed to prove the Fermi 2 EDG capabilities for the following items:

a. Rapid start

b. Voltage response

c. Load acceptance.

Quantities recorded during these tests included

a. Generator voltage

b. Generator current

c. Generator kilowatts

d. Field voltage and current

e. Motor current

f. Frequency

g. Elapsed time

h. Motor speed

i. Motor-connected load (such as pump flow and pressure)

j. Other quantities as necessary.

Detailed procedures for these tests were developed as part of the Startup (Preoperational) Test Program, to meet the criteria established in Regulatory Guide 1.41.

8.3.1.2.2.3 Safety Evaluation

The primary bases for selecting EDGs are reliability and total independence. Normal sources of power are extremely reliable, and the probability of coincident failures of all sources of offsite power into the plant is very low. The EDGs are provided as onsite power sources to provide backup to the offsite sources of power. It is imperative that the EDGs are not influenced by the same environment that affects the offsite power sources. For these reasons, the diesel generator units, which are selfsustained and require no offsite electrical power sources for operation, were selected as standby auxiliary power sources.

The ability of the EDG to start rapidly on demand is consistent with the concept of maintaining continuity of the ECCS under accident or emergency conditions. A continuous source of auxiliary power for the plant is ensured by the facilities described previously. The reliability demonstration tests are discussed in Subsection 8.3.1.1.8.3.

The following events occur in the order indicated for (a) a LOCA, or (b) a loss of offsite power:

a. The EDGs are started automatically. After reaching rated speed and voltage, they are ready to be loaded. However, the breakers remain open

b. If there has also been a loss of offsite auxiliary power sources, all 4160-V and 480-V feeder breakers on the service buses are tripped open, except for the 4l60/480-V transformers and certain essential breakers for MCCs

   At the same time the divisional EDGs are started, and after reaching rated speed and voltage, the respective EDG breakers will close automatically

c. When the voltage on an ESF bus is restored by the EDG, essential auxiliaries are started automatically in a predetermined sequence. Manual operation from the main control room is also available for all essential auxiliaries. The EDGs can be stopped manually if offsite power is restored.

The control circuits are designed to provide the automatic features described. They allow the reactor operator to take other appropriate action as circumstances require.

Monitoring of automatic functions is provided in the main control room, thereby permitting the reactor operator to observe that proper conditions have been established.

All components of the EDG system are designed, constructed, and enclosed in accordance with the performance objectives for Category I design. Similarly, the entire system as well as the structures surrounding the system are protected against other natural and man-made phenomena.

8.3.1.2.3 Class 1E Electrical Equipment in Hostile Environments

Safety-related equipment required to operate in hostile environments and its environmental qualifications are given in Section 3.11. Section 3.11 defines the environmental conditions for various areas of the plant. Tables 3.11-1 and 3.11-3 give the accident basis environmental envelope. Table 3.11-4 lists the safety equipment and its operating environment both inside and outside the primary containment.

8.3.1.2.4 Loss of Non-Class 1E Instrumentation and Control Power System Bus During Power Operation

IE Bulletin 79-27 addresses a loss of an instrumentation bus, either safety related or not safety related, that could affect the ability to attain cold-shutdown status.

Fermi 2 has redundant systems that can be used to attain a cold-shutdown status. These systems are discussed in Chapter 6.

The instrument power supplies for the following engineered safety systems were reviewed for IE Bulletin 79-27:

a. High-pressure coolant injection (HPCI)

b. Reactor core isolation cooling (RCIC)

c. Automatic depressurization

d. Core spray

e. Residual heat removal (RHR)

f. Reactor protection

For the purposes of the review, a complete loss of the feedwater system was assumed.

The results of the review indicated that no modifications were required at Fermi 2 to ensure the attainment of cold shutdown according to the concerns of IE Bulletin 79-27. This conclusion is based on the following:

a. Instrumentation associated with systems required for a cold shutdown is powered from ac and/or dc sources

   1. The ac instrumentation is fed from 480-V MCC 72B-2A or 72C-3A (Division I) and MCC 72F-2A or 72E-5A (Division II). Each of these feeds a delta-connected transformer bank that, in turn, feeds three instrumentation and control buses. Each of these buses is separately fused, and each bus has only seven loads, all of which are separately fused. Figure 8.3-7 shows this configuration. Each feeder powers a distribution cabinet, and circuits from each distribution cabinet are individually fused. These circuits feed individual instrument loops, which consist of an instrumentation power supply, transmitter, and indicating instrument

   2. The dc instrumentation is powered by 130-V batteries (one per division) or by 24-V batteries (one per division). Each of these dc distribution systems has characteristics similar to those of the ac system described above.

   Thus, the instrumentation power system at Fermi 2 is very diverse.

b. If a main ac power source is lost, such as a 480-V bus, the "bus energized" light will go out on the combination operating panel in the control room, an annunciator window will light, and the sequence-of-events recorder will indicate which breaker(s) operated. Critical instrumentation, such as that for reactor water level and pressure, is maintained via uninterruptible supplies, which are fed from the same division battery. Each uninterruptible supply powers only one or, in a few cases, up to five instrument loops. These supplies are Class 1E and are not physically close to each other. Such critical instrumentation is redundant across divisions

c. If any dc power sources are lost, an alarm and annunciator indication will be initiated in the control room. In this case, sufficient instrumentation associated with systems in the opposite division will be available. In addition, critical instrumentation fed by the failed supply will be maintained, since such instruments are fed by small, qualified, uninterruptible supplies. The alternative source, as mentioned above, is the ac power source in the same division

d. If power to a small group of instruments is lost, through a failure of a distribution cabinet or an individual circuit, the operator will be readily aware that power has been lost. The indicating instrument will drop to zero; the coordinated manual control switch or pushbutton backlight for that instrument or function will go out. However, the system redundant to that which suffered the instrument power loss will be available to achieve cold shutdown. The instrumentation for that system is powered from a totally separate source.

8.3.1.3 Conformance To Appropriate Quality Assurance Standards

The Quality Assurance Program covering design, fabrication, testing, purchase, and shipment of equipment for safety-related systems is discussed in Section 17.1. Quality Assurance procedures to implement the requirements of IEEE 336-1971 (Regulatory Guide 1.30) are used during installation, inspection, and testing of electrical equipment.

8.3.1.4 Independence of Redundant Systems

8.3.1.4.1 System Independence

The cabling criteria for Fermi 2 are established to afford complete independence of redundant safety systems as well as maximum reliability within each safety system. Guidelines for the cabling criteria follow the general criteria for electrical equipment described in Subsection 3.12.3.

The independence of safety systems is achieved primarily by the physical layout of the plant itself. Class 1E electrical equipment is totally redundant. In addition to the general separation achieved by the plant layout, definite separation requirements are imposed between equipment and cables of redundant divisions. Cables for redundant channels of the RPS and ESF are so arranged and installed that no single credible event could cause damage to more than one of the redundant systems. The systems are so designed that the occurrence of such an event on one system can in no way affect the other system.

For trays or conduits crossing a single insulated process steam line, a minimum separation of 12 in. is required. Crossing multiple insulated steam lines or running parallel to a single insulated steam line is avoided. However, if not avoidable, a 4-ft separation is required. Deviations from this criterion are evaluated and resolved on a case-by-case basis.

Non-Class 1E systems do not degrade the separation between redundant systems. In the case where separation distances are compromised by non-Class 1E cable trays, a fire-resistant barrier is used. Barrier use in these cases conforms to the redundant separation requirements.

Protective measures for cables required to meet the identified safe-shutdown path in the fire-protection analysis in Appendix 9A are applied as indicated in that section.

Routing of RPS or ESF control or power cables is avoided through rooms or spaces where there is a potential for the accumulation of large quantities (gallons) of oil or other combustible fluids through leakage or rupture of lube oil or cooling systems. Where such routing is unavoidable, only one division of RPS or ESF cables is allowed.

In the RHR complex, there is no separate BOP cable tray system. The BOP cables on the south side of the building centerline are routed as ESF, Division I; those on the north side are routed as ESF, Division II. This means that no BOP cables can cross safety system divisions, thereby ensuring complete isolation and independence of the redundant safety systems.

In addition to the separation of cables for redundant safety systems, physical separation is provided between cables classified as power, control, and instrument. Each is run in a separate tray system. The definition of each type of cable is as follows:

a. Power cables – Power cables, as described, generally fall into two voltage levels of 600-V and 5000-V insulation. These are the cables that provide electrical energy for motive power or heating to all 4160-V ac, 480-V ac, 208-V ac, and 260-V dc auxiliaries. Cables used to provide electrical energy to switchgear, MCC, and distribution panels also fall into this category. Lighting power and 260-V dc are not run in the cable tray, but in separate trays or conduits

b. Control cables – Control cables are those cables that provide 120 V ac and 125 V dc, for components which affect the automatic or manual control of auxiliary equipment or the 24 V dc for annunciators which provide alarms for indication of the state of those auxiliary components

c. Instrument cables – Instrument cables are those low voltage or low-current cables that carry signals from such analog devices as thermocouples, resistance temperature detectors, transducers, pneumatic-to-electric converters, or low-level digital signals. They generally are sized 16 AWG or smaller. The instrument cables also include the fiber optic cables that carry light pulses rather than current or voltage.

Cable tray design is such that, where practical, the trays containing power cables are the highest level in stacked trays.

In some cases, cables for small 460-V motors may contain both the power and the control for those motors. These cables are routed with other control cables in control cable trays.

Instrumentation cables are installed in separate conduit or in separate nonventilated solid trays with covers to provide electromagnetic shielding. In general, instrument trays occupy the lowest of a stack of cable trays.

The minimum vertical distance between stacked trays of the same safety-related system or between stacked trays of a non-safety-related system is 1 ft from the bottom of the upper tray to the top rail of the lower tray. This provides accessibility to the tray for adding or replacing cables.

Separation of redundant safety systems and power, control, and instrument cables of the same safety or nonsafety systems extend through the primary containment penetrations.

Penetrations are grouped in two separate areas, one to the north and one to the south of the reactor centerline. Penetrations for the divisions of ESF, RPS, and NMS are separated into the two areas by division. Penetrations are divided by division and by class of service as follows:

	Division I	Division II	BOP
5 kV power			6*
480V power	1	1	
120V control	2	2	
Control rod drive			6*

	Division I	Division II	BOP
Thermocouple			2*
Low level signal			2
RPS	1	1	
NMS	2	2	

* Half of these penetrations are located in each divisional area.

8.3.1.4.2 Cable Reliability

All safety related cables and balance of plant cables routed in cable trays utilize materials that are designed to meet the electrical requirements of IEEE/ICC/WG-12-32 after being subjected to 1.8×10^8 rads gamma integrated over a 40-year period. In addition, a fire test was conducted for all cables 14 AWG and larger and a fire retardancy test for cables 16 AWG and smaller. Refer to Section 9A.5.d.3(f) for a description of tests on cables 14 AWG and larger. Temperature and humidity tests were conducted to meet the LOCA BWR requirements, as detailed in Section 3.11.

Cables not subject to these requirements are routed in enclosed raceway (except as otherwise noted) and are as follows:

a. BOP medium voltage underground cables

b. Lighting cables

c. Communication cables (i.e., computers, telephone, data, etc.) will be routed in enclosed raceways unless otherwise approved by engineering.

d. Security system cables

e. BOP vendor supplied wiring and their replacements

f. Internal panel wiring in the control center (not subject to the radiation resistance requirements only)

8.3.1.4.2.1 Ampacities

Power cable values are sized according to criteria mentioned in ICEA Pub. No. P-54-440-1975 for cables in open-top trays and ICEA Pub. No. P-46-426 for cables in conduits and underground ducts. Sizing of cables is controlled via design instructions and engineering calculations in the design process. Ampacities for cables outside the drywell are based on a conductor temperature of 90°C and air ambient temperature of 40°C. To correct for cable diameters, a diameter correction mentioned in the ICEA publication was applied.

Power cables installed inside the drywell are sized at 65°C (149°F) air ambient with the exception of cables used only during cold shutdown where 40°C (104°F) air ambient may be utilized and cables in certain areas inside the drywell where the temperature exceeds 65°C (149ºF). Cables installed in operating environmental conditions above 65°C (149°F) were evaluated. The ampacity tables for 65°C (149°F) were obtained by applying a temperature correction to the cable ampacities at 40°C. The temperature correction formula was obtained from ICEA Pub. No. P-46-426.

Power cable values are selected on the basis of 115 percent bus load amps for bus feeder cables and 125 percent full load amps for cables feeding motors, heaters, etc. These values can be overruled by engineering dispositions.

8.3.1.4.2.2 Fire Protection of Cables

Cables are fabricated with tested, fire-resistant insulating and jacketing materials. Flame tests were conducted by the selected cable vendors with the results certified and submitted to Edison. Cable types were not accepted unless it was proven that a self-sustaining propagating fire did not result under rigid test conditions.

Fire stops are installed in all horizontal and vertical cable tray penetrations through walls and floors except for a few select wall penetrations identified as required for pressure venting from a postulated high-energy pipe break. The high-energy pipe break venting paths are identified in Subsection 3.6.2. For cable tray penetrations that are not fire stopped, fire breaks are provided that do not affect vent area requirements. Walls identified as fire walls are not used for pressure relief and all electrical tray penetrations are fire stopped. Fire breaks have not been added along horizontal and vertical tray runs because of division of the plant into fire zones and the use of cable that was tested and purchased to be nonpropagating.

Although tray penetrations are generally used for convenience where the maintenance of a pressure differential between areas is not required, fire stops are nevertheless provided to prevent the spread of fire from one area to another. Part of the opening provided is taken up by the barrier designed in accordance with the wall structure itself. Derating effects of cable capacity are considered when establishing the depth of the fire-resistant fill in the penetration. When penetrating a floor, the tray section is completely enclosed for a distance of 8 ft above the floor surface.

Cable tray penetrations through secondary containment will be fire stopped and sealed with either the multicable transit manufactured by Nelson Electric Company or an approved silicone foam fire stop.

The multicable transit consists of a steel rectangular frame through which the cables are pulled. The spaces inside the frame around the cable are packed with elastomer inserts of a proprietary formulation. The entire assembly has been fire tested to UL 263 followed by a hose stream test as specified in UL 10B. UL rates the transits for Classification and Follow-up Services of Underwriters Laboratories, Inc., and allows it to be marked:

Underwriters Laboratories, Inc.

Classified

Wall Opening Protective

Multi-Cable Device

Fire Rating: 3 hr minimum

The other cable tray fire penetrations will be sealed using a fire stop made of

a. Dow-Corning Q3-6548 Silicone RTV Foam, or

b. Other material to achieve an ANI approved 3-hr barrier.

At the designated safety-related fire barriers, Edison has provided 3-hr-rated penetration fire stops, tested and qualified in accordance with the NELPIA/MAERP (ANI) standard method of cable and pipe penetration fire stops. The thickness is adequate to meet the test requirements of ASTM E-119. Fire stops at walls not rated as fire barriers are rated for 30 minutes.

If it becomes necessary to breach or repair a completed fire stop, the silicone foam fire stops can be repaired using silicone foam repair procedures and controls.

Edison recognizes the need for periodic surveillance. These surveillances determine the condition of the fire stops and seals and will be conducted in accordance with the Technical Specifications requirements.

Holes and other voids in sleeve penetrations through floors to switchgear, MCCs, and other panels are plugged with a suitable fire-resistant material. In areas of high cable concentration, such as a cable spreading room, smoke-detection devices are provided. The design and configuration of the area determines the actual location of the devices.

The QA procedures to be used to verify that penetration fire stops and seals have been properly installed include

a. Verification by QC personnel that fire stops and seals are made of the specified materials

b. Monitoring of installation by QC personnel (using inspection procedures and checklists) to ensure compliance with identified design requirements.

8.3.1.4.2.3 Environmental Effect on Cables

Cable materials are evaluated for the effects of environmental conditions. Cable insulation temperature ratings consider the effects of ambient temperature and ohmic heat resulting from loads on the cable.

Where possible, adverse environmental effects are reduced by restricting cable passage through affected areas. However, cables within areas such as the primary containment are subjected to small pressure variations and radiation levels over the 40-year operational life of the plant, possibly at normal operating temperature conditions that may exceed the design rating of the cable insulation. The effect of these ambient temperatures on the service life of the cable are evaluated.

An additional requirement of these cables is to operate satisfactorily in the environment during and after the design-basis accident (DBA) outlined in Section 3.11 and Table 3.11-3. Throughout the period indicated, the cables may be subjected to a relative humidity of 100 percent as well as to the temperatures and pressures outlined in Table 3.11-3. The cable manufacturers are required to test samples of cable to demonstrate that they can withstand the conditions of the DBA defined in Section 3.11, and so certify.

8.3.1.4.3 Cable Trays

NOTE: Reduced design loadings for hangers were specified as a result of reverification of hanger loading and design.

The power and control cable trays are prefabricated sheet metal structures consisting of longitudinal channel side rails connected by transverse hat section members spaced on 9-in. centers. Hanger loading is limited to the reduced design loading (cable and tray weight plus firewrap load, tray cover load, and side rail weight). During initial design, the cable trays within the relay room, cable spreading room, and directly below the relay room floor were designed to withstand a dead weight loading of 50 lb./ft.^{2} , in addition to 200-lb. live load anywhere along the 8 foot maximum tray span, with a two-to-one safety factor. All other trays were designed to withstand a dead weight loading of 40 lb./ft.^{2} in addition to the live load with the same safety factor. In cases where a reduced design loading for a hanger was specified, cable trays were designed for such reduced load. An on-going program was later established to monitor the actual weight of cables in the trays and to account for fire wrap, conduit, and air drop loads. Cable tray design load is adjusted to reflect these actual loads. For the trays in the drywell, a concentrated live load of 250 lb was specified. In the design specification for cable trays, deadweight loading did not include the weight of fire wrap material or any other attachments, such as top hat covers, that were subsequently added. Accordingly, hanger modifications were made where necessary, and the structural adequacy of the cable trays was reverified.

Instrument cables are installed in nonventilated solid metal trays with covers to provide adequate electromagnetic and electrostatic shielding. Ladder-type sections are used in the relay room over the cabinets where cable dropouts are required.

All cable tray hangers for RPS and ESF circuits are of Category I design. The trays are adequately supported and braced to withstand maximum horizontal and vertical forces. The transition tray sections are structurally connected to form a tray system.

Tray fills in both the control and instrumentation tray systems are initially limited by a computer program to 60 percent fill by cross-sectional area, but they may exceed 60 percent fill by specific instruction to the computer detailing the route to be taken. No control or instrumentation tray is permitted to exceed the deadweight loading limit of its hangers.

Tray fills in the power cable tray systems are initially limited to 47.1 percent fill by cross-sectional area. This value is equivalent to 3 in. of calculated depth, where depth is calculated according to the formula given in the ICEA-NEMA Standard Ampacity for Cables in Open Top Trays (ICEA P54-440, NEMA WC51-1975). Power trays may exceed 47.1 percent fill by specific instruction to the computer detailing the tray route to be taken.

Power trays that exceed 47.1 percent calculated fill are reviewed to verify that the temperature ratings of the cables are not exceeded. The temperature ratings of safety related cables are not exceeded in power trays greater than 47.1% fill. No power tray is permitted to exceed the deadweight loading limit of its hangers.

8.3.1.5 Physical Identification of Safety-Related Equipment

All safety-related equipment is identified using a color and/or numbering scheme that is both permanent and conspicuous. The purpose of the numerical and color-coding of cable conduits and trays is to uniquely define each cable and routing as to voltage level, service, and channel where appropriate. This provides a sure system for ascertaining the proper installation of each cable. Details of the numbering and color-coding schemes are in the following subsections.

8.3.1.5.1 Cable Identification

Cables are assigned an alphanumeric code number that is used for the purpose of identification. This number denotes the equipment category and tray system to which the cable is assigned. A permanent cable identification tag that indicates the cable number and segregation code plainly and legibly is affixed to each end of the cable. The number also appears on any wiring drawing, intercabling diagram, or plan electrical (electrical installation) drawing on which the cable appears. Cables are color coded in accordance with plant specifications. Cables belonging to ESF Division I have orange jackets; cables belonging to ESF Division II have blue jackets. Cables which are pulled QA 1 with a black jacket are required to have the cable jacket re-identified (phase taped) per plant specifications. Also, in cases where divisional color jacketed cable have been pulled BOP, cable jacket re-identification (phase taping) is required per plant specification. In general, the BOP cables have black jackets except for certain cases, described in plant specifications. Black-, neutral-, and magenta-colored jacket cables are installed in divisional trays in a limited number of cases due to lack of cables having proper jacket colors in that size (e.g., the coaxial cables with a black or magenta jacket and thermocouple leads with a clear neutral jacket to expose the underlying tracers).

8.3.1.5.2 Cable Tray and Conduit Identification

Each cable tray has an alphanumeric identification number applied to its side at 25-ft intervals and at room entrances. This identification reflects the classification, power level, and channel of the tray section and is so coded. The ESF trays are color-coded orange and blue by division every 25 ft. The ESF cables are installed only in tray sections or conduits with a code identical to the code assigned to each cable. The BOP cables, except those in the RHR complex, which are treated (though not identified) as ESF cables, are routed only in BOP-coded cable trays.

Conduits installed for ESF and RPS cables are also assigned number codes that show cable routing. These number codes are affixed to the conduit at appropriate locations, and are color-coded to denote safety function. The RPS and NMS conduits will be uniquely color coded.

8.3.2 DC Power Systems

8.3.2.1 Description

8.3.2.1.1 General

The dc power system consists of two independent Class 1E battery systems, one system per division. Each system supplies dc power at 260 V dc and 130 V dc.

There is also a 260/130-V dc BOP system serving BOP loads. Further, each high-voltage switchyard has its own independent source of dc power for circuit breaker control. There are two batteries and chargers in the 345-kV switchyard and one battery and charger in the 120-kV switchyard.

Certain positions on the ESF 480-V buses supply non-safety-related loads. The control logic power for these positions as well as the safety-related positions is supplied by the Class 1E battery systems. Non-safety-related dc power loads, such as emergency oil pumps, are normally supplied by the BOP battery system. Where non-safety-related power loads exist on the Class 1E battery systems, a Class 1E isolation device will disconnect the non-safety-related load from the Class 1E battery system on receipt of a LOCA signal.

The ESF and BOP systems are protected from voltage variation by an undervoltage and two overvoltage circuits at the charger. One overvoltage circuit deactivates the rectifier bridge when the voltage exceeds 139.5 V for BOP and 138.5 V for Div I and II, while the other alarms to the main control room any voltage surpassing 136 V for BOP and 134 V for Div. I and II. The undervoltage relay alarms in the main control room if the voltage at the main distribution panel drops below 128.5 V for BOP and 124.2 V for Div. I and II.

8.3.2.1.2 260/l30-V DC Class 1E Power System

Two center-tapped 260-V batteries are provided for Class 1E loads. They are designated as 2PA for Division I and 2PB for Division II, and are shown in Figure 8.3-9. The batteries are located in separate rooms in the auxiliary building. The chargers and related equipment for the Class 1E batteries are located outside the battery rooms, in accordance with the separation criteria required for redundant systems.

Each 260-V battery is divided into two 130-V batteries connected in series. Each l30-V battery section has an adequately sized battery charger. These chargers are connected in parallel through fusing to their respective battery. For each 260-V battery, a 130-V spare battery charger is provided that can replace either of the normal 130-V connected chargers. The replacement can be made manually when it has been verified that the charger is connected to the proper 130-V battery, as shown in Figure 8.3-9. Each division's two 130-V batteries and their chargers are the source of dc control power for that respective division.

To maximize the reliability of system control power, the following philosophy is applied:

a. Control power for each of the two load groups within a division is supplied from a separate 130-V dc section of that division's battery

b. Power for control of each division's two diesel generators and their associated switchgear is supplied from the 130-V dc battery section supplied from their respective load group.

The 260-V sources furnish power for the dc motors necessary during shutdown conditions. For 260-V use, the battery is connected directly to dc MCCs through adequate fusing. The two center-tapped 260-V batteries 2PA and 2PB (identical) are redundant and separated according to IEEE Standard 308-1971 and General Design Criterion 17.

The loads supplied from the ESF batteries are shown in Table 8.3-15.

8.3.2.1.3 48/24-V DC Power System

8.3.2.1.3.1 Introduction

A reliable source of isolated low-voltage dc energy must be available to provide power for neutron monitoring instrumentation. The system is designed to be free of electrical noise, and is reliable in that the loads that are the most needed have the highest probability of being served. A failure in any part of the system is isolated so that it does not disable the entire system. The 48/24-V dc system is not required to be Class 1E, but because of physical relationships with the 260/130-V Class 1E batteries, they are Seismic Category II/I.

Figure 8.3-10 shows a one-line diagram of the 48/24-V dc system required to operate the various monitoring instruments. One 48/24-V battery, center tapped with the tap grounded at the instrument ground system, is supplied for each of the two systems. The batteries, designated 2IA and 2IB, are redundant. The batteries are located in the same rooms with the 260/130-V Class 1E batteries as follows: battery 2IA with 2PA and 2IB with 2PB. Each 48-V dc source is provided from two 24-V batteries connected in series charged by two 24-V chargers.

There is a main distribution panel with three buses: positive, neutral, and negative. The neutral bus is grounded to the instrument ground bus. Two 24-V series connected batteries and chargers are connected in parallel to these buses.

Each system has a +24-V dc and a -24-V dc battery charger connected in series with a common ground. The primary source of power is from the battery chargers, with the batteries serving as a backup source of power. A fifth charger that can replace any of the four normal chargers is supplied.

The 24-V dc power system supplies power for all 24-V dc requirements through the use of two independent systems. The systems, identified as system A and system B, are described in Subsections 8.3.2.1.3.2 and 8.3.2.1.3.3.

8.3.2.1.3.2 System A

System A furnishes power to the following instruments:

a. Source range monitor units

b. Trip auxiliary unit--source range

c. Intermediate range monitor units

d. Trip auxiliary units--intermediate range

e. Process radiation monitor units--stack gas

f. Trip auxiliary unit--air ejector offgas

g. Linear amplifier unit--air ejector offgas

h. Miscellaneous instrument loops.

System A has as its primary sources of power a positive (+ to N) 24-V battery charger identified as battery charger 2IA-1, and a negative (N to -) 24-V battery charger identified as battery charger 2IA-2. The primary sources have as a backup a positive (+ to N) 24-V battery, and a negative (N to -) 24-V battery.

The system is protected from voltage variation by one under-voltage circuit and two overvoltage circuits at the charger. One overvoltage circuit opens the charger dc circuit breaker when the voltage exceeds 28.5 V, while the other alarms to the main control room any voltage surpassing 26.9 V. The undervoltage relay alarms to the main control room if the voltage drops below 25 V.

This circuit monitors both the plus and minus sides of the system. A loss of power from the battery chargers does not interrupt service. A loss of ac feed to the battery chargers will also alarm in the control room.

8.3.2.1.3.3 System B

System B furnishes power to the following instruments:

a. Source range monitor units

b. Trip auxiliary unit--source range monitor

c. Intermediate range monitor units

d. Trip auxiliary units--intermediate range monitor

e. Process radiation monitor unit--reactor building closed loop cooling water

f. Process radiation monitor unit--reactor building service water effluent

g. Process radiation monitor unit--radwaste effluent.

h. Miscellaneous instrument loops.

System B also has as its primary sources of power a positive (+ to N) 24-V battery charger identified as battery charger 2IB-1, and a negative (N to -) 24-V battery charger identified as battery charger 2IB-2. The primary sources have as a backup a positive (+ to N) 24-V battery and a negative (N to -) 24-V battery.

The protection and test facilities for system B are the same as those for system A.

The battery chargers are of the full-wave silicon-rectifier type. They are capable of working independently since loads are different on the positive and negative buses.

8.3.2.1.4 Maintenance and Testing

The plant batteries and other equipment associated with the dc system are easily accessible for inspection and testing. Service and testing are accomplished on a routine basis in accordance with recommendations of the manufacturer and requirements of IEEE 450-1972. Typical inspections include visual inspections for leaks and corrosion and the testing of all batteries for voltage, specific gravity, and level of electrolyte. Battery testing will be performed at least once per 24 months to ensure the capacity as described in Section 8.3.2.2.2 is satisfied.

8.3.2.1.5 Balance-of-Plant 260/l30-V DC System

One 260/130-V battery designated 2PC is provided for BOP systems and is located in the radwaste building. There are two dc MCCs fed in parallel from battery 2PC. The 2PC battery system is shown in Figure 8.3-11.

8.3.2.2 Analysis

8.3.2.2.1 Safety Design Basis

The plant safety battery system is a Class 1E system and consists of two 260/130-V dc control and power batteries. Each battery is of adequate size to safeguard the plant until ac power sources are restored. Each battery has its own charger, which is sized to recharge the battery after discharge while carrying its steadystate load within a time compatible with the recommendations of the battery manufacturer. One standby charger is provided for each of the two 260/130-V dc power batteries. The plant safety battery system is arranged so that no single circuit component failure prevents the system from providing power to vital loads. Feeds for the chargers are from critical buses and redundancy is maintained.

The existing 345-kV switchyard is provided with two separate control batteries that also have separate chargers. The 120-kV switchyard has its own battery, normal charger, and spare charger.

8.3.2.2.2 Capacity

Design calculations determined safety related battery capacity by developing load versus time plots of dc power demand for accident and safe- shutdown conditions. The safety related battery capacity was then chosen such that under the worst-case condition with no chargers available, the batteries are able to carry all required loads for 4 hours without battery voltage dropping below the minimum voltage necessary to operate the respective components as designated within the applicable design calculation requirements and component voltage acceptance criteria.

The required safety related 130 V batteries are demonstrated operable at least once per 24 months by verifying that either:

a. The battery capacity is adequate to supply and maintain in operable status all of the actual emergency loads for the design duty cycle (4 hr) when the battery is subject to a battery service test, or

b. The battery capacity is adequate to supply a dummy load for a profile as described within the applicable design calculation while maintaining the battery terminal voltage greater than or equal to the minimum voltage necessary to operate the bounding component as designated within the applicable design calculation requirements.

Design calculations determined BOP battery capacity by developing load versus time plots of dc power demand for station blackout (SBO) and Appendix R dedicated shutdown conditions. The BOP battery capacity was then chosen such that under the worst-case condition with no chargers available, the batteries are able to carry all required loads for 1.5 hours without battery voltage dropping below the minimum voltage necessary to operate the respective components as designated within the applicable design calculation requirements and component voltage acceptance criteria.

The required BOP 130 V batteries are demonstrated operable at least once per 72 months by verifying that the battery capacity is adequate to supply and maintain in operable status all of the actual emergency loads, or an equivalent dummy load, for the design duty cycle (1.5 hr) when the battery is subject to a battery service test.

The chargers were sized so that any charger is able to recharge a totally discharged battery in 24 hr while supplying maximum predicted load.

8.3.2.2.3 Compliance With Design Criteria

The description in the previous subsections and the dc system shown in Figures 8.3-9 and 8.3-10 demonstrate the compliance of this design with all Regulatory Guides and General Design Criteria, as well as with all other applicable design criteria and standards including IEEE 308-1971.

8.3.2.2.4 Safety Evaluation

Each safety related 130-V battery in a division has one designated charger fed on the ac side from an MCC of the same division. One 130-V spare charger is provided per division and is also fed on the ac side from another MCC of the same division.

There are two redundant power and control dc systems for ESF loads. The safety related divisional ESF batteries are of the same size, capable of carrying the load for 4 hr without chargers, although it is highly improbable not to have either offsite or onsite power available.

In case of a safety related charger failure, the spare charger is employed manually.

The safety related batteries are permanently in service and working while the power plant is operating; therefore, any failures are detected and resolved during normal operation.

The two divisions are totally independent as far as ac feeds for the battery chargers, the batteries, and their distribution systems.

The Float and Equalize voltages for the respective Division 1 and 2 batteries are as maintained within the applicable design calculation requirements. The Battery (Final) Discharge voltages are maintained at the minimum voltage necessary to operate the respective components as designated within the applicable design calculation requirements and component voltage acceptance criteria.

Each BOP 130-V battery has one designated charger fed on the ac side from a BOP MCC. One BOP 130-V spare charger is provided and is also fed on the ac side from another BOP MCC. The BOP batteries are of the same size, capable of carrying the load for 1.5 hr without chargers, although it is highly improbable not to have either offsite or onsite power available. In case of a BOP charger failure, the spare charger is employed manually. The BOP batteries are permanently in service and working while the power plant is operating; therefore, any failures are detected and resolved during normal operation.

There is no battery control from the main control room; however, the following abnormal conditions are alarmed or recorded in the main control room:

	<u>DC system alarms</u>
DIV. I	Battery 2A-1 charger (ac power failure)
	Battery 2A-2 charger (ac power failure)
	Battery 2A-1 high voltage
	Battery 2A-2 high voltage
	Battery 2A-1 low voltage
	Battery 2A-2 low voltage
DIV. II	Battery 2B-1 charger (ac power failure)
	Battery 2B-2 charger (ac power failure)
	Battery 2B-1 high voltage
	Battery 2B-2 high voltage
	Battery 2B-1 low voltage
	Battery 2B-2 low voltage
BOP	Battery 2C-1 charger (ac power failure)
	Battery 2C-2 charger (ac power failure)
	Battery 2C-1 high voltage
	Battery 2C-2 high voltage
	Battery 2C-1 low voltage
	Battery 2C-2 low voltage
48/24V	Battery 2IA
	24V battery A1 charger (ac power failure)
	24V battery A2 charger (ac power failure)
	Battery 2IA high voltage
	Battery 2IA low voltage
48/24V	Battery 2IB
	24V battery B1 charger (ac power failure)
	24V battery B2 charger (ac power failure)
	Battery 2IB high voltage
	Battery 2IB low voltage.

8.3 ONSITE POWER SYSTEMS

REFERENCES

1. Final Report, Starting and Load Acceptance Reliability Test, September 25 through October 3, 1968, Colt Industries, Fairbanks-Morse, Inc., Power System Division.
2. IEEE Conference Paper 69 CP 177-PWR, Fast Starting Diesel Generator for Nuclear Plant Protection, presented at the 1969 IEEE Winter Power Meeting, Power Generation Committee, New York City, New York, January 26-31, 1969.

TABLE 8.3-1 HAS BEEN INTENTIONALLY DELETED

TABLE 8.3-2 EMERGENCY DIESEL GENERATOR SYSTEM DIVISIONAL CONNECTED LOADS

RHR PUMPS DATA

CONDITION	FLOW (GPM)	BHP	MOTOR EFF.	HP INPUT	KW INPUT
A	15,200	2,100	93.0%	2,260	1,688
B	11,000	1,900	93.0%	2,045	1,527

CORE SPRAY PUMPS DATA

CONDITION	FLOW (GPM)	BHP	MOTOR EFF.	HP INPUT	KW INPUT
A	3,250	670	93.0%	720	536
B	4,000	750	93.5%	802	600

RHR Pump

Conditions

A Four pumps pumping into both loops with one loop broken (single failure)

B Shutdown cooling after blowdown to main condenser

Core Spray

Conditions

A Paired Pump rated

B Paired Pump runout

Typical loads energized on EDGs

Motor operated Valves
Instrumentation
Drywell Cooling Fans
Standby Gas Treatment System
EECW and EESW Systems
Control Center Ventilation Systems
ECCS Room Coolers
Auxiliary Building Cooling
Control Air Compressor/Dryer

Control Center Air Conditioning
EDG Auxiliaries and RHR EFS Loads
Auxiliary Building Ventilation
Emergency Lighting – Control Room
Security Lighting
RHR Service Water Pumps*
Cooling Tower Fans: High Speed/Low Speed*
Power Control Battery Charger*
Emergency Lighting – Remaining*

* Loads the operators would normally expect to add to the EDGs through manual operation for extended shutdown cooling.

Other manual loads can be added by the operator if capacity of respective EDG is available.

TABLE 8.3-3 EMERGENCY DIESEL GENERATOR SYSTEM: LOSS OF POWER, EMERGENCY SHUTDOWN AT ZERO TO TEN MINUTES

LOCA Load (0-10 Minutes)

EDG	Total Load (kW)	Total Rotating Load (kW)	Load Increase Due to Max Freq (kW)	Total EDG Loading (kW)	Rating (kW)	EDG Margin (kW)
11	2587	2444	82	2669	3135	466
12	2882	2666	89	2971	3135	164
13	2501	2441	82	2583	3135	552
14	2904	2671	89	2993	3135	142

TABLE 8.3-4 EMERGENCY DIESEL GENERATOR SYSTEM: LOSS OF OFFSITE POWER, EXTENDED SHUTDOWN AFTER TEN MINUTES

LOCA Load (10+ Minutes)

EDG	Total Load (kW)	Total Rotating Load (kW)	Load Increase Due to Max Freq (kW)	Total EDG Loading (kW)	Rating (kW)	EDG Margin (kW)
11	2742	2585	87	2829	2850	21
12	1810	1531	51	1861	2850	989
13	2632	2584	87	2719	2850	131
14	1650	1393	47	1697	2850	1153

LOOP Load (No LOCA)

EDG	Total Load (kW)	Total Rotating Load (kW)	Load Increase Due to Max Freq (kW)	Total EDG Loading (kW)	Rating (kW)	EDG Margin (kW)
11	2333	2176	73	2406	2850	444
12	1048	820	27	1075	2850	1775
13	2225	2176	73	2298	2850	552
14	1093	842	28	1121	2850	1729

TABLE 8.3-5 EMERGENCY DIESEL GENERATOR LOADING SEQUENCE: LOSS-OF-COOLANT ACCIDENT AND LOSS OF OFFSITE POWER (DIVISION I EDGS 11, 12) (DIVISION II EDGS 13, 14)

Time (sec)			
Overall	EDG	EDG 11 (13)	EDG 12 (14)
0	-	Accident occurs	Accident occurs
3	-	Diesel starts	Diesel starts
13	-	Rated speed and voltage	Rated speed and voltage
13	0	EDG breaker closes	EDG breaker closes
13	0	Auxiliary 480-V transformers energized, instrumentation	Auxiliary 480-V transformers energized
13	0	RHR pumps and MOVs	RHR pumps and MOVs
18	5	Core spray pumps and MOVs	Core spray pumps and MOVs
18	5	Emergency lighting Main Control Room & Communication System Feed DIV I.	Emergency lighting Main Control Room & Communication System Feed DIV II.
28	15	Reactor drywell cooling fans	Reactor drywell cooling fans and SGTS
33	20	Battery room vent fans	EECW and service water
38	25	ECCS and auxiliary room cooling	ECCS and auxiliary room cooling
48	35	Air compressor and dryer	
58	45	EDG service water and auxiliaries	EDG service water and auxiliaries
68	55		Control center air conditioning fans and chiller*, control room recirculation emergency makeup fan

* Chiller compressor is a manually restored load.

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TABLE 8.3-8 DIESEL RESPONSE TO LOADING[g]

	Minimum Voltage (percent)[a]			Minimum Frequency (percent)[c]		Recovery Time (sec)		
	Colt Program	Edison Program	Preop Test[b]	Colt Program	Preop Test[b]	Colt Program	Edison Program	Preop Test[b]
Starting of RHR pump (2000 hp)[h]	78 (69.4)[e]	72.5	69-73 (61)[f]	95	90-95[d]	3	2.75	4-5
Starting of CS pump (800 hp) with RHR pump operating	89 (87.2)[e]	87.9	89-91 (71)[f]	98	98-99 (96)[d]	7	6.97	5-7

[a] Minimum voltage specified in Regulatory Guide 1.9: 75 percent.

[b] Preoperational Test Results - Approximate range for the four EDGs. Minimum values are a deviation from the recommended values of Regulatory Guide 1.9, but are momentary. The preoperational test demonstrated the starting and load-accepting capabilities of the EDGs.

[c] Minimum frequency specified in Regulatory Guide 1.9: 95 percent.

[d] Value in parenthesis for CS reflects EDG testing performed with Woodward 2301A based governor control system. Values for RHR with Woodward 2301A based governor control system fell within existing ranges shown and do not indicate any new value.

[e] Value in parenthesis reflects Coltec Study for Basler series boost exciter, which is the current exciter in service. The value before the parenthesis is maintained for historical purposes and is associated with the Portec shunt type static exciter.

[f] Value in parenthesis reflects the minimum value among all EDGs from testing performed during refueling outages since replacement of Portec shunt type static exciter with Basler series boost exciter. The testing demonstrates the starting and load-accepting capabilities of the EDGs.

[g] Regulatory Guide 1.9, Rev. 2 Section C.4 allows testing to justify and validate voltage and frequency dip levels below the stated nominal values as acceptable based on satisfactory motor starting. Additional discussion of conformance with Regulatory Guide 1.9 is provided in Appendix A.1.9.

[h] The two motors considered were the RHR pump motors (2000-hp motors for pumps A, B, and C and 2250-hp for pump D).

TABLE 8.3-9 OTHER PLANTS USING COLT EMERGENCY DIESEL GENERATORS

A.	1 unit	-	2665 kW for Northeast Utilities, Millstone Point Nuclear Plant No. 1
B.	2 units	-	2500 kW for Carolina Power & Light, Robinson Nuclear Plant
C.	2 units	-	3000 kW for Northern States Power, Prairie Island Nuclear Plant
D.	2 units	-	3000 kW for Vermont Yankee Corporation, Vermont, Yankee Nuclear Plant
E.	2 units	-	3000 kW for Metropolitan Edison, Three Mile Island Nuclear Plant No. 1
F.	4 units	-	3250 kW for Philadelphia Electric Company, Peachbottom Nuclear Station No. 2 and No. 3
G.	3 units	-	3250 kW for Baltimore Gas & Electric Company, Calvert Cliffs Nuclear Station Units No. 1 and No. 2
H.	2 units	-	3000 kW for Florida Power Corporation, Crystal River Nuclear Station
I.	2 units	-	3000 kW for Jersey Central Power & Light Company, Three Mile Island Nuclear Station No. 2
J.	3 units	-	3250 kW for Georgia Power Company, Hatch Nuclear Plant
K.	2 units	-	3250 kW for Iowa Electric Light and Power Company, Duane Arnold Nuclear Plant
L.	3 units	-	3000 kW for Virginia Electric & Power Company, North Anna Nuclear Plants No. 1 and No. 2
M.	2 units	-	3250 kW for Northeast Utilities, Millstone Point Nuclear Plant No. 2

TABLE 8.3-10 CONTROL FUNCTIONS OF EMERGENCY DIESEL GENERATOR LOCAL PANELS AND MAIN CONTROL ROOM CONTROLS

	Local EDG Panel	Engine Gage Board	Main Control Room
Speed selector switch (Rated/Idle)	X[b]	-	-
Local-remote selector	X	-	
Start switch	X	-	X
Stop switch	X	-	X
Voltage (Raise-Lower) control	X	-	X
Governor (Raise-Lower) control	X	-	X
Voltage regulator (Auto, Manual)	X	-	X
Synchroscope switch (Off, On)	X	-	X
Prelube pump switch (Off, On)	X		
4160-V circuit breaker (Open, Close, Trip)	X		
Coolant heater (Off, Auto)	-	X	
Coolant pump (Hand, Off, Auto)	-	X	
Lube-oil heater (Off, Auto)	-	X	
Lube-oil pump (Hand, Off, Auto)	-	X	
Generator space heater (Off, Auto)	-	X	
Fuel-oil standby pump (Hand, Off, Auto)	-	X	-
Fuel-oil transfer pump A (Off, Run)	X	-	X
Fuel-oil transfer pump B (Off, Run)	X	-	X
Diesel generator SW pump (Off, Run)	X	-	X
EDG trip reset	X		X
Fuel tank dump valves			X
DGSW discharge crosstie valve			X
480-V breaker control switches			X
4160-V breaker control switches			X
LOCA bypass switch			X
Exciter reset	X	-	X
Exciter bypass switch (normal, bypass)	X[(a)]		
Exciter emergency shutdown pushbutton	X		

[a] An emergency start of the EDG engine will occur with the exciter bypass switch in bypass, however the bypass position will prevent an auto or manual reset of the exciter.

[b] The EDG will auto-start on an emergency start signal with the switch in the “Idle” position. However, the engine will not accelerate automatically to the rated speed of 900 RPM.

TABLE 8.3-11 EMERGENCY DIESEL GENERATOR METERING

	Local EDG Panel	Engine Gage Board	Main Control Room
Synchroscope	X		X
kW	X		X
kVAR	X		X
Bus voltage	X		X
Generator voltage	X		X
Frequency	X		X
Armature amps	X		X
Field voltage, dc	X		X
Field amps, dc	X		X
Watthour meter	X		
DGSW flow			X
X-Y-Z phase amps			X
DG essential bus transformer current			X
Essential bus power on			X
480-V diesel bus volts			X

TABLE 8.3-12 EMERGENCY DIESEL GENERATOR CONTROL PANEL ALARMS AND TRIPS

	Emergency Mode		Test Mode	
Local Control Panel	Trip	Alarm	Trip	Alarm
Lube-oil temperature high		X	X	X
Lube-oil temperature low		X		X
Lube-oil pressure low[a]	X	X	X	X
Lube-oil sump level low		X		X
Jacket coolant temperature high		X	X	X
Jacket coolant temperature low		X		X
Jacket coolant pressure low		X	X	X
Jacket coolant level low		X	X	X
Crankcase pressure high[a]	X	X	X	X
Overspeed	X	X	X	X
Inlet air filter p high		X		X
Start failure	X	X	X	X
Start air pressure low		X		X
Local control		X		X
Switch not in auto position		X		X
Generator bearing temperature high		X		X
Overvoltage or ground fault		X	X	X
Field failure		X	X	X
Lube-oil tank level high or low		X		X
Fuel-oil day tank level low		X		X
EDG auto start		X		X
EDG out of service		X		X
Fuel-oil standby pump running		X		X
Fuel-oil pressure low		X	X	X
DGSW pump running[b]		(b)		
DGSW pump off[b]		(b)		
DGSW pump trip		X[b]		X[b]
Fuel-oil transfer pump A, run[b]		(b)		
Fuel-oil transfer pump A, off[b]		(b)		

TABLE 8.3-12 EMERGENCY DIESEL GENERATOR CONTROL PANEL ALARMS AND TRIPS

Local Control Panel	Emergency Mode Trip	Emergency Mode Alarm	Test Mode Trip	Test Mode Alarm
Fuel-oil transfer pump A, trip		X[b]		X[b]
Fuel-oil transfer pump B, run[b]		(b)		
Fuel-oil transfer pump B, off[b]		(b)		
Fuel-oil transfer pump B, trip		X[b]		X[b]
EDG differential trip	X	X[c]	X	X[c]
Exciter trip	X[d]	X[b]	X[e]	X[b]

[a] The crankcase overpressure and low lube-oil pressure sensors are connected in two-out-of-three logic.

[b] Panel light indication.

[c] Relay target indication.

[d] Exciter trips on EDG differential trip or exciter emergency shutdown push button in emergency mode.

[e] Under normal slow start operation, the exciter is tripped with the exciter bypass switch in the bypass position.

TABLE 8.3-13 EMERGENCY DIESEL GENERATOR ALARMS IN THE MAIN CONTROL ROOM

	Annunciator Alarm	Sequence Recorder
Lube-oil tank level high/low	X	X
Lube-oil temperature high/low	X	X
Lube-oil pressure low	X	X
DGSW pump auto start		X
DGSW pump low flow	X	X
Crankcase pressure high	X	X
Overspeed	X	X
Start failure	X	X
Starting air pressure low	X	X
Auto start	X	X
Generator trouble	X	X
Overvoltage/ground	X	X
Fuel-oil storage tank level high/low	X	X
Fuel-oil day tank level low	X	X
Fuel-oil pressure low	X	X
Jacket coolant trouble	X	X
Not ready for auto start	X	X
Exciter trip	X	X
In local control	X	X
Fuel-oil standby pump running	X	X
Not in auto position	X	X
Lube-oil sump level low	X	X
Inlet air filter ΔP high	X	X
Motor tripped	X	X
LOCA start defeated	X	X

TABLE 8.3-14 120V AC DISTRIBUTION PANEL

Distribution Cabinet: H21-P561 (Regulated*)*
Description: 120 VAC Distribution Panel (Division I)
MPU: 1 **Cabinet:** 2 **Circuit:** 1

Panel/Device	BRANCH Circuit	DESCRIPTION
P50P402A	1	Control Air Relay Cabinet

Distribution Cabinet: H21-P557 (Regulated)
Description: 120 VAC Distribution Panel (Division I)
MPU: 1 **Cabinet:** 2 **Circuit:** 2

Panel/Device	BRANCH Circuit	DESCRIPTION
D11P285	1	PRMS Control Center Emergency Air South Inlet Monitor Rack
H21P296A	1, 2, 4	CCHVAC Instrument Rack
D11P297	2	PRMS Control Center Emergency Air North Inlet Monitor Rack
H21P285A	3	CCHVAC Chiller Panel
H21P296C	5, 11	CCHVAC Automatic Temperature Control Panel
H21P527	6	General Supply Air System Control Panel
H21P528	7	General Exhaust Air System Control Panel

TABLE 8.3-14 120V AC DISTRIBUTION PANEL

Distribution Cabinet: H21-P559 (Regulated)
Description: 120 VAC Distribution Panel (Division I)
MPU: 1 **Cabinet:** 2 **Circuit:** 3

Panel/Device	BRANCH Circuit	DESCRIPTION
P44N417A	6	Valve Position Transmitter EECW Pump P4400C001A Discharge
P44N422A	7	Valve Position Transmitter EECW Heat Exchanger P4400B001A/P4400B001C
H21P282	8	Primary Containment H_2/O_2 Monitor Analyzer Cabinet
H21P328A	12	Drywell Cooling Fan Control Panel

Distribution Cabinet: H11-P901 (Regulated*)*
Description: 120 VAC Distribution Panel (Division I)
MPU: 1 **Cabinet:** 2 **Circuit:** 6

Panel/Device	BRANCH Circuit	DESCRIPTION
H11P626	2	Core Spray Cabinet
H11P617	3	RHR Relay Cabinet
H11P868	5	Termination Panel
H11P857	7, 10	Relay Cabinet
H11P622	9	Inboard Valve Relay Cabinet
H11P891	11	Termination Cabinet
H11P914	12, 18	Primary Containment Monitoring Equip & Misc. Relay Panel
H11P888	14	Termination Cabinet

TABLE 8.3-14 120V AC DISTRIBUTION PANEL

Distribution Cabinet: H11-P900 (Regulated)
Description: 120 VAC Distribution Panel (Division I)
MPU: 1 **Cabinet:** 3 **Circuit:** 1

Panel/Device	BRANCH Circuit	DESCRIPTION
H11P614	1	NSSS Temperature Recorder & Leak Detection Cabinet
H11P613	3, 4, 6, 10	NSSS Process Instrument Cabinet
H11P604	5	PRMS Instrument Rack
H11P869	9	System Service Control Term. Cabinet
H11P601	11	ECCS Combination Operating Panel
H21P521	13	SGT Ventilation Control Panel
H21P532	15	RHR Emergency Cooling Ventilation Panel
H21P534	16	Thermal Recombiner Ventilation Control Panel
H21P536	17	CS & HPCI Room Ventilation Control Panel
H21P590	18	RB HVAC Control Panel
H11P914	20	Primary Containment Monitoring Equip & Misc. Relay Panel

TABLE 8.3-14 120V AC DISTRIBUTION PANEL

Distribution Cabinet: H11-P902 (Un-Regulated)
Description: 120 VAC Distribution Panel (Division II)
MPU: 2 **Cabinet:** 1 **Circuit:** 6

Panel/Device	BRANCH Circuit	DESCRIPTION
H11P627	2	Core Spray Cabinet
H11P618	4	RHR Relay Cabinet
H11P870	5, 7, 15	Relay Panel
H11P855	8, 16	Termination Cabinet
H11P915	9, 21	Primary Containment Monitoring Equip & Misc. Relay Panel
H11P820	11	Termination Cabinet
H11P623	12	Outboard Valve Relay Panel
H11P853	14	Termination Cabinet

Distribution Cabinet: H21-P562 (Regulated)
Description: 120 VAC Distribution Panel (Division II)
MPU: 2 **Cabinet:** 2 **Circuit:** 1

Panel/Device	BRANCH Circuit	DESCRIPTION
P50P402B	1	Control Air Relay Cabinet

TABLE 8.3-14 120V AC DISTRIBUTION PANEL

Distribution Cabinet: H21-P558 (Regulated)
Description: 120 VAC Distribution Panel (Division II)
MPU: 2 **Cabinet:** 2 **Circuit:** 2

Panel	BRANCH Circuit	DESCRIPTION
D11P290	1	PRMS Control Center Emergency Air South Inlet Monitor Rack
H21P296B	1, 2, 4	CCHVAC Instrument Rack
D11P298	2	PRMS Control Center Emergency Air North Inlet Monitor Rack
H21P285B	3	Control Center AC Chiller Panel
H21P296D	5, 11	CCHVAC Automatic Temperature Control Panel
H21P527A	6	RB Supply Air System Control Panel
H21P529	7	General Exhaust Air System Control Panel

Distribution Cabinet: H21-P560 (Regulated)
Description: 120 VAC Distribution Panel (Division II)
MPU: 2 **Cabinet:** 2 **Circuit:** 3

Panel/Device	BRANCH Circuit	DESCRIPTION
P44N422B	5	Valve Position Transmitter EECW Heat Exchanger P4400B001B/P4400B001D
P44N417B	6	Valve Position Transmitter EECW Pump P4400C001B Discharge
H21P283	8	Primary Containment H_2/O_2 Monitor Analyzer Cabinet
H21P328B	11	Drywell Cooling Fan Control Panel

TABLE 8.3-14 120V AC DISTRIBUTION PANEL

Distribution Cabinet: H11-P903 (Regulated*)*
Description: 120 VAC Distribution Panel (Division II)
MPU: 2 **Cabinet:** 3 **Circuit:** 1

Panel	BRANCH Circuit	DESCRIPTION
H11P612	3, 11	NSSS Process Instrument Cabinet
H11P614	4	NSSS Temperature Monitoring & Leak Detection Panel
H11P620	5	Isolated Transmitter E41K822 for AOV E41F011
H11P602	9	ECCS Combination Operating Panel
H11P862	10	System Service Control Term Cabinet
H11P817	12	Drywell Cooling, SGTS HVAC Cabinet
H21P520	15	SGT Ventilation Control Panel
H21P533	17	RHR Emergency Cooling Ventilation Panel
H21P535	18	Thermal Recombiner Ventilation Control Panel
H21P537	19	CS & HPCI Room Ventilation Control Panel
H21P538	20	CS & HPCI Room Ventilation Control Panel
H21P591	21	EECW HVAC Panel
H11P915	22	Primary Containment Monitoring Equip & Misc. Relay Panel

TABLE 8.3-15 VITAL 260/130-VDC POWER SYSTEM POWER AND INSTRUMENTATION AND CONTROL

DIVISION I

Power MCC 2PA-1, 260VDC
RCIC Turb gland seal vacuum pump
RCIC Turb gland seal condensate pump
RCIC Motor-operated valves
Motor-operated isolation valves

Control 2PA2, 130VDC (+, N)
Switchgear, 4160V (64B, 11EA)
Switchgear, 480V (72B, 72EA)
Diesel control (EDG 11)
EDG 11 & 12 Auto Load Sequencer
Core Spray System Control (DIV I)
HPCI System Control (Bus A)
Auto depressurization system (Bus B)
Misc loads (recorders/indicators/
solenoid operated valves/inverters/
power supplies/relays)

Control 2PA2, 130VDC (N, -)
Switchgear, 4160V (64C, 12EB)
Switchgear, 480V (72C, 72EB)
Diesel control (EDG 12)
RCIC System Control (Bus A)
RHR system control (DIV I)
Auto depressurization system (Bus A)
Misc loads (recorders/indicators/
solenoid operated valves/inverters/
power supplies/relays)

DIVISION II

Power MCC 2PB-1, 260VDC
HPCI Turb gland seal vacuum pump
HPCI Turb gland seal condensate pump
HPCI Turb auxiliary oil pump
HPCI Motor-operated valves
Motor-operated isolation valves

Control 2PB2, 130VDC (+, N)
Switchgear, 4160V (65E, 13EC)
Switchgear, 480V (72E, 72EC)
Diesel control (EDG 13)
EDG 13 & 14 auto load sequencer
HPCI system control (Bus B)
Auto depressurization system (Bus B)
Misc loads (recorders/indicators/
solenoid operated valves/inverters/
power supplies/relays)

TABLE 8.3-15 VITAL 260/130-VDC POWER SYSTEM POWER AND INSTRUMENTATION AND CONTROL

DIVISION II (continued)

Control 2PB2, 130VDC (N, -)	Horse Power
Switchgear 4160V (65F, 14ED)	-
Switchgear 480V (72F, 72ED)	-
Diesel control (EDG 14)	-
RCIC system control (Bus B)	-
RHR system control (DIV II)	-
Core spray system control (DIV II)	-
Auto depressurization system (Bus A)	-
Misc loads (recorders/indicators/ solenoid operated valves/inverters/ power supplies/relays)	

Figure Intentionally Removed
Refer to Plant Drawing SD-2500-01

Fermi 2

UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 8.3-1

ONE-LINE DIAGRAM - PLANT 4160 V AND 480V
SYSTEM SERVICE INCLUDING SWITCHYARD

Figure Intentionally Removed
Refer to Plant Drawing SD-2500-03

FIGURE 8.3-2

ONE-LINE DIAGRAM, 4160 V
BUSES 64B-C

Figure Intentionally Removed
Refer to Plant Drawing SD-2500-04

Fermi 2
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FIGURE 8.3-3

ONE-LINE DIAGRAM, 4160 V
BUSES 65E, 65F, 65G

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Refer to Plant Drawing SD-2500-08

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FIGURE 8.3-4

ONE-LINE DIAGRAM, 4160 V
BUSES 11EA, 12EB, 13EC, 14ED

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Refer to Plant Drawing SD-2510-01

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FIGURE 8.3-5

480 V BUSES 72B, 72C, 72E AND 72F

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Refer to Plant Drawing SD-2510-05

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FIGURE 8.3-6

480V BUSES 72EA,
72EB, 72EC, 72ED

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Refer to Plant Drawing SD-2530-01

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FIGURE 8.3-7

ONE-LINE DIAGRAM, 120 V INSTRUMENT AND CONTROL POWER FEEDER, DIVISIONS I & II

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Refer to Plant Drawing I-2570-01

FIGURE 8.3-8

OPERATION OF POWER LINE FEED AND TIE BREAKERS, 4160 V BUSES 64B AND 11 EA FUNCTIONAL LOGIC DIAGRAM

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Refer to Plant Drawing SD-2530-10

Fermi 2

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FIGURE 8.3-9, SHEET 1

ONE-LINE DIAGRAM – 260/130 48/24-V DC

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Refer to Plant Drawing SD-2530-11

Fermi 2

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FIGURE 8.3-9, SHEET 2

ONE-LINE DIAGRAM - 260/130 48/24 V DC

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Refer to Plant Drawing SD-2530-17

Fermi 2

UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 8.3-10

ONE-LINE DIAGRAM 48/24-V DC
INSTRUMENTATION BATTERIES DISTRIBUTION

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Refer to Plant Drawing SD-2530-12

Fermi 2

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FIGURE 8.3-11

ONE LINE DIAGRAM 260/130 V DC
BALANCE OF PLANT BATTERY
2 PC DISTRIBUTION

8.4 STATION BLACKOUT (SBO)

8.4.1 Introduction

10 CFR 50, Section 50.63 (Station Blackout Rule) (reference 1) requires that each light-water-cooled nuclear power plant be able to withstand and recover from a station blackout (SBO) of a specified duration. Licensees are expected to have the baseline assumptions, analyses, and related information used in their SBO evaluation documented and available for Nuclear Regulatory Commission (NRC) review. Section 50.63 also identifies the factors that must be considered in specifying the SBO duration and requires that, for the SBO duration, the plant be capable of maintaining core cooling and appropriate containment integrity.

The object of the SBO rule is to reduce the risk of severe accidents resulting from SBO by maintaining highly reliable ac electric power systems and, as additional defense-in-depth, assure that nuclear plants can cope with an SBO for a specific period of time.

The governing criteria for SBO are contained in 10 CFR 50.63. The term “Station Blackout” is defined as the loss of offsite ac power to the essential and nonessential electrical buses concurrent with turbine trip and the unavailability of the redundant onsite emergency ac power systems. However, ac power to buses fed by station service batteries through inverters is considered available along with the dc power to buses fed by the batteries.

8.4.2 SBO Coping Evaluation

Regulatory Guide (RG) 1.155, Station Blackout, (reference 2) describes a means acceptable to the NRC for meeting the requirements of 10 CFR 50.63. RG 1.155 states that the NRC has determined that the Nuclear Management and Resource Council (NUMARC) document NUMARC 87-00, Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors, (reference 3) also provides guidance that is in large part identical to the RG 1.155 guidance and is acceptable to the NRC for meeting these requirements. When reference to NUMARC 87-00 is made, it also includes reference to the supplemental NUMARC letter of January 4, 1990 (reference 4).

The reactor core and associated systems have been reviewed to determine that there are sufficient capacity and capability to ensure that the core is cooled, the reactor coolant system is isolated, and appropriate containment integrity is maintained in the event of an SBO for the required duration.

Systems required for decay heat removal have been reviewed to ensure that those portions of the systems which are required to cope with the consequences of an SBO are available. Effects of nonavailability of support systems such as instrument air, HVAC, and ac power are considered. Condensate storage tank and battery capacities have been reviewed for adequacy.

Combustion Turbine Generator (CTG) 11-1 is designated as an alternate ac (AAC) power source for the plant and is available within one (1) hour to the blacked out unit. In the event CTG 11-1 is inoperable, one of the remaining CTG’s can be started using a standby diesel generator. The alternative CTG has the same time availability criteria as CTG 11-1. Plant coping is controlled predominately by class IE dc power and steam driven sources until the

AAC power is available for loading within one hour. The AAC receives its fuel from a fuel tank located near the unit and independent of any fuel tanks for the EDGs.

The Fermi 2 plant has been evaluated against the requirements of the SBO rule using guidance from NUMARC 87-00 except where RG 1.155 takes precedence. The results of this evaluation are detailed as follows.

8.4.2.1 SBO Coping Duration

RG 1.155 and NUMARC 87-00 Section 3 were used to determine an SBO coping duration of four (4) hours for Fermi 2. The specific SBO duration is based on the redundancy of the onsite emergency ac power sources, the reliability of the onsite emergency ac power sources, the expected frequency of loss of offsite power (LOSP), and the probable time needed to restore offsite power. The coping duration is based on the following design characteristics using the NUMARC 87-00 methodology:

1. Offsite power design characteristic group is classified “P2”.
2. Emergency power configuration group is classified “B”.
3. EDG target reliability is “0.95”.

8.4.2.2 SBO Coping Analysis Assumptions

The assumptions used in the coping analysis are as follows:

1. RG 1.155 and NUMARC 87-00 provide general guidance for the SBO coping analysis.
2. The unit is operating at 100 per cent rated thermal power for at least 100 days prior to the event initiation.
3. Initiating conditions will be loss of offsite power and Station Blackout. No design basis accidents, other events, or additional single failures are assumed to occur prior to or during the SBO event.
4. A reactor SCRAM immediately follows an LOSP.
5. Reactor coolant system inventory losses are limited to normal system leakage, losses from blowdown and recirculation pump seal leakages (18 gal/min per pump maximum).
6. Credit is taken for operator actions where appropriate.
7. CTG 11-1 is available for loading within one (1) hour of the SBO event, or CTG 11-2,11-3, or 11-4 is available with blackstart capability using a standby diesel generator, and available for loading within one (1) hour of the SBO event.
8. Equipment needed for the SBO coping duration is available at the site.

8.4.2.3 SBO Coping Capabilities

Applicable plant systems/functions, as identified in RG 1.155 and NUMARC 87-00 guidelines, are available to successfully cope with the SBO event to the extent required by RG 1.155 for the required SBO duration.

The SBO coping evaluation concludes that the various systems and components required for reactor core cooling are available. The CTG 11-1 or alternate CTG with the standby diesel generator in conjunction with the battery capacity has been found to be adequate for the four hour coping duration. The ability to maintain the reactor cooling system (RCS) inventory and containment integrity has been evaluated and confirmed. The effects of the loss of ventilation on equipment needed for SBO has been evaluated. The plant can successfully cope with the SBO event for the required four hour duration with negligible impact on the equipment qualified life and with no impact on the operability of the equipment.

The plant has the capability to cope with an SBO for the coping duration of four hours as discussed below:

1. Capability to provide core cooling is demonstrated by the following:

   a. RCS isolation

      RCS isolation is provided to prevent loss of inventory through normally open lines.

   b. Main steam line isolation

      Main steam line isolation is achieved by automatic closure of the main steam isolation valves (MSIVs) upon loss of offsite power. Manual closure capability of the MSIVs is also available. Controlled steam release capability is available to remove decay heat via the safety relief valves (SRVs) to the suppression pool. The SRVs are self-actuating at the set relieving pressure, but may be operated manually at pressures below the valve setpoint.

   c. High pressure coolant injection (HPCI) system availability

      During SBO, the high injection volume of the HPCI system is not necessary, since loss of coolant accident conditions are not postulated.

   d. Reactor core isolation cooling (RCIC) system availability

      During SBO, a steam flowpath from the reactor and a water flowpath from either the condensate storage tank (CST) or the suppression pool are available to the turbine driven RCIC pump.

      The RCIC system starts and initially feeds to the reactor from the CST until the CST reaches its low level setpoint. Upon reaching this limit, the RCIC suction automatically shifts to the suppression pool. All necessary instrumentation and valves required to assure automatic transfer to the suppression pool are available during an SBO.

   e. CST capacity

Adequate condensate inventory is available for the required coping duration without additional water supply. The inventory in one CST is adequate for the required SBO coping duration of four hours.

f. Batteries and battery charger capacity

To maintain the electrical and instrumentation components needed for core cooling and decay heat removal following SBO, Fermi 2 requires class IE as well as non-IE batteries to support operation of the AAC. A battery capacity calculation has been performed pursuant to NUMARC 87-00, section 7.2.2 to verify that required class IE and non-IE batteries have sufficient capacity to meet Station Blackout loads for one hour. The class IE batteries were determined to be adequate to meet Station Blackout loads for one hour. The non-IE batteries that support the AAC, switchgear and associated functions were determined to be adequate to meet Station Blackout loads for one hour.

The associated battery chargers for the division 1 IE battery and the necessary non-IE station batteries are connected within one hour and power is available to support battery operation in excess of the one hour from the AAC. Therefore the batteries are capable of adequate support of the SBO loads for the four hour coping duration.

g. Compressed air system requirements

No air-operated valves are relied upon to cope with a station Blackout for one hour. The loss of the compressed air system during an SBO would have no impact on maintaining both decay heat removal capabilities and RCS inventory.

The only pneumatic operated valves relied upon to cope with a Station Blackout are the two (2) low-low set relief valves and five (5) ADS Safety Relief Valves (SRVs) that are operated by pressurized nitrogen. Each valve has an accumulator sized to provide five (5) actuations of the valve on loss of the nitrogen supply.

The division 1 Control Air Compressor can be powered by the AAC source and would be available after the AAC is started and connected to the loads within one hour.

h. Instrumentation requirements

Adequate instrumentation is provided to assess the core reactivity, RCS inventory, core cooling capability, decay heat removal capability, and availability of necessary ac and dc power systems.

2. Ability to maintain adequate RCS inventory

As allowed by NUMARC guidelines, recirculation pump seal leakage is assumed not to exceed 18 gpm per pump. A design calculation on CST inventory was performed using the 18 gpm per pump leakage plus the 25 gpm maximum allowable Technical Specification leakage for a total of 61 gpm leak rate. Additionally reactor depressurization was assumed to be required. The results indicate that less than 150,000 gallons are required which is less than the volume of water that must be maintained in the CST while in Modes 1, 2 and 3. The RCIC system is capable of providing sufficient makeup inventory to the reactor pressure vessel to maintain water level. Standby Feedwater system is also available to be powered from the AAC to maintain the reactor water level.

3. Ability to maintain appropriate containment integrity

Appropriate containment integrity is provided during the required duration of the SBO. Valves necessary for containment isolation or which must be operated during the four hour SBO event can be positioned independent of the preferred and blacked out unit class IE emergency power supply. Means of closure include manual operation, dc powered operation, AAC powered operation and air operated valves that fail closed on loss of air, as discussed as acceptable in NUMARC 87-00. Valve position can be determined by either control panel indicating lights or by mechanical valve position indicators at the valves. The system operating procedure on primary containment isolation system has been revised to include actions necessary to verify containment isolation valves are in their appropriate position during an SBO.

4. Effects of loss of ventilation

Those areas of the plant which contain equipment required to operate during an SBO to achieve and maintain safe shutdown have been evaluated to determine their average ambient steady state temperatures occurring during the SBO duration. This evaluation was performed in accordance with the guidelines established in NUMARC 87-00, Appendix F. This evaluation has established reasonable assurance of operability of equipment in these areas during as SBO event.

5. Equipment environmental evaluation

Areas of the plant housing equipment/components required for SBO coping have environmental conditions which are either below the component environmental qualification design limit or are only slightly above the design limit and are well below the minimum generic limit established in NUMARC 87-00.

A plant specific heat up analysis of the primary containment was performed. The analysis is documented in a design calculation and concludes that the containment design temperature of 340 degrees F is not exceeded within the first hour of the SBO event. The HVAC systems for the drywell are not available during the first hour, but will be reestablished when the AAC source is available. The drywell is a dominant area of concern not from an equipment operability concern but to ensure that drywell temperature would not exceed the design limit of 340 degrees F. Fermi 2 has a Mark 1 containment.

The HVAC system for the Control Center Complex which is not identified as a dominant area of concern is not available during the first hour of the SBO event. A design calculation has verified that the Control Room temperature will not exceed 120 degrees F during an SBO event. Since equipment inside instrument and control cabinets are exposed to their own electrical heat loads, doors of cabinets containing energized equipment within the Control and Relay Rooms relied upon to cope with an SBO should be opened within thirty (30) minutes of the SBO event onset, per NUMARC 87-00, Section F.5. An increase in air transfer is provided by opening cabinet doors, thus, keeping the instrumentation inside cooler. Procedures have been revised to include this requirement for an SBO event.

Equipment in the HPCI and RCIC rooms has been evaluated and determined to be operable at the calculated temperatures of 180 degrees F and 158 degrees F respectively. Both the HPCI and RCIC rooms have equipment area high temperature sensors which are capable of causing isolation of the HPCI or RCIC systems. Calculations show that temperatures will exceed the setpoints of 150 degree F. The systems will isolate unless operator action is taken. Procedures have been revised to ensure that the equipment area high temperature signals are disabled for an SBO event.

Weather hazards such as extreme temperatures, wind, and flooding will not impact components required for an SBO event.

6. Emergency lighting requirements

   Emergency lighting is provided in the Control Room to enable station operators to perform the necessary manual actions to cope with the SBO. Adequate emergency lighting is available for those areas of the plant where operator actions and/or ingress or egress is required. Emergency lighting is provided by self-contained battery powered Appendix R lighting and other battery powered lighting provided for the SBO event.

7. Identification of required operator actions and training

   Operator actions and training that are required, inside and outside the Control Room, to cope with the SBO event are identified in plant procedures and the operators are trained as applicable on the procedures.

8. Procedure interface considerations

   RG 1.155 provides the guidance that procedures and training should include all operator actions necessary to cope with an SBO for at least the duration determined according to RG position 3.1 and to restore normal long term cooling/decay heat removal once ac power is restored. Procedures have been integrated with plant-specific technical guidelines and the emergency operating procedure upgrade program.

9. Diesel generator reliability program requirements

   Elements of the EDG program are contained in RG 1.155. An EDG reliability program has been integrated within other existing programs and plant procedures and is consistent with the guidance of RG 1.155, Section 1.2. The target reliability of the EDGs is 95% which is consistent with the plant category and coping duration in the regulatory guide.

10. Quality Assurance

   A quality assurance program consistent with the guidance of RG 1.155 is in place for SBO equipment. Quality Assurance activities have been implemented as were determined appropriate for the existing equipment consistent with the guidance in Appendix A of RG 1.155.

8.4 STATION BLACKOUT (SBO)

REFERENCES

1. 10CFR 50.63, Loss of All Alternating Current Power.
2. Regulatory Guide 1.155, Station Blackout, dated August, 1988.
3. NUMARC 87-00, Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors, Revision 1, dated August, 1991.
4. NUMARC Letter, "Station Blackout (SBO) Implementation: Request for Supplemental SBO Submittal to NRC", dated January 4, 1990.
5. Topical Report, Appendix F Topical Report for NUMARC 87-00 (discusses temperature effects of equipment operability) dated October, 1988.
6. NRC-89-0061, "Station Blackout", dated April 17, 1989.
7. NRC-90-0060, "Detroit Edison Response to Request for Supplemental SBO Submittal to NRC", dated March 29, 1990.
8. NRC-91-0086, "Station Blackout Rule Implementation", dated July 17, 1991.
9. NRC-92-0017, "Completion of Station Blackout Rule Implementation", dated February 21, 1992.
10. NRC-92-0068, "Confirmation Response to NRC Supplemental Safety Evaluation on Fermi 2 Implementation of Station Blackout Rule (10 CFR 50.63)," dated May 20, 1992.
11. NRC Letter, "Fermi-2 Conformance to Station Blackout Rule 10 CFR 50.63 (TAC No. 68545) includes SBO Safety Evaluation." dated June 12, 1991
12. NRC Letter, "Fermi-2 - Supplemental Safety Evaluation - Response to Station Blackout Rule (TAC No. M81254)" dated April 9, 1992.
13. NRC Letter, "Fermi-2 - NRC Supplemental Safety Evaluation - Implementation of the Station Blackout Rule (SBO), 10 CFR 50.63 (TAC No. 81254)", dated June 16, 1992.
14. TRVEND 0000 0115 6839 R0. Fermi-2 Thermal Power Optimization Task Report T0903A: Station Blackout Response Analysis.
15. TRVEND 24MCGNF3FTRT0903, Rev 2, "Fermi Unit 2 GNF3 NFI and 24-Month Cycle Extension Task T0903: Station Blackout," GEH Document Number 004N8141 (Rev 1), Edison File#: T19-076.

CHAPTER 9: AUXILIARY SYSTEMS

9.1 FUEL STORAGE AND HANDLING

9.1.1 New-Fuel Storage

9.1.1.1 Design Bases

The new-fuel storage racks, as shown in Figure 9.1-1, are designed to maintain sufficient spacing between the new-fuel assemblies under fully loaded conditions to ensure that the array will limit the effective multiplication factor (k_{eff}) to ≤0.90 for the dry condition and to ≤ 0.95 in the event of complete flooding of the storage vault. New-fuel storage racks are supplied for 30 percent of the full core fuel load.

These racks are designed to withstand combined loadings, including impact and seismic disturbance, to ensure against damage to the racks or distortion of the fuel storage arrangement.

The new-fuel storage vault is designed to preclude flooding of the new-fuel assemblies.

9.1.1.2 Facilities Description

9.1.1.2.1 New-Fuel Storage Vault

After receipt, uncrating, and transfer to the operating floor, the new fuel may be placed in dry storage in racks. These racks are contained in a Category I new-fuel storage vault. The new fuel may be placed in the new fuel storage vault, provided criticality concerns are addressed as outlined in letter EF2-61,906. The vault, shown in Figure 9.1-2, accepts 23 new-fuel storage racks, each of which accommodates 10 new-fuel assemblies. The 230-assembly capacity of the vault amounts to 30 percent of the 764 assemblies in the reactor. The vault dimensions are shown in Figure 9.1-2.

The vault is closed at the top by a shield plug 12 in. thick. The shield plug is divided into five sections, each with redundant lifting rings. The openings and shield plugs are steel lined. The plugs extend 4 in. above the refueling floor. The vault floor slopes to an open drain located in the center of the vault floor.

The new-fuel vault is served by the reactor building crane.

9.1.1.2.2 New-Fuel Storage Racks

The new-fuel storage racks provide a place for storing new fuel in the new-fuel storage vault, as shown in Figure 9.1-1. The location of the new-fuel storage vault within the station complex is shown in Figure 9.1-3. Each new-fuel storage rack holds up to 10 channeled or unchanneled fuel assemblies in a row, spaced nominally 6.625 in. apart, center-to-center.

The new-fuel storage racks are designed so that arrangement in rows on a nominal 11.5-in. center-to-center spacing between rows limits the k_{eff} of the array to ≤ 0.90 for the dry condition. The k_{eff} is ≤ 0.95 in the event of complete flooding of the storage vault. The fuel assemblies are loaded into a rack through a hole in the top of each rack. Each hole for a fuel assembly has adequate clearance for the insertion or withdrawal of the assembly while enclosed in a protective plastic wrapping. Guides are provided to guide the fuel element spacers the full length of their insertion into the rack so that damage to the fuel assemblies is precluded. The spacers and the upper tie plate of the fuel element rest against the rack to provide lateral support. The design of the racks prevents accidental insertion of the fuel assembly in a position not intended for the fuel. The weight of the fuel assembly is supported by the lower tie plate which is seated in a chamfered hole in the rack base. The new-fuel racks can withstand an upward force of 6000 lb.

9.1.1.3 Safety Evaluation

Calculations of k_{eff} are based upon the geometrical arrangements of the fuel array, and subcriticality does not depend upon the presence of neutron-absorbing materials. The arrangement of the fuel assemblies in the fuel storage racks results in a k_{eff} below 0.90 in a dry condition or in the absence of moderator. In an abnormal condition, if the fuel array were to be flooded with water, k_{eff} would not exceed 0.95. The criticality analysis for initial licensing of the new-fuel storage vault is provided in Reference 1. Use of the new fuel storage vault is currently restricted as discussed in Section 9.1.1.2.1.

The new-fuel storage racks are designed to meet Category I requirements as described in Section 3.2. Stresses in a fully loaded rack will not exceed stresses specified by ASTM Specifications (B108, B179, B209, and B221) on light-weight metal alloys when subjected to a 1.5g horizontal acceleration.

The storage rack structure is designed to withstand the impact resulting from a falling object possessing 2000 ft-lb of kinetic energy. The structural arrangement is such that no lateral displacement of the fuel occurs; therefore, subcritical spacing is maintained.

The new-fuel racks are designed to be restrained by hold-down bolts in case a stuck fuel assembly is inadvertently hoisted and to ensure that rack spacing does not vary under specified loads. The rack structure and hold-down bolts are designed to maintain the minimum required cell spacing due to forces that might occur if a fuel bundle were to jam in the rack during removal.

The new-fuel storage racks are made from aluminum. All welds are in accordance with GE standards which are based on ASME Section IX and ASTM Standards Part 6. The material choice is based on a consideration of the susceptibility of various metal combinations to electrochemical reaction. When considering the susceptibility of metals to galvanic corrosion, aluminum and 300-series stainless steel are relatively close together, insofar as their coupled potential is concerned. The use of stainless steel fasteners in aluminum to avoid detrimental galvanic corrosion is a recommended practice and has been used successfully for many years by the aluminum industry.

9.1.1.4 Testing and Inspection

The new-fuel storage racks do not require any special periodic testing or inspection for nuclear safety purposes.

9.1.2 Spent Fuel Storage

9.1.2.1 Design Bases

Spent fuel storage space is provided to accommodate 3590 fuel assemblies. Stainless steel high-density fuel storage racks are provided for all fuel assemblies. The spent fuel assemblies are placed in racks designed to ensure a k_{eff} equivalent of $\leq$0.95 with the spent fuel pool filled with unborated water at 68°F for both normal and abnormal storage conditions.

The calculated k_{eff} includes margins for uncertainty in the calculations, including mechanical tolerances, which are statistically combined such that the true k_{eff} will be less than 0.95 with a 95 percent probability at a 95 percent confidence level.

To ensure that the analysis followed a conservative approach, the criticality calculations for the high-density racks were performed with the following criteria:

a. Initial uniform enrichment of 4.9 weight percent ^{235}U with credit for gadolinia burnable poison normally present

b. Maximum reactivity evaluated at the point of peak reactivity over burnup

c. Both unchanneled and channeled fuel with maximum expected distortion

d. Abnormal and accident conditions considered

e. Lattice of storage racks is infinite in all directions; that is, no credit for axial or radial neutron leakage

f. Unborated water at 20°C.

To simplify the analysis, no credit is taken for:

a. Neutron absorption in minor structural members; that is, spacers and Inconel springs are replaced by water in the calculation

As indicated in Section 4.0 of Reference 1 and Section 4.0 of Reference 3, the results of the criticality analysis for the spent fuel racks show that for all normal and abnormal storage conditions, the calculated k_{∞} is below the criterion of $k_{eff} \leq 0.95$.

The spent fuel storage racks (SFSR) are designed such that no fuel assembly can be placed within the rack array in other than a design storage location.

The spent fuel pool and storage racks, containing their full complement of fuel, are designed to meet Category I requirements.

Reference 1 documents the Abnormal and Accident Conditions analyzed for the Holtec High Density Racks. Reference 3 documents similar analyses performed for the Joseph Oat High Density Racks.

Spent fuel storage racks are designed and arranged so that the fuel assemblies can be handled efficiently during refueling operations.

Shielding for the spent fuel storage arrangement is sufficient to protect plant personnel so that exposure to radiation is well within the Occupational Limits of 10 CFR 20.101.

The spent fuel storage facilities provide the capability to limit the potential offsite exposures in the unlikely event of significant release of radioactivity from the stored fuel to a fraction of 10CFR50.67 limits.

9.1.2.2 Facilities Description

9.1.2.2.1 Spent Fuel Pool

The two main functions of the Category I spent fuel pool are to provide a storage place for irradiated fuel and other radioactive equipment requiring shielding and to provide a convenient area for performing work on selected radioactive equipment. The spent fuel pool is shown in Figure 9.1-3. The spent fuel pool has an inside length of 40 ft, an inside width of 34 ft, and a height of 38 ft 9 in. The surface of the water is maintained at Elevation 683.5 ft (New York Mean Tide, 1935) by scuppers that act as skimmers and wave suppressors. This results in a minimum water depth for shielding of 7 ft above the top of the fuel while it is being moved over storage racks. The Technical Specifications require that a minimum of 22 ft of water be maintained over the top of irradiated fuel assemblies in the spent fuel storage pool racks during movement of irradiated fuel assemblies in the spent fuel storage pool. Pool water-level indication is painted on the north and east walls of the spent fuel pool starting at 18 ft above the stored fuel assemblies. Spent fuel pool levels are monitored by primary and backup instrumentation channels and level indication is provided in the main control room and reactor building 2nd floor grid B-11 which are capable of supporting pool actual water levels to comply with NRC Order EA 12-051. Refer to Figure 9.1-23 for details.

The spent fuel pool is of poured reinforced-concrete construction with an all-welded stainless steel plate liner. The water in the spent fuel pool is filtered, demineralized, and cooled as described in Subsection 9.1.3.2.

The stainless steel spent fuel pool liner is designed in accordance with the following codes and standards: ASME Boiler and Pressure Vessel (B&PV) Code Section VIII, Division 1, Subsection B (for welds); and ACI 347, recommended practice for concrete formwork (for tolerances). The liner can withstand thermal loads due to operating temperatures of 125° to 150°F (assume installation temperature of 70°F) and thermal loads due to abnormal temperatures inside the pool of 212° and external temperatures of 150°F. The liner plate is designed based on an acceptance criterion that neither the construction allowable tensile stress (f_t), nor the allowable compressive stress (f_c), exceeds 0.67 yield stress (f_y). The normal allowable compressive membrane strain is 0.003 in./in. and the abnormal allowable compressive membrane strain is 0.005 in./in. All welded seams in the pool liner are backed by channels to collect any possible leakage. All the channels are interconnected to the bottom peripheral drain with four separate outlet drains that are used to monitor leakage. The leaktight integrity of the spent fuel pool liner is verified to be upheld in a postulated fuel assembly drop accident. (Analysis shows that the fuel assembly can be dropped 17 ft 7 in. without penetrating the liner or causing overall slab instability.)

Two self-sealing gates with a monitored drain between them separate the spent fuel pool from the reactor well pool.

Should there be leakage, this arrangement would permit the repair of a gate without disturbing the integrity of the spent fuel pool. Each gate has two solid-rubber seals that seal to the spent fuel pool liner.

Spent fuel assemblies will be stored in thirteen (13) Joseph A. Oat supplied high-density stainless steel racks (designated F1600E002A through H and F1600E002J through N) (See Figures 9.1-4 for the design details of these racks.) These racks have a nominal 6.22-in. center-to-center distance between assemblies (pitch). Each of these racks each contain 169 storage cells. There are nine (9) additional Holtec supplied racks (designated F1600E011A through I) with a nominal 6.23-in. pitch, (See Figure 9.1-15 for the design details of these racks). The spent fuel storage rack description, individual rack size and the number of storage cells are summarized below:

Spent Fuel Pool

Rack and Storage Capacity Summary

Rack Description	Size	Total Number of Cells		
F1600E002A through H	13 X 13	169 X 8	=	1352
F1600E002J through N	13 X 13	169 X 5	=	845
F1600E011A and B	9 X 11	99 X 2	=	198
F1600E011C	19 X 19	361 X 1	=	361
F1600E011D	12 X 17	204 X 1	=	204
F1600E011E	9 X 17	153 X 1	=	153
F1600E011F	9 X 12 minus 28 Cell cutout	80 X 1	=	80
F1600E011G	9 X 13 minus 28 Cell cutout	89 X 1	=	89
F1600E011H	9 X 14	126 X 1	=	126
F1600E011I	13 X 14	182 X 1	=	182
Storage Cell Total				3590

Two of the above cells may be used for Boraflex in-service surveillance program.

The arrangement of the fuel storage modules is shown in Figure 9.1-3 (Sheet 3). Four dual purpose cells in F1600E011F and six dual purpose cells in Rack F1600E011G are provided to store defective fuel assembles, control rods, control guide tubes and other equipment and components.

The spent fuel pool is also used to store 104 control rods that are suspended in a vertical position from 52 hooks. These hooks are mounted on frames located adjacent to the spent fuel shipping cask restraining framework on the west wall and on the south wall of the pool. A total of 114 control rods (104 suspended from hooks plus 10 in the dual-purpose cell racks) can be accommodated in the spent fuel pool. If storage for more than 114 rods should ever be required, the rods can be supported by mounting additional hooks on the equipment lugs on the east wall of the pool or control rod curb hanger(s) may be utilized. Temporary storage racks may also be used, as needed, to store control rod blades.

The area in the vicinity of the north wall of the spent fuel pool is laid out as a working area. In Figure 9.1-3, Sheet 3, two fuel-preparation machines are shown, an outline of which is shown in Figure 9.1-8. The function of the fuel-preparation machines is to remove and replace fuel bundle channels. The fuel preparation machines are used for fuel inspections and new fuel receipt/transfer activities. Strict administrative control on the fuel preparation machine's full-up end stop is required for personnel protection. Holtec high density Racks F1600E011C and F1600E011H are designed to support a specially engineered overhead platforms referred to as "Holtec Overhead Platforms (HOPs)" on top of the rack which permits storage of miscellaneous objects up to five tons total dry weight without interfering with the normal functions of the module. The structural and thermal-hydraulic qualification of these racks includes the appropriate consideration of the overhead platform.

A special storage area is provided on the west wall of the spent fuel pool to accommodate the spent fuel shipping cask. Details of the storage area are given in Subsection 9.1.4.2.1.

The spent fuel pool is supplied with several types of underwater lights; some provide general illumination and others provide specific local illumination.

The spent fuel pool shielding design objectives and design criteria are presented in detail in Subsections 12.1.1 and 12.1.2. Special provisions for ventilation of the fuel pool area are discussed in Subsection 12.1.1.1. Estimates of exposure to plant personnel in the fuel pool area are presented in Subsection 12.1.5.2.2.

9.1.2.2.2 Spent Fuel Storage Racks

Spent fuel storage racks provide a place in the spent fuel pool for storing spent fuel assemblies received from the reactor pressure vessel (RPV). There are two types of high density spent fuel storage racks (Holtec and Oat) being used. Both are full-length top entry racks, designed to preclude the possibility of criticality under normal and abnormal conditions.

The original Oat high-density spent fuel storage racks are of welded stainless steel construction with a neutron absorber sandwiched between the stainless steel sheets. The neutron absorber is marketed under the trade name of Boraflex, supplied by BISCO of Park Ridge, Illinois. The original high-density spent fuel racks are designed and fabricated by the Joseph Oat Corporation of Camden, New Jersey.

The basic philosophy of the high-density spent fuel storage rack design is consistent with the NRC Position Paper (Reference 2), General Design Criteria (GDC) 61 and 62, and Standard Review Plan (SRP) Sections 9.1.1 and 9.1.2. Seismic classification and analysis are in accordance with Regulatory Guides 1.29, 1.61, and 1.92.

The modules of the Holtec high density spent fuel racks are square cross-section boxes. Each box is equipped with Boral neutron absorber panels on its sides to form a composite box.

Reference 3 contains a detailed discussion of various aspects of the Oat high-density fuel rack design, analysis, and fabrication.

The high-density spent fuel storage racks provide for a total of 3590 storage locations arranged in 22 racks. All the racks are freestanding; that is, they are not anchored to the pool floor or connected to the pool wall through snubbers or lateral restraints. For the new racks, the minimum gap between adjacent racks is 1.0 in. at all locations, and the nominal gap between the fuel pool wall and storage rack is 2.39 in. The respective gaps for the Oat racks are 3.625 and 24 to 28 inches.

Of the 3590 storage locations, 3588 locations are intended for the storage of spent fuel assemblies. Two locations are designated for the Boraflex neutron absorber material surveillance program. This program is described in plant procedures. An additional 53 locations are inaccessible due to interferences. This will reduce the available storage locations to 3535. If the two Holtec Overhead Platforms (HOPs) are installed, an additional four cells per HOP will be unavailable.

The Oat high-density fuel storage racks are constructed from SA-240, type 304, austenitic stainless steel sheet material; SA-240, type 304, austenitic stainless steel plate material; and SA-182, type F304, austenitic stainless steel forging material. Boraflex, a patented brand name product of BISCO, serves as the neutron absorber material in the Oat high-density racks. Boraflex material has been tested in a fuel-pool-like environment to a minimum of 1.03×10^{11} rad and found to perform satisfactorily. Boraflex has been observed, however, to shrink and develop gaps. These effects have been evaluated in Reference 7. Alterations in physical properties and offgassing due to irradiation and material chemical or galvanic interactions with the rack structure have been considered in the design of the rack.

The Holtec high density racks are constructed from SA-240, type 304L, austenitic stainless steel sheet and plate material; and male spindles (lower part of support feet) of SA-564-630; age hardened at 1100°F. The storage cells are 6.035 ± 0.04 in. square cross-section. Modules F1600E011E-I are 3 inches shorter than the other Holtec racks with the result that the bale handle is exposed. This is for ease of fuel handling operations. They employ Boral as the neutron absorber material. Boral is a thermal neutron poison material composed of boron carbide and 1100 alloy aluminum. The composite boxes containing the Boral panels and enveloping sheathing are arrayed in a vertical fixture over a solid monolithic baseplate. Boron-10 is the neutron-absorptive agent in both Boraflex and Boral. The boron carbide and aluminum materials in Boral do not degrade as a result of long-term exposure to radiation.

The Oat high-density fuel storage rack contains storage cells that have a 6-in. minimum (+0.125 in., -0 in.) internal cross-sectional opening. These cells are straight to within ± 1/8 in. These dimensions ensure that fuel assemblies with maximum permissible out-of-straightness can be inserted into the storage cells without interference.

To illustrate the elements that make up a typical Oat rack, Figure 9.1-10 shows a horizontal cross section of an array of 3 x 3 cells. (A typical Oat high-density fuel storage rack has an array of 13 x 13 cells.)

The construction of the Oat racks may be best described by the basic building blocks of the design, namely the "cruciform," "ell," and "tee" elements, shown in Figure 9.1-11. The cruciform element is made of four angular subelements, "A" (Figure 9.1-12), with the neutron absorber material tightly sandwiched between the stainless steel sheets. The long edges of the cruciform are welded using a 0.070-in.-thick stainless steel backing strip as shown in Figure 9.1-13. The bottom of the cruciform assembly has a 4-1/4-in.-high stainless steel strip that prevents slippage of the poison material downward due to gravitation loads or operating conditions. The top of the cruciform is also end welded, using a spacer strip as shown in Figure 9.1-13. Skip welding at the top ensures proper venting for off-gassing.

The "ell" and "tee" elements are constructed similarly using angular subelements “A” and “B” and flat subelements "C" (Figures 9.1-12 and 9.1-14). Having fabricated the required quantities of the "cruciform," "tees," and "ells," the assembly is welded in a specially designed fixture that serves the vital function of maintaining dimensional accuracy while fillet welding the adjacent spokes of all elements. In this manner, the cells are produced that are bonded to each other along their long edges, thus, in effect, forming an "egg crate." The following manufacturing deviations were detected subsequent to installation in the spent fuel pool: a cruciform was installed upside down in F1600E002J (Module A9), and a tee was installed upside down in F1600E002L (Modules A11). The effects of these manufacturing deviations have been analyzed in Reference 7 and determined to be acceptable for use.

The bottoms of the cell walls are welded to the base plate, which has 4.75-in.-diameter holes concentric with cell center lines. Carefully machined sleeve elements are positioned in the base plate and are fillet welded to the base plate (Figure 9.1-15). The conical machined surface of the sleeve provides a contoured seating surface for the "nose" of the fuel assembly. Thus, the contact stresses at the fuel assembly nose bearing surface are minimized.

The central hole in the sleeve provides the coolant flow path for heat transport from the fuel assembly cladding. Lateral holes in the cell walls (Figure 9.1-15, Sheet 1) provide the redundant flow path in the unlikely event that the main coolant flow path is clogged.

The composite box assemblies of the Holtec high density racks are arrayed in a vertical fixture over a solid monolithic baseplate which is machined with an array of equispaced cylindrical holes containing tapered crowns (Figure 9.1-15, Sheets 2 and 3). These tapered holes serve as the seating surface for the nose of the fuel assembly.

The high-density fuel storage rack assembly is supported at four corners. The supports elevate the rack base plate 7.5 in. above the pool floor level, thus creating the water plenum for coolant inventory (Figures 9.1-4 and 9.1-5).

The high-density fuel storage racks are designed to meet Category I requirements, in accordance with Regulatory Guide 1.29. They are required to remain functional during and after a safe-shutdown earthquake (SSE). As noted previously, these high-density fuel storage racks are neither anchored to the pool floor nor attached to the side walls. The individual rack modules are not interconnected. Furthermore, a high-density fuel storage rack may be completely loaded with fuel assemblies (which corresponds to greatest rack inertia), or it may be partially loaded so as to produce maximum geometric eccentricity in the structure.

Dynamic simulation analyses involving nine Holtec high density and thirteen Oat high density spent fuel storage racks have been performed to establish the structural margins of safety. Six simulations modeled 22 high density fuel racks (13 Oat and 9 Holtec) in the pool for campaign II with a comprehensive Whole Pool Multi Rack (WPMR) model. References 1 and 3b presents the incorporation of all relevant physical data into the computer code

DYNARACK which then handles simultaneous simulation of all racks in the pool as a WPMR 3-D analysis. Some classical single rack runs were also performed. Parameters varied were interface coefficients of friction and extent of storage locations occupied by spent nuclear fuel, ranging from nearly empty to full. A WPMR run was also performed with four Holtec racks installed in the SFP for the same scenario that resulted in the greatest displacement from among the parametric runs. The results show that all stresses are well below their corresponding ASME Section III, Subsection NF limits and there is no rack-to-rack or rack-to-wall impact. Results also show that rack overturning is not a concern.

Nonlinearities of fuel-to-rack impact and, if appropriate, rack-to-rack impact are included. The racks are designed as freestanding and the effects of rack slide are addressed. Hydrodynamic effects are also included. No additional credit for structural damping is taken unless substantiated by testing or detailed analysis.

Synthetic time-histories in three orthogonal directions (N-S, E-W, and vertical) are generated in accordance with the provisions of SRP 3.7.1. The SRP calls for both the response spectrum and the power spectral density corresponding to a generated acceleration time-history to envelop their target (design basis) counterparts with only finite enveloping infractions. The time-histories for the pool have been generated to satisfy this preferred (and more rigorous) criterion. The seismic files also satisfy the requirements of statistical independence mandated by SRP 3.7.1. Time-history accelerograms were generated for a 20-sec duration of OBE and SSE events, respectively. These artificial time-histories are used in all the non-linear dynamic simulations of the racks.

The time-history data were generated from the floor response spectra given in Section 3.7. These spectra are enveloped with a smooth design spectra. For a complete time-history analysis of the equipment situated on the pool floor, artificial time-history accelerations in three orthogonal directions were generated so that their corresponding response spectra will envelop the smoothed design spectra mentioned above. These artificial time-history series were also verified to be statistically independent.

Figure 9.1-16 displays the dynamic model for the high-density fuel storage racks. Features of the dynamic model are as follows.

a. The fuel rack structure motion is captured by modeling the rack as a 12 degree-of-freedom structure. Movement of the rack cross-section at any height is described by six degrees-of-freedom of the rack base and six degrees-of-freedom at the rack top. In this manner, the response of the module, relative to the baseplate, is captured in the dynamic analyses once suitable springs are introduced to couple the rack degrees-of-freedom and simulate rack stiffness

b. Rattling fuel assemblies within the rack are modeled by five lumped masses located at H, .75H, .5H, .25H, and at the rack base (H is the rack height measured above the baseplate). Each lumped fuel mass has two horizontal displacement degrees-of-freedom. Vertical motion of the fuel assembly mass is assumed equal to rack vertical motion at the baseplate level. The centroid of each fuel assembly mass can be located off-center, relative to the rack structure centroid at that level, to simulate a partially loaded rack

c. Seismic motion of a fuel rack is characterized by random rattling of fuel assemblies in their individual storage locations. All fuel assemblies are assumed to move in-phase within a rack. This exaggerates computed dynamic loading on the rack structure and, therefore, yields conservative results

d. Fluid coupling between rack and fuel assemblies, and between rack and wall, is simulated by appropriate inertial coupling in the system kinetic energy. Inclusion of these effects uses the methods of References 3c and 3d for rack/assembly coupling and for rack-to-rack coupling

e. Fluid damping and form drag are conservatively neglected

f. Sloshing is found to be negligible at the top of the rack and is, therefore, neglected in the analysis of the rack

g. Potential impacts between the cell walls of the new racks and the contained fuel assemblies are accounted for by appropriate compression-only gap elements between masses involved. The possible incidence of rack-to-wall or rack-to-rack impact is simulated by gap elements at the top and bottom of the rack in two horizontal directions. Bottom gap elements are located at the baseplate levation. The initial gaps reflect the presence of baseplate extensions, and the rack stiffnesses are chosen to simulate local structural detail

h. Pedestals are modeled by gap elements in the vertical direction and as "rigid links" for transferring horizontal stress. Each pedestal support is linked to the pool liner (or bearing pad) by two friction springs. The spring rate for the friction springs includes any lateral elasticity of the stub pedestals. Local pedestal vertical spring stiffness accounts for floor elasticity and for local rack elasticity just above the pedestal. Details of the derivation and computation of the element stiffnesses are given in Reference 4

i. Rattling of fuel assemblies inside the storage locations causes the gap between fuel assemblies and cell wall to change from a maximum of twice the nominal gap to a theoretical zero gap. Fluid coupling coefficients are based on the nominal gap in order to provide a conservative measure of fluid resistance to gap closure

j. The model for the rack is considered supported, at the base level, on four pedestals modeled as non-linear compression only gap spring elements and eight piecewise linear friction spring elements; these elements are properly located with respect to the centerline of the rack beam, and allow for arbitrary rocking and sliding motions.

The high-density spent fuel storage racks are designed to withstand the most severe environmental, loading, and seismic conditions assumed to occur simultaneously. Load combinations are in accordance with SRP Section 3.8.4.

The structural acceptance criteria are in accordance with ASME B&PV Code Section III, Subsection NF.

The breakdown of the load combinations and acceptance limits is as follows:

D + L	Normal limits of NF 3231.1a

$D + L + E$	Normal limits of NF 3231.1a
$D + L + T_o$	The lesser of 2 S_y and S_u
$D + L + T_o + E$	The lesser of 2 S_y and S_u
$D + L + T_a + E$	The lesser of 2 S_y or S_u
$D + L + T_a + E^1$	Faulted condition limits of NF 3231.1c

where

D = dead loads of racks, buoyant rack weight

L = live loads, buoyant fuel weight

E = operating-basis earthquake (OBE) seismic loads including impact of fuel due to clearance within rack

T_o = operating thermal load

T_a = accident thermal load based on pool temperature of 212°F

E^1 = safe-shutdown earthquake seismic loads including impact of fuel due to clearance within rack

In addition to thermal and seismic loads, the high-density spent fuel storage racks are designed to withstand each of the following loadings superimposed on the submerged rack dead weight plus the weight of any stored fuel:

a. A 1200-lb uplift force applied at the top of the rack in the "weakest" storage location. The force is assumed to be applied on one wall of the storage cell boundary as an upward shear force. The damage, if any, is limited to the affected storage locations

b. Fuel assembly dropped on top of the rack with an impact energy of 2000 ft-lb. The impact energy is assumed to correspond to a buoyant mass of 600 lb dropped from a height of 40 in. The impact is assumed to occur on the top ridge of the rack

c. A horizontal force of 1000 lb applied at the most vulnerable location on the top of the rack. The load is assumed to act over the width of one storage cell. The subcriticality of all fuel assemblies is to be maintained with a $k_{eff} \leq 0.95$

d. A fuel assembly (assumed buoyant weight = 600 lb) dropping 16 ft 9 in. through a storage location and impacting the base. Local failure of the base plate is acceptable; however, an impact with the pool liner is not allowed. The subcriticality of all fuel assemblies is to be maintained with a $k_{eff} \leq 0.95$.

The allowable stress criteria are in accordance with ASME B&PV Code Section III, Subsection NF. The high-density spent fuel storage racks were checked for normal operating conditions, severe environmental conditions (OBE), extreme environmental conditions (SSE), and abnormal plant conditions (pool temperature = 212°F), and were found to be satisfactory.

The design of the Fuel Pool Cooling and Cleanup System (FPCCS) is described in Subsection 9.1.3. The decay heat load generated by the stored spent fuel is calculated in accordance with NRC Branch Technical Position ASB 9-2 (BTP ASB 9-2) (Reference 23). Where noted, heat up analyses are performed using the corrected form of the BTP decay heat model (References 24 and 25).

The spent fuel pool capacity expansion mentioned in Subsection 9.1.2.2 will occur over a series of campaigns, with the storage capacity increasing after each campaign. The bounding configuration from a thermal-hydraulic standpoint is the final, maximized configuration. This involves the largest number of stored assemblies and therefore the highest SFP decay heat load and lowest net SFP thermal capacity. All analyses discussed in this section are performed for the final configuration and thereby bound all intermediate configurations.

Thermal-hydraulic qualification analyses for the modified rack array are as follows:

a. Evaluation of the maximum bulk temperature. The bulk temperature is limited to 150°F for all conditions where forced cooling is available

b. Evaluation of loss-of-forced cooling scenarios, to establish minimum times to perform corrective actions and maximum makeup water requirements

c. Determination of the maximum local temperature in the pool to establish that localized boiling in the SFSRs is not possible

d. Evaluation of the maximum temperature difference between the fuel rod cladding and the local SFP water, to establish that nucleate boiling is not possible while SFP forced cooling is operating.

For each of the above analyses, evaluation is performed for an analytically bounding scenario as detailed below.

During normal SFP operation, the maximum normal bulk temperature of 150°F is based on the Fuel Pool Cooling and Cleanup System with the SFP gates installed.

In the scenario as addressed in support of the Amendment 141 spent fuel pool re-rack (Reference 7c), an emergency full core discharge comprised of 764 assemblies is discharged into an SFP that already contains 4016 previously discharged assemblies. This analyzed fuel inventory (4780) conservatively exceeds the maximum licensed capacity of 4608 assemblies. The minimum decay time of the previously discharged fuel assemblies for this scenario is 12 months. In addition to those mentioned above, the following conservative framework is applied in the maximum pool bulk temperature calculation:

a. The decay heat load is based on a discharge schedule with bounding parameters (i.e., maximum irradiation time and batch size) for all projected discharges.

b. Design temperatures are used for the coolant water flow inlet to the FPCCS and RHR System heat exchangers.

For evaluating the minimum time-to-boil and corresponding maximum boiloff rate, the following conservatisms are applied:

a. Loss of forced cooling is assumed to occur coincident with the SFP peak decay heat generation.

b. The thermal capacity of the SFP is based on the net SFP water volume only. The energy storage capability of the fuel racks, fuel assemblies and pool structure is neglected.

c. Makeup water supplied to maintain the SFP water level is assumed to be at the coincident SFP bulk temperature. No credit is taken for the difference in enthalpy between the SFP and the cooler makeup water, maximizing the boiloff rate.

For the same pool inventory described above for the maximum pool temperature case, the results of the analysis show that, in the extremely unlikely event of a complete failure of both the FPCCS and RHR System, there would be sufficient time available for corrective actions. The maximum water boiloff rate is less than the minimum available makeup capacity of 100 gpm available from the condensate storage tanks. Additional sources of makeup are also available.

In order to determine an upper bound on the maximum local water temperature, a series of conservative assumptions are made:

a. The walls and floor of the SFP are modeled as adiabatic surfaces, neglecting conduction heat loss through them.

b. Heat losses by thermal radiation and natural convection from the SFP surface are neglected.

c. The rack-to-wall gaps are modeled as 2 inches wide. The actual rack-to-wall gaps are larger.

d. The bottom plenum gap used in the model is approximately 50 percent of the actual gap.

e. No downflow is assumed to exist between the rack modules.

f. The hydraulic resistance of every SFSR cell is determined based on the most hydraulically limiting fuel assembly type.

g. The hydraulic resistance of every SFSR cell is determined based on the most restrictive water inlet geometry of the cells over the rack support pedestals.

h. The hydraulic resistance of every SFSR cell includes the effects of blockage due to an assumed dropped fuel assembly lying horizontally on top of its rack. This condition bounds the effects of contemplated overhead platforms, which add little extra flow resistance because of the large (~16 in.) spacing between the cell exit and the platform. Blockage due to a dropped assembly also bounds that of a vertically blocked gate, because the width of a channeled assembly is larger than the gate thickness.

i. With a full core discharged into the SFP racks and placed approximately equidistant from the coolant water inlet and outlet, the remaining cells in the spent fuel pool are postulated to be occupied with previously discharged fuel.

j. The in-pool sparger piping is modeled as truncated above the elevation of the racks.

k. In the evaluation of local water temperatures in dual-purpose rack cells containing loaded damaged fuel containers, only two of the cell baseplate holes are credited. This conservatively neglects the two additional baseplate holes and the eight cell side holes, thereby yielding greater than 100 percent redundancy in these cells.

The maximum local water temperature is substantially lower than the local boiling temperature at the top of the SFSRs and nucleate boiling does not occur anywhere within the Fermi 2 SFP.

Dose calculations (Subsection 9.1.3.3) performed based on the boiling condition indicate that the spent fuel pool cooling and cleanup system is adequate to provide reasonable assurance that the plant can be operated without undue risk to the health and safety of the public, consistent with the requirements of Criterion 2 of 10 CFR 50, Appendix A.

9.1.2.2.3 ISFSI Storage Pad

The function of the Independent Spent Fuel Storage Installation (ISFSI) storage pad is to provide a level resting surface for dry fuel storage casks. The pad is a 141' by 141' square reinforced concrete structure that is two feet thick designed to accommodate sixty four dry storage casks. The pad is compliant with ACI 349, "Code Requirements for Nuclear Safety-Related Concrete Structures," 2001, and designed in accordance with 10CFR Part 72-Licensing requirements for the independent storage of spent nuclear fuel, high-level radioactive waste, and reactor-related greater than Class C waste. The pad includes a surrounding fence with signage indicating that the pad is a radiologically controlled area. There is a subsurface drainage system surrounding the pad to help prevent the soil under the pad from being displaced as a result of freeze and thaw cycles. The subsoil in the area to the north of the pad has also been prepared for possible future expansion of the pad to allow additional placement of up to thirty two dry storage casks.

9.1.2.3 Safety Evaluation

The design of the spent fuel pool and storage racks meets the requirements of Regulatory Guide 1.13, except as noted in Appendix A of the UFSAR. Moreover, the spent fuel storage racks are designed to meet Category I requirements as described in Section 3.2.

The SFP will contain original Oat racks and Holtec racks introduced in Subsection 9.1.2.2.1. A wide range of conditions has been addressed in the design validation of all the racks. Examples relevant to the Oat racks include SFP water temperature increase to 212°F, the effect of manufacturing deviations (inverted cruciform and tees) and Boraflex panel degradation. Every Boraflex panel is assumed to have experienced an 8-10 in. gap (or reactivity equivalent) randomly distributed in the axial direction and losses in width and areal B-10 density due to thinning within the reactivity margin that is provided in the criticality analysis (see References 7 and 22). References 7 and 22 provide a discussion of the techniques and assumptions used in the criticality analysis of the Oat racks. The K_{eff} for the existing spent fuel storage racks, including an allowance for uncertainties is shown in the above references to be less than or equal to the 0.95 limit.

The criticality analyses for the high density fuel storage racks were performed with the MCNP code. MCNP (Monte Carlo N-Particle Transport) is a continuous energy Monte Carlo code. See Section 3.13.3.17.

As the SFP capacity expansion progresses, a greater and greater percentage of the pool will be occupied by Holtec high-density racks. Neutronic coupling between the Oat Boraflex racks and the Holtec Boral racks is precluded by the water gap between modules and by the absorber panels on both sides of the gap. Accordingly, to ensure that the design of the spent fuel storage racks provides for a $k_{eff} \leq 0.95$, the following normal and abnormal conditions are addressed in References 7b and 22 for the new racks:

a. The nominal design case, normal positioning of spent fuel assemblies in the spent fuel storage rack to act as a baseline

b. Temperature and water density effects: analyses are performed for a temperature decrease to 4°C (maximum water density), boiling (giving rise to voids) at various levels in the SFP. The calculations confirm that the reference temperature of 4°C is most conservative

c. Abnormal location of a fuel assembly was shown to have a negligible reactivity effect, while the nominal case was shown to yield a higher reactivity than a case with the fuel assembly moved to the corner of the storage rack cell (a four assembly cluster at closest approach)

d. The drop of a fuel assembly on a spent fuel storage rack. Such event was found to result in an insignificant increase in the calculated k_{eff}

e. The effect on reactivity of tolerances with respect to rack manufacture (stainless steel thickness, lattice spacing), B-10 loading, Boral width, fuel (enrichment and depletion) uncertainties has also been assessed.

The maximum calculated reactivity, including allowance for all uncertainties, was below 0.95.

Consideration has been given to various objects that might be dropped into the spent fuel pool and impact with the spent fuel storage racks. The spent fuel storage racks are designed to withstand the dropping of a fuel assembly as documented in Reference 1 for Holtec Racks and Reference 3 for Joseph Oat racks. A pool gate drop is evaluated to assess damage to the stored fuel assemblies in a fuel rack, the drop of an overhead platform during installation onto the top of a rack is evaluated, and an additional evaluation was also performed to consider the ability of the rack to withstand the uplift force from a stuck fuel assembly. The drop accident events postulated for the Fermi 2 fuel pool were analyzed and found to produce localized damage well within the design limits for the racks. Consequently, the spent fuel storage racks have a very large margin of safety.

The materials of the high-density spent fuel storage racks are described above in Subsection 9.1.2.2.2.

Provision is made to limit potential offsite exposures in case of significant release of radioactivity from the spent fuel. This would be done by using the standby gas treatment system (SGTS), when necessary, to control the release rate of radioactivity from the fuel storage area.

By maintaining the minimum spent fuel pool water level and the use of the normal reactor building ventilation, the exposure to plant personnel is maintained below the limits of 10 CFR 20.

Subsection 9.1.3.3 discusses the radiological consequences of loss of cooling to the spent fuel pool.

9.1.2.4 Testing and Inspection

A detailed and rigorous inspection of the Holtec high-density spent fuel storage modules is carried out at the fabrication facility prior to their release. The racks are also receipt inspected at the site before the racks are installed in the pool.

The design incorporates provisions for periodic testing of the Boraflex poison material throughout the life of the plant to verify the continued presence of a sufficient amount of neutron absorber in the spent fuel storage racks to maintain a $k_{eff} \leq 0.95$.

In situ verification of the poison material was performed at initial installation for the Oat racks to confirm the presence of the neutron absorber (Boraflex) in the spent fuel storage racks.

9.1.2.5 Reactivity of Fuel in Storage

The basic criterion associated with the storage of both irradiated (spent) and new fuel is that the effective multiplication factor of fuel stored under normal conditions will be ≤ 0.90 for the low density racks and ≤ 0.95 for the high density racks. Abnormal storage conditions are limited to a k_{eff} of 0.95 for both high and low density racks.

For the low density racks removed from the Spent Fuel Pool during Cycle 12, these storage criteria were satisfied if the uncontrolled lattice k_∞ calculated in the normal reactor core configuration met the following condition:

$k_\infty \leq 1.31$ for 20°C to 100°C. (Reference 7a)

For the Oat high density racks, these storage criteria will be satisfied if the uncontrolled lattice k_∞ calculated in the normal reactor core configuration (standard cold core geometry) is less than or equal to 1.3113 (Reference 7). For the Holtec racks, the design-basis hypothetical bundle has a k_∞ of 1.3392 in standard cold core geometry. These values reflect the more limiting of the GE14 (References 7 and 7b) and GNF3 (Reference 22) criticality analyses. The net result is the k_∞ condition to meet the storage criteria is higher for the Holtec racks than for the Oat and the original low density racks. Thus, the Oat and low density racks are more limiting. The maximum k_∞ in the normal reactor core configuration at cold conditions for fuel assemblies in the spent fuel storage racks is 1.31, based on the Technical Specifications.

The peak uncontrolled lattice k_∞ in normal reactor core configuration is calculated by the fuel fabricator for each bundle type.

9.1.3 Fuel Pool Cooling and Cleanup System

9.1.3.1 Design Bases

The fuel pool cooling and cleanup system (FPCCS) is designed to remove the decay heat produced by stored spent fuel assemblies during all anticipated conditions of plant operation and during plant refueling outages 18 days after reactor shutdown. This includes refueling using either a full-core offload or core shuffle method. The system consists of two identical trains, which include pumps, heat exchangers, and filter-demineralizers.

The heat load in the spent fuel pool is anticipated to increase subsequent to each progressive refuel outage until the pool is filled to the maximum capacity where all of the storage locations are filled. The spent fuel pool temperature is maintained at or below 125°F during normal operation and 150°F during refuel outages. In anticipation of installing additional storage locations in the pool, the spent fuel pool and the FPCCS have been evaluated for a normal operating temperature of 150°F. However, additional engineering evaluation is required if the spent fuel pool is to be maintained at a temperature greater than 125°F during normal operating conditions.

The Amendment 141 spent fuel pool re-rack criteria for the FPCCS design analysis were as follows:

a. The originally installed spent fuel pool storage capacity was, nominally, 3.0 cores (2383 assemblies), plus room for removing a full core. EDP-27387 (Campaign I) and EDP-34306 (Campaign II) placed additional racks in the pool, increasing the installed capacity to 3588 locations, with a maximum licensed capacity to 4608 locations.

b. The original Amendment 141 re-rack licensing analysis considered both one-quarter core 12-month and one-third core 18-month fuel discharges; plant operation began at Cycle 1 with one-third core 18-month fuel discharge cycles. The spent fuel pool and the FPCCS have been analyzed assuming a maximum spent fuel population composed of the following:

    1. 6.25 cores composed of 20 groups of spent fuel assemblies, each of the first 19 groups containing from 176 to 228 assemblies discharged approximately every 18 months, ending with a full core discharge 30 years after the first cycle.

c. The spent fuel assemblies have a power history giving the discharge batch an average irradiation less than or equal to 50,000 MWd/MTU

d. The system heat load removal capacity is based on heat exchangers sized for a design heat load of 16.66 x 10^6 Btu/hr with a 55°F hot-to-cold side inlet temperature differential and two trains operating. The system is managed to maintain the spent fuel pool bulk temperature at or below 125°F during normal plant power operation with up to 3.0 cores of spent fuel stored in the spent fuel pool.

e. The decay heat was calculated assuming a bounding 4780 assemblies, exceeding the actual number of licensed storage locations (4608), based on the uncorrected BTP ASB 9-2 (Reference 23) decay heat model. The original Amendment 141 spent fuel pool re-rack evaluation (Reference 7c) was subsequently updated to consider both the impact of a 3486 MWth GNF3-based 24-month equilibrium fuel cycle as well as the effect of the assumed EDP-80016 installation of BORALCAN inserts to address historical Boraflex degradation associated with the original Joseph Oat racks. This more recent evaluation was performed using a corrected form of the BTP ASB 9-2 decay heat model (Reference 24 and 25) that predicts lower calculated decay heat loads, even though the actual GNF3 equilibrium core has a higher exposure (5.74 years at 3486 MWth) and corresponding real higher relative decay heat. In addition, whereas the original re-rack analysis considered 4780 loaded pool locations the analysis updated for GNF3 is based on the licensed capacity of 4608 locations (6.03 cores). The effect of these updates is a net reduction in calculated pre and post offload pool decay heat such that the original analysis remains bounding. Except as noted, the description of the more limiting original Amendment 141 analysis results are retained below. The following assumptions are made to calculate decay heat load to the spent fuel pool.

    1. Each discharged assembly has been irradiated for 5.2 years

    2. During the irradiation period, the reactor is operating at 100 percent power

    3. After shutdown, the RHR cooling system is used as the primary decay heat removal system for up to 18 days while the reactor head is off and refueling/maintenance operations are proceeding, including full-core offload when scheduled

    4. In applying BTP ASB 9-2, the uncertainty factor K for irradiation time $t > 10^7$ sec is taken to be 0.1

f. Refer to Table 3.2-1 for seismic and quality group for FPCCS system.

g. The FPCCS is designed to achieve the following additional functions.

    1. Minimize corrosion product buildup and control water clarity, through filtration and demineralization so that the fuel assemblies can be efficiently handled underwater

    2. Minimize fission product concentration in the water that could be released from the spent fuel pool to the reactor building environment

    3. Monitor spent fuel pool water level and maintain a water level above the fuel sufficient to provide shielding for normal building occupancy

    4. Maintain the bulk water temperature at less than 150°F, with the heat loading resulting from the removal of a full core either during plant

refueling (greater than 18 days cooling) or in a plant outage following a normal refueling. This may be achieved by being able to interconnect the RHR system and the FPCCS to supplement spent fuel pool cooling.

5. Preclude siphoning the spent fuel pool by providing siphoning breakers on all lines penetrating the spent fuel pool.

9.1.3.2 System Description

The FPCCS cools the spent fuel pool by transferring decay heat through heat exchangers to the reactor building closed cooling water system (RBCCWS), as shown in Figure 9.1-23. Water purity and clarity in the spent fuel pool, reactor well pool, and dryer-separator storage pool are maintained by filtering and demineralizing the pool water as shown in Figure 9.1-24.

The FPCCS is composed of two trains. Each train is designed to remove 8.33 x 10^6 Btu/hr with a 55°F (FPCCS to RBCCW inlet flows) temperature differential, 550 gpm tube flow and 800 gpm (RBCCW) shell flow (Table 9.1-1). The system consists of two fuel pool cooling pumps; two heat exchangers; two filter-demineralizers; two skimmer surge tanks; and associated piping, valves, and instrumentation. The two fuel pool cooling pumps are connected in parallel, as are the two heat exchangers. The pumps and heat exchangers are located in the reactor building below the level of the bottom of the spent fuel pool.

The filter-demineralizer units are located in the radwaste building in separate shielded cells, with enough clearance to permit removing filter elements from the vessels. Each cell contains only the filter-demineralizers and piping. All air-operated valves (such as inlet, outlet, recycle, vent, and drain) are located on the outside of one shielding wall of the cell, together with necessary piping and headers, instrument elements, and controls. Penetrations through shielding walls are located so as not to compromise radiation shielding requirements (Subsection 12.1.2).

The pumps circulate the spent fuel pool water in a closed loop, taking suction from the skimmer surge tanks through the heat exchangers, circulating the water through the filter-demineralizers, and discharging nominally 7’ -6” below the normal water level in the fuel storage pool. The cooled water traverses the pool, picking up heat and debris before starting a new cycle by discharging over the skimmer weirs and scuppers into the skimmer surge tanks. The normal makeup water source for the system is provided from the condensate storage tank to the skimmer surge tanks.

Backup cooling is provided to the spent fuel pool by means of a permanently piped cross tie to the RHR system. In this mode of operation, one RHR pump and the corresponding RHR division heat exchanger will provide the means to cool the spent fuel pool. This cooling circuit is established by opening cross-tie valves V8-3264, G4100F016 and V8-3029, G4100F036 and closing FPCCS valves V8-3006, G4153F004 and V8-3253, G4100F011 (Figure 9.1-23). For the designed piping configuration, the RHR pump flow is throttled with valve G4100F231 to a maximum of 3500 gpm. If the fuel pool gates are removed and the reactor cavity is flooded up, the RHR discharge may be configured to split the flow between the reactor cavity and fuel pool by opening G4100F036. The RHR suction will be from the operating SDC loop, therefore G4100F016 is closed. During this split flow configuration, the FPCC is operated in parallel with RHR SDC as FPCC is discharging to the reactor cavity, G4153F004 and G4100F039 are open and G4100F011 is closed. An RHR heat exchanger will remove the total spent fuel pool decay heat load of approximately 42.22 x 10^6 Btu/hr of a full-core offload, completed at 156 hrs decay cooling since reactor shutdown, with about a 49°F temperature differential (Table 9.1-1). To ensure the availability of backup cooling via the RHR system, the cross-tie piping, the FPCCS piping from the skimmer tanks to the first anchor downstream of valve V8-3006, and the FPCCS piping from the first anchor upstream of valve V8-3253 to the spent fuel pool are Seismic Category I.

Both FPCCS heat exchangers operating in parallel are designed to remove the maximum heat load produced by various combinations of spent fuel discharged from the equilibrium fuel cycle at the time the RHR system is isolated from the spent fuel pool, plus the heat being released by batches discharged at previous refueling (see Subsection 9.1.3.1). The maximum heat load 18 days after a reactor shutdown with about 4276 fuel bundles in the spent fuel pool is 14.29 x 10^6 Btu/hr. The maximum heat load 18 days after reactor shutdown with 9 1/3 core off loads in the spent fuel pool is approximately 11.9 x 10^6 Btu/hr. This load is within the capacity of the FPCCS heat exchangers with a temperature differential of about 39°F. Re-evaluated for the GNF3 equilibrium cycle with 4088 pool locations filled, the 18 day heat load is predicted to be 11.54 x 10^6 Btu/hr.

During refueling outages (up until mode change for plant restart), when spent fuel pool circulating flow is interrupted to drain the reactor well and the dryer/separator storage pool or when the FPCCS becomes incapacitated, either of the RHR system heat exchangers may be used to supplement spent fuel pool cooling in the event the pool bulk temperature cannot be maintained below 150°F. During refueling outages, the RHR system can provide necessary supplemental cooling of the spent fuel pool until the RHR system is isolated from the spent fuel pool to restore low-pressure coolant injection (LPCI) standby mode. After RHR is isolated, the spent fuel pool decay heat is managed to remain within the FPCCS duty capability. Table 9.1-1 also lists the characteristics of an RHR subsystem in the fuel pool cooling assist mode.

The design of the spent fuel pool is such that the top of the stored fuel is at a lower elevation than the bottom of the gate between the reactor well and spent fuel pool. There are no connections to the spent fuel pool that could drain the pool below the elevation of the bottom of the gate when the gate is removed for refueling, or below the normal spent fuel pool level when the gate is in place. To prevent water from being siphoned out of the pool, the piping entering the spent fuel pool is fitted with normally submerged vents which will break a siphon before the minimum required water coverage over the stored fuel is lost. A level indicator, mounted at the valve rack, monitors reactor well water during refueling. A high rate of leakage through the refueling bellows assembly, drywell to reactor seal, or the spent fuel pool gates is indicated on the operating floor instrument racks.

Spent fuel pool water is continuously recirculated during normal FPCCS operation. The circulation patterns within the reactor well and spent fuel pool are established by the placement of the diffusers and skimmers to sweep particles dislodged during refueling operations away from the work area and out of the pool.

For refueling operations, the reactor well and dryer-separator storage pools are filled by transferring water from clean stored condensate. After the vessel head is removed, the fill water is transferred through the reactor vessel by flooding vessel level up into the reactor well. Clarity and purity of the pool water are maintained by a combination of filtering and ion exchange. The cleanup system has sufficient capacity to ensure pool water clarity and purity. The water purity is maintained by monitoring the demineralizer conductivity and differential pressure with periodic sampling and analysis of spent fuel pool water. The filter-demineralizers maintain water purity within the chemical limits specified below.

	Fuel Pool Chemical Limits	Demineralizer Effluent
Conductivity	≤ 3 μmho/cm at 25°C	≤ 1 μmho/cm at 25°C
Chloride	≤ 500 ppb	≤ 50 ppb
pH	5.3-7.5 at 25°C	6.0-7.5 at 25°C
Total insolubles	≤ 1 ppm	

Demineralizer differential pressure operating limit is 30 psi, and an alarm is provided at 25 psi. No radiochemical limits are needed to monitor the spent fuel pool water and initiate corrective action for the following reasons:

a. Crud buildup that would contribute to gross gamma activity is minimized by the filter-demineralizer

b. Iodine-131, with an assumed concentration of 64 μCi/g, is the most radiologically significant nuclide; doses from the other nuclides, by comparison, are relatively negligible

c. The assumed concentration of 64 μCi/g of ^{131}I is almost 10^{-6} of the specific activity if its solubility limit is attained. Therefore, assuming a partition factor of 10 and a removal efficiency of 99 percent by the SGTS, ^{131}I would not be a problem.

The system flow rate is larger than that required for two complete water changes per day of the spent fuel pool, or one change per day of the fuel storage, reactor well, and dryer-separator pools.

The maximum system flow rate is twice the flow rate needed to maintain the specified water quality. Particulate matter is removed by powdered ion-exchange resin-fiber mixtures. Alternatively, a combination of powdered resin and precoated material such as cellulose may be used as the disposable filter medium. The filter elements are stainless steel mesh elements mounted vertically in a tube sheet and replaceable as a unit. The filter vessel is constructed of carbon steel and coated with a phenolic resin material.

Spent fuel pool water and demineralizer effluent are sampled and analyzed once per week.

Instrument readings for conductivity and differential pressure are taken once per shift. Alarms sound in the control room if demineralizer conductivity, flow, or differential pressure limits are attained so that corrective action may be initiated. Backwashing and precoating operations are controlled from a local panel in the radwaste building. The spent filter medium is removed from the elements by backwashing with air and condensate and then is flushed to the phase separator tank.

A poststrainer in the effluent stream of the filter-demineralizer limits the migration of filter material. The filter-holding element can withstand a differential pressure greater than the developed pump head for the system.

System instrumentation is provided for both automatic and remote manual operations. A low-low level switch stops the circulating pumps when surge tank reserve capacity is low. Manual control for the circulating pumps is either from local panels or the control room panel. Pump low suction pressure automatically turns off the pumps.

The FPCCS has alarm functions for cooling pump low discharge pressure, refueling bellows seal leakage, spent fuel pool gate reactor well seal leakage, skimmer surge tank high level, spent fuel pool high level, and skimmer surge tank low level. All of these functions give a common alarm signal to the main control room; for example, spent fuel pool cooling system trouble. Each function also has a light, located on local control panels, which determines the cause of the common alarm in the main control room. In addition, there are specific alarms in the control room for spent fuel pool high temperature, spent fuel pool low level, and spent fuel pool demineralizer trouble.

The local control panels receive power from a standby source if normal power is not available. Circulating pump motor loads are considered nonessential loads and will be operated as required under accident conditions.

9.1.3.3 Safety Evaluation

The FPCCS maintains the peak spent fuel pool bulk temperature below 150°F with the maximum design decay heat load during an outage and at or below 125°F during normal plant power operation. Although the spent fuel pool and the FPCCS are evaluated for a normal operating temperature of 150°F, additional engineering evaluation is required if the spent fuel pool is to be maintained at a temperature greater than 125°F during normal operating conditions. The FPCCS and RBCCW pumps are powered from redundant buses; this ensures continued normal cooling operation. The RHR system provides a safety source of emergency makeup water and redundant heat removal capability.

No inlets, outlets, or drains are provided that would permit the spent fuel pool to be drained below a safe shielding level. Lines extending below this level are equipped with siphon breakers, check valves, or other suitable devices to prevent inadvertent pool drainage. The line draining the space between the two gates is sufficiently high to preclude draining excessive water above the spent fuel storage racks.

Except during refueling operations, the spent fuel pool will be isolated from the reactor head cavity and dryer-separator storage pool by two redundant watertight gates that close the opening through which spent and new fuel is transported to and from the spent fuel pool. The bottom of the gate opening is above the top of the fuel storage racks in the bottom of the spent fuel pool to ensure that the stored fuel can never be uncovered.

The only interconnection between the cooling and cleanup subsystems is the spent fuel pool itself. The FPCCS return lines to the spent fuel pool are provided with siphon breakers.

The decay heat load in the spent fuel pool may vary widely because of various possible combinations of the following:

a. The number of groups and the respective irradiation periods of spent fuel assemblies in the racks (see Subsection 9.1.3.1.b. and e.)

b. The duration of time-after-shutdown for each of the spent fuel groups.

The original Amendment 141 re-rack decay heat calculated for the bounding case of an emergency full core offload using the assumptions of Subsection 9.1.3.1 resulted in a maximum calculated spent fuel pool heat load of 42.65 x 10^6 Btu/hr (12.5 MWt). Re-evaluated for GNF3 based on the corrected BTP decay heat model (References 24 and 25), Reference 7c predicts a maximum pool heat load is 40.7 x 10^6 Btu/hr (approx. 12 MWt). In either case, the FPCCS does not have the heat removal capacity to maintain the pool temperature to less than 125°F. Engineering evaluation is required to operate with this heat load in the spent fuel pool.

The FPCCS is normally capable of maintaining the spent fuel pool temperature at or below its maximum normal design temperature of 125°F. Under full-core offload with spent fuel pool decay heat load above the system design capacity, the required differential temperature across the FPCCS heat exchangers exceeds the nominal design temperature differential. In the event of other system abnormal conditions of decay heat load higher than available FPCCS removal capacity due to other refueling outage activities and/or FPCCS capacity restriction (e.g., due to maintenance), the heat load may also result in higher temperature differential across the operating FPCCS heat exchanger(s). This would cause the temperature of the spent fuel pool to rise. Should FPCCS not be able to maintain spent fuel pool temperature below 150°F, then an RHR loop would be aligned to take suction from, and discharge to, the spent fuel pool. If the fuel pool gates are removed and the reactor cavity is flooded up, then the suction remains from the shutdown cooling line and the discharge may be split between the recirculation loop and the fuel pool. The use of the RHR system in the fuel pool cooling assist mode makes both low pressure coolant injection (LPCI) subsystems inoperable.

FPCCS and natural circulation have been analyzed to be capable of serving as an alternate method of decay heat removal to enable RHR Shutdown Cooling to be taken out of service for maintenance during refueling. When operating in this alternate shutdown cooling mode, the fuel pool gates are removed and the RPV cavity is flooded. Entry into this mode requires satisfying the refuel technical specification associated with high RPV water level. FPCCS is normally operated with two pumps and two heat exchangers in service. In this capacity, FPCCS and natural circulation maintain FPCCS suction temperature less than 140°F, cooling both the old and freshly off-loaded assemblies in the fuel pool as well as those remaining in the RPV. RWCU may also be placed in operation with the regenerative heat exchanger bypassed to provide additional cooling and in-vessel mixing. This ability to enter this mode of FPCCS operation for RHR maintenance activities is evaluated on a per cycle basis using the expected vessel and spent fuel pool heat loads. The activity is managed such that normal shutdown cooling can be restored within 8 hrs. This is an arbitrary time frame that conservatively assures cooling can be restored prior to the onset of pool and core boiling. In addition, the operation of this mode restricts the operation of temporary auxiliary pool water filtration units such that the flow discharge does not interfere with the core exit flow and thereby impede natural circulation cooling.

The heat load to the spent fuel pool is caused by the decay heat of the fission products and the activated heavy elements (^{239}U and ^{239}Np) contained in the spent fuel assemblies stored in the racks, including those temporarily stored for a refueling outage. Since different combinations of assemblies are reinserted into the core than were originally removed (possibly including some reinserted assemblies that were removed at prior refuelings), the decay heat load will vary from cycle to cycle. The original Amendment 141 design analysis conservatively assumed a higher number of assemblies in the spent fuel pool storage racks than there are actual storage locations as presented in Subsection 9.1.2.2.2 above. Table 9.1-2a presents the fractional decay heat as a function of time after shutdown for this bounding case determined with the method given based on the uncorrected BTP ASB 9-2 decay heat model. Pool decay heat corresponding to a 24-month GNF3 fuel cycle is presented in Table 9.1-2b.

The data in the table for the prior discharges are based on a full-power operating period of 5.2 years that is conservatively consistent with an approximately one-third core, 18-month equilibrium fuel cycle. The number of fuel assemblies and the decay heat contribution for each discharge are also given in Table 9.1-2a and Table 9.1-2b. The decay heats in MW for fuel assemblies discharged in normal refuelings for the entire plant cycle, ending with a normal partial core unload of 260 assemblies, are presented in Tables 9.1-3a and 9.1-3b are computed as follows:

$$\text{QDKP}\ (t_s) = \text{RTP MWt} \times \frac{P}{P_o}(t_o, t_2) \times \frac{N}{764}$$

where

$\text{QDKP}\ (t_s)$ = decay heat of fuel assemblies that have been stored in spent fuel pool racks for t_s sec, MW_t

RTP MWt = 100 percent of the rated thermal output of core

$\frac{P}{P_o}(t_o, t_2)$ = fractional decay heat

$\frac{N}{764}$ = fraction of full core discharged per Refueling/Unload

Tables 9.1-3a and 9.1-3b give the cumulative spent fuel pool heat load and quantity of spent fuel stored in the racks versus time after the initial discharge to the spent fuel pool for 18-month and 24-month fuel cycles, respectively. To develop a conservative maximum spent fuel pool heat load, the case of a complete operating cycle followed by an emergency full core offload is considered. Under the original heat load analysis, the total number of assemblies in the spent fuel pool was taken as 4780. This maximum heat load case includes 19 approximately one-third core discharges from previous refuelings plus a full-core offload of the last operating cycle started at 2-1/2 days decay cooling from reactor shutdown. The maximum spent fuel pool heat load in this case would be 12.50 Mwt (~42.65 x 10^6 Btu/hr; see Table 9.1-1). In this case, one loop of the RHR system would be needed in the fuel pool cooling assist mode to maintain bulk temperature below 150°F.

Upon completion of refueling activities, FPCCS is evaluated to determine that it is capable of maintaining the spent fuel pool temperature below 125°F. Insufficient decay heat removal capability may occur due to FPCCS performance degradation, capacity limitation due to insufficient temperature differential from high RBCCW service water temperature, larger than normal core discharge, and/or less than design cooling time from reactor shutdown. If this situation should exist, then one loop of RHR would continue to be employed to control the spent fuel pool temperature until the FPCCS decay heat removal capacity is sufficient to allow plant restart (RHR LPCI is considered inoperable and Technical Specifications limits with RHR LPCI inoperable apply to plant operations).

Should two active components in the spent fuel pool cooling system be unavailable and the RHR system be unavailable for cooling, the spent fuel pool water temperature would be inherently limited to 212°F, on boiling.

An analysis has been performed to determine the radiological doses at the site boundary which might result as a consequence of a complete loss of cooling of the spent fuel pool (see Reference 15). Such a complete loss of pool cooling is not considered a Design Basis Accident, and it is not considered a design basis for the fuel pool or for the FPCCS. The subject radiological analysis is currently included in the UFSAR for information only, and is not part of the basis for NRC acceptance of the FPCCS design. Details of the analysis are as follows:

a. Heat released from the spent fuel is conservatively assumed to have a constant value for a period of 30 days after the assumed loss of the FPCCS. For purposes of evaluating the radiological dose consequences only, it is conservatively assumed that no other heat removal method is available except for spent fuel pool boiling and that the time to achieve pool boiling is zero. Makeup water is assumed to be provided at a rate equal to that of boiling and thus maintains the spent fuel pool water volume at a constant value of approximately 48,000 ft^3. Potential makeup sources are the RHR service water, condensate storage, and fire protection system.

b. There is 1.3×10^{-2} μCi/g of ^{131}I in the reactor water during power production (see Table 11.1-3). The temperature, pressure, and flow rate of the spent fuel pool water are much lower than those of the water in the reactor under full-power conditions. Spent fuel in the spent fuel pool storage racks should not cause a water iodine concentration greater than the reactor water concentration, even assuming the spent fuel pool begins to boil. Notwithstanding the above, a ^{131}I concentration of 64 μCi/g was assumed and used. This concentration is more than 5000 times the ^{131}I concentration in the spent fuel pool water during full-power operation and adequately accounts for an "iodine spike."

c. The variation of iodine concentration in the spent fuel pool as a function of time is calculated realistically to account for decay, boiling, and the addition of makeup water. Two cases are considered: one assumes the makeup water to contain no radioactivity, and the other assumes an unlimited supply of makeup water at an initial concentration of 64 μCi/g.

d. The spent fuel pool water volume is about 48,000 ft^3. Based on a concentration of 64 μCi/g, there would be about 87,300 Ci of ^{131}I in the spent fuel pool water. Doses were calculated from other nuclides (gas and particulate) and it was concluded that ^{131}I is the most radiologically significant radionuclide, the others by comparison being negligible.

e. Iodine in the spent fuel pool water is assumed to be released from the pool at a rate that corresponds to the initial concentration and boiling rate with the application of a partition factor of 10.

f. The use of a partition factor of 10 is justified as follows: the solubility limit for iodine in hot water is 0.078 g/100 ml of water. If this amount of ^{131}I were to be dissolved in water, the specific activity would be 9.9 x 10^7 μCi/ml. The iodine concentration used in this analysis was 64 μCi/g. However, assuming the spent fuel pool water contained an amount of stable iodine equal to the radioiodine that would exist in the water during this postulated accident, the spent fuel pool water would still be able to accept almost one million times more iodine before the solubility limit was reached. On the basis of solubility, therefore, a partition factor of 10 is justified.

g. Iodine removal efficiency credit for the SGTS is assumed to be 99 percent, consistent with Regulatory Guide 1.52. The SGTS is designed to accommodate an inlet relative humidity of 100 percent; that is, the secondary containment is conservatively assumed to be filled with saturated air.

h. The meteorological condition assumed for the accident is the fifth percentile short-term (accident) χ/Q's for actual site meteorological data provided from Edison's 60-m tower and as reported to, and accepted by, the NRC staff (NRC letter dated April 26, 1976, G. W. Knighton to H. Tauber, Reference 8). These data are presented in Table 2.3-27.

i. The calculations estimate the 2-hr thyroid (inhalation) dose at the site boundary to be 0.17 rem for both radioactive and nonradioactive makeup water. The 30-day thyroid (inhalation) dose at the low-population zone for radioactive makeup is 0.186 rem; whereas for nonradioactive makeup, the 30-day dose is 0.134 rem.

Results indicate that the dose from this postulated accident would not exceed a fraction of 10 CFR 100 limits.

Thermal-hydraulic calculations confirm that the peak clad temperature for the hottest assembly, offloaded after 2-1/2 days of decay heat cooling from reactor shutdown, will remain below the local saturation temperature assuming a bundle inlet temperature at the maximum spent fuel pool temperature of 150°F. In addition, the calculations confirm that at the time of maximum spent fuel pool decay heat loading, with surface temperature approaching boiling (bulk temperature approximately 200°F), the hottest assembly peak clad temperature would still not exceed local saturation temperature. Should the spent fuel pool water temperature increase to the surface boiling point, the peak fuel cladding temperature would be slightly higher than the local saturation temperature ($T_{sat[racks]} \approx 240°F$). This fuel cladding temperature is a fraction of the fuel cladding temperature during normal plant operation. The physical characteristics of the fuel and the integrity of the fuel cladding would not experience changes that could cause an activity concentration in the spent fuel pool water in excess of the activity in the reactor water during full-power operation. Dose calculations performed by Edison, based on the above, indicate that the design criteria applied to the spent fuel pool cooling system are adequate to provide reasonable assurance that the plant can be operated without undue risk to the health and safety of the public, consistent with the requirements of Criterion 2 of Appendix A to 10 CFR 50.

In summary, the spent fuel pool cooling system's design, siphon-breaking piping arrangement, redundant transfer gates, emergency makeup water supply from the RHR service water system, and RHR backup capability provide a completely reliable system for the storage and cooling of spent fuel.

9.1.3.4 Testing and Inspection

Prior to power operation following a refueling outage, a determination will be made that the heat generation rate in the spent fuel pool is within the current capacity of the FPCCS with both trains in normal operation at a spent fuel pool bulk temperature less than or equal to 125°F.

No special tests are required for instrumentation on the FPCCS. The instrumentation will be subjected to routine testing. The FPCCS Preoperational Test program is discussed in Chapter 14.

9.1.4 Fuel Handling System

9.1.4.1 Design Bases

The fuel handling system provides a safe and effective means for transporting and handling fuel from the time it reaches the plant until the time it leaves the plant after postirradiation cooling.

9.1.4.2 Equipment Description

Table 9.1-5 is a listing of tools and servicing equipment supplied with the nuclear system. The following paragraphs briefly describe the use of some of the major tools, servicing equipment, spent fuel shipping cask, and reactor building crane. Where applicable, safety aspects of the design are discussed. For a historical discussion of the reactor building crane and spent fuel cask-handling details, see Reference 9. The procedure for load testing at 125 percent rated load described in Section 2.3.2 of Reference 9 has been modified in accordance with the guidelines established in NUREG-0554, ANSI B30.2, and NRC BTP ASB 9-1.

9.1.4.2.1 Independent Spent Fuel Storage Installation (ISFSI)

ISFSI program description

Under 10CFR72.210, Fermi is issued a general license for the storage of spent fuel in an Independent Spent Fuel Storage Installation (ISFSI). An ISFSI is a facility designed, constructed, and licensed for the interim storage of spent nuclear fuel and other radioactive materials associated with spent fuel storage in accordance with 10CFR72.

Upon approval of the Final Safety Analysis Report (FSAR) for the HI-STORM 100 Cask System, the NRC issued Certificate of Compliance (CoC) Docket No. 72-1014 and Safety Evaluation Report (SER) Docket No. 72-1014 for use of the HI-STORM 100 Cask System.

As a General Licensee, Fermi is authorized to use the HI-STORM 100 Cask System in accordance with appropriate documents and procedures.

Fermi selected the HI-STORM 100 Cask System to maintain adequate on-site spent fuel storage capacity which comprises of three discrete components: The Multi-Purpose Canister (MPC), the Holtec International Transfer Cask (HI-TRAC) and the Holtec International Storage Module (HI-STORM).

The MPC is a confinement system for the stored fuel. It is a welded, cylindrical canister with a honeycombed fuel backet, a baseplate, a lid, a closure ring, and a canister shell. All MPC components that come into contact with spent fuel pool water or ambient environment are made entirely of stainless steel or passivated aluminum/aluminum alloys such as neutron absorbers.

The HI-TRAC transfer cask provides shielding and structural protection of the MPC during loading, unloading and movement of the MPC from the spent fuel pool to the storage overpack. The transfer cask is a multi-walled (carbon steel/lead/carbon steel) cylindrical vessel with a neutron shield jacket attached to the exterior.

The HI-STORM 100 storage overpack provides shielding and structural protection of the MPC during storage. The overpack has four air inlets at the bottom and four air outlets at the top to allow air to circulate naturally through the cavity to cool the MPC inside. The inner shell has supports attached to its interior surface to guide the MPC during insertion and removal, provide a medium to absorb impact loads, and allow cooling air to circulate through the overpack. The side wall consists of plain (un-reinforced) concrete that is enclosed between inner and outer carbon steel shells.

The use of ISFSI Systems Structures and Components (SSCs) for storage and handling of spent fuel shall be in accordance with Fermi's 10CFR72.212 Evaluation Report and ISFSI related procedures.

9.1.4.2.2 Reactor Building Crane

An overhead traveling (reactor building) crane is utilized in the Fermi 2 reactor building to handle heavy objects, including the spent fuel shipping and transfer casks. The essential design bases applicable to Fermi 2 spent fuel cask handling are:

a. To minimize, to the maximum extent practical, the probability of dropping heavy objects into the fuel storage pool resulting in damage to fuel or compromising the integrity of the pool

b. To prevent a spent fuel shipping cask drop from exceeding the design limits for the cask as set forth in 10 CFR 71

c. To minimize the probability and the effect of dropping heavy objects, including the spent fuel shipping and transfer casks, during movement through the reactor building, so that damage is prevented to structures, systems, and components important to safety.

In order to obviate the possibility and to minimize the probability, to the greatest extent practical, of occurrence of events a, b, or c above, the special crane design features and improvements that have been incorporated are the following:

a. A completely redundant hoisting system

b. An upgrading of the crane for SSE and design-basis tornado

c. Upgrading of the crane quality assurance criteria

d. Crane control redundancy

e. A crane surveillance and test program

f. Administrative control of crane movements.

Crane operations over the spent fuel storage pool when fuel assemblies are stored therein are not allowed when either of the following conditions occur:

a. less than 22 feet of water over the top of irradiated fuel assemblies seated in the spent fuel storage pool racks.

b. less than the Technical Specification required ac electrical power sources operable, when in modes 4, 5 and when handling irradiated fuel in the secondary containment.

Prior to suspending crane operations, fuel assemblies shall be placed in a safe condition.

The reactor building crane is of the single trolley top running type, carried on two main girders. The girders have a rated lifting capacity of 125 short tons and a span of 113 ft 9 in. Power is applied by twin hoist motors through two gearboxes to the two drum gear rings, located on each end of the drum. In this manner, the hoist mechanism is duplicated. In normal operation, the twin hoist trains share the load, but each is separately able to carry the rated load at allowable code stresses, thus providing adequate safety should one gear train fail. Both hoist trains are provided with electrical and electromechanical type brakes; each of the latter is capable of sustaining the load should a mechanical failure occur in a gear train. Each mechanical brake is sized for 150 percent motor torque or 300 percent for redundant systems. (This is based on a required brake torque of 277.5 ft-lb, and a rating of each of the two 13-in. brakes of 550 ft-lb. The required brake torque, B_T, is calculated by using

$$B_T = 1.5 \times 33{,}000\ {}^{P_{hp}}/_{2\pi N}$$

where P_{hp} is the motor horsepower of 20, and N is equal to 570 rpm.)

The electrical brakes complement the mechanical brakes. The electrical brakes can limit the hoist-lowering speed to 1.6 fpm at rated load in the event of failure of both the redundant mechanical brakes. If there should also be a loss of normal power to the electrical brakes, an integrated alternator generates enough power to the units to prevent the lowering speed from exceeding the fully rated load speed.

For the main hoist, this speed is 4.7 fpm at rated load. The reactor building floor and the floor under the equipment hatch have sufficient strength to withstand the impact of a fully rated load at this speed.

The redundant wire rope system consists of two balanced reeving systems utilizing two individual wire ropes. These two wire ropes are reeved side by side from double-scoured drum groovings at each end of a single drum through the upper and lower block sheaves and to the double-sheave-type equalizer. Breakage of one cable system would reduce the factor of safety, but since each system is reeved to both sides of the bottom block and upper block system, there is no swinging or pendulum action of the block upon failure of one system. Equalizer sheaves are used in preference to equalizer bars so that ropes may more readily adjust to differences in length without the need for physical maintenance. Each of the equalizers is hung from a main pivot mechanism which is designed to be redundant within itself.

For the Fermi 2 crane, the wire rope safety factor for each single wire rope is a minimum of 10. This is determined by dividing the design rated load (125 tons) by the number of load-carrying parts (l6) and the efficiency factors (0.933) and comparing the result with the published breaking strength of 102 (nominal) tons for the 1-1/4 in. (nominal) diameter rope. The design of the dual reeving system is consistent with paragraph 3.f of BTP ASB 9-1.

In both the lower and upper blocks, the sheaves are mounted in a structural cage system having supporting plates on each side of each sheave. Thus, the load being carried by the sheave pin is shared by each of these support plates. Should a pin fail on any one particular sheave group, the adjacent sheave still maintains its integrity. This allows either reeving system to take over the entire load.

The main hook block is provided with a conventional hook, and the redundant feature is provided by two smaller hooks, each capable of sustaining 50 percent of the rated load at code stresses. The two additional hooks are individually mounted on their own pins and supported directly in the main block frame. They are intended for use only when handling the fuel cask.

To ensure against damage due to a tornado, the crane is provided with electrically operated locking bars that effectively connect the unloaded crane to the runway when it is not in use. These locking bars are capable of withstanding a tornado windforce of 410 lb/ft^2 intensity at a maximum of 90 percent of the yield strength of the crane components.

Earthquake protection is provided by restraints on the crane and trolley to prevent either from leaving its respective rails due to horizontal and/or vertical displacement. Seismic responses of the crane, based on its fundamental frequency in the vertical and two horizontal directions (perpendicular and parallel to the girder), have been calculated for the SSE and are 0.65g.

The crane is designed to accommodate SSE forces and deflections with the rated load suspended in the cask-hoisting position. Crane accelerations for the vertical SSE in the unloaded condition were also determined and found in all cases to be less than 1.0g. Seismic uplift forces are therefore not encountered.

The crane responses to the SSE, as determined above, are well below the design limits of the reactor building crane. Thus, the crane will remain within its restraints if subjected to an SSE.

Crane control can be either from the cab or by radio control. In the event that the crane cab becomes uninhabitable, control may be continued by means of the remote radio control provided. The only crane components that are actuated by the crane electrical control system and are an integral part of the mechanical load-retaining hoist system are the two shoe-type hoist holding brakes. The two electrical control components that actuate the hoist holding brakes are either the raise or lower hoist reversing contactors. If either the raise or lower hoist reversing contactor fails to open when called upon, the backup is the stop button in either the cab or in the radio control, which will interrupt the main power to the crane, causing the two independent hoist holding brakes to set and thereby stop the load.

To ensure that crane control can only be executed from one position at a time, a master control transfer switch is situated on the bridge. This switch must be manually operated by the operator and thus interrupts all of the control circuits so there can be no simultaneous operation of the crane from both the radio control and the cab control.

The crane control system is protected from actuation by signals from an outside source by use of a Security Start circuit. With this feature, the control system cannot be enabled until multiple conditions have been met which are unique to each receiver and its companion transmitter. To activate the equipment under control, the specific companion transmitter must be used. With this security start feature, there is no possibility of an outside source radio transmitter interfering with this system or causing inadvertent actuation since these foreign signals could not match the security circuit's multiple enabling conditions.

The crane test and surveillance programs include both preoperational tests and periodic testing, surveillance, and inspection programs.

Preoperational tests include crane hook certification to 100 percent overload, gear train no-load running tests, and complete functional tests after final crane assembly.

Periodic testing, surveillance, and inspection programs will be performed no more than 1 year prior to any usage of the crane. However, these tests and inspections will be performed just prior to each major refueling outage. Periodic testing will be conducted not more than 1 month prior to lifting of the first cask for a spent fuel transfer. The programs include magnetic particle or liquid penetrant examination of all hook surfaces; inspection of wire ropes for wear or damage, and measurements of wire rope diameters; other periodic testing, maintenance, and surveillance conducted in accordance with Occupational Safety and Health Administration (OSHA) requirements as set forth in 29 CFR 1910.179, Paragraphs (j), (k), (m), and (n); and periodic inspections as recommended by the crane manufacturer. Testing prior to refueling also includes a full test run of all motions of a typical fuel cask unloading and loading sequence.

The spent fuel cask-handling operation is performed under strict procedural control and under the direct supervision of the Shift Manager or his designated operator. The crane operator receives his instructions from the flagman by verbal communication. All operations that cannot be visually observed by the crane operator from his cab are transferred to radio control.

Personnel carrying out cask- and fuel-handling operations are qualified to meet the guidelines set forth in Regulatory Guide 1.8.

The reactor building crane is designed in accordance with the requirements of:

a. EOCI No. 61, Class A Service, and the structural guidelines of CMAA Specification No. 70

b. Seismic response spectra for Fermi 2

c. Material Specifications: ASTM; AISI; SAE; ASA

d. Electrical Specifications: N.E.C.; NEMA; IEEE; NBFU

e. Welding: AWS

f. Federal, State, and local codes, including OSHA.

Welding specifications used in the crane fabrication are as follows:

a. Manual shielded metal-arc welding (SMAW) in accordance with AWS D1.1 and AWS D14.1 for welding of structural steel of unlimited thickness and base metals of ASTM-A36, ASTM-A242, ASTM-A441, and ASTM-A572. The required preheat and interpass temperatures are as follows:

Plate Thickness (in.)	Minimum Preheat and Interpass Temperature (°F)		
Up to 3/4	50	50	
3/4 to 1-1/2	150	70	For FCAW
1-1/2 to 2-1/2	225	150	
Over 2-1/2	300	225	

(Reference: P&H welding procedure WP-SC of September 1972)

b. Flux cored arc welding (FCAW), same application as above

c. Submerged arc welding (SAW), same application as above, with preheat and interpass temperatures as for FCAW

d. Joint welding procedure classification tests were performed for all welding processes, including groove and fillet type welds

e. No postweld heat treatment was performed.

Girders, trolley frame, and general structures are constructed of ASTM, A-36 steel. The end ties are of ASTM, A-514 material.

9.1.4.2.3 Fuel Servicing Equipment

Two fuel-preparation machines are used to remove the channels from fuel assemblies and to reinstall the channels on fuel bundles. Additionally, the fuel preparation machines are used for fuel inspections and new fuel receipt/transfer activities. Strict administrative control on the fuel preparation machine's full-up end stop is required for personnel protection. These machines are designed to be removed from the pool for servicing.

The new-fuel transfer crane is a 1500 lb, wall-mounted, traveling-hinged boom crane which services the area (B, E, 15, 17) in Figure 9.1-3.

A new fuel uprighting stand is used to hold the steel shipping box in a vertical position while the fuel assembly is removed. A new-fuel inspection stand is used to restrain the fuel bundle in a vertical position for inspection. The inspection stand can hold two bundles. The new fuel uprighting stand and the inspection stand are approximately designated by point C,15 in Figure 9.1-3.

The general-purpose grapple is a small, hand-actuated tool used generally with the fuel. The grapple can be attached to the Reactor building auxiliary hoist and the auxiliary hoists on the refueling platforms. The general-purpose grapple or approved equivalent is used to remove new fuel from the vault, place it in the inspection stand, and transfer it to the fuel storage pool. It also can be used to shuffle fuel in the pool and to handle fuel during channeling.

A channel-handling boom with a spring-loaded takeup reel is used to assist the operator in supporting a portion of the weight after the channel is removed from the fuel assembly. The boom is set between the two fuel-preparation machines. With the channel-handling tool attached to the reel, the channel may be conveniently moved between fuel-preparation machines.

9.1.4.2.4 Servicing Aids

General area underwater lights are provided with a suitable reflector for downward illumination. Suitable light support brackets, independent of the platform, are furnished to support the portable lights in the reactor pressure vessel (RPV) to allow the light to be positioned over the area being serviced. Local area underwater lights are small-diameter lights for additional downward illumination. Drop lights are quartz lamps with no reflector and are used for intense radial illumination where needed. These lights are small enough in diameter to fit into fuel channels or control blade guide tubes. Portable underwater cameras and monitor are part of the plant optical aids. The transmitted image can be viewed on a monitor. This assists in the inspection of the vessel internals and general underwater surveillance in the RPV and fuel storage pool. A general-purpose clear plastic viewing aid that floats is used to break the water surface for better visibility.

Portable underwater vacuum/filter units are provided to assist in removing crud and miscellaneous particulate matter from the pool floor or from the RPV. These units may be completely submerged for extended periods. Fuel pool tool accessories are also provided to meet servicing requirements.

9.1.4.2.5 Reactor Vessel Servicing Equipment

Reactor vessel servicing equipment is supplied for safe handling of the vessel head and its components, including nuts, studs, bushings, and seals.

The head strongback is used for lifting the drywell head and for backup lifting of RPV head. The strongback is designed to keep the head level during lifting and transport. It is cruciform in shape with four equally spaced lifting points. The strongback is designed so that no single component failure can cause the load to drop or to swing uncontrollably. The head strongback meets the requirements of NUREG-0612. The strongback, including hook pins and turnbuckles, has been load tested to three times its rated capacity of 93 tons in accordance with ANSI N14.6-1978, Paragraph 6.3.

The RPV head strongback carousel combines the functions for stud tensioning/detensioning operations, closure stud nut and washer handling and storage (by supporting the Nut Rack), and the head strongback previously used for reactor pressure vessel head lifting and transport. The carousel meets the requirements of NUREG-0612. The carousel including hook pins and turnbuckles, has been load tested to three times its rated capacity of 117.3 tons in accordance with ANSI N14.6-1978, Paragraph 6.3.

A vessel nut-handling tool is provided. This tool handles four nuts and features a spring device to lift the nut and clear the threads.

The head-holding pedestals are designed to properly support the vessel head and permit seal removal and replacement, seal surface cleaning, and inspection. The mating surface between vessel and pedestal is selected to minimize the possibility of damaging the vessel head.

The RPV ventilation equipment consists of a portable unit that is attached to the RPV head for the purpose of removing trapped radioactive gases under the head during removal. After the head nuts and washers are removed, the RPV ventilation system is attached. As the head is raised, the trapped gases are drawn from the area under the head, passed through chemical filters, and exhausted. This eliminates possible inhalation doses to personnel during RPV head removal.

9.1.4.2.6 In-Vessel Servicing Equipment

The instrument strongback is attached to the reactor building crane auxiliary hoist and is used to lift replacement in-core detectors from their shipping containers.

The auxiliary hoist on the refueling platform is used with appropriate grapples to handle control rods, flux monitors, sources, and other internals of the reactor. Interlocks on both the grapple hoist and auxiliary hoist are provided for safety purposes. The refueling interlocks are described and evaluated in Subsection 7.6.1.1.

The Reactor Cavity Work Platform is used during the In-service Inspection of the vessel and other refueling outage related activities. This platform remains on the Reactor Building Fifth Floor during normal operation, secured safely to the reactor cavity concrete shield blocks. During refueling outages the platform will be installed in the reactor cavity, supported by eight (8) legs resting freely on the refueling deck. The leak-tight work area of the platform remains partially submerged in the flooded reactor cavity. The jib crane associated with this platform can be used to handle objects weighting up to 500 pounds.

The Reactor Cavity Work Platform is considered Seismic Category II/I since it is not required to ensure the three requirements of Category I system as discussed in Section 3.2.1. This Work Platform is designed to accommodate safe-shutdown earthquake (SSE) forces and deflections. Dynamic analysis using the Fermi 2 site characteristics for the refueling floor of the reactor building verifies that the Reactor Cavity Work Platform can withstand the SSE for the Fermi 2 site and will remain supported by the eight legs resting on the refueling deck.

The lifting lugs for the Reactor Cavity Work Platform are designed so that no single component failure can cause the load to drop or to swing uncontrollably. The lifting devices meet the requirements of NUREG-0612. The lift and handling system, including hook, pins and turnbuckles, has been load tested to three times its rated capacity of approximately 28 tons, in accordance with ANSI N14.6-1978, Paragraph 6.3.

9.1.4.2.7 Refueling Equipment

The refueling platform is used as the principal means of transporting fuel assemblies between the reactor well and the fuel storage pool. The platform travels on tracks extending along each side of the reactor well and the fuel storage pool. The platform supports the refueling grapple and auxiliary hoists. The grapple is suspended from a trolley system that can traverse the width of the platform. Platform operations are controlled from an operator station on the trolley. The platform contains a position-indicating system that indicates the position of the fuel grapple over the core.

The refueling platform is designed to accommodate safe-shutdown earthquake (SSE) forces and deflections. It has been designed to withstand a 1.5g horizontal and a 0.14g vertical acceleration based on static analysis. Dynamic analysis using the Fermi 2 site characteristics for the refueling floor of the reactor building verifies that the refueling platform can withstand the SSE for the Fermi 2 site and will remain on the rails. However, the refueling platform is considered Seismic Category II/I since it is not required to ensure the three requirements of Category I system as discussed in Subsection 3.2.1.

To ensure access to the drywell for inspection and maintenance during spent fuel transfer, a refueling shield bridge is utilized. A U-shaped trough lined with a nominal 6 in. of lead is placed across the gap between the RPV flange and the inner edge of the fuel transfer canal. When in place, the refueling shield bridge provides sufficient shielding to ensure continuous access to the drywell during spent fuel transfer.

9.1.4.2.8 Storage Equipment

Specially designed fuel storage racks are provided. For a description of fuel storage racks and fuel arrangement, see Subsections 9.1.1 and 9.1.2.

If sipping indicates a fuel assembly with defects of a large enough magnitude, the defective-fuel assembly is placed in a defective-fuel storage container. The defective-fuel storage containers (containing defective fuel) are stored in the Dual Purpose cells of the fuel storage racks. These are used to isolate leakage of defective fuel while in the fuel storage pool and during shipping. A defective-fuel storage container containing a fuel bundle may be moved.

The channel is removed from the defective-fuel assembly before it is placed in the container.

9.1.4.2.9 Under Reactor Vessel Servicing Equipment

The necessary equipment to remove several control rod drives (CRDs) during a refueling outage is provided. An equipment-handling platform with a rectangular open center is provided. This platform can rotate to provide space under the vessel so that a CRD can be lowered and removed. If a control rod guide tube must be removed, the thermal sleeve within the CRD housing must be rotated to disengage the guide tube. A thermal sleeve tool that permits installation or complete removal at the thermal sleeve is provided for this purpose. Special tools and instruments to service and test individual control rod hydraulic units are also provided.

Miscellaneous tools are provided to install and remove the neutron detectors. A drain can be opened after in-core insertion to drain any residual water. Correct seating of the in-core string is indicated when drainage ceases.

Additional tools and servicing equipment not covered in these paragraphs are listed in Table 9.1-5.

9.1.4.2.10 Dry Storage Cask Servicing Equipment

A variety of ancillary equipment is used to lift, move, and prepare the dry storage transfer cask and MPC as discussed in the HI-STORM 100 System FSAR. This includes such items as lifting devices, (e.g., lift yoke, lift links, and slings), draining, drying, and backfill equipment, and welding equipment. After a dry storage cask loading campaign is completed the ancillary equipment is either removed from the site or stored in the dry cask equipment storage building near the ISFSI.

9.1.4.3 Description of Fuel Transfer

The fuel handling system provides a safe and effective means for transporting and handling fuel from the time it reaches the plant until it leaves the plant after postirradiation cooling. The previous subsection described the equipment and methods utilized in fuel handling. The following paragraphs describe the integrated fuel transfer system.

9.1.4.3.1 Arrival of Fuel on the Fermi Site

Fuel arrives on the Fermi site by truck. The fuel elements are shipped in steel boxes that support the fuel element along its entire length. The stainless steel box is contained in a stainless steel overpack. Cushioning material and a support frame positions the stainless steel box in the overpack. Two fuel assemblies are contained in each shipping container. Each shipping container is designed to ensure subcritical geometry in handling as required by 10 CFR 71.

A specific criticality safety analysis, as identified in reference 12 herein, was performed for safe storage, handling and transport of GE BWR nuclear fuel shipping containers during new fuel receipt for Fermi 2. A new generic criticality evaluation, identified as reference 16 herein, has been performed for the new stainless steel shipping container. The updated analysis provides assurance that an inadvertent criticality is highly improbable during onsite storage, handling and transportation of new fuel within shipping containers. This meets the criterion of GDC 62, "Prevention of Criticality in Fuel Storage and Handling." The former safety analysis provided is the bases for Fermi 2's exemption from the requirements of 10 CFR 70.24, as granted by the Nuclear Regulatory Commission and identified by reference numbers 13 and 14 herein. The exemption requires criticality monitoring in areas where fuel is handled outside the inner metal shipping containers (the refuel floor). In contrast, the exemption allows administrative controls, such as the use of geometrically safe configurations as bound by the aforesaid former safety analysis for areas in which the new fuel remains in the inner metal shipping containers (the yard and the reactor building up to the refuel floor). The updated criticality evaluation provides for similar controls. Therefore, monitoring for an inadvertent criticality while handling or transporting new fuel is not required in the yard or during transport to the refuel floor.

The fuel can be handled by wearing gloves and other protective clothing. The containers are lifted to the refueling floor through the equipment hatch using the reactor building crane. Once the fuel is removed from the inner shipping containers on the refuel floor, criticality monitoring is required. Monitoring for an inadvertent criticality event on the refuel floor, is provided by two redundant detectors (D21-N115 and D21-N117). These detectors are high sensitivity gamma ray detectors (GM tubes) and are located on the east wall approximately 9 ft to 12 ft in the air. The alarm trip setting on these detectors is in the proscribed range of 5-20 mR/hr, which is adequate to detect the minimum accident of concern as described in 10 CFR 70.24 and ANSI/ANS 8.3-1986. The alarm circuitry of these detectors is arranged in a fail safe mode such that any malfunction of the detectors or a loss of power results in an alarm condition. Additionally, the detectors have a meter pegging circuit which precludes a downscale low reading (no foldover) during saturation of the GM tube due to high intensity radiation fields. Periodic performance tests are conducted to confirm instrument response to radiation and the operability of the alarm signal generator.

The aforementioned design meets the criterion of GDC 63, "Monitoring Fuel and Waste Storage." Additionally, Fermi 2 personnel are instructed to evacuate areas in which radiation or criticality alarms are activated. Evacuation of plant areas is periodically tested by the conduct of emergency response drills.

Depending on the laydown area, the metal containers can be placed in the new fuel uprighting stand using the auxiliary hoist, the new-fuel transfer crane, or a mobile crane. Any of these cranes can be used to transfer fuel from the new fuel uprighting stand to the inspection stand and to the fuel pool. Transfer of fuel from the new fuel storage vault can be done only with the auxiliary hoist. However, due to the lack of criticality detector redundancy, Fermi 2 does not strictly comply with 10 CFR 70.24 with regard to the new fuel storage vault. Accordingly, the spent fuel pool is used for storage of new fuel rather than the new fuel storage vault.

9.1.4.3.2 Refueling Procedure

Figure 9.1-28 defines, in general, the steps that make up a refueling outage. The heavy lines on the chart define the critical path in a normal outage. Deviations from this path may be encountered under normal circumstances for various reasons, such as scheduling and convenience. The reactor shall be determined to have been subcritical for at least 60 hours by verification of the date and time of subcriticality prior to movement of irradiated fuel in the reactor pressure vessel.

9.1.4.3.3 Departure of Fuel From the Fermi Site

Spent fuel assemblies may be shipped off-site in two different ways: 1) directly from the spent fuel pool into a shipping cask or 2) after a period of storage at the ISFSI and then in a shipping cask. For direct shipping, fuel assemblies from the spent fuel pool are conveyed by the fuel-handling bridge crane into the spent fuel cask located in the fuel storage pool. After insertion into the spent fuel cask, the cask head is replaced, and the flooded container with fuel is raised out of the pool by the reactor building crane for transfer to the cleaning station. The cleaning station is a depression in the floor adjacent to the pool and is designed for 1000 pounds per square foot load. The cask head is bolted down, and the cask is thoroughly cleaned. Final transfer from the cleaning station down the shaft to the vehicle-loading station is by crane. The cask is laid on its side on a flatbed, one to a flatbed, for return to the off-site fuel processing/storage facility.

For fuel to be stored at the ISFSI before shipping off-site, fuel assemblies from the spent fuel pool are conveyed by the fuel-handling bridge crane into the multi-purpose canister (MPC) while inside a HI-TRAC transfer cask. The HI-TRAC containing the fuel-loaded MPC will be removed from the spent fuel pool and moved to a location in the Dryer-Separator Storage Pool for additional processing activities. The HI-TRAC with the fuel-loaded MPC is then transferred to the Cask Transfer Facility (CTF) outside the Reactor Building. At the CTF, the fuel-loaded MPC will be transferred from the HI-TRAC to the storage overpack (HI-STORM). The HI-STORM with the fuel-loaded MPC is moved by a Vertical Cask Transporter (VCT) to the ISFSI pad, which is described in Section 9.1.2.2.3. The fuel will remain at the ISFSI pad until it is ready to be shipped off-site in an NRC-licensed transportation cask pursuant to 10 CFR 71.

9.1.4.4 Control of Heavy Loads in Close Proximity to Irradiated Fuel or Safety Systems

The NRC in Reference 10 concluded that Fermi 2 meets the guidelines of NUREG-0612 for the handling of heavy loads near spent fuel. Travel paths for the handling of these loads have been graphically described, and the procedures controlling adherence to these travel paths have been identified.

The reactor building crane, Subsection 9.1.4.2.2, main hoist is single-failure proof. There are no heavy-load handling applications at Fermi 2 other than those that can be handled by the main hoist, that require handling within single-failure-proof guidelines. In order to meet NUREG-0612 guidelines, the reactor building crane auxiliary hoist has a load-limit feature that restricts the hoist from handling heavy loads (greater than 2000 lb) over the spent fuel pool and open reactor vessel.

The training and qualification of crane and hoist operators are in accordance with NUREG-0612 guidelines. The testing, inspection, and maintenance of these cranes and hoists also conform to these guidelines. Hoisting of all heavy loads around critical equipment will be covered by written procedures.

Cranes, hoists, and slings used to handle heavy loads around critical equipment are in conformance with the standards specified in NUREG-0612. The matrix analysis performed on all heavy load hoist combinations has identified all potentially affected safety system components and has defined the hazard elimination category under the NUREG-0612 guidelines for each of these components.

The special lifting devices at Fermi 2 include the head strongback, the dryer/separator lifting device, the spent fuel transfer cask lifting yoke and the RPV head strongback carousel. These special lifting devices, except for the lifting yoke, were found acceptable by the NRC in Reference 10. All lifts of the spent fuel transfer cask are made with a single-failure-proof lifting system to ensure the likelihood of a drop of either load is so low as to be considered not credible. A single-failure-proof lifting system consists of the crane, lifting devices (e.g., lifting yoke, lift links or brackets, slings, etc.), and interfacing lift points (e.g., cask lifting trunnions and MPC lift cleats). The design of the RB crane lifting system for lifts of a spent fuel transfer cask or canister inside the power plant meets the guidelines for a single-failure-proof lifting system in NUREG-0612, Section 5.1.6.

Periodic testing of these special lifting devices meets the guidelines of NUREG-0612 by following ANSI N14.6-1978 and the NRC's interpretation of the NUREG-0612 guidelines provided with Reference 11. Testing and/or inspection of the RB crane lifting system components used to lift and move dry spent fuel storage cask equipment inside the power plant is performed in accordance with NUREG-0612, Section 5.1.6.

9.1 FUEL STORAGE AND HANDLING

REFERENCES

1. Holtec Report HI-992154, "Licensing Report for Spent Fuel Rack Installation at Fermi Unit 2", (DECo File Number R1-7696)

1a. Letter from Holtec to B. Cummings, Impact of Proposed Rack Height Reduction on Existing Calculations, March 17, 2006 (DECo File Number P1-16952)

2. NRC Position Paper, subject: "Fuel Pool Storage and Handling Application," April 1978 and amended January 1979.

3. Joseph Oat Corporation, Licensing Input on High Density Spent Fuel Racks for Fermi II Project, Report TM-586, Camden, New Jersey.

3a. Deleted

3b. Holtec Proprietary Report HI-961465 – WPMR Analysis User Manual for Pre&Post Processors & Solver, August, 1997.

3c. Singh, K.P. and Soler, A.I., Dynamic Coupling in a Closely Spaced Two-Body System Vibrating in Liquid Medium: The Case of Fuel Racks, 3rd International Conference on Nuclear Power Safety, Keswick, England, May 1982.

3d. Fritz, R.J., The Effects of Liquids on the Dynamic Motions of Immersed Solids, Journal of Engineering for Industry, Trans. of the ASME, February 1972, pp 167-172.

4. S. Levy and J. P. D. Wilkinson, The Component Element Method in Dynamics with Application to Earthquake and Vehicle Engineering, McGraw-Hill, New York, New York, 1976.

5. Joseph Oat Corporation, A Method for Hydro-Thermal Analysis of High Density Fuel Racks, Standard Document No. 20, Camden, New Jersey.

6. Southern Science Applications, Inc., Benchmark Calculations for Spent Fuel Storage Racks, Report SSA-127, Dunedin, Florida.

7. Global Nuclear Fuel, GE-14 Boraflex Spent Fuel Storage Rack Criticality Analysis for Fermi 2 Unit 2. (R1-7976)

7a. General Electric Company, General Electric Standard Application for Reactor Fuel, Latest Revision.

7b. Global Nuclear Fuel, GE-14 Boral Spent Fuel Storage Rack Criticality Analysis for Fermi 2 Unit 2. (R1-7687)

7c. Holtec Report HI-992207, Bulk SFP Thermal-Hydraulic Analyses For Reracking of Fermi Unit 2. (R6-422)

7d. Global Nuclear Fuel, GE-14 Defective Fuel Storage Rack Criticality Analysis for Fermi 2 Unit 2. (R1-7686)

8. Letter from G. W. Knighton, NRC, to H. Tauber, Detroit Edison, April 26, 1976.

9. Detroit Edison Co., "Summary Report, FSAR Stage Open Item, Fuel Cask Storage Pool Reactor Building, Crane Redundancy Fuel Cask Drop Accident," EF2-25622, June 25, 1974.

9.1 FUEL STORAGE AND HANDLING

REFERENCES

10. Letter from B. J. Youngblood, NRC, to Wayne Jens, Detroit Edison, subject: Issuance of Supplement No. 5 to NUREG-0798-Fermi 2, March 21, 1985.

11. Letter from B. J. Youngblood, NRC, to H. Tauber, Detroit Edison, subject: Control of Heavy Loads at Fermi 2 in Accordance with NUREG-0612, November 1, 1983.

12. Letter from General Electric (RDW:98-037) to Detroit Edison, "Detroit Edison Company Fuel Handling Criticality Assessment," dated April 9, 1998. Superseded by Reference 16.

13. Detroit Edison Letter NRC-98-0063, "Request for Exemption from 10 CFR 70.24, Criticality Accident Requirements," dated April 17, 1998.

14. NRC Letter, "Fermi 2 - Issuance of Exemption from the Requirements of 10 CFR 70.24 (TAC NO. MA1645)," dated June 2, 1998.

15. Detroit Edison Design Calculation DC-4231 Vol I, “Loss of Decay Heat Removal – High Density Fuel Storage Pool.”

16. RAJ II Safety Analysis Report, Docket No. 71-9309, Chapter 6, Criticality Evaluation.

17. NUREG-0612, “Control of Heavy Loads at Nuclear Power Plants,” U.S. NRC, July, 1980.

18. HI-STORM 100 System 10 CFR 72 Certificate of Compliance 1014, Amendment 5.

19. HI-STORM 100 System 10 CFR 72 Final Safety Analysis Report, Revision 7.

20. Detroit Edison Company Independent Spent Fuel Storage Installation 10 CFR 72.212 Evaluation Report, as updated.

21. NRC Order EA-12-051, Order Modifying Licenses with Regard to Reliable Spent Fuel Pool Instrumentation.

22. TRVEND 24MCGNF3FTRT0211, GNF3 – Boral and Boraflex Fuel Storage Rack Criticality Analyses for Fermi Unit 2.

23. Branch Technical Position ASB 9-2, “Residual Decay Energy for Light-Water Reactors for Long-Term Cooling.” Attached to NUREG-0800, Section 9.2.5 (NRC ADAMS Accession# ML052350549).

24. W3F1-2004-0102, Supplement to Amendment Request NPF-38-249, Extended Power Uprate Waterford Steam Electric Station, Unit 3 (NRC ADAMS Accession# ML043010238).

25. WATERFORD STEAM ELECTRIC STATION, UNIT 3 – ISSUANCE OF AMENDMENT RE: EXTENDED POWER UPRATE (TAC NO. MC1355) Dated April 15, 2005 (NRC ADAMS Accession# ML051030068).

TABLE 9.1-1 FUEL POOL COOLING AND CLEANUP SYSTEM

Total pool, well, and pit volume	107,000 ft^3	
Fuel storage pool net water volume[c]	42.030 ft^3	
Operating heat load	9.12 x 10^6 Btu/hr	
Design heat load[c]	16.66 x 10^6 Btu/hr	
Maximum heat load (core offload)[c]	42.65 x 10^6 Btu/hr	
	Fuel Pool Cooling Water Pumps	
Quantity	2	
Type	Horizontal, centrifugal	
Design flow/TDH (each)	550 gpm/300 ft	
Motor hp	60 hp	
	Fuel Pool Cooling Heat Exchangers	
Quantity	2	
Design code	ASME B&PV, Section VIII	
	Shell Side	Tube Side
Fluid circulated	RBCCW[a]	Spent fuel pool water
Sizing Temperature	95 °F	125 °F
Sizing Fluid flow	800 gpm	550 gpm
Number of passes	1	2
Material	CS, SA-106B	SS-304, SA-249
Design system pressure	150 psig	200 psig
Design system temperature	150 °F	150 °F
Spent Fuel Pool Cooling Capacity of FPCCS		
FPCCS to RBCCW Inlet temperature differential	30 °F	55 °F
Cooling Capacity, Btu/hr:		
1 pump/1 H-X, design service rated	4.56 x 10^6	8.33 x 10^6
2 pump/2 H-X, design service rated	9.12 x 10^6	16.66 x 10^6

Fuel Pool Filter-Demineralizers

Type	Pressure precoat
Quantity	2
Design filter area	270 ft^2
Filter capacity	550 gpm
Maximum pressure drop	30 psi
Design code	ASME B&PV, Section VIII

TABLE 9.1-1 FUEL POOL COOLING AND CLEANUP SYSTEM

Holding pump flow	150 gpm
Precoat flow	>400 gpm

Spent Fuel Pool Cooling Capacity of RHR[b]

RHR to RHRSW Inlet ΔT	36 °F	49 °F	61 °F
Cooling capacity, Btu/hr			
RHR/FPC-Assist @ 3,500 gpm	30.72×10^6	42.22×10^6	52.51×10^6
RHR/SDC @ 10,000 gpm	41.6×10^6		

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[a] Maximum design temperature of RBCCW is 95°F at 85°F lake water temperature. When lake water temperature is 60°F or below, the RBCCW is controlled to 70°F.

[b] All RHR design capacity values assume 9,000 gpm RHR Service Water flow and fully fouled (service rated) heat exchanger tubes.

[c] These values assume additional storage locations are added in the spent fuel pool to be consistent with Tables 9.1-2 and 9.1-3.

TABLE 9.1-2a FRACTIONAL DECAY HEAT VERSUS TIME AFTER SHUTDOWN, 5.2 YEARS' IRRADIATION, ONE-THIRD CORE, 18-MONTH CYCLE WITH EMERGENCY CORE OFFLOAD AT 3430 MWt AND 3486 MWt

Time After Shutdown, t_s (days)	T_s (sec)	$\frac{P}{P_o}$	Number of Assemblies Discharged to Pool	Decay Heat per Discharge QDKP[1] 3430 MWt	Decay Heat per Discharge QDKP[2] 3486 MWt
1.08E+04	9.33E+08	6.109E-05	220	0.0603	0.0399
1.02E+04	8.81E+08	6.333E-05	228	0.0648	0.0429
9.67E+08	8.35E+08	6.563E-05	224	0.0660	0.0437
9.21E+03	7.96E+08	6.763E-05	228	0.0692	0.0458
8.27E+03	7.15E+08	7.193E-05	176	0.0568	0.0376
7.48E+03	6.46E+08	7.573E-05	220	0.0748	0.0495
6.93E+03	5.99E+08	7.853E-05	224	0.0790	0.0522
6.38E+03	5.51E+08	8.138E-05	224	0.0818	0.0541
5.40E+03	4.67E+08	8.434E-05	224	0.0849	0.0561
6.29E+03	4.57E+08	8.746E-05	224	0.0879	0.0582
4.74E+03	4.10E+08	9.063E-05	224	0.0911	0.0603
4.20E+03	3.63E+08	9.395E-05	200	0.0844	0.0558
3.65E+03	3.15E+08	9.740E-05	200	0.0875	0.0579
3.10E+03	2.68E+08	1.011E-04	200	0.0908	0.0601
2.55E+03	2.20E+08	1.053E-04	200	0.0945	0.0628
2.01E+03	1.74E+08	1.112E-04	200	0.0998	0.0670
1.46E+03	1.26E+08	1.237E-04	200	0.1111	0.0771
9.12E+02	7.88E+07	1.627E-04	200	0.1460	0.1114
3.65E+02	3.15E+07	3.423E-04	200	0.3074	0.2742
6.50E+00	5.62E+05	3.107E-03	764	10.6600	10.653
		Total	4780	12.50	11.959

[1] 3430 MWt QDKP values obtained using uncorrected BTP ASB 9-2 (Rev 5 of Reference 7c).
[2] 3486 MWt decay heat values represent GNF3 fuel evaluated using corrected BTP ASB 9-2 (References 23-25).

TABLE 9.1-2b FRACTIONAL DECAY HEAT VERSUS TIME AFTER SHUTDOWN, 5.74 YEARS' IRRADIATION, ONE-THIRD CORE, 24-MONTH GNF3 EQUILIBRIUM CYCLE WITH EMERGENCY CORE OFFLOAD AT 3486 MWt

Time After Shutdown, t_s (days)	T_s (sec)	$\frac{P}{P_o}$	Number of Assemblies Discharged to Pool	Decay Heat per Discharge QDKP[1] 3486 MWt
11.32E+03	9.782E+08	3.834E-05	184	0.0322
10.59E+03	9.151E+08	4.022E-05	244	0.0448
9.861E+03	8.520E+08	4.219E-05	244	0.0470
9.131E+03	7.889E+08	4.426E-05	244	0.0493
8.400E+03	7.258E+08	4.643E-05	244	0.0517
7.670E+03	6.627E+08	4.871E-05	244	0.0542
6.939E+03	5.995E+08	5.110E-05	244	0.0569
6.209E+03	5.364E+08	5.360E-05	244	0.0597
5.478E+03	4.733E+08	5.623E-05	244	0.0626
4.748E+03	4.102E+08	5.899E-05	244	0.0657
4.017E+03	3.471E+08	6.190E-05	244	0.0689
3.287E+03	2.840E+08	6.502E-05	244	0.0724
2.556E+03	2.209E+08	6.879E-05	244	0.0766
1.826E+03	1.577E+08	7.588E-05	244	0.0845
1.095E+03	9.467E+07	1.038E-04	244	0.1155
3.65E+02	3.155E+07	3.004E-04	244	0.3344
6.50E+00	5.616E+05	3.056E-03	764	10.653
		Total	4608[2]	11.930

[1] Decay heat values obtained using corrected BTP ASB 9-2 (Rev 8 of Reference 7c).

[2] Amendment 141 Licensed capacity.

TABLE 9.1-3a CUMULATIVE POOL HEAT LOAD AND QUANTITY OF FUEL STORED IN POOL AT END OF NORMAL 18-MONTH REFUELING CYCLE AT 3430 MWt AND 3486 MWt

Time After Initial Discharge (years)	Decay Heat per Discharge QDKP[1] (MWt)	Quantity of Fuel Stored After Discharge (assemblies)	Bulk Pool Heat Load After Discharge 3430 MWt[1]	Bulk Pool Heat Load After Discharge 3486 MWt[2]
30.0	0.060	220	0.060	0.0394
28.5	0.064	448	0.124	0.0817
27.0	0.065	672	0.189	0.125
25.7	0.068	900	0.257	0.170
23.2	0.056	1076	0.313	0.207
21.0	0.074	1296	0.387	0.256
19.5	0.078	1520	0.465	0.308
18.0	0.081	1744	0.546	0.361
16.5	0.084	1968	0.630	0.417
15.0	0.087	2192	0.717	0.474
13.5	0.090	2416	0.807	0.534
12.0	0.083	2616	0.890	0.589
10.5	0.086	2816	0.977	0.646
9.0	0.090	3016	1.066	0.705
7.5	0.093	3216	1.160	0.767
6.0	0.098	3416	1.257	0.832
4.5	0.106	3616	1.363	0.905
3.0	0.129	3816	1.493	1.000
1.5	0.218	4016	1.711	1.183
0.0106	4.551	4276	6.262	5.728

[1] Decay heat obtained using uncorrected BTP ASB 9-2 (Rev 5 of Reference 7c).
[2] Decay heat for GNF3 obtained using corrected BTP ASB 9-2 (References 23-25).

TABLE 9.1-3b GNF3 CUMULATIVE POOL HEAT LOAD AND QUANTITY OF FUEL STORED IN POOL AT END OF NORMAL 24-MONTH REFUELING CYCLE AT 3486 MWt

Time After Initial Discharge (years)	Decay Heat per Discharge QDKP[1] (MWt)	Quantity of Fuel Stored After Discharge (assemblies)	Bulk Pool Heat Load After Dicharge 3486 MWt
32.0	0.031	184	0.031
30.0	0.044	428	0.075
28.0	0.046	672	0.121
26.0	0.048	916	0.169
24.0	0.051	1160	0.220
22.0	0.053	1404	0.273
20.0	0.056	1648	0.328
18.0	0.058	1892	0.386
16.0	0.061	2136	0.447
14.0	0.064	2380	0.512
12.0	0.067	2624	0.579
10.0	0.071	2868	0.650
8.0	0.074	3112	0.724
6.0	0.080	3356	0.803
4.5	0.094	3600	0.897
2.0	0.168	3844	1.066
0.0103	4.334	4088	5.400

[1] Decay heat obtained using corrected BTP ASB 9-2 (Rev 8 of Reference 7c).

TABLE 9.1-4 HAS BEEN INTENTIONALLY DELETED

TABLE 9.1-5 TOOLS AND SERVICING EQUIPMENT

Fuel Servicing Equipment

Fuel-preparation machines
New fuel inspection stand
Channel bolt wrenches
Channel-handling tool

Fuel inspection fixture

General-purpose grapples

Servicing Aids

Pool tool accessories
Actuating poles
General area underwater lights
Local area underwater lights
Drop lights
Underwater camera and monitor system
Underwater vacuum/filter units
Viewing aids
Lights support brackets
In-core detector cutting tool
In-core manipulator

Reactor Pressure Vessel Servicing Equipment

RPV servicing tools
Steam line plugs
Shroud head bolt wrenches
RPV nut-handling tool
Head-holding pedestals
Head nut plus washer racks
Head stud rack
Dryer-separator sling
Head strongback
Steam line plug installation tool
RPV head ventilation equipment
Reactor Cavity Work Platform
RPV Head Strongback Carousel

In-Vessel Servicing Equipment

Instrument strongback
Control rod grapple
Control rod guide tube grapple
Fuel support grapple
Grid guide
Control rod latch tool
Instrument-handling tool
Orifice grapple (peripheral)
Control rod guide tube seal
In-core guide tube seals
Orifice holder (peripheral)
Blade guides

Refueling Equipment

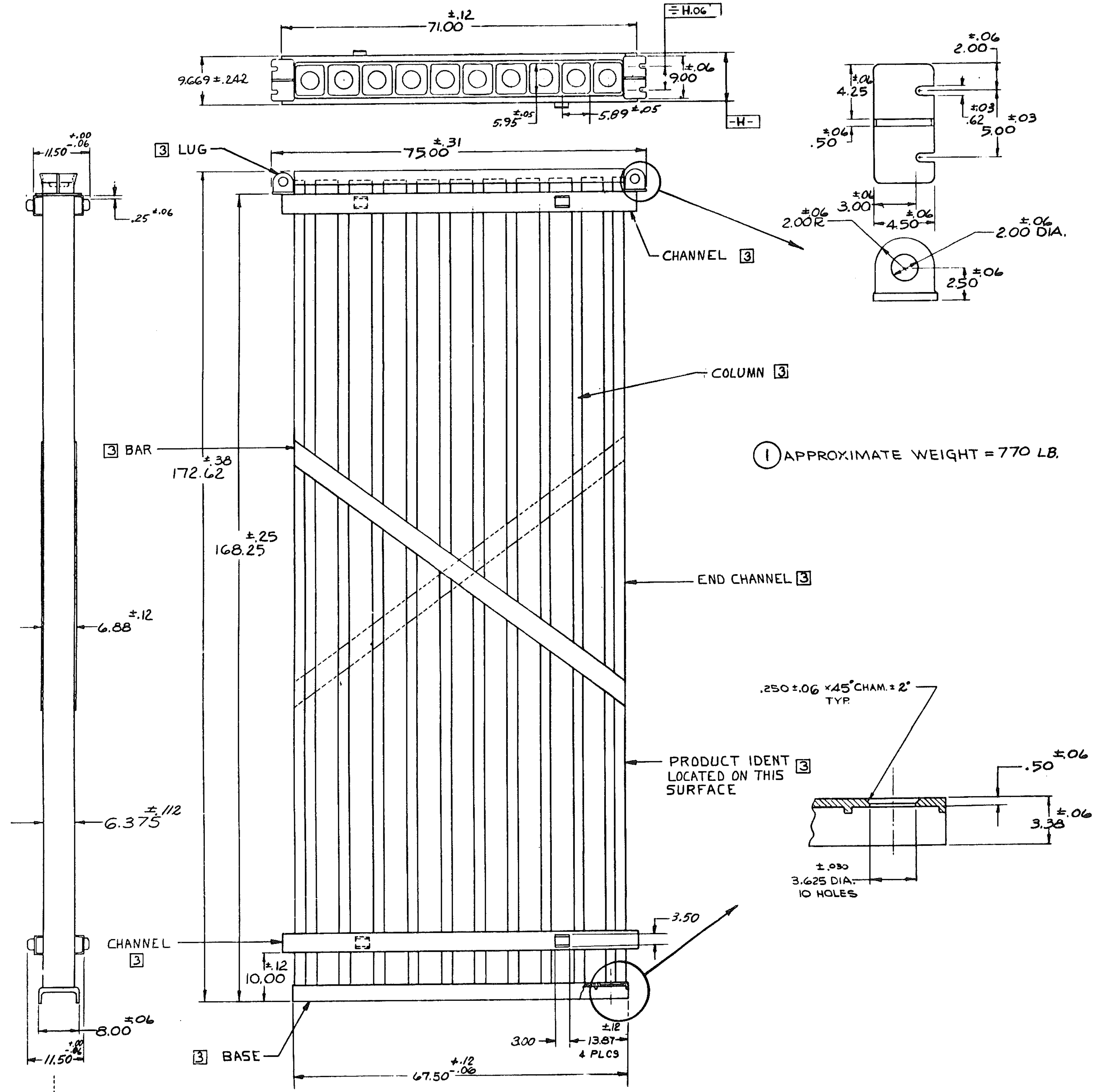
Refueling equipment servicing tools
Refueling platform equipment
Refueling shield bridge

Storage Equipment

Spent fuel storage racks
Storage racks (control rod)
Defective-fuel storage containers

Under Reactor Pressure Vessel Servicing Equipment

CRD servicing tools
CRD hydraulic system tools
Neutron monitoring system servicing tools
CRD handling equipment
Equipment-handling platform
Thermal sleeve installation tool
In-core flange seal test plug



GENERAL ELECTRIC COMPANY DRAWING NO. 922D173, REV. C

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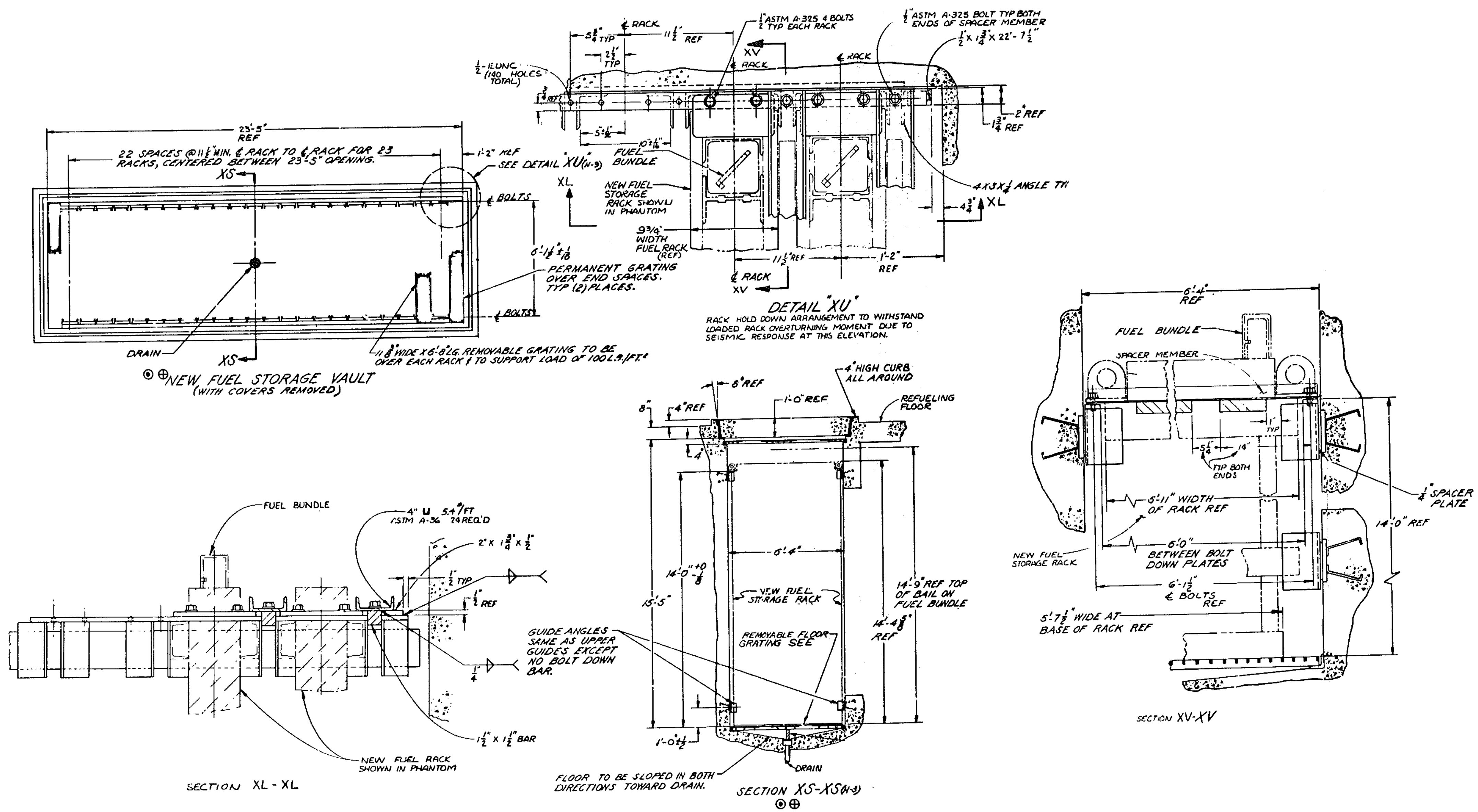
FIGURE 9.1-1

NEW-FUEL STORAGE RACK



GENERAL ELECTRIC COMPANY DRAWING NO. 762E156, REV. A

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FIGURE 9.1-2

NEW-FUEL STORAGE VAULT

Figure Intentionally Removed
Refer to Plant Drawing A-2003-01

FIGURE 9.1-3, SHEET 1

REFUELING FACILITIES

Figure Intentionally Removed
Refer to Plant Drawing A-2003-02

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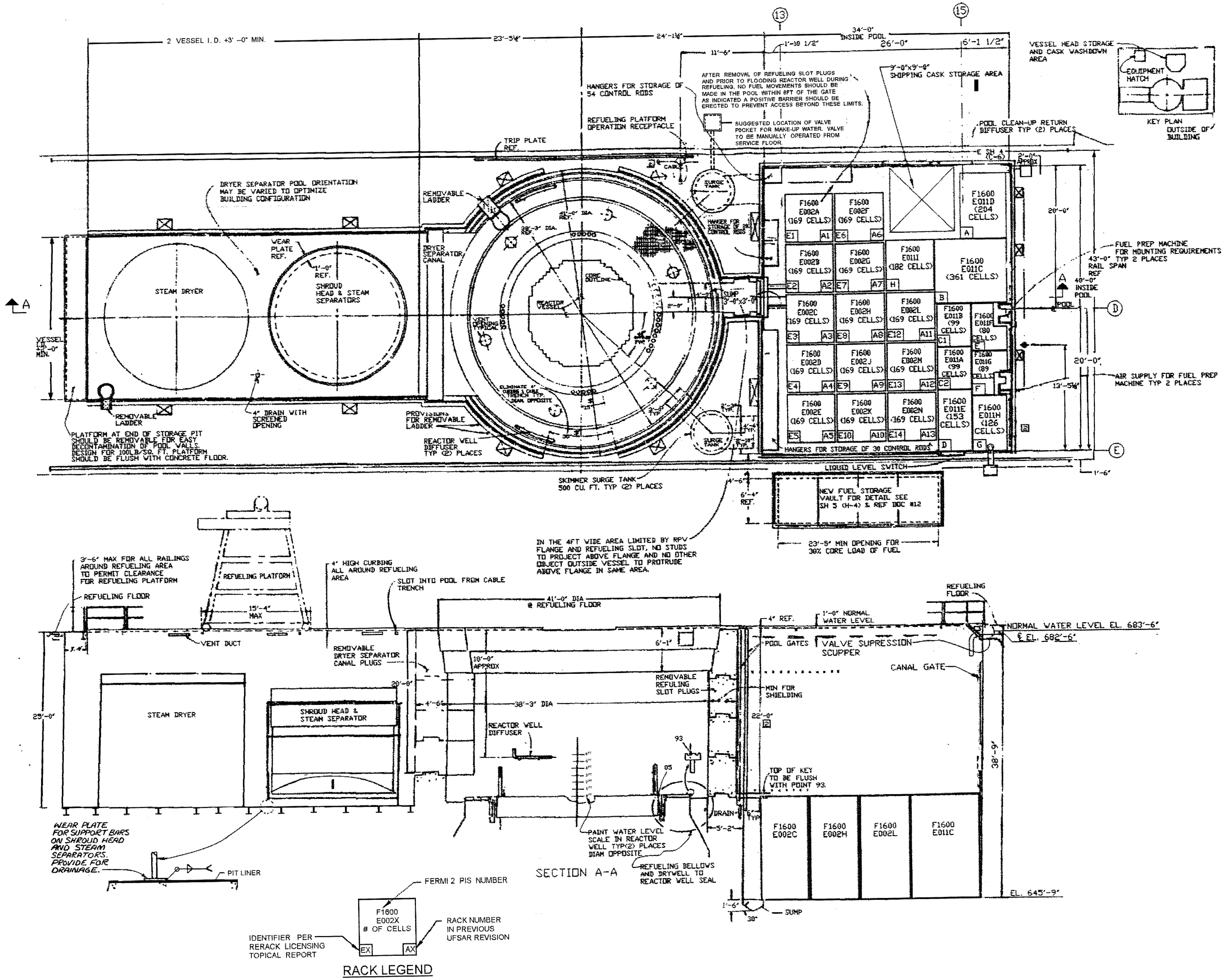
FIGURE 9.1-3, SHEET 2

REFUELING FACILITIES



NOTES:

1. FUEL POOL FLOOR LOADING SHOULD INCLUDE WEIGHT OF STORED FUEL ELEMENTS.
2. NEW FUEL STORAGE VAULT FLOOR GRATE LOADING, 1,500#/SQ. FT.
3. RAIL INSTALLATION TO BE DESIGNED FOR 10,000#/ WHEEL WITH 10' -0" MIN, WHEEL SPAN.
4. APPROX. SIZE & WEIGHT OF SHIPPING CASK 7' -0" X 18' -6" X 100 TON FLOOR REINFORCEMENT SHOULD BE ADEQUATE TO SUPPORT 100 TON OR REACTOR BUILDING CRANE RATING, WHICH EVER IS GREATER.

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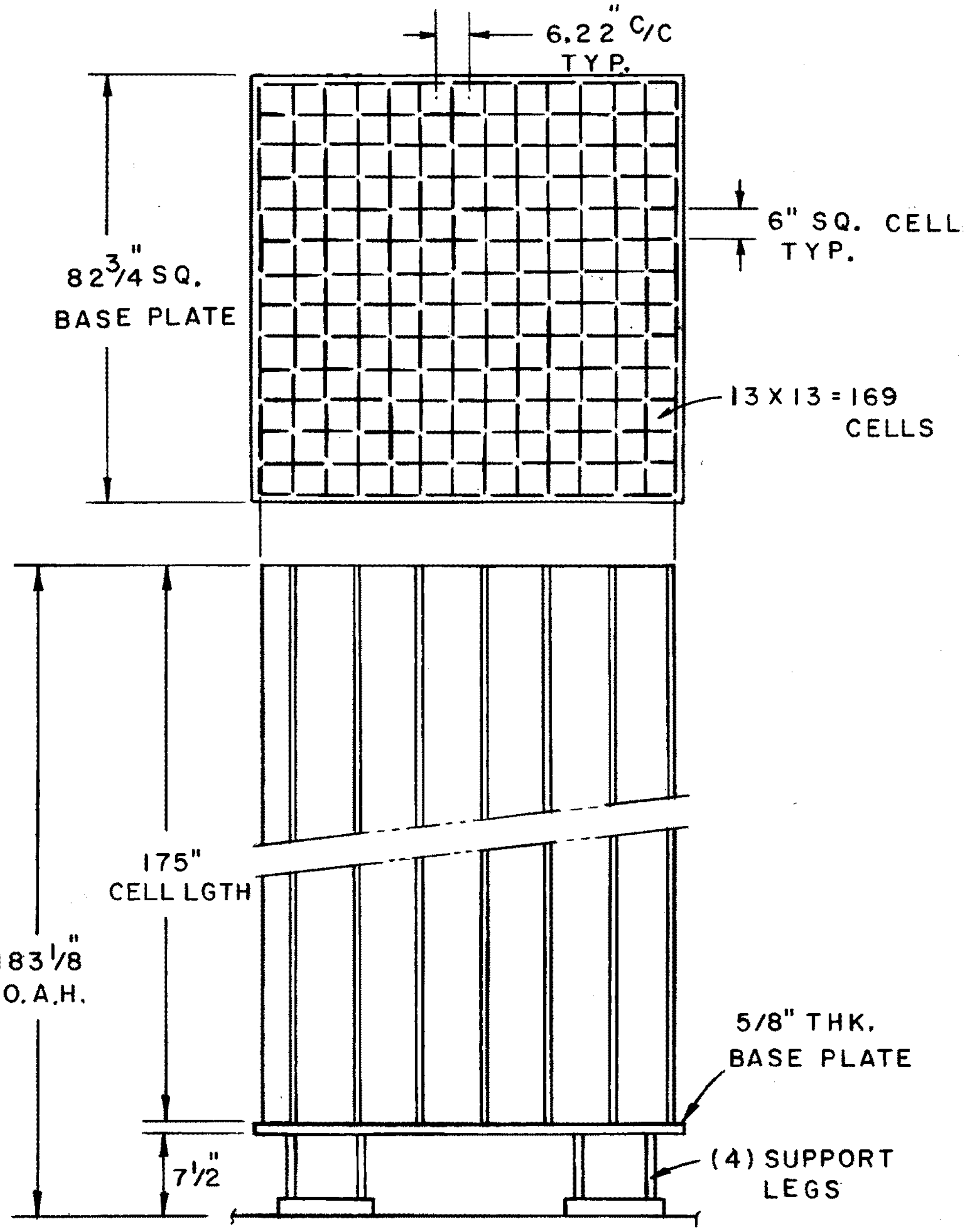
FIGURE 9.1-3, SHEET 3

REFUELING FACILITIES

BASED ON GENERAL ELECTRIC COMPANY DRAWING NO. R6-222



NOTE: DIMENSIONS ARE NOMINAL AND FOR INFORMATION ONLY

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FIGURE 9.1-4

MODULE TYPE "A" (169 CELLS)
OAT HIGH-DENSITY SPENT FUEL RACKS

FIGURES 9.1-5 THROUGH 9.1-7
HAVE BEEN INTENTIONALLY DELETED

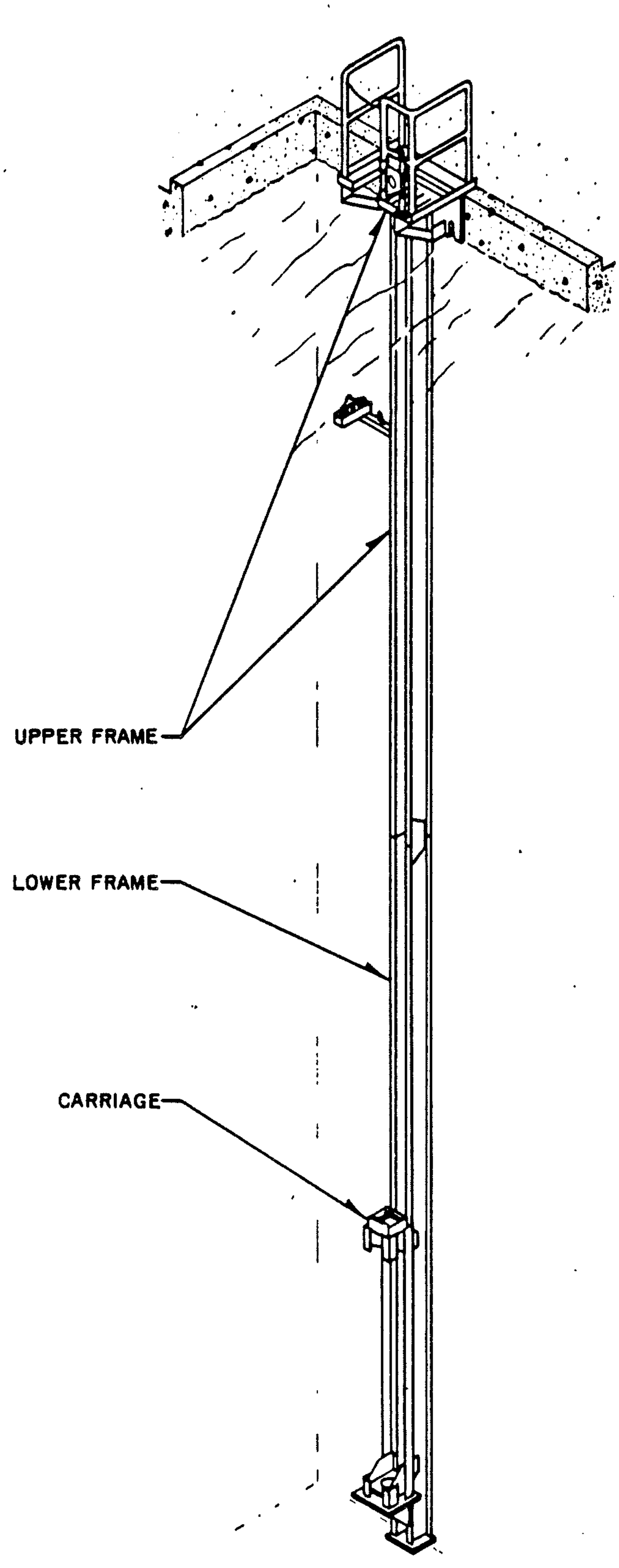

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FIGURE 9.1-8

FUEL PREPARATION MACHINE

FIGURE 9.1-9 HAS BEEN INTENTIONALLY DELETED

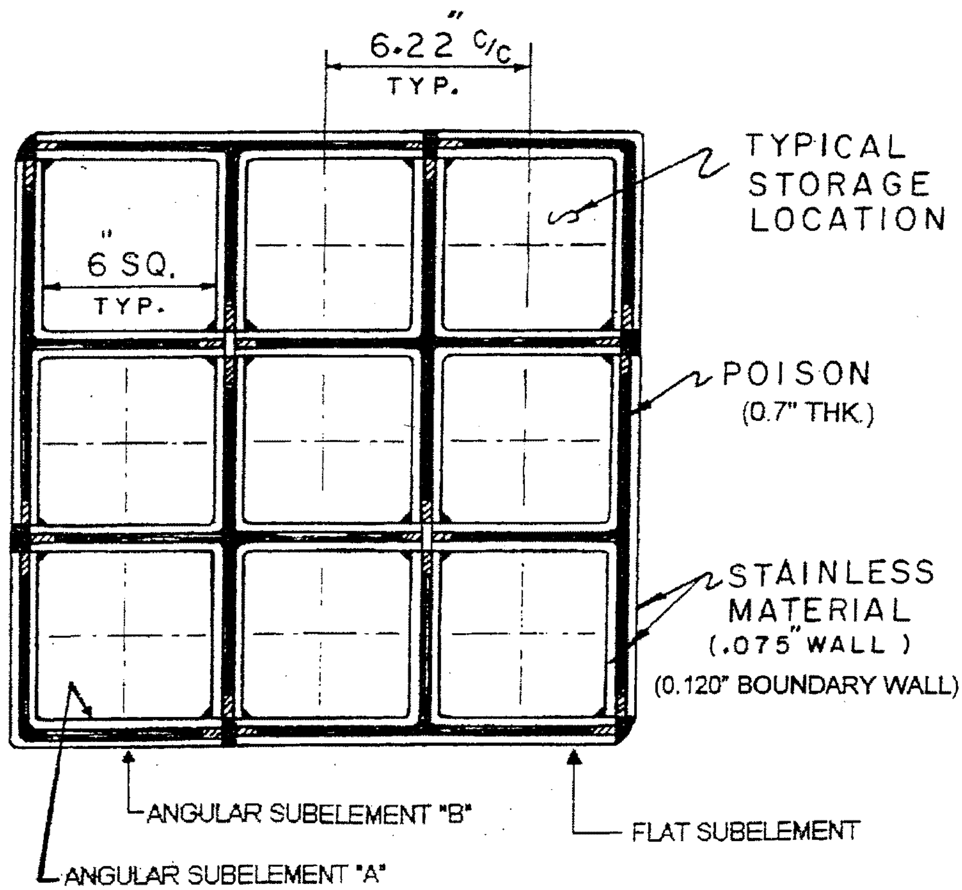

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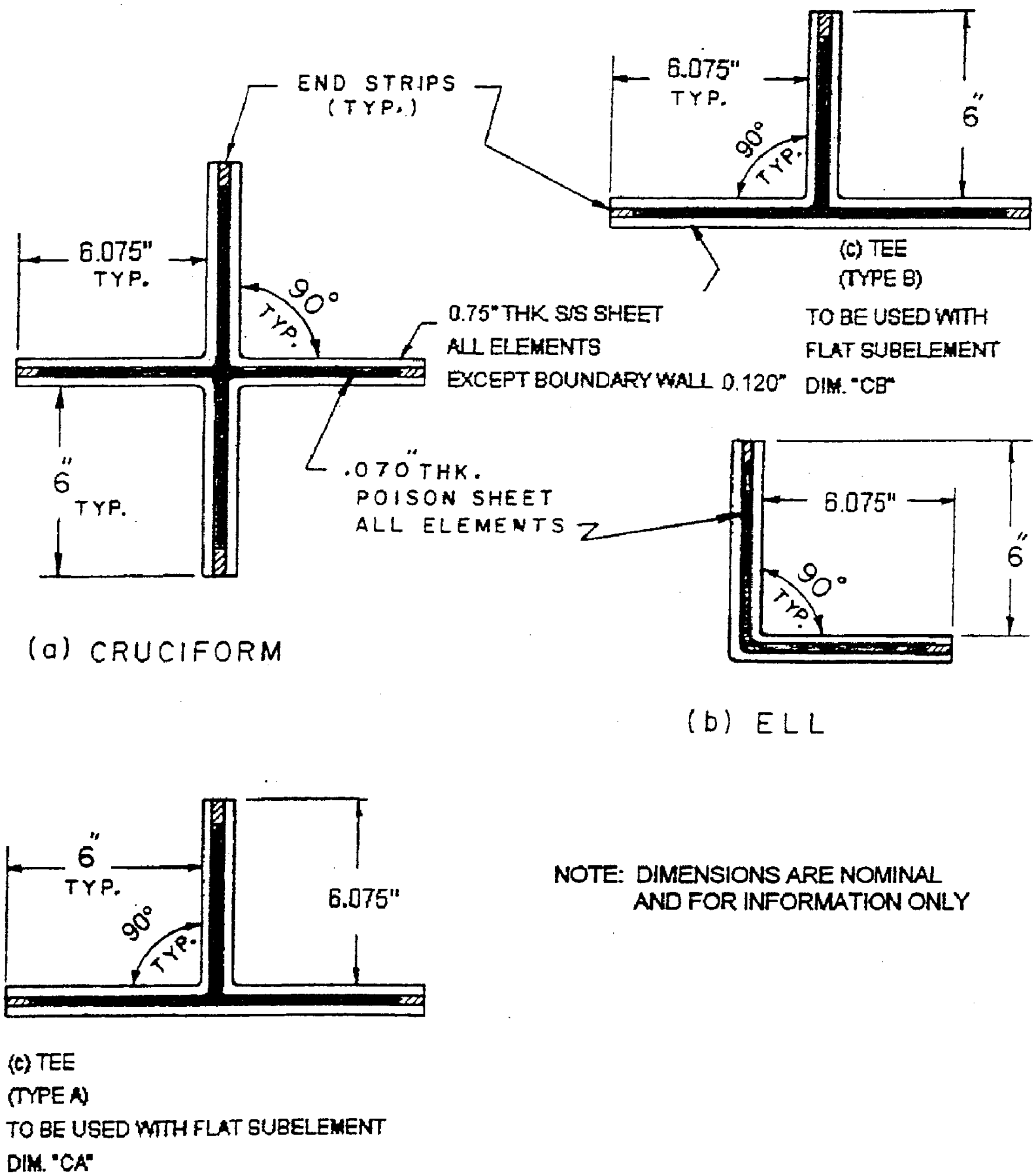
FIGURE 9.1-10

ARRAY OF CELLS (3x3) OAT HIGH DENSITY SPENT FUEL RACKS



NOTE: DIMENSIONS ARE NOMINAL AND FOR INFORMATION ONLY

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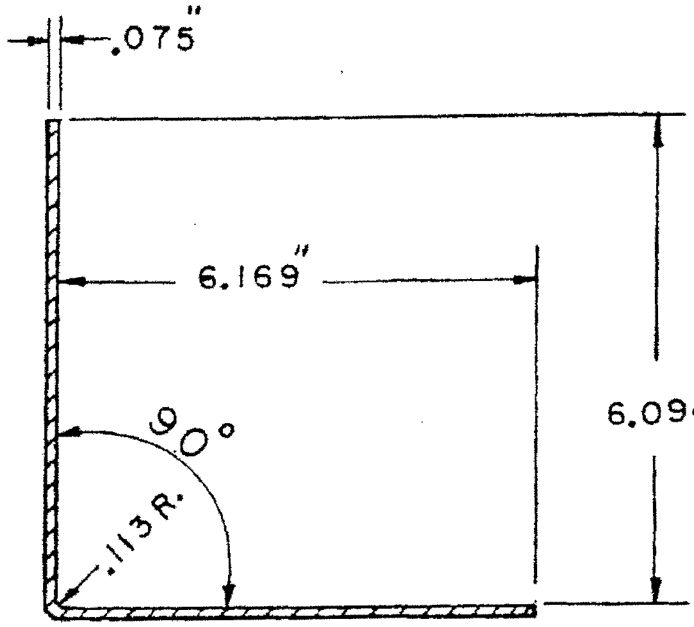
FIGURE 9.1-11

ELEMENTS CROSS SECTION OAT HIGH DENSITY SPENT FUEL RACKS



NOTE DIMENSIONS ARE NOMINAL AND
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FIGURE 9.1-12

ANGULAR SUBELEMENT "A" OAT HIGH DENSITY SPENT FUEL RACKS

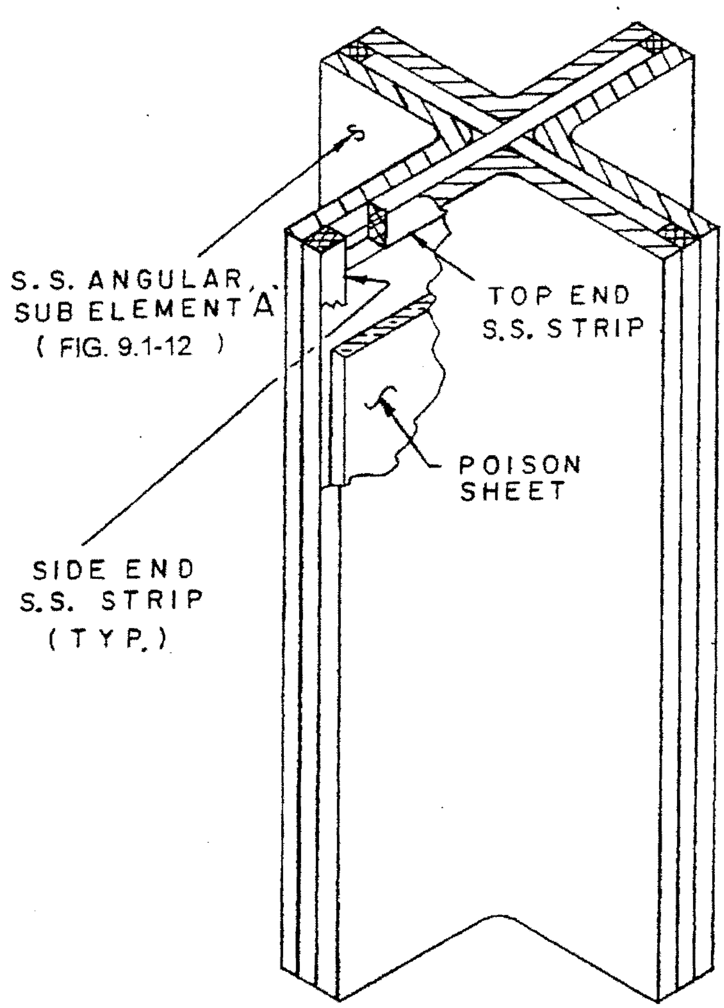

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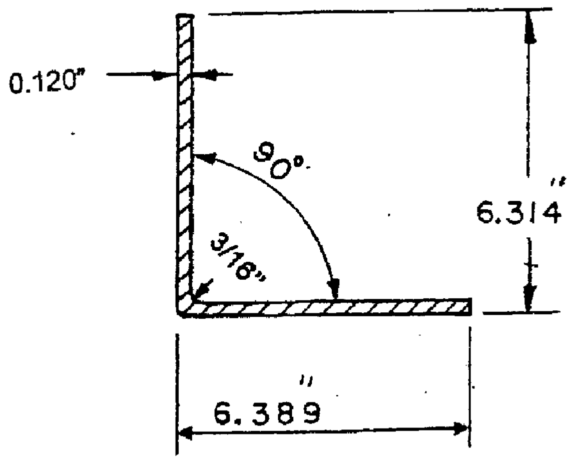
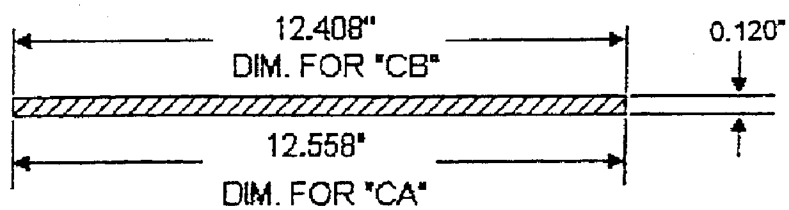
FIGURE 9.1-13

**CRUCIFORM ELEMENT (ISOMETRIC VIEW)
OAT HIGH-DENSITY SPENT FUEL RACKS**



(a) ANGULAR SUB ELEMENT "B"



(b) FLAT SUB ELEMENT "C"

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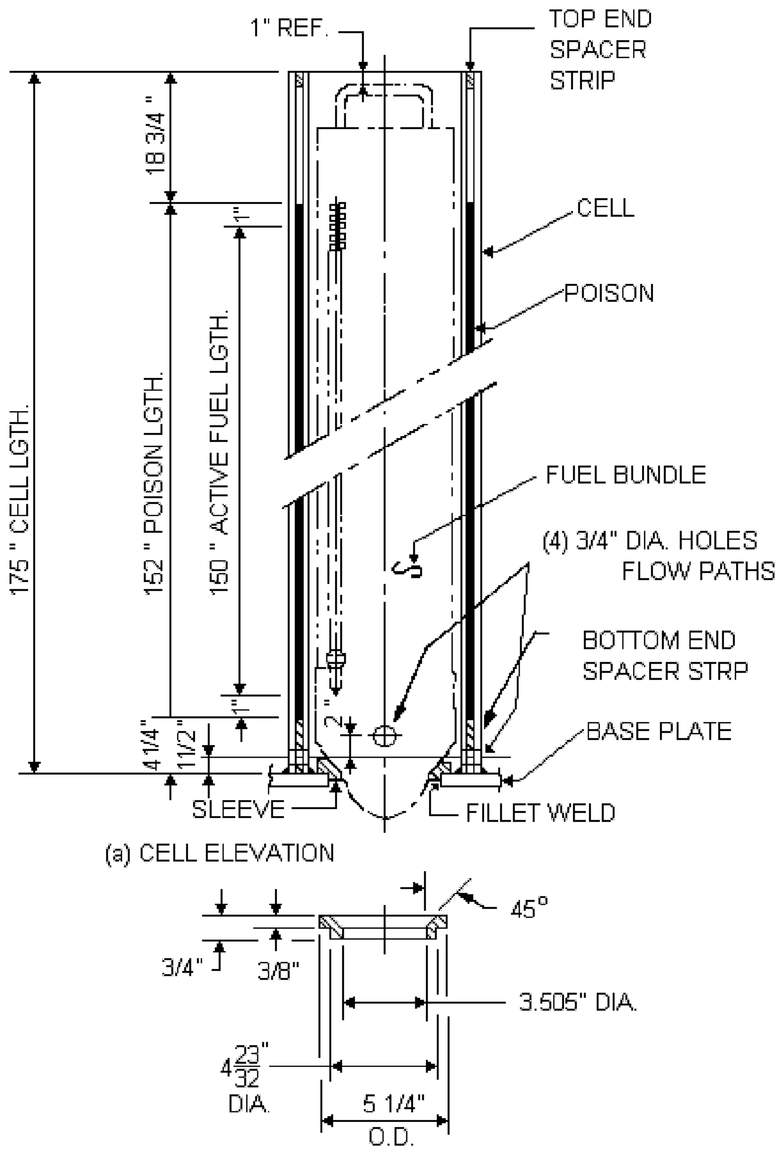
FIGURE 9.1-14

SUBELEMENTS – OAT HIGH DENSITY SPENT FUEL RACKS



(a) CELL ELEVATION

(b) SLEEVE DETAIL

NOTE: DIMENSIONS ARE NOMINAL AND FOR INFORMATION ONLY

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FIGURE 9.1-15, SHEET 1

TYPICAL CELL ELEVATION – OAT HIGH DENSITY SPENT FUEL RACKS

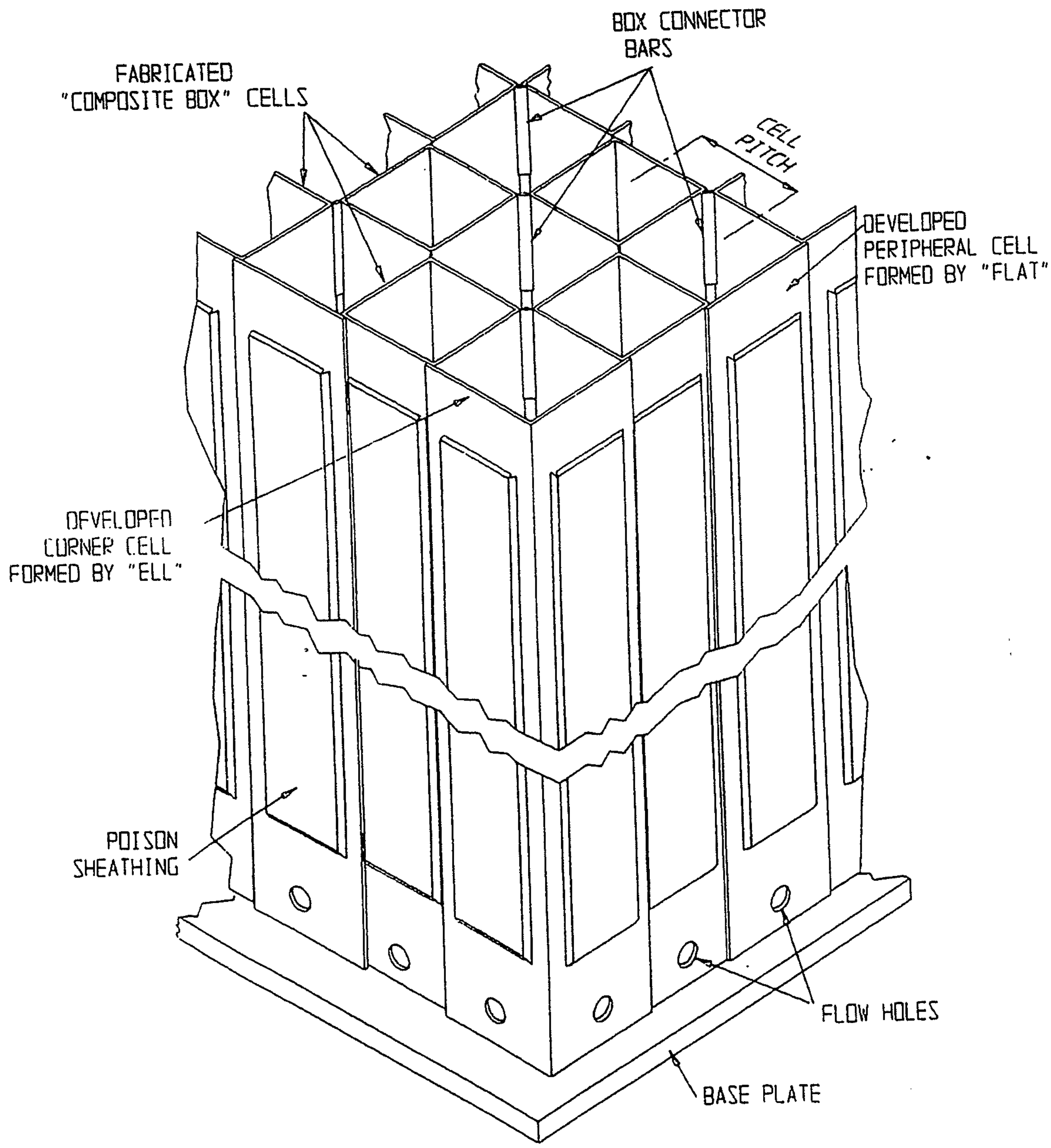

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FIGURE 9.1-15, SHEET 2

TYPICAL ARRAY OF HOLTEC HIGH DENSITY STORAGE CELLS (NON-FLUX TRAP CONSTRUCTION)

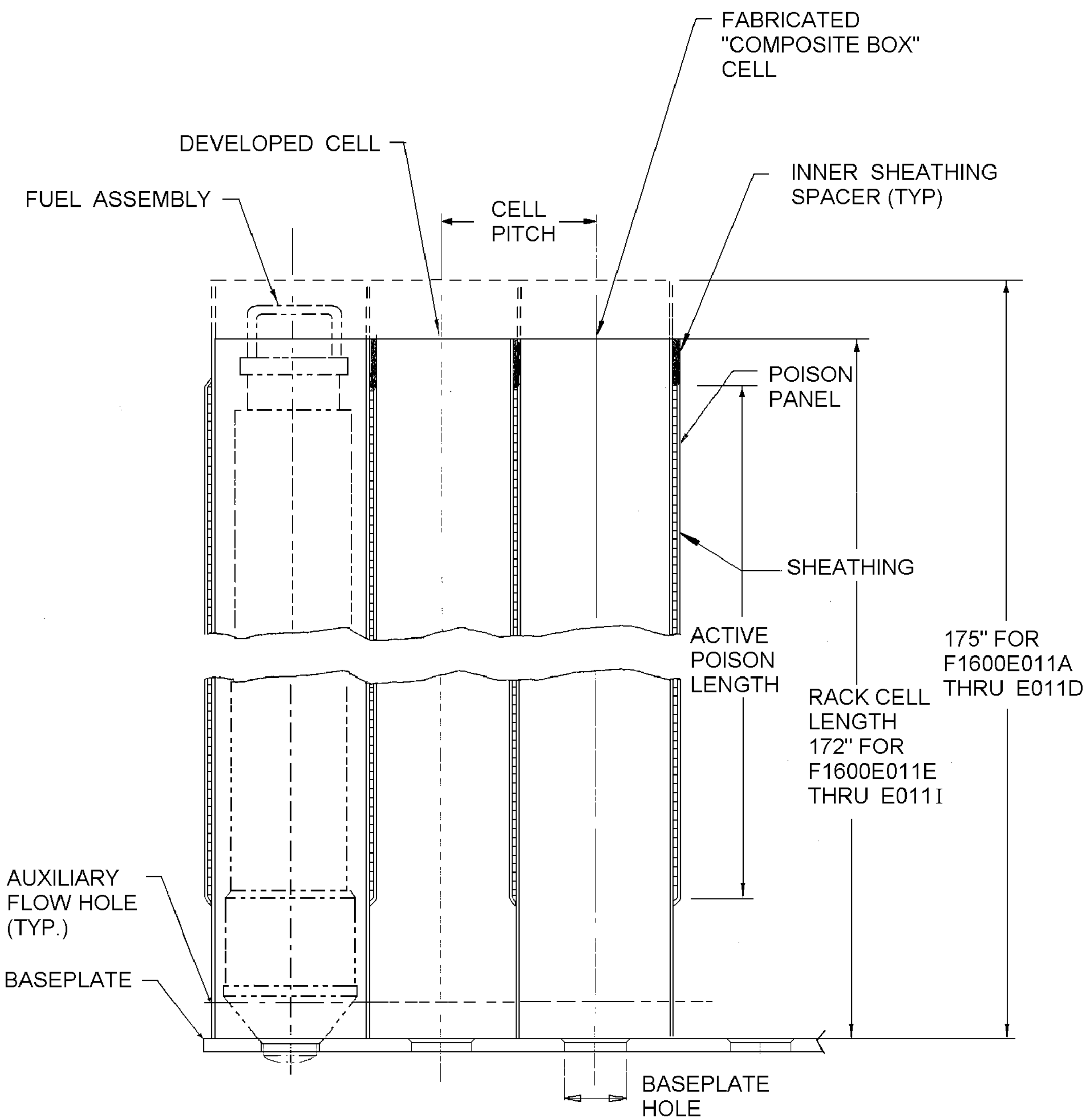

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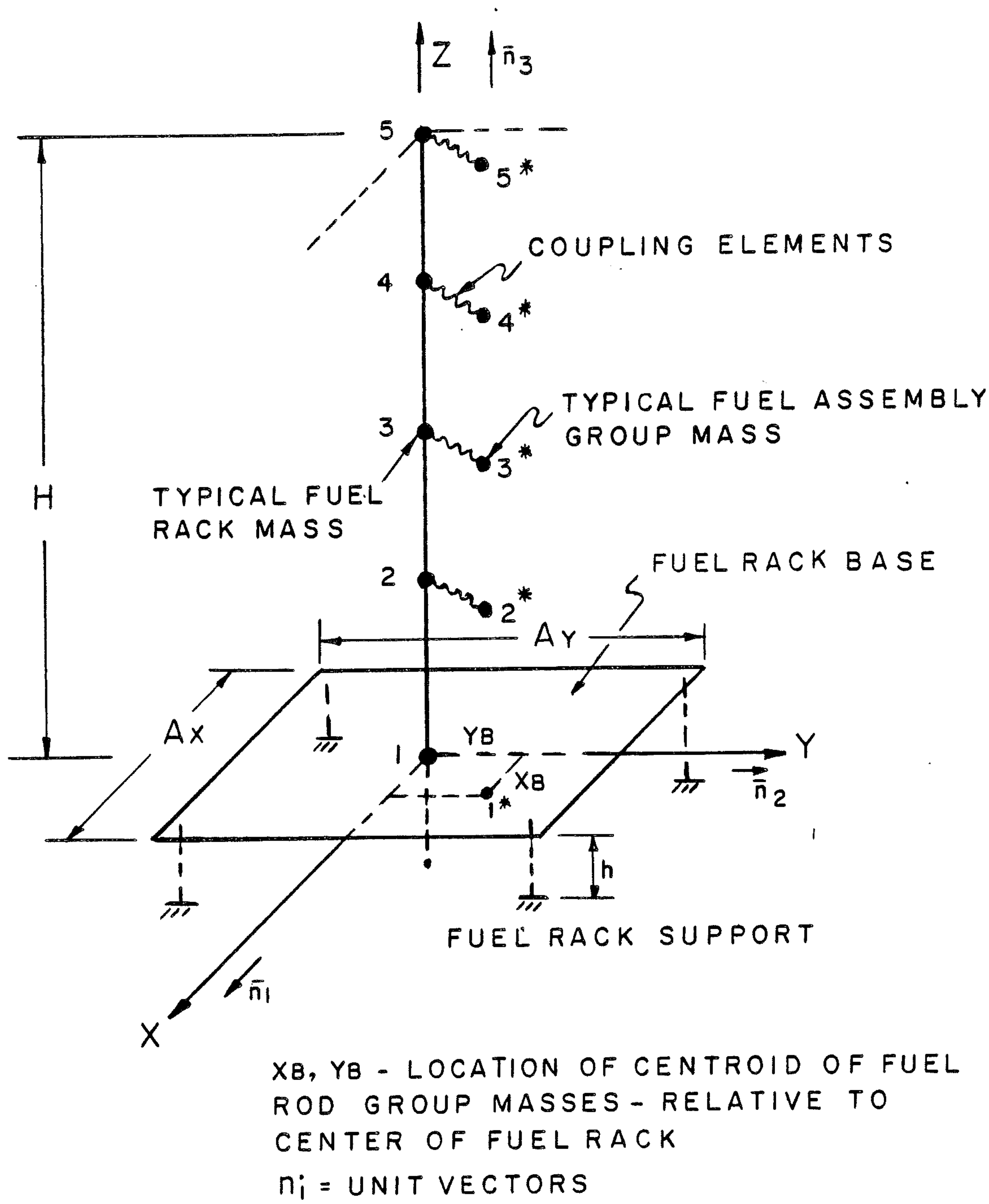
FIGURE 9.1-15, SHEET 3

ELEVATION VIEW OF A TYPICAL HOLTEC HIGH DENSITY STORAGE RACK MODULE



SOURCE: FIGURE 6.1, JOSEPH OATS REPORT TM 586 (REFERENCE 1)

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FIGURE 9.1-16

DYNAMIC MODEL – HIGH-DENSITY SPENT FUEL RACKS

FIGURES 9.1-17 THROUGH 9.1-22
HAVE BEEN INTENTIONALLY DELETED

Figure Intentionally Removed
Refer to Plant Drawing M-2048

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FIGURE 9.1-23

FUEL POOL CLEANING AND CLEANUP SYSTEM
P&ID

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Refer to Plant Drawing M-2049

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FIGURE 9.1-24

FUEL POOL FILTER/DEMINERALIZER

FIGURE 9.1-25 HAS BEEN DELETED

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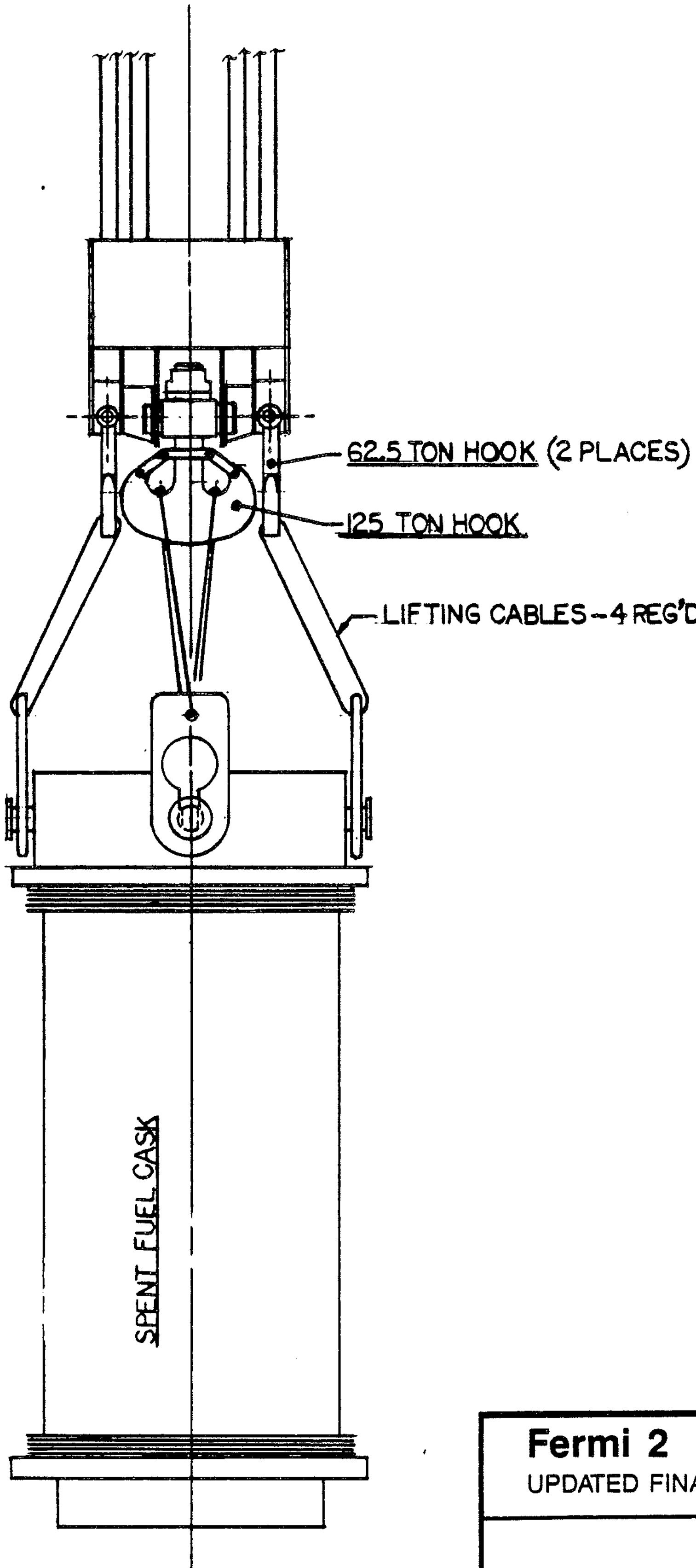

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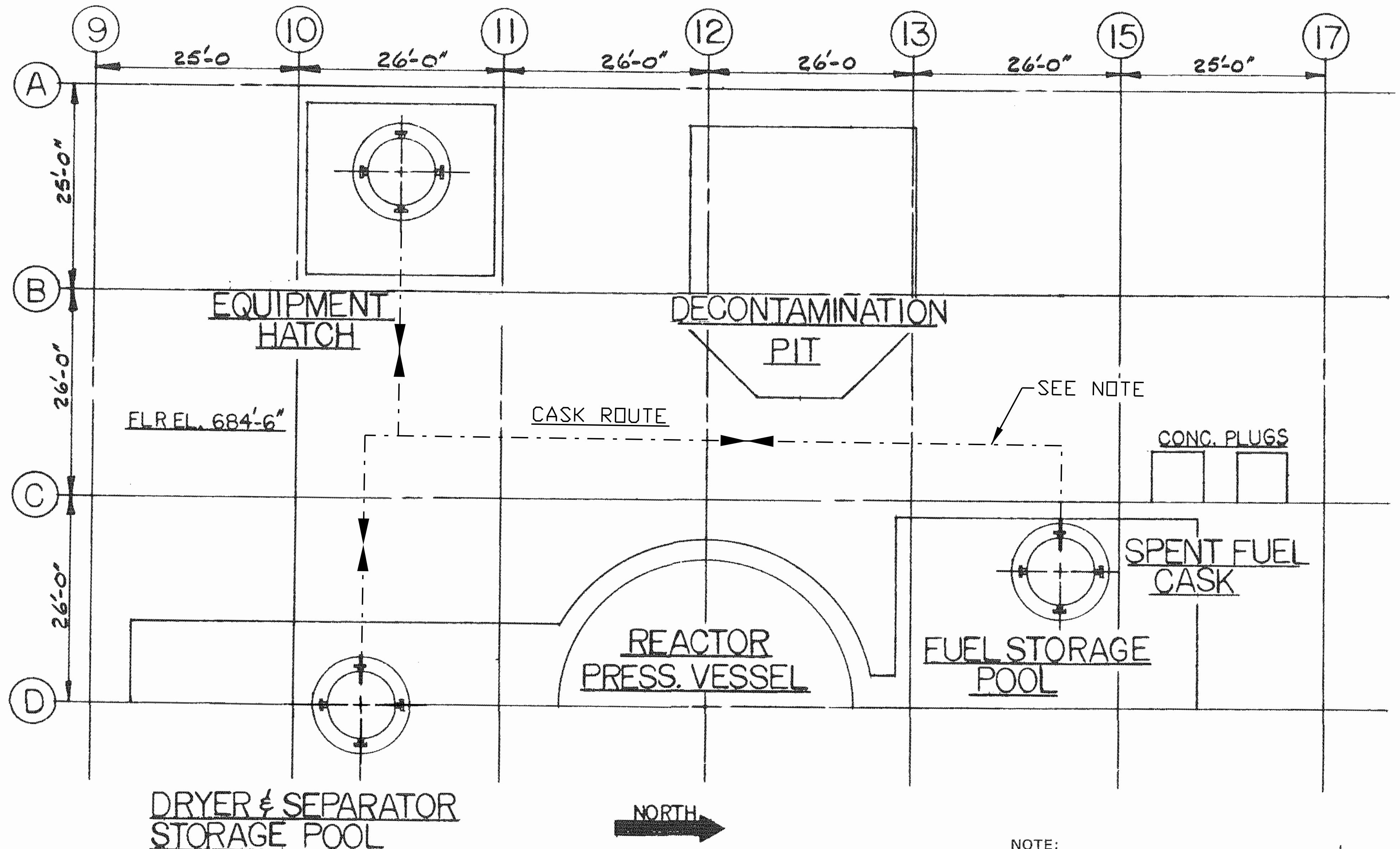
FIGURE 9.1-26

CASK RIGGING SCHEME



NOTE:
WIDE BLACK TAPE OR PAINT ON FLOOR TO GUIDE CRANE OPERATOR.

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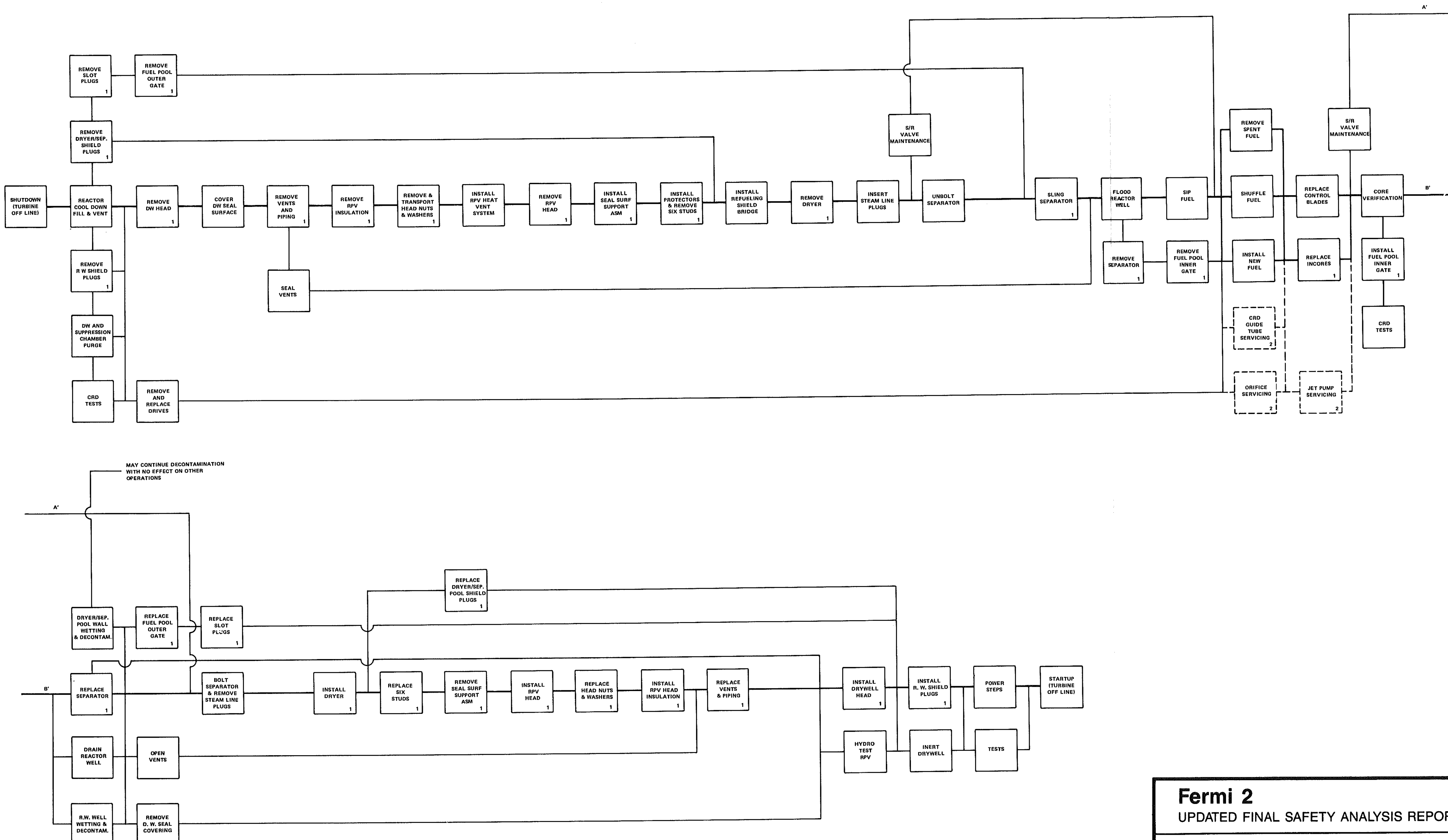
FIGURE 9.1-27

OPERATING FLOOR CASK TRAVELING PATH



GENERAL ELECTRIC COMPANY DRAWING NO. 197R568, REV. D

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FIGURE 9.1-28

PLANT REFUELING OUTAGE – FLOW DIAGRAM

9.2 WATER SYSTEMS

9.2.1 General Service Water System

9.2.1.1 Design Bases

The general service water (GSW) system is designed to remove various plant heat loads principally from the reactor, turbine, and radwaste buildings during normal station operation. Cooling water is drawn directly from Lake Erie, passed through traveling screens, pumped throughout the plant, and is then returned to the circulating water system where the heat is ultimately rejected to the atmosphere via the plant's natural draft cooling towers.

The GSW system is designed to operate at a higher pressure than the systems it cools, to provide protection against potential outleakage of radioactive contaminants to the environment.

The GSW system is classified as a nonnuclear system and is constructed in compliance with standards for Quality Group D components. This criterion is met by designing the system to ASME Section VIII and ANSI B31.1.0 code requirements. The system is nonseismic, except that portion of the system within the reactor building, auxiliary building, and RHR complex which is designated as Seismic Category II/I.

9.2.1.2 System Description

The GSW system, as shown in Figure 9.2-1, Sheet 1 is designed to remove heat from or provide water to the following equipment on a continuous basis:

a. The reactor building closed cooling water system (RBCCWS) heat exchangers

b. The turbine building closed cooling water system (TBCCWS) heat exchangers

c. The turbine oil coolers

d. The generator hydrogen coolers

e. The radwaste evaporator condenser

f. Reactor building and turbine building room coolers

g. Circulating water pump bearing cooling water and lubricating water.

h. GSW biocide injection system

i. Supplemental cooling chilled water system

The GSW system also provides, on an intermittent basis, water for the following systems or functions:

a. Circulating water biocide injection system

b. Traveling water screen backwashing and deicing

c. Fire protection system (FPS) makeup (via the FPS jockey pump or the GSW to FPS cross-tie line)

d. Residual heat removal (RHR) reservoir makeup

e. Lawn sprinklers

f. Sump flushing.

g. The Sanitary Sewage Treatment Facility (outside protected area)

h. Side Stream Liquid Radwaste Processing System (SSLRPS)

GSW system pump data is shown in Table 9.2-1.

The GSW system takes its water from Lake Erie. The lake water is drawn into an intake canal, passed through a trash rack and a traveling screen, and enters the GSW pump pit. The five GSW pumps take suction from the intake pit and discharge the water into a common header. The GSW pumps operate continuously, maintaining pressure in the GSW header. Minimum pump flow protection is provided by relief valves at each pump's discharge to prevent overheating in the event that the pump is inadvertently run deadheaded. Relief valves are provided in the system piping to prevent overpressurizing the system.

The GSW pump house is located on the existing intake canal serving Fermi 1. It houses the five 25 percent-capacity GSW pumps, two 100 percent-capacity circulating water reservoir makeup pumps, and two 100 percent-capacity fire pumps. The two stage GSW pumps are of the vertical wet-pit type, rated for 7700 gpm flow, and a tested head between 241 and 270 ft. Since the flow demand varies seasonally, the pumps are manually started and stopped by the operator from the main control room. Each pump has a basket strainer located in its discharge line to remove suspended material that has been carried through the traveling screens at the pump house inlet. The strainers are provided with automatic self-backwashing feature.

The GSW system is treated with a biocide to inhibit slime and algae growth and to control organic and inorganic fouling of heat exchanger and piping surfaces. The biocide injection system is shown in Figure 9.2-1, Sheet 2.

Traveling screens and stationary racks are provided to keep floating debris from entering the GSW intake pit. A line from the GSW supply header automatically provides high-pressure water to each screen for backwashing whenever the differential pressure across the screens rises above a predetermined value. A screen deicing line, tapped off the GSW discharge header just prior to its connection into the main condenser circulating water line, provides warm water to keep ice from forming around the screens.

The majority of GSW flow to equipment being cooled is controlled by temperature control valves. Each valve is modulated in response to the exit temperature of the process equipment that the GSW is cooling. The flow to remaining GSW loads is modulated by manual flow valves.

A cross connection is provided from the HPCI Test Line piping to the GSW piping to be used as part of the Flexible and Diverse Coping Strategy (FLEX) to mitigate Beyond Design Basis External Events (BDBEE) in response to NRC Order EA-12-049.

9.2.1.3 Safety Evaluation

The GSW system is not required to be operable in order to effect the safe shutdown of the reactor. Thus, the GSW system is not designed for a single active or passive failure as required of a safety or safety-related system, but sufficient redundancy and automatic protective features are provided to ensure efficient plant operation and availability. Since the GSW system is not an engineered safety feature (ESF), it is not powered by an essential power bus.

The only portion of the GSW system directly involved in reactor operation and shutdown is the section serving the RBCCWS (via the RBCCW shell and tube heat exchangers and the supplemental cooling chilled water system chiller condensers). If the GSW system becomes inoperative, the emergency equipment service water system (EESWS) takes over to serve the equipment essential to safe reactor shutdown through the emergency equipment cooling water system (EECWS) (described in Subsection 9.2.2). The EECWS and the EESWS are powered off the essential buses. No failure in the GSW system can prevent a safe shutdown of the reactor.

The GSW intake structure is designed for operation during low lake levels by drawing water through a 54-in. line from the circulating water reservoir. On low lake level, an alarm alerts the operator of the condition. If necessary, the operator can supply GSW from the circulating water reservoir by opening the normally closed valve in the 54-in. connecting line between the circulating water reservoir and the GSW pump intake pit, and simultaneously closing the sluice gates to isolate the intake canal from the intake pit. The GSW and circulating water systems can be operated for a limited period of time in this mode to support plant load reduction and shutdown. Subsection 2.2.3.1 further discusses the low water considerations.

Radioactive contamination of GSW is avoided by using closed heat exchangers between the service water and the closed cooling water systems. The GSW remains uncontaminated by operating at higher pressure than the cooled system, and any leakage would be from the GSW system to either the TBCCWS or the RBCCWS. In addition, further protection is provided by activity detection equipment located in the circulating water discharge line downstream from the GSW system discharge connection so that both systems are monitored for radioactive contamination.

The cross connection between the HPCI Test Line (at the orifices) and the GSW System is designed to prevent cross contamination during normal plant and under DBA conditions. Double isolation valves are used in the cross connection piping to avoid any potential cross contamination. A tell-tale drain is provided between the two isolation valves to monitor potential leakage or failure of either isolation valve.

9.2.1.4 Tests and Inspections

Initial construction tests such as hydrostatic leak tests were conducted per ASME Section VIII and ANSI B31.1.0 code requirements. Initial system flow distribution, valve operability, instrumentation and control loop checks, and alarm setpoints were done in accordance with the Preoperational Test program. After plant startup, heat exchanger operating performance is observed using actual system heat loads.

Periodic testing of the GSW pumps is done during normal system operation by utilizing each pump's test lines and orifice. Each pump's head and flow point is then compared to its initial flow characteristic curve, and an assessment is made for any deterioration to determine the need for any corrective pump maintenance. Instruments and controls are inspected periodically. No periodic leak tests are planned since the system is continuously operating. Periodic visual inspection of the system will detect minor leakages, such as those from valve stems, flanges, and instrument tubing connections.

9.2.1.5 Instrumentation

Sufficient instrumentation is provided to allow the plant operator to assess the status of the GSW system. The GSW pumps are manually started and shut down from the control room operating panel via coordinated manual control (CMC) switches. Pump status and motor amperage readouts are provided in the control room.

The discharge from each GSW pump flows through an automatic self-cleaning strainer and a discharge isolation valve. GSW system pressure is regulated by changing the number of pumps in service, adjusting the GSW flow through heat exchangers, and/or bypassing some flow back to the pit as necessary. The discharge header pressure is indicated with high and low pressure alarms in the control room.

Water levels in the GSW pump house are measured on each side of the traveling screens to provide additional pump operating intelligence to plant operators. This level instrumentation controls traveling screens and alarms the control room operator of abnormal inlet water levels.

The GSW flow to the major GSW users, turbine oil-coolers, generator hydrogen coolers, TBCCW coolers, and RBCCW coolers, are modulated by temperature control valves. The process temperatures are also provided with a high and low temperature alarm in the control room. The other GSW loads are modulated by manual controls.

9.2.2 Cooling System for Reactor Auxiliaries

9.2.2.1 Design Bases

The RBCCWS is designed to remove heat from the auxiliary equipment housed in the reactor building and auxiliary building during normal plant operation. The RBCCWS is cooled by the GSW system, and makeup is supplied by the demineralized makeup water system. The supplemental cooling chilled water system provides a source of chilled water for cooling the water supplied to each division of EECW serviced by the RBCCW supplemental cooling loops. The GSW system provides service water for condenser cooling of the SCCW chillers. The RBCCW supplemental cooling loops are intended for operation when the GSW supply temperature is greater than 60°F.

In the event of a mechanical failure of the RBCCWS, high drywell pressure, or upon loss of offsite electrical power, the EECWS will start automatically (or may be manually initiated) to cool equipment needed for reactor shutdown. In addition, the EECWS may be used to augment RBCCW for the purpose of assisting in equipment cooling. The EECWS is cooled by the EESWS which is supplied by the RHR reservoir.

To provide for reactor shutdown under severe natural environmental conditions, as well as upon loss of normal offsite power and failure of the RBCCWS, two full-capacity Emergency Equipment Cooling Water loops are provided.

Motor-operated isolation valves are provided to isolate the nonessential loads on the RBCCWS from each EECW loop.

The RBCCW system is operated at a pressure lower than the GSW system to prevent leakage of potentially radioactive water to the environment. Continuous surveillance of the quality and activity level of the RBCCWS is maintained to detect inleakage of GSW or inleakage from the cooled reactor building auxiliary components.

During emergency situations when EECW is in operation, the EECW pressure is slightly greater than the EESW pressure at the EECW heat exchangers. It would take multiple equipment failures to create a situation where radioactive contamination would enter the EESW. First a component being cooled by EECW would have to leak contaminated water into EECW. This would have to be accompanied by a failure in the EECW heat exchanger in order to release radioactive material into the RHR reservoir. If this were to happen, drift losses from the cooling towers could cause a radioactive release to the environment. Given the fact that it would take multiple equipment failures and that monitoring and sampling provisions exist (as described in Subsections 11.4.3.9.2.3 and 11.4.3.9.2.4), the potential for an unmonitored radioactive release is minimal.

The makeup line between the EECW makeup tank and the EESW system for each division is furnished with a check valve and a normally closed air-operated isolation valve. The test return line is provided with two isolation valves that are closed during normal operation. These valves would minimize the potential of radioactively contaminated water leaking into the EESW system during normal operation. The check valve in the makeup line and the closed test return line isolation valves would also minimize the potential for radioactively contaminated water leaking into the EESW system during a design basis accident. The check valves installed as boundary valves on the nitrogen inerting (T48) and demineralized makeup water (P11) systems would minimize the potential for radioactively contaminated EECW water leaking into these systems.

System construction for cooling the essential equipment necessary for reactor shutdown is in compliance with standards for Quality Group C or Quality Group B. Components and equipment not essential to reactor shutdown are built as a minimum to Quality Group D standards. The EECWS is Category I, and is designed in accordance with ASME Section III, Class 2 and Class 3 requirements. The RBCCWS is Seismic Category II/I and is designed to ASME Section VIII and ANSI B31.1.0 code requirements.

9.2.2.2 System Description

The RBCCWS, as shown in Figure 9.2-2, is designed to remove heat from reactor auxiliaries that fall into two categories: those that are essential to reactor shutdown and those that are non-essential to reactor shutdown. Table 9.2-2 lists RBCCWS component design parameters.

The RBCCWS outside of the RBCCW supplemental cooling loops consists of two RBCCW heat exchangers and three 50 percent-capacity pumps. The two, divisional RBCCW supplemental cooling loops are each designed with one RBCCW supplemental cooling (plate-and-frame) heat exchanger and two 100 percent-capacity RBCCW supplemental cooling pumps (see Figure 9.2-2(2)). During normal operation, two heat exchangers and two pumps operate to provide cooling to all the essential and nonessential heat loads. The third pump is in standby and is designed to be started manually on low RBCCWS pressure. When the RBCCW supplemental cooling loops are in operation, one RBCCW supplemental cooling pump will operate for each EECW division. The second pump in each division is in standby and is designed to automatically start on loss of the operating pump. The RBCCW supply header temperature is maintained nominally at 70°F by a temperature control valve modulating the GSW flow through the RBCCW heat exchanger. During the summer season, the RBCCW temperature may be higher. When these higher temperature conditions occur, the RBCCW supplemental cooling loops may be used to cool the water that is supplied to EECW. The water temperature exiting each RBCCW supplemental cooling heat exchanger will be maintained by a temperature control valve which may be operated in automatic or manual mode. Both divisional loops of RBCCW supplemental cooling exchange heat with the supplemental cooling chilled water (SCCW) system. SCCW may be placed in operation when the GSW supply temperature exceeds 60°F. The system thermal capacity is based on a nominal 85°F RBCCW temperature. System pressure is controlled by a differential PCV located in the bypass line between the suction and discharge headers of the RBCCW pumps. Makeup to the system as well as system expansion and contraction resulting from load changes are provided by a makeup tank. Makeup water is automatically supplied via a level control valve. Normal makeup is from the demineralized water system and alternatively from the condensate storage system.

Reactor auxiliaries impose a maximum cooling load on the RBCCW heat exchangers of approximately 68 x 10^6 Btu during normal operation. This requires approximately 10,000 gpm of GSW, assuming a maximum service water temperature of 85°F. Circulation on the RBCCW side of the heat exchanger is approximately 8000 gpm; heat exchanger rate is based on temperatures of 112°F in and 95°F out.

The GSW is not used directly because the relatively high impurity level in this system might result in fouling of equipment heat transfer surfaces. Furthermore, the intermediary loop between contaminated reactor auxiliaries and the GSW system provides additional protection against radioactive water leakage into the environment.

The EECW section of the RBCCWS consists of two redundant full-capacity loops, each with two (2) 100 percent capacity heat exchangers, pump, and makeup pump and tank, as shown in Figures 9.2-3 and 9.2-4. One heat exchanger is manually aligned for service. The second heat exchanger is provided as a backup. The twin systems designated as Division I and Division II are cooled by the EESWS. The EESWS, described in Subsection 9.2.5, is powered off the essential buses and is designed to be redundant throughout. Upon loss of offsite power, high drywell pressure, or failure of the RBCCWS, both divisions of the EECWS are automatically activated; that is, pumps start, makeup tanks isolation valves open, and valves isolate the nonessential portion of the RBCCWS. The makeup tanks isolation valves do not start to open until the divisional isolation valves are closed. Upon loss of RBCCWS differential pressure between the supply and return headers, either Division I and/or Division II EECW loops will start automatically, depending on the portion of the

RBCCWS affected. The EECWS may also be manually initiated. Component design parameters of the EECWS are shown in Table 9.2-3.

The EECW heat exchangers are designed for a maximum heat load of 13.6 mBtu/hr. This requires approximately 1450 gpm of EESW, assuming a maximum service water inlet temperature of 89°F. Circulation on the EECW side of the heat exchanger is approximately 1700 gpm; heat exchanger rate is based on temperatures of 111.1°F in and 95°F out. The EECWS temperature is maintained nominally at 70°F in a similar manner as the RBCCW heat exchanger by modulating the heat exchanger exit cooling water flow.

The replacement of the original shell-and-tube EECW heat exchangers with a plate-and-frame design increased nominal heat transfer capability, but reduced the minimum flow channel dimension from 0.78-in. diameter tubes to 0.0732 inch plate spacing; thus, making the new units potentially more susceptible to plugging. The design analyses that define minimum EECW heat exchanger thermal performance consider the potential effects of initial plugging and plugging rate to establish the thermal performance and heat exchanger differential pressure vs. flow test criteria necessary to ensure the accident mission can be accomplished with credit for only one of the two identical units provided in each division. Once the maximum allowed normal operating plugging limit on a unit is reached, the EECW and EESW flows may be aligned to the clean spare heat exchanger in each division; thereby facilitating maintenance without interrupting normal plant operation.

The RBCCW makeup tank and the EECW makeup tanks are supplied with demineralized water and pressurized with nitrogen during normal plant operation. Normal makeup to the tanks is supplied automatically from the demineralized makeup water system by a level control valve. The pressure regulating valve of the normal nitrogen supply system maintains a nitrogen blanket in the tank at a pressure which will keep the EECW loop full to the upper elements. Nitrogen is provided to prevent leakage of oxygen into the system, thereby retarding corrosion of the closed cooling water system.

The EECW (Division I and Division II) system makeup tank is connected with a makeup line to the EESW system to provide an alternate makeup supply for each division when the normal makeup supply to this tank is lost during and after the design basis accident. The isolation valves for the alternate makeup supply consist of a check valve and an air-operated valve which opens automatically on a makeup pump start, a loss of air or a loss of electrical power. This valve is normally closed to prevent EESW, low quality water from entering the EECW, high quality water system during winter operation when TCV F400A/B is nearly closed. Each makeup pump auto starts and provides the makeup water to the tank. A check valve is installed in this makeup supply line to prevent a reverse flow from the EECW makeup tank to the EESW system. The test return line is provided with two isolation valves that are closed during normal operation and accident conditions to minimize the potential for radioactively contaminated water leaking into the EESW system. Inadvertent injection to the EECW system is minimized by system initiation setpoints and permissives. Inadvertent injection of EESW water into the EECW system during testing is minimized by isolation of the tank during testing. The makeup tank for Division I is also provided with the emergency backup nitrogen supply cylinders which automatically provide nitrogen to the makeup tank whenever the normal nitrogen supply is lost and/or the nitrogen supply pressure is reduced below approximately 26 psig. The check valves are added as the boundary valves between the makeup tank and nonsafety-related nitrogen inerting and demineralized water makeup systems to reduce the potential loss of the makeup tank inventory or pressure due to the loss of the nonsafety-related systems. The backup nitrogen supply cylinders are sized to maintain nitrogen pressure in the makeup tank until the makeup tank has refilled the EECW loop during an Appendix R fire. This will maintain a positive suction head on the EECW pump and provide protection against momentum transients when the EECW pump experiences a delayed start during the dedicated shutdown scenario.

The following equipment, considered essential to reactor shutdown, can be cooled either by the RBCCWS or, in an emergency, by at least one division of the EECWS:

a. RHR pumps (two out of four)

b. Core spray pumps (two out of four)

c. Reactor auxiliary space coolers (three in Division I or four in Division II)

d. Standby control air compressor, aftercooler, and space cooler (one out of two sets)

e. Deleted

f. Switchgear room space coolers (two out of four)

g. Standby gas treatment room space cooler (one out of two)

h. Control center air conditioning equipment (one out of two)

i. Auxiliary building battery charger area space coolers (one out of two).

The nonessential components of the RBCCW that are connected to the EECWS piping have automatic isolation valves installed in their supply lines. The following equipment, considered nonessential to reactor shutdown, is cooled only by the RBCCWS:

a. Two in-series reactor water cleanup nonregenerative heat exchangers

b. Water sample station cooler

c. Twin reactor water cleanup pump seals and bearings

d. Twin fuel pool heat exchangers

e. Twin recirculating pump motor-generator coupling cooler heat exchangers

f. Recirculating pump motor-generator ventilation cooling coils

g. Steam tunnel cooler

h. Drywell equipment sump heat exchanger

i. Reactor building equipment sump heat exchangers (two)

j. Control rod drive (CRD) pumps

k. Battery room space cooler

l. Drywell penetration cooling (eight)

m. High-pressure cask-washdown pump heat exchanger

n. Instrument rack H21-P284.

NOTE: All twin units are sized for 100 percent redundancy.

Two additional loads, drywell coolers (seven per division) and the reactor recirculation pumps, are normally cooled by RBCCW. Flow to this equipment is maintained upon activation of the EECWS. Should EECWS activate in conjunction with a high drywell pressure signal, the supply valve to the drywell will close, thus ensuring cooling of the essential loads.

9.2.2.3 Safety Evaluation

The EECW Division I and Division II portions of the RBCCWS are designed to provide cooling to equipment required for reactor shutdown in spite of a single active or passive failure. Division I and Division II loops are completely isolable from each other. Each loop of the EECWS is operable from a separate emergency bus. Single-failure analysis for the RBCCW and EECW systems is presented in Table 9.2-4. Upon activation of the EECWS, all nonessential loads of the RBCCWS will be isolated except for the drywell coolers and the reactor recirculation pumps. These loads can be manually isolated from the control room and the supply valve will be automatically closed if a high drywell pressure occurs.

The EESWS cooling the EECWS is also completely redundant and powered off separate emergency buses. This system is discussed in Subsection 9.2.5.

The EECWS components of Division I and Division II are located in different areas of the reactor building to preclude failure of both systems due to pipe whip, jet forces, and generated missiles. Physical separation also provides protection against common failure induced by fire, as described in Appendix 9A.

To detect leakage from the RBCCW and EECW systems, the makeup tanks are provided with low-level alarms and an alarm on the makeup valve stem position. Excessive opening of the makeup valve will be indicative of a substantial system leak. Inleakage of GSW or SCCW will be indicated by a high-level alarm in the RBCCW makeup tank. The RBCCWS is continuously monitored for radioactivity. Leakage to GSW and SCCW is minimized by operating the RBCCW at a relatively low pressure.

The use of demineralized water for makeup and nitrogen capping of the makeup tanks gives reasonable assurance against long-term degradation caused by impurities in the circulating loops. Additionally, corrosion inhibitors are added for pH and oxygen control. Alternatively, the cooling water system may be maintained with pure demineralized water only, with no chemicals added.

The makeup line between the EECW makeup tank and EESW system in each division provides emergency makeup water to the makeup tank by automatically starting the makeup pump and opening the air-operated valve. This makeup system is initiated on either low makeup tank pressure or low makeup tank level when the makeup tank isolation valve is open, and normal pump suction pressure is achieved. In Division I the backup nitrogen supply system to the EECW makeup tank is automatically actuated, based on the makeup tank pressure, upon loss of the nonsafety-related nitrogen inerting system and maintains the nitrogen pressure throughout a dedicated shutdown fire scenario. The check valves installed in the nonsafety-related water and nitrogen supply lines will protect the makeup tank from the potential loss of water inventory or nitrogen pressure.

Both EECW loops are automatically started on high drywell pressure or upon loss of normal offsite power. Upon failure of the RBCCWS, such as pipe rupture, redundant differential pressure switches automatically start the EECW pump(s), depending on the location and severity of the break, and initiate appropriate loop isolation consistent with the operating EECW pump(s).

EECW may be manually initiated with the nonessential loads subsequently restored to facilitate RBCCW heat exchanger cleaning, to enhance drywell cooling during high lake water (GSW) temperature, for testing, or to provide RHR Reservoir freeze protection during extreme cold weather. EECW auto-start on high drywell pressure (i.e., a LOCA) or on a loss of offsite power is unaffected by this mode of operation; therefore, these signals will initiate the automatic protective action of reisolating the nonessential portions of RBCCW piping located inside the EECW system envelope. A loss of RBCCW while EECW is operating in this mode will not reinitiate EECW or reisolate the nonessential loads. This action is not required, however, since this is not a condition requiring protective action as described in Section 7.1.2.1 and EECW remains capable of supporting the safe shutdown of the plant in this configuration.

9.2.2.4 Tests and Inspections

Initial construction tests such as hydrostatic leak tests were conducted per applicable code requirements for the RBCCW and EECW systems. Initial system flow distribution, valve operability, instrumentation and control loop checks, and alarm setpoints were done in accordance with the Preoperational Test program as discussed in Chapter l4. Heat exchanger operating performance will be observed during plant operation. Availability of the RBCCW standby pump and automatic start of the EECW pumps and makeup pumps are tested periodically. Periodic inspections and testing will be performed to monitor heat exchanger performance and cleanliness. Individual pump performance will be assessed in regularly scheduled inspections that can be performed without interruption of plant operation. Isolation of the EECWS will be tested periodically by simulating the initiating events that automatically bring the EECW and EESW systems into operation.

No periodic leak tests will be performed because the system is under continuous pressure during operation. Periodic visual inspection of the system will detect minor leakages such as those from valve stems, flanges, and instrument tubing.

9.2.2.5 Instrumentation

The RBCCW pump motors are equipped with standard controls and protective devices, and are monitored from the main control room. Readouts to observe pressure and inlet and outlet temperatures in the RBCCW and EECW systems are also provided in the main control room. Interlocks are provided on the RBCCW pumps to prevent their starting upon low makeup tank level and/or low suction pressure. High/low pump differential pressure and high/low makeup tank level are alarmed for the RBCCW and EECW systems. Low suction pressure is alarmed only on the EECW pumps. Individual components are equipped with local temperature indicators to periodically monitor performance. The temperature of the RBCCWS (or the EECWS) during operation is controlled by modulating the discharge flow of tube-side cooling water through the respective heat exchangers.

High- and low-level alarms and alarms for low system pressure are provided on the makeup tanks to alert the operator of system leakage and EECW makeup pump failure.

The RBCCW supplemental cooling pumps will be controlled and monitored from a control panel located in the basement of the turbine building. When one or more of these pumps trip, a common trouble alarm will be generated in the main control room. An interlock is provided to trip the RBCCW supplemental cooling pumps on low flow to the RBCCW header. A trip of the operating pump will automatically start the standby pump supplying the same division. A low level in the RBCCW makeup tank will prevent operation of all RBCCW supplemental cooling pumps. During the normal mode of operation when both loops of supplemental cooling are in operation, an interlock is provided to prevent these pumps from operating without the SCCW chillers in operation. Should no SCCW chillers be in operation, none of the pumps will start and all operating RBCCW supplemental cooling pumps will be tripped.

During the normal mode of operation one of the following two (2) modes are applicable. These two (2) modes of operation are dependent upon a single SCCW chiller's Full Load Amps (FLA) reading. Mode 1 allows the operation of any one single chiller and two (2) chilled water pumps to provide cooling to both RBCCW-SCS loops SCS-1 and SCS-2 when GSW inlet temperature is low. Mode 2 requires the operation of two (2) chillers and two (2) chilled water pumps to provide cooling for both RBCCW SCS loops.

If it is desired to operate only the supplemental cooling pumps or chilled water pumps for the purpose of maintaining water quality, a maintenance switch is provided which permits operation of the pumps without the chillers running.

The water temperature exiting each RBCCW supplemental cooling heat exchanger is maintained at the required value by a temperature control valve that controls the bypass of RBCCW flow around the heat exchanger.

9.2.3 Demineralized Water Makeup System

9.2.3.1 Design Bases

The demineralized water makeup system is designed to deionize water and store it for makeup to the reactor coolant system and plant auxiliary system and services, and is designed as a direct source of water for flushing and cleaning operations.

The raw water is supplied from the potable water system. The influent and effluent water qualities are shown in Tables 9.2-5 and 9.2-6, respectively.

The demineralized water makeup system is nonseismic, and is constructed in compliance with standards for Quality Group D components. This criterion is met by designing the system to ASME Section VIII and ANSI B31.1.0 code requirements.

9.2.3.2 System Description

The demineralized water makeup system consists of a 300-gal potable water holding tank, a packaged skid-mounted reverse osmosis unit, and two raw water booster pumps with associated distribution piping.

Normal operation of the make-up demineralizer is manually initiated from the reverse osmosis (RO) unit control panel. The booster pump takes suction from the raw water holding tank and sends it to the RO water treatment system. The RO system consists of three separate skid mounted units. The first skid is the pretreatment unit which contains the media filters, carbon filters and the softeners. The second skid is the main RO unit which includes both passes of the reverse osmosis system and the cleaning pump. The last skid, the post treatment unit, contains the transfer pump, ultraviolet light and deionization (DI) bottles.

The normal operation of the RO units is in series. The system operated in the series mode, will provide approximately 25 gpm of purified water. Only one of the two booster pumps needs to operate to supply water to the RO unit. The purified water is stored in the demineralizer make-up water storage tank. The concentrate which is the reject water of this system is simply concentrated potable water and is discharged into the boiler blowdown sump.

Potable water flow into the holding tank is controlled automatically by a level control inlet valve. Operation of the system depends on the water level in the makeup demineralized water storage tank. Makeup demineralized water storage tank level indication with a low-level alarm is provided in the main control room.

Connections are provided to recycle the contents in the demineralized storage tank through the makeup demineralizer to upgrade the quality of the water as it deteriorates due to CO_2 absorption during storage.

9.2.3.3 Safety Evaluation

The demineralized water makeup system is not required for reactor shutdown and as such is not a safety-related system. Redundancy to ensure continuity of design function is not required. Because of the processes involved in this facility, only high-purity water is handled, and no long-term degradation of equipment is anticipated.

9.2.3.4 Tests and Inspections

Initial system flow checks, valve operability, instrumentation and control loop checks, and alarm setpoints were performed in accordance with the Preoperational Test program as discussed in Chapter 14. Flow meters are provided to ascertain pump performance as are on-line conductivity monitors to determine water quality. Grab samples will be taken periodically to confirm water quality and to verify instrument accuracy.

Visual inspection will detect minor leakages such as those from valve stems, flanges, and instrument tubing. Potable water booster pumps will be operated on a rotating basis.

9.2.3.5 Instrumentation

The demineralized water makeup system is operated from the RO unit control panel which is a local panel located in the auxiliary boiler house. Local flow meters provide indication of raw water flow through the system, including the flow through the various skids of the RO unit. On-line conductivity monitors provide information on the various skids of the RO unit performance. The various RO unit trouble alarms and the raw water holding tank low level alarm will shut down the RO unit operation. Any one of these alarms will also initiate the make-up demineralizer trouble alarm in the main control room.

Switchover and operation of the regenerative and backwashing cycle are manual and done from the local RO unit control panel.

All process instrumentation, including that required to maintain temperature, pressure, and flow for the process cycle and the regenerative cycle, is locally indicated.

9.2.4 Potable Water System

9.2.4.1 Design Bases

The potable water system for Fermi 2 is composed largely of existing facilities at Fermi 1, with extended underground distribution lines.

The potable water system is designed to comply with Quality Group D Standards and State of Michigan Health Department code requirements.

9.2.4.2 System Description

The potable water system for Fermi 2 consists of an underground distribution header with branches to the various facilities that require service.

Fermi 2 demand is supplied by the Frenchtown Water System. The 100,000 gallon elevated storage tank on site is abandoned in place. Potable water is used in Fermi 2 to supply the demineralized water makeup system described in Subsection 9.2.3, sanitary plumbing, drinking fountains, washrooms, kitchen facilities, safety showers, and TBHVAC evaporative coolers.

9.2.4.3 Safety Evaluation

The potable water system has no apparent source of contamination. There are no interconnections between the potable water system and any other systems, except that the potable water supplies the demineralized water makeup system and TBHVAC evaporative air coolers. Potential contamination is precluded by an open break in the fill pipe for the demineralized water make-up system and the TBHVAC evaporative air cooler. Because the facility is specifically intended to handle and eliminate impurities, no long-range degradation of equipment is foreseen. Apart from the demineralized water makeup system (which is not critical to the operation or safe shutdown of the reactor), end users of the potable water system are plant personnel. There is, therefore, no requirement for redundancy in order to maintain uninterrupted service. Adequate water supply to the safety showers and eyewash stations is maintained by the tandem booster pumps of the potable water system with one in operation and the other in standby.

9.2.4.4 Tests and Inspections

No special test or inspections are required for the Potable and Sanitary Water System.

9.2.4.5 Instrumentation

Indicating instruments are read out locally in the Potable Water Building.

9.2.5 Ultimate Heat Sink

The ultimate heat sink is provided by the RHR complex, which contains the RHR service water (RHRSW) system, the EESWS, the diesel generator service water system, the mechanical draft cooling towers, the emergency ac power system (diesel generators), and the reservoir. The systems are shown in Figure 9.2-6. The ultimate heat sink design conforms to the requirements of Regulatory Guide 1.27.

9.2.5.1 Design Bases

The RHRSW system is designed for the following functions:

a. With the RHR system, to remove decay heat and residual heat from the nuclear system so that refueling and nuclear system servicing can be performed

b. With the RHR system, to supplement the fuel pool cooling system with additional cooling capacity

c. With the RHR system, to remove decay heat and residual heat from the nuclear system by cooling the suppression pool water, following a postulated LOCA

d. To provide a method to flood the reactor pressure vessel (RPV), acting as a backup in the extremely unlikely event that all RHR (low pressure coolant injection [LPCI] mode) and core spray pumps fail to operate following a postulated LOCA

e. To provide a method to flood primary containment so that the fuel can be removed from the RPV following a postulated LOCA.

The EESWS is designed to provide a cooling water source for the EECWS. The system functions only during a loss of offsite power, high drywell pressure, or upon failure of the RBCCWS.

The diesel generator service water system is designed to provide a cooling water source for the emergency diesel generators (EDGs) during testing and emergency operation.

The ultimate heat sink system structures are designed to comply with Category I requirements. System construction is designed to comply with requirements for Quality Group C components. Piping, valves, and pumps conform to the ASME Section III Class 3 Code requirements.

The ultimate heat sink system is sized to provide sufficient cooling for 7 days following a reactor shutdown without makeup water addition to the RHR reservoir.

The system structures (pump house, diesel generator building, reservoir, and cooling towers) are designed so that the equipment is physically separated or separated by barriers to ensure against multiple damage from missiles, pipe whip, and fire.

The ultimate heat sink is designed to withstand severe natural phenomena (safe-shutdown earthquake, tornado, storm, flood, and freezing). It is designed to withstand any single failure of manmade structures or components. All necessary electrical equipment is served by the essential buses in the event of loss of offsite power.

The RHRSW supply pressure is less than the pressure in the recirculating RHR system during a normal shutdown or under accident conditions. Therefore, radiation detectors are attached to return lines from the RHR heat exchangers to the cooling towers to monitor for leaks in the exchangers.

9.2.5.2 System Description

The RHR complex consists of a single highly reliable water supply (reservoir); a means for heat rejection (cooling towers); a standby power source comprising four EDGs; a makeup and decanting system; and associated pumps, piping, and instrumentation.

9.2.5.2.1 RHR Complex Reservoir

The RHR complex reservoir consists of two one-half-capacity reinforced-concrete structures of Category I construction, each with a capacity of 3.41 x 10^6 gal of water at elevation 583 ft. The reservoirs are connected by redundant QA I, Seismic I, ten-inch penetrations which permit access to the combined inventory of the two reservoirs for either RHRSW, EESW, or EDGSW division usage, which assures that the 7-day supply of water is available.

Normal reservoir water level is at Elevation 583 ft (New York Mean Tide, 1935). Waterproof construction of the walls is provided to Elevation 590 ft (New York Mean Tide, 1935) for protection against flooding from Lake Erie. Subsection 2.4.2.2.3 contains a further discussion of the RHR complex flood protection. Each division of the reservoir is fitted with a floodproof nonsiphon overflow to eliminate excess water. Makeup water delivery ports are designed to prevent siphon losses in the event of a break in makeup water supply piping.

Reservoir water loss due to leaks in the RHRSW, EESW, or diesel generator service water lines is detected by redundant level indicators in each division of the reservoir. Comparison between expected water level due to cooling tower losses and actual indicated level will provide sufficient data to determine any system leakage.

9.2.5.2.2 Cooling Towers

A two-cell induced-draft cooling tower is located over each division reservoir. The towers are of Category I fireproof construction with reinforced-concrete shells, cement board fill, and mist eliminators. Each tower is designed to cool one division of the plant load (one RHR heat exchanger, one EECW heat exchanger, and two EDGs), thus providing complete redundancy. Component design parameters for each tower are given in Table 9.2-7.

Each RHRSW cooling tower cell fan is driven by a 150-hp two-speed motor. The motor is connected to the ESF bus of the EDGs for a redundant power supply, and is manually started and stopped from the main control room.

The towers and fan drives are provided with a reinforced-concrete protective shell for tornado, earthquake, and missile protection.

The fans are provided with a brake system to prevent overspeed from the design-basis tornado. The fan drive shaft is provided with a shield to protect it from tornado missiles.

The cooling tower structure is designed to withstand horizontal and vertical tornado missiles. The cooling fan motor is enclosed in a concrete cubicle designed to repel both types of missiles, and the cooling tower gear hub and shaft are protected by missile shields. Using the guidelines in Standard Review Plan (SRP) Section 3.5.1.4, the only design missile that can be elevated to the top of the towers is the 1-in.-diameter by 3-ft, 8-lb rebar. This missile could damage the cooling tower fan blades if the velocity is sufficiently high. However, analysis has shown that the probability of damaging fans in both cooling tower divisions by rebar tornado missiles is very low (see subsection 3.5.1.3 for more detail). Not withstanding this low probability, two spare sets of two RHR cooling tower fan blades and the necessary tools to install them are stored in the RHR complex building in a location protected from the tornado and tornado missiles. In the event that the cooling tower fan blades are damaged, the blades can be replaced and the fan restored to an operating condition. Plant safe shutdown will not be precluded in the event of tornado missile damage to all four of the RHR cooling tower fans, including assuming a loss of offsite power and a single independent failure. The plant organization estimates that it would take six hours or less to replace a set of cooling tower fan blades. If no fans are available for six hours, reservoir temperature is calculated rise to approximately 100 degrees F. All essential equipment cooled by the UHS is capable of performing its required safety functions at the higher reservoir temperature. One cooling tower fan can maintain hot standby and two cooling tower fans can achieve cold shutdown under these conditions.

In addition to missiles, miscellaneous debris can fall into the tower from the tornado. The debris would not damage the fan blades or other structural components of the towers. The debris would be removed while the blades are being replaced.

9.2.5.2.3 Emergency Diesel Generators

The EDGs are located as a part of the RHR complex. Two divisional pairs of two EDGs are provided; only one divisional pair is required for a safe plant shutdown. The divisional separation is maintained in the EDG system; each EDG division powers only equipment of that same division, and is cooled by that same division. In this manner, no postulated single failure can affect more than one division. A more detailed description of the system is provided in Subsection 8.3.1.1.8 and Subsections 9.5.4 through 9.5.7.

The EDG building is a Category I reinforced-concrete structure. An isolation wall is provided between each EDG for fire and missile protection. Independent fire detection and automatic fire- fighting systems are provided for each EDG.

Diesel generator cooling water is supplied from the RHR reservoirs with each diesel generator supplied by its own pump. Supply lines are also independent for each diesel generator. The diesel generator service water pumps start and stop automatically in conjunction with the diesel generators. The diesel generator service water supplies cooling water to the lube oil heat exchanger, the engine inlet air cooler heat exchanger, and the engine jacket coolant heat exchanger. Demineralized water with corrosion inhibitors is used for the closed loop engine jacket coolant. Makeup is provided by the demineralized water storage tank. The diesel generator service water flows through the tube side of the three-stage heat exchanger. The first stage cools the engine inlet air coolant system, then the second stage cools the lube oil, and finally the third stage cools the jacket coolant.

9.2.5.2.4 Makeup and Blowdown Systems

The makeup system is provided to replace evaporation and blowdown losses during normal shutdown cooling. The makeup system is not designed to withstand accidental and natural phenomena nor to function in the event of a single failure. The system is designed to fill and replenish the reservoir as required, to prevent flooding of the reservoirs, and to prevent siphon losses from the reservoirs in the event of a pipe break. The water makeup and the decanting system are shown in Figure 9.2-7.

Normal makeup water will be supplied by the plant GSW system. Normal water level in each division of the reservoir will be maintained automatically by regulating supply valves.

Five GSW (7700 gpm each) pumps are available to supply makeup water, using installed GSW system piping.

The blowdown system is provided to control the buildup of solids in the reservoir water during normal shutdown cooling. The piping is designed to prevent siphoning from the reservoirs in the case of a line break or other incident. Decanting pumps route blowdown from the reservoir to the main condenser circulating water reservoir. Details of blowdown from the main condenser circulating water reservoir are described in Subsection 10.4.5. Details of effluent monitoring are given in Section 11.4.

9.2.5.2.5 Pumps

Each division of the complex is provided with full-size vertical turbine pumps and a separate reinforced-concrete pump house. All pumps are mounted to ensure adequate net positive suction head (NPSH) under all anticipated operating modes. The pump vendor indicates that a minimum submergence at Elevation 554.6 ft will prevent vortexing of the inlet water to the suction bell of the emergency diesel generator service water (EDGSW) pumps, assuming rated flow at 100°F. The other service water pumps, the EESW and RHRSW pumps, require a minimum submergence at Elevation 554.9 ft and 555.7 ft, respectively. The pump motors and electrical switchgear are located at Elevation 590 ft (New York Mean Tide, 1935), ensuring that the system will continue to operate even if the reservoir is breached during the postulated site high-water event. The pumps and pump houses are Category I construction. Column bracing is provided as required to limit stress to allowable values. All pumps are connected to the essential bus for redundant power supply.

The RHRSW pumps are started and stopped manually from the main control room. Each pair of pumps is capable of delivering 9000 gpm* to the RHR heat exchangers and then to the cooling towers. In the flooding mode, the head of water is sufficient to fill 300,000 ft^3 of air space in the drywell in 1 week, at a rate of approximately 250 gpm. In the event of failure of all four of the 10,000-gpm RHR pumps, the RHRSW pumps in Division II will be capable of backup to the RHR pumps in the LPCI mode at the rate of 3250 gpm.

The 1600-gpm EESW pumps are started automatically on demand of the EECWS. One 800-gpm diesel generator service water pump is provided for each of the four diesel generators.

These pumps start and stop automatically, corresponding to the operation of the respective EDG.

Since the reservoir is covered as shown in Figures 1.2-26 through 1.2-28 and 1.2-31, no automatic backwash strainers are provided on the pump discharge.

NOTE: *RHRSW pump flow reduces below 9000 gpm with time due to the RHR reservoir evaporative and drift losses.

9.2.5.2.6 Piping

The piping system consists of two redundant loops. Each loop serves one division of the system.

Separate piping systems supply the service water from the pumps to the RHR and EECW heat exchangers. The EDG units also have individual cooling water supply lines. The RHRSW and EESW return lines are combined into a single header for each division and are routed to the reservoir via the cooling towers. Diesel generator cooling water return lines for each division also join these two common return headers to the cooling towers. The piping conforms to the following conditions:

a. Piping is Quality Group C and Category I (except for the makeup line and the overflow line). Thermal stress and seismic analysis calculations are made in accordance with the ASME Code Section III, Subsection ND for Class 3 components

b. Pressure indicators are provided on the discharge side of the RHRSW and EDGSW pumps, with PCVs for minimum-flow protection. The PCV air operators are supplied with interruptible air, and the valves fail closed on loss of air

c. Heat removal rate is controlled by a remote manually controlled globe valve on the RHR (for RHRSW), an automatic control valve on the EESW, and a manually controlled globe valve on the diesel generator service water system

d. The cross tie required for primary containment flooding is located in Division II between the discharge side of one pair of RHRSWS pumps and the discharge pipe of the shell side of an RHR system heat exchanger

   Keylock dual isolation valves are provided on the cross tie and are normally closed to prevent the service water from entering the RHR system loop. A testable check valve is provided to prevent the RHR system water from leaking into the service water loop. The cross tie is sized for a flow of 3250 gpm. The two isolation valves are motor operated from the main control room

e. Provision is made for process radiation monitoring on the service water discharge of each RHR heat exchanger division

f. The EESW pumps are provided with spring to close pressure regulating valves for minimum flow protection.

9.2.5.3 Safety Evaluation

The ultimate heat sink consists of a single highly reliable water source with fully redundant cooling towers, pumps, and conduits capable of providing sufficient cooling for 7 days to permit safe shutdown and cooldown of the nuclear unit in the event of a design-basis accident. Procedures for ensuring continued cooling availability after 7 days are available. The RHR complex is designed for a single active or passive failure of any fluid system component without loss of safety function. The ultimate heat sink is capable of withstanding the effects of the most severe natural phenomenon associated with the site. Other applicable site-related events have been analyzed, including a single failure of man-made structural features. System failure analysis is summarized in Table 9.2-8.

9.2.5.3.1 Protection Against Natural Phenomena

The physical separation of RHRSWS Division I and Division II equipment, along with the single highly reliable water source with the two reservoirs cross-connected contributes to the reliability of system performance in the event of damage by natural phenomena (earthquake, tornado, storm, or flood) to provide a sufficient water source for 7 days.

9.2.5.3.1.1 Earthquakes

The RHRSWS is designed to meet Category I requirements. The method used in the seismic analysis of the RHR complex is similar to that of the reactor building as outlined in Section 3.7.

9.2.5.3.1.2 Tornadoes

A design-basis tornado and the missiles it might generate are described in Sections 3.3 and 3.5.

9.2.5.3.1.3 Freezing

The RHR building is designed to protect the reservoirs from direct exposure to winter weather. The floors of the RHR building cover a large portion of the reservoir surfaces and the remaining portion of the reservoirs is covered by floor gratings and tower baffles and is protected by high walls. In addition, 80 to 90 percent of the reservoir water is below the frost line. Drain lines provide passive freeze protection for the Mechanical Draft Cooling Tower (MDCT) spray distribution headers by allowing standing water to drain to the RHR Reservoir subsequent to MDCT operation.

The pump columns below the pump room are protected from freezing by an enclosure which is installed at the two open sides of the area below the pump room floor. The enclosed air volume temperature is locally monitored from the pump room.

During unit operation, the RHR complex reservoirs would receive heat from surveillance testing of plant systems such as the EDG, high pressure coolant injection (HPCI), and reactor core isolation cooling (RCIC) systems, and from other plant activities (such as operating the torus water management system). This heat would go directly to the RHR complex or the torus. Heat sent to the torus is removed by sending it to the RHR complex. During unit shutdowns, the RHR complex would receive reactor decay heat that is sufficient to prevent the reservoirs from freezing. The RHR complex also has cold weather bypasses around the cooling towers that can direct service water to the reservoirs instead of the RHR complex cooling towers. This would help retain the heat sent to the reservoirs.

The reservoir temperatures are monitored by readout in the control room and alarm at 43°F. The heat added to the reservoir during normal operation and testing is expected to be sufficient for this temperature to be exceeded during the winter. If needed, additional heat may be used to increase the reservoir temperatures by operating an EECWS or a temporary system installed for that purpose. Surveillance requirements of the reservoir temperature and required action in the event of low temperatures are contained in the Technical Specifications.

9.2.5.3.1.4 Floods

The reactor/auxiliary building and the RHR complex are designed to withstand the maximum postulated flood-water level and associated wave actions as described in Subsection 2.4.2.2 and Section 3.4.

The reservoir overflow is a nonsiphon floodproof port. Sidewalls are waterproofed to Elevation 590 ft (New York Mean Tide, 1935) and are above the Lake Erie stillwater level at the plant site. All active equipment that could be damaged by water (pump motors, switchgear, diesel generators) is located above the maximum flood-water level. The site flood considerations and plant protective structures are discussed in Subsections 2.4.2, 2.4.3, and 2.4.5.

9.2.5.3.1.5 Snow and Ice

The RHR complex roof structure is designed for the probable maximum snow and ice (including cooling tower drift) loads. The roof structure is capable of supporting a maximum loading of 70 lb/ft^2.

9.2.5.3.2 Protection Against Accident Phenomena

The RHR complex is designed to withstand the effects of the most severe natural phenomena associated with the Fermi plant site, as stated in Subsection 9.2.5.3.1 above. Other applicable site- related events such as river blockage, river diversions, reservoir depletion, or transportation accidents are not applicable to the design or postulated to occur. Flooding of the plant by surface runoff is not possible (Subsection 2.4.3.5). Transportation accidents are expected to have no effect on the complex because

a. The nearest main-line railroad and interstate highway are at least 3 miles from the plant site

b. The nearest ship channel is at least 4-1/2 miles from the plant site; the lake is of insufficient depth for commercial traffic in the plant vicinity; and the RHR complex is approximately 1100 ft inland from the lake shore

c. No significant aircraft operations occur in the plant vicinity.

A single failure of man-made structures such as the cooling tower or the pump house would not result in the loss of capability of the heat sink to accomplish its safety functions, because of the redundancy and separation of these components. A breach in the reservoir retaining wall above grade elevation would not compromise the reservoir's 7-day capacity since the reservoir capacity is contained below grade of 583 ft. A below grade structural failure would only result in a limited degree of water loss since the damaged reservoir(s) would leak only until the ground-water elevation is reached. The 7-day capacity includes allowance for a below grade structural crack in both reservoir basins. Stability of ground-water level is discussed in Subsection 2.4.13.

The RHR complex structures, systems, and components are designed so that the minimum performance requirements of the complex can be met in case the postulated turbine missile strikes the complex.

Typical missiles that could be ejected from the EDGs will be small auxiliary items knocked loose from the engine exterior by blows from within. The maximum velocity of the missiles would be 40 fps, with a maximum mass of 5 lb each. The walls of the EDG rooms are designed to withstand such missiles and contain them within the room. Refer to Subsection 3.5.1 for further discussion of these postulated missiles.

9.2.5.3.3 System Reserve Capacity

The ultimate heat sink system was originally sized to provide sufficient cooling for 30 days following an accident without make-up water addition to the RHR reservoir. Regulatory Guide 1.27 states that a UHS capacity of less than 30 days may be acceptable if it can be demonstrated that replenishment can be effected to ensure the continuous capability of the sink to perform its safety functions, taking into account the availability of replenishment equipment and the limitations that may be imposed on freedom of movement following an accident. In order to provide additional head for the service water pumps, a 7-day reservoir replenishment was reviewed and was found to satisfy the R.G. 1.27 guidelines.

The Fermi 2 UHS design evolved long before the post-TMI improvements in Emergency Preparedness. Those improvements are reflected in the Detroit Edison Radiological Emergency Response Preparedness Plan. One of the objectives of this program is effective and timely implementation of emergency measures. Detroit Edison now has the resources of the Emergency Response Organization to rapidly identify the need for reservoir replenishment and to direct procurement of material and field implementation. This change significantly improves the ability to provide reservoir replenishment within 7 days as it relates to resolving problems associated with freedom of movement following an accident or occurrence of severe natural phenomena.

The 7-day make-up provision for the RHR reservoir is consistent with the 7-day make-up provisions allowed for replenishment of the diesel generator fuel supply. Therefore, this period of time is sufficient to recover from the effects of natural phenomena such as tornado, storm, earthquake or flood and restore site access for replenishment activities.

The reservoir replenishment procedure requires that reservoir make-up be established within 7 days following exceeding the Technical Specification reservoir level limit. Make-up will be provided by the normal make-up system or using RHR Complex fire hoses. If these systems are not available, temporary equipment will be used. The necessary pumps and hoses are commercially available from many sources and 7 days is sufficient time to procure and install the equipment. The procedure requires redundant replenishment equipment so that a single failure will not interrupt make-up. Necessary equipment requirements and vendors are listed to allow rapid procurement. Temporary pumps are located in lower postulated post-accident dose rate areas so that access in available for monitoring and periodic refueling. The water source will be either Lake Erie, the Fermi 1 discharge canal, the circulating water reservoir, the on-site Quarry Lake or Swan Creek. Projected dose for hose installation is below allowable limits. The temperature and quality of make-up water is maintained to ensure that the service water systems and cooling towers perform as required. Siphon of the reservoir is prevented by ensuring that hoses are not placed into the reservoir water.

The reservoir will continue to store approximately 6 million gallons of water which was the previous 30-day supply. However, the level below that needed for 7 days of operation will be used to provide additional service water pump head margin. Therefore, if the level were to go below that required for 7 days of operation, a slow degradation in service water pump performance (discharge head) below design requirements would be possible.

The 7-day supply calculations utilize the Marley design and test data for cooling tower drift and evaporative water losses. In addition, the seven day supply also assumes a below grade structural crack in both reservoir basins and losses for EECW makeup using EESW. To maximize drift and evaporative losses, the reservoir basins are assumed to be cross-connected and both divisions of EDGs, RHR, EECW/EESW, and RHRSW cooling towers are assumed to be operating. The RHR heat exchanger was assumed to be clean (unfouled) to maximize heat loads on the ultimate heat sink. Constant historical worst-case meteorological data is used to compute evaporative water losses. The 7-day supply also assumes initial reservoir level at the technical specification limit of 580’-0” versus the normal operations level of between 582’-0” and 583’-0” which provides additional conservatism.

The RHR reservoirs are sized to provide for the evaporative and drift losses from the RHR cooling towers for 7 days following a design-basis recirculation line break, assuming a total loss of offsite power for the 7-day period. Evaporative losses are calculated as a function of cooling tower range using computer generated curves based on data supplied by the cooling tower manufacturer.

Since the cooling towers are designed to function largely by evaporative heat transfer, water loss due to evaporation is the largest contributor to water consumption. Drift losses (liquid droplet carryover in the air stream) are assumed to be 0.05 percent of liquid flow. Drift losses in combination with the other secondary contributors to water consumption (i.e. reservoir leakage and EECW makeup*) are small compared to evaporative loss.

* The cooling load for the spent fuel pool is not included since the normal burden is insignificant. When all or part of the core is unloaded, the cooling load in the spent fuel pool will increase, and the cooling load imposed by decay heat in the core will decrease proportionately.

The RHR reservoirs are nominally maintained between 583 ft and 582 ft elevation by an automatic makeup system. The Technical Specifications limit is established at 580 ft, or 5,980,000 gal. The 7-day water loss will result in a water level above Elevation 567'-6". This level is above the minimum submergence level required for the service water pumps as indicated in Subsection 9.2.5.2.5.

The heat load into the suppression pool as a function of time for the first 24 hours post LOCA was taken from the suppression pool peak temperature calculations described in Section 6.2.1.3.3. This suppression pool heat load includes decay heat (based on a pre-trip power level of 3499 MWt, which is 102% of 3430 MWt), sensible/blowdown energy, and RHR and core spray pump heat. The heat input to the suppression pool after 24 hours is from decay heat and pump heat. The decay heat after 24 hours is determined using the Standard Review Plan, Section 9.2.5, Branch Technical position ASB 9-2. The fractions of decay heat (as a fraction of operating power) versus time were converted to decay heat using a pre-trip reactor power level of 3499 MWt, which is 102% of 3430 Mwt.

The heat from the station auxiliary systems includes heat from the EECWS, the EDGs, and pump energy. The heat from the EECWS includes the emergency core cooling system (ECCS) pump cooling, control room air conditioning, air compressor cooling, ECCS room coolers, thermal recombiner area coolers, and standby gas treatment system (SGTS) room coolers. The thermal recombiner units are retired in place, de-energized, and isolated from primary containment with redundant locked-closed isolation valves. The associated area coolers are retained and credited as a heat sink for post-accident environmental conditions. The heat rejected by the EDGs is based on loads commensurate with the function required during each stage of the 7-day period. The pump energy created by the work input of the RHR, core spray, RHRSW, EECW, EESW, and EDGSW pumps has been considered.

The LOCA coincident with a loss of offsite power is the worst-case condition for reservoir water usage because:

a. The main condenser is unavailable for removal of any core decay energy or primary system energy

b. The EDGs run at the highest loads, resulting in highest heat rejection to the complex

c. The EECWS is operating (in lieu of RBCCWS)

The reservoir is not sized to supply the water required for flooding the core or primary containment to allow access to the core for accident recovery. Flooding of the primary containment is a long-term action, initiated many days or weeks after an accident, following an administrative decision. Such a decision would not be made until offsite power is available and the makeup water system is restored to service.

9.2.5.3.4 Multiple Water Sources

Two half-sized reservoirs are provided, each with a capacity of 3,410,000 gal of water at elevation 583 ft. Redundant penetrations cross-connect the two reservoirs and permit access to the total UHS water supply in the event of a mechanical failure in one division. Each division of the system has a separate piping system with adequate separation such that a failure of one will not induce failure of the other. The reservoirs are designed to withstand all applicable site-related natural and accidental phenomena, and there is no retaining "dam," as such, to fail. The water in the UHS is stored below site grade level and approximately 90 percent of the total water volume is below site ground-water level. Therefore, it is concluded that there is an extremely low probability of losing the 7-day cooling capability of the UHS.

9.2.5.4 Tests and Inspections

Initial construction tests such as hydrostatic leak tests of the RHRSWS were conducted per applicable code requirements. Initial system flow checks, valve operability, instrumentation and control loop checks, and alarm setpoints were done in accordance with the Preoperational Test program as discussed in Chapter 14. After startup, a test will be run to observe the heat exchanger (including cooling tower) performance. Periodic tests are made to assess continuing pump performance and to demonstrate piping system integrity. The RHRSWS is periodically checked during its normal system function of cooling down the plant, such as during refueling or other outages. The EESWS will be tested in conjunction with the EECWS. The diesel generator service water system is tested in conjunction with the diesel generator testing. The reservoir and cooling tower are periodically inspected for macro and micro biological fouling and are treated, as required. Sampling and surveillance for control of dissolved solids and macro and micro biological fouling are performed by the Chemistry Section.

9.2.5.5 Instrumentation

System temperatures, pressures, and flows are monitored either locally or in the main control room. Pressure, temperature, and flow indicators are provided with local readouts. Pump and fan motors and controls incorporate standard protection devices.

Makeup for the RHRSW reservoir is automatic (except under accident conditions), controlled by level monitors in the two RHRSW reservoir divisions. These level monitors signal low-level alarms in the main control room.

9.2.6 Condensate Storage and Transfer System

9.2.6.1 Design Bases

The condensate storage and transfer system is designed to store and distribute condensate and demineralized water for use throughout the plant during normal and shutdown plant conditions. To provide for high plant availability, two full-capacity 600,000-gal storage tanks are provided, one designed as the normal storage tank and the other as the return tank. Demineralized water is stored in a 50,000-gal storage tank.

The condensate storage and return tanks are located near the turbine building and the auxiliary boiler house. They are arranged to permit gravity feed to condensate supply pumps and to the HPCI, RCIC, CRD, standby feedwater (SBFW), and core spray systems. During normal station operation, hotwell level is raised as necessary by vacuum dragging water to the hotwell from the CST or CRT. When the plant is shutdown, or when a greater flow is required, the normal, or if necessary the emergency, hotwell supply pumps will start and stop automatically depending on hotwell level. The condensate storage tank is designed to deliver its last 150,000 gal only to the HPCI or RCIC system (see Section 6.3.2.6).

A containment wall surrounds the tanks. Surveillance of surface conditions and radioactive content will be performed during plant operation.

The makeup demineralizer storage tank is located near the auxiliary boiler house and gravity feeds to the demineralized water transfer pumps and jockey pump. These pumps provide demineralized water to the service risers and the condensate storage tank.

Collection and distribution piping for the condensate and demineralized water is carbon and stainless steel. A cathodic protection system is supplied for the piping. The condensate tanks are fabricated of corrosion-resistant, high-strength aluminum alloy.

Piping to the HPCI and RCIC systems conforms to Quality Group B standards and is built to ASME Section III, Class 2, requirements. The balance of the condensate storage facilities conforms to Quality Group D standards and is built to ASME Section VIII and ANSI B31.1.0 code requirements. The tanks are designed to withstand a 100-mph wind when empty. They conform to USAS B96.1, "Welded Aluminum-Alloy Field-Erected Storage Tanks," code requirements. A minimum water temperature of 40°F is maintained in the insulated condensate storage tank by steam from the auxiliary boiler.

9.2.6.2 System Description

The condensate storage and transfer system, as shown in Figure 9.2-10, consists principally of two large storage tanks and three pumps, with associated receiving and distribution lines, one demineralized water tank, and three pumps with associated receiving and distribution lines. Component design parameters are given in Table 9.2-9. The condensate return and the condensate storage tanks are 600,000-gal aluminum tanks with open vents. The condensate storage tank is insulated and has sufficient heating capacity to maintain a water temperature of at least 40°F, which is the design limit for thermal shock to the RPV nozzles. Both tanks are located inside a containment wall near the turbine building. The condensate storage tank receives demineralized water from the demineralized water makeup system and may also receive low-conductivity water from the condensate return tank. There is also a normally closed balance line connecting these two tanks to allow gravity transfer from one tank to the other above the 150,000-gal limiting level of the storage tank.

Containment for any condensate loss that might be experienced is provided by a containment wall in the immediate area around the condensate storage tanks, as shown in Figure 9.2-11. All valves associated with either condensate storage tank are located in valve pits at the base of the tank. Any leakage into either valve pit is automatically pumped through a 4-in. drain line to the waste collector tank in the radwaste building.

A single wall, 3 ft high above the normal grade level, encloses both condensate storage tanks. This forms a contained area approximately 109 ft wide by 232 ft long. The contained area is also excavated 3 ft below grade level. The enclosed area has been sealed with a Hypalon liner (waterproof barrier) to contain all spillage of contaminated water from the condensate system and prevent it from entering the soil in the condensate storage tank and condensate return tank diked area.

Relief valves are installed in the condensate return tank valve pit to prevent inlet piping overpressurization. A 30 gpm relief valve discharges directly to the CRT valve pit. Relief valves with 600 and 5000 gpm relief capacities discharge into the lined dike area surrounding the CRT and CST for subsequent cleanup and processing.

Direct access to Lake Erie by lost condensate seeping into the ground is prevented by the clay fill seal beneath the shore barrier. Initial movement of any seepage would be downward to mix and dilute with the ground water from the dolomite aquifer. Thereafter the diluted material would move into and through the aquifer at the same rate of flow and direction of movement as the transient ground water. The direction of movement would be to the east, at a rate of 0.24 ft per day or less. In essence, this would be the same sequence of events as that documented for the loss of all radwaste water to the aquifer in Edison's response to AEC Question 10.2 in the Fermi 2 PSAR, except that the condensate water would be orders of magnitude less radioactive.

The storage tanks are provided with horizontal slots (weirs) in the sides of the tanks with ducting to channel overflow down the side of the tank and eliminate spray. An alarm system is provided that alarms in the control room to indicate that a tank is in the process of overflowing. This alarm system is independent of any other instrumentation or alarms associated with the condensate storage tank or condensate return tank.

Recycle streams are treated and monitored prior to transfer to the condensate return tank. If water in the condensate return tank requires further treatment, it can be transferred to the radwaste system by gravity for processing, or it can be sent through the polishing demineralizer via the hotwell and condensate system.

It is possible for the following water sources to be transferred directly to the condensate tanks:

a. Return from radwaste system

b. Return from CRDs

c. HPCI pump test return

d. RCIC pump test return

e. SBFW pump test return

The inlet valves on the condensate storage tank and condensate return tank are provided with an interlock to prevent the two valves from being simultaneously closed. This interlock provides protection against overpressurization of the tank inlet piping by the CRD, HPCI, RCIC, or SBFW pump.

Treated recycled condensate water is normally routed to the condensate return tank. Typical sources are:

a. Reactor well drain

b. Return from drywell seal rupture

c. Spent fuel storage pool drain

d. Main condenser high-level relief

The demineralized water makeup system supplies only the heated condensate storage tank, the auxiliary boiler, and the demineralized water distribution system.

The condensate storage tank is sized for the following duty:

Fuel pool and reactor well	410,000 gal
Reserve for the HPCI and RCIC pumps (see Section 6.3.2.6)	150,000 gal
Additional reserve	40,000 gal
Total	600,000 gal

The condensate storage tank provides a source of water for the HPCI, RCIC, SBFW, core spray, and CRD pumps. Either condensate tank can supply the low-pressure turbine hood spray pump through a common header.

The condensate return tank is the same size as the condensate storage tank in order to provide operational flexibility so that one tank may be substituted for another for certain functions as described herein. The condensate return tank has sufficient capacity for:

Fuel pool and reactor well	410,000 gal
Additional reserve	190,000 gal
Total	600,000 gal

The primary function, however, of the return tank is to receive condensate from the plant and to store any temporary excess condensate. Excess water from the condenser hotwell is normally relieved to this tank. During normal station operation, hotwell level is raised as necessary by vacuum dragging water to the hotwell from the CST or CRT. When the plant is shut down, or when a greater flow is required, the normal, or if necessary the emergency, hotwell supply pumps will start and stop automatically depending on hotwell level. Makeup to the hotwell is normally supplied by the hotwell supply pump drawing condensate from the condensate return tank. During normal station operation, the hotwell supply pump starts and stops automatically, depending on the hotwell level of the condenser.

Condensate for distribution to other plant areas is supplied from the condensate pump discharge header, downstream of the condensate polishing demineralizers, via a pressure-reducing valve. Condensate at 100 psig feeds the condensate storage system distribution header.

The condensate storage and transfer system distribution pumps are housed in the turbine building and are supplied from the same header, feeding from either condensate tank. The three pumps required for distribution are described as follows:

a. The condensate storage jockey pump (one 100-gpm pump) is used to maintain condensate pressure during startup/ shutdown and supply water to the condensate distribution header whenever the supply from the condensate system is not available. The condensate storage jockey pump has minimum flow protection to provide sufficient pump cooling in the event of low or zero flow in the condensate distribution system. The condensate distribution system supplies the following:

    1. Radwaste building

    2. The turbine building backwash tank

3. A reactor building supply header. This portion of the reactor building supply header is intended for preoperational flushing and fill, and not for makeup.

   It provides RHR system flushing and maintains the RHR keep fill system. As such, the various distribution branches to the following items are normally valved off:

   (a) RBCCW makeup tank

   (b) EECW makeup tank (two).

The reactor building supply header supplies makeup to the following:

   (a) Cleanup phase separators

   (b) Reactor water cleanup filter-demineralizer

   (c) Fuel pool skimmer surge tank

b. The normal hotwell supply pump is a 600-gpm pump discharging to the main condenser hotwell level control station. The normal hotwell supply pump can be used to supply water to the condensate distribution system when either of the other two sources (jockey pump or condensate system supply) are insufficient or out of service. The normal hotwell supply pump has a minimum flow valve which provides flow protection for a limited time. Should plant outage activities require prolonged operation of the pump with minimum flow, a supplemental, temporary flow path is established to provide adequate minimum flow protection.

c. The emergency hotwell supply pump is a 2000-gpm pump with an independent distribution line to the main condenser hotwell and branch to the TBCCWS for flushing. This emergency pump can also discharge into the condensate return line to the storage tanks. In this way, it can be used to transfer condensate water from one tank to the other.

The makeup demineralized water tank supplies demineralized water for the following:

a. Condensate storage tank

b. Auxiliary boiler deaerator makeup

c. TBCCWS makeup

d. RBCCWS makeup

e. EECWS makeup

f. Standby liquid control tank in reactor building

g. Service risers in turbine building, reactor building, auxiliary building, and radwaste building

h. Plant instrument backflush

i. Cask washdown in reactor building

j. Health Physics and chemistry laboratories

k. Deleted

l. Emergency showers in the radwaste building

m. Core spray system charging, and for maintaining the keep fill system.

The demineralized water is distributed to the condensate storage tank and throughout the plant by two 100-gpm transfer pumps and by a 20-gpm jockey pump. Normally the jockey transfer pump operates continuously with bypass flow unloading on low water demand. The jockey pump thereby provides a minimum hydrostatic pressure of 30 psi throughout the system. On increasing flow demand (system pressure decreases), one 100-gpm transfer pump starts automatically. If flow demand is still not satisfied and header pressure continues to drop, the second transfer pump starts.

9.2.6.3 Safety Evaluation

Adequate protection from environmental conditions is provided by designing the tanks to withstand a 100-mph wind when empty. The tanks are designed for -10°F to 95°F ambient temperatures.

Condensate water within the plant is separated from the demineralized water system and confined to areas of limited access. Health Physics surveillance is maintained on this equipment. An exclusion fence surrounds the condensate storage and condensate return tanks. Because of these conditions, personnel injury from radiation is extremely unlikely. Construction materials are corrosion resistant and should serve without failure during the 40-year life of the plant. The tank is constructed of aluminum alloy, and the HPCI and RCIC pump suction lines are stainless steel. Carbon steel piping is provided with cathodic protection.

The design of the demineralized water makeup system precludes radioactive contamination of the storage tank. The transfer line between the uncontaminated demineralized water storage tank and the potentially contaminated condensate storage tank terminates in the condensate storage tank above the normal operating water level. This feature, along with check valves at the transfer pump discharge lines and the normally closed motor-operated isolation valve, provides reasonable assurance against inadvertently contaminating the demineralized water makeup system. Contamination of the potable water system is prevented by an open break between it and the demineralizer water makeup system.

Active functioning of the condensate storage and transfer system is not required during a reactor shutdown. Suction for RCIC (or HPCI) can be manually transferred from the condensate tank to the Category I suppression pool. In addition, on low level in the tank, suction is automatically transferred. Therefore, it is not necessary to install redundant power sources and redundant water sources throughout the condensate system. Nevertheless, the system is designed with certain redundancies (e.g., cross- connections, standby pumps) to reduce, as far as practical, the probability of causing a plant shutdown because of some failure in the condensate storage and transfer system.

Normally, water from the plant is returned to the condensate return tank after treatment and analysis. The water in the return tank will be analyzed to ensure that it is of sufficiently high quality. In the event that water has excessive radioactivity or conductivity readings, it will be transferred to either the polishing demineralizer via the hotwell or to radwaste for further treatment. These operating procedures will ensure a source of high-quality water for station operation.

Leakage is controlled by utilizing welded construction for the storage tanks, and as much as is practicable for the piping. Each penetration on the tank is supplied with an isolation valve. Levels in the two storage tanks are recorded and alarmed in the main control room.

Accidental release of liquids in the condensate storage tank would not result in concentrations in Lake Erie exceeding the limits of 10 CFR 20. Any accidental release that is not retained by the lined containment around the storage tanks will infiltrate the site fill; however, horizontal permeability of the soil will provide sufficient holdup to attain the required decontamination factor by radioactive decay before entering Lake Erie. No credit is taken for filtration or ion exchange through the soil.

9.2.6.4 Tests and Inspections

Initial construction tests such as hydrostatic leak tests were conducted per applicable code requirements for the condensate storage system. Initial system flow tests, valve operability, instrumentation and control loop checks, and alarm setpoint checks were performed in accordance with the Preoperational Test program as discussed in Chapter 14.

Periodic tests are conducted to confirm pump performance and operation of automatic controls. Inspection for system leakage is coincident with pump testing and routine monitoring activities.

9.2.6.5 Instrumentation

Pump motors are equipped with standard controls and protective devices and are controlled and monitored from the main control room. Each pump's flow is indicated locally. The level and temperature of the condensate storage tanks and the demineralized water storage tank are continuously recorded in the main control room. High-and low-water-level and overflow alarms are provided. Level and temperature indicators are provided locally at the tanks.

The storage tank temperature can be manually controlled from the main control room by continuously circulating stored condensate through the condenser hotwell.

9.2.7 Cooling System for Turbine Auxiliaries

9.2.7.1 Design Bases

The TBCCWS is designed to remove heat from auxiliary equipment housed in the turbine building. The TBCCWS is cooled by the GSW system and makeup is supplied by the demineralized water system. The TBCCWS is designed to operate at a lower pressure than the GSW system to prevent leakage to the environs.

The TBCCWS is nonseismic and is constructed in compliance with standards for Quality Group D components. This criterion is met by designing the system to ASME Section VIII and ANSI B31.1.0 code requirements.

9.2.7.2 System Description

The TBCCWS, as shown in Figure 9.2-12, consists of two 100 percent-capacity TBCCWS heat exchangers and three 50 percent-capacity pumps. The TBCCWS component design parameters are listed in Table 9.2-10. During normal operation, one heat exchanger and two pumps operate to remove all the equipment heat loads. The third pump is in standby and is designed to be started manually on low TBCCWS pressure. The TBCCW supply header temperature is maintained by a temperature control valve modulating the GSW flow through the TBCCW heat exchanger. System pressure is controlled by a differential PCV located in the bypass line between the suction and discharge headers of the TBCCW pumps. Makeup to the system as well as system expansion and contraction due to load changes are provided by a makeup tank. Makeup water is automatically supplied via a tank level control valve from the demineralized makeup water system. A pressure-regulating valve maintains nitrogen overpressure in the tank. Nitrogen is provided to prevent the introduction of oxygen into the system, thereby retarding corrosion of the closed cooling water system, and to maintain a positive suction head on the pumps.

Turbine auxiliaries impose a maximum cooling load on the TBCCW heat exchanger of approximately 45 x 10^6 Btu/hr during normal operation. This requires approximately 9000 gpm of GSW, assuming a maximum GSW temperature of 85°F. Circulation on the TBCCW side of the heat exchanger is approximately 6000 gpm; design temperatures are 110°F in and 95°F out. Normal operating temperature is 80°F out. The operating temperature range is 75°F to 88°F as measured at the TBCCW pump suction. The TBCCW header temperature control high-alarm setpoint is 88°F and the low-alarm setpoint is 75°F.

The GSW is not used directly because the relatively high impurity level in this system might result in fouling of equipment heat transfer surfaces. Furthermore, the intermediary loop between potentially contaminated turbine auxiliaries and the GSW system provides additional protection against radioactive water leakage into the environment. The following equipment is cooled by the TBCCWS:

a. First floor:
    1. Station air compressors with associated coolers
    2. Heater feed pump lube oil coolers
    3. Heater drain pump motors
    4. Condenser mechanical vacuum pumps
    5. Oil coolers for each reactor feed pump and turbine drive
    6. Coolers for air conditioning unit serving the Health Physics laboratory and radwaste control room
    7. Cooler for the chemical sampler

b. Second floor:

1. Generator bus duct cooler heat exchangers
2. Hydrogen seal oil coolers
3. Stator winding coolers
4. Excitation equipment area air coolers
5. Offgas system aftercoolers.

c. Third floor:

1. Ring water coolers for the offgas vacuum pumps
2. Adsorber room air conditioner cooler for the offgas system
3. Unitized actuators cooling.
4. Offgas Chiller Refrigeration Unit N6200D010 Condenser.

9.2.7.3 Safety Evaluation

Turbine auxiliaries housed in the turbine building are not considered essential to safe reactor shutdown. An alternative power source for TBCCW pumps and controls is not required. Because a reactor shutdown can be safely executed without depending upon turbine auxiliaries, no alternative water supply to the TBCCWS is required. Redundancy is therefore properly limited to two normally operating pumps and one standby pump to facilitate periodic tests and maintenance and to ensure plant availability.

The design of the TBCCWS avoids direct application of GSW to cooling components and heat exchangers. This excludes impurities from the turbine auxiliaries and service piping and reduces the chances of long-term degradation from fouling or corrosion. Additionally, corrosion inhibitors are added for pH and oxygen control. Alternatively, the TBCCW system may be maintained with pure demineralized water only with no chemicals added.

The TBCCWS operates at a lower pressure than does the GSW system to protect against leakage into the GSW system. Leakage from the TBCCWS into the building is detected by a low-level alarm in the makeup tank and by an alarm on the makeup level control valve stem position. Excessive opening of the makeup valve is indicative of a substantial system leak. Inleakage of GSW will be indicated by a high-level alarm in the makeup tank.

9.2.7.4 Tests and Inspections

Initial construction tests such as hydrostatic leak tests were conducted per applicable code requirements for the TBCCWS. Initial system flow distribution, valve operability, instrumentation and control loop checks, and alarm setpoints were done in accordance with the Preoperational Test program as discussed in Chapter 14. Heat exchanger performance is observed during plant operation using actual system heat loads.

Instruments and controls are inspected periodically. No periodic leak tests are planned since the system is continuously operating and pressurized. Periodic visual inspection of the system will detect minor leakages, such as those from valve stems, flanges, and instrument tubing.

9.2.7.5 Instrumentation

Pump motors are equipped with standard controls and protective devices, and are monitored from the main control room. Readouts to observe pressure and inlet and outlet temperatures in the TBCCW are provided in the main control room. Interlocks are provided on the TBCCW pumps to prevent their starting on low makeup tank level and/or low suction pressure. The temperature of the TBCCWS during operation is controlled by modulating the discharge flow of GSW through the TBCCW heat exchangers. Closed loop pressures are regulated by pump unloading (bypass) valves.

High- and low-level alarms are provided on the makeup tank as are alarms for low system pressure, to alert the operator of system leakage or loss of nitrogen capping.

9.2.8 Torus Water Management System

9.2.8.1 Design Bases

The torus water management system (TWMS) is designed to provide thermal mixing of the torus water, torus water volume inventory control, torus water quality maintenance, and to drain and fill the torus to facilitate inside torus recoating, inspections, and repair work. The TWMS design flow, makeup, and discharge rates are based on draining or filling the 1,000,000 gal of torus water in 48 hr and circulating the torus water at a rate of 500 gpm (maximum). Figure 9.2-13 is the system schematic.

The TWMS pumps (refer to Table 9.2-11) are located in the subbasement of the reactor building in the HPCI room. The interconnected piping required to perform the circulating, cleaning, draining, and filling functions of the TWMS is located in the reactor, turbine, and auxiliary buildings.

The TWMS primary containment penetrations and the associated isolation valves are classified as ASME Section III, Class 2, and designated as Category I. The balance of the TWMS is classified as ASME Section VIII for pressure vessels and ANSI B31.1.0 for piping, and is designated as nonseismic.

9.2.8.2 System Description

The TWMS pumps take suction from two torus connections placed at a 180° angle around the torus from each other. Water is similarly returned to the torus using two different torus connections also at a 180° angle from each other. These torus connections were selected to maximize thermal mixing efficiency to the extent practical.

The TWMS normally maintains torus water quality. The TWMS pumps will transfer torus water to the condensate system at the main condenser continuously or intermittently, as selected by the operator. Clean condensate from the condensate reject line to the condensate storage tank provides return water to the torus. The rate at which torus water is transferred to the condensate system for cleaning and subsequently returned to the torus is regulated by the control room operator to maintain the proper torus water level and desired quality. One facet of the primary containment monitoring system provides the operator with a wide-range torus water level indication and one aspect of the TWMS provides a narrow-range torus level indication.

As required for recoating, inspections, and repair work, the TWMS is used to drain and fill the torus. Torus draining is accomplished by using the TWMS pumps to transfer torus water directly to the main turbine condenser for storage. Torus filling is accomplished using a condensate system pump to transfer water back to the torus through the TWMS return piping. During the filling operation, one of the eight polisher/demineralizers may be placed into service to clean the water returned to the torus.

9.2.8.3 Safety Evaluation

The TWMS is not required for reactor shutdown or accident mitigation and as such is not a safety-related system. However, the availability of the TWMS increases the reliability and availability of the plant. The reliable operation of the TWMS is ensured through the redundancy of the TWMS pumps (two at 250 gpm each) and two 50 percent-capacity suction and discharge lines with required isolation valves.

To ensure that the TWMS will not impair the safety function of the torus, the TWMS primary containment isolation valves automatically close. These valves trip in response to selected primary containment isolation system isolation signals (refer to Table 6.2-2) and to the high-high level alarm of the drywell floor drains or the torus room floor drain sump. The power supplies for containment isolation valves are arranged so that loss of one supply cannot prevent automatic isolation of a TWMS suction or return line when required. Torus water level and temperature limits and alarms are monitored and provided by the primary containment monitoring system, which is designated as a safety-related system.

Administrative controls and other constraints are provided to ensure that the suppression pool is not drained by the TWMS when the need for the ECCSs could be required. The limiting conditions for the draining of the suppression pool are specified in the Technical Specifications. Operational procedures for the TWMS include detailed information on the draining of the suppression pool. The TWMS pumps will automatically trip, preventing a torus water-level decrease, when the torus water level low-low alarm setpoint is reached at an elevation of 556.83 ft (2 in. below normal level) except when in the torus drain mode of TWMS.

Because the TWMS is considered a moderate energy system, flooding and spraying effects from postulated cracks in the system piping have been evaluated. Flooding and spraying effects have been determined to be enveloped by the limiting RHR pump discharge line crack (refer to Subsection 3.6.2.3.4.1.2). System overpressure protection is maintained by pump discharge relief valves.

9.2.8.4 Tests and Inspections

Initial system flow checks, valve operability, and instrumentation and control loop checks were performed in accordance with the test program as discussed in Chapter 14. A flow meter in the TWMS transfer line to the condensate system is provided to indicate the torus water removal rate and establish TWMS pump operability. Conductivity monitors on the discharge side of the polisher/ demineralizers provide continuous monitoring of the water returned to the torus. Minor leakages such as those from valve stems, flanges, and instrument tubing are detected through visual inspection.

9.2.8.5 Instrumentation

The TWMS is operated from the control room. Flow meter indication of the torus water flow to the condensate system is provided in the main control room. Position indication for the TWMS primary containment isolation valves and the control valves on the transfer and return lines are also provided in the main control room. Torus water management system controls and instrumentation are augmented by the containment monitoring functions of the primary containment monitoring system and the water quality monitoring devices in the turbine building.

9.2.9 Supplemental Cooling Chilled Water System

9.2.9.1 Design Basis

The SCCW system is a closed cooling water system which during normal plant operation will provide chilled water that will be used to lower the temperature of the cooling water supply to EECW that is normally cooled by RBCCW. The SCCW system is designed to remove 100 percent of the normal heat produced by the EECW system during normal operation. The SCCW system transfers the heat it has removed to the GSW system via mechanical chillers.

The SCCW system is designed to operate at a higher pressure than the RBCCW system to provide protection against potential outleakage of radioactive contaminants from the RBCCW system.

The SCCW system is classified as a non-nuclear system and is constructed in compliance with standards for Quality Group D components. This criterion is met by designing the system to ASME Section VIII and ANSI B31.1.0 code requirements. The system is nonseismic.

9.2.9.2 System Description

The SCCW system, as shown on Figure 9.2-14, is designed to remove heat from the RBCCW system headers that supply cooling water to the EECW headers and from the fan coil that cools the SCCW chiller area (turbine building basement).

The SCCW system consists of three 50 percent-capacity chillers (two normally operating), only one may be operating during low load conditions, three 50 percent-capacity chilled water pumps (two normally operating), a chilled water expansion tank and associated valves and controls. The system is designed to be started when RBCCW temperature first exceeds its nominal control temperature and left in operation until the RBCCW temperature can be maintained at or below its nominal control temperature. Table 9.2-12 provides SCCW system design parameters.

After a manual startup from the local control panel, system operation does not require operator intervention unless it is desired to rotate equipment that is operating or a trouble signal is annunciated in the control room. In the event a chiller were to trip, the standby chiller would automatically start. A trip of one of the operating chilled water pumps would automatically start the standby pump. The chiller trip logic is tied to the chilled water pump operation to ensure an adequate number of pumps are operating.

An expansion tank is provided to accommodate changes in water volume as the temperature of the chilled water varies. This tank will also maintain a constant chilled water pump suction pressure.

The demineralized water system will provide system make-up water.

9.2.9.3 Safety Evaluation

The SCCW system is not required for the safe shutdown of the reactor or for accident mitigation. Therefore, the SCCW system is not designed for a single active or passive failure as required of a safety-related system, but sufficient redundancy and automatic protective features are provided to ensure efficient system operation and availability. Since the SCCW system is not an engineered safety feature (ESF), it is not powered by an essential power bus.

The SCCW system is involved in normal plant operation. During periods when RBCCW temperature is above its nominal control point, it may be used to cool the cooling water supply to EECW that is normally cooled by RBCCW. If the SCCW system trips off or is removed from service, RBCCW and/or EECW, as required, will perform the cooling function. The RBCCW system is nonsafety and its pumps are not powered by an essential bus. If the RBCCW cooling water temperature is not available, the EECW and EESW systems can be used to provide the required cooling of the drywell and other equipment. The EECW and EESW systems are powered off essential buses. A failure of the SCCW system will not prevent a safe shutdown of the reactor.

The possibility of radioactive contamination of the SCCW system is reduced by using plate heat exchangers between the RBCCW supplemental cooling and SCCW systems. The SCCW system operates at a higher pressure than the RBCCW supplemental cooling system and therefore any leakage would be from the SCCW system into the RBCCW supplemental cooling system. The SCCW system does not contain a radiation monitor. Due to the design of a plate type heat exchanger, any leakage is likely to be to the ambient (auxiliary building) rather than to the SCCW system. The SCCW system is manually sampled to detect any developing problems. Should the barrier between RBCCW and SCCW fail, there is no potential release path to the environment. The SCCW system interfaces with the GSW system via mechanical chillers. The closed refrigerant system which is between the SCCW and GSW systems has a relief valve which exits the turbine building. However, that relief valve setpoint is much higher than any pressure that can be developed in the SCCW system and therefore does not constitute a release path.

9.2.9.4 Tests and Inspections

Initial construction tests such as hydrostatic leak tests were conducted per ANSI B31.1.0 code requirements. Initial system flow distribution, instrumentation and control loop checks and alarm setpoints were performed in accordance with the design change test program.

9.2.9.5 Instrumentation

Sufficient instrumentation is provided to allow the plant operator to assess the status of the SCCW system. Three alarm windows are provided in the main control room to alert the operator to system trouble. The specific details regarding these alarms are provided by control panels located in the vicinity of the chiller units.

In the event a chiller was to trip, the standby chiller would automatically start. A trip of one of the operating chilled water pumps would automatically start the associated standby pump.

During the normal mode of operation when both supplemental cooling loops are in operation, interlocks have been provided to prevent the operation of a chilled water pump should no chillers be in operation. In addition, should all operating chillers trip and the standby unit not start, the operating chilled water pumps will trip.

9.2 WATER SYSTEMS

REFERENCES

1. AEC letter Docket 50-341, from Voss A. Moore, Assistant Director for Boiling Water Reactors/Directorate of Licensing, to The Detroit Edison Company, dated November 30, 1973.

2. Applicant's Responses to the July 9, 1973 AEC letter with 17 questions regarding the RHRSW Pond (Complex) Design, Docket 50-341, dated August 10, 1973.

TABLE 9.2-1 GENERAL SERVICE WATER SYSTEM PUMP DATA

General Service Water Pump

Number supplied	Five
Type	Vertical, wet-pit, turbine
Fluid	Chlorinated lake water
Capacity, gpm	7700
Total head, ft (Tested two stage pump)	241 to 270
Motor	
Type	Vertical, dripproof, induction
Horsepower	900
Speed	1779
Voltage/frequency/phase	4000/60/3

Circulating Water Makeup Pump

Number supplied	Two
Type	Vertical, wet-pit, turbine
Fluid	Chlorinated lake water
Capacity, gpm	15,000
Total head, ft	32
Motor	
Type	Vertical, dripproof, induction
Horsepower	200
Speed	880
Voltage/frequency/phase	460/60/3

TABLE 9.2-2 REACTOR BUILDING CLOSED COOLING WATER SYSTEM COMPONENT PARAMETERS

RBCCW Pumps

Number supplied	Three
Type	Horizontal, single-stage centrifugal
Fluid	Demineralized water
Capacity, gpm	4000
Total head, ft	167
Motor	
Type	Horizontal 445 TS Frame
Horsepower	200
Speed, rpm	1770
Voltage/frequency/phase	460/60/3

RBCCW Supplemental Cooling Pumps

Number supplied	Four (Two per EECW Division)
Type	Horizontal, single-stage centrifugal
Fluid	Demineralized water
Capacity, gpm	1557 for EECW Division I
	1715 for EECW Division II
Total head, ft	260
Motor	
Type	Horizontal 445 TS Frame
Horsepower, HP	150
Speed, rpm	1785
Voltage/frequency/phase	460 V/60 Hz/3

RBCCW Heat Exchangers

Number supplied	Two
Type	Shell and tube, single pass
Heat transfer duty, Btu/hr	67.8×10^6
Heat transfer area, ft^2	12,780
Design code	ASME Section VIII, TEMA Class C
Shell	
Fluid	Demineralized water
Design pressure, psig	150
Design temperature, °F	120
Flow, gpm	8000
Inlet temperature, °F	112
Outlet temperature, °F	95
Material	Carbon steel A-285-C
Tube	
Fluid	Lake water

TABLE 9.2-2 REACTOR BUILDING CLOSED COOLING WATER SYSTEM COMPONENT PARAMETERS

Design pressure, psig	175
Design temperature, °F	120
Flow, gpm	10,000
Inlet temperature, °F	85
Outlet temperature, °F	99
Material	304 stainless steel

RBCCW Supplemental Heat Exchangers

Number supplied	Two 1 @ 100% capacity for EECW Division I 1 @ 100% capacity for EECW Division II
Type	Plate heat exchanger
Heat transfer duty, Btu/hr	10×10^6 for EECW Division I 11.5×10^6 for EECW Division II
Heat Transfer Area, ft^2	1229 for EECW Division I 1272 for EECW Division II
Design code	ASME Section VIII
Material	Plates: 304 SS Nozzles: 316 SS
Cold Side	
Fluid	SCCW, demineralized water
Design pressure, psig	150
Design temperature,°F	150
Flow, gpm	1100 for EECW Division I 1300 for EECW Division II
Inlet temperature,°F	60.2
Outlet temperature,°F	78.4 for EECW Division I 77.9 for EECW Division II
Hot Side	
Fluid	RBCCW Supplemental, demineralized water
Design pressure, psig	150
Design temperature,°F	150
Flow, gpm	1557 for EECW Division I 1715 for EECW Division II
Inlet temperature,°F	82.9 for EECW Division I 83.4 for EECW Division II
Outlet temperature,°F	70

Note: The heat duties are the maximum expected values and will not occur simultaneously.

RBCCW Makeup Tank

TABLE 9.2-2 REACTOR BUILDING CLOSED COOLING WATER SYSTEM COMPONENT PARAMETERS

Number provided	One
Type	Horizontal, elliptical dished heads
Design pressure, psig	100
Design temperature, °F	120
Operating pressure, psig	45
Internal volume, gal	600
Liquid volume, gal	300
Pressurizing gas	Nitrogen
Material	Carbon steel ASTM-A515 GR70

TABLE 9.2-3 EMERGENCY EQUIPMENT COOLING WATER SYSTEM COMPONENT DESIGN PARAMETERS

EECW Pumps

Number supplied	Two
Type	Horizontal, centrifugal
Fluid	Demineralized water
Capacity, gpm	1775
Total head, ft	167
Motor	
Type	Induction, dripproof
Horsepower	100
Speed, rpm	1785
Voltage/frequency/phase	460/60/3

EECW Heat Exchanger

Number supplied	Four (Two per EECW Division)
Type	Single Pass, Plate and Frame
Heat transfer duty, Btu/hr	13.6 x 10^6
Heat transfer area, ft^2	4214.1 ft^2
Design code	ASME Section III, Class 3,
Hot Side	
Fluid	Demineralized water
Design pressure, psig	150
Design temperature, °F	150
Flow, gpm	1700
Inlet temperature, °F	111.1
Outlet temperature, °F	95
Material	T-316 Stainless Steel
Cold Side	
Fluid	RHR service water
Design pressure, psig	175
Design temperature, °F	150
Flow, gpm	1450
Inlet temperature, °F	89

TABLE 9.2-3 EMERGENCY EQUIPMENT COOLING WATER SYSTEM COMPONENT DESIGN PARAMETERS

Outlet temperature, °F	107.9
Material	T-316 Stainless Steel

EECW Makeup Tank

Number provided	Two
Type	Horizontal, elliptical dished heads
Design pressure, psig	100
Design temperature, °F	140
Operating pressure, psig	36
Internal volume, gal	600
Liquid volume, gal	300
Pressurizing gas	Nitrogen
Material	Carbon steel SA-515 Grade 70

EECW Makeup Pump

Number provided	Two
Type	Motor driven horizontal centrifugal, vert. disch
Power	480 Vac/3Ph, 3.0 HP
Design pressure	60 ft TDH
Design flow	20 gpm
Material	Stainless steel

EECW Makeup Pressure Regulator Valve

Number provided	Two
Type	Discharge regulator, self-actuated
Size	1-1/2 in.
Setpoint (discharge)	36 psig
Maximum design flow	25 gpm (Div I): 15 gpm (Div II)
Minimum design flow*	10.4 gpm (Div I): 8.3 gpm (Div II)`
Design makeup flow to EECW Head Tank*	2.7 gpm (Div I, or Div II)

* Coincident flows

TABLE 9.2-4 REACTOR BUILDING CLOSED COOLING WATER AND EMERGENCY EQUIPMENT COOLING WATER SYSTEMS FAILURE ANALYSIS

Component	Failure Mode	Consequences on Safety
RBCCW pumps	Loss of pumping due to loss of offsite power	Loss of offsite power automatically starts both EECW pumps and initiates isolation of the nonessential loads.
RBCCW pumps	Trip on low suction pressure or low makeup tank water level	Each EECW pump will start on low differential pressure between its respective supply and return headers. Isolation of nonessential loads is also initiated. (a)
RBCCW piping	Pipe rupture in the RBCCWS	Each EECW pump will start on low differential pressure between its respective supply and return headers. Isolation of nonessential loads is also initiated. (b)
EECW pump	Fails to start due to failure of one set of diesel generators	Redundant full-capacity EECW loop is provided, powered off the second emergency bus.
EECW piping	Piping leak or rupture in the EECWS	Automatic makeup valve will open to maintain tank level. If leak exceeds makeup capacity, the low tank level or low suction pressure will be alarmed. Redundant full-capacity EECW loops are provided that are isolable from each other.
EECW Makeup Tank	Loss of nonsafety-related demineralized water and nitrogen inerting systems	Safety related EESW makeup water to the makeup tank restored by automatic start of EECW makeup pump if makeup tank has low pressure or level and makeup tank isolation valve is open, and normal pump suction pressure is achieved. Nitrogen pressure in the makeup tank will be automatically maintained by the backup nitrogen supply for Division I until the makeup tank Nitrogen leaks off and the Makeup tank is filled and Pressurized with EESW water via the makeup pump

TABLE 9.2-4 REACTOR BUILDING CLOSED COOLING WATER AND EMERGENCY EQUIPMENT COOLING WATER SYSTEMS FAILURE ANALYSIS

Component	Failure Mode	Consequences on Safety
Isolation valve between EECW and RBCCW [P4400F601A(B), P4400F603A(B)]	Fails to close for isolating nonessential loads	Water may be lost from the EECW loop if a break exists in the RBCCWS. Redundant EECW loop available.
Isolation valve on makeup tank outlet line	Fails to open on automatic system initiation	Low suction pressure to the EECW pump may alarm, requiring manual shutdown, but the other redundant EECW division is available. Makeup pump is disabled.
Isolation valve on nonessential load in essential loop	Fails to close on demand	No adverse effects since the heat loads and flow requirements for the nonessential loads affected are small. (c)
Control valves	Loss of control air or instrument power supply	The EESW temperature control valve will fail open. The EECW will continue to operate and provide the necessary cooling water. The Div I controller will continue to operate on a loss of offsite power to fail the TCV open. NIAS is available for Temperature Control Valve (TCV) P44F400A/B.
Isolation valve for Drywell Loads	Fails to close on high drywell pressure/signals	Redundant full-capacity EECW loop is provided plus the valve can be closed manually.

TABLE 9.2-4 REACTOR BUILDING CLOSED COOLING WATER AND EMERGENCY EQUIPMENT COOLING WATER SYSTEMS FAILURE ANALYSIS

Component	Failure Mode	Consequences on Safety

(a) The differential header pressure sensors are located inside the EECW system boundary; thus, if EECW has been manually initiated with the nonessential loads subsequently restored (either for RBCCW heat exchanger cleaning, enhanced drywell cooling during periods of high lake water temperature, testing, or to provide RHR Reservoir freeze protection during extreme cold weather), a loss of RBCCW pumps while EECW is operating in this mode would not reinitiate EECW or re-isolate the nonessential loads. This protective action is not required, however, since this is not a condition requiring protective action as described in Section 7.1.2.1 and EECW remains capable of supporting the safe shutdown of the plant in this configuration. EECW auto-start on high drywell pressure (i.e., a LOCA) or on a loss of offsite power is unaffected by this mode of operation; therefore, these signals will initiate the automatic protective action of reisolating the nonessential portions of RBCCW piping located inside the EECW system envelope.

(b)The differential header pressure sensors are located inside the EECW system boundary; thus, if EECW has been manually initiated with the nonessential loads subsequently restored (either for RBCCW heat exchanger cleaning, enhanced drywell cooling during periods of high lake water temperature, testing, or to provide RHR Reservoir freeze protection during extreme cold weather), a rupture of the RBCCW piping outside of the EECW system envelope while EECW is operating in this mode would not reinitiate EECW or reisolate the nonessential loads. This protective action is not required, however, since this is not a condition requiring protective action as described in Section 7.1.2.1 and EECW remains capable of supporting the safe shutdown of the plant in this configuration.

(c) If a rupture of the RBCCW piping located inside the EECW system envelope were to occur (with EECW either in standby or in operation for RBCCW heat exchanger cleaning, enhanced drywell cooling during periods of high lake water temperature, testing, or to provide RHR Reservoir freeze protection during extreme cold weather), it is unlikely that the loss in differential header pressure would be sufficient to cause an EECW auto-start due to the small bore of these nonessential lines. It is also unlikely that the RBCCW head tank would deplete to the low level RBCCW pump trip setpoint since the normal makeup capacity exceeds the predicted leak rates. These events rely on the normal EECW makeup supply to feed the break until operators locate and isolate the leak. Again, the protective actions of initiating EECW and isolating the nonessential loads are not required since this is not a condition requiring protective action as described in Section 7.1.2.1 and EECW remains capable of supporting the safe shutdown of the plant during the period required to locate and isolate the break.

Consequences default to those of a rupture of EECW piping as described in the table above.

TABLE 9.2-5 MAKEUP DEMINERALIZED WATER SYSTEM TYPICAL INFLUENT WATER QUALITY ANALYSIS

Major Cation Constituents	Calcium Carbonate $CaCO_3$ (ppm)
Calcium (Ca^{++})	42
Magnesium (Mg^{++})	8
Sodium (Na^{+})	11
Total cations	61

Major Anion Constituents	Calcium Carbonate $CaCO_3$ (ppm)
Bicarbonate (HCO_3^-)	74
Carbonate ($CO_3^=$)	Not Detected
Chloride ($C1^-$)	20
Fluoride (F^-)	0.1
Hydroxide (OH^-)	0
Sulfate ($SO_4^=$)	45
Total anions	139

Additional Analysis

pH at 25°C	7.6
Specific conductivity, mmho/cm at 25°C	275[a]
Total solids, ppm	160
Total hardness, ppm as $CaCO_3$	124
Total alkalinity, ppm as $CaCO_3$	87
Iron, ppm as Fe	Trace
Soluble silica, ppm as SiO_2	0.4
Insoluble silica, ppm as SiO_2	0.07
Turbidity, Jackson Turbidity Units	<0.1
Free carbon dioxide, ppm as CO_2	0
Free available chlorine, ppm as Cl_2	1.1
Total Phosphate, ppm as PO_4	0.2[b]
Chemical oxygen demand, ppm as O_2	12

[a] This value will vary with the season, with a maximum of 350 mmho/cm during periods of heavy runoff.

[b] The total phosphate figure may vary based on the actual treatment at the Frenchtown Plant

TABLE 9.2-6 DEMINERALIZED WATER MAKEUP SYSTEM TYPICAL EFFLUENT WATER QUALITY

Specific conductivity, mmho/cm at 25°C	0.1
pH at 25°C	6.5 to 7.5
Chloride (ppb as Cl^-)	2
Silica (ppb as SiO_2)	<5
Total metallic impurity (ppb of which 2 ppb maximum is Cu)	<10

TABLE 9.2-7 ULTIMATE HEAT SINK COMPONENT DESIGN PARAMETERS

RHR Service Water Pumps	
Number supplied	Four
Type	Vertical, turbine type
Fluid	Service water
Capacity, gpm	4500
Total head, ft	185
Motor	
Type	Vertical, induction, dripproof
Horsepower	300
Speed, rpm	1800
Voltage/frequency/phase	4000/60/3
Emergency Equipment Service Water Pumps	
Number supplied	Two
Type	Vertical, turbine
Fluid	Service water
Capacity, gpm	1600
Total head, ft	145
Motor	
Type	Vertical, induction, dripproof
Horsepower	100
Speed, rpm	1760
Voltage/frequency/phase	460/60/3
Diesel Generator Service Water Pumps	
Number supplied	Four
Type	Vertical, turbine
Fluid	Service water
Capacity, gpm	800
Total head, ft	115
Motor	
Type	Vertical, induction, dripproof
Horsepower	50
Speed, rpm	1760
Voltage/frequency/phase	460/60/3
Cooling Towers	
Number supplied	Two
Type	Induced Draft
No. of cells/tower	Two

TABLE 9.2-7 ULTIMATE HEAT SINK COMPONENT DESIGN PARAMETERS

Design flow, gpm	13,000
Design heat load, Btu/hr	160×10^6
Water inlet temperature, °F	116
Water outlet temperature, °F	89
Ambient air dry bulb, °F	92
Ambient air wet bulb, °F	76
Fan motor horsepower	150
Fan type	Eight blades, two-speed
Motor electrical requirements	460/60/3

TABLE 9.2-8 ULTIMATE HEAT SINK FAILURE ANALYSIS

Component	Failure Mode	Consequences on Safety
RHRSW, EESW, and DGSW pumps	Loss of pumping due to loss of offsite power	Power is automatically supplied by the emergency buses fed by the diesel generators.
RHRSW, EESW, or DGSW pump	Loss of pumping due to mechanical failure	RHRSW has one-half capacity still available in one division, completely redundant division still intact. A check valve in pump discharge prevents loss of flow through malfunctioning pump. EESW has full capacity pump in redundant division. DGSW pump failure will cause loss of the particular EDG it services. One half of the electrical division plus full redundant electrical division still remain.
RHRSW, EESW, and DGSW pumps	Do not start due to failure of one divisional pair of diesel generators to start on loss of offsite power	Redundant RHRSW, EESW, and DGSW pumps are provided which are powered off the redundant divisional pair of diesel generators.
RHRSW, EESW, and DGSW pumps	Do not start due to failure of one EDG to start on loss of offsite power	The RHRSW pump associated with the particular EDG will not start; 150 percent cooling capacity still provided. The associated DGSW pump will not start but is not needed. The EESW pump is normally run off a particular EDG. Associated EDG failure causes loss of associated EESW pump. Manual throw-over to other EDG within a division is provided to increase reliability during EDG maintenance. Full-capacity redundant division pump intact.
Valve or piping in Division I or Division II	Loss of flow path due to pipe break or failure of valve to open	Fully redundant flow path with separate supply and return lines is provided to redundant RHR heat exchanger, redundant EECW heat exchanger, and redundant diesel generator.

TABLE 9.2-8 ULTIMATE HEAT SINK FAILURE ANALYSIS

Component	Failure Mode	Consequences on Safety
RHR complex structures	Local structural failure due to tornado-borne missiles, turbine missiles, or EDG missiles	Division I and Division II components are physically separated and divided by a divisional barrier wall. Structure will withstand external missiles. Each EDG is protected by interior walls designed to withstand EDG generated missiles.
Cooling tower structure	Collapse or damage from tornado-borne or turbine missiles	Full-capacity redundant cooling tower provided. Physical separation prevents loss of both divisions.
Cooling tower fan motor	Mechanical failure of fan blades or motor	Each cooling tower has two one-half capacity cells. With redundant cooling tower, capacity of 150 percent still available.
	Failure to start due to diesel generator failure to respond upon loss of offsite power	The particular fan motor not needed as service water pump capacity also reduced; 150 percent cooling capacity still available.

TABLE 9.2-9 CONDENSATE STORAGE SYSTEM COMPONENT DESIGN PARAMETERS

Normal Hotwell Supply Pump	
Number supplied	One
Type	Centrifugal
Fluid	Condensate
Capacity, gpm	600
Total head, ft	246
Motor	
Type	Dripproof, induction
Horsepower	60
Speed, rpm	3550
Voltage/frequency/phase	460/60/3
Emergency Hotwell Supply Pump	
Number supplied	One
Type	Centrifugal
Fluid	Condensate
Capacity, gpm	2000
Total head, ft	108
Motor	
Type	Dripproof, induction
Horsepower	75
Speed, rpm	1750
Voltage/frequency/phase	460/60/3
Condensate Storage Jockey Pump	
Number supplied	One
Type	Centrifugal
Fluid	Condensate
Capacity, gpm	100
Total head, ft	246.2
Motor	
Type	Dripproof, induction
Horsepower	15
Speed, rpm	3500
Voltage/frequency/phase	460/60/3
Condensate Tanks	
Number provided	Two
Type	Vertical, cylindrical
Design code	USAS B96.1
Design pressure, psig	Hydrostatic head
Design ambient temperature, °F	-10 to 95
Operating pressure, psig	Atmospheric

TABLE 9.2-9 CONDENSATE STORAGE SYSTEM COMPONENT DESIGN PARAMETERS

Internal volume, gal	600,000
Dimensions	
Diameter, in.	644 I.D.
Height, in.	432
Material	Aluminum alloy, B-209-5454

Demineralized Water Storage Tank

Number provided	One
Type	Vertical, cylindrical
Design code	USAS B96.1
Design pressure	Hydrostatic head
Design ambient temperature, °F	-10 to 95
Operating pressure	Atmospheric
Internal volume, gal	50,000
Dimensions	
Diameter, in.	228 I.D.
Height, in.	288
Material	Aluminum alloy, SB-209-5454

TABLE 9.2-10 TURBINE BUILDING CLOSED COOLING WATER SYSTEM COMPONENT DESIGN PARAMETERS

TBCCW Pumps

Number supplied	Three
Type	Horizontal, single-stage centrifugal
Fluid	Demineralized water
Capacity, gpm	3000
Total head, ft	57.8
Motor	
Type	Open dripproof
Horsepower	60
Speed, rpm	1770
Voltage/frequency/phase	460/60/3

TBCCW Heat Exchangers

Number supplied	Two
Type	Shell and tube, single pass
Heat transfer duty, Btu/hr	45 x 10^6
Design code	
Shell	TEMA Class C
Fluid	Demineralized water
Design pressure, psig	150
Design temperature, °F	120
Flow, gpm	6000
Inlet temperature, °F	110
Outlet temperature, °F	95
Material	Carbon steel
Tube	
Fluid	Lake water
Design pressure, psig	175
Design temperature, °F	120
Flow, gpm	9000
Inlet temperature, °F	85
Outlet temperature, °F	95
Material	SB-543 Alloy C194

TBCCW Makeup Tank

Number provided	One
Type	Horizontal, elliptical dished heads
Design pressure, psig	20
Design temperature, °F	120

TABLE 9.2-10 TURBINE BUILDING CLOSED COOLING WATER SYSTEM COMPONENT DESIGN PARAMETERS

Operating pressure, psig	15
Internal volume, gal	600
Liquid volume, gal	300
Pressurizing gas	Nitrogen
Material	Carbon steel ASTM A-515 Grade 70

TABLE 9.2-11 TORUS WATER MANAGEMENT SYSTEM COMPONENT DESIGN PARAMETERS

TWMS Pumps

Number supplied	Two
Type	Horizontal, single-stage centrifugal
Fluid	Torus water
Capacity, gpm	250
Total head, ft	480 (rated)
	500 (by test)

Motor

Type	Open dripproof
Horsepower	75
Speed, rpm	3550
Voltage/frequency/phase	460/60/3

9.2-12 SUPPLEMENTAL COOLING CHILLED WATER SYSTEM DESIGN PARAMETERS

A. Chillers	
Type	Centrifugal, water cooled
Quantity	Three, 50% capacity each
Refrigerant	R-134a (HFC 134a)
Capacity, tons refrigeration	800 each
Input Power, kw	505
Evaporator	
Chilled water source	SCCW, demineralized
Chilled water flow, gpm	1230
Chilled water temperature, °F	75.8 in/60.2 out
Chilled water pressure drop, ft	16.1
Condenser	
Cooling water source	GSW
Cooling water flow, gpm	2000
Cooling water temperature, °F	85 in/96.2 out
B. Chilled Water Pumps	
Number supplied	Three, 50% capacity each
Type	Centrifugal single stage, horizontal split case
Fluid	Demineralized water
Capacity, gpm	1230
Total head, ft	110
Motor	
Type	Horizontal 324T Frame
Horsepower, HP	40 hp
Speed, rpm	1775
Voltage/Frequency/Phase	460 V/60 Hz/3
C. Expansion Tank	
Number provided	One
Type	Vertical with diaphragm
Design pressure, psig	125
Design temperature, °F	125
Operating pressure, psig	30
Total volume, gal	134
Acceptance volume, gal	46
Pressurizing gas	Air
Material	Carbon steel

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Refer to Plant Drawing M-2010

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FIGURE 9.2-1, SHEET 1

GENERAL SERVICE WATER

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Refer to Plant Drawing M-5743-1

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UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 9.2-1, SHEET 2

GENERAL SERVICE WATER
BIOCIDE INJECTION SYSTEM

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FIGURE 9.2-1, SHEET 3

GENERAL SERVICE WATER SYSTEM
PIPING DIAGRAM

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UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 9.2-2, SHEET 1

REACTOR BUILDING CLOSED COOLING WATER
SYSTEM PIPING DIAGRAM

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FIGURE 9.2-2, SHEET 2

REACTOR BUILDING CLOSED COOLING WATER
PIPING DIAGRAM

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FIGURE 9.2-3

EMERGENCY EQUIPMENT COOLING
WATER SYSTEM - DIVISION 1
PIPING DIAGRAM

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FIGURE 9.2-4

EMERGENCY EQUIPMENT COOLING WATER SYSTEM
DIVISION II - PIPING DIAGRAM

FIGURE 9.2-5 HAS BEEN DELETED

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FIGURE 9.2-6

RESIDUAL HEAT REMOVAL SERVICE WATER SYSTEM (DIVISION 1) RESIDUAL HEAT REMOVAL COMPLEX

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Refer to Plant Drawing M-N-2054

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FIGURE 9.2-7

SERVICE WATER, MAKEUP, DECANT, AND
OVERFLOW SYSTEMS - DIVISIONS I AND II
RESIDUAL HEAT REMOVAL COMPLEX

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FIGURE 9.2-9 HAS BEEN DELETED

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FIGURE 9.2-10

CONDENSATE STORAGE AND TRANSFER

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Refer to Plant Drawing C-Y-2003

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FIGURE 9.2-11

CONTAINMENT WALL AROUND CONDENSATE STORAGE TANKS

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FIGURE 9.2-12, SHEET 1

TURBINE BUILDING CLOSED COOLING WATER
SYSTEM PIPING DIAGRAM

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Figure Intentionally Removed
Refer to Plant Drawing M-4100

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FIGURE 9.2-13

TORUS WATER MANAGEMENT SYSTEM

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Refer to Plant Drawing M-2020

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FIGURE 9.2-14

SUPPLEMENTAL COOLING CHILLED WATER
SYSTEM - PIPING DIAGRAM

9.3 PROCESS AUXILIARIES

9.3.1 Compressed Air System

9.3.1.1 Design Bases

The Fermi 2 station and control air system provides the plant with a reliable source of clean, dry, oil-free compressed air for plant operation. Control air system is designed to provide oil and dirt-free air with a dewpoint of -40°F (at pressure). The control air compressors, aftercoolers, dryers, and receiver tanks are provided to supply air to some of the engineered safety feature (ESF) equipment in the plant when the normal supply of control air is not available. Because the noninterruptible portion of the control air system provides control air to ESF equipment, it is classified as a safety-related system.

The station air and interruptible control air systems are constructed in compliance with standards for Quality Group D components. The criteria are met by designing the systems to ASME Section VIII and ANSI B31.1.0 code requirements. These systems are nonseismic.

The noninterruptible control air system is constructed in compliance with upgraded standards for Quality Group D components. These criteria are met by designing this system to ASME Section III, Class 3 requirements. The system is Category I.

9.3.1.2 System Description

The air system is composed of two subsystems. The first is the supply and distribution of station air and the second is the supply and distribution of interruptible and noninterruptible control air. The station air and interruptible control air supply equipment is located in the turbine building. The non-interruptible control air system is located in the auxiliary building. The station and control air systems are the source of compressed air for use in routine maintenance operations, in equipment process cycles such as demineralizer backwashing, and as an instrument and control media. The compressed air system is shown in Figure 9.3-1.

The station air system consists of three, two stage, nonlubricated compressors equipped with inlet filter-silencers, and intercoolers and aftercoolers. Two 150-ft^3-capacity air receivers and the station air distribution piping, valves, and fittings complete the station air equipment.

In operation, ambient air from the turbine building is drawn into the station air compressors via the inlet filter-silencers. This air is compressed, cooled, and discharged into the station air receivers. Normal practice is to have one compressor running and one lined up in automatic. The running compressor maintains near constant pressure (100 psig) in the air receivers while the compressor in automatic is available to start if more capacity is required. A connection is provided in the 8” inlet line to the west Air Receiver tank (P5001A002) for installing and operating an alternate air source at any time when an additional source of compressed air is desired to supply or supplement the needs of the compressed air system. The use of this tap is administratively controlled and, when not in use, a blank flange is installed.

From the station air receiver, the station air is distributed throughout the plant via the station air header/riser system. The station air system is sized to minimize the pressure loss of air at the point of use.

The noninterruptible control air portion of the system consists of two 100 percent-capacity 100 scfm, single-stage nonlubricated reciprocating air compressors; two 100 percent-capacity parallel strings of oil filters, air dryers, and afterfilters; two control air receivers; and associated piping, fittings, and valves. During normal plant operation, the source of noninterruptible and interruptible control air is through interconnections between the station and control air systems. Compressed air from the station air system is supplied through one of these interconnections to the Division I and II noninterruptible control air compressor discharge headers. The air then flows from each header through its divisional 100 percent-capacity filter and dryer. It is cleaned of all particles of dirt ≥0.5µm (nominal), ≥0.9µm absolute, and then dried by a regenerative desiccant-type dryer which is designed to establish a -40°F dewpoint (at line pressure). After leaving the filter/dryer, the noninterruptible control air flows to its divisional control air receiver from which it eventually flows to its point of use through its divisional noninterruptible control air distribution system.

Another station air connection supplies the interruptible control air system. The interruptible control air system contains two 100 percent redundant dryers. Each dryer has its own prefilter, afterfilter, and instrumentation. Each dryer unit is capable of supplying the same quality of instrument air as the noninterruptible control air system. Redundancy allows for maintenance to be performed on one unit without jeopardizing the system's air quality or quantity. Dryer redundancy improves the reliability of the interruptible control air system. The interruptible control air flows to the interruptible control air receiver, which supplies the interruptible control air distribution system. The station and control air compressors, air receivers, filters, and dryers are designed to operate in an ambient temperature range of 60°F to 100°F, a range of 20 percent to 100 percent relative humidity, and a radiation field of 1mR/hr.

The control air distribution system is divided into two distinct parts: interruptible and noninterruptible. Noninterruptible control air (NIAS) supplies, through two separate distribution systems (Divisions I and II), equipment in the following systems:

a. Standby gas treatment system (SGTS)

b. Control center air conditioning system (CCACS)

c. Primary containment atmosphere monitoring system (PCAMS)

d. Emergency equipment cooling water system (EECWS)

e. Primary containment pneumatic supply system

f. Torus to reactor building vacuum relief system.

g. Railroad bay airlock door seals.

In addition, Division I NIAS provides control air for the following:

a. Primary containment isolation of drywell equipment and floor drain sump pump discharge lines

b. Back-up supply for Division I (N_2) pneumatic supply to the primary containment.

Division II NIAS supplies, in addition, air operated valves in the following systems:

a. High pressure coolant injection system (HPCI)

b. Reactor core isolation cooling system (RCIC).

c. Standby Gas Treatment Primary Containment Isolation Valves which support Torus Venting.

d. Torus Vent Secondary Containment Isolation Valves.

All other control air users are connected to the interruptible control air distribution system. Interruptible control air (IAS) is supplied through its own set of filters, dryer, and receiver tank, which is fed from the station air system.

The station air compressors and their associated coolers are cooled by the turbine building closed cooling water system (TBCCWS). The control air compressors and aftercoolers are cooled by the reactor building closed cooling water system (RBCCWS) or the EECWS.

During normal operation, any one of three installed station air compressors will be in operation. One of the other two will be in "auto" and the third compressor will be in the "off" position. Normal operating pressure from the station air compressors is nominally 100 psig. If the station air header pressure drops below 95 psig, the compressor in "auto" will automatically start.

If the pressure drops to 90 psig, an alarm in the control room will be initiated and the third compressor may be manually started from the control room panel. If the station air header pressure continues to decrease, at 85 psig the station air supply header isolates and only supplies the IAS and NIAS. An alarm is initiated in the control room.

Should station air supply pressure to either division of NIAS decrease to 85 psig, its division's control air compressor automatically starts and the station air supply isolates from the NIAS and alarms. Each division of NIAS is supplied at this point by its own control air compressor.

There is a normally locked closed intertie between Divisions I and II of the noninterruptible control air system. During a maintenance outage on a control air compressor, after cooler, filters, or dryer of one division the intertie may be opened so that the division having the outage may be fed by the other division. Similarly, the normally closed interruptible control air intertie to Division II noninterruptible control air system may be opened during a Division II supply maintenance outage (i.e., Division II compressor, after cooler, filters/dryer outage). In this latter case, loss of offsite power or any other station air failure would render Division II of the noninterruptible control air system inoperable. The intertie auto isolation valve will close on loss of power or low header pressure, thus maintaining Division II noninterruptible air receiver tank integrity. In addition, the isolation valve for the station air supply to the noninterruptible control air system interconnection has a normally locked closed bypass valve and a normally locked open outlet valve. These valves may be unlocked and repositioned (i.e., the bypass valve opened and the outlet valve closed) to provide an alternate lineup for station air supply to the noninterruptible control air system to support normal plant operation in the event the isolation valve is unavailable.

9.3.1.3 Safety Evaluation

The noninterruptible portion of the control air system is required to effect a safe reactor shutdown; it is also required for control during long-term recovery. The station air system and interruptible control air system are not required to effect a safe reactor shutdown. The pneumatic supply to the primary containment is normally fed from the nitrogen inerting system (Subsection 9.3.6). An intertie is provided to permit Division I noninterruptible control air to be used as an emergency backup to the Division I containment pneumatic supply system.

Bottled nitrogen can also be connected to both containment pneumatic supply divisions as an additional backup supply source. Bottled nitrogen can also be used to reopen Division II PCMS isolation valves, T5000F420B and T5000F421B, that go closed in the event of an extended power failure as shown in Figure 7.6-11.

On loss of offsite power, the control air compressors are automatically started with power supplied from the emergency diesel generators (EDGs). Enough receiver capacity is provided to supply compressed air to the air users for the short duration transition period (See Table 8.3-5) before control air compressor load pickup by the diesel generators is required. With normal offsite power available, the control air compressors start immediately on low noninterruptible control air header pressure.

Maximum plant availability and control air system reliability are ensured by providing three station air compressors and two standby control air compressors. Additionally the control air compressors are powered by independent ESF power sources, and each division includes a control air receiver tank sized to supply compressed air to air users for the short duration transition period during a loss of offsite power event until control air compressors are in-service (See Table 8.3-5).

Control air accumulators are located so as to maximize protection for the associated valve and nearby safety-related equipment. Physical separation criteria for the associated system of the valve were also maintained in determining the accumulator location. Inside the drywell, the accumulators have been integrally supported and welded to drywell support steel; outside the drywell, anchor bolts have been used to secure the welded accumulator support structures in position. The accumulator supports and anchor system were analyzed for stressed conditions resulting from seismic excitation, thrust loading from a tank rupture or supply line rupture, and external jet impingement during a LOCA environment. In each of the above loading conditions, the support and anchor designs were found to be adequate to preclude the accumulators from becoming missiles.

9.3.1.4 Tests and Inspections

Initial construction tests such as air leak tests were conducted per applicable code requirements for the station and control air systems. Initial system flow checks, valve operability, instrumentation and control loop checks, and alarm setpoints for the control air subsystem were done in accordance with the Preoperational Test program as discussed in Chapter 14. The station air subsystem was subjected to similar acceptance testing. The quality of the air delivered by the filter/dryer units was also determined.

Periodic examinations of filters and dryers and periodic replacement of filter cartridges are scheduled to ensure control air quality. Periodic inspections are made of compressors to ensure performance of these active units.

Periodic inspections of receiver tanks are performed. Inspection of instruments is made to confirm actuation of relief valves, isolation valves, automatic switchovers, and alarms. Automatic compressor starts are also demonstrated.

9.3.1.5 Instrumentation

Local (turbine building) instrumentation in the station and interruptible control air systems is provided to monitor line and receiver air pressure, pressure drop across filters, compressor airflow rates, and temperature of the compressed air and cooling water. Similar local instruments in the reactor/auxiliary building are provided for the noninterruptible control air system.

Main control room instrumentation consists of pressure indication of station air and control air headers (with low-pressure alarms), selector switches to isolate either division of noninterruptible air, and control switches for the control air compressors.

The station air compressors are started in the main control room and controlled locally.

9.3.2 Process Sampling

Figures 9.3-2, 9.3-3, and 9.3-4 illustrate the sampling systems in the reactor building, turbine building, and radwaste building, respectively. Details of the process radiation monitoring system (RMS) are given in Section 11.4.

9.3.2.1 Design Bases

The Fermi 2 process sampling system is designed to permit samples to be taken for the following purposes:

a. To maintain radiological surveillance

b. To provide analog measurement signals to controls for process equipment

c. To evaluate the performance of system equipment

d. To measure the quality of the process fluid.

Rad Protection supervision is provided where required (some samples will be radioactive). Wherever samples are delivered through shielding walls, backflushing facilities are provided to confine the radioactive material to the shielded area. Where necessary to avoid health hazards to operators, the system is designed with special safeguards, such as one or more remote air-operated block valves with remote position indicators. The system is designed to permit continuous sampling and minimize plate-out or decay that could bias analyses.

Where feasible, the system piping and sample taps are designed to permit mixing and sampling before process inventories are transferred in the process train.

To ensure that the samples taken are representative, the following considerations are provided for in the design:

a. Line lengths are minimized and the smallest practical line diameter is used to reduce lag time and to minimize plating-out of sample

b. Sampling lines avoid traps, deadlegs, and dips

c. The sample flow rates and line sizes are chosen to ensure flow in the turbulent-flow regime.

Sample lines are type 304 stainless steel tubing. After the source or isolation valves, lines connected to Quality Groups A, B, and C systems are constructed to meet Quality Group D requirements. Lines connected to Quality Group D systems are constructed to meet Quality Group D requirements.

All sample tubing or piping, from the point where it connects to a process system to and including the source valve (or if inside primary containment, from the source to the isolation shutoff valve outside primary containment) is the same piping class as the system piping to which it connects. Further, sample lines are either pitched to drain or are equipped with vents and drains, and are designed to prevent damaging water hammer in operation. External lines are heat traced to prevent freezing and all hot lines are stress analyzed to accommodate thermal movement.

9.3.2.2 System Description

Tables 9.3-1 through 9.3-4 describe the process sampling system by listing, for each system sampled, the sample locations, the analyses to be performed, and anticipated pressures and temperatures. Grab samples are taken for laboratory analysis. Grab samples may be taken locally near the process point or remotely at a central sampling station. For remote grab samples, a sample line is routed from the process pipe to the central sampling station. For local grab samples, a sample line is routed from the process pipe to the nearest accessible area for plant personnel. To determine whether a grab sample should be remote or local, the samples are put into the following classification or criteria:

a. Classification or criteria for remote grab sample:

   1. Sample is taken frequently

   2. Sample point is inaccessible during operation

   3. Sample has to be conditioned

   4. Sample may be radioactive

   5. Entrained gases must be vented through a hood.

b. Classification or criteria for local grab samples:

   1. Sample is taken infrequently

   2. Sample point is accessible

   3. Sample taken only during shutdown

   4. Sample tends to form deposits which would cause plugging of longer lines.

Remote grab samples are routed to a central sampling station, where they are temperature conditioned to 120°F or less and are provided with manual flow control. Continuous samples are routed to the central sampling station where the samples are regulated for proper flow and are temperature controlled as required by the instrument manufacturer. Continuous samples are provided with a means for taking grab samples at the central sampling station and are designed so that grab samples do not reduce flow below the design requirements of the continuous analysis instrumentation.

After sample conditioning, except for those samples recovered directly into the process flow, the samples flow through the analysis instrumentation to the radwaste floor drain system.

A special sample drain collection/recovery system has been designed to reduce radwaste burden by collecting and recovering certain sample drains which are of sufficient water quality to allow recovery into the condensate process flow without radwaste processing. The system consists primarily of a single tank with 240 gallon working volume and 20 gpm pump. Normally this system discharges to the condensate pump suction header but defaults to turbine building floor drains.

Central sampling stations are located in the radwaste, turbine, and reactor buildings. This is done to minimize the length of the sample lines and therefore shorten the transport time for the samples. Each central sampling station contains the remote grab and continuous samples as discussed in previous paragraphs, and the temperature conditioning equipment and analysis instrumentation. The central sampling stations are provided with exhaust hoods to draw air from the sample sinks. Airflow is 100 to 150 linear ft per minute.

All remote sample lines, where possible, are pitched 1/4 in./ft in direction of flow. The sample line lengths are as short as possible and the routing avoids traps, deadlegs, and dips upstream from the sample discharge. Sample flow is in the turbulent-flow region to minimize deposition and to ensure representative samples. Local samples are located in well-ventilated accessible areas. Drain funnels are provided to carry sample streams, which are not recoverable, to the floor drain system.

9.3.2.3 Safety Evaluation

Samples that require special handling, and all sample lines that flow continuously, lead to central sampling stations in the reactor building, the turbine building, or the radwaste building. The central sampling stations are equipped with ventilation hoods, backflushing facilities, and pressure and temperature controls. Remote air-operated sample valves are controlled from these central sampling stations.

High-pressure sample lines are required to pass hydrostatic tests with the process units they serve and must conform to the same construction standards.

All sample lines have a shutoff valve located as close as possible to the sample source connection. This valve is manually operated if accessible, and solenoid operated where inaccessible.

Solenoid valves are designed to fail closed. Division II PCMS isolation valves T5000F420B and T5000F421B fail closed following a power failure but can be reopened since these valves are equipped with DC solenoid valves powered from a DC battery and the pneumatic power for these solenoids is provided from bottled nitrogen as shown in Figure 7.6-11. Soft-seated solenoid valves are provided to ensure minimum leakage because leakage could go undetected for long periods of time. Since all samples have a potential for becoming radioactive, the following special precautions are taken to minimize radiation hazards to plant personnel:

a. Sample lines are routed wherever possible in shielded areas where plant personnel have little or no access

b. Equipment that tends to trap activated "crud" is kept behind shield walls

c. Provisions are made for sample line backflushing with demineralized water at the sample stations

d. Ventilated hoods are provided at the sample station

e. Local grab samples are located in well-ventilated areas that are accessible to plant personnel

f. Remote samples are extended through shield walls if located near radioactive equipment or if the sample line creates significant radiation field.

9.3.2.4 Tests and Inspections

During plant operation or shutdown, no special tests or inspections are required for sample lines and sample stations beyond inclusion in the test and inspection programs conducted on the systems they serve. Continuous analysis instrumentation will be periodically checked and recalibrated.

9.3.2.5 Instrumentation

Pressure controls and remotely operated valves are procured to the same specification as the lines they are sampling. The continuous monitors installed in various sample stations are identified by function in Tables 9.3-l through 9.3-4.

9.3.3 Plant Equipment and Floor Drains

9.3.3.1 Design Bases

The plant equipment and floor drainage systems are designed to collect and remove all waste liquids from their points of origin to a suitable disposal area in a controlled and safe manner. Water from radioactive drains is collected for sampling and analysis prior to disposal to the environment in accordance with 10 CFR 20. Drain line penetrations through containment barriers are designed to maintain containment during normal operation and design-basis accidents (DBAs).

In the reactor, auxiliary, turbine, and radwaste buildings, most drain water is considered potentially radioactive and is accumulated for periodic discharge to the radwaste system for treatment. In general, drainage from production equipment is of high purity and high activity relative to floor drain discharge, and is collected separately from the floor drain discharges. In the radwaste process, cleanup of the floor drain accumulations may be more complex and could require more unit separation than do the equipment drain accumulations routed to the radwaste waste collector tank.

Equipment drain water of relatively high purity and high activity is separately collected and discharged to the radwaste waste collector tank and subsequent cleanup train. If the effluent from this cleanup train is of satisfactory quality, the purified stream is normally recycled to the 600,000-gal condensate return tank. Floor drain water of relatively low purity is collected in separate sumps and periodically discharged to the radwaste floor drain collector tank and cleanup train. If this water is of satisfactory quality, the purified stream may also be recycled to the CST or exhausted to the plant circulating water reservoir decanting line that flows into Lake Erie.

The normal equipment and floor drain water in each quadrant of the reactor building sub-basement is collected in the local sump of the respective quadrant. The drain water from the NW and SE quadrant sumps is discharged to the radwaste waste collector tank. The drain water from the SW and NE quadrant sumps is discharged to the radwaste floor drain collector tank.

Equipment drain connections are generally through open funnels (sight drains) at those locations where it is considered desirable to verify performance at a glance, where periodic temperature observations may be required, or where the coolant water system is a high pressure system and might overpressurize drain lines and equipment.

Drain system piping effecting drywell isolation is constructed to meet standards for Quality Group B components. They are designed to ASME Section III, Class 2 code requirements. The balance of the drain system is either Quality Group C designed to ASME Section III, Class 3 code requirements or Quality Group D, designed to ANSI B31.1.0, except for the recirculating sump heat exchangers. Their piping is designed to ASME Section VIII and to ANSI B31.1.0 code requirements.

All the equipment drain piping above the floor in the reactor building sub-basement is designed to ANSI B31.1.0 code requirements.

9.3.3.2 System Description

NOTE: Pump rates are nominal flow rates.

The Fermi 2 drainage system is designed for accumulation of discharges from equipment and floor drains inside the reactor building, auxiliary building, turbine building, and radwaste building, and for periodic transfer of these accumulations to the liquid radwaste system.

Within the reactor building, seven separate drain collection systems operate, each with an independent sump. The reactor and auxiliary buildings drain systems are shown in Figures 9.3-5 and 9.3-6.

An equipment drain collection system from primary coolant components terminates in a 1100-gal nominal capacity sump located in the drywell area under the reactor pressure vessel (RPV) with twin parallel 50-gpm transfer pumps that discharge to the radwaste waste collector tank. The sump is closed and vented, with a recirculating bypass capability from the transfer pump discharge header line returning to the sump. This bypass flows through a heat exchanger cooled by RBCCW. The sump fluid is automatically recirculated on a signal from a temperature sensor in the sump, in order to protect radwaste-system resins from deleterious overheating. The sump liquid setpoint is 135°F. Periodic sump discharge is initiated automatically on a signal from the sump level controller. The discharge header to the radwaste waste collector tank penetrates the primary containment wall. In order to preserve the integrity of primary containment, this line is sealed by the submerged pump suction lines inside primary containment.

These lines are also protected by one air-operated isolation valve and one motor-operated isolation valve installed in tandem in the discharge header; one valve is located inside containment, the other outside. Each valve is fed from a different division. These isolation valves are automatically closed by a rise in pressure inside primary containment and by other primary containment isolation signals (See Table 6.2-2).

Equipment drains from secondary containment spaces in the reactor building and auxiliary building are also collected and discharged to the radwaste waste collector tank. Two drain sumps, each holding 1500 gal (nominal capacity), are provided, each with twin submersible pumps and bypass heat exchangers.

The fourth drain system in the reactor building draws from a trench drain and an undervessel drain and exhausts to the radwaste floor drain collector tank. This system is similar to the equipment drain systems located in the drywell discussed previously. Dual isolation valves ensure the integrity of primary containment, but the bypass cooling heat exchanger is omitted. Sump capacity is 1000 gal (nominal capacity).

The fifth and sixth drain systems in the reactor building collect from the floor drains in secondary containment areas and exhaust through twin parallel pumps to the radwaste floor drain collector tank. These systems, like the other floor drain system, have no sump cooling provision. Each sump has a 1500-gal nominal capacity.

The seventh reactor building drain system consists of a sump in the torus area (with no collection piping). This system discharges through twin parallel transfer pumps and an external water seal to the radwaste floor drain collector tank. This sump has a 900-gal nominal capacity.

Equipment and floor drains in the emergency core cooling system (ECCS) pump rooms, in the subbasement of the reactor building, have been physically separated to prevent possible flooding between ECCS Division I and Division II equipment through the drain lines in the event of an accident that causes one of the rooms to flood.

Equipment and floor drains in the emergency core cooling system (ECCS) pump rooms,in the sub-basement of the reactor building, are collected in each room's sump to prevent possible inter-divisional flooding between ECCS Division I and Division II, with the exception of HPCI room. The floor and equipment drains from the HPCI room are collected in the RHR Division II pump room sump. A motor operated auto-close flood control valve is provided in the floor and equipment drain line to prevent possible flooding between the two rooms in the event of an accident that causes one of the rooms to flood. The flood control valve will normally be open, but will close on high-high sump level to prevent water from backing up into the subbasement floor and equipment drains. The valves will reopen on low sump level. Selected RHR pump and rack H21-P596B drains in the southwest corner room are hard piped to the southeast corner sump, but are isolated by normally closed manual valves.

Flooding of any individual corner room or the HPCI room due to a line break in either room can be confined to that corner room. The configuration of the motor operated flood control valve and its associated sump is shown in Figure 9.3-6. The level switch data for the motor operated flood control valve is given in Table 9.3-5.

The motor-operated flood-control valve and its limit switches are tested periodically to ensure their satisfactory performance. This testing is done as required by the Performance Evaluation Procedures of the overall plant surveillance program. Maintenance procedures cover the testing of the valves. Switches and other pertinent instrumentation are covered by a section of the overall balance-of-plant (BOP) preventive maintenance program.

The turbine building has eight separate radioactive drain collection systems, each with an independent sump. The drain system is shown in Figures 9.3-8 and 9.3-9.

Two equipment drain sumps, with nominal capacities of 400 and 4400 gal, collect oil-free radioactive liquids from equipment and piping systems. Each sump has twin 50-gpm sump pumps that periodically discharge to the waste collector tank in the radwaste building.

A third 2300-gal nominal capacity service water drain sump is provided to collect nonradioactive liquids from such systems as the general service water (GSW) system, and TBCCWS piping. This sump can be emptied into the liquid waste holding pond in the yard.

Two floor drain sumps, with nominal 1600-gal and 4400-gal capacities, are provided to collect oil-free liquids, and each has twin 50-gpm sump pumps discharging to the floor drain collector tank in the radwaste building.

Finally, three sumps, with approximate capacities of 1900, 2200, and 3000 gal, are provided to collect oil-contaminated liquids. These sumps are each provided with two 50-gpm to 64-gpm pumps as well as a 200-gpm or a 250-gpm emergency pump. The discharge is normally routed to an oil-water separator prior to treatment in the radwaste building. The emergency pumps can be used to empty the sumps to the liquid waste holding pond, if desired.

The radwaste building contains an equipment and a floor drain sump, each with a 900-gal nominal capacity. First-floor leakages drain directly into the waste collector tank or into the floor drain collector tank located in the basement. Basement leakages are collected in the appropriate sump and pumped out by twin 50-gpm pumps. The system drains are shown in Figures 9.3-10 and 9.3-11.

The RHR complex drain system is segregated into two types of wastes, oil-free water and oil-contaminated water. Equipment and floor drains that are potentially contaminated with oil drain to a manway which is connected by an overflow line to the liquid waste holding pond. Equipment and floor drains that are oil free drain to another manway which is connected by an overflow line to the circulating water reservoir. The piping pits are provided with sump pumps which discharge to the clear-water manway. The RHR system drains are shown in Figure 9.3-12.

9.3.3.3 Safety Evaluation

All potentially contaminated internal drain water is processed through the radwaste purification trains before release or recycle. The integrity of primary containment is ensured by tandem isolation valves. The drainage system is protected from overpressure by open sight funnel drains at most collection points.

To further ensure performance, the high-temperature drains in the reactor building are cooled by the RBCCWS. This ensures an acceptable net positive suction head (NPSH) at the transfer pumps.

9.3.3.4 Tests and Inspections

The drain lines are all welded and all required tests for joint soundness were carried out in accordance with applicable codes. For this reason, the closing field welds are in accessible positions.

Because spare pumps are installed, no periodic qualifying tests were undertaken. Completed piping has been hydrostatically tested in the field.

9.3.3.5 Instrumentation

Each sump is equipped with a high-high-level alarm to signal automatic initiation of the second pump. The starting of the second pump would be indicative of a system leakage. In addition, temperature controls are provided to cool critical sumps by actuating the flow of sump water through heat exchangers.

All reactor building sumps have leak-detection instrumentation. Timers monitor the operation of the sump pumps both for frequency and for length of operation. Leakage is detected by a pump operating before the timers time out or by a pump operating too long. Leakage is alarmed in the main control room.

9.3.4 Chemical, Volume Control, and Liquid Poison Systems

The only BWR systems that are related to this general class of systems are the standby liquid control system (SLCS) and the reactor water cleanup (RWCU) system.

The SLCS is described in Subsection 4.5.2.4 and the RWCU system is described in Subsection 5.5.8.

9.3.5 Failed Fuel Detection System

In the event of gross rod failure, the increased activity in the coolant would be transferred to the steam and detected by the main steam line RMS. Downstream of the steam line monitors are the offgas RMS and the reactor building exhaust vent RMS. The design bases, system description, safety evaluation, tests and inspections, and instrumentation applications for each of these subsystems are found in Section 11.4.

9.3.6 Nitrogen Inerting System

9.3.6.1 Design Bases

The Fermi 2 nitrogen inerting system provides and maintains a nitrogen atmosphere inside the primary containment and also provides pressurized nitrogen for pneumatic service inside the primary containment and distribution throughout the plant. The system schematic is shown in Figures 9.3-13 and 9.3-14.

The nitrogen inerting system supply is located outside the reactor building on the west side. The components are shown in Figure 9.3-15. The remainder of the system is located in the reactor building. The nitrogen inerting system supplies nitrogen gas at the proper pressure and temperature for inerting the primary containment and for distribution throughout the plant.

The nitrogen inerting system design requirements are the following:

a. To provide nitrogen gas at the proper temperature and pressure to inert the primary containment to a minimum of 97 percent by volume of nitrogen. The nitrogen gas will be injected into the primary containment and the existing atmosphere will be displaced out through the reactor/auxiliary building ventilation system or through the SGTS. Mixing of the injected nitrogen will be accomplished by the use of the drywell cooling system (see Subsection 9.4.5).

b. To provide nitrogen makeup for atmospheric leakage out of the primary containment during normal operation and to ensure that a positive pressure is maintained inside the primary containment with respect to the secondary containment. Makeup requirements to some degree will be taken care of by the bleed-off of nitrogen gas from the pneumatic instrumentation inside the primary containment. Provisions for nitrogen addition to the primary containment atmosphere have been made at the drywell and suppression chamber supply lines through a separate on-line purge system. This system controls the pressure of the drywell and torus through vent/makeup of nitrogen

c. To provide nitrogen gas for the pressurized distribution system for the following services:

    1. To provide pressurized nitrogen for the pneumatic instrumentation inside the primary containment. During normal operation, nitrogen will be supplied to this instrumentation from the nitrogen inerting system. In the event of a loss of nitrogen supply, bottled nitrogen will be available for emergency use for the pneumatic requirements inside the primary containment

    2. To provide pressurized nitrogen to any other remaining services requiring nitrogen throughout the plant.

Air purging of the primary containment to the breathable limit will be accomplished by the use of the reactor/auxiliary building ventilation system or the SGTS.

9.3.6.2 System Design

The nitrogen inerting system primary containment penetrations and the associated isolation valves are classified as ASME Section III, Class 2. The pneumatic supply system inside primary containment is classified as ASME Section III, Class 3. The balance of the nitrogen inerting system pressure vessels are classified as ASME Section VIII, and the piping is classified as ANSI B31.1.0.

The nitrogen inerting system primary containment penetrations and associated isolation valves and the pneumatic supply system inside primary containment are designated as Category I. The remainder of the system is classified as nonseismic.

The nitrogen inerting system has been designed in accordance with the following criteria.

a. Liquid nitrogen requirements are based on the following usage:

   1. To inert the primary containment to less than 3 percent by volume of oxygen

   2. To provide additional nitrogen to the primary containment to compensate for leakage.

   3. To provide nitrogen for the pressurized distribution system.

b. The inerting and air purging procedures for the primary containment will be completed in approximately 6 hr.

c. The minimum distribution temperature of the nitrogen gas for all phases of operation of the nitrogen inerting system is controlled. The vaporizing medium during the primary containment inerting procedure is saturated steam at 15 psig from the plant auxiliary boilers. Heat for the pressurized distribution system will be provided electrically

d. The design capacity of the liquid storage tank is based on the service requirement of the pressurized distribution system for Fermi 2 and the vapor loss from the storage tank during the interval of storage

e. The receiver usable capacity will be designed to allow a system flow rate of 50 cfm for a period of 5 minutes if the liquid nitrogen source should be out of service. A full-capacity standby receiver is available

f. The pressurized distribution system is designed to allow connection of bottles as a backup source of nitrogen

g. The design flow of the nitrogen gas to the primary containment for the inerting procedure is 3000 scfm.

9.3.6.3 Design Evaluation

The system fluid will be commercial 99-percent pure nitrogen. The fluid will not be radioactive. System components for the handling of liquid nitrogen have been constructed of materials suitable for temperatures of -320°F.

The liquid nitrogen storage tank provides the source of supply for pressurized nitrogen distribution. The tank is equipped with a pressure build coil and an auxiliary pressure build vaporizer. The pressure build coil will transfer heat to the liquid nitrogen to generate saturated nitrogen vapor.

The nitrogen inerting system has a steam vaporizer and electric heat exchanger. The steam vaporizer will be used only when nitrogen is required for the inerting of the primary containment. The electric heat exchanger is used to supply gaseous nitrogen for pressurized distribution.

The nitrogen receivers provide temporary storage to meet sudden demands for pressurized nitrogen throughout the plant. One receiver will be in full standby to allow maintenance without disturbing normal plant operation.

The source of system pressure is the liquid nitrogen storage tank. The vapor pressure in the tank will be regulated to provide the required system pressure. All pressure-retaining components of the system are equipped with properly sized pressure relief valves. Piping that is handling liquid nitrogen has pressure relief valves installed in any segment where liquid nitrogen could become entrapped between closed valves. All liquid nitrogen transfer lines are sloped upward in the direction of flow to prevent vapor pocket buildup at the nitrogen source.

The nitrogen inerting system is not required for the safe shutdown of the reactor, and hence is not required to protect the health and safety of the public. However, the continuous operation of the plant is contingent upon the nitrogen inerting system maintaining the required nitrogen atmosphere inside the primary containment. Therefore, to ensure that nitrogen gas is always available to meet the primary containment nitrogen requirements, small amounts of bottled, high-pressure nitrogen will be stored at the site as a secondary source of nitrogen supply.

9.3.6.4 Tests and Inspections

The liquid storage and vaporizing facilities for the nitrogen inerting system are located outside the reactor building and are accessible for inspection. The nitrogen receiver tanks and bottled nitrogen tanks are located in the reactor building and are accessible for inspection during normal plant operation. Initial system checks, valve operability, instrumentation and control loop checks, and alarm setpoints for the nitrogen inerting system were done in accordance with the Preoperational Test program as discussed in Chapter 14. The temperature and pressure of nitrogen delivered by the steam and electric vaporizers have also been determined.

Periodic inspections of receiver tanks and the passive Division II backup nitrogen supply system will be performed. The inspection of instruments will be made to confirm the actuation of relief valves and alarms. The system and its components will be periodically tested and maintained as appropriate for the system safety classification.

9.3.6.5 Instrumentation Requirements

When the primary containment is being inerted, pressure and temperature control will be maintained in the following manner:

a. A pressure control valve located downstream of the liquid storage tank discharge and the steam vaporizer automatically maintains a discharge pressure of approximately 30 psig

b. A temperature indicator is located in the condensate discharge line of the steam vaporizer as is a low-temperature switch that shuts down the nitrogen discharge from the vaporizer at preset temperature.

Pressure and temperature control of the pressurized nitrogen distribution system will be maintained as follows:

a. A pressure control station located between the liquid storage tank and the electric heat exchanger automatically maintains a downstream pressure of approximately 110 psig

b. A variable setpoint temperature controller on the discharge side of the electric heat exchanger maintains a nitrogen discharge temperature

c. A pressure control station located downstream of the receivers maintains a downstream pressure

d. The drywell makeup station will sense the pressure of the primary containment and the secondary containment and with manual action, a positive pressure will be maintained in the primary containment

e. The provision for a bottle backup station will include a manually operated pressure regulator to maintain the receiver pressure when required. However, Division II is backed up by a passive nitrogen supply using bottles in the secondary containment. This capability supports manual operation of Division II SRVs from the control room for certain post-fire shutdowns requiring low pressure makeup systems

f. A pressure indicator is provided to monitor pressure downstream of the receivers. When the pressure of the receiver in operation reaches a setpoint, an alarm is provided to indicate low receiver pressure.

The primary containment isolation valves will automatically isolate on high drywell pressure, low reactor level, or high reactor building radiation.

TABLE 9.3-1 PROCESS SAMPLING SYSTEM

Item No.	Description	Sample tap Location	Purpose of Sample	Type of Analysis	Analysis Mode	Source Operating Temperature (°F)	Source Operating Pressure (psig)
1	TBCCW (2)	E and W heat exchanger outlet	Tube leaks	Conductivity Laboratory	Local grab	95/130	35
2	Condenser	Condenser leak troughs	Spare tap not used				
3	Condensate (3)	Condensate pumps discharge north-center-south	Condensate quality and tube leaks	Laboratory	Grab station	94	213
4	Condensate	Condensate pumps discharge header	Spare tap not used			94	213
5	Condenser (6)	Condenser leak troughs inlet and outlet each quadrant turbine	Spare taps -not used			100	-14
6	Condenser	Condenser leak trough	Spare tap not used			125	147
7	Condenser circulating water system (2) A or B	NE and SE water box influent	Water analysis	pH, Biocide Residual laboratory	Local Grab	95	50
8	Condenser circulating water system (2) A or B	E and W water boxes effluent	Water analysis	Biocide Residual Conductivity, pH, Total solids Laboratory	Local Grab	100	50
9	Condensate polishing demineralizer	Polishing demineralizer inlet header	Condensate quality and tube leaks	Conductivity Cation, Dissolved 0_2 Corrosion Products Laboratory	Continuous Grab station	94	213
10	Condensate polishing demineralizer	Polishing demineralizer outlet header	Treated condensate quality	Conductivity Dissolved 0_2 Corrosion Products Laboratory	Continuous Grab station	94	213
11	Feedwater heaters (4) 11, 11A, 11B, 11C	No. 2 FWH effluent header 2N, 2C, 2S	Water analysis	Laboratory	Grab station	388 170	498 634
12	Reactor feedwater system (2) A and B	After last heater 6A and 6B (2)	Water analysis	Laboratory	Continuous Grab station	425	1106
13	Heater feed	Heater feedpump discharge header	Water analysis	Laboratory	Grab station	94	700
14	Main steam (2) (A or B)	Main steam line	Steam conditions	Conductivity Laboratory	Continuous Grab station	549	1020
15	Drains cooler	Drain discharge to condenser	Water analysis	Laboratory	Local grab	134 104	-12 psia
16	Deaerating No. 5 heater (2) drain	No. 5N + 5S drain outlet	Drain water quality for pumping drains forward	Corrosion Products when required Laboratory	Local grab or tie continuous with item 25	392	224 210
17	Feedwater heaters (12)	Condensate inlet and outlet to heaters	Water analysis	Laboratory	(a)	105-400	580 634
18	Feedwater heaters (12)	Drains inlet and outlet to heaters	Water analysis	Laboratory	(b)	105-400	-13.5-345

TABLE 9.3-1 PROCESS SAMPLING SYSTEM

Item No.	Description	Sample tap Location	Purpose of Sample	Type of Analysis	Analysis Mode	Source Operating Temperature (°F)	Source Operating Pressure (psig)
19	Condensate polishing demineralizer	Polishing demineralizer inlet header	Condensate quality	Conductivity Laboratory	Continuous Grab station	94	213
20	Condensate polishing demineralizer	Polishing demineralizer effluent header	Demineralizer efficiency	Conductivity Laboratory	Continuous Grab station	94	213
21	General service water header	Effluent header to circulating water	Water analysis	Biocide Residual	Local grab	85	80-125*
22	Reactor Feedwater System	36 in. header after heater 6A and 6B	Water analysis	Conductivity Dissolved 02 Turbidity Corrosion Products Laboratory Dissolved H2	Continuous Grab station	425	1116
23	Condensate (4)	Hotwell discharge pipe each quadrant, condenser	Tube leaks	Conductivity Sodium Laboratory	Continuous Grab station	91.7	-9
24	Circulating water decant	Circulating water decant line	Sample of decant to Lake Erie	Laboratory	Local grab	85	50
25	Feedwater heater drains	Heater drain pumps discharge header	Evaluating heater drain contribution to feedwater	Dissolved 0_2 Turbidity Corrosion Products	Continuous Grab station	392	791
26	Circulating water decant before radwaste	Discharge of decant pumps	Water analysis	Corrosion Products Laboratory	Local grab	95	50
27	Makeup demineralizer storage tank	Tap on tank	Tank water purity	Laboratory	Local grab	Ambient	Tank head
28	Condensate storage tank	Tap on tank	Tank water purity	Laboratory	Local grab	Ambient (>40°F)	Tank head
29	Condensate return tank	Tap on tank	Tank water purity	Laboratory	Local grab	Ambient (95°F)	Tank head
30	Inlet line to condensate return tank	CRT return line	CRT supply purity	Laboratory	Local grab	95	58
31	Torus water management	Discharge of torus water management pumps	Water analysis	Laboratory	Grab station	160	210
32	SCCW Chilled Water (3)	Outlet of chilled water evaporator	Water analysis	Laboratory	Local grab	60	100

(a) Local grab for Sample No. 17a, c, d and e

(b) Local grab for Sample No. 18c and d

* Bounds plant operating procedures

TABLE 9.3-2 PROCESS SAMPLING SYSTEM

Item No.	Description	Sample tap Location	Purpose of Sample	Type of Analysis	Analysis Mode	Source Operating Temperature (°F)	Source Operating Pressure (psig)
33	SCCW (1)	Chilled water common return	Water analysis	Laboratory	Local grab	76	100
34	RBCCW (3)	RBCCW Return Headers from EECW	Water analysis	Laboratory	Local grab	85	80
35	RBCCW (2)	Heat exchanger outlet (2) N and S	Tube leaks	Conductivity	Local grab	85	80
36	RBCCW	Pump discharge header	Tube leaks	Conductivity	Grab station	85	80
37	Reactor primary coolant water	Main recirculating system pipe	Monitor reactor water when cleanup is isolated	Conductivity Dissolved 0_2 pH, Corrosion Products Laboratory Dissolved H_2	Continuous Grab station	540	1230
38	Reactor water cleanup filter-demineralizer	Filter inlet pipe	Reactor water quality	Conductivity Laboratory	Continuous Grab station	120	1214
39	Reactor water cleanup filter-demineralizer (2) (A or B)	Filter outlet pipe	Demineralizer efficiency	Corrosion Products Conductivity Laboratory	Continuous Grab station	120	1214
40	Suppression pool (4)	RHR pump suction A, B, C, D	Water analysis	Laboratory	Local grab	90	Atm
41	Standby liquid control	Dip from tank	Test for boron concentration	Laboratory	Dip sample	90	Atm
42	Reactor shutdown cooling system (2) (A and B)	RHR heat exchanger outlet A & B	Water analysis	Conductivity Dissolved 0_2 pH, Laboratory Dissolved H_2	Continuous Grab station	335	480
43	Cleanup phase separator decant	Decant line to waste collector tank	Process data	Laboratory	Local grab	125	130
44	Cleanup phase separator sludge	Cleanup sludge discharge mix pump	Process data	Laboratory	Local grab	70-130	70
45	Fuel pool water	Dip from fuel Storage pool	Water analysis	Laboratory	Dip sample	70	Atm

TABLE 9.3-2 PROCESS SAMPLING SYSTEM

Item No.	Description	Sample tap Location	Purpose of Sample	Type of Analysis	Analysis Mode	Source Operating Temperature (°F)	Source Operating Pressure (psig)
46	EECW Division I Outlet (2)	Heat exchanger	Plate Leaks	Laboratory	Local grab	85-95	80
47	EECW Division II Outlet (2)	Heat exchanger	Plate Leaks	Laboratory	Local grab	85-95	80
48	Reactor water cleanup heat exchangers (2) cooling water	Cooling water (RBCCW) outlet, A and B RWCU heat exchanger	Tube leaks	Laboratory	Local grab	110	80
49	Fuel pool heat exchangers (2) and cooling water	Cooling water (RBCCW) outlet, A and B fuel pool cooling and clean- up heat exchanger	Tube leaks	Laboratory	Local grab	110	80
50	Reactor water cleanup	Cleanup pump discharge (RWCU Inlet)	Reactor water quality	Conductivity Dissolved 02 pH Corrosion Products Laboratory Dissolved H2	Continuous Grab station	537	1220
51	Reactor water cleanup	RWCU Outlet header (before addition to feedwater	Cleanup system operation	Corrosion Products Conductivity Laboratory	Continuous Grab station	537	1220
52	Spent fuel pool circulating system	Fuel pool pump discharge (2) A and B	Water quality	Laboratory	Local grab	130	130
53	Service water discharge from RBCCW heat exchangers	Service water discharge header from heat exchangers	Tube leaks	Laboratory	Local grab	100	80-125*
54	Control rod drive	CRD filter outlet	CRD water quality	Conductivity Dissolved oxygen	Grab Station		
55-56	Not used						

TABLE 9.3-2 PROCESS SAMPLING SYSTEM

Item No.	Description	Sample tap Location	Purpose of Sample	Type of Analysis	Analysis Mode	Source Operating Temperature (°F)	Source Operating Pressure (psig)
57	Reactor Water Cleanup	Cleanup Pump Suction	Reactor Water Quality	Laboratory Conductivity Dissolved O2 ph Dissolved H2	Grab Station, Continuous	537	1050

* Bounds Plant Operating Procedures

TABLE 9.3-3 PROCESS SAMPLING SYSTEM

Item No.	Description	Sample tap Location	Purpose of Sample	Type of Analysis	Analysis Mode	Source Operating Temperature (°F)	Source Operating Pressure (psig)
58	Floor drain demineralizer	Outlet pipe	Demineralizer efficiency	Laboratory	Local grab	140	40-140
59	Turbine building floor drain oil separator	Discharge to floor drain collector tank	Process data	Laboratory	Local grab		
60	Turbine building floor drain sumps (3)	Discharge to oil separator	Process data	Laboratory	Local grab		
61	Turbine building floor drain sumps (3)	Discharge to trash pond	Process data	Laboratory	Local grab		
62	Not used						
63	Floor drain sumps (7)	Sump pump discharge to floor drain collector tank	Process data	Laboratory	Local grab		
64	Equipment drain sumps (6)	Sump pump discharge to waste collector tank	Process data	Laboratory	Local grab		
65	Radwaste building emergency drains sump (5)	Sump pump discharge	Process data	Laboratory	Local gab	140	40-140
66	Radwaste evaporator (2) (A and B)	Concentrate pump discharge A and B	Process data	Laboratory	Local grab	165	40
67	Waste surge tank pump discharge	Waste surge tank	Process data	Laboratory	Grab station	140	40-140
68	Waste collector tank	Waste collector tank pump discharge	Process data	Laboratory	Grab station	140	40-140
69	Floor drain collector tank pump discharge	Floor drain collector tank pump discharge	Process data	Laboratory	Grab station	80	100
70	Not used						
71	Not used						
72	Waste sample tanks (2) (A and B)	Waste pump dis-charge	Discharge suitability	Laboratory	Grab station	40-140	40-140
73	Waste sample tank	Recirculating line to waste sample tank	Discharge suitability	Laboratory	Grab station	40-140	40-140

TABLE 9.3-3 PROCESS SAMPLING SYSTEM

Item No.	Description	Sample tap Location	Purpose of Sample	Type of Analysis	Analysis Mode	Source Operating Temperature (°F)	Source Operating Pressure (psig)
74	Waste collector filter-demineralizer	Filter-demineralizer outlet	Filter-demineralizer efficiency	Laboratory	Local grab	140	140
75	Not used						
76	Waste demineralizer	Demineralizer outlet	Demineralizer efficiency	Laboratory	Local grab	140	40-140
77	Floor drain filter-demineralizer	Filter-demineralizer outlet	Filter-demineralizer efficiency	Laboratory	Local grab	140	40-140
78	Not used						
79	Condensate phase separator	Condensate decant pump discharge	Process data	Laboratory	Local grab	80	Atm
80	Chemical waste tank	Chemical waste pump discharge	Process data	Laboratory	Grab station	80	40
81	Fuel pool cooling and cleanup filter-demineralizer	Inlet pipe	Fuel pool water quality	Laboratory	Local grab	130	130
82	Fuel pool cooling and cleanup filter-demineralizer	Outlet pipe efficiency	Filter	Laboratory	Local grab	125	130
83	Not used						
84	Not used						
85	Distillate (2)(A and B) surge tank	Distillate surge tank (A and B)	Distillate data	Laboratory	Grab station	40	40
86	Radwaste effluent	Discharge line to decant line	Discharge data	Laboratory	Grab station	150	50
87 to100	See Table 9.3-4						
101	Waste collector etched-disk filter	Discharge to etched-disk filter	Filter efficiency	Laboratory	Local grab	40-140	55-167
102	Waste collector oil coalescer filter	Discharge of oil coalescer	Oil coalescer efficiency	Laboratory	Local grab	0-140	55-167
103	Floor drains etched-disk filter	Discharge of etched-disk filter	Filter efficiency	Laboratory	Local grab	40-140	22-100
104	Floor drains oil coalescer	Discharge of oil coalescer	Oil coalescer efficiency	Laboratory	Local grab	40-140	22-100

TABLE 9.3-3 PROCESS SAMPLING SYSTEM

Item No.	Description	Sample tap Location	Purpose of Sample	Type of Analysis	Analysis Mode	Source Operating Temperature (°F)	Source Operating Pressure (psig)
105	Distillate surge tank A	Discharge of distillate A pump	Distillate data	Laboratory	Local grab	40	40
106	Distillate surge tank B	Discharge of distillate B pump	Distillate data	Laboratory	Local grab	40	40
107	Evaporator feed surge tank	Discharge of evaporator feed-pumps	Process data	Laboratory	Grab station	80	100
108	Centrifuge	Decant line to waste clarifier	Process data	Laboratory	Local grab	140	Atm
109	Extruder/evaporator distillate	Discharge line to waste clarifier	Process data	Laboratory	Local grab	212	0
110	Floor drain demineralizer	Demineralizer outlet before strainer	Distillate quality	Conductivity	Continuous	140	40-140
111	Waste demineralizer	Waste demineralizer discharge	Distillate quality	Conductivity	Continuous	140	40-140
112	Waste collector oil coalescer filter	Discharge of oil coalescer	Water effluent quality	Conductivity	Continuous	40-140	55-167
113	Floor drain oil coalescer	Discharge of oil coalescer	Process data	Conductivity	Continuous	40-140	22-100
114 to 119	Not used						
120	Fuel pool cooling and cleanup demineralizer A	Demineralizer A effluent	Demineralizer efficiency	Conductivity	Continuous	140	40-140
121	Fuel pool cooling and cleanup demineralizer B	Demineralizer B effluent	Demineralizer efficiency	Conductivity	Continuous	140	40-140
122	Circulating water	Circulating water pumps discharge header	pH control	pH	Continuous with recirculating pump operation	60	50
123	Not used						
124	Floor drain demineralizer	Floor drain demineralizer outlet before recycle valve	Demineralizer efficiency	Conductivity	Continuous	140	40-140
125	Waste demineralizer	Waste demineralizer discharge	Demineralizer efficiency	Conductivity	Continuous	140	40-140

TABLE 9.3-3 PROCESS SAMPLING SYSTEM

Item No.	Description	Sample tap Location	Purpose of Sample	Type of Analysis	Analysis Mode	Source Operating Temperature (°F)	Source Operating Pressure (psig)
126	TBCCW supply	Discharge header from pumps	Process data	Laboratory	Local grab	95	50
127	Radwaste evaporator (2) (A and B)	Discharge lines from A and B distillate pumps to distillate coolers	Process data	Laboratory	Local grab	135	Atm
128	Evaporator drains holdup tank	Discharge line from evaporator drains pump	Process data	Laboratory	Local grab	165	Atm
129	Not used						
130	Radwaste system fuel pool filter-demineralizer A outlet	Line to fuel pool cooling cleanup system	To check water purity	Laboratory	Local grab	140	40-140
131	Radwaste system fuel pool filter-demineralizer B outlet	Line to fuel pool cooling cleanup system	To check water purity	Laboratory	Local grab	140	40-140
132	RHR heat exchanger B	Discharge to RPV	Water analysis	Conductivity	Continuous	335	480
133	RHR heat exchanger A	Discharge to RPV	Water analysis	Conductivity	Continuous	335	480
134	RHR heat exchanger B(service water)	Discharge to RHR	Radiation water tube leaks	Isotopic chloride	Continuous grab	155	80
135	RHR heat exchanger A(service water)	Discharge to RHR	Tube leaks	Isotopic chloride	continuous grab	155	80
136 to 151	Not used						
152	RHR Division I	RHR service water return, Division I	Tube leaks	Laboratory	Grab station	155	80
153	RHR Division II	RHR service water return, Division II	Tube leaks	Laboratory	Grab station	155	80
154 to157	Not used						
158	Main and reheat system	52-in. manifold	Spare tap			542	997
159	Not used						

TABLE 9.3-3 PROCESS SAMPLING SYSTEM

Item No.	Description	Sample tap Location	Purpose of Sample	Type of Analysis	Analysis Mode	Source Operating Temperature (°F)	Source Operating Pressure (psig)
160	Offgas vacuum and recombiner chain	20-in. manifold	Spare tap			94	-14.2
161	Offgas vacuum and recombiner chain	2.2-minute delay pipe from precooler	Monitor hydrogen and oxygen	Hydrogen oxygen	Continuous	70	-14.2
162	Offgas vacuum and recombiner chain	2.2-minute delay pipe from precooler	Spare tap			70	
163	Stator Winding Cooling de-oxygenating unit	Inlet/outlet of contactors	Monitor dissolved oxygen	Oxygen	Grab Sample	Ambient	80
164	Stator Winding Cooling demineralizer unit	Vent/drain stator winding cooling unit	Oxygen & metallic imputities	Conductivity	Grab Station	150	180
165	Station and control air	2-in. air header	Monitor control air moisture	Dewpoint hygrometer	Continuous	75	110
166 to 169	Not used						
170	Primary containment monitoring system	In reactor drywell	To check quality of reactor atmosphere	Hydrogen oxygen content	Continuous	135	2
171	Primary containment monitoring system	In reactor drywell	To check quality of reactor atmosphere	Hydrogen-oxygen content	Continuous	135	2
172	Primary containment monitoring system	In suppression pool	To check quality of atmosphere in suppression pool	Hydrogen-oygen content	Continuous	150	2
173	Primary containment monitoring system	In suppression pool	To check quality of atmosphere in Suppression pool	Hydrogen-oxgen content	Continuous	150	2
174	Not used						
175	Not used						

TABLE 9.3-4 PROCESS SAMPLING SYSTEM

Item No.	Description	Sample tap Location	Purpose of Sample	Type of Analysis	Analysis Mode	Source Operating Temperature (°F)	Source Operating Pressure (psig)
87	Auxiliary boiler steam (2)	N and S steam drum	Steam quality	Laboratory	Local grab	341	105
88	Auxiliary boiler feedwater	Feedwater inlet header	Feedwater quality	Laboratory	Local grab	220	125
89	Makeup demineralizer anion exchanger	Discharge from anion exchanger	Demineralizer efficiency	Conductivity	Continuous	80	50
90	Makeup demineralizer mixed bed	Discharge from mixed- bed exchanger	Demineralizer efficiency	Conductivity	Continuous	80	40
91	Makeup demineralizer	Makeup demineralizer outlet	Demineralizer efficiency	Conductivity	Continuous	80	40
92	Makeup demineralizer potable water	Raw water booster pump discharge	Raw water data	Laboratory	Grab station	80	50
93	Makeup demineralizer carbon filter	Carbon filter discharge	Filter efficiency	Laboratory	Local grab	80	65
94	Makeup demineralizer cation exchanger (2)	Discharge from cation exchanger	Demineralizer efficiency	Laboratory	Grab station	80	60
95	Makeup demineralizer anion exchanger (2)	Discharge from anion exchanger	Demineralizer efficiency	Laboratory	Grab station local grab	80	50
96	Makeup demineralizer mixed bed (2)	Discharge from mixed bed exchanger	Demineralizer efficiency	Laboratory	Grab station local grab	80	40
97	Makeup demineralizer system	Makeup deminer-	Demineralizer alizer outlet	Laboratory efficiency	Grab station	80	40
98	Makeup demineralizer acid solution	Discharge to mixed bed and cation exchangers	Acid concentration	Laboratory	Grab station	80	50
99	Makeup demineralizer caustic solution	Discharge to mixed bed and anion exchangers	Process data caustic concentration	Laboratory	Grab station	80	50
100	Not used						

TABLE 9.3-5 REACTOR BUILDING: FLOOD CONTROL VALVE

Division	Sump	Isolation Valve	Level Switch[a]
II	DO76 (Floor and equip. drains)	T4500F601	LSE-N076-B

[a] Switch limit points:

High-high	45 in. (valve closes)
High	39 in.
Low	24 in. (valve opens)
Low-low	22 in.

Figure Intentionally Removed
Refer to Plant Drawing M-2015

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FIGURE 9.3-1

STATION AND CONTROL AIR SYSTEM

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Refer to Plant Drawing I-2400-04

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UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 9.3-2

SAMPLES IN REACTOR BUILDING

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Refer to Plant Drawing I-2400-03

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FIGURE 9.3-3

SAMPLES IN TURBINE BUILDING

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Refer to Plant Drawing I-2400-02

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FIGURE 9.3-4

SAMPLES IN RADWASTE BUILDING

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Refer to Plant Drawing M-2223

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FIGURE 9.3-5
EQUIPMENT DRAINS IN AUXILLARY AND
REACTOR BUILDING

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Refer to Plant Drawing M-2224

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FIGURE 9.3-6

FLOOR DRAINS IN AUXILIARY AND
REACTOR BUILDINGS

Figure Intentionally Removed
Refer to Plant Drawing M-2218

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FIGURE 9.3-7

FLOOR AND EQUIPMENT DRAINS IN REACTOR BUILDING SUBBASEMENT

Figure Intentionally Removed
Refer to Plant Drawing M-2534

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FIGURE 9.3-8

EQUIPMENT DRAINS IN TURBINE BUILDING

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Refer to Plant Drawing M-2535

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FIGURE 9.3-9

FLOOR DRAINS IN TURBINE BUILDING

Figure Intentionally Removed
Refer to Plant Drawing M-2550

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FIGURE 9.3-10

EQUIPMENT DRAINS IN RADWASTE BUILDING

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Refer to Plant Drawing M-2551

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FIGURE 9.3-11

FLOOR DRAINS IN RADWASTE BUILDING

Figure Intentionally Removed
Refer to Plant Drawing M-N-2050

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FIGURE 9.3-12

EQUIPMENT DRAINS AND FLOOR DRAINS
(DIVISIONS I AND II) RESIDUAL HEAT REMOVAL
COMPLEX - P&ID

Figure Intentionally Removed
Refer to Plant Drawing M-3445

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FIGURE 9.3-13
NITROGEN INERTING SYSTEM

Figure Intentionally Removed
Refer to Plant Drawing M-3445-1

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FIGURE 9.3-14

NITROGEN INERTING SYSTEM

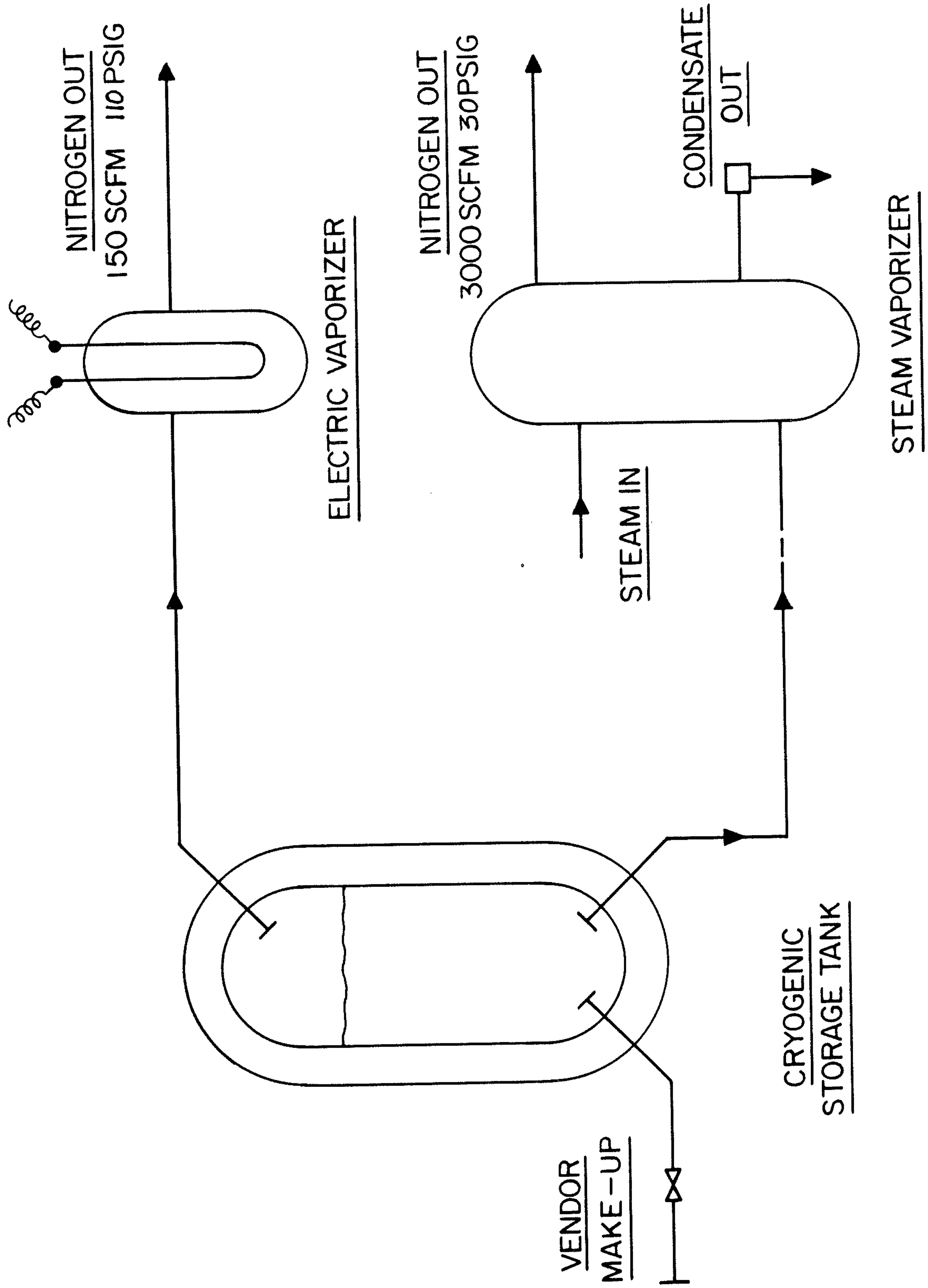

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FIGURE 9.3-15

NITROGEN INERTING SYSTEM SUPPLY

9.4 AIR CONDITIONING, HEATING, COOLING, AND VENTILATION SYSTEMS

9.4.1 Control Center Air Conditioning System

9.4.1.1 Design Bases

The control center air conditioning system (CCACS) is designed to provide ventilation, heating, and cooling, and to limit the relative humidity in the control center envelope (as described in Subsection 9.4.1.2) during normal operation and following a design-basis accident (DBA).

The CCACS is designed as follows:

a. The system is designed to limit the maximum relative humidity* to 60 percent and the nominal ambient temperature to 75°F dry bulb during normal operation, except for the mechanical equipment room (MER) and SGTS room, to ensure comfort of the operators as well as to obtain an optimum environment for controls and instrumentation. The system is designed to limit the nominal ambient temperature in the MER to 95°F during normal operation and following a design-basis accident, and in the SGTS room to 104°F during normal operation. The system is designed to maintain the above temperatures, assuming an ambient temperature of 95°F dry bulb and 75°F wet bulb during the summer and -10°F dry bulb during the winter

b. The system is designed to detect and limit the introduction of radioactive material into the main control room and to remove airborne radioactivity from the environment therein such that the dose to main control room personnel following a DBA does not exceed the requirements of General Design Criterion 19

c. The system is designed to limit the introduction of chlorine gas into the main control room

d. Redundant components are powered by their corresponding redundant Division I and Division II engineered safety feature (ESF) buses

e. The system is designed to accomplish its design objectives assuming a single active component failure. A single active failure in the Halon fire protection system will cause loss of cooling to the relay room, cable spreading room, or computer room. Redundant smoke/Halon dampers are not provided. Adequate time exists to take manual actions to restore airflow

f. The CCACS is designed to meet Category I requirements.

---

* The relative humidity in the control room and the computer room is controlled between a minimum of 40 percent and a maximum of 60 percent.

g. The system is designed for accessibility in making adjustments and periodic inspections and for testing principal system components to ensure continuous functional reliability

h. The control center emergency air filtration system design conforms to Regulatory Guide 1.52 except as stated in Subsection A.1.52. The system is redundant only at the active component level.

Environmental design considerations relating to main control room habitability following an accident are discussed in Subsection 6.4.1.

The CCACS is designed to maintain the control center under a positive pressure of approximately 1/4 ± 1/8-in. water gage in the "recirculation mode" in order to minimize inleakage of contaminated air. Such outside contamination could be the result of radioactivity leakage after a LOCA.

Isolation valves and isolation dampers are capable of remote manual operation so that failure of their control system will not render the system inoperable.

Surveillance of airborne radioactivity levels in the main control room is provided by the airborne radiation monitoring system (Subsection 12.2.4).

9.4.1.2 System Description

9.4.1.2.1 System Equipment

The control center envelope encloses a total air volume of approximately 275,960 ft^3 (during normal mode) and 252,731 ft^3 (during emergency modes). The following areas are air conditioned as separate zones as indicated:

Zone	Area Description
1	Relay room
2	Cable spreading room
3	Main control room
4	Computer room
6	Office
7	Conference room
8	Mechanical equipment room and standby gas treatment system (SGTS) rooms (during normal mode). However, the SGTS rooms are not part of the control center envelope during emergency modes (See Subsection 9.4.1.2.3)

The CCACS diagram is shown in Figures 9.4-1, 9.4-2, and 9.4-3, and principal system component design data are listed and described in Table 9.4-1. The CCACS consists of two

100 percent-capacity air-conditioning supply units, an air distribution system, and an emergency filtration system. The control center is heated, cooled, and pressurized by a recirculating air system.

There are four operating modes for the ventilating system, as follows:

a. Normal Mode: A minimum of 2769 cfm outside air mixes with recirculated ventilating air, bypassing the emergency makeup and recirculation filters

b. Purge Mode: 100 percent outside air is circulated through the control center and exhausted to the atmosphere to purge any smoke or fumes within the control center

c. Recirculation Mode: A maximum of 1800 cfm outside air is filtered and mixes with 1200 cfm recirculated air that is filtered again and mixed with recirculating ventilation air to prevent intrusion and to provide continuous removal of contaminants during a radiation-release emergency

d. Chlorine Mode: All outside intakes are closed to prevent ingress during a chlorine-release emergency. Ventilating air is recirculated with 1200 cfm passing through the emergency recirculation filter.

Each of the multizone air-conditioning supply units includes a fail-closed air-operated inlet damper, an electronic air cleaner, a roll filter, a centrifugal fan, and an electrically heated hot deck and a cold deck with a chilled water cooling coil. The supply air temperature for each zone is controlled by a pair of zone dampers that proportion the hot and cold air. Each of the air-conditioning supply units is served by a Category I chiller unit. During normal operation, the condenser section of the chiller is cooled by the reactor building closed cooling water system (RBCCWS). During emergency operation, the chiller condenser is cooled by the emergency equipment cooling water system (EECWS).

The emergency filtration system processes control center air and makeup air through charcoal filters if the control center is subjected to airborne contamination. This system consists of two separate emergency air intakes. Each has a dual set of "bubble tight" dampers in each of two parallel lines.

These dampers are valves with pneumatic piston actuators. The emergency makeup air filter train is sized for a flow rate of 3000 cfm, but is restricted to a maximum emergency intake flow of 1800 cfm. The filter train consists of the following components arranged in the direction of flow:

a. Mist eliminator (prefilter type)

b. Two electric heaters, one each for Division I and Division II

c. High-efficiency particulate air (HEPA) filter with a design filtration efficiency of 99.97 percent for 0.3 μm particles or larger. The filters are installed and field tested such that a 95 percent decontamination efficiency can be assumed for removal of particulate iodine

d. 2-inch deep charcoal adsorber. The carbon is purchased, lab tested, and tested for bypass leakage after installation such that a 95 percent decontamination efficiency can be assumed for removal of all forms of gaseous iodine

e. HEPA filter with a design filtration efficiency of 99.97 percent for 0.3 μm particles or larger.

The emergency intake flow is then combined with 1200 cfm of control center recirculation airflow. This airflow is then processed through the recirculation air filter train.

The emergency recirculation filter train is sized for a flow rate of 3000 cfm and consists of the following filters in the direction of flow:

a. Prefilter

b. HEPA filter with a design filtration efficiency of 99.97 percent for 0.3 μm particles or larger. The filters are installed and field tested such that a 95 percent decontamination efficiency can be assumed for removal of particulate iodine.

c. 4-inch deep charcoal adsorber. The carbon is purchased, lab tested, and tested for bypass leakage after installation such that a 95 percent decontamination efficiency can be assumed for removal of all forms of gaseous iodine.

d. HEPA filter with a design filtration efficiency of 99.97 percent for 0.3 μm particles or larger.

The air is drawn through these emergency filters by one of two redundant emergency recirculation air fans. Redundant air-operated dampers are installed on the intake, upstream of make-up air filter unit, and exhaust side of each of the fans. The fans receive electrical power from ESF buses.

In order to provide adequate makeup air to the control center during normal operation, the intake air damper is provided with a minimum stop to ensure a minimum airflow at all times except while the control center is isolated. The design minimum airflow is 2769 cfm. This minimum airflow is based on the normal airflow to the main control room exhaust vent, the exfiltration from the building, and the ventilation air supplied to the standby gas treatment room, kitchen, and washrooms. A modulating damper in the system exhaust restricts exhaust flow relative to supply airflow rate to maintain approximately 1/4 ± 1/8 in. of water difference between the lower of the outside ambient pressure or the turbine building pressure and control center pressure when the system is in the normal mode.

The two fan-coil cooling units are located in the mechanical equipment room. Each of these units is sized to dissipate the total heat load generated in the mechanical equipment room during an emergency. The units are of the factory-assembled, integral-fan-type with a chilled water cooling coil. One fan-coil unit is for Division I and the other for Division II. Chilled water is supplied to these units from the control center chillers.

The air conditioning system is equipped with alarms annunciated in the main control room for detection of equipment malfunction. Each division has similar alarms. A malfunction in the operating division will annunciate an alarm; if necessary, the entire division will be shut down manually and the standby division will be manually started. Shutoff dampers on the outlet of each unit are interlocked with the fan starter. Chiller starter contacts are held open until verification of chilled water, condenser water flow, supply air, and return airflow. The chiller starter contacts are tripped if oil pressure is not verified after a time delay.

For heat and smoke removal from the control center complex in the event of a fire in either the relay room or the cable spreading room, the fire detection system automatically switches the air conditioning system to a purge mode. Smoke and fire detection systems for the control center are covered in Subsection 9.5.1.

All electrical power for motor operation is supplied by the reactor building ESF buses and the division concept of separation and redundancy is maintained. Power to these buses is supplied from the emergency diesel generator (EDG) system if offsite electrical power is lost. Refer to Subsection 7.3.5 for a discussion of the CCACS instrumentation and controls.

9.4.1.2.2 Normal Operation

During normal operation, the master selector switches in the main control room activate all components in the Division I or Division II system. A mixture of return and outside air is filtered, then cooled, heated, and dehumidified, as required by a multizone air-conditioning supply unit. Each zone thermostat modulates zone mixing dampers to obtain the supply air temperature necessary to satisfy the zone cooling or heating requirements.

Heating is supplied by an electric heating coil and is provided on demand from any one of the zone thermostats. The air temperature leaving the heating coil is maintained at approximately 95°F and reset to lower temperatures on rising outside air temperature. Steam is supplied by the auxiliary boiler and controlled by humidistats located in the control room and computer room. Positive pressure is maintained in the control center by throttling the exhaust air modulating damper. This damper modulates only in the normal mode. It has no essential function and opens upon loss of power to allow "purge" mode operation if required. Exhaust fans are provided in the kitchen and washrooms.

9.4.1.2.3 Emergency Operation

During an emergency, the control center is isolated from all other areas of the plant. All air supplies to the standby gas treatment rooms and the normal operation of air intake and exhaust ducts are dampered closed.

The multizone air-handling unit, the chiller, chilled water pump and the return air fan continue to operate as during normal operation. The return air damper assumes a full open position. Condenser water is supplied from the EECWS. The fan in the mechanical equipment room fan-coil cooling unit is also energized under room thermostat control. Chilled-water flow through the cooling coil of the unit continues unimpeded as during normal operation.

The emergency recirculation air fan is energized and the isolation dampers on the emergency intake air duct are opened. Pressure control dampers, which regulate the proportion of recirculated air to emergency makeup air, modulate to maintain approximately 1/4 ± 1/8-in. water gage positive pressure in the control room. The dampers in the kitchen and washroom exhaust air ducts are closed. In the event that chlorine gas is detected in the control center by control room personnel, manual operator action will place the CCHVAC system in chlorine mode which will cause all system isolation dampers to automatically close. Damper position indications in the main control room allow continuous monitoring of system performance and confirm all remote manual control actions taken.

9.4.1.3 Safety Evaluation

Continued operation of the CCACS during both normal and emergency conditions is ensured by the following:

a. Design of system components to meet Category I requirements

b. Redundancy of components to meet single active failure. Smoke/Halon dampers are not single active failure proof. A system single-failure analysis is presented in Table 9.4-2

c. During loss of offsite power, all active components, such as valve and damper operators, fan motors, controls, and instrumentation, are served by their respective emergency power sources.

d. The unfiltered inleakage into the main control room is limited to a maximum of 173 cfm as evaluated in accordance with the AST methodology in Regulatory Guide 1.183.

Alarms in the control center will alert the operator to any malfunction in the CCACS so that, if necessary, he can manually actuate the standby division. The instrumentation in the main control room is designed to operate without degradation of performance in an ambient temperature of 120°F.

Detection of radioactivity in the main control room environment is provided by radiation monitors, as described in Subsection 12.2.4. Signals generated by high radioactivity in the control center makeup air, the reactor building exhaust, and fuel pool exhaust; low reactor water level; and high drywell pressure will initiate automatic isolation of the control center.

Protection of main control room personnel against an offsite chlorine release can be provided by manual isolation of the main control room and the use of breathing apparatus by the main control room operators as discussed in Section 6.4.

A discussion and analysis of the chlorine accidents considered in the design of the plant and an evaluation of the habitability of the main control room after a chlorine accident are presented in Subsection 6.4.3.4.

An evaluation of the buildup of carbon dioxide in the main control room, with the CCACS isolated, is given in Subsection 6.4.1.2.

A fire outside the plant will not affect control room habitability because the control center will be isolated. The operator will receive an indication of an onsite fire through the control center air inlet smoke detector.

The sources of smoke closest to the control center outside air intake are the system service and main unit transformers approximately 80 to 240 ft from the air intake. Smoke from a fire outside the plant should be detected within 1 minute after the smoke begins to enter the control center. The control center can then be manually isolated in less than 10 sec. The operators will have immediate access to self-contained breathing apparatus for respiratory protection as discussed in Section 6.4.

9.4.1.4 Inspection and Testing Requirements

The CCACS equipment was subjected to a dynamic system test to directly verify the acceptability of the supplied equipment in accordance with the design specifications. At the conclusion of the work, all of the heating, cooling, hydronic, and ventilating systems were tested and balanced to meet the design conditions.

Routine procedures require checking for proper mode of operation, proper positioning of dampers, and proper operation of the system equipment. All those dampers which are required to provide tight shutoff were checked in the closed position by the vendor to verify proper operation of the seals, and those dampers are periodically observed in service to confirm proper functioning of the operating air connections. Design provisions are made so that active components of the air conditioning system can be periodically inspected for operability and required functional performance.

Initial system flow distribution, valve operability, instrumentation and control loop checks, and alarm setpoints were done in accordance with the Preoperational Test program as discussed in Chapter 14.

The control center emergency filtration system has been subjected to shop test, acceptance test, and inservice inspection in accordance with Regulatory Guide 1.52 as delineated in Appendix A. Laboratory testing was also in accordance with Regulatory Guide l.52. The control center emergency filtration system was given a preoperational test as discussed in Chapter 14.

An inservice surveillance program has been implemented in accordance with the Technical Specifications to ensure that the main control room emergency filtration system can perform its design functions.

9.4.2 Reactor/Auxiliary Building Ventilation System

9.4.2.1 Design Bases

The reactor/auxiliary building ventilation system is designed to provide normal ventilation for the reactor and auxiliary buildings and to maintain the temperature in general access areas between 65°F and 104°F. The temperature in potentially contaminated areas is maintained between 65°F and 125°F. To maintain these temperatures, additional room coolers have been added to selected areas. Equipment in the emergency core cooling system (ECCS) pump rooms was originally designed to operate at temperatures below 148°F during emergency conditions. The actual conditions to which this equipment is environmentally qualified under the Fermi 2 EQ program are documented in EQ0-EF2-018. Also see Section 3.11 for discussion of original Fermi 2 design and environmental qualification activities performed for Fermi 2. During normal operation, when the emergency core cooling equipment is not in service, the temperature in these rooms is maintained below 104°F.

The HVAC System for battery rooms controls the temperature at an approximate value of 75°F. The ventilation system is designed to maintain these temperatures when the outside ambient dry bulb temperature is between -10°F and 95°F.

The ventilation system provides a means of purging the drywell of the nitrogen inerting atmosphere, prior to entry by personnel.

The system is designed to maintain airflow from areas of low potential radioactivity to areas of progressively higher potential radioactivity. In addition, the system will maintain the reactor and auxiliary buildings at a negative pressure with respect to the ambient pressure, assuming a maximum wind velocity of 32 mph.

All components, piping, valves, and dampers are designed to meet the criteria of appropriate system quality group classification as listed in Subsection 3.2.2. The reactor/auxiliary building ventilation system is nonseismic, with the exception of ventilation penetrations of the reactor building secondary containment and the engineered safeguard equipment space coolers, which are Category I. The reactor building secondary containment ventilation penetrations consist of the ventilation ductwork and associated isolation valves and actuators. The isolation valves and space coolers receive control and operating power from buses that are connected to the EDGs. The essential battery room ventilation fans are also Category I. The power supplies to these fans are from motor control centers (MCCs) that were installed non-1E, but are automatically restorable from essential power. The MCCs were purchased to the same specifications (except for documentation requirements) as Class 1E, and their installation is seismically qualified. The MCCs will be maintained as 1E equipment.

9.4.2.2 System Description

The reactor/auxiliary building ventilation system is shown in Figure 9.4-4, Sheets 1 and 2. The nominal size and type of principal system components are listed in Table 9.4-3.

Areas in the reactor and auxiliary buildings that have separate ventilation and air conditioning and/or cooling systems are not covered in this subsection. These areas, given in the following listing, are covered in the indicated subsections:

a. Steam tunnel (Subsection 9.4.6)

b. Control center and standby gas treatment system (SGTS) room (Subsection 9.4.1)

c. Drywell cooling (Subsection 9.4.5).

Normal ventilation of the SGTS equipment rooms is handled by the CCACS and is discussed in Subsection 9.4.1. However, ventilation of these rooms is isolated during a DBA. The emergency fan-coil coolers, which are included as part of the reactor/auxiliary building ventilation system, will then handle the cooling requirements for this room.

Air conditioning of the motor-generator set is discussed in Subsection 9.4.11.

The reactor/auxiliary building ventilation system supplies filtered outside air to accessible areas of the reactor and auxiliary buildings through a central fan system consisting of an outside air intake, filters, heating coils, and three 50 percent-capacity fans. The air intake is located midway down the south side of the auxiliary building. The ventilation air is supplied to accessible areas of the buildings through ductwork and is exhausted from areas of high potential contamination through a common vent located on top of the auxiliary building. Three 50 percent-capacity exhaust fans are provided.

Normally, one exhaust and one supply fan are on standby. Gravity backdraft dampers with counterbalancing weights are provided to prevent backflow of contaminated air and permit control of the required differential pressure (approximately 1/4 in. of H_2O) between general access areas and potentially contaminated areas. Backdraft dampers are fitted on the inlets of exhaust ducts that run between general access areas and potentially contaminated areas.

Each of the two battery rooms that are located in the auxiliary building has two 100 percent-capacity exhaust fans. One air-conditioning unit serves both battery rooms. However, safety- related space coolers provide essential cooling at the battery charger location next to each battery room. The exhaust fans draw air into and through the battery room from general access areas and exhaust the air to other general access areas when the air conditioner is off. The main function of the battery exhaust fans is to prevent the buildup of hydrogen from reaching an explosive concentration in the battery room. The fan units are seismically qualified and powered from an automatically restorable ac bus on loss of offsite power. The air-conditioning unit is not considered part of the ESFs in that it is provided only to prolong the life of the batteries. However, battery charger area coolers are capable of maintaining area temperature under 120°F independent of the air-conditioning unit, with or without a loss of offsite power.

The design of the refueling floor area ventilation is sized for a minimum of 7 air changes per hour based on the volume in the lower 15 ft of the refueling area. The supply air outlets are located 15 ft above the refueling floor level. The airflow is directed across the refueling floor toward the pools. The building ventilation system exhaust takes suction from the following refueling areas:

a. Dryer-separator storage pool - 25 percent, 8250 cfm

b. Fuel storage pool - 50 percent, 16,500 cfm

c. The reactor well - 25 percent, 8250 cfm.

During non-refueling periods, the reactor well will not be ventilated; however, the excess air will be exhausted along the wall above the refueling floor.

The ventilation system also serves to purge the primary containment to permit personnel access. This is accomplished through the cross tie between the primary containment purge piping and the building ventilation system. Sufficient airflow (8500 cfm) is provided to purge the drywell and suppression chamber a minimum of three air changes per hour. The purge air is normally processed through the building exhaust system. However, when the drywell atmosphere is contaminated, initiating a reactor building heating, ventilation, and air conditioning (HVAC) shutdown and isolation, the purge air is processed through the SGTS, which is described in Subsection 6.2.3.

The only areas not ventilated in the reactor and auxiliary buildings are stairwells that are fire rated.

Two reactor building isolation dampers are provided in each supply and exhaust duct that penetrates the reactor building. These dampers are closed when there is high radioactivity in the reactor building, high drywell pressure, low reactor water level, or loss of offsite power. When the reactor building is isolated, the ventilation supply and exhaust fans are tripped off and the reactor building is maintained under negative pressure by the SGTS. The same signal that isolates the reactor building ventilation also signals the isolation valve between the reactor building ventilation duct and the SGTS to open. A reactor building isolation pushbutton is provided in the main control room. The fan-coil cooling units are intended primarily to function while the reactor building is isolated, at which time the ventilation system is shut down. The fan-coil cooling units are either automatically controlled by a thermostat located in the room they serve or they are operated in a manual mode where they operate continuously. Thus, the fan-coil units will also aid to cool their respective areas whenever the ventilation system is unable to maintain the designed room temperatures.

During normal plant operation and outages, it sometimes becomes necessary to take a fan-coil unit out-of-service for preventive or corrective maintenance. When this happens, the plant determines the operability of the safety-related equipment that relies on the fan-coil unit for local cooling and then follows the plant's Technical Specifications.

The following fan-coil cooling units are required to operate following a DBA and, as such, are part of the plant ESFs:

a. One unit of 100 percent capacity furnished for each division of residual heat removal (RHR) pumps

b. One unit of 100 percent capacity furnished for each division of core spray pumps. The Division I unit also cools the reactor core isolation cooling (RCIC) pump

c. One unit of 100 percent capacity furnished for the high pressure coolant injection (HPCI) pump room

d. One unit of 100 percent capacity furnished for each division of SGTS filter unit room

e. One unit of 100 percent capacity furnished for each division of EECW pumps

f. Deleted

g. Two units, each of 50 percent capacity, furnished for each division of the switchgear room

h. This item is not used

i. One unit of 100 percent capacity furnished for each division of the control air compressors

j. One unit of 100 percent capacity furnished for each division of the battery charging area.

The fan-coil cooling units recirculate room air to remove heat generated by process equipment. Cooling water is normally supplied to the fan-coil units by the RBCCWS. During malfunction of the RBCCWS or on loss of offsite power, cooling water is supplied by the EECWS. All of the above fan-coil cooling units are physically separated by virtue of their location.

Radiation monitors are provided in the building exhaust to monitor the release of airborne activity. Upon detection of high radioactivity in the exhaust vent, an alarm is sounded in the main control room. Simultaneously, the building ventilation system fans are automatically tripped off and the isolation dampers are closed automatically. A description of the monitoring system is presented in Subsection 12.2.4.

9.4.2.3 Safety Evaluation

The reactor/auxiliary building ventilation system is required to operate only during normal plant operations except the fan-coil cooling units, the battery room exhaust fans, and the reactor building supply and exhaust isolation dampers, which are required to operate after a DBA. To ensure the reliable and safe operation of the ventilation system over the full range of normal plant operations, the portion of the system that is not required to operate after a DBA incorporates the following design features:

a. The ventilation system maintains the building at a negative pressure with respect to the ambient pressure to preclude exfiltration of potentially contaminated air. (The reactor building is maintained at a negative pressure by the SGTS following the isolation of the reactor building)

b. Backdraft dampers are used in the ventilation system to prevent backflow between general access areas and contaminated areas

c. Standby exhaust and supply fans are provided to increase the availability of the ventilation system

d. The ventilation system in the area of the refueling pool is designed to exhaust more air than is supplied. In addition, the supply air is directed across the refueling pool. This method of ventilating the refueling pool area limits the spread of radioactivity from the refueling pool to other parts of the reactor building

e. Potentially contaminated effluent rising from the surface of the refueling pool and the dryer-separator pool is entrained in the normal ventilation air and is drawn into the exhaust openings located above the pool water level. A radiation monitor is provided on the exhaust ducts from the pool areas. The monitors will alarm in the main control room if a high radiation level is detected and will automatically start the SGTS, isolate the reactor building normal air intake and exhaust, and place the CCACS into recirculation mode.

The fan-coil cooling units, the battery room exhaust fans, and the reactor building supply and exhaust isolation dampers, all of which are required to operate after a DBA, incorporate the following design features to ensure their reliable and safe operation following a DBA:

a. Battery room exhaust fans and fan-coil units receive power from the same division as the equipment they protect. The diesel generators are the source of electrical power in the event of a loss of normal offsite power

b. The loss of any of the fan-coil units has the same effect on the safety of the plant as the loss of the equipment being cooled. Therefore, a single failure of the ventilation system affecting the safety-related equipment rooms will not prevent safe shutdown of the plant. Each ECCS subsystem (Division 1 RHR pump room, Division 2 pump room, Division 1 core spray and RCIC pump room, Division 2 core spray pump room, and HPCI pump room) has its own integral area cooling subsystem and fan-coil unit which is supplied from the same essential bus as the ECCS subsystem being cooled and which is an ESF. The loss of a particular ECCS subsystem, its room, or its equipment area cooling subsystem would result in automatic initiation of the redundant ECCS subsystem

c. Each battery room has two 100 percent-capacity exhaust fans. The loss of one of these fans has no effect on plant availability.

9.4.2.4 Inspection and Testing

All equipment is factory inspected and tested in accordance with applicable equipment specifications, quality assurance requirements, and codes. The system ductwork and erection of equipment were inspected during various construction stages, and construction tests were performed on all components of the system. The system was balanced for the design airflow and system operating pressures in accordance with Sheet Metal and Air Conditioning Contractors National Association procedures. Controls, interlocks, and safety devices on each system were adjusted and tested to ensure proper sequence of operation. Initial system flow distribution, valve and damper operability, instrumentation and control loop checks, and alarm setpoints were done in accordance with the Preoperational Test program as discussed in Chapter 14. Periodic tests of all system functions will be performed in accordance with normal operating procedures.

9.4.2.5 Instrumentation and Controls

Each exhaust and supply fan is manually controlled from the main control room. In order to ensure that a negative pressure is maintained in the reactor building while starting a fan combination, a time delay is provided so that the exhaust fan will start first. In addition, the motor starters are interlocked after starting to ensure that the associated fan shuts down when either an exhaust or supply fan is tripped.

The outside barometric pressure is detected on each of the four sides of the building and compared with the pressure being detected on the inside of the building. The difference between the lowest outside pressure and the inside pressure then is used as the control signal for modulating the inlet vanes of the ventilation system exhaust fan in order to maintain the building pressure lower than the outside pressure. Should the pressure in the building become excessively high or low (2.50 in. H_2O above or below the setpoint), the fans are automatically tripped.

The fan-coil cooling units located in a harsh environment are operated in a manual mode where they run continuously. The remainder of the fan-coil cooling units are operated in an automatic mode where the units start when the thermostat in the room being cooled reaches its setpoint.

Tripping of the supply and/or exhaust fans and dampers is indicated by audible and visible alarms in the main control room and audible and visible alarms on the refueling floor.

9.4.3 Radwaste Building Ventilation System

9.4.3.1 Design Bases

The radwaste building ventilation system is designed to maintain a suitable environment that conforms to the equipment and personnel ambient requirements in that area. The specific temperature design criteria used in sizing the system components are as follows:

a. Outside air design temperatures

   1. Dry bulb temperature, -10°F to 95°F

   2. Wet bulb temperature, 75°F maximum.

b. Inside air design temperatures

   1. Radwaste office, control room, and Health Physics laboratory, 75°F ±5°F

   2. Other general access areas, below 105°F

   3. All other areas, below 125°F.

In order to maintain the general access areas as free from potential radioactivity as possible, the system is designed to direct airflow from general access areas to areas of higher potential radioactivity. Exfiltration of potentially contaminated air to the environment is prevented by maintaining the building at a lower pressure than the ambient pressure.

Filters are provided in both the intake and exhaust systems. The intake filters reduce the amount of dust particles that are induced into the radwaste building. The exhaust filters are provided to remove particulate activity from the ventilation exhausts of the radwaste building.

Local hoods are provided to exhaust fumes from selected equipment handling radioactive wastes. Each fume hood exhaust system is designed to maintain a minimum face velocity of 100 fpm across the door opening of the hood.

This system is required to function under normal operating conditions only and therefore is not specifically designed to operate after a DBA. This system is nonseismic.

9.4.3.2 System Description

The radwaste building ventilation system diagram is presented in Figures 9.4-5 and 9.4-6. The nominal size and type of principal system components are presented in Table 9.4-4.

The radwaste building ventilation system consists of two 100 percent supply fans, two l00 percent exhaust fans, one fume hood exhaust fan, and a radwaste control room and laboratory air conditioning system. System fans, including booster fans, take suction through modulating dampers, a prefilter, and either a HEPA or a high-efficiency filter. The intake, exhaust, and fume hood fans all discharge through shutoff dampers. The supply fans take suction through louvers that are located above the radwaste building and supply a total of approximately 22,567 cfm to principal areas of various floor levels of the building. These fans also supply approximately 1650 cfm to the pipe tunnel between the radwaste and turbine buildings. Normally, air is supplied to general access areas and is exhausted from potentially contaminated areas. Wherever an exhaust duct is located between a general access area and an area of higher potential radioactivity, the inlet to the duct is fitted with a backdraft damper. This prevents exfiltration of air from a higher to a lower potential radioactive area. The Drum Conveyor Rooms and a portion of the Drum Conveyor Operating Aisle (DCOA) Room (east of column line S) were converted to a storage area. A 9'x8' opening was installed in the Radwaste Building south wall (just east of column line T), and three openings in the wall between the Drum Conveyor Rooms and the DCOA Room. To isolate this storage area from the Radwaste Building to allow maintaining the design negative pressure in the remainder of the building, fire walls were installed and all perimeter walls, ceiling, and floor penetrations, including drains, were made air tight. In addition, the registers on the supply duct along column line 14 in the DCOA Room were closed, the make up vents on the west wall of Drum Conveyor Room III were sealed, and the return duct routed along column line V was removed and the ceiling penetration sealed. A new return air register was installed in the return air duct in the East Corridor area in order to compensate for the air supply isolated from the Drum Conveyor Room.

Each of the radwaste building exhaust fans discharges approximately 31,818 cfm from the radwaste building. The exhaust fans take suction from all principal areas on the various floor levels of the building and from the vents of the following tanks and equipment:

a. Waste collector tank
b. Waste surge tank
c. Waste sample tanks
d. Floor drain sample tank
e. Floor drain collector tank
f. Waste sludge tank
g. Spent resin tank
h. Centrifuges
i. Condensate phase separators
j. Chemical waste tank
k. Radwaste evaporators.
l. Side Stream Liquid Radwaste Processing System (SSLRPS) Distillation Inlet Batch Tank
m. SSLRPS Post Treatment System Inlet Batch Tank
n. SSLRPS High and Low Rad Side Stream Evaporator Condenser Air Exhausts
o. SSLRPS Sample Batch Tank
p. SSLRPS Granular Activated Carbon Filter Tanks
q. SSLRPS Mixed Bed Filter Tanks

In addition, the hood exhaust fan in the Health Physics area exhausts approximately 6600 cfm from the radwaste laboratory fume hoods. The radwaste exhaust fans and the fume hood exhaust fan discharge air through a common exhaust vent located on top of the radwaste building. A radiation monitor is connected to the common exhaust header.

The radwaste office, radwaste control room, and Health Physics laboratory air conditioning subsystem consists of a double-duct air-handling unit, fan, steam heating coil, evaporator-type cooling coil, and remote water-cooled chiller unit which is cooled by the turbine building closed cooling water system (TBCCWS). Steam to the heating coils is supplied by the auxiliary boilers. The system supply ductwork consists of three decks: hot, cold, and auxiliary. The hot and cold ducts go to mixing boxes that mix the air to the temperature required by each room. The auxiliary air is ducted to the low-level laboratory fume hood through a pressure reducing valve. Return air is ducted to the air-conditioning unit, where it is mixed with fresh air to make up for the air exhausted by the fume hood exhaust fan. The air-conditioning unit consists of a filter, preheat coil, fan, cooling coil, and heating coils with face and bypass dampers.

In addition to the normal ventilation systems, a Dedicated Shutdown Air Conditioning Unit is installed on the second floor of the Radwaste building to support post-fire dedicated shutdown as described in section 7.5.2.5 and Appendix 9A. It is a split system with the air-handling unit (AHU) located inside the room and outside condensing unit located on the adjacent roof. The AHU consists of an inlet filter, fan, evaporator-type cooling coil, condensate collection tank and condensate pump. The discharge ductwork and dampers cool the area in the vicinity of the dedicated shutdown panel. The condensing unit is a split system cooling condenser consisting of two refrigerant circuits that reject heat to the ambient outdoor air. Each circuit consists of a compressor/motor, coil and fan/motor.

Radiation monitors are provided in the building exhaust vent to monitor the release of airborne radioactivity. Upon detection of high radioactivity in the exhaust vent, an alarm is sounded in the main control room. Simultaneously, the building ventilation system fans are tripped off and the isolation dampers are closed automatically. A description of the monitoring systems is presented in Subsection 12.2.4.

9.4.3.3 Safety Evaluation

The radwaste building ventilation system is required to operate only during normal plant operation. However, the system does incorporate features to ensure its reliable and safe operation over the full range of normal plant operation. These features include the installation of standby exhaust and intake fans, and the use of backdraft dampers between general access areas and areas of potentially high radioactivity to prevent general access areas from becoming contaminated. In addition, the system is designed to prevent exfiltration of potentially contaminated air to the environment by maintaining the internal pressure of the radwaste building negative with respect to the ambient pressure.

The Dedicated Shutdown Air Conditioning Unit supports a post-fire shutdown from outside the Main Control Room as described in Section 7.5.2.5.

9.4.3.4 Inspection and Testing

All equipment has been factory inspected and tested in accordance with applicable equipment specifications, quality assurance requirements, and codes. The system ductwork and erection of equipment were inspected during various construction stages. Construction tests were performed on all components of the system. The system has been balanced for the design airflow and system operating pressures. Controls, interlocks, and safety devices on each system were adjusted and tested to ensure proper sequence of operation. Initial system flow distribution, valve operability, instrumentation and control loop checks, and alarm setpoints were done in accordance with the Preoperational Test program as discussed in Chapter 14.

The Dedicated Shutdown Air conditioning Unit is also balanced for its operating conditions. This system and its components will be tested and maintained periodically, as appropriate for the system safety classification.

9.4.3.5 Instrumentation and Controls

Each exhaust and supply fan is manually controlled from the main control room. In order to ensure that a negative pressure is maintained in the radwaste building while starting a fan combination, a time delay is provided to make the exhaust fan start first. In addition, the motor starters are interlocked after starting to make the associated fan shut down when either an exhaust or supply fan is tripped.

The outside barometric pressure is detected on each of three sides of the building and compared with the pressure being detected on the inside of the building. The difference between the lowest outside pressure and the inside pressure then is used as the control signal for modulating the inlet vanes of the ventilation system exhaust fan in order to maintain the building pressure lower than the outside pressure. Should the pressure in the building exceed the alarm setpoints, the fans will be manually tripped.

The balance-of-plant battery room cooling equipment is controlled by a thermostat.

The exhaust air radiation monitoring system will alarm in the main control room in the event of high radioactivity in the exhaust header. A radwaste building isolation pushbutton is provided in the main control room to isolate the exhaust and shut down the supply and exhaust fans.

The instrumentation and controls for the Dedicated Shutdown Air Conditioning System are discussed in Section 7.5.2.5.

9.4.4 Turbine Building Ventilation System

9.4.4.1 Design Bases

The turbine building ventilation system is designed to provide a suitable environment for personnel and to ensure the integrity of equipment and controls located in the turbine building.

The turbine building ventilation system, which has been modified to repitch the fans on the supply and return air, is designed to maintain the temperature in general access areas below 115°F and to ensure that the temperature in all other areas within the turbine building is below 125°F, with the following exceptions:

a. The lube oil room, feedwater heater room, turbine building overhead crane bay, off gas preheater, off gas filter, turbine deck, and the second floor steam tunnel exceed the 115°F and 125°F design temperatures. The maximum nominal temperature for the steam tunnel is 180°F (measured at the ceiling). The maximum nominal temperature for the other specified rooms is less than 150.5°F.

b. The offgas system charcoal adsorber room, which has its own air conditioning system to ensure that the temperature within the room is 70°F (Nominal), and the excitation equipment area, which has its own air cooling system to ensure that the nominal temperature within the area does not exceed approximately 104°F.

The turbine building ventilation system is designed based on the following outside air temperatures:

a. Dry bulb temperature, -10°F to 95°F

b. Wet bulb temperature, 75°F maximum.

To maintain areas within the turbine building as free from potential radioactive contamination as possible, the system is designed to direct the airflow from areas of low potential radioactivity to areas of progressively higher potential radioactivity. The exhaust from the turbine building is monitored to detect and annunciate high radiation levels.

Exfiltration of potentially contaminated air to the environment is prevented by maintaining the building at a negative pressure with respect to the plant environment.

This system is required to function under normal plant operating conditions only and therefore is not specifically designed to operate after a DBA. The system components are designed to nonseismic requirements, with the exception of a few PAS system components located in the Auxiliary Building which are designed to seismic class II/I requirements.

9.4.4.2 System Description

The turbine building ventilation system is shown schematically in Figure 9.4-7. The nominal size and type of principal system components are presented in Table 9.4-5.

The turbine building is heated, cooled, and ventilated during normal and shutdown operation by a circulating air system. The building is heated by the ventilation air intake heating coils, and unit space heaters which are serviced by the auxiliary boiler of the plant. Cooling of the building is accomplished by circulating outside air throughout the ventilation system. All outside air enters the building through an intake located on top of the building and then passes through an evaporative air cooler cooling unit, the fresh air intake dampers, a filter bank, heating coils, a shutoff damper, and two of the three 50 percent-capacity intake fans. The air from these fans is generally distributed to areas of low potential radioactivity through distribution ducts. If the air is discharged into an area of high potential radioactivity, it is exhausted from that area by exhaust ducts and is discharged through the building exhaust enclosure. The air that is discharged into areas of low potential radioactivity is circulated through areas of higher potential radioactivity by the use of propeller fans. The air is then induced into the exhaust ductwork and discharged through the exhaust enclosure by two of the three 50 percent-capacity fans.

A radiation monitor is provided in the building exhaust vent to monitor the release of airborne radioactivity. Upon detection of high radioactivity in the exhaust vent, an alarm is sounded in the main control room. Simultaneously, the building ventilation system fans are automatically tripped off. A description of the monitoring systems is presented in Subsection 12.2.4.

The ventilation system also provides ventilation to the switchgear and exhaust fan rooms of the radwaste building and to the RBCCWS equipment area in the auxiliary building.

The offgas system charcoal adsorber room is provided with one air change per hour. Three cooling coil units are provided in the adsorber room, complete with fan, direct expansion cooling coil, and expansion valve. The compressor/condenser units are located outside the adsorber room. Cooling water is supplied to the condenser by the TBCCWS. The three cooling units are sized to maintain the adsorber room at 70°F during normal operation.

Gravity-type backdraft dampers having adjustable counterbalancing weights are provided on the discharge of propeller fans functioning to exhaust air from general access areas to potentially contaminated areas. This prevents backflow of contaminated air.

The excitation equipment area is provided with a separate air cooling system located on the second floor of the turbine building. Two 100% capacity, water cooled air coolers are provided to maintain the excitation equipment area at a nominal ambient temperature of 104°F during normal operation. Cooling water is supplied by the TBCCW System.

9.4.4.3 Safety Evaluation

The turbine building ventilation system is required to operate only during normal plant operation. However, the system incorporates features to ensure its reliable and safe operation over the full range of normal plant operation. These features include the installation of standby exhaust and intake fans, and the use of backdraft dampers between general access areas and areas of potentially high radioactivity to prevent general access areas from becoming contaminated. With respect to the higher temperature areas in the turbine building (i.e. areas above 115°F/125°F), an evaluation of the impact to equipment and personnel was performed. Results of the review show that the components are fully capable of functioning at the higher temperatures. Plant personnel are not required to access any of the high temperature areas during plant operation or following an accident condition in order to safely shut down and/or maintain the plant in a safe shutdown condition.

The system is designed to prevent exfiltration of potentially contaminated air to the environment by maintaining the internal pressure of the turbine building negative with respect to the ambient pressure.

A radiation monitor in the exhaust vent automatically trips the turbine building ventilating system in the event of a high radiation level.

9.4.4.4 Inspection and Testing

All equipment has been factory inspected and tested in accordance with applicable equipment specifications, quality assurance requirements, and codes. The system ductwork and erection of equipment were inspected during various construction stages. Construction tests were performed on all components of the system. The system has been balanced for the design airflow and system operating pressures. Controls, interlocks, and safety devices on each system were adjusted and tested to ensure proper sequence of operation. Initial system flow distribution, valve and damper operability, instrumentation and control loop checks, and alarm setpoints were done in accordance with the Preoperational Test program as discussed in Chapter 14.

9.4.4.5 Instrumentation and Controls

Each exhaust and supply fan is manually controlled from the main control room and, to ensure that a negative pressure is maintained in the turbine building while starting a fan combination, a time delay is provided to ensure that the exhaust fan starts first. In addition, the motor starters are interlocked after starting to ensure that the associated fan shuts down when either an exhaust or supply fan is tripped.

The outside barometric pressure is detected on each of the four sides of the building and compared with the pressure being detected on the inside of the building. Should the pressure in the building become excessively high or low, both the supply and exhaust fans are automatically tripped.

The adsorber room cooling equipment is controlled by a thermostat.

9.4.5 Drywell Cooling System

9.4.5.1 Design Bases

The cooling system is designed to maintain the average ambient temperature at 135°F. The drywell volumetric average temperature may increase over 135°F and up to 145°F. The area around the primary coolant recirculating pump motors is limited to 128°F during normal operation. During a scram, the system is designed to limit the temperature in the area below the reactor pressure vessel (RPV) to 185°F. The system is not required to operate following a LOCA and is isolated.

The design of the system permits periodic inspection and testing of the principal system components where they are accessible.

The power supply to the drywell cooling unit fans is designed to allow operation from the EDG-fed buses if normal ac power is not available.

The system components, excluding single-speed fan and fan motors but including fan-coil units and ducts, are Category I.

The cooling water supply piping to the fan-coil units in the drywell is provided with a check valve inside containment and one remote, manually actuated isolation valve outside containment. The supply line outboard isolation valves will automatically close on high drywell pressure initiation of EECWS. The cooling water return piping has two remote, manually actuated isolation valves, one on each side of the drywell wall for containment isolation.

Pressure relief valves are provided to relieve hydrostatic pressure caused by water expansion in the cooling water header subsequent to system isolation during and after a LOCA. The system will be operated during nitrogen purging of the containment in order to provide proper mixing of the containment atmosphere.

9.4.5.2 System Description

The system design for drywell cooling is presented in Figure 9.4-8. The nominal size and type of principal system components are listed in Table 9.4-6.

The system design is based on recirculating drywell air and cooling water through fan-coil units to limit the maximum drywell temperature. Cooling water is supplied by the RBCCWS under normal conditions and EECWS during abnormal operating conditions. However, high drywell pressure in conjunction with EECW operation will automatically close the EECW supply line outboard isolation valves.

The cooling system consists of 14 fan-coil coolers. Each unit is furnished with cooling coils, supply air fan, distribution ductwork, air-diffusing devices, and controls. Drywell temperature is maintained by mixing the cool air with the heated air at the heat source.

The fourteen drywell coolers are physically separated into two divisions, each consisting of five single-speed and two two-speed coolers. During normal plant operation, six of seven drywell cooler fans in each division are continuously operating in order to maintain the drywell atmosphere temperatures below the prescribed limits. All of the two-speed fans operate at high speed during normal operation.

All of the fan motors are provided with temperature detectors for the motor windings, a bearing vibration detector, and an integral space heater to maintain motor temperature above ambient during motor shutdown.

All ductwork is fabricated from carbon steel. Each section is galvanized after fabrication.

Electrical power for operation of the Category I cooling units is supplied from ESF buses, maintaining the divisional concept of separation and redundancy. Electrical power for operation of the single-speed fans is supplied from EDG restorable BOP buses. One-half of the fans are supplied from the Division I bus, the other half from the Division II bus. These buses are supplied from the EDG system if offsite electrical power is lost.

Cooling water is supplied to the coolers from two redundant EECWS piping loops during abnormal operation of the system. The loops are designated as Division I loop and Division II loop. Each loop is designed to supply cooling water to one-half of the coolers. Both loops are supplied by cooling water from a single header of the RBCCWS during normal operation.

9.4.5.3 Safety Evaluation

The drywell cooling system is not required for the safe shutdown of the plant. The system incorporates features that ensure its reliable operation over the full range of normal plant operations. These features include the separation of the system into two cooling divisions.

In the event of a postulated design basis accident (LOCA), all of the single-speed drywell cooler fans in AUTO are automatically tripped, and the four two-speed drywell cooler fans then automatically shift to slow speed. Plant procedures provide the necessary guidance for returning any of the drywell coolers to service.

This is done to preclude the possibility of two phase flow phenomenon accompanied by potential water hammer damage due to the initial formation of steam bubbles and their subsequent collapse by the introduction of colder supply water to the drywell cooling system.

Instrumentation is provided to monitor the temperature in various zones in the drywell and to annunciate high temperatures in the main control room.

The equipment and ducts inside the drywell are designed to Category I requirements. Relief valves on the EECWS preclude the possibility of coil rupture inside the drywell as a result of a rise in cooling water temperature and pressure after closure of the isolation valves.

All equipment meets the criteria of the appropriate system quality group classification and codes listed in Subsection 3.2.2.

Upon the loss of offsite power, all fans will trip off. All previously operating units will be restarted automatically using power supplied to the essential and BOP buses from the diesel generators, unless a LOCA signal is also present concurrent with the loss of offsite power.

9.4.5.4 Inspection and Testing

The system will not be accessible during reactor operation. Routine testing and inspection of the system will be accomplished during scheduled reactor shutdowns. However, monitoring devices are provided to determine that the fan-coil units are functioning properly during normal operation.

All equipment has been factory inspected and tested in accordance with the applicable equipment specifications, quality assurance requirements, and codes. System ductwork and the erection of equipment has been inspected for quality assurance during various construction stages. Construction tests were performed on all mechanical components. The system was balanced for the design airflow and system operating pressures. Controls, interlocks, and safety devices on each system were cold checked, adjusted, and tested to ensure proper sequence of operation. Initial system flow distribution, valve and damper operability, instrumentation and control loop checks, and alarm setpoints were done in accordance with the Preoperational Test program as discussed in Chapter 14.

9.4.5.5 Instrumentation and Controls

The drywell cooling system is a "full-on" system in that no modulating controls are installed to automatically reduce or maintain set temperatures. The cooling water flow through the cooling coils and the airflow are constant. Manual balance valves are provided at each air discharge diffuser to adjust the airflow. Cooling capacity can be reduced by shutting down individual unit coolers.

Controls required for remote operation of the system are located in the main control room.

Restart of the cooling units after a loss of offsite power is accomplished automatically on a permissive signal. Restart of the cooling units is initiated within 90 sec after a loss of offsite power, and all cooling units will be in operation within 120 sec after a loss of offsite power.

Thermocouples are provided in various areas in the drywell to monitor the temperature, with alarms and temperature indication provided in the main control room.

9.4.6 Steam Tunnel Cooling System

9.4.6.1 Design Bases

The system is designed to maintain the temperature in the steam pipe tunnel below 130°F and is nonseismic.

9.4.6.2 System Description

A diagram of the steam tunnel cooling system is shown in Figure 9.4-9. Nominal sizes and types of principal system components are listed in Table 9.4-7.

The system consists of two 100 percent-capacity cooling coils and fans that are connected to a common supply plenum. The supply ducts from the plenum deliver the cooled air to various areas within the tunnel. The air is returned to the cooling coils by the induced draft of the fan. Cooling water is supplied to the cooling coils by the RBCCWS.

Balancing dampers are provided in each supply duct downstream of the common supply plenum, and shutoff dampers are provided for each fan.

A pressure equalizing line between the steam tunnel and the reactor building functions primarily to maintain secondary containment negative atmospheric pressure within the steam tunnel in the event of a DBA.

9.4.6.3 Safety Evaluation

The steam tunnel cooling system is required to operate only during normal plant operation. To ensure high reliability of the system and safe operation over the full range of normal plant operation, two 100 percent fan-coil units are provided.

9.4.6.4 Inspection and Testing

All equipment has been factory inspected and tested in accordance with the applicable equipment specifications, quality assurance requirements, and codes. Controls and safety devices on each system have been cold checked, adjusted, and tested to ensure the proper sequence of operation. Initial system flow distribution, valve and damper operability, instrumentation and control loop checks, and alarm setpoints were done in accordance with the Acceptance Test program as discussed in Chapter 14.

Routine maintenance and tests, based on the manufacturer's recommendations and/or operating/maintenance experience, are scheduled in accordance with the plant preventive maintenance program.

9.4.6.5 Instrumentation and Controls

The steam tunnel cooling system is manually controlled from the main control room.

A temperature-sensing element is located inside the steam tunnel and displays the temperature in the main control room. This same element sounds an alarm in the main control room when the steam tunnel air temperature exceeds 160°F.

9.4.7 Residual Heat Removal Complex Ventilation Systems

The RHR complex is composed of two identical divisions. The safety-related equipment in one division is 100 percent redundant to that in the other division. Each RHR division is composed of two diesel generator rooms, two diesel oil storage rooms, two switchgear rooms, and a pump room. The diesel-fuel-oil storage room ventilation system is used to purge the diesel generator room, diesel generator oil storage room, and air receiver room. This system operates continuously for all modes of plant operation. Each division of the RHR complex includes ventilation systems, as described in the following subsection. Failure analysis of the ventilation system for the RHR complex is provided in Table 9.4-8.

A typical ventilation system flow diagram for the RHR complex is presented in Figure 9.4-10. Nominal sizes and types of principal system components are listed in Tables 9.4-9 through 9.4-12.

9.4.7.1 Residual Heat Removal Diesel Generator Room Ventilation System

9.4.7.1.1 Design Bases

The diesel generator room ventilation systems are not required to operate during plant operation unless the ventilation equipment itself is in the manual mode, the diesel generators are running, or the room temperature rises above the room temperature controller setpoint.

The diesel generator room ventilation systems limit the temperature of each diesel room to a maximum of 122°F in conformance with the equipment requirements. The systems are available under all plant operating conditions.

Outside air with a maximum design temperature of 95°F is used to dissipate heat produced by the operation of the equipment in the diesel room.

The systems are designed to Category I requirements.

The fans are powered from ESF buses corresponding to the diesel generators they are serving.

The air intake and exhaust openings are located a sufficient distance apart to preclude reintroduction of exhaust air into the room. The outside air intakes and exhaust openings are protected by missile walls or slabs.

9.4.7.1.2 System Description

Each diesel room is provided with two 50 percent-capacity supply air fans. The operation of the fans induces outside air through a control damper and mixes the recirculation air from the diesel room in order to maintain the minimum air temperature above 65°F during diesel generator operation. The recirculation air path is provided with a control damper.

The mixed air is discharged into the diesel room by the supply fans. A part of the exhaust air is recirculated, depending upon the temperature of the return air. The balance of the exhaust air is forced through gravity dampers provided at the exhaust outlet.

Each division of the RHR complex is redundant to the other, thereby satisfying the need to make the respective equipment redundant.

9.4.7.1.3 Safety Evaluation

The loss of any ventilating fan or damper does not affect the safe-shutdown capability of the plant, since separate ventilation systems are provided for each redundant diesel generator.

To ensure maximum automatic fire-fighting capability, and to minimize potential cold-weather damage to equipment, the outside air damper fails closed upon loss of control power.

9.4.7.1.4 Inspection and Testing

All equipment has been factory inspected and tested in accordance with the applicable equipment specifications, quality assurance requirements, and codes. System ductwork and erection of equipment has been inspected for quality assurance requirements during various construction stages. Construction tests were performed on all mechanical components and the system was balanced for design airflow rates and system operating pressures. Controls, interlocks, and safety devices on each system were cold checked, adjusted, and tested to ensure proper sequence of operation. Initial system flow distribution, valve and damper operability, instrumentation and control loop checks, and alarm setpoints were done in accordance with the Preoperational Test program as discussed in Chapter 14.

Routine maintenance and tests, based on the manufacturer's recommendations and/or operating/maintenance experience, are scheduled in accordance with the plant preventive maintenance program.

9.4.7.1.5 Instrumentation

Each diesel generator room ventilation fan is interlocked to start with the operation of the respective diesel generator set. The ventilation fan will start automatically on high room temperature and can also be manually started by the switches provided in the main control room.

Temperature controllers sense temperature in each diesel generator room to modulate the intake and recirculation air dampers to maintain the room temperature within the design limits.

Indication of room temperature is provided locally. Damper position is indicated locally and in the main control room. An alarm is provided in the main control room for high and low room temperature. Supply fan "no airflow" indication is provided locally and is indicated and alarmed in the main control room.

9.4.7.2 Residual Heat Removal Switchgear Room Ventilation System

9.4.7.2.1 Design Bases

The switchgear room ventilation system is not required to operate during plant operation unless the ventilating equipment is in the manual mode, corresponding essential equipment is running, or the room temperature rises above the room temperature setpoint.

The system dissipates the heat produced by the switchgear room equipment, and limits the inside ambient temperature to 104°F under all plant operating conditions.

The outside air, with a design ambient temperature of 95°F, is used for cooling if necessary.

The system is designed to Category I requirements. Electrical power is furnished from the same ESF buses that supply power to equipment in the room being cooled.

The air intake and exhaust openings are located a sufficient distance apart to preclude reintroduction of exhaust air into the system. The outside air intakes and exhaust openings are protected by missile barriers.

9.4.7.2.2 System Description

Each switchgear room system consists of an intake air duct, high efficiency filter, and two 50 percent-capacity fans in parallel, arranged in the order given. The fan outlets are connected to a common supply air duct that distributes air to the switchgear room.

An outside air control damper is provided on the outside air duct, and a recirculation damper is provided on the mixing box upstream of the supply air filter. The operation of fans induces outside air and recirculated air into the mixing box to maintain the minimum air temperature above 65°F.

The mixed air is discharged in the switchgear room through the supply air duct system. A part of the exhaust air is recirculated, depending upon room temperature, and the balance of the air is forced through gravity dampers provided at the exhaust outlet.

9.4.7.2.3 Safety Evaluation

The loss of any ventilating fan does not affect the safe-shutdown capability of the plant, since a separate ventilation system is provided for each switchgear room.

To ensure maximum automatic fire-fighting capability, and to minimize potential cold-weather damage to equipment, the outside air damper fails closed upon loss of control power.

9.4.7.2.4 Inspection and Testing

All equipment was factory inspected and tested in accordance with the applicable equipment specifications, quality assurance requirements, and codes. System ductwork and the erection of equipment were inspected during various construction stages. Construction tests were performed on all mechanical components, and the system was balanced for the design airflow rates and system operating pressures. Controls, interlocks, and safety devices on each system were cold checked, adjusted, and tested to ensure the proper sequence of operation. Initial system flow distribution, valve operability, instrumentation and control loop checks, and alarm setpoints were done in accordance with the Preoperational Test program as discussed in Chapter 14.

Routine maintenance and tests, based on the manufacturer's recommendations and/or operating/maintenance experience, are scheduled in accordance with the plant preventive maintenance program.

9.4.7.2.5 Instrumentation and Controls

Each switchgear room ventilation system is started automatically on high room temperature or when its corresponding diesel generator sets are started. In addition, manual switches are provided in the main control room. A temperature controller located in the switchgear room modulates the intake and recirculation air dampers to maintain the room temperature within the design limits.

Room temperature and filter high differential pressure are indicated locally. An alarm is provided in the main control room for high and low room temperature. Supply fan "no airflow" indication is provided locally and is indicated and alarmed in the main control room.

9.4.7.3 Pump Room Ventilation System

9.4.7.3.1 Design Bases

The pump room ventilation system is not required to operate during normal plant operation unless the ventilating equipment itself is in the test mode, the corresponding essential pump is running, or the room temperature rises above the room temperature controller setpoint.

The system provides ventilation and limits the temperature of the pump room to 104°F.

The system dissipates the heat produced by the pumps and associated equipment, limiting the inside ambient temperature to 104°F under all plant operating conditions. The outside air, with a design ambient temperature of 95°F, is used for cooling.

The system is designed for Category I requirements. Electrical power is furnished from the same ESF buses that supply power to the equipment in the room being cooled.

The air intake and exhaust openings are located a sufficient distance apart to preclude reintroduction of exhaust air to the system. The outside air intakes and exhaust openings are protected by missile barriers.

9.4.7.3.2 System Description

The pump room ventilation system consists of an intake air duct, high efficiency filter, and two 50 percent-capacity fans in parallel, arranged in the order given. The fan outlets are connected to a common supply air duct that distributes air in the pump room.

An outside air control damper is provided on the outside air duct and a recirculation damper is provided on the mixing box upstream of the supply air filter. The operation of fans induces outside air and recirculated air into the mixing box to maintain a mixed air temperature above 65°F.

The mixed air is discharged to the pump room through the supply air duct system. A part of the exhaust air is recirculated, depending upon the room temperature, and the balance of the air is forced through the gravity dampers provided at the exhaust outlet. The intake and exhaust air openings are protected from missiles.

9.4.7.3.3 Safety Evaluation

The loss of the ventilating system does not affect the safe shutdown capability of the plant, since separate ventilation systems are provided for each redundant pump room.

To ensure maximum automatic fire-fighting capability and to minimize potential cold-weather damage to equipment, the outside air damper fails closed upon loss of control power.

9.4.7.3.4 Inspection and Testing

All equipment was factory inspected and tested in accordance with the applicable equipment specifications, quality assurance requirements, and codes. System ductwork and the erection of the equipment were inspected for quality assurance requirements during various construction stages. Construction tests were performed on all mechanical components, and the system was balanced for the design airflow rates and system operating pressures. Controls, interlocks, and safety devices on each system were cold checked, adjusted, and tested to ensure the proper sequence of operation. Initial system flow distribution, valve and damper operability, instrumentation and control loop checks, and alarm setpoints were done in accordance with the Preoperational Test program as discussed in Chapter 14.

Routine maintenance and tests, based on the manufacturer's recommendations and/or operating/maintenance experience, are scheduled in accordance with the plant preventive maintenance program.

9.4.7.3.5 Instrumentation and Controls

The pump room ventilation system is started automatically on high temperature or when the corresponding EDGs are running. Manual switches are provided in the main control room.

Room temperature and filter high differential pressure are indicated locally. An alarm is provided in the main control room for abnormal high or low room temperature. Supply fan "no airflow" indication is provided locally and is indicated and alarmed in the main control room.

9.4.7.4 Diesel-Fuel-Oil Storage Room Ventilation System

9.4.7.4.1 Design Bases

The diesel-fuel-oil storage room ventilation system is used to pull an adequate quantity of ventilation air through the diesel generator room, CO_2 storage room, fuel-oil storage room, and ventilation equipment room to maintain the temperature in these rooms below 104°F while the diesel is not operating and below 125°F when the diesel is operating. This system is designed to operate continuously for all modes of plant operation.

The outside air, with a design ambient temperature of 95°F, is used for cooling.

The system is designed to Category I requirements. The system is powered from ESF buses corresponding to the respective diesel generator.

9.4.7.4.2 System Description

The system exhausts air through exhaust ducts from the diesel generator room, CO_2 storage room, fuel-oil storage room, and ventilation equipment room. Air is induced through exhaust ducts by an exhaust fan. The exhaust air is discharged to the atmosphere through a missile-protected exhaust opening.

Nominal sizes and types of principal system components are listed in Table 9.4-12. Fire dampers are provided between rooms.

9.4.7.4.3 Safety Evaluation

The loss of any ventilating fan does not affect the safe-shutdown capability of the plant, since a ventilation system for each set of redundant rooms is provided.

9.4.7.4.4 Inspection and Testing

All equipment was factory inspected and tested in accordance with the applicable equipment specifications, quality assurance requirements, and codes. System ductwork and the erection of equipment were inspected for conformance with drawing and specification requirements during various construction stages. Construction tests were performed on all mechanical components, and the system was balanced for the design air and system operating pressures. Controls, interlocks, and safety devices on each system were cold checked, adjusted, and tested to ensure the proper sequence of operation. Initial system flow distribution, valve and damper operability, instrumentation and control loop checks, and alarm setpoints were done in accordance with the Preoperational Test program as discussed in Chapter 14.

Routine maintenance and tests, based on the manufacturer's recommendations and/or operating/maintenance experience, are scheduled in accordance with the plant preventive maintenance program.

9.4.7.4.5 Instrumentation and Controls

Manual switches are provided in the main control room. An indication of the temperature in each room except for the CO_2 storage room, fuel-oil storage room, and diesel generator ventilation equipment room is provided, along with an alarm in the main control room for high room temperature.

9.4.7.5 RHR Complex Heating System

9.4.7.5.1 Design Basis

Electric unit heaters are provided for the following areas:

a. RHR pump room

b. Diesel generator room

c. CO_2 storage room

d. Switchgear room

e. Switchgear ventilation equipment room

f. Diesel generator ventilation equipment room.

The electric unit heaters will maintain the RHR complex equipment rooms at an ambient temperature of 65°F during normal operation and shutdown. The electric unit heaters can be powered from an essential bus. The operation of the heaters inside the diesel generator rooms is required to support the standby readiness of each diesel by ensuring the temperature inside the diesel generator rooms remains above a design minimum value of 40°F. This ensures the initial combustion air inside the EDG intake manifolds remains above the 40°F minimum value necessary to support fast, cold-starting.

9.4.7.5.2 System Description

The electric unit heaters are self-contained with their own fan, heating coil, and thermostat. The heaters recirculate room air to maintain area air temperatures above 65°F. A Control Room Process Computer point alarms if the EDG room temperature begins to approach the 40°F design minimum value so that appropriate corrective action may be taken to restore the room environment.

9.4.7.5.3 Safety Evaluation

The RHR Complex Heating System has no safety design bases. However, the system is relied upon to maintain the temperature of the initial combustion air above the 40°F design minimum required for reliable fast, cold-weather starting. Thus, while the loss of the unit heaters during normal operation does not directly affect the safe-shutdown capability of the plant, EDG operability is compromised if the room is not maintained above the required 40°F.

9.4.7.5.4 Inspection and Testing

All unit heaters were factory inspected and tested in accordance with the applicable equipment specifications. Erection of the heaters was in conformance with drawing and specification requirements. Construction tests were performed on the unit heater system to ensure that the heaters will provide the desired flow distribution. Controls and safety devices for each unit heater were checked and adjusted to ensure proper operation. During the heating season, the heating units are periodically inspected to verify continued proper operation. Operator rounds are performed to verify EDG room temperatures are within the design envelope daily.

9.4.7.5.5 Instrumentation and Controls

Control of the electrical unit heaters is by an individual thermostat built into each unit heater.

9.4.8 Plant Heating System

9.4.8.1 Design Bases

The plant heating system is designed to limit the minimum temperature inside the reactor building, auxiliary building, radwaste building, and other miscellaneous facilities to 65°F. The system is designed to preheat the ventilation air to 65°F and provide perimeter heating to these buildings during the winter. The turbine building heating system is similar. However, the supply air temperature may be controlled in a range of 55°F to 65°F during the heating season.

The system performs its function during normal plant operation and shutdown. The heating steam isolation valves and piping on either side of the secondary containment boundary are seismic I. The remainder of the plant heating system is nonseismic. The system is required to function under normal plant operating conditions. Safety related motor operated isolation valves in the heating steam piping at the secondary containment boundary have been provided to allow the operators to isolate the steam piping in the event of a postulated break in the heating steam piping.

9.4.8.2 System Description

A diagram of the plant heating system is shown in Figure 9.4-11. Nominal sizes and types of principal system components are listed in Table 9.4-13. Steam is used for plant heating in the reactor, auxiliary, turbine, and radwaste buildings. Electrical unit heaters are provided to heat all other buildings. Steam is supplied to heating coils, located in the building ventilation supply system, and to unit heaters from the auxiliary steam boilers via a 15 psig pressure reducing station. To ensure that the steam pressure in the heating system does not exceed 15 psig, the reducing station is equipped with a pressure relief valve. The unit heaters are provided to offset transmission heat loss through exposed walls and roofs. The condensate from the heating coils is returned to a deaerator located in the auxiliary boiler room.

Permanent fuel oil, feedwater, and steam line connections are provided so that a portable boiler can be connected to the existing system to supply steam in a timely manner in the event of failure of the auxiliary boilers.

The system is designed to maintain the building temperature at 65°F, with an ambient temperature of -10°F.

9.4.8.3 Safety Evaluation

The operation of the plant heating system is not required to ensure the safe shutdown of the plant.

The system incorporates features that ensure its reliable operation over a full range of normal plant operations. These features include the installation of control valves on the coil inlet and multiple condensate return pumps.

Instrumentation is provided to monitor the temperature and pressure at various points.

Necessary safety features are provided for the operation of auxiliary boilers.

9.4.8.4 Inspection and Testing

All equipment was factory inspected and tested in accordance with the applicable equipment specifications, quality assurance requirements, and codes. System ductwork and the erection of equipment were inspected for quality assurance during various construction stages. Construction tests were performed on all mechanical components, and the system was balanced for the design water flows and system operating pressures.

Controls, interlocks, and safety devices were cold checked, adjusted, and tested to ensure their proper operation. Initial system flow distribution, valve and damper operability, instrumentation and control loop checks, and alarm setpoints were done in accordance with the Acceptance Test program as discussed in Chapter 14.

Maintenance is performed on a scheduled basis in accordance with the recommendations of the equipment manufacturer and/or operating/maintenance experience.

9.4.8.5 Instrumentation and Controls

The plant heating system works in conjunction with various ventilation systems in the plant. The system is put in service by manually starting the auxiliary boiler. The steam temperature and pressure at various points are monitored and indicated. The capacity control of the coils is achieved by modulating the inlet steam and not by throttling the condensate quantity, thereby precluding the possibility of coil freezeup resulting from low steam flow conditions.

The unit heaters are controlled by locally mounted thermostats with integrated on-off-auto switches.

9.4.9 General Service Water Pump House Heating and Ventilation System

9.4.9.1 Design Bases

The system is designed to maintain the temperature in the pump and switchgear rooms between 50°F and 120°F during all normal modes of plant operation and during plant shutdown periods. The ambient design temperature is between -10°F and 95°F.

The system is nonseismic.

9.4.9.2 System Description

A diagram of the general service water pump house heating and ventilation system is shown in Figure 9.4-12. Nominal sizes and types of principal system components are listed in Table 9.4-14.

The pump room is provided with three propeller-type fans equipped with gravity backdraft dampers. The fans are mounted in the roof of the pump house. A centrifugal blower unit equipped with an air filter and an intake damper is mounted on an outside wall of the switchgear room.

The pump room fans draw outside air into the room through intake louvers located at either end of the pump house. The switchgear room fan supplies outside air to the room and forces the heated air into the pump room.

Five electrical heaters are provided in the pump room and one in the switchgear room. The heating units heat and recirculate room air.

9.4.9.3 Safety Evaluation

This system is not required for the safe shutdown of the plant. An indication of high and low room temperatures, along with an alarm, is provided in the main control room.

9.4.9.4 Inspection and Testing

All equipment was factory inspected and tested in accordance with the applicable equipment specifications, quality assurance requirements, and codes. Controls, interlocks, and safety devices on each system were cold checked, adjusted, and tested to ensure the proper sequence of operation. Initial system flow distribution, valve operability, instrumentation and control loop checks, and alarm setpoints were done in accordance with the Preoperational Acceptance Test program as discussed in Chapter 14.

Routine maintenance and tests, based on the manufacturer's recommendations and/or operating/maintenance experience, are scheduled in accordance with the plant preventive maintenance program.

9.4.9.5 Instrumentation and Controls

Heating and ventilating of each room are controlled by a thermostat located in that room. Each ventilating fan is equipped with a local on-off switch. High and low temperatures for the pump and switchgear rooms are alarmed in the main control room.

9.4.10 Circulating Water Pump House Ventilation System

9.4.10.1 Design Bases

The circulating water pump house ventilation system is designed to limit the temperature in the pump room, switchgear room, and chemical treatment room to a maximum of 104°F.

The ventilation system is nonseismic.

9.4.10.2 System Description

Nominal sizes and types of principal system components are listed in Table 9.4-15.

The circulating water pump house has three separate ventilation systems, one each for the pump room, switchgear room, and chemical treatment room.

9.4.10.2.1 Pump Room

At each circulating water pump location, there is one exhaust fan that draws room air through the pump motor shroud for motor cooling and provides ventilation of the pump area during pump operation. For operation during cold weather, warm air from the pump motor shroud is mixed with a mixture of recirculated room air and outside air to maintain room temperature. During warm-weather operation, outside air is drawn directly into the pump area, through the pump motor shroud, and discharged back to the outside, thereby providing pump area ventilation and adequate cooling for the pump motor. Supplemental electric heating is provided to maintain room temperature well above freezing during cold weather when the circulating water pump is out of service.

9.4.10.2.2 Switchgear Room

Operation of the switchgear room ventilation system is initiated when the switchgear room temperature reaches 80°F. The exhaust fan starts and the outside air damper opens automatically.

9.4.10.2.3 Chemical Treatment Room

The ventilation fan in the chemical treatment room draws in air from the adjacent pump room when the chemical treatment room temperature is below 80°F. Above 80°F, the pump room damper closes and the outside air damper opens. When the chemical treatment room temperature is below 50°F, a room thermostat regulates the electric duct heaters at the ventilating fan.

9.4.10.3 Safety Evaluation

The circulating water pump house ventilation systems are required to operate only during normal plant operation.

9.4.10.4 Tests and Inspections

All equipment was factory inspected and tested in accordance with applicable equipment specifications, quality assurance requirements, and codes. The system ductwork and erection of equipment were inspected during various construction stages. Construction tests were performed on all components of the system. The system was balanced for the design airflow and system operating pressures. Controls, interlocks, and safety devices on each system were adjusted and tested to ensure proper sequence of operation. Initial system flow distribution, valve and damper operability, instrumentation and control loop checks, and alarm setpoints were done in accordance with the Preoperational Acceptance Test program as discussed in Chapter 14.

9.4.10.5 Instrumentation

All rooms are provided with high and low temperature alarms in the main control room. Flow status lights are provided for all rooms and an alarm is provided for a loss of ventilation flow in the pump room.

9.4.11 Motor-Generator Set Cooling System

9.4.11.1 Design Bases

The motor-generator (M-G) set cooling system is designed to provide 104°F cooling air to the reactor recirculating pump M-G sets.

The system is nonseismic.

9.4.11.2 System Description

A diagram of the M-G set cooling system is shown in Figure 9.4-13. Nominal sizes and types of principal system components are listed in Table 9.4-16.

Three 50 percent fan-coil cooling units are provided to cool the two reactor recirculating pump M-G sets located on the fourth floor of the reactor building. The cooling unit fans induce room air to flow through each generator and motor. The air is then drawn through a common exhaust duct system to the fan-coil units. The fan-coil unit cools the air and discharges it back into the room. Two of the three fan-coil units are normally operating, with the third on standby. The standby unit is automatically started if the discharge air temperature in one of the two operating cooling units exceeds 125°F. The cooling coils are cooled by the RBCCWS.

9.4.11.3 Safety Evaluation

The M-G set cooling system is required to operate only during normal plant operation.

In order to ensure that the system has a high reliability during normal plant operation, three 50 percent fan-cooling coil units are provided.

9.4.11.4 Inspection and Testing

All equipment was factory inspected and tested in accordance with the applicable equipment specifications, quality assurance requirements, and codes. Controls, interlocks, and safety devices on each system were cold checked, adjusted, and tested to ensure the proper sequence of operation. Initial system flow distribution, valve and damper operability, instrumentation and control loop checks, and alarm setpoints were done in accordance with the Preoperational Acceptance Test program as discussed in Chapter 14.

Routine maintenance and tests, based on the manufacturer's recommendations and/or operating/maintenance experience, are scheduled in accordance with the plant preventive maintenance program.

9.4.11.5 Instrumentation and Controls

Two M-G set cooling units are selected to operate manually when the M-G sets need to be started. If after 30 sec the chosen fan does not provide airflow, it will be tripped and a standby fan started. Temperature switches are also provided in the discharge of the cooling units to trip above 125°F and automatically start a standby fan. Alarms are provided in the main control room for "motor trip" and "M-G set vent air fan auto start" to alert the operator that the automatic trip has occurred.

TABLE 9.4-1 CONTROL CENTER HVAC SYSTEM MAJOR COMPONENTS DESCRIPTIONS

A. Air Handling Equipment Trains

Type	Built-up
Quantity	Two, 100 percent capacity

1. Air Handling Units

Type		Blow-through
Quantity		Two, 100 percent capacity
Capacity:	cooling, Btu/hr	12×10^5
	heating, Btu/hr	5.3×10^5

2. Supply Air Fans

Type	Centrifugal
Drive	Belt, variable speed
Capacity, scfm	37,000
Total static pressure, in. H_2O	3.6
Motor, hp	40

3. Supply Air Filters

Type	Fiberglass roll filter with electrostatic precipitator
Quantity	Two, 100 percent capacity
Efficiency (NBS Dust Spot Test)	90 percent
Capacity, scfm	37,000
Pressure Drop (Clean), in. H_2O	0.16

4. Return Air Fans

Type	Centrifugal
Drive	Belt
Quantity	Two, 100 percent capacity
Capacity, scfm	35,550
Total static pressure, in. H_2O	2.5
Motor, hp	25

B. Refrigeration Units

Type	Centrifugal packaged chillers (water cooled)
Quantity	Two, 100 percent capacity
Capacity, tons	100
Power, kW	85

TABLE 9.4-1 CONTROL CENTER HVAC SYSTEM MAJOR COMPONENTS DESCRIPTIONS

C. Chilled Water Pumps

Type	Centrifugal, vertically split casing
Total dynamic head capacity, gpm	300
Total dynamic head, ft H_2O	50
Motor, hp	7.5

D. Emergency Makeup Air Filter Trains

Type	Built-up
Quantity	One, 100 percent capacity
Components of emergency makeup air filter trains	

1. Fans

Type	Centrifugal
Drive	Belt
Quantity	Two, 100 percent capacity
Capacity, scfm	3000
Static pressure, in. H_2O	11
Motor, hp	20

2. Makeup Air Filter

a. Prefilter-Moisture Separator

Type	Baffles & fiberglass
Medium	Fiberglass 5 1/2 in.
Efficiency (per NBS Dust Spot Test)	85 percent
Pressure Drop (Clean), in. H_2O	0.80 in. at 1800 cfm flow saturated air at 70 °F

b. Electric Heaters

Type	Resistance, single stage
Quantity	Two
Capacity, kW	12

c. HEPA Filters

Type	High-efficiency particulate dry
Medium	Glass fiber (fire retardant)
Efficiency	Design efficiency of 99.97 percent for 0.3µm particles or larger.

TABLE 9.4-1 CONTROL CENTER HVAC SYSTEM MAJOR COMPONENTS DESCRIPTIONS

c. HEPA Filters (cont.)

	Installed and tested such that an overall decontamination efficiency of 95 percent is assumed for removal of particulate iodine
Pressure drop (Clean) in. H_2O	1.1

d. Charcoal Adsorber

Type	2-in. gasketless
Quantity	One bank
Medium	Impregnated charcoal
Efficiency, percent	Lab tested to ensure a 99 percent removal efficiency for methyl iodide Installed and tested in the adsorber housing such that an overall decontamination efficiency of 95 percent is assumed for removal of all forms of gaseous iodine
Capacity, cfm	3000 by design, 1800 maximum during operation

3. Recirculation Air Filter

a. HEPA Filters

Type	High-efficiency particulate dry
Medium	Glass fiber (fire retardant)
Efficiency	Design efficiency of 99.97 percent for 0.3µm particles or larger. Installed and tested such that an overall decontamination efficiency of 95 percent is assumed for removal of particulate iodine.
Pressure Drop (Clean), in. H_2O	1.1

b. Charcoal Adsorber

Type	4-in. gasketless
Quantity	One bank

TABLE 9.4-1 CONTROL CENTER HVAC SYSTEM MAJOR COMPONENTS DESCRIPTIONS

b. Charcoal Adsorber (cont.)

Medium	Impregnated charcoal
Efficiency	Lab tested to ensure a 99 percent removal efficiency for methyl iodide.
	Installed and tested in the adsorber housing such that an overall decontamination efficiency of 95 percent is assumed for removal of all forms of gaseous iodine.
Capacity, cfm	3000

E. Control Center Air Conditioning Equipment Room Fan-Coil Cooling Units

1. Type — Package

2. Quantity — Two

3. Components of each unit

a. Fan

Type	Centrifugal
Quantity	One
Drive	Belt
Capacity, scfm	1200
Static pressure, in. H_2O	1.03
Motor, hp	1.0

b. Heat Exchange Coil

Type	Finned tube
Face velocity, ft/minute	449
Capacity, Btu/hr	49,100

F. Control Center Computer Room Air Conditioning Units

1. Type — Horizontal package

2. Quantity — Two

3. Components of each unit

TABLE 9.4-1 CONTROL CENTER HVAC SYSTEM MAJOR COMPONENTS DESCRIPTIONS

a. Air Conditioning Unit

Fan type	Centrifugal
Quantity	One
Drive	Belt
Capacity, scfm	6200
Static pressure, in. H_2O	2
Motor, hp	7-1/2
Cooling coil type	6-row direct expansion
Face velocity, ft/minute	500
Capacity, Btu/hr - nominal	180,000

b. Refrigeration Compressors

Quantity	Two
Size, tons	15
Type	Semi-hermetic reciprocating 3-stage unloading
Motor amps (RLA)	29 @ 460 V
Refrigerant	R-22

c. Air-Cooled Condensers

Quantity	Two
Gross heat rejection each, Btu/hr	229,000
Motors per unit	Three
Motor, hp (each)	3/4

TABLE 9.4-2 MAIN CONTROL ROOM AIR CONDITIONING SYSTEM SINGLE-FAILURE ANALYSIS

System	Component Malfunction	Comments
1. Offsite power	Not available	Emergency diesels start and supply electrical load to systems
2. Emergency diesels	One not available	The operative diesel supplies necessary to power one of the System's redundant active components
3. Main control room air conditioning	Rupture of equipment casing and/or ducts	Consideration has been given in the detailed design to withstand the design- basis temperature, pressure, and seismic forces during a postaccident situation. The equipment and components are also inspectable and protected against credible missiles
	Rupture of chiller piping or loss of one of the chiller systems	Rupture is not considered credible since all piping is designed to withstand the design-basis temperature, pressure, and seismic forces during a post accident situation and is inspectable and protected from missiles. 100 percent redundant control center air conditioning systems are provided. The operating division will be shut down and the standby division manually started
	System fan fails	100 percent redundant fans are provided. Loss of a fan will be alarmed in the control room. The operating division must be shut down and the standby division manually started
	Normal intake or exhaust isolation damper fails to close	Two redundant dampers provided in series in each line. Each damper in series receives power from a separate ESF bus. This ensures that at least one damper in each line will close
	One of the emergency filtration intake isolation dampers fails to close during a chlorine accident	Four dampers provided, two per division in each line. The dampers are normally closed and fail closed
	One of the kitchen/washroom exhaust isolation dampers fails to close during a chlorine accident	Four dampers provided, two in each exhaust duct. Each damper in each exhaust duct receives power from a separate ESF bus. This ensures that at least one damper will close in each exhaust duct.
	One of the emergency filtration intake isolation dampers fails to open	Redundant intake lines provided. Two intake isolation dampers provided in each line. Both dampers in series receive power from the same ESF bus. This ensures that two dampers in series will open.
	Smoke/Halon dampers for relay room, cable spreading room or computer room close	Loss of cooling to the respective room. Manual action is required to reopen dampers.

TABLE 9.4-3 REACTOR/AUXILIARY BUILDING VENTILATION AND COOLING SYSTEM COMPONENTS DESCRIPTIONS

A. Reactor Auxiliary Building Ventilation Supply

1. Type — Built-up

2. Components

a. Fans

Type	Vaneaxial
Quantity	Three, 50 percent capacity
Drive	Direct
Capacity, scfm	52,088 each
Total pressure, in. H_2O	4.75
Motor, hp	75

b. Filters

Type	Disposable cartridge
Quantity	One bank
Media	Glass fiber (fire retardant)
Efficiency (NBS Dust Spot Test)	85 percent
Capacity, scfm	104,176
Pressure Drop (Clean), in. H_2O	0.5

c. Heating Coils

Type	Finned tube
Quantity	One bank
Capacity, Btu/hr	8.4×10^6

B. Reactor Auxiliary Building Ventilation Exhaust Fans

Type	Vaneaxial
Quantity	Three, 50 percent capacity
Drive	Direct
Capacity, scfm	54,388 each
Total pressure, in. H_2O	5.1
Motor, hp	75

C. Battery Room Exhaust Fans

Type	Centrifugal
Drive	Direct
Quantity	Four
Capacity, scfm	400

TABLE 9.4-3 REACTOR/AUXILIARY BUILDING VENTILATION AND COOLING SYSTEM COMPONENTS DESCRIPTIONS

Total static pressure, in. H_2O	1.7
Motor, hp	1

D. HPCI Pump Cubicle Fan-Coil Unit

1. Type — Package

2. Quantity — One

3. Components of each unit

a. Fan

Type	Centrifugal
Quantity	One
Drive	Belt
Capacity, scfm	6400
Total static pressure, in. H_2O	3.3
Motor, hp	7.5

b. Heat Exchange Coil

Type	Finned tube
Face velocity, ft/minute	650
Capacity, Btu/hr	2.95×10^5

E. Core Spray Pump Cubicle Fan-Coil Unit

1. Type — Package

2. Quantity — One

3. Components of each unit

a. Fans

Type	Centrifugal
Quantity	Two
Drive	Belt
Capacity, scfm	11,800 total
Total static pressure, in. H_2O	4.1
Motor, hp	15

b. Heat Exchange Coil

TABLE 9.4-3 REACTOR/AUXILIARY BUILDING VENTILATION AND COOLING SYSTEM COMPONENTS DESCRIPTIONS

Type	Finned tube
Face velocity, ft/minute	690
Capacity, Btu/hr	5.4×10^5

F. Core Spray/RCIC Pump Cubicle Fan-Coil Unit

1. Type — Package

2. Quantity — One

3. Components of each unit

a. Fans

Type	Centrifugal
Quantity	Two
Drive	Belt
Capacity, scfm	14,500
Total static pressure, in. H_2O	3.3
Motor, hp	15

b. Heat Exchange Coil

Type	Finned tube
Face velocity, ft/minute	645
Capacity, Btu/hr	6.25×10^5

G. RHR Pumps Cubicles Fan-Coil Units

1. Type — Package

2. Quantity — Two

3. Components of each unit

a. Fans

Type	Centrifugal
Quantity	Two
Drive	Belt
Capacity, scfm	18,200
Total static pressure, in. H_2O	3.5
Motor, hp	20

TABLE 9.4-3 REACTOR/AUXILIARY BUILDING VENTILATION AND COOLING SYSTEM COMPONENTS DESCRIPTIONS

b. Heat Exchange Coil

Type	Finned tube
Face velocity, ft/minute	589
Capacity, Btu/hr	8.43×10^5

H. Essential Switchgear Room Fan-Coil Units

1. Type — Package

2. Quantity — Four

3. Components of each unit

a. Fans

Type	Centrifugal
Quantity	Two
Drive	Belt
Capacity, acfm	9750
Total static pressure, in. H_2O	2.5
Motor, hp	5

b. Cooling Coil

Type	Finned tube
Face velocity, ft/minute	696
Capacity, Btu/hr	10.5×10^4

I. SGTS Cubicle Fan-Coil Units

1. Type — Package

2. Quantity — Two

3. Components of each unit

a. Fans

Type	Centrifugal
Quantity	One
Drive	Belt
Capacity, scfm	9030
Total static pressure, in. H_2O	0.5
Motor, hp	3

TABLE 9.4-3 REACTOR/AUXILIARY BUILDING VENTILATION AND COOLING SYSTEM COMPONENTS DESCRIPTIONS

b. Heat Exchange Coil

Type	Finned tube
Face velocity, ft/minute	516
Capacity, Btu/hr	1.95×10^5

J. Deleted

K. Control Air Compressor Fan-Coil Units

1. Type — Package

2. Quantity — Two

3. Components of each unit

a. Fans

Type	Centrifugal
Quantity	One
Drive	Belt
Minimum capacity, acfm	4600
Total static pressure, in. H_2O	Free delivery
Motor, hp	5

b. Heat Exchange Coil

Type	Finned tube
Minimum capacity, Btu/hr	49,500

L. Thermal Recombiner Fan-Coil Units

1. Type — Package

2. Quantity — Two

3. Components of each unit

a. Fans

Type	Centrifugal
Quantity	One
Drive	Belt
Capacity, scfm	6500

TABLE 9.4-3 REACTOR/AUXILIARY BUILDING VENTILATION AND COOLING SYSTEM COMPONENTS DESCRIPTIONS

Total static pressure, in. H_2O	Free delivery
Motor, hp	5

b. Heat Exchange Coil

Type	Finned tube
Face velocity, ft/minute	812
Capacity, Btu/hr	68,975

M. EECW Pump Fan-Coil Units

1. Type — Package

2. Quantity — Two

3. Components of each unit

a. Fans

Type	Centrifugal
Quantity	One
Drive	Belt
Minimum capacity, acfm	4600
Total static pressure, in. H_2O	Free delivery
Motor, hp	5

b. Heat Exchange Coil

Type	Finned tube
Minimum capacity, Btu/hr	49,500

N. Battery Room Air Conditioning Unit

1. Type — Package

2. Quantity — One

3. Components of each unit

a. Fans

Type	Centrifugal
Quantity	One
Drive	Belt
Capacity, scfm	6000

TABLE 9.4-3 REACTOR/AUXILIARY BUILDING VENTILATION AND COOLING SYSTEM COMPONENTS DESCRIPTIONS

Total external static pressure, in. H_2O	0.5
Motor, hp	5

b. Evaporator Coil

Type	Finned tube
Face velocity, ft/minute	500
Capacity, Btu/hr	1.38×10^5

c. Condenser

Type	Shell and tube, water cooled

d. Compressor

Type	Hermetic
Nameplate data	26 amp @ 460-V ac

O. Battery Charging Area Fan-Coil Units

1. Type — Horizontal package

2. Quantity — Two

3. Components of each unit

a. Fans

	Division I	Division II
Type	Centrifugal	Centrifugal
Quantity	One	One
Drive	Belt	Belt
Capacity, acfm	5370	2800
Total static pressure, in. H_2O	1/3	1/4
Motor, hp	5	2

b. Cooling Coil

Type	Fin-tube, water cooled	
Capacity, Btu/hr	69,000	33,000

P. Switchgear Room Air Conditioning Units

1. Type — Split system

2. Capacity, Btu/hr — 120,000

TABLE 9.4-3 REACTOR/AUXILIARY BUILDING VENTILATION AND COOLING SYSTEM COMPONENTS DESCRIPTIONS

3.	Quantity	Four (two per room)
4.	Condensing Unit	
	Fans	Propeller
	Quantity	One each
	Motor, hp	1 each
	Refrigerant	Freon 22
5.	Air-Handling Unit	
	Fan	Centrifugal
	Quantity	One each
	Drive	Belt
	Motor, hp	3
	Coil face area, ft^2	11.2

TABLE 9.4-4 RADWASTE FACILITY VENTILATION SYSTEM COMPONENTS DESCRIPTIONS

A. Radwaste Building Ventilation Supply

1. Type — Built-up

2. Components

a. Fans

Type	Centrifugal
Quantity	Two
Drive	Belt
Capacity, scfm	32,400
Total static pressure, in. H_2O	3.00
Motor, hp	25

b. Prefilter

Type	Pad
Quantity	One bank (15 filters)
Medium	Glass fiber (fire retardant)
Nominal capacity, scfm	30,000
Pressure Drop (Clean), in. H_2O	
At rated flow (30,000 cfm)	0.4
At actual flow (32,800 cfm)	0.45

c. High-Efficiency Filter

Type	Vericel
Quantity	One bank (15 filters)
Medium	Glass fiber (fire retardant)
Efficiency	80-85 percent
Nominal capacity, scfm	30,000
Pressure Drop (Clean), in. H_2O	
At rated flow (30,000 cfm)	0.55
At actual flow (32,800 cfm)	0.64

d. Heating Coil

Type	Finned tube
Quantity	One bank
Capacity, Btu/hr	2.88×10^6

TABLE 9.4-4 RADWASTE FACILITY VENTILATION SYSTEM COMPONENTS DESCRIPTIONS

B. Radwaste Building Ventilation Exhaust

1. Type	Built-up
2. Components	
a. Fans	
Type	Centrifugal
Quantity	Two
Capacity, scfm	33,700
Total static pressure, in. H_2O	6.5
Motor, hp	50
b. Prefilter	
Type	Disposable cartridge
Quantity	One bank
Efficiency (NBS Dust Spot Test)	85 percent
Nominal capacity, scfm	60,000
Resistance (Clean), in. H_2O	
At rated flow (60,000 cfm)	0.55
At actual flow (45,945 cfm)	0.42
c. HEPA Filters	
Type	Astrocel
Quantity	One bank (30 filters)
Medium	Glass fiber (fire retardant)
Efficiency, percent with 0.3 micron dioctyl phthalate (DOP)	99.97
Nominal capacity, scfm	60,000
Pressure Drop (Clean), in. H_2O	
At rated flow (60,000 cfm)	1.16
At actual flow (45,945 cfm)	0.80

C. Radwaste Battery Room Air Conditioning Unit Package

1. Type	Package
2. Components	
a. Fans	
Type	Centrifugal
Quantity	One
Drive	Belt

TABLE 9.4-4 RADWASTE FACILITY VENTILATION SYSTEM COMPONENTS DESCRIPTIONS

Capacity, scfm	2000
Total external static pressure, in. H_2O	0.25
Motor, hp	3/4

b. Evaporator

Type	Finned tube
Face velocity, ft/minute	460
Capacity, Btu/hr	56,500

c. Condenser

Type	Tube-in-tube, water cooled

d. Compressor

Type	Hermetic

D. Health Physics Laboratory Air Conditioning Unit

1. Type — Split system

2. Components

a. Fans

Type	Centrifugal
Quantity	One
Drive	Belt
Capacity, scfm	11,280
Total external static pressure, in. H_2O	4.5
Motor, hp	20

b. Evaporator

Type	Finned tube
Face velocity, ft/minute	343
Capacity, Btu/hr	4.69×10^5

c. Condenser

Type	Shell and tube

d. Compressor

TABLE 9.4-4 RADWASTE FACILITY VENTILATION SYSTEM COMPONENTS DESCRIPTIONS

Type	Hermetic
Motor, hp	40

e. Preheat Coil

Type	Finned tube
Face velocity, ft/minute	500
Capacity, Btu/hr	3.57×10^5

f. Reheat Coil

Type	Finned tube
Face velocity, ft/minute	454
Capacity, Btu/hr	2.36×10^5

E. Fume Hood Exhaust Fan

Type	Centrifugal
Drive	Belt
Capacity, scfm	6500
Total static pressure, in. H_2O	6.0
Motor, hp	1

F. Dedicated Shutdown Air Conditioning Unit Package

1. Type — Split System

2. Components

a. Air Handling Unit Fan

Type	Centrifugal
Drive	Belt
Capacity,scfm	6,000
Total external Static Pressure,(in.H20)	1.84
Motor,(HP)	5

b. Evaporator

Type	Finned Tube
Face velocity,(Ft/Minute)	616
Capacity (BTU/Hr)	240,830
Refrigerant Type	R22

c. Condenser

TABLE 9.4-4 RADWASTE FACILITY VENTILATION SYSTEM COMPONENTS DESCRIPTIONS

Number of Condensers	2
Type	Finned Tube-Air Cooled
Fan Motor(HP)	1 (for each condenser)
Type	Direct Drive

d. Compressor

Number of Compressors	2
Type	Hermetic Scrolls
Motor (HP)	10

TABLE 9.4-5 TURBINE BUILDING VENTILATION SYSTEM COMPONENTS DESCRIPTIONS

A. Turbine Building Ventilation Supply System

1. Type — Built-up

2. Components of each unit

a. Fans

Type	Vaneaxial
Quantity	Three, 50 percent capacity
Drive	Direct
Capacity, cfm	205,000
Total pressure, in. H_2O	5.54
Motor, hp	250

b. Filter

Type	High efficiency
Quantity	One bank
Media Efficiency (NBS Dust Spot Test)	85 percent
Capacity, scfm	390,000
Pressure Drop (Clean), in. H_2O	0.5

c. Heating Coil

Type	Finned tube
Quantity	One bank
Face velocity, ft/minute	695
Capacity, Btu/hr	20×10^6

d. Evaporative Air Cooler

Type	Wetted fill
Quantity	Two sections
Flow Rate	250,000 cfm
Pressure Drop	0.5 in WG

B. Turbine Building Ventilation Exhaust Fans

Type	Vaneaxial
Quantity	Three, 50 percent capacity
Drive	Direct
Capacity, cfm	215,000
Total pressure, in. H_2O	4.5

TABLE 9.4-5 TURBINE BUILDING VENTILATION SYSTEM COMPONENTS DESCRIPTIONS

Motor, hp	250
C. Offgas Adsorber Room Air Conditioning System	
1. Type	Split system
2. Quantity	Three, 50 percent capacity
3. Components of each unit	
a. Fan-Coil Units	
Quantity	Three
Fans	
Type	Centrifugal
Quantity (per fan-coil unit)	Two
Drive	Belt
Capacity, scfm	2250 each fan
Total external static pressure, in. H_2O	0.1
Motor, hp	1
Evaporator Coils	
Type	Finned tube
Quantity (per fan-coil unit)	One
Face velocity, ft/minute	470
Capacity, Btu/hr	129,600
b. Condensers	
Type	Shell and tube
Quantity	Three
c. Compressors	
Type	Semi-Hermetic reciprocating
Quantity	Three
Power input	22.5 amps @ 460 V ac
D. Deleted	
E. Excitation Equipment Area Air Cooling System	

TABLE 9.4-5 TURBINE BUILDING VENTILATION SYSTEM COMPONENTS DESCRIPTIONS

1.	Type	Self Contained Water Cooled Air Conditioning Units
2.	Quantity	Two
3.	Capacity	30 Tons Cooling Each
4.	Manufacturer	Trane
5.	Components of Each Unit	
	Fan Type	Vertical Discharge Direct Drive
	Quantity	Two
	Capacity, scfm	12,000
	Static Pressure, in. WC	4.5
	Motor HP	25

F. Operational Support Center (OSC) Air Conditioning System

1.	Type	Split system
2.	Quantity	One
3.	System Capacity	15 Tons Cooling
4.	Design Flow	6,000 scfm
5.	Manufacturer	Trane
6.	Components of Unit	
	Fan Types	Supply (5.0 hp) (Centrifugal) Return (3.0 hp) (Centrifugal)
	Condensing Unit	
	Compressors	2 @ 7.5 hp each
	Condenser Fans	2 @ 1/2 hp each
	Refrigerant	R-22

TABLE 9.4-5 TURBINE BUILDING VENTILATION SYSTEM COMPONENTS DESCRIPTIONS

G. SCCW Chiller Area (Turbine Building Basement) Fan Cooler

Quantity	1
Fans	
Type	Centrifugal
Drive	Belt Driven
Capacity, scfm	9000
Total Pressure, in H_2O	2.00
Motor, hp	5
Cooling Coil	
Type	Finned tube, 6 Rows
Quantity	1 Bank
Face Velocity, fpm	470
Capacity, Btu/hr	387,187 Total 322,596 Sensible
Chilled Water Flow, gpm	50
Chilled Water Temp, °F	60 in/75.7 out
Filters	
Type	Medium Efficiency, Throwaway
Quantity	1 Bank
Pressure Drop (Dirty), in H_2O	0.40

TABLE 9.4-6 DRYWELL COOLING SYSTEM COMPONENTS DESCRIPTIONS

A. Drywell Fan-Coil Units

1. Type	Built-up
2. Quantity	14
3. Components of each unit	
a. Fans	
Type	Vaneaxial
Quantity	One
Drive	Direct
Capacity, scfm	20,000
Total pressure, in. H_2O	5.0
Motor, hp	30
b. Coils	
Type	Finned tube
Quantity	Two (see Note below)
Capacity, Btu/hr	324,000

Note: Various drywell coolers have been replaced utilizing a split coil design in place of the original single full size coil while retaining the units' functionality and capacity.

TABLE 9.4-7 STEAM TUNNEL COOLING SYSTEM COMPONENTS DESCRIPTIONS

A. Steam Tunnel Fan-Coil Units

1. Type	Package
2. Quantity	Two
3. Components of each unit	
a. Fan	
Type	Centrifugal
Quantity	One
Drive	Belt
Capacity, scfm	24,700
Total static pressure, in. H_2O	3.7
Motor, hp	25
b. Heat Exchange Coil	
Type	Finned tube
Face velocity, ft/minute	645
Capacity, Btu/hr	6.95×10^5

TABLE 9.4-8 RHR COMPLEX HEATING AND VENTILATION SYSTEM FAILURE ANALYSIS

System	Component Malfunction	Comments
Diesel generator room ventilation	One or both the supply air fans for a diesel room fail	Failure of one or both of the supply air fans will actuate a no-flow alarm in the main control room through its associated differential pressure switch, and the temperature in the diesel room will rise. The operator will take the necessary actions in accordance with the alarm response procedures
	Outside air damper fails closed and recirculating air damper fails open	The system will operate at 100 percent recirculation air. The temperature may rise as a result of the outside air damper failing closed. The high temperature in the diesel generator room will actuate an alarm in the control room, and the operator will take the necessary actions in accordance with the alarm response procedures
	Controller memory fails, the outside air and recirculating air dampers fail “as is”	The system will operate at the “as is” damper position at the time of failure. The temperature may rise or drop depending on the damper position and outside temperature. The temperature high or temperature low alarm for the diesel generator room will actuate an alarm in the control room, and the operator will take the necessary actions in accordance with the alarm response procedures
Switchgear room ventilation	Failure of one or both fans for individual switchgear room ventilation	Failure of one or both fans will actuate a no- flow alarm in the main control room through its associated differential pressure switch, and the temperature in the switchgear room will rise. The operator will take the necessary actions in accordance with the alarm response procedures
	Outside air damper fails closed and recirculating air damper fails open	The system will operate at 100 percent recirculation air. The temperature may rise as a result of the outside air damper failing closed. The high temperature in the switchgear room will actuate an alarm in the control room, and the operator will take the necessary actions in accordance with the alarm response procedures
	High pressure differential across the supply air filter	High pressure differential across the filter will illuminate a local indicator light. The operator will take the necessary actions depending upon the room temperature
	Controller memory fails, the outside air and recirculating air dampers fail “as is”	The system will operate at the “as is” damper position at the time of failure. The temperature may rise or drop depending on the damper position and outside temperature. The temperature high or temperature low alarm for the switchgear room will actuate an alarm in the control room, and the operator will take the necessary actions in accordance with the alarm response procedures

TABLE 9.4-8 RHR COMPLEX HEATING AND VENTILATION SYSTEM FAILURE ANALYSIS

Pump room ventilation	Failure of one or both fans for individual pump room ventilation	Failure of one or both supply air fans will actuate a no-flow alarm in the main control room through its associated differential pressure switch, and the temperature in the pump room will rise. The operator will take the necessary actions in accordance with the alarm response procedures
	Outside air damper fails closed and recirculating air damper fails open	The system will operate at 100 percent recirculation air. The temperature may rise as a result of the outside air damper failing closed. The high temperature in the pump room will actuate an alarm in the control room, and the operator will take the necessary actions in accordance with the alarm response procedures
	High pressure differential across the supply air filter	High pressure differential across the filter will illuminate a local indicator light. The operator will take the necessary actions depending upon the room temperature.
	Controller memory fails, the outside air and recirculating air dampers fail “as is”	The system will operate at the “as is” damper position at the time of failure. The temperature may rise or drop depending on the damper position and outside temperature. The temperature high or temperature low alarm for the pump room will actuate an alarm in the control room, and the operator will take the necessary actions in accordance with the alarm response procedures

TABLE 9.4-9 DIESEL GENERATOR ROOM VENTILATION SYSTEM COMPONENTS DESCRIPTIONS

(Per Division of RHR Complex)

Ventilation Fans

Type	Vaneaxial
Quantity	Four
Drive	Direct
Capacity, scfm	34,000
Total pressure, in. H_2O	2
Motor, hp	15

TABLE 9.4-10 SWITCHGEAR ROOM VENTILATION SYSTEM COMPONENTS DESCRIPTIONS

(Per Division of RHR Complex)

Ventilation Fans

Type	Centrifugal
Quantity	Four
Drive	Direct
Capacity, scfm	3900
Total pressure, in. H_2O	2
Motor, hp	3

TABLE 9.4-11 PUMP ROOM VENTILATION SYSTEM COMPONENTS DESCRIPTIONS

(Per Division of RHR Complex)

Ventilation Fans

Type	Vaneaxial
Quantity	Two
Drive	Direct
Capacity, scfm	12,500
Total pressure, in. H_2O	2
Motor, hp	7.5

TABLE 9.4-12 DIESEL-FUEL-OIL STORAGE ROOM VENTILATION SYSTEM COMPONENTS DESCRIPTIONS

(Per Division of RHR Complex)

Ventilation Fans

Type	Centrifugal
Quantity	Two
Drive	Direct
Capacity, scfm	2500
Total pressure, in. H_2O	2
Motor, hp	2

TABLE 9.4-13 PLANT HEATING SYSTEM COMPONENTS DESCRIPTIONS

A. Condensate Return Unit (Turbine Building)

1.	Condensate return tank capacity, gal	2000
2.	Pump	
	Number supplied	Three
	Type	Centrifugal
	Design pressure, psig	150
	Design temperature, °F	365
	Capacity, gpm	120
	Total head, psi	70
	Motor	
	Horsepower	10
	Speed, rpm	3550
	Voltage/frequency/phase	460/60/3

B. Condensate Return Unit (Boiler Building)

1.	Condensate return tank capacity, gal	36
2.	Pump	
	Number supplied	Two
	Type	Centrifugal
	Design pressure, psig	150
	Design temperature, °F	365
	Capacity, gpm	15
	Total head, psi	26
	Motor	
	Horsepower	3/4
	Speed, rpm	3500
	Voltage/frequency/phase	460/60/3

C. Condensate Return Unit (Reactor Building)

1.	Condensate return tank capacity, gal	198
2.	Pump	
	Number supplied	Two
	Type	Centrifugal
	Design pressure, psig	150
	Design temperature, °F	365
	Capacity, gpm	90
	Total head, psi	35
	Motor	
	Horsepower	5
	Speed, rpm	3500
	Voltage/frequency/phase	460/60/3

D. Unit Heaters

Steam pressure, psig	15
Capacity, mBtu/hr	44.4 to 310

TABLE 9.4-13 PLANT HEATING SYSTEM COMPONENTS DESCRIPTIONS

E. Auxiliary Steam Boilers

Number supplied	Two
Steam capacity, lb/hr	50,000 (each)
Operating pressure, psia	120
Design pressure, psig	250
Feedwater temperature, °F	227
Steam temperature	Saturated
Fuel	No. 2 oil

F. Feedwater Pumps

Number supplied	Three
Type	Centrifugal
Fluid	Demineralized condensate
Design pressure, psig	200
Design temperature, °F	250
Capacity, gpm	120 (each)
Total head, ft	400
Motor	
Type	324 TS
Horsepower	30
Speed, rpm	3500
Voltage/frequency/phase	400/60/3

G. Deaerating Heater

Capacity, lb/hr	100,000
Design pressure, psig	120
Design temperature, °F	450
Operating pressure, psig	5
Dissolved oxygen at design load, cm^3/l	0.005
Dissolved at 120 percent design load, cm^3/l	0.005
Vented steam required at full load, lb/hr	169

TABLE 9.4-14 GENERAL SERVICE WATER PUMP HOUSE HEATING AND VENTILATION SYSTEM COMPONENTS DESCRIPTIONS

A. Pump Room Ventilation Exhaust Fans

Type	Vertical roof ventilator
Quantity	Three
Drive	Direct
Capacity, scfm	25,300
Total external static pressure, in. H_2O	1/4
Motor, hp	5

B. Switchgear Room Ventilation Supply

1. Fan

Type	Centrifugal
Quantity	One
Drive	Belt
Capacity, scfm	2850
Total ext. static pressure, in. H_2O	5/8
Motor, hp	3/4

2. Filter

Type	Disposable
Quantity	One bank
Medium	2-in.-thick flat fiberglass

C. Pump Room Heating

Type	Vertical electric unit heaters
Quantity	Five
Capacity, kW	20 (68,200 Btu/hr)
Fan capacity, scfm	1300
Motor, hp	1/6

D. Switchgear Room Heating

Type	Horizontal electric unit heater
Quantity	One
Capacity, kW	10
Fan capacity, scfm	750
Motor, hp	1/10

TABLE 9.4-15 CIRCULATING WATER PUMP HOUSE VENTILATION SYSTEM COMPONENTS DESCRIPTIONS

A. Pump House Ventilation

1. Fans

Type	Axial flow
Quantity	Five
Drive	Direct
Capacity, scfm (each)	21,400/32,000
Total external static pressure, in. H_2O	0.90/2.00
Motor, hp	20

B. Pump Room Heating

1. Heaters

Type	Horizontal elec. unit heaters
Quantity	10
Capacity, kW/Btu/hr	15/51,195
Fan capacity, scfm	750

C. Chemical Treatment Room Ventilation and Heating

Type	Built-up

1. Exhaust System

Fan

Type	Axial flow roof exhauster
Quantity	One
Drive	Belt
Capacity, scfm	6000
Total ext. static pressure, in. H_20	0.45
Motor, hp	1

2. Supply System

Fan

Type	Axial duct
Quantity	One
Drive	Direct
Capacity, scfm	6000
Total ext. static pressure, in. H_2O	0.875
Motor, hp	2

TABLE 9.4-15 CIRCULATING WATER PUMP HOUSE VENTILATION SYSTEM COMPONENTS DESCRIPTIONS

a. Duct Heater

Type	Electric fin tube
Quantity	One
Capacity, kW/Btu/hr	80/273,000

b. Duct Heater

Type	Electric fin tube
Quantity	One
Capacity, kW/Btu/hr	22.5/76,770

D. Switchgear Room Ventilation and Heating

1. Fan

Type	Axial flow roof exhauster
Quantity	One
Drive	Belt
Capacity, scfm	6000
Total ext. static pressure, in. H_2O	0.45
Motor, hp	1

2. Heater

Type	Horizontal electric unit
Quantity	Five
Capacity, kW/Btu/hr	5/17,076
Fan capacity, scfm	420

TABLE 9.4-16 MOTOR-GENERATOR SET COOLING SYSTEM COMPONENTS DESCRIPTIONS

1.	Type	Built-up
2.	Quantity	Three
3.	Components of each unit	
	a. Fan	
	Type	Vaneaxial
	Quantity	One
	Drive	Direct
	Capacity, scfm	38,000
	Total pressure, in. H_2O	1.9
	Motor, hp	20
	b. Heat Exchange Coil	
	Type	Finned tube
	Face velocity, ft/minute	650
	Capacity, Btu/hr	1.8×10^6

Figure Intentionally Removed
Refer to Plant Drawing M-2751

Fermi 2

UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 9.4-1

CONTROL CENTER AIR CONDITIONING SYSTEM
AIR FLOW DIAGRAM

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Refer to Plant Drawing M-2847

Fermi 2

UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 9.4-2

CONTROL CENTER AIR CONDITIONING SYSTEM FLOW DIAGRAM

Figure Intentionally Removed
Refer to Plant Drawing M-4325

Fermi 2

UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 9.4-3

CONTROL CENTER AIR CONDITIONING WATER
CONTROL FLOW DIAGRAM

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Refer to Plant Drawing M-2707-1

FIGURE 9.4-4, SHEET 1

REACTOR AND AUXILIARY BUILDING
VENTILATION SYSTEM FLOW DIAGRAM
UNIT NO. 2

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Refer to Plant Drawing M-2707

Fermi 2

UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 9.4-4, SHEET 2

REACTOR AND AUXILIARY BUILDING
VENTILATION SYSTEM FLOW DIAGRAM
UNIT NO. 2

Figure Intentionally Removed
Refer to Plant Drawing M-4952

Fermi 2

UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 9.4-5, SHEET 1

RADWASTE BUILDING VENTILATION FLOW DIAGRAM

Figure Intentionally Removed
Refer to Plant Drawing M-4953

Fermi 2

UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 9.4-5, SHEET 2

RADWASTE BUILDING VENTILATION FLOW DIAGRAM

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Refer to Plant Drawing M-2711

Figure Intentionally Removed
Refer to Plant Drawing M-2240

Fermi 2

UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 9.4-7, SHEET 1

TURBINE BUILDING VENTILATION
FLOW DIAGRAM

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Refer to Plant Drawing M-2240-1

Fermi 2

UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 9.4-7, SHEET 2

TURBINE BUILDING VENTILATION
FLOW DIAGRAM

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Refer to Plant Drawing M-4127

Fermi 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 9.4-8
DRYWELL COOLING SYSTEM FLOW DIAGRAM

Figure Intentionally Removed
Refer to Plant Drawing M-2756

Fermi 2

UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 9.4-9

STEAM TUNNEL COOLING SYSTEM
FLOW DIAGRAM

Figure Intentionally Removed
Refer to Plant Drawing M-N-2058

Fermi 2

UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 9.4-10

DIVISION II RESIDUAL HEAT REMOVAL COMPLEX
TYPICAL VENTILATION SYSTEM - DIESEL
GENERATOR 13 - FLOW DIAGRAM

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Refer to Plant Drawing M-2271

Figure Intentionally Removed
Refer to Plant Drawing M-S-2003

Fermi 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 9.4-12

GENERAL SERVICE PUMP HOUSE VENTILATION SYSTEM FLOW DIAGRAM

Figure Intentionally Removed
Refer to Plant Drawing M-2708

Fermi 2

UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 9.4-13

MOTOR-GENERATOR SET COOLING SYSTEM FLOW DIAGRAM

9.5 OTHER AUXILIARY SYSTEMS

9.5.1 Fire Protection System

9.5.1.1 Design Basis

9.5.1.1.1 Introduction

The fire protection system is designed to provide adequate fire protection for all potential fire hazards. It provides prompt fire detection, alarm, and suppression. The fire protection system is designed to supplement the other fire protection safeguards incorporated into the plant design, including a low combustible fire loading and adequate separation of fire areas. Included in the total fire protection system are a fire protection water supply and distribution system, a fire detection and alarm system, and gaseous extinguishing systems, as well as fixed water spray and automatic sprinkler systems. Manual fire protection hose connections are provided on all floors, and hydrants are located in the yard. Plant operators are trained on a routine basis in fire-fighting techniques.

The Fermi 2 fire protection system has been developed using the fire hazards analysis, National Fire Protection Association (NFPA) standards, and recommendations made by the Nuclear Energy Liability-Property Insurance Association (NEL-PIA) (now named American Nuclear Insurers (ANI)) after its review of the entire system. This method is equivalent to postulating peak fire intensities due to the fire calculations and experience inherent in the standards and NEL-PIA recommendations.

The entire fire protection system is designed using the NFPA standards and the NEL-PIA recommendations for guidance.

The concrete building materials, the compartmentalization, and fire doors provide the structural features needed to prevent the spread of fires in Category I structures. The concrete used in the walls, floors, and ceilings will not support combustion. The compartmentalization of the plant for shielding purposes also provides fire barriers between equipment areas. The fire zones in the safety-related areas are established in the fire hazards analysis presented in Appendix 9A.

Because of the plant construction using noncombustible materials, the fire protection system is a nonseismic system. The piping is designed to Category II/I criteria (Section 3.7).

9.5.1.1.2 Codes and Standards

The following codes and standards were used for guidance in the design of the Fermi 2 fire protection system:

a. NFPA-10, Portable Fire Extinguishers - 1978

b. NFPA-12, Carbon Dioxide Systems - 1977

c. NFPA-12A, Halogenated Fire Extinguishing Agent Systems – 1977. Guidance in NFPA-12A, Standard on Halon 1301 Fire Extinguishing Systems – 2009, Section 6.7.2.4.2(5), is also used, with supporting justifications identified in FPEE-20-0006.

d. NFPA-13, Installation of Sprinkler Systems - 1980. Certain deviations to NFPA-13 requirements, with supporting justifications, are identified in sections 9.5.1.2.3.3, 9A.4.1.6.1, 9A.4.1.7.1, 9A.4.2.3.1, 9A.4.3.1 and 9.5.1.2.1.

e. NFPA-13A, Care and Maintenance of Sprinkler Systems - 1976

f. NFPA-13E, Fire Department Operations in Properties Protected by Sprinklers and Standpipe Systems - 1973

g. NFPA-14, Standpipe and Hose Systems - 1976

   Certain deviations to NFPA-14 requirements, with supporting justifications, are identified in sections 9.5.1.2.1 and 9A.2.3.5.2.

h. NFPA-15, Water Spray - Fixed Systems - 1979

i. NFPA-20, Centrifugal Fire Pumps - 1970

   Certain deviations to NFPA-20 requirements, with supporting justifications, are identified in section 9.5.1.2.3.2.

j. NFPA-24, Outside Protection – 1970

   Certain deviations to NFPA-24 requirements, with supporting justifications, are identified in section 9.5.1.2.1.

k. NFPA-30, Flammable and Combustible Liquids - 1977

l. NFPA-72D, Proprietary Protective Signaling Systems for Watchman, Fire Alarm, and Supervisory Service - 1975

m. NFPA-72E, Automatic Fire Detectors - 1974

n. NFPA-198, Fire Hose (Including Couplings and Nozzles) - 1972

o. Underwriters Laboratories approved materials for fire protection

p. ANSI Specification B1.1, B18.2.1, Nuts and Bolts

q. ANSI Specification B31.1.0, Power Piping

r. ANSI Specification B16.1 - 1967, Standard Flange

s. 10 CFR 50, Appendix A, Criterion 3, Fire Protection.

9.5.1.1.3 Multiple-Unit Fire Protection

Fermi 2 is not a multiple-unit plant; therefore, no precautions are necessary to protect the operating plant during the construction of multiple units.

9.5.1.2 System Description

9.5.1.2.1 General Description

The FPS is shown in Figures 9.5-1, 9.5-2, and 9.5-3.

The dedicated fire protection water supply is obtained from a 2500-gpm electric-driven fire pump and a 2500-gpm diesel-driven fire pump located in the GSW pump house. Either fire pump will supply the required fire protection water demands. The diesel- and electric-driven fire pumps are normally on standby, since the fire mains are supplied with makeup water and pressurization from the FPS jockey pump which takes suction from the GSW pump header. The FPS jockey pump operates continuously, maintaining pressure in the fire main. If fire header pressure falls below GSW header pressure, makeup water will also be supplied via the cross-tie line between GSW and FPS. The electric fire pump starts automatically when the fire protection system header pressure drops to 130 psig, and the diesel fire pump starts when the fire protection system header pressure drops to 110 psig; both require manual shutdown once started. The fire pumps meet the intent of NFPA Standard 20 (except for certain deviations identified in section 9.5.1.2.3.2) and NEL-PIA recommendations, and are Underwriters Laboratories (UL) approved. The fire main loop is completely isolable from the GSW system, and a check valve is provided to prevent flow from the fire main loop into the GSW system. This design provides flexibility to support the fire main loop while maintaining its integrity with respect to system flow.

The distribution fire main in the yard surrounding the plant is a 12-in. and 14-in. underground header, which is buried below the frost line to prevent freezing. Normally open valves with post indicators are installed in the fire main on each side of every branch and also on every branch leading from the fire main. Those valves, together with individual hydrant shutoff valves, permit isolation of a line break anywhere, with minimum interruption of service to undamaged sections. Hydrants and underground fittings are provided with suitable thrust blocks to prevent blowouts of the system. The underground portion of the system is coated with corrosion-resistant materials and is also protected by cathodic protection, as applicable.

The 12-in. fire main is designed to provide the required water demands for the automatic sprinkler systems and 500 gpm for all hose demands. The hose pipe system is designed as an NFPA Standard 14 Class II hose system. Pressure reducing devices are not installed as required by NFPA-14 at all hose station outlets where the pressure exceeds 100 psig, to reduce the pressure with required flow at the outlet to 100 psig. This is acceptable because the hose stations and fire hose are only used by trained fire brigade members, and adjustable pattern fog nozzles are provided at all hose stations, except for the fifth[h] (refueling) floor of the reactor building where solid stream nozzles are provided. Pressure reducing devices that significantly reduce pressure are provided for hose station outlets on the fifth floor of the reactor building and on floors below the grade floor of 583 ft 6 in., due to excessively high pressure at those hose stations. The reason for utilizing a higher pressure at hose stations is to be able to more effectively fight fires at the ceiling height where cable trays are located. The fuel storage tank for the diesel fire pump holds sufficient fuel to continuously operate the pump for a minimum of 8 hr.

The fire main loop serves the outdoor hydrants, which are spaced in accordance with NFPA Standard 24. Additional hydrants on branches of the main loop are located in the general vicinity of the cooling water towers, in the protected area, and in the vicinity of the warehouses and the CTG fuel storage tank outside the protected area. Underground branches from the fire main loop supply water to the reactor, turbine, radwaste, auxiliary, residual heat removal (RHR) complex, Independent Spent Fuel Storage Installation (ISFSI) equipment storage, FLEX Storage Facility (FSF#1), and warehouse buildings within the protected area. A separate branch with an isolation valve supplies warehouses, fire hydrants and other buildings as shown in Figure 9.5-1, Sheet 2. In addition to the 12-in. steel pipe, this branch includes 12-in., 8-in. and 6-in. portions of transite pipe, 6-in. cement lined ductile iron pipe, 6-in. portions of poly vinyl chloride pipe, as well as 14-in. high density polyethylene (HDPE) pipe, as shown in Figure 9.5-1, Sheet 2. The underground fittings are provided with suitable thrust blocks to prevent blowouts of the system. Valves are provided to isolate this branch in the event of a pipe failure. The underground feeds into the RHR Complex building are embedded in an exterior wall and floor where the two lines are exposed to outdoor temperatures. Freezing is avoided by a combination of exterior wall insulation and by running a continuous amount of water through the lines during the winter season. This is an alternative method of providing freeze protection to the specific requirements of NFPA 13 and 24 and was in a report filed with the NRC in VP-85-0204 (Reference section 9A.1.1.2).

The sprinkler system supplies water to the sprinklers. At a set ambient temperature, the sprinkler system initiates water flow in the sprinkler. An alarm valve and/or flow switch in the line actuates a visible and audible alarm in the main control room for sprinklers in the protected area. Indication for those sprinkler systems in the owner controlled area are located within normally manned security areas. The areas covered by the sprinkler systems are indicated in Table 9.5-1.

The deluge system consists of a system employing open sprinklers attached to a piping system connected to the fire protection water supply through a valve that is opened by the operation of a fire detection system installed in the same area as the sprinklers. Audible and visible alarms are actuated in the main control room for the deluge systems located in the protected area. The deluge valves in the protected area can also be opened by manual switches from the main control room. These deluge valves can be reset only when there is no pressure upstream of the valve. This can be achieved by manually closing the outside screw and yoke valve upstream of the deluge valve. Position-indicating lights for the deluge (and outside screw and yoke) valves of both the sprinkler and the deluge systems in the protected area are provided in the main control room. Provisions for monitoring the electrical control circuits of the deluge valve manual switches are also incorporated into the main control room for valves in the protected area. Indications for those fire protection valves in the owner-controlled area are located within normally manned security areas. Areas with deluge system protection are listed in Table 9.5-1.

Each divisional pair of diesel generators is provided with a low-pressure CO_2 flooding system. The initiation of CO_2 in the diesel generator room does not affect the starting and running of the diesel generators. The diesel-fuel-oil storage tanks are protected by wet-pipe sprinkler systems. The fuel oil storage tanks are contained in their own rooms with elevated doorways that would prevent the fuel oil from flowing into other adjacent areas in the event of a rupture of the tanks. In addition, floor drains are provided in these rooms to drain the oil, and the water from the sprinkler system, to the outside liquid chemical waste holding pond. Diking is also provided around the 150,000-gal auxiliary boiler fuel-oil storage tank.

The standby gas treatment system (SGTS) charcoal filters are provided with a low-pressure CO_2 flooding system.

Fire protection and detection also include provisions of motor-operated dump valves on the reactor feedpump (RFP) turbine-oil reservoir and the emergency diesel generator (EDG) fuel-oil storage tank, fusible-link fire dampers in the supply and return air ducts of the ventilation systems of the reactor and service buildings, control center, and RHR complex, and ionization detectors and/or photoelectric detectors for the detection of combustion products and smoke. The turbine building is provided with 13 heat- and smoke-relief vents in the roof, which open either automatically on high temperature or high pressure in the building or manually from the main control room.

Portable fire extinguishers are deployed throughout the plant, and each unit is selected on the basis of the type of fire anticipated. NFPA Standard 10 was used as a guide for the selection, spacing, location, use, and maintenance of the portable extinguishers. Approximately 200 portable fire extinguishers are distributed throughout all the floors of the reactor, auxiliary, RHR, turbine, and radwaste buildings. These include multipurpose portable dry-chemical extinguishers for Class A, B, and C fires and portable CO_2 and Halon extinguishers. Where necessary, in support of the manual fire suppression systems, masks and portable breathing apparatus are provided for personnel protection.

Temperature, photoelectric, infrared, or ionization detectors are provided throughout the plant and are identified in Appendix 9A. In addition, the activation of any automatic fire-fighting equipment, component, or detector energizes visible and audible alarms in the main control room.

The type of fire-extinguishing equipment provided for each area is as follows:

Type	Area
Yard main and hydrants	Exterior of buildings, yard structures, and storage areas
Deluge and sprinkler systems	Parts of reactor, turbine, radwaste, and service buildings, transformer area, oil storage, reservoirs, diesel-fuel-oil storage tanks in RHR complex, ISFSI equipment storage building, warehouse, and FLEX Storage Facilities #1 and #2
Standpipe system and hose stations	On every floor inside all major plant buildings, except the office building annex (034)
Automatic CO_2 extinguishing systems	Diesel generator rooms, SGTS charcoal filters, cable tunnel (manual only), outside Division II switchgear room, and selected cable tray areas
Portable fire extinguishers	Throughout the plant, especially in critical control areas where general flooding could adversely affect safety-related equipment
Automatic Halon suppression systems	Relay room, cable spreading room, computer room and other selected minor areas
Automatic Clean Agent suppression system	Parts of radwaste building and the Security Diesel Generator enclosures

9.5.1.2.2 Control Room Protection Systems

A potential main control room fire would be extinguished by manual fire-fighting techniques. Portable CO_2 and Halon extinguishers are provided, and if needed, the normal standpipe and hose connections are located outside the main control room. Equipment in the main control room is noncombustible.

The main control room fire detection system covers the main control room, the areas above the false ceiling, inside the COP panels, and under the computer area floor. Main control room habitability in the event of smoke is maintained by the ventilation system as described below.

The exhaust from each zone listed in Subsection 9.4.1.2.1 is either partially recirculated or completely exhausted under normal operating conditions. All of the control center air conditioning system (CCACS) zones are equipped with ionization-type detectors or other approved types of detectors. These areas include the air conditioning system mechanical equipment room, computer/main control room, cable spreading room, and relay room. If smoke is detected by any of the early-warning ionization detectors, an indicating light on the area smoke, fire, and radiation protection panel in the main control room will illuminate, indicating the zone, and an audible alarm will be sounded in the main control room. The control center ventilation will automatically be placed in the smoke purge mode of operation upon confirmed actuation of the Halon system in the cable spreading room or relay room. The ventilation systems for the cable spreading room and relay room automatically isolate when the Halon system initiates in these areas. This prevents dilution of the Halon when the control center ventilation is placed in the purge mode of operation. The purge mode results in once-through ventilation system operation throughout the control center (approximately seven air changes per hour) with no recirculation. This operation clears smoke from the fire area and prevents smoke and Halon from being recirculated into the main control room. The smoke purge mode, however, is overridden by a LOCA signal which places the ventilation system into 100 percent recirculation.

Wherever the control center ventilation supply or return ducts penetrate a fire barrier wall, a 3-hr fire damper installation is provided or a specific fire hazards analysis evaluation has been performed and documented. These fire dampers automatically close either by spring action or by gravity when a fusible link melts on high temperature. In the cable spreading and relay room supply and return ducts, remotely resettable dampers are provided that automatically close when the gaseous system actuates. These dampers can be reset from the main control room. Position indication is provided on the remotely resettable dampers.

In the event of a fire outside the main control room but within the control room complex, the early-warning fire detection system will alert the operators to the problem. The fire detection system includes all areas of the control center. A ventilation equipment room fire will be extinguished by manual fire-fighting means. A relay or cable spreading room fire will be extinguished by manual means or by the automatic Halon suppression system.

A panel is installed outside the main control room that satisfies the requirements of 10 CFR 50, Appendix R, paragraph III.L for alternative or dedicated plant shutdown. The approach to the alternative shutdown design, the analysis, and method used are described further in Subsection 7.5.1.5.

Automatically initiated water systems are not employed on control center complex Class 1E electrical equipment because of the loss of reliability associated with the operation of fire protection equipment. The relay room, selected cable tray areas, and the EDGs are protected with automatic gaseous systems. Class 1E equipment located in other areas is protected by early-warning fire detectors. The above areas are identified in Appendix 9A.

9.5.1.2.3 Design Features

The design features of the Fermi 2 fire protection system equipment are described in the subsections that follow.

9.5.1.2.3.1 Electric Fire Pump

The electric fire pump has the following specifications: 2500 gpm at a discharge pressure of 150 psi, 1780 rpm, and 370-ft total developed head. The motor is 4000 V, 300 hp. The fire pump is UL listed equipment. The controller is not UL listed but does meet the general design and functional requirements of listed controllers. Status alarms indicating the availability of the electric fire pump are provided in the control room.

9.5.1.2.3.2 Diesel Fire Pump

The diesel fire pump has the following specifications, UL listed for 2500 gpm at a discharge pressure of 150 psi, 1775 rpm, and 370-ft total developed head. The engine is a diesel engine, UL listed for 340 hp, 2300 rpm, with a 275-gal fuel-oil tank for 8 continuous hr of operation. This pump and controller are UL listed equipment. Alarms are provided in the control room to indicate pump availability.

The electric fire pump was rebuilt and has replaced the original diesel fire pump. The diesel engine driver, when de-rated in accordance with NFPA 20, cannot develop the required horsepower to operate the diesel fire pump at rated speed to meet NFPA 20 requirements at the 100 percent and 150 percent flow points. The inability of the de-rated diesel driver and pump to meet the NFPA 20 flow and pressure requirements is an acceptable deviation because the diesel fire pump can provide the required flow and pressure demand for simultaneous operation of a suppression system and 500 gpm for hose streams.

9.5.1.2.3.3 Sprinkler Systems

The sprinkler systems are wet- or dry-pipe systems designed to provide a minimum water spray density per square foot of the most hydraulically remote area using NFPA Standard 13 and NEL-PIA requirements as guidelines. The sprinkler alarm check valves have been modified by adding a small bypass line to the trim of each valve to prevent any overpressure developing on the sprinkler system because of temperature changes or other reasons. This trim arrangement differs from the listed alarm check valve trim arrangements required by NFPA 13 but has no adverse effect on the functions of the Fermi sprinkler systems.

Other noncompliances with NFPA 13 have been evaluated in accordance with Generic Letter 86-10 as acceptable. These include the omission of return bend piping on pendent sprinklers, the omission of auxiliary drains on small trapped sections of sprinkler piping, the use of in-place welding to join and modify piping, and the lack of minimum required clearance distance for sprinklers below ceilings, ducts, or other items. The lack of return bends is acceptable based on the periodic change-out of the pendent sprinkler to prevent excessive accumulation of sediment in the sprinkler waterway. The other subject noncompliances are acceptable based on not adversely affecting the required function of the sprinkler systems and based on the administrative controls of the plant Fire Protection Program procedures.

The minimum water spray density used for each sprinkler system was determined by the occupancy classification defined in NFPA Standard 13 listed below:

Sprinkler System	Occupancy Classification
High pressure coolant injection (HPCI) room	Extra hazard, group #1
Reactor core isolation cooling (RCIC) room	Ordinary hazard, group #3
Motor-generator (M-G) set and oil cooler area	Extra hazard, group #1
Torus room	Ordinary hazard, group #3
Equipment unloading area	Ordinary hazard, group #3
2nd floor reactor building area	Ordinary hazard, group #3
Auxiliary building basement area	Ordinary hazard, group #3
Auxiliary building 1st floor mezzanine	Extra hazard, group #1
Cable spreading room (Elevation 630 ft)	Extra hazard, group #1
EDG fuel tank rooms	Extra hazard, group #1
Diesel fire pump room	Ordinary hazard, group #3

The sprinkler heads used in these systems are all fusible-link closed heads.

9.5.1.2.3.4 Deluge Systems

The deluge systems are open directional spray nozzle systems designed to provide density in accordance with NFPA Standard 15 and NEL-PIA requirements.

Deluge valves are solenoid valve operated, controlled automatically by the fire protection system or controlled manually from the main control room.

9.5.1.2.3.5 Gaseous Suppression Systems

A 6-ton low pressure CO_2 storage unit is provided for two EDGs in the same division. A total of two units each serving two EDGs is located in the RHR complex. The CO_2 system for the SGTS provides internal protection for the charcoal beds. Each SGTS division has an independent 1.25-ton CO_2 system. CO_2 systems are provided to protect certain areas of the reactor/auxiliary building, as listed in Table 9.5-1. A low pressure CO_2 storage unit is located outside the reactor building. A distribution system will select the proper zone where the fire is detected. Halon and Clean Agent suppression systems are provided in areas identified in Table 9.5-1.

9.5.1.2.3.5.1 General Design Information for the RHR Complex and Reactor/Auxiliary Building CO_2 Systems

The CO_2 system instrumentation and control equipment detects fires, initiates and terminates fire suppression discharges, and monitors system performance. Detection of fires is accomplished by heat and/or smoke detectors. Detection devices activate alarms to indicate the presence of a fire and activate control equipment to initiate discharge of fire-extinguishing agents. Discharge is delayed for sufficient time to enable personnel to leave the area. Activation of fire suppression equipment is accomplished either manually at local panels or automatically by fire detection devices. The control instrumentation directs the discharge into the selected area and closes ventilation dampers to isolate the fire and contain the discharge. Alarms indicate the operation of the systems.

Controls automatically terminate the discharge after a predetermined time. Instrumentation monitors the system operation and alarms under abnormal conditions. The CO_2 system controls provide for proper operation of the storage tank refrigeration unit.

Wall and floor penetrations for the areas protected by the CO_2 system are sealed to contain the CO_2 discharge. Any CO_2 leakage that may occur after the area is isolated is included in the extended discharge application rate. Further, upon completion of the system, a concentration test was conducted to confirm the design parameters.

Entrance to an area after a CO_2 discharge can be gained by resetting the ventilation dampers to the open position and initiating the exhaust function. To further aid in purging, portable smoke fans can be used as needed. Self-contained breathing apparatus is available and can be used to gain access for manual fire fighting or cleanup.

9.5.1.2.3.5.2 Design Guidance for Reactor/Auxiliary Building CO_2 Systems

a. The CO_2 storage capacity is sufficient to provide two-shot (100-percent redundancy) protection for the hazard area requiring the greatest quantity of CO_2, based on a design concentration of 50 percent. The quantity of CO_2 includes a 50 percent margin for leakage during an extended discharge. This allowance is based on all accesses and ventilation ducts being closed

b. The distribution system pipe sizing and arrangement are based on providing and maintaining an extinguishing concentration of CO_2 in the hazard area for 20 minutes. This is accomplished by applying an initial discharge at a sufficiently high rate to achieve a 30 percent concentration in 2 minutes or less, and the design 50 percent concentration in 7 minutes or less, in conjunction with an extended discharge at a lower rate sufficient to maintain the 30 percent concentration for 20 minutes

c. The design CO_2 concentration is 50 percent for each protected area. Flooding factors are based on the guidelines of NFPA Standard 12 for total flooding systems, assuming dry electrical wiring hazards in general cable areas

d. The storage tank refrigeration unit is sized to maintain the storage tank at 0°F and 300 psig, assuming the highest expected ambient temperature of 105°F. Power is provided as described in item e below

e. Fire detection devices, actuating instrumentation, and control equipment are powered from the 120-V restored ac bus. In addition, the fire detection system for CO_2 actuation is provided with a 4-hr, 24-V dc battery system.

9.5.1.2.3.5.3 Design Guidance for Diesel Generator CO_2 Systems

a. Each division contains two EDGs. The 6-ton storage tank for each division will provide one complete shot to both EDGs or double shot protection for one EDG

b. The design CO_2 concentration is 50 percent for each protected area. Based on guidelines of NFPA 12, the minimum design concentration for diesel fuel is 34 percent

c. Detection devices consist of thermal detectors

d. Fire detection and CO_2 controls are normally powered from the balance-of-plant 130-V dc system. Emergency power for the fire detection and CO_2 controls are powered from a 120-V manual restored ac bus. The power is then rectified to 130-V dc. Power for the refrigeration units and room warning lamps are powered from a 120-V manual restored ac bus

e. The system is designed to maintain the room concentrations for 20 minutes.

9.5.1.2.3.5.4 Design Guidance for the Standby Gas Treatment System CO_2 System

a. When the SGTS charcoal bed temperature reaches 250°F, an alarm sounds, which alerts the control room operator to an overtemperature condition well before there is danger of ignition. If the beds continue to heat up and reach 310°F, the low pressure CO_2 Suppression System will be automatically initiated and 250 lb of CO_2 are injected in the bed over a 10-minute period. This actuation of the CO_2 system is indicated on the fire protection mimic panel and an alarm on the control panel. Based on the alarm response procedure, the SGTS exhaust and cooling fans will be manually shut off if they are running.

   This cycle is repeated as long as the temperature exceeds 310°F. Each of the divisional CO_2 storage tanks holds enough CO_2 for 10 injections

b. Detection devices consist of a continuous thermal fire detection system

c. The detection devices and CO_2 controls are powered from the 120-V restored ac bus.

9.5.1.2.3.5.5 Design Guidance for Halon Systems

a. The Halon storage capacity consists of a main bank and a reserve bank for each system. Each bank will provide sufficient capacity for a complete shot

b. The systems are designed to provide a minimum 5 percent concentration for a 10-minute holding period

c. Emergency power for the fire detection and halon control systems is powered from a 120-V restored ac bus.

9.5.1.2.3.6 Design Guidance for Clean Agent Systems

a. The Clean Agent storage capacity consists of two storage cylinders, a primary and a reserve, for each system. Each will provide sufficient capacity to provide protection for the potential hazard based on concentration, volume of area, and known leakage pathways out of the designated area.

b. The systems are designed for a discharge time to provide a 95 percent minimum design concentration for flame extinguishment based on a 20 percent safety factor and will not exceed 10 seconds.

c. Power for the fire detection and Clean Agent control systems is provided by a separate dedicated 120V, 1 phase 60Hz source that will not be shutdown on system operation.

Use of this system is limited to the Security Diesel Generator enclosures and areas in the Radwaste Building which do not include any systems or circuits credited for reactor shutdown in the event of a fire (i.e. – activation of the Clean Agent fire suppression system will not adversely affect the plant's ability to achieve and maintain shutdown in the event of a fire).

9.5.1.2.3.7 Turbine Room Roof Vents

Thirteen roof vents in the turbine room are opened automatically at 20-psf differential pressure, or at 160°F by fusible link, or manually from the main control room, or locally by pull rings.

9.5.1.2.3.8 Dampers

Fire dampers located in the ventilation ductwork are curtain type with fusible links. Dampers are either spring loaded or rely on gravity to close. The fire damper will close only when high temperature melts the fusible link. Resettable smoke/halon and smoke/CO_2 dampers provided with the gaseous systems have the damper position monitored in the main control room.

9.5.1.2.3.9 Instrumentation

a. Flow Switches

Flow switches are provided in various locations of the fire protection system to detect water flow

b. Thermal Detectors

Thermal detectors are provided as part of the equipment package for the deluge systems, the EDG CO_2 systems, and the Security Diesel Generator enclosures.

c. Ionization Detectors

Ionization detectors are provided in areas requiring early-warning detection. Additionally, a separate ionization detection system was installed to actuate the gaseous systems (except for the CO_2 systems in the EDG rooms in the RHR building, where thermal detectors are used as noted above and the under-floor detectors in the main control room computer room where photoelectric detectors are used along with ionization detectors above the floor).

d. Photoelectric Detectors

Photoelectric detectors are used in areas requiring early-warning detection. These are usually used in place of ionization detectors in areas with difficult access. Photoelectric detectors are used under the floor, to actuate the halon system, in the main control room, computer room.

e. Infrared Detectors

Infrared detectors are utilized on the fifth floor of the reactor building and in the Security Diesel Generator enclosures.

f. Instrumentation and Control

Instrumentation and control of the fire protection systems is fed from various power sources identified in Sections 9.5.1.2.3.5 and 9.5.1.2.3.9. The sprinklers operate independently of ac or dc power. The deluge valves are controlled and fed from the dc power system. The standpipe system, which also supplies the sprinkler and deluge systems, is pressurized in a ready-for- service condition without need for valve operation. The GSW pumps and the electric fire pump operate from the ac system service and are not connected to the onsite power source. On loss of offsite power, the diesel fire pump starts and operates from its own 24-V battery and charger system

g. Fire Detector Location

The types and locations of fire detectors are provided in Appendix 9A.

9.5.1.2.3.10 Fire Detection Circuits

The Fermi 2 early warning only fire detection high-voltage system is a Class B system as defined in NFPA Standard 72D, employing a configuration of two independent detector circuits designated Group A and Group B. Because of the 220-V dc operating voltage, the fire detection circuits are not Class I per NFPA Standard 70. It is not a requirement of Appendix A to BTP APCSB 9.5-1 for the detection circuits to meet NFPA Standard 70, Class I. The Fermi 2 design does meet the Class 3 requirements of this code. However, the danger of a fault-initiated fire is minimized because the current is low (milliamperes) and the power is only about 200 W at each detection panel. Also, the fire detection circuits are routed in non-safety-related trays and are contained in conduits outside the trays.

In the redundant safety division areas, the early warning only fire detection circuits employ a two-circuit configuration of detectors designated Group A and Group B. Each detector group has approximately half the detectors of a given detection area. The two groups of detectors are installed in an interspersed configuration covering the protected region. The detector density in each detection area is such that floor area per detector is within the current NFPA recommendation.

In non-safety-related areas, the early warning only detector circuits are of a single group energized from either of the two main panels. The single group detector circuits are about evenly divided between the two panels to achieve a balanced arrangement. The service building complex has a separate fire detection panel.

The two early warning only fire detector groups are powered from separate non-Class 1E motor control centers (MCCs). Each MCC is fed from opposite divisional Class 1E switchgear. Normal offsite power provides the primary supply for the detectors. Upon loss of offsite power, the detectors are automatically connected to the onsite EDG. This design meets the requirements of Appendix A of BTP APCSB 9.5-1.

The reactor/auxiliary building gaseous suppression systems use a low-voltage smoke detection system. The design is a Class A cross-zoned detection system with a detector required from each zone to actuate the gaseous systems. Power is supplied from a 120-V ac restored bus. Additionally, a 4-hr, 24-V dc battery package provides secondary (backup) power.

For the Security Diesel Generator enclosures, a cross-zoned fire detection system uses both infrared and heat detectors. Should the second heat detector alarm, then the clean agent solenoid activates and, after the thirty second timer expires, the clean agent is released.

All fire detector circuits, flow switch circuits, and alarm bell circuits are electrically supervised in accordance with requirements of the NFPA.

Sensitivity of the ionization smoke detectors is adjustable. Final sensitivity settings are determined after a period of fire detection system operation. The sensitivity used is the highest that is practical and consistent with minimization of false alarms.

In the main control room, annunciator windows are provided for fire alarm (detector actuation or flow switch actuation) and fault in the fire detection/protection circuits. A fault annunciation would occur upon a detector circuit or bell circuit open, ground, or short; detector out of socket (open circuit); power loss; or outside screw and yoke water valve not full open. Other fault conditions, such as low CO_2 pressure, also are covered by an alarm.

On the main control room panel, a display is provided to indicate fire detection zone number in the alarm state, CO_2 release, outside screw and yoke valve closed, power status at panels, and smoke/CO_2 shutoff damper open/closed.

The fire annunciator system, a fire protection system mimic, is combined with the area radiation mimic. The mimic shows the building outlines, with orientation in respect to one another as accurately as possible, within which are color-coded alarm lights for fire, high temperature, smoke, and radiation.

A fire alarm will sound when flow switches indicate flow in the fire protection ring header, or flow in a deluge or sprinkler system, or flow from the electric or diesel fire pump. The alarm will designate the area on the mimic panel. An area indication on the mimic will alarm when any of the outside screw and yoke valves are closed or any deluge valve is opened. The panel will indicate the general area in which a fire detector is indicating the presence of smoke or fire. In the plant, a local panel for each area will display detailed information for each detector. Startup of either the electric or diesel fire pump will be alarmed.

The following remote manual control functions can be performed in the main control room: the deluge valves can be manually initiated by pushbutton. The smoke roof vents in the turbine house can be manually opened, and the smoke dampers can be manually closed. The electric and diesel fire pumps can be manually started from the main control room. The motor-operated dump valves on the EDG fuel-oil storage tank, on the main turbine-oil reservoir, and on the reactor feed pump oil reservoir can be operated from the main control room.

The system diagram of the fire protection system is given in Figure 9.5-1. Table 9.5-1 provides a list of the equipment and devices that make up the fire protection system.

9.5.1.2.3.11 Fire Barriers

The fire hazards analysis has identified the fire barriers and determined the barrier requirements for the floors, walls, and ceilings enclosing separate fire areas and for the doors and other penetrations through these barriers. (See Appendix 9A.) See Subsection 8.3.1.4.2.2 for a discussion of cable tray fire barriers at floor and wall penetrations.

9.5.1.2.3.12 Fire Emergency Lighting and Communications

Fixed emergency lighting with 8-hr battery power supplies is provided in the main control room, in all plant areas where operator action, for safe shutdown in the event of fire, is required within 8 hrs and along access and egress routes for these areas. Emergency communications capability is provided by telephones, public address systems, and radio communications equipment powered from redundant power sources. Repeater stations are installed to improve the quality of radio communication. Loss of a particular repeater will not result in a loss of communication capability in the area adjacent to the repeater.

9.5.1.2.4 Atmosphere Control

To aid in smoke removal, the reactor/auxiliary building ventilation system will continue to operate in the event of a fire in the reactor/auxiliary building except when a loss of offsite power results in initiation of the standby gas treatment system and automatic isolation of RBHVAC. The airflow will generally follow a path from areas of low potential radioactivity to areas of progressively higher potential radioactivity before finally being exhausted to the atmosphere at the roof of the reactor/auxiliary building. Fire dampers are provided where all ventilation ducts penetrate fire barrier walls.

The control center in the auxiliary building is equipped with its own air conditioning system and is not connected with the reactor/auxiliary building ventilation system during emergency mode operation of the CCACS as described in Section 6.4.4.2. Smoke, combustible and explosive gases, and airborne toxic contaminants in the reactor/auxiliary building atmosphere will not enter the control center because the CCACS maintains the atmosphere at a slight positive pressure with respect to the reactor/auxiliary building atmosphere.

The air conditioning zones within the control center can be individually isolated by smoke dampers that are operated from the control room. The detection system and smoke removal process are described in Subsection 9.5.1.2.2. Habitability of the main control room after a chlorine-release accident is discussed in Appendix A, Regulatory Guides 1.78 and 1.95.

Because of the combustible liquids stored in the diesel-oil storage room and the diesel generator room of the RHR complex, a purge ventilation fan will operate continuously (except during an actual fire). The diesel generator room, the CO_2 storage room, diesel-oil storage room, and diesel generator ventilation equipment room will be continuously purged with a 2500-cfm exhaust fan. Each EDG and diesel-oil storage room has a separate exhaust purge fan. Loss of airflow in the purge system is alarmed in the main control room. The exhaust fan will be automatically stopped if a signal is received from the automatic fire protection systems.

The RHR complex is divided into various fire zones, as indicated in Appendix 9A. The ventilation systems for the diesel generator switchgear zone and the EDG zone (two per division) and the pump room zone are entirely separate. Isolation of any of these zones will not affect the ventilation systems in other zones.

The CO_2 system for each EDG requires automatic shutdown of the ventilation system to be effective. The design of the system will allow operation of the remaining EDG in the division as well as the other unaffected division. Other zoned dampers are motor operated and controlled by startup or shutdown of the ventilation fans in the main control room. The ventilation fans for all zones can be manually shut down for fire containment or manually started or left running for smoke purge purposes. The 3-hr-rated fire dampers at ventilation duct penetrations of fire barriers will close only when high temperature melts the fusible link.

9.5.1.2.5 Electrical Cable Fire Protection

The electrical cables are fabricated with fire-retardant insulating and jacketing material. NEL-PIA has approved this design. Fire stops are included in all wall and floor tray penetrations, and fire barriers are installed in areas where a fire could propagate from one area or tray system to another. Details of the fire-resistant wall penetrations are found in Subsection 8.3.1.4.2.2.

Redundant engineered safety feature (ESF) equipment is fed by redundant essential electrical circuits. Physical separation is provided between electrical divisions to prevent loss of more than one division from a fire. As part of the fire hazards analysis, areas were identified that have more than one division in the same fire zone. In these areas, a fire barrier and/or a suppression system was added. The fire hazards analysis shows that any postulated fire will not prevent the ability to initiate or maintain shutdown of the reactor.

Fire protection instrumentation and control circuits are classified as non-safety-related and are not redundant. These cables could be lost and not cause loss of the portable fire extinguishers or loss of the standpipe automatic or manual systems. The electric fire pump and diesel fire pump with its own starting battery are normally on standby since the fire mains are supplied with makeup water and pressurization from the FPS jockey pump which takes suction from the GSW pump header.

These numerous sources of water to the fire protection water header ensure a source of water for extinguishing fires. No motor-operated valves are required to operate. The hose connections and valves are operated manually. Loss of fire protection instrumentation to the main control room would not prevent extinguishing a fire.

9.5.1.3 System Evaluation

9.5.1.3.1 Introduction

A fire hazards analysis of the Fermi 2 fire protection provisions was originally conducted in accordance with BTP APCSB 9.5-1 based on the Fermi 2 design as of April 1977. A point-by-point comparison was made with Appendix A to BTP APCSB 9.5-1. Subsequent minor revisions have been made to keep the analysis current. The results of these fire protection evaluations of Fermi 2 are included in Appendix 9A. Fermi 2 is in compliance with the guidance of Appendix R to 10 CFR 50, Sections III.G, III.J, and III.O. The deviations of Fermi 2 from Appendix R are addressed in Appendix 9A. These deviations provide an equivalent level of protection to the technical requirements of Section III.G of Appendix R.

The possibility of fire is minimized by the use of noncombustible materials in the construction of the plant. The spread of fire from one area to adjacent areas is prevented by high-integrity concrete enclosures and by fire-rated barrier walls where necessary.

The plant design is reviewed by NEL-PIA for potential fire hazards, and recommendations made by NEL-PIA on flame-retardant materials for structures, insulation, and electrical and mechanical equipment have been used.

The fire protection water system is not considered essential to the safe shutdown of the reactor. It is not designed to Category I requirements. The failure of the system piping or the inadvertent operation of the system does not affect the operation of the safety-related systems, as adequate drainage is provided in all buildings to prevent flooding and as all safety-related systems are designed to be protected from water spray and jet forces from the piping in the area. Flow switches provided throughout the system indicate system operation in the main control room. The layout and valving arrangement of the underground water system permit isolation of any defective section, without interruption of service to other parts of the plant. The inadvertent operation of the CO_2 systems does not affect the operation of safety-related equipment in the area. Smoke dampers in areas with gaseous fire suppression systems are remotely resettable from the main control room so that inadvertent actuation does not cause loss of ventilation to these areas.

The fire hydrants are installed at various yard locations such that the maximum distance between adjacent hydrants is not more than 300 ft, and, if possible, are within 40 ft of the plant buildings. Adequate pressure in the system lines will be available at the uppermost floors of all the buildings. Early-warning detection alarm instrumentation, smoke damper closure, CO_2 and Halon systems actuation alarms, and indication in the main control room of water fire protection system actuation provide reliable identification of the location of any fire so that corrective measures can be instituted with minimum delay. Temperature-operated (fusible-link) fire dampers in the ventilation ducts help contain the fire in the affected area. Audible fire alarms in the areas protected with CO_2 systems warn personnel of the impending actuation of the CO_2 system.

Table 9.5-2 provides a failure mode and effects analysis to demonstrate that operation of the fire protection system in areas containing safety-related equipment does not produce an unsafe condition or preclude a safe shutdown.

9.5.1.3.2 Failure of Nonseismic Fire Protection Systems

For safety-related buildings, the fire protection systems are seismic Category II/I. Therefore, the fire protection system piping will not fall and damage Category I equipment. The overall design of the fire protection system, because it is not a safety-related system, has not included design features to withstand the effects of single failures, except that the underground supply piping and fire pumps will allow for a single break or pump failure.

9.5.1.3.2.1 RHR Complex CO_2 System Failure

The CO_2 system is designed to discharge approximately 5000 lb of CO_2 into one diesel generator room. This quantity of CO_2 will flood the room and extinguish the fire by cutting off the supply of oxygen. If the CO_2 system inadvertently discharges into the diesel room, it will cause cooling that will lower the room temperature and the equipment temperature. The operating heat loads in the EDG room are less than 1,840,000 Btu/hr. The CO_2 discharge can provide approximately 20 minutes of cooling for this heat load. It is estimated that the CO_2 would not reduce the room temperature more than 100°F and at most would reduce the diesel engine generator temperature 40°F.

The inadvertent operation of the CO_2 system will not affect the operation of the EDG, since separate combustion air is provided for the engine by direct connection to the outside. Also, the CO_2 discharge horns are not directed toward any of the equipment. The horns are designed so that there is not a concentrated blast, but a diffuse stream of CO_2 vapor and solid particles. The cold gas will warm up and the solid particles will vaporize before coming into contact with the equipment. The quantity of cooling provided by the CO_2 system and the fact that it does not directly impact on the equipment will eliminate the possibility of thermal shock and will not cause a significant drop in equipment temperatures.

The rupture of a CO_2 storage tank will not cause damage to any safety-related equipment. Each CO_2 storage tank is located in its own room, and no safety-related equipment is located in that room. A rupture of the tank would confine the CO_2 to that room except for a possible small leakage under the doors. The CO_2 would extinguish any fire within that room. Leakage under the doors into the diesel generator room would not affect the operation of the diesels because they are designed to operate in a CO_2 environment.

9.5.1.3.2.2 Failure of Water Fire Protection Systems

The analysis of water fire protection line failures and the subsequent effect of water on safety-related equipment is presented in Subsection 3.6.2.3, which includes an analysis of the failure of all moderate-energy fluid systems throughout the plant, including the RHR complex.

To avoid freezing of the RHR fire protection water supply mains, a continuous flow of approximately 0.1 gpm is maintained during the winter.

9.5.1.3.2.3 Failure of Other Gaseous Systems

The gaseous systems provided other than in the control center will not cause loss of function of Class 1E equipment since the equipment can operate in a gaseous environment. The gaseous systems in the control center will also not affect Class 1E equipment. Failure (closure) of the smoke/Halon dampers for the relay room, cable spreading room or computer room will cause loss of cooling to their respective rooms. Manual actions are required to reopen these dampers to reestablish airflow. As described in Subsection 9.5.1.2.2, the smoke purge mode of the control center ventilation prevents concentration of Halon in areas outside the Halon suppression zone. The CO_2 storage tank for CO_2 systems inside the auxiliary building is located outside the plant.

9.5.1.3.3 Removal of Fire-Fighting Water

Floor drains are designed to remove the expected fire-fighting water flow from areas where fixed water fire suppression systems are installed or where fire hoses may be used. Equipment is installed on pedestals to protect it from water. Water drainage from areas which may contain radioactivity is collected in the floor drain collection tank for normal liquid radioactive waste.

9.5.1.4 Inspection and Testing Requirements

Preoperational testing of the fire pumps, hydrants, sprinklers, deluge systems, gaseous systems, standpipe, and hose systems was performed in accordance with the applicable NFPA codes. In addition, the instrumentation and control for the automatic starting of the fire pumps, flow detection and alarm, and SGTS thermal detection systems was tested for operability and limits.

Inspection, testing, and maintenance of all equipment of the fire protection system use the applicable NFPA codes as guidelines.

9.5.1.5 Personnel Qualification and Training

The fire-fighting training program, testing, and inspection are discussed in Subsection 13.2.4.

9.5.2 Communications Systems

9.5.2.1 Design Bases

A comprehensive communications system is provided to ensure reliable intraplant communications, offsite commercial telephone service, and offsite emergency communications capabilities. Effective communication between personnel during startup, operation, shutdown, refueling, and maintenance is made possible by the use of an adequate number of telephones, public address speakers, and two-way radios.

The public address speaker system and the two-way radio repeaters are powered from emergency power bus 72B. The other diverse means of communications are physically independent to preclude the loss of all systems as a result of a single failure.

An emergency alarm system is installed that provides an alarm signal to ensure personnel evacuation.

9.5.2.2 System Description

9.5.2.2.1 Two-Way Radio

Two separate communication channels of unique wave lengths for operations personnel and for maintenance personnel are provided to enable two-way radio communication between the main control room and the various plant buildings. The main control room is equipped with handheld microphones on each panel section and at the operations desk console. Portable transmitter-receivers of the hearing-protector headset and boom-mike type, operating on either or both channels, are provided for use by the operations and maintenance personnel for communication between various areas of the plant.

To improve reception from the various plant buildings, monitor receivers are provided in these buildings. The radio transmitter carrier frequencies are chosen so that no interference with the reactor building or turbine building radio-controlled crane is possible.

9.5.2.2.2 Hi-Com (Public Address) System

The Hi-Com system provides two separate and independent channels of communication, namely page and party lines. The Hi-Com loud-speakers are powered by individual amplifiers, and the system is supplied from the ac emergency system, which is powered by the EDG upon loss of normal offsite power.

The system layout permits communication between the main control room and site buildings and areas of the plant. The volume level of each Hi-Com channel is adjusted to be louder than the ambient background noise level. For high-noise areas where ear protection is required, or site emergency evacuation notification is not broadcasted, special arrangements for evacuation notification have been provided as described in Subsection 9.5.2.2.4.

The handsets permit channel switchover from paging to party line conversations between any two or more handset stations.

9.5.2.2.3 Telephone System

An independent dial telephone system is provided to facilitate simultaneous conversations between extensions which are located throughout the plant and Detroit Edison network. The main control room is provided with telephones, some of which have access to the Edison network via microwave and also have access to the local telephone company exchange via land line. Incoming calls are received automatically from either network. Microwave provides backup offsite communication in the event of loss of land line resulting from environmental conditions. A telephone is installed in each elevator.

9.5.2.2.4 Emergency Alarm System

The emergency alarm system is designed to broadcast distinct signals using the plant Hi-Com system to the plant. This alarm system is activated from the control room, and different tones have been provided. Activation of the emergency alarm system automatically adjusts the output volume level of each Hi-Com station to a preferred level of 10 dB above the calculated background noise. If the preferred level of 10 dB (above background noise) cannot be obtained, a speaker output of not less than 7 dB above the calculated background noise is acceptable. In Hi-Com broadcast areas where the 7 dB differential could not be obtained or the background noise exceeds 95 dB, visual beacons are provided for emergency notification. For high-noise areas where ear protection is required or site emergency evacuation notification is not broadcasted, special arrangements for evacuation notification are provided by damage and rescue team searches. If a plant area evacuation is required, the Emergency Director (Shift Manager - short term or Executive Director - Nuclear Production - long term) will dispatch the damage and rescue team after Security receives notification of missing personnel.

9.5.2.3 Inspection and Testing Requirements

All communication systems were inspected and tested at the completion of installation to ensure their operability. Most of the systems, except for the emergency alarm system, are used daily and hence do not need any special testing. Testing of the emergency alarm system is carried out on a routine basis.

9.5.3 Lighting Systems

9.5.3.1 Design Bases

The lighting system is designed to provide indoor and outdoor illumination during normal plant operation and during shutdown. During failure of offsite power sources, the system provides alternative emergency lighting to critical facilities.

9.5.3.2 System Description

The lighting system is composed of the normal facilities, the emergency facilities, and the special lighting for the main control room.

The normal area lighting system consists of fixtures and facilities placed in areas of the plant to meet the target light intensities identified by the Illuminating Engineering Society (IES) for nuclear power plants and industrial facilities. Light-Emitting Diode (LED) lighting is used in general areas, office areas, entry points and stairwells. Where LED lighting is not used, high intensity discharge (HID) lighting is typically used for general areas and fluorescent lighting is typically used for office areas, entry points and stairwells. Provisions for containment of mercury containing elements are made where breakage of the bulbs could potentially result in direct mercury intrusion into the reactor coolant.

Normal lighting for the plant buildings is supplied by a grounded 480/277-V and 208/120-V, three-phase, four-wire distribution system from the distribution receptacle panels located in the reactor, auxiliary, and radwaste buildings. These panels receive power from the 480-208/120-V lighting transformers that are powered by 480-V switchgears in the master distribution panels.

Lights that utilize the 480/277-V system are directly supplied from the master distribution panels. The receptacle panels are conveniently located throughout the plant to permit efficient distribution of the lighting load.

One-third of the lights in vital operating areas such as the main control room, RHR complex, reactor building, safety-related equipment areas and access routes, stairwells, and exits are powered by the ESF 480-V buses so that an offsite power failure does not produce a total blackout in these areas. In addition, emergency lighting units consisting of battery-operated sealed-beam units capable of 8 hr of continuous operation are provided in these critical areas of the plant where operator action is required within 8 hrs for safe shutdown in the event of a fire. Emergency lighting for Station Blackout (SBO) is provided by these 8-hr Appendix R Fire Protection units where they exist, or by 4-hr emergency battery lights where Appendix R lighting units are not required. These are activated automatically on loss of normal power. Adequate redundancy is provided in the emergency lighting equipment.

9.5.3.3 Safety Evaluation

Provision of normal power supply, diesel generator power, and individual batteries to the lighting system, together with physical separation and redundancy in the system, ensures dependable lighting to all critical areas at all times.

9.5.3.4 Inspection and Testing Requirements

Periodic inspection of the lighting system, including batteries and simulation tests to monitor operation for the automatic actuation of the emergency lighting, is performed to ensure a reliable lighting system.

9.5.4 Diesel Generator Fuel-Oil Storage and Transfer System

9.5.4.1 Design Bases

The diesel generator fuel-oil storage and transfer system is designed to perform its operational function automatically during emergency conditions. Each diesel generator is furnished with an individual fuel-oil storage tank.

The onsite storage capacity of each of the fuel-oil storage tanks is determined on the basis of continuous operation of the diesel generators for 7 days at continuous load. In addition, the storage capacity includes requirements for testing of the diesel generators. Full day tanks provide more than 2 hr of fuel supply to each diesel generator.

The system complies with Appendix B of ANSI Standard N195-1976, "Fuel Oil Systems for Standby Diesel Generators" and is designed to Category I requirements. The system piping and as much equipment as practicable are designed to either ASME B&PV Code Section III, Class 3 or the Diesel Engine Manufacturers Association (DEMA) standards as shown in Figures 9.5-4, 9.5-5, and 9.5-6. The diesel generator fuel-oil storage and transfer system for each diesel generator is separate and is located in separate compartments. The system is housed in the RHR complex, and, as such, is protected from flooding, tornado winds, and missiles. Adequate fire protection is provided and fire walls separate each compartment containing the individual diesel generator and its associated systems.

The ventilation system for the diesel generator room and CO_2 storage tank room is designed to maintain room temperatures between 65°F and 104°F when the diesel is not operating. The ventilation system for the fuel oil storage room is designed to maintain room temperatures between greater than 32°F and 104°F when the diesel is not operating. When the diesel is operating, the ventilation system is designed to maintain the temperature in the fuel oil storage tank room and the CO_2 storage tank room below 125°F. A separate ventilation system maintains the diesel generator room below 122°F when the diesel is running.

Provisions are made for independently testing redundant components.

9.5.4.2 System Description

Four 2850-kW diesel-engine-driven generators power the ESF buses and are located in the RHR complex. The fuel-oil storage and transfer system is shown in Figures 9.5-4, 9.5-5, and 9.5-6. Power to all of the auxiliaries for each diesel generator is fed from the respective diesel generator.

Each diesel generator set is supplied by a 42,000-gal diesel-fuel storage tank located adjacent to the associated diesel generator. The capacity of the storage tank is based on 7 days fuel supply at 210 gal/hr, plus fuel requirements for routine engine testing. The fuel-oil day tanks are of 550-gal capacity. Two redundant motor-driven fuel-oil transfer pumps deliver fuel to the day tank. Fuel flows by gravity from the day tank to the suction of the engine-driven fuel pump.

The engine driven pump is safety related and required to operate in order to mitigate a design basis accident. An electric motor driven fuel pump is also provided to purge air from the fuel line following maintenance on the fuel oil system. The electric motor driven fuel pump will receive a start signal if a low pressure condition exists on the supply side of the duplex filter. Although the electric motor driven pump is not credited to operate during a design basis accident, it is considered to be a passive safety-related pump. Both pumps supply fuel to the engine fuel injectors.

One transfer pump is started automatically when the diesel generator starts and the day tank overflow is routed to the fuel-oil storage tank. The other transfer pump is started automatically by a low-level switch on the fuel-oil day tank.

The fuel oil storage tanks are filled from tanker trucks through yard couplings and are vented above grade. Each storage tank is fitted with level sight glasses and high- and low-level alarms. Each day tank is fitted with a level sight glass and low-level alarm. Redundant motor-operated and manual valves for draining of the storage tank are provided.

Fuel quality in the storage tanks is ensured by using two strainers between the storage tank and the fill line connection and by performing delivery and periodic sampling for water and sediment. Each of the four EDGs has redundant fuel transfer pumps and separate fill lines to each day tank from each storage tank. Each transfer pump is fitted with a strainer. In addition, between the day tank and the EDG skid there is a strainer for the engine-driven fuel-oil pump line and a duplex filter before the fuel injectors.

The day tank is kept full, and, as required, one of the transfer pumps automatically operates (with the other pump in standby) to maintain the tank level. If sediment plugs the running pump's strainer and the day tank level drops, the alternate transfer pump will automatically start and the low level alarm will sound if the level continues to drop. The plugged strainer can be cleaned by blowing down within the time interval established by the fuel inventory remaining when the low level alarm sounds. Also, the strainers at the fuel transfer pumps and between the day tank and the EDG have pressure differential indicators that are to be monitored during monthly testing.

9.5.4.3 Safety Evaluation

The diesel generator fuel-oil storage and transfer system is designed to Category I requirements and also to withstand any single failure and still satisfy the design requirements. Although any single failure may result in loss of fuel to one diesel generator, the plant demand is met by the remaining three diesel generators. There are no common components of the fuel-oil system between any EDGs. The diesel generator and its associated fuel-oil storage tank, fuel-oil day tank, transfer pumps, and piping are physically separated and adequately protected against tornado missiles, flooding, and fire. The EDG fuel-oil storage tank room is designed to contain the entire volume of oil and the floor drains are sized to handle the fuel oil and sprinkler volumes. Refer to Subsection 9.3.3 for details.

Independent thermal detectors for fire detection are provided in each diesel generator compartment. Automatic fire-fighting systems such as carbon dioxide and wet-pipe sprinkler systems are also provided. In the event of a fire, fuel oil from the storage tank can be dumped to a basin in the yard by opening the dump valves from the main control room. See Subsections 9.5.1.2.3.3 and 9.5.1.2.3.5 and Appendix 9A.

No shortage of fuel supply can be reasonably anticipated, because low-level alarms are periodically inspected and an ample fuel supply is ensured, both by redundant equipment and by conservatively sized reserves. Arrangements are made for the procurement of additional supplies of oil when needed.

The diesel-fuel-oil storage tanks are fabricated from ASME-SA285, Grade C carbon steel. The piping and tanks are inside the RHR complex, and hence no corrosion problems are anticipated during the life of the plant.

9.5.4.4 Inspection and Testing Requirements

All components of the diesel-generator fuel-oil storage and transfer system are tested after installation in accordance with the applicable codes. The Preoperational Test program verifies system performance including indicating instrumentation and alarm signals. Operation of the fuel-oil system is tested by periodic operation of each generator under load.

9.5.4.5 Instrumentation Application

Each diesel-fuel-oil storage tank and fuel-oil day tank is provided with local level sight glasses. High- and low-level alarms for the storage tank and low-level alarm for the day tank are provided. Fuel transfer pump motors are provided with automatic starting circuits and standard Institute of Electrical and Electronics Engineers protection.

Remote operation of each transfer system is possible from the main control room.

9.5.5 Diesel Generator Cooling Water System

9.5.5.1 Design Basis

The diesel generator cooling water system is designed to provide adequate cooling water to remove the heat given off by the lube-oil coolers, inlet air coolers, and the engine jacket coolant heat exchangers. The engine jacket coolant system, which is a closed loop system, removes heat from the engine and transfers it to the diesel generator service water system. The diesel generator service water system is part of the RHR service water (RHRSW) system described in Subsection 9.2.5.

The jacket coolant system is designed to Category I requirements and the system piping, valves, and heat exchangers meet either the requirements of the ASME B&PV Code Section III, Class 3, the DEMA standards, or Group D (ANSI B31.1), and are seismically supported as shown in Figures 9.5-7 through 9.5-9.

9.5.5.2 System Description

The diesel generator service water system, which supplies cooling water from the RHR reservoir to the diesel generator components, is described in Subsection 9.2.5.

The diesel generator jacket coolant system shown in Figure 9.5-7 is described in this section. Each diesel generator is provided with a separate and independent jacket coolant system.

Major components of the system are an expansion tank, an engine-driven jacket coolant pump, an engine-driven air-cooler coolant pump, a standby coolant circulating pump, a heat exchanger, an air cooler, a standby heater, a three-way thermostatic bypass valve, a three-way air-operated bypass valve, high- and low-temperature alarms, low-pressure alarm, and indicators for pressure and temperature.

The jacket coolant is demineralized water with corrosion inhibitors. The engine-driven coolant pump maintains coolant circulation in the closed loop during diesel generator operation. The expansion tank accommodates the volume changes in the coolant due to temperature changes and also provides a means for venting the system. In addition, the expansion tank is to provide for minor system leaks at pump shaft seals, valve stems, and other components, and to maintain the net positive suction head (NPSH) on the system recirculating pump. System losses are made up by adding demineralized water to the expansion tank. The cooling-water expansion tank for each diesel engine has a capacity of 57 gal. The EDG manufacturer considers this tank size adequate to maintain continuous full-load operation for 7 days under normal conditions. To provide the required pump NPSH, the bottom of the expansion tank is located at an elevation of 603 ft, which is above the highest point of the engine cooling system (Elevation 601 ft).

The heat removed by the coolant from the engine is transferred to the diesel generator service water through a heat exchanger. To maintain the coolant temperature in the proper operating range, a three-way thermostatic valve controls the amount of coolant passing through or around the heat exchanger. The orifices in the bypass lines across the heat exchanger are sized based on the system piping and equipment pressure losses to provide design flows through the heat exchanger. To ensure quick starts, a motor-driven standby circulating pump maintains the jacket coolant temperature at approximately 110°F by pumping the coolant through a thermostat-controlled electric heater.

The system instrumentation consists of a low-level expansion tank alarm, a jacket coolant high- and low-temperature alarm, a jacket coolant low-pressure alarm, and system pressure and temperature indicators.

The jacket coolant also cools the scavenger air in a separate subloop of the engine jacket coolant system. This closed loop system has an engine-driven coolant pump, heat exchanger, and three-way air-operated bypass valve. This valve is automatically adjusted to maintain proper scavenger air temperature. The coolant loop is connected to the jacket water expansion tank for both filling and venting. Reliable cold fast starting requires initial EDG combustion air having a temperature of greater than 40°F. The RHR Complex Heating System, which normally maintains the EDG room temperature above 65°F, is relied upon to maintain the temperature of the initial combustion air above the 40°F design minimum required for reliable fast, cold starting of the units.

9.5.5.3 Safety Evaluation

Each diesel generator has independent jacket coolant and service water systems. The jacket coolant system meets the single- failure criterion in that if a failure in the system prevents the operation of its associated diesel generator, the remaining diesel generators will provide adequate emergency power to meet the safe-shutdown requirements of the plant.

The jacket coolant system is housed within Category I structures and the system piping, valves, and heat exchanger meet the seismic and other code requirements specified in Subsection 9.5.5.1.

9.5.5.4 Inspection and Testing Requirements

Inspection and testing of the system are performed as a part of the overall engine performance checks and routine scheduled engine testing. Instrumentation provided for expansion tank level and coolant temperature is inspected regularly. The jacket coolant chemistry is checked periodically and suitably treated to maintain desired quality.

9.5.6 Diesel Generator Starting System

9.5.6.1 Design Bases

Each diesel generator is equipped with a separate starting system to provide cranking power on demand. A compressed-air starting system is employed to provide fast starts and high reliability.

Each starting system includes separate air receivers, piping, and air start distributors and can independently start the EDG. The combined capacity of the two air receivers per system is sized to provide compressed air for starting a diesel generator five times without recharging.

One air compressor is provided for each diesel generator and automatically recharges the air receivers to normal operating pressure when required. Piping is provided to cross-connect the EDG Air Compressors so that one EDG's air compressor can charge the air receiver for both EDGs within a division.

The system piping and components, excluding the air compressors, dryers, and piping upstream of the air receiver inlet check valves, are designed to Category I requirements, and are also designed and constructed in accordance with ASME B&PV Code Section III, Class 3 where practicable. Code classifications are identified in Figures 9.5-8 through 9.5-10. The system is protected from tornado winds, external missiles, and flooding since it is housed in the RHR complex. Separation is provided between systems so that failure of one starting system disables only the associated diesel generator.

9.5.6.2 System Description

The starting system for each diesel engine consists of a motor-driven air compressor which keeps two air receivers pressurized at all times. A separate compressed-air line from the outlet of each of these air receivers serves the start distributors for the air-over-piston starting mechanism. On the inlet side of each of the air receivers, a check valve has been provided to prevent backflow to the compressor. The diesel generator starting system is shown in Figures 9.5-8 through 9.5-10.

The air receivers have low-pressure alarms, pressure indicators, and low-pressure switches to start the motor-driven air compressors and thus ensure that the air receivers are filled with air to the required pressure for EDG standby. One air compressor can be manually valved to charge the air receivers for both EDGs within a division. This operation is for temporary situations and may require manual initiation of the air compressor. The air receivers are equipped with drain valves that are manually opened to drain moisture accumulation. In addition, a refrigerated air dryer is provided between the compressors and the receivers to ensure that the air supplied is adequately dehumidified. Relief valves are provided on the air receiver and on the discharge piping from the compressor to prevent overpressurization.

There are two air start subsystems for each EDG. The two subsystems increase the reliability of an air start in the case of a failure due to fouling of an air start valve with contaminants and moisture. The use of air strainers further precludes the fouling of the air start system.

9.5.6.3 Safety Evaluation

The diesel generator starting system, excluding the air compressor, is designed to Category I requirements and is located inside the RHR complex. The starting system for each diesel generator is independent and physically separated from starting systems of other diesel generators.

Failure of a motor-driven air compressor or the piping up to the air receiver check valves does not prevent the functioning of the starting system. Similarly, manually operating an air compressor connected to all EDG air receivers within a division does not affect the function of the starting air system as an operable EDG only requires that the air receivers be charged, regardless of the source of air. A single failure of the air receiver, starting solenoid valves air distributor, or connecting piping does not prevent the starting of the EDG. Adequate redundancy is provided in the number of diesel generators to effectively perform the required safety functions.

9.5.6.4 Inspection and Testing Requirements

The system is operated and tested initially for flow path obstructions, leaks, flow capacity, and mechanical operability. The low-pressure alarms are calibrated and the low-pressure switch is checked to ensure reliability of compressor activation. Relief valves are set and checked. The diesel generator starting system was tested as part of the Preoperational Test program as discussed in Chapter 14. Subsequent testing is scheduled to meet plant Technical Specifications.

9.5.6.5 Instrumentation Application

The air receivers are provided with pressure indicators, low-pressure alarms, and low-pressure switches to activate the air compressor. Local manual starting of the air compressors is possible.

9.5.7 Diesel Generator Lubrication System

9.5.7.1 Design Bases

The diesel generator lubrication system is designed to provide adequate engine lubrication under all operating conditions, including immediate full-load operation after starting. The system maintains the lube-oil temperature in the specified range under all loading conditions and ambient temperatures.

The system is designed to Category I requirements and meets the DEMA or Quality Group D design and construction requirements except for the lube-oil cooler, which is designed and constructed in accordance with ASME B&PV Code Section III, Class 3 requirements. Specific code classifications are shown in Figures 9.5-4, 9.5-5, and 9.5-11.

9.5.7.2 System Description

The diesel generator lubrication system is shown schematically in Figure 9.5-11. This system is an integral part of the diesel generator package and is supplied by the vendor. Each diesel generator has a separate and independent lube-oil system.

Major components of the system are: a lube-oil tank, an engine-driven lube-oil pump, a lube-oil circulation pump and heaters, a full-flow lube-oil filter with an internal relief valve, a thermostat three-way bypass valve, a lube-oil cooler, a full-flow strainer, three lube-oil pressure switches, high- and low-temperature switches, a motor-driven prelube pump, and panel-mounted temperature, pressure, and crankcase vacuum gages.

The lube oil flows by gravity from the lube-oil tank to the sump located at the base of the engine. Lube-oil flow to the engine is regulated by a level control switch. The engine-driven lube-oil pump takes oil from the sump through a suction strainer and passes it through a full-flow filter. The lube-oil filters are equipped with a pressure indicator and an oil sample tap. Depending on the oil temperature, the thermostatically controlled three-way valve on the discharge side of the filter directs the lube oil through or around the lube-oil cooler. The lube oil is cooled by the diesel generator service water system, which flows through the tubes of the lube-oil cooler. Before being delivered to the engine, the lube oil passes through a three-element strainer that removes large particles that might have become entrained in the oil.

A 2-hp motor-driven prelube pump, which can be manually operated from the remote panel, is provided for prelubricating the engine prior to nonemergency starts. Prelubrication is not required on emergency starts. However, a vendor-supplied prelubrication piping modification is installed and eliminates the potential for dry starts. This piping routes the keep-warm system so that it discharges into the upstream side of the lube-oil strainer. This will provide continuous lube oil to the lower bearings and greatly reduce voids in the lube-oil system. The solid lube-oil system will provide faster lubrication of the upper bearings on the starting of the diesel and the engine-driven pump.

For purposes of lubrication on the bearings of the upper crankline, operating procedures require approximately 2 minutes of prelubrication prior to planned starts of the diesel generators. Also, operating procedures require, whenever possible, gradual loading and unloading of the diesels to ensure that the bearings are adequately lubricated before they are subjected to the stress associated with high speed and large loads.

The lube-oil headers are routed so that they will not readily drain when the engine is stopped. In addition, lube-oil booster/accumulators are provided for the more remote areas of the engine (aft lower main bearing and upper crankline). This booster system fills with oil during normal engine operation. The next time the engine is started, the lube oil in the accumulator is forced into the subject bearings by starting air pressure, thus filling the bearings with oil as the engine begins to be rotated in starting. A standby motor-driven circulation pump keeps the lube oil in the system warm (when the diesel engine is idle) by passing the oil over thermostatically controlled heater elements and returning the oil to the engine-driven pump discharge.

Three lube-oil low-pressure switches are provided. Actuation of one of the switches causes an audible alarm, and actuation of any two switches shuts down the engine. Three high-pressure switches are provided for the crankcase which actuate an audible alarm and shut down the engine in the same manner as the lube-oil low- pressure switches. The lube-oil tank is provided with high- and low-level switches and alarms and a low-level switch and alarm is provided in the engine sump. In addition, high- and low-temperature alarms, crankcase low-level alarm, pressure gauges, and temperature indicators are provided as shown in Figure 9.5-11.

9.5.7.3 Safety Evaluation

The lube-oil system, including lube-oil storage for each diesel generator, is completely independent of the lube-oil systems of the other diesel generators. Therefore, failure of one lube-oil system results in the loss of only one diesel generator in a division. The other diesel generator in the division, along with the diesel generators in the second division, is adequate to meet the safe-shutdown requirements of the plant.

The lube-oil system is designed to Category I requirements.

The diesel engines are designed to contain a crankcase explosion. The manufacturer conducted actual crankcase explosion tests (20 lb/in.^{2}) and then designed the crankcase inspection cover and fasteners to contain such explosions (100 lb/in.^{2}). These tests showed that the explosion was not harmful to the engine and posed no danger to the operators.

9.5.7.4 Inspection and Testing Requirements

The operability of the lube-oil system is tested and inspected along with the scheduled overall testing of the engine. Lube-oil samples are analyzed and diesel engine main bearing gap checks are performed in accordance with the Technical Specifications.

TABLE 9.5-1 <u>FIRE PROTECTION EQUIPMENT AND DEVICES LIST</u>

I. <u>Water Systems</u>

A. Electric fire pump

B. Diesel fire pump

C. Fire Protection System Jockey Pump

D. Standpipe System

1. Hose reels and connections
2. Yard hydrants inside protected area
3. Yard hydrants outside protected area

E. Deluge Systems

1. Transformer Bay
   a. Service Transformer No. 64
   b. Service Transformer No. 65
   c. Main Transformer No. 2A
   d. Main Transformer No. 2B

2. Radwaste Building Roof
   a. Voltage Regulator Transformer No. 65L (On Roof)

3. Turbine Building
   a. Hydrogen Seal Oil Unit (EL 613'-6")

F. Pre-Action Sprinkler Systems

TABLE 9.5-1 FIRE PROTECTION EQUIPMENT AND DEVICES LIST

1. Service Building
    a. Receiving and Loading Dock Area

2. Outside Protected Area
    a. Piping Warehouse (Warehouse 21)
    b. Piping Warehouse (Warehouse 20)(Fed through Warehouse 21 above)

G. Wet Pipe Sprinkler Systems

1. Reactor Building
    a. RCIC Turbine and Pump and Core Spray Room (EL 540’-0”)
    b. HPCI Turbine and Pump Room (EL 540’-0”)
    c. Torus Room Floor (EL 540’-0”)
    d. Railroad Unloading Area (EL 583’-6”)
    Separation Area (EL 613’-6”)
    e. Cable Trays (EL 613’-0”)
    f. MG Sets/Duct Area (EL 569’-6”)

2. Auxiliary Building
    a. Air Compressor Room (EL 551’-0”)/Corridor (EL 562’-0”)/Cable Trays (EL 562’-0”)/Cable Tunnel Trays (EL 562’-0”)
    b. Cable Trays (EL 583’-6” and 603’-6”)

3. RHR Complex
    a. Emergency Diesel Generator Fuel Oil Tank Room No. 11 (EL 590’-0”)
    b. Emergency Diesel Generator Fuel Oil Tank Room No. 12 (EL 590’-0”)
    c. Emergency Diesel Generator Fuel Oil Tank Room No. 13 (EL 590’-0”)

TABLE 9.5-1 FIRE PROTECTION EQUIPMENT AND DEVICES LIST

d. Emergency Diesel Generator Fuel Oil Tank Room No. 14 (EL 590'-0")

4. Radwaste Building
   a. Storage Area
   b. Extruder Area and Chemical Stores
   c. Drum Storage and Conveyor Area

5. On-Site Storage Facility
   a. Solid Waste/Empty Drum Storage/Compactor Areas/Asphalt Tank and Pump Rooms
   b. Truck Loading/Dry Active Waste Areas

6. Turbine Building
   a. Equipment Hatch
   b. North RFPT Room
   c. Bearing Pits and Under Turbine Area
   d. Used Oil Storage Area
   e. South RFPT Room
   f. RFPT Oil Reservoir Room
   g. Main Turbine oil Reservoir
   h. Cable Tunnel Trays (EL 628'-6")

7. Service Building
   a. Warehouse Storage Area
   b. Material Store/Dead Files

8. Office Building Annex
   a. Record Storage Area

9. General Service Water Pump House

TABLE 9.5-1 FIRE PROTECTION EQUIPMENT AND DEVICES LIST

a. Diesel Engine Fire Pump Room

10. Miscellaneous Buildings Inside Protected Area
    a. Maintenance Oil Storage Building (Warehouse 18)
    b. Availability Improvement Building (AIB)
    c. ISFSI Equipment Storage Building

11. Miscellaneous Buildings Outside Protected Area
    a. Warehouse 19 (Warehouse B)
    b. General Training and Orientation Center (GTOC)(Warehouse 30)
    c. Warehouse 22 (Warehouse G)
    d. Warehouse 23 (Warehouse H)

H. Manual Wet Pipe Sprinkler Systems

1. Auxiliary Building
   a. Cable spreading Room (EL 630’-6”)
   (System provides supplemental protection for the Halon suppression system provided for the Cable Spreading Room)

I. Manual Flooding Systems

1. Control Center HVAC Make-up Filter Charcoal Absorber Unit (EL 677’-6”)
2. Reactor Building HVAC Recirculation Filter Charcoal Absorber Unit (EL 677’-6”)
3. Office Building Annex Charcoal Filter Beds

J. Dry Pipe Sprinkler System Outside Protected Area

TABLE 9.5-1 FIRE PROTECTION EQUIPMENT AND DEVICES LIST

1. FLEX Storage Facility 2

K. Dry Pipe Sprinkler System Inside Protected Area

1. FLEX Storage Facility 1

II. Gaseous Systems

A. Carbon Dioxide Suppression Systems

1. RHR Complex
   a. Emergency Diesel Generator Room No. 11 (EL 590’-0”)
   b. Emergency Diesel Generator Room No. 12 (EL 590’-0”)
   c. Emergency Diesel Generator Room No. 13 (EL 590’-0”)
   d. Emergency Diesel Generator Room No. 14 (EL 590’-0”)

2. Auxiliary Building
   a. Cable Tunnel (EL 613’-6”)
   b. Cable Trays (EL 631’-0”)
   c. Outside Division II Switchgear Room (EL 643’-6”)

3. Standby Gas Treatment System
   a. Standby Gas Treatment System Charcoal Filter Beds (EL 677’-6”)

B. Carbon Dioxide Hose Reel Stations

1. Outside the Relay Room (EL 613’6”)
2. Outside the Division I Switchgear Room (EL 613’6”)
3. Inside the Division II Switchgear Room (EL 643’6”)

C. Halon Suppression Systems

TABLE 9.5-1 FIRE PROTECTION EQUIPMENT AND DEVICES LIST

1. Auxiliary Building
    a. Relay Room (EL 613'-6")
    b. Cable Spreading Room (EL 630'-6")
    c. Computer Room (EL 655'-6")
    d. Computer Room Sub Floor (EL 655'-6")

2. Service Building
    a. Electrical Equipment Room
    b. Central Alarm Station

3. Office Building Annex
    a. Computer Room (Above Floor)
    b. Computer Room (Sub Floor)

4. Guard House
    a. File Room
    b. Secondary Alarm Station

D. Clean Agent Suppression System
    1. Parts of Radwaste Building
    2. Security Diesel Generator Enclosures

III. Confinement Control

A. Compartmentalization of structures with fire doors

B. Fire dampers in ventilation systems

C. Roof vents in Turbine Building Area

D. Remotely resettable smoke dampers in Carbon Dioxide suppression

TABLE 9.5-1 FIRE PROTECTION EQUIPMENT AND DEVICES LIST

system protected areas

IV. Detection Systems

A. Thermal Detection

B. Photoelectric Detection

C. Ionization Detection

D. Infrared Detection

TABLE 9.5-2 FAILURE MODE AND EFFECTS ANALYSIS: INADVERTENT OPERATION OF SAFETY-RELATED FIRE PROTECTION SYSTEM

Fire Protection System	Safety-Related Equipment Protected	Results of Inadvertent Operation of Fire Protections System
HPCI turbine room sprinkler system	HPCI turbine	Loss of HPCI turbine. HPCI not needed for normal shutdown of reactor. Backup LOCA protection provided by automatic depressurization system and low-pressure ECCS
RCIC turbine room sprinkler system	RCIC turbine, core spray pumps	Loss of RCIC turbine. RCIC not needed for normal shutdown. If Division I reactor is isolated, backup protection provided by HPCI. Core spray pump motors are dripproof
M-G set oil coupler and oil cooler sprinkler system	Reactor building structure	Recirculation pumps lost if M-G sets lost. Recirculation pumps not needed for shutdown of reactor
EDG CO_2 system	EDG	Operation of CO_2 system will not hinder operation of an EDG
Diesel-fuel-oil storage room sprinkler system	EDG fuel-oil tanks, day tank, lube-oil tank, and fuel-oil transfer pumps	Tanks will not be affected, but transfer pumps could be lost. An EDG can run 2 hr without fuel-oil transfer pumps. At most, only one EDG can be lost. EDGs in other division provide backup to shut down reactor
SGTS CO_2 system	SGTS charcoal beds	One division of the SGTS temporarily lost until it is manually restarted. No permanent damage to the charcoal filter beds. Remaining SGTS not affected
Sprinkler system in cable tray area over torus	Cable trays, torus, and reactor building structure	Cable trays not affected by sprinklers. Motor-operated valve operators are dripproof. A sump pump is provided in torus area
Sprinkler system in railroad bay area in reactor building at Elevation 583 ft 6 in.	Division II cable trays	Cable trays not affected by sprinklers
Sprinkler system in reactor building at Elevation 613 ft 6 in.	Divisions I and II cable trays	Cable trays not affected by sprinklers
Sprinkler system in auxiliary building at Elevation 551 ft and 562 ft	Divisions I and II cable trays	Cable trays not affected by sprinklers. Control air compressors in Divisions I and II separated by 65 ft

TABLE 9.5-2 FAILURE MODE AND EFFECTS ANALYSIS: INADVERTENT OPERATION OF SAFETY-RELATED FIRE PROTECTION SYSTEM

Fire Protection System	Safety-Related Equipment Protected	Results of Inadvertent Operation of Fire Protections System
Sprinkler system in auxiliary building at Elevation 583 ft and 603 ft	Divisions I and II cable trays	Cable trays not affected by sprinklers
Halon system in relay room, control center at Elevation 613 ft	Divisions I and II relay cabinets and cable trays	Electrical equipment not affected by Halon system. Ventilation dampers remotely resettable (1)
CO_2 system in cable tunnel, auxiliary building at Elevation 613 ft	Divisions I and II cable trays	Cable trays not affected by CO_2 system
Halon system in cable spreading room, at control center Elevation 630 ft	Divisions I and II cable trays	Cable trays not affected by Halon system. Ventilation dampers remotely resettable (1)
CO_2 system in cable tray area, auxiliary building at Elevation 630 ft	Divisions I and II cable trays	Cable trays not affected by CO_2 system
CO_2 system outside switchgear room in auxiliary building at Elevation 641 ft	Divisions I and II cable trays, motor control centers	Cable trays and electrical equipment not affected by CO_2 control centers system
Halon system in main control room computer under and above floor area, Elevation 655 ft	Main control room	Computer not safety related. Control room habitability discussed in Subsection 9.5.1.2.2 (1)

Note 1): Fire Protection relay failure will cause loss of cooling to relay room, cable spreading room or computer room.

Figure Intentionally Removed
Refer to Plant Drawing M-2135

FIGURE 9.5-1, SHEET 1

FIRE PROTECTION SYSTEM DIVISIONS I AND II
RESIDUAL HEAT REMOVAL COMPLEX P&ID

Figure Intentionally Removed
Refer to Plant Drawing M-2135-1

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FIGURE 9.5-1, SHEET 2

FIRE PROTECTION SYSTEM DIVISIONS I AND II
RESIDUAL HEAT REMOVAL COMPLEX P&ID

Figure Intentionally Removed
Refer to Plant Drawing M-2086

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FIGURE 9.5-2

FIRE PROTECTION SYSTEM
REACTOR AND AUXILIARY BUILDINGS P&ID

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Refer to Plant Drawing M-N-2051

FIGURE 9.5-3

FIRE PROTECTION SYSTEM - DIVISIONS I AND II
DIESEL GENERATOR ROOM P&ID

Figure Intentionally Removed
Refer to Plant Drawing M-N-2048

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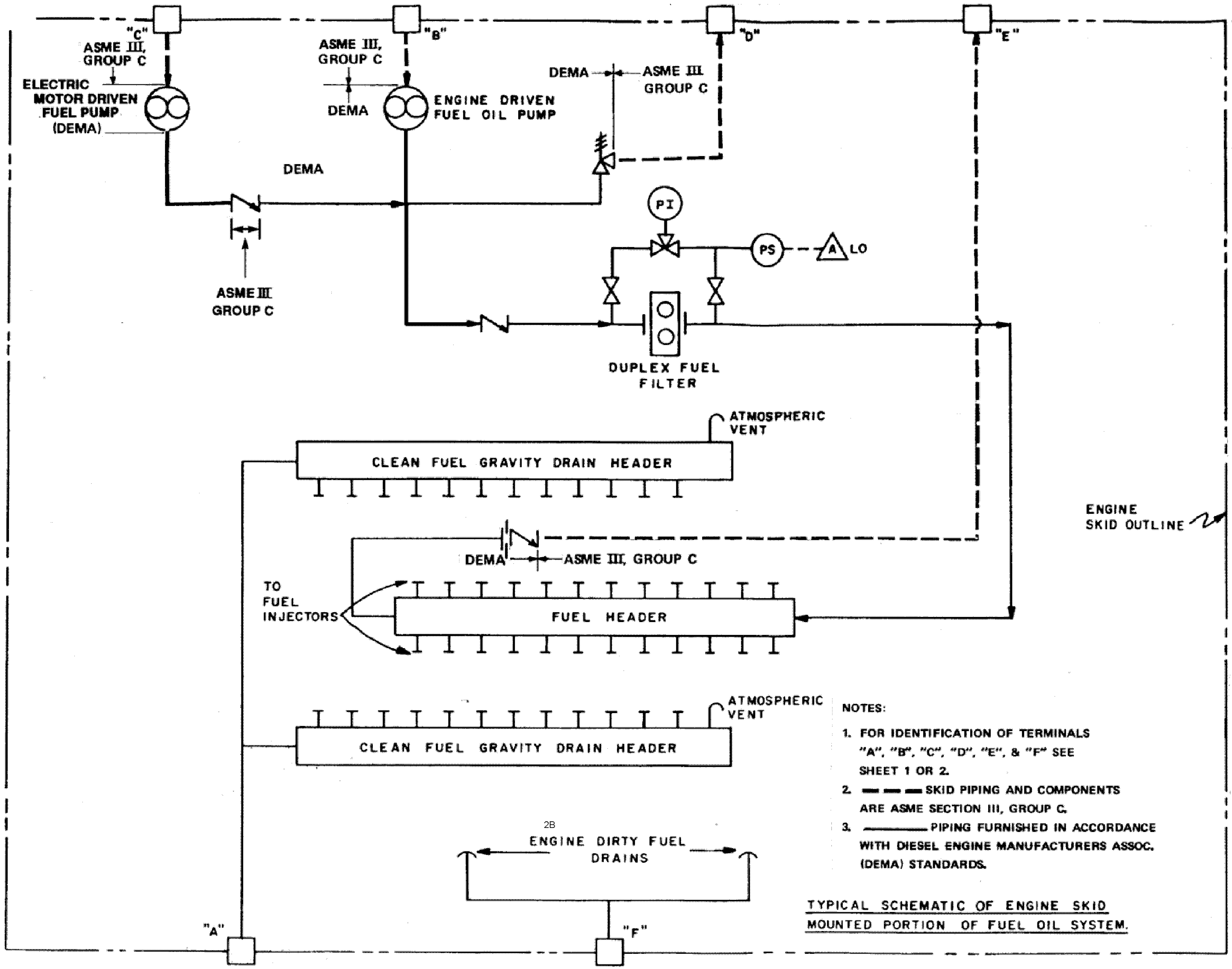
FIGURE 9.5-4

DIESEL-FUEL-OIL SYSTEM AND LUBE OIL SYSTEM
DIVISION I - RESIDUAL HEAT REMOVAL COMPLEX
P&ID

Figure Intentionally Removed
Refer to Plant Drawing M-N-2049

FIGURE 9.5-5

DIESEL-FUEL-OIL SYSTEM AND LUBE OIL SYSTEM
DIVISION II - RESIDUAL HEAT REMOVAL COMPLEX
P&ID



NOTES:

1. FOR IDENTIFICATION OF TERMINALS "A", "B", "C", "D", "E", & "F" SEE SHEET 1 OR 2.
2. — — — SKID PIPING AND COMPONENTS ARE ASME SECTION III, GROUP C.
3. ——— PIPING FURNISHED IN ACCORDANCE WITH DIESEL ENGINE MANUFACTURERS ASSOC. (DEMA) STANDARDS.

TYPICAL SCHEMATIC OF ENGINE SKID MOUNTED PORTION OF FUEL OIL SYSTEM.

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FIGURE 9.5-6

ENGINE-SKID MOUNTED DIESEL-FUEL-OIL SYSTEM

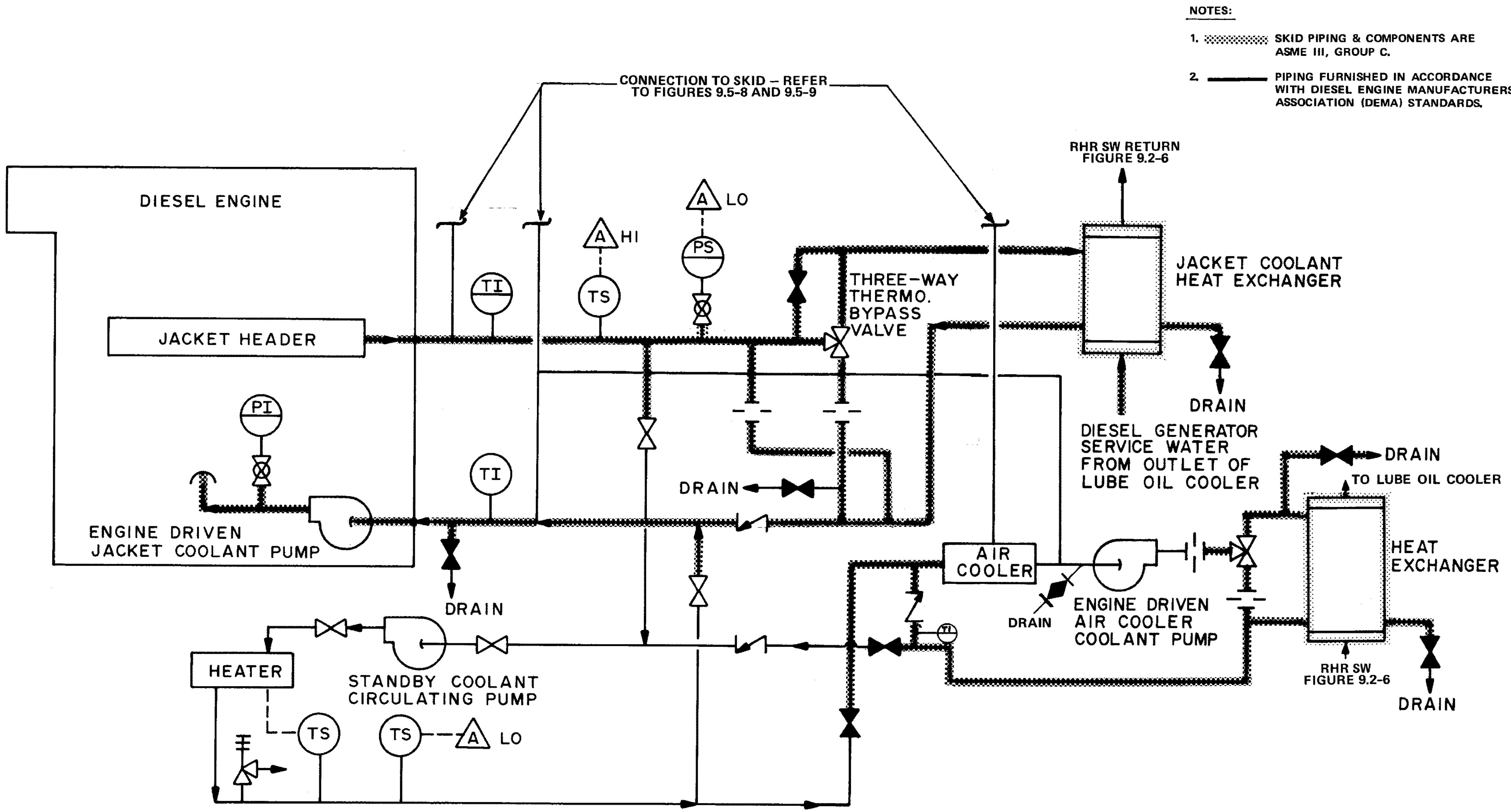

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FIGURE 9.5-7

DIESEL GENERATOR JACKET COOLANT SYSTEM

REV 13 06/05

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Refer to Plant Drawing M-N-2046

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FIGURE 9.5-8

DIESEL GENERATOR SYSTEM
DIVISION-RESIDUAL HEAT REMOVAL COMPLEX
P&ID

Figure Intentionally Removed
Refer to Plant Drawing M-N-2047

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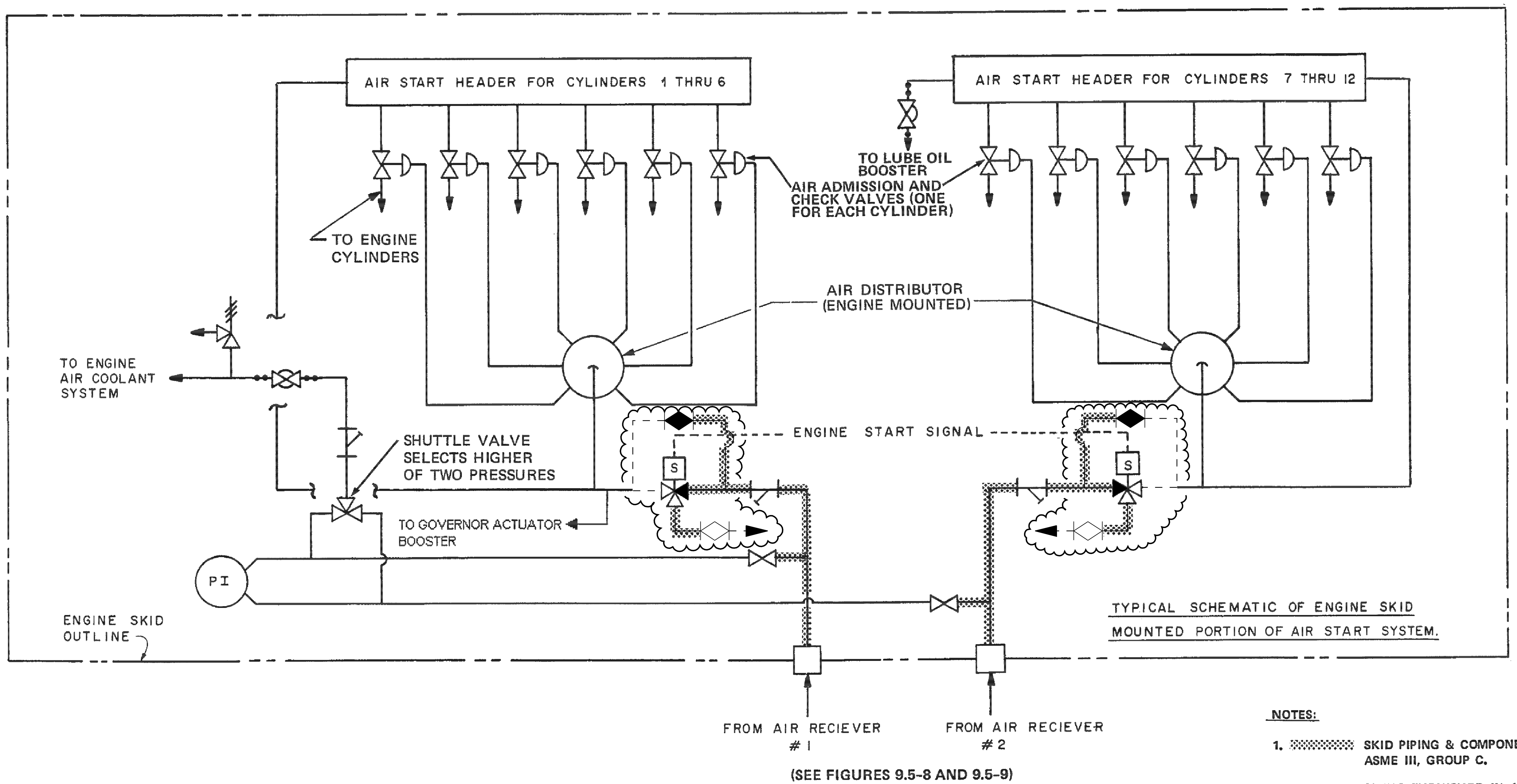
FIGURE 9.5-9

DIESEL GENERATOR SYSTEM
DIVISION II - RESIDUAL HEAT COMPLEX
P&ID



NOTES:

1. SKID PIPING & COMPONENTS ARE ASME III, GROUP C.
2. PIPING FURNISHED IN ACCORDANCE WITH DIESEL ENGINE MANUFACTURERS ASSOCIATION (DEMA) STANDARDS.
3. NON-ASME SKID PIPING (FURNISHED BY EDISION)

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FIGURE 9.5-10

ENGINE-SKID MOUNTED DIESEL GENERATOR AIR START SYSTEM

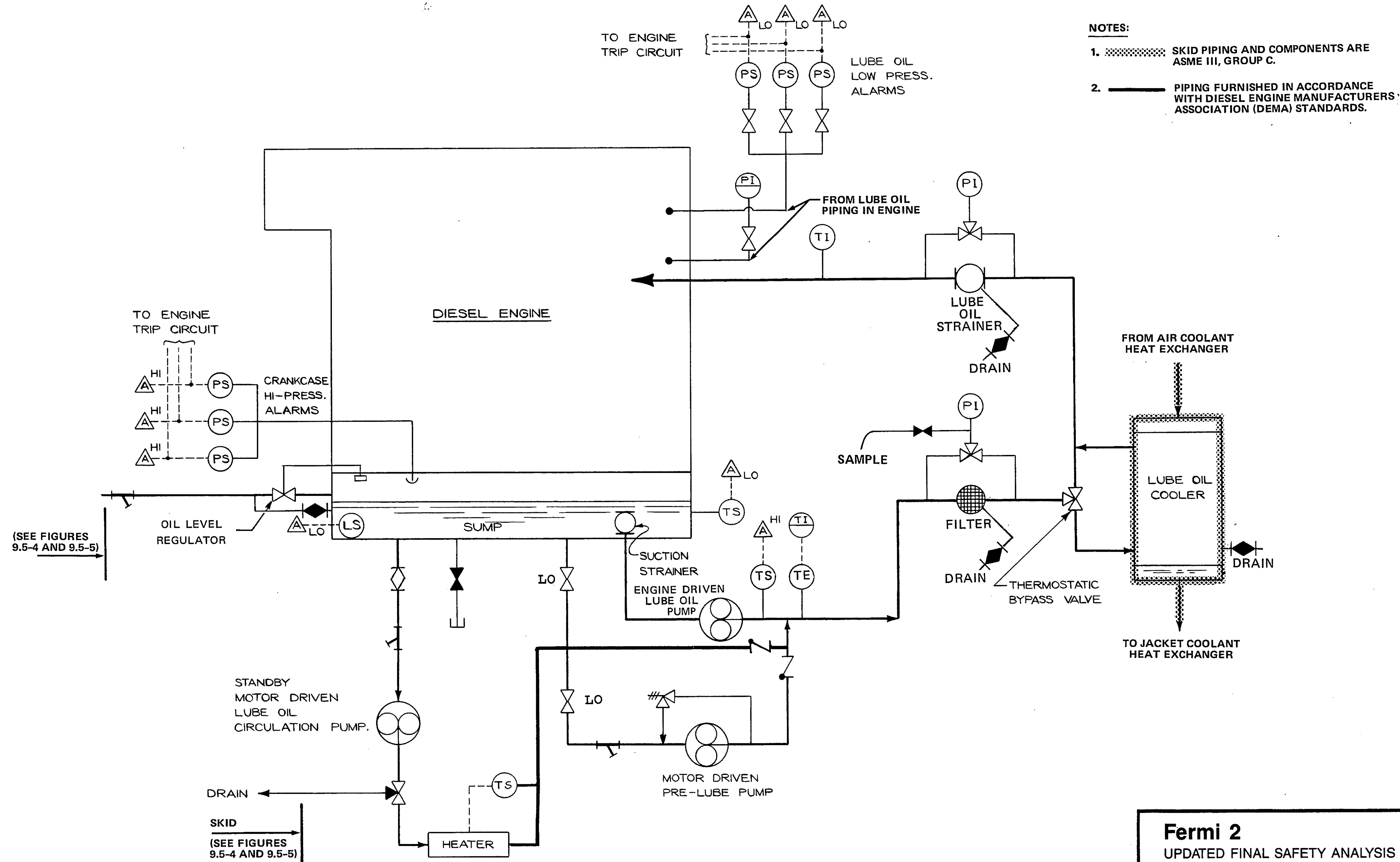

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FIGURE 9.5-11

DIESEL GENERATOR LUBRICATION SYSTEM

9A.1 INTRODUCTION

9A.1.1 Background and Purpose

9A.1.1.1 General

In a letter dated May 3, 1976, the NRC transmitted to Edison a copy of revised Standard Review Plan (SRP) 9.5.1, "Fire Protection," dated May 1, 1976, which included Branch Technical Position (BTP) APCSB 9.5-1. This revision of SRP 9.5.1 contained new guidelines for NRC staff evaluations of fire protection in its review of nuclear power plant construction permit applications docketed after July 1, 1976. The letter stated (1) that to the extent reasonable and practical, the revised SRP will be used by the NRC staff in evaluating fire protection provisions of operating plants, applications currently under review for construction permits and operating licenses, and future applications for operating licenses for plants then under construction; and (2) that the NRC would provide more definitive criteria or acceptable alternatives for the application of SRP 9.5.1 when available.

In a subsequent letter dated September 30, 1976, the NRC transmitted Appendix A to APCSB 9.5-1, which provides for plants docketed prior to July 1, 1976, certain acceptable alternatives to the positions given in SRP 9.5.1. This letter also directed Edison to conduct an evaluation of the fire protection provisions for Fermi 2. The evaluation must include a fire hazards analysis conducted under the technical direction of a qualified fire protection engineer and performed to the level of detail indicated by enclosure 2 to NRC's letter "Supplementary Guidance on Information Needed for Fire Protection Program Evaluation." In addition, the evaluation must provide a detailed comparison of the fire protection provisions proposed for Fermi 2 with the appropriate guidelines in Appendix A to APCSB 9.5-1, which for Fermi 2, are those designated as "plants under construction and operating plants."

As a result of the correspondence, Edison performed a fire protection evaluation of Fermi 2. The fire protection evaluation consisted of performing a fire hazards analysis, doing a point-by-point comparison to Appendix A of APCSB BTP 9.5-1, developing fire protection related drawings, and evaluating the overall Fermi 2 fire protection program.

This evaluation was conducted by Gilbert Associates, Inc., Reading, Pennsylvania, under the technical direction of W. A. Brannen, who is a qualified fire protection engineer. His qualifications include full membership in the Society of Fire Protection Engineers and registration as a Professional Engineer in fire protection in the Commonwealth of Pennsylvania.

The original evaluation report was submitted as Amendment 10 to the original FSAR in November 1977 and subsequently revised and amended in Amendments 39, August 1981; 45, November 1982; 52, December 1983; 58, July 1984; and post OL Revision 1 in March 1985. It presented the results of the fire protection evaluation (fire hazards analysis), the methodology employed, and a description of the shutdown systems of Fermi 2, as well as a point-by-point comparison to Appendix A of APCSB 9.5-1.

Subsequent Appendix R analyses have been performed and have resulted in the submittal of deviations for specific plant fire zones and the design and installation of an alternative shutdown system. The Fermi 2 safe-shutdown capability and systems are discussed in Sections 9A.3 and 7.5.

During the course of the NRC review, the NRC asked for additional information, which was transmitted in Edison letter EF2-53791, dated June 18, 1981, documenting commitments made by Edison at the fire inspection exit critique of May 15, 1981, and at a meeting in Bethesda, Maryland, on May 27, 1981. Changes to Section 9A.4 described in Edison letter EF2-53791 were incorporated in FSAR Amendment 39.

During 1984, Edison met with the NRC staff several times to resolve staff concerns about the potential consequences of a postulated fire in the Fermi 2 control room. As a result of these meetings, Edison committed to provide an alternative shutdown system that could operate independently of the control center. The basis, the design, and the analysis of this alternative shutdown approach were described in Edison letters to the NRC (EF2-72001 and EF2-71994, dated October 22, 1984, and EF2-72718, dated August 16, 1984). Appropriate information presented in these letters has been incorporated into Section 9A and Subsection 7.5.2.5.

Appendix E, "Safety Evaluation Report on the Fire Protection Program for the Fermi 2 Facility," of Supplement No. 5 to the SER issued March 1985 replaces and supersedes Appendix E of the SER dated July 1981 and SSER 2 dated January 1982. Approval of the Fermi 2 fire protection program is provided in SSER No. 5. Subsequent information and approval are provided in SSER No. 6 dated July 1985.

In the process of updating Section 9A, Generic Letter 86-10 was used as guidance in developing and incorporating Section 9A.6, Fire Protection and Alternative Shutdown System Conditions for Operations.

Since the original Fermi 2 fire hazards analysis, the NRC produced clarification on fire protection features for nuclear power facilities, for example, Generic Letters 81-12, 82-21, 84-09, 85-01, and 86-10. Generic Letter 86-10, "Implementation of Fire Protection Requirements," clarifies such subjects as documentation, deficiency notification, and removal of Fire Protection Limiting Conditions for Operation and Surveillance Requirements from the Technical Specifications. This clarification has been considered in the development of the Fermi 2 Fire Protection Program. Generic Letter 86-10 was used as guidance in developing Section 9A.6, Fire Protection and Alternative Shutdown System Conditions for Operations.

The fire protection system limiting conditions for operation and surveillance requirements have been removed from the Technical Specifications and included in Section 9A.6.

Section 9A.1 presents the results of the fire protection evaluation of Fermi 2. The methodology used and a description of the shutdown systems are presented in Sections 9A.2 and 9A.3, respectively. The fire hazards analysis is presented in Section 9A.4. The point-by-point comparison to Appendix A of APCSB 9.5-1 is provided in Section 9A.5. The fire protection and alternative shutdown system conditions for operations are provided in Section 9A.6.

9A.1.1.2 Documents

The following is a listing of pertinent correspondence with the NRC and of other fire protection program documents. The documents have been incorporated into UFSAR as appropriate.

Letters to the NRC

Date	Number	To	From	Subject
01-28-87	VP-NO-87-0014	NRC	F. E. Agosti	Alternative Shutdown System – Additional Information
12-10-86	GP-86-0014	NRC Region III Keppler	B. R. Sylvia	CTG Diesel Fuel Oil Warmer Installation Clarification
10-14-86	VP-86-0136	NRC Adensam	F. E. Agosti	3L Appendix R Alternate Shutdown Testing
02-20-86	VP-86-0006	NRC Andensam	F. E. Agosti	Deviation Reg-Emergency Lighting
01-21-86	VP-86-0002	NRC Adensam	W. H. Jens	Alternate Shutdown System
01-03-86	VP-85-0221	NRC Adensam	W. H. Jens	Alternate Shutdown System
03-04-85	NE-85-0365	NRC Youngblood	W. H. Jens	Resolution of Certain Fire Protection Issues
12-07-84	EF2-72025	NRC Youngblood	W. H. Jens	Additional Information Concerning Fire Protection
03-07-85	NE-85-0345	NRC Youngblood	W. H. Jens	Request to Revise Draft FERMI 2 Technical Specification 3.3.7.9
02-18-85	EF2-70391	NRC Region III Keppler	W. H. Jens	Additional Fire Protection Information
10-23-85	VP-85-0204	NRC Region III Keppler	W. H. Jens	Amended Final Report of 10 CFR 50.55(e), Item 116 “Potential Deficiency by allowing Freezing of Buried Piping Systems”

Date	Number	To	From	Subject
09-27-84	EF2-72260	NRC Youngblood	W. H. Jens	Additional Information Concerning “Cross-over” Cable Fire Stops and Use of Vinyl Tile Center
10-29-85	VP-85-0202	NRC Region III Keppler	W. H. Jens	Diesel Fuel Oil Warmer
02-04-85	NE-85-0275	NRC Youngblood	W. H. Jens	Additional Fire Protection Information
08-03-84	EF2-72717	NRC Youngblood	W. H. Jens	Submittal…Deviations to Appendix R
10-22-84	EF2-72001	NRC Youngblood	W. H. Jens	Design of Alternate Shutdown Approach
08-16-84	EF2-72718	NRC Denton	W. H. Jens	Alternate Shutdown in the Control Center Complex
10-22-84	EF2-71994	NRC Denton	W. H. Jens	Implementation of Alternative Shutdown at FERMI 2
08-04-84	EF2-69218	NRC Youngblood	W. H. Jens	Transmittal of Fire Protection Information
06-18-85	VP-85-0142	NRC Youngblood	W. H. Jens	Additional Fire Doors and Dampers
01-09-85	NE-85-0030	NRC Youngblood	W. H. Jens	Fire Door Qualification Report

Other Documents

Fire Protection:

Technical Requirements Manual	3.12.1 Fire Detection Instrumentation
Technical Requirements Manual	3.12.2 Fire Suppression Water System
Technical Requirements Manual	3.12.3 Spray and Sprinkler Systems
Technical Requirements Manual	3.12.4 CO_2 Systems
Technical Requirements Manual	3.12.5 Halon Systems
Technical Requirements Manual	3.12.6 Fire Hose Stations

Technical Requirements Manual 3.12.7 Yard Fire Hydrants and Hydrant Hose Houses

Technical Requirements Manual 3.12.8 Fire Rated Assemblies

Dedicated Shutdown System Design Review Summary, February 24, 1986.

Supplement No. 5 of the Safety Evaluation Report - March 1985.

Supplement No. 6 of the Safety Evaluation Report - July 1985.

9A.1.2 Applicable Codes

The following National Fire Protection Association (NFPA) codes were used for guidance in the development of the Fermi 2 fire protection program.

NFPA Code	Edition Used
10	1978
12	1977
12A	1977
13	1980
13A	1976
13E	1973
14	1976
15	1979
20	1970
24	1970
30	1977
72E	1974
72D	1975
198	1972

The 1978 edition was used for other NFPA codes not specifically mentioned above or in Subsection 9.5.1.1.5. Certain deviations to the above listed NFPA codes have been evaluated as being acceptable and are discussed in Subsection 9.5.1.

9A.1.3 Fire Protection Program

9A.1.3.1 Objective and Purpose

The Fermi 2 fire protection program defines the requirements and responsibilities for control of the fire protection equipment and activities and is designed to minimize the adverse effects of fires on safety-related structures, systems, and components and to ensure safe-shutdown capability in the event of a plant fire.

This program has been established to outline the fire protection systems and associated tasks and personnel necessary to perform those tasks to ensure that the fire protection program is effective in minimizing risks associated with fires. Fire protection activities associated with safety-related systems, components, or structures will be conducted in accordance with the provisions of the Operating License.

9A.1.3.2 Description

The fire protection program consists of the following components:

a. Definition of the organizational responsibilities and lines of communication, pertaining to fire protection, between the various positions/organizations

b. Qualification of personnel responsible for fire protection at Fermi 2

c. Composition, duties, and qualifications of the plant fire brigade

d. Establishment and maintenance of the fire protection training program

e. Administrative controls to minimize the amount of combustibles that safety-related areas may be exposed to and the control of potential ignition sources

f. Fire-fighting strategies for safety-related areas

g. Periodic inspection, maintenance, and testing of fire detection and protection systems

h. Training of necessary plant personnel for fire watch duty

i. Assurance that necessary actions are taken to minimize fire risk and repairs are made as soon as practical when fire equipment is taken out of service

j. Procedures that establish a method for design control, procurement, installation, and testing for fire protection in safety-related areas

k. A quality assurance (QA) program so that the requirements for design, procurement, installation, testing, and administrative controls for fire protection in safety-related areas are satisfied

l. The necessary fire protection equipment, communications equipment, and emergency lighting which has been installed in accordance with the fire hazards analysis contained in this appendix.

9A.1.3.3 Organizational Responsibilities

a. The senior onsite nuclear manager is responsible for the operation of Fermi 2 and therefore has overall responsibility for the fire protection program

b. The senior onsite nuclear manager in charge of engineering has been delegated management responsibility for the formulation and effectiveness of the fire protection program

c. Nuclear Engineering is directly responsible for:

   1. Having a qualified fire protection engineer within Nuclear Engineering. This engineer assists in the formation, maintenance, and periodic review of the fire protection program

   2. Establishing and maintaining the overall fire protection program description

   3. Developing and maintaining the fire detection/ protection design and configuration control for onsite facilities and location of the safe-shutdown equipment for fires

   4. Reviewing fire protection practices and evaluating design-related sections of insurance inspections

   5. Ensuring that the fire protection program associated with safety-related systems, components, and structures conforms to NRC requirements by:

      (a) The performance of fire hazards analyses, and evaluations as required

      (b) The review and evaluation of designs in accordance with current fire codes and standards for applicability to the plant

      (c) The evaluation of operating experience reports (i.e., License Event Reports, Safety Evaluation Reports [SERs], Inspection and Enforcement Bulletins, Circulars, and Notices) for the potential impact on plant fire safety.

d. The Executive Director – Nuclear Production has been delegated the responsibility for:

   1. Implementing and coordinating the Fermi 2 fire protection program

   2. Having a fire protection specialist

   3. Organizing and implementing the plant fire brigade. The fire brigade is composed of a minimum of five Plant personnel and shall be maintained onsite at all times.* The fire brigade shall not include the Shift Manager, the Shift Technical Advisor/Operations Shift Engineer, nor the two other members of the minimum shift crew necessary for safe shutdown of the unit nor any personnel required for other essential functions during a fire

* The fire brigade composition may be less than the minimum requirements for a period of time not to exceed 2 hr, in order to accommodate unexpected absences, provided immediate action is taken to fill the required positions.

emergency. To be a fire brigade member, personnel must first complete the required fire brigade training, rad-worker training, and respirator training, and be physically qualified

4. Managing fixed and transient combustibles; flammable and combustible liquids, cutting, welding, and grinding activities, and other ignition sources to minimize associated fire hazards

5. Housekeeping and fire inspection performance

6. Assisting Nuclear Training in development of training programs for the plant fire brigade, fire watch, and site personnel

7. Maintaining, operating, and inspecting fire protection systems, components, and equipment

8. Developing and implementing the fire "Pre-Plans"

9. Developing the maintenance, surveillance, and administrative procedures for the fire protection program.

e. Nuclear Quality Assurance is directly responsible for audits, surveillances, and inspections of the fire protection program including operations, maintenance, and modifications of fire prevention components, equipment, and systems to ensure compliance with procedural and regulatory requirements

f. Nuclear Training is responsible for maintaining the Fire Protection Training Program as follows:

1. Training both onsite and offsite fire brigade personnel.

2. Conducting and evaluating required plant fire drills.

3. Developing plant fire evacuation plans.

4. Training fire protection inspectors.

5. Training fire watch personnel.

g. Onsite Review Organization (OSRO) is responsible for review of changes to the Fire Protection Program per Section 17.2.

9A.1.3.4 <u>Drill</u>

The Frenchtown Fire Department will participate with the plant fire brigade in a drill at least once per year. This requirement may be satisfied as part of the Radiological Emergency Response Preparedness Plan program.

9A.1.3.5 <u>Audits</u>

Audits of the fire protection program shall be performed as specified in Section 17.2.

9A.2 METHODOLOGY - FIRE HAZARDS ANALYSIS

9A.2.1 Introduction

A fire hazards analysis of the Fermi 2 fire protection provisions was originally conducted in accordance with Appendix A to Branch Technical Position (BTP) APCSB 9.5-1. The original fire hazards analysis was based on the design as of April 1977. The original fire hazards analysis concentrated on buildings housing shutdown equipment. The objective of the analysis was to determine the potential effects of a fire at a given location within the plant and then to judge whether a fire at a given location would adversely affect the ability to safely shut down the plant. Specific fire hazards in other buildings and areas were evaluated to determine the effect of a fire on the 3-hr-rated walls separating these buildings and areas from the buildings containing safe-shutdown equipment. Where it was determined that a single fire might jeopardize plant safe shutdown, a design change was implemented. The final analysis and conclusions, as presented in Section 9A.4, were based on the design that incorporated these changes. Subsequent revisions have been made to keep the fire hazards analysis current. Subsequent analyses were due to the change in the rule. These analyses were performed to verify Fermi 2 compliance with the new technical requirements of 10 CFR 50, Appendix R, Sections III.G, J, and O. In this effort Edison reassessed the Fermi 2 fire protection program and performed additional safe-shutdown analyses that resulted in the design and installation of the alternative shutdown system and dedicated shutdown panel. Also, Edison requested deviations from specific conditions of Appendix R. The results of the fire protection evaluations and subsequent analyses of Fermi 2 are included in Section 9A.4.

A deviation is a condition which when analyzed/evaluated does not strictly adhere to the rule but does have conditions which provide an equivalent level of protection to that of the requirements.

The deviations of Fermi 2 from Appendix R are addressed in Reference 1. These deviations provide justification that an equivalent level of protection to that of the technical requirements of Section III.G of Appendix R exists for Fermi 2.

At Fermi 2, fire hazards analyses have been and are performed in two phases: the first is that of an information collection process; the second is the actual analysis and effects evaluation.

9A.2.2 Information Collection

Before a fire hazards analysis can be performed, Fermi 2 plant information is obtained such as plant shutdown equipment, inventory of combustibles, structural fire barriers, and existing and planned fire detection/protection equipment. This information is then reviewed and documented in the fire hazards analysis. As required, the information is then incorporated on the fire protection layout drawings, Figures 9A-1 through 9A-18.

9A.2.2.1 Plant Shutdown Equipment

Plant safe-shutdown operation starts with the reactor at normal full power and terminates with the reactor in the cold-shutdown condition with long-term cooling in operation. Plant safe- shutdown equipment is defined as mechanical, electrical, and ventilation equipment, including instrumentation, controls, and cables, required for the shutdown operation. Shutdown is from the main control room, under normal and abnormal conditions, with certain exceptions. For these exceptions, such as a fire in the control center complex (control room, relay room, and cable spreading room), the plant can be shut down from outside the control room using the alternative shutdown system. Additional information concerning the safe-shutdown sequence is presented in Section 9A.3.

9A.2.2.2 Inventory of Combustibles

The inventory of combustibles and calculation of combustible (fire) loading for all fire zones in the plant is contained in a detailed engineering design calculation. The major types of combustibles inventoried for the fire hazards analysis are petroleum products, electrical insulation, charcoal filters, Thermo-Lag material, and maintenance and operating supplies. The fire loading values (Btu/ft^2) determined in the inventory process are used to calculate the total fire loading of the zone as described in Subsection 9A.2.3.3. The resultant calculated total fire loading for each fire zone is then classified as low, moderate, or high, and this descriptive quantitative term is utilized in the Fire Hazards Analysis in Section 9A.4. These terms are being used as discussed in the Fire Protection Handbook. A low fire load is one that does not exceed an average of 100,000 Btu per square foot of net floor area; a moderate fire load exceeds an average of 100,000 Btu per square foot of net floor area but does not exceed an average of 200,000 Btu per square foot; a high fire load exceeds an average of 200,000 Btu per square foot of net floor area but does not exceed an average of 400,000 Btu per square foot. These terms were developed in British Fire Loading Studies and assume (or allow) even higher load limits in limited isolated areas for each level (low, moderate, or high) but only these average fire load limits are being used for the Fermi 2 Fire Hazards Analysis in order to add conservatism to the analysis.

Petroleum products are defined, for the purposes of the fire hazards analysis, as lubricants and fuel oil. Lubricants are tabulated for all equipment containing 1 gal, or more, of oil. Lubrication of equipment requiring smaller quantities of oil is normally accomplished through sealed bearings or oil/grease cup arrangements that require very small quantities of lubricant. These small quantities are not considered significant to the fire hazards analysis and are not included in specific area/zone fire loadings. Fuel oil for diesel-driven equipment and the auxiliary boiler is discussed in the individual zone analyses.

Transformers inside plant buildings are of dry-type construction and contain no petroleum products.

Electrical insulation consists primarily of cable insulation and jackets. Small quantities of other combustible materials are used in switchgear and control panels. The type of cable insulation used in construction was primarily ethylene propylene. Cables have overall fire-retardant jackets of Neoprene or Hypalon. For purposes of the fire hazards analysis, all cable insulation was assumed to be combustible and to have a heat content of 10,000 Btu/lb (Reference 2). Cables have been type tested in accordance with the flame test of Edison's Specification 3071-80 (Reference 3) and are certified to be of fire-retardant construction. This is equivalent to the IEEE-383 test. Metal cable trays are of either the ladder type without covers or the solid-bottom type with covers (see Subsection 9A.2.3.1.8). Control, instrument, and small power cables installed in trays are random and lie in multiple layers.

Large power cables are installed in a single layer and are spaced. Conduits contain one or more cables. Although some delay in fire propagation through conduits can be expected, no credit is taken for such delay in this evaluation.

Electric Power Research Institute (EPRI) tests have demonstrated that an electrical short will not propagate a fire in the type of cable installed at Fermi 2. Therefore, an exposure fire would be required for propagation of a cable fire. The EPRI test "NP 1881" documents that a minimum of 4 gal of flammable liquid burning for 10 minutes is necessary to cause a cable fire to slowly propagate. In the test, the cable fire self-extinguished after approximately 30 minutes. This indicates the EPR/Hypalon-jacketed cable has a high resistance to fire.

For the fire hazards analysis, cable insulation quantities were estimated using the following procedure:

a. A representative cable size was established for each tray class, based on tray classification (power, control, instrument, etc.)

b. The cable fill percentage per tray was determined from the cable routing database.

c. The insulation quantity was obtained by multiplying the tray length, weight of insulation of the cable size representative of the tray loading and actual tray fill percentage for all areas.

The total insulation weight was obtained through a summation of all trays in the fire zone. The cable tray lengths given in the cable routing database were used rather than measuring the tray length existing in each fire zone. This was a conservative simplifying assumption because the tray numbers do not automatically change where they pass through fire barriers or across fire zones boundaries. Therefore, the full length of the tray is added to the fire zones on both sides of the barrier or boundary. In most areas of the plant, cable in conduit was ignored based on the facts that it is a small percentage of the total cable and that the conservatism in the estimating procedure would offset the cable in conduit.

Insulation in motors is a small quantity in comparison to the quantity of cable insulation. Combustible materials inside instrumentation, control, and relay cabinets mainly consist of cable insulation, bakelite in relay housings, and small quantities of miscellaneous materials.

The Btu content of electrical and instrument cabinets was established based on an investigation of combustibles within several electrical panels at Fermi.

Electrical insulation in motor control centers and switchgear consists mainly of cable insulation. The Btu content was determined by a review of several MCC at Fermi.

Charcoal quantities were estimated based on the size of charcoal filters having comparable flow rates.

Maintenance and operating supplies consist of lube oil, hydraulic fluid, paper, cloth, plastic, and other items required for normal plant operations. In contrast to petroleum products, electrical insulation, and charcoal, which are permanent and are part of the plant design, these combustibles are nonpermanent, may vary with time, and can be moved. For the fire hazards analysis, it is assumed that plant housekeeping procedures will keep nonpermanent combustibles in general plant areas to limited quantities. In those areas where it is known that maintenance and operating supplies must be maintained, estimates are based on previous operational experience.

For fire hazards analyses performed subsequent to the original, the inventory of combustibles has been and is being addressed in accordance with the National Fire Protection Association (NFPA) "Fire Protection Handbook," latest edition. This document was used to determine the criteria for evaluating additions to the combustible inventory in each zone at Fermi 2.

The purpose of the inventory of combustibles (fire loading/ combustible loading descriptive level) is to provide the evaluating fire protection engineer with an approximation of the quantity of combustible hazards within the fire zone or area being evaluated or analyzed. The combustible loading is just one of several factors considered when performing a fire hazards analysis or evaluation. The fire protection engineer also considers the type of combustible, its use, its location, ignition sources, and fire detection and suppression systems within the given zone. These are more important to the evaluation than is the quantity of combustibles. Therefore, these factors are given greater consideration when performing fire hazards analyses and evaluations for Fermi 2.

When new cables, single or in conduit, are added to the plant, their fire loading values are not added to the fire zone's fire loading value because the fire loading value presented by them is insignificant compared to the existing estimates. Cables in conduit are accepted as not contributing to the fire loading of a fire zone or area.

When significant amounts of combustibles as described above or cable trays are added to a fire zone, the combustible loading is reviewed accordingly and its effects evaluated for the affected fire zones.

9A.2.2.3 Review of Structural Fire Barriers

For the original fire hazards analysis, walls, floors, and ceilings were assigned fire-resistance ratings based on their construction. Door ratings were established to conform with the fire rating of the walls in which they are installed. Each penetration in a designated fire barrier is fire stopped with the appropriately rated firestop. Cable tray penetrations through non-rated walls, floors, and ceilings are fire stopped (see Figures 9A-1 through 9A-18). See Subsection 9A.2.3.1.1 for a discussion on internal seals inside electrical conduits penetrating rated fire barriers.

Subsequent design and analysis ensures that the barriers separating safety-related zones will prevent the propagation of fires.

9A.2.2.4 Existing Fire Detection/Protection Equipment

For the original fire hazards analysis, the following information was reviewed concerning existing fire detection and protection equipment:

a. Type and location of fire detector

b. Configuration of fire protection (water) system

c. Type and location of valving

d. Type, capacity, and location of fire pump

e. Type and location of hose reel

f. Type and location of fire extinguisher

g. Location and configuration of permanently installed water sprinkler or deluge systems

h. Location and configuration of permanently installed gaseous fire suppression systems

i. Type of actuation for fire protection systems.

In addition to the above, sprinkler system densities are taken into account in performing fire hazards analyses and evaluations.

9A.2.2.5 Fire Protection Layout Drawings

Fire protection layout drawings (Figures 9A-1 through 9A-18) have been developed to present information related to the fire hazards analysis. The drawings show each safety-related building, including equipment not required for safe shutdown from a fire, fire barriers within each building, the plant shutdown equipment found within each building, and fire detection and suppression equipment. These drawings support the basis for the fire hazards analysis.

9A.2.3 Fire Hazards Analyses and Evaluations

Following information collection and drawing preparation, the original fire hazards analysis was performed.

Subsequent fire hazards analyses are performed using a similar process plus new considerations that have been learned or identified as requiring evaluation. The steps used to perform these analyses and general considerations are discussed below. The detailed analysis for each fire zone, with results, is presented in Section 9A.4.

9A.2.3.1 Identification of Fire Areas/Zones

To provide a systematic analysis that can be updated in the future, the plant is divided into fire areas in accordance with the definitions of BTP APCSB 9.5-1. The fire areas are: fire area RB, reactor building; fire area AB, auxiliary building; fire area TB, turbine building; and fire area RHR, residual heat removal complex. For analytical purposes, the fire areas have been further subdivided into fire zones. Fire zone boundaries occur at existing physical features of buildings such as floors/ ceilings and walls.

Although certain rooms are enclosed by rated fire walls, floors, and ceilings, which by definition makes them fire areas, they are considered zones or parts of a zone for this analysis.

The analysis, discussed in Section 9A.4, is presented on a building-by-building basis.

9A.2.3.1.1 Fire Barrier Penetrations

Fire barrier penetrations are provided with approved rated seals or have been evaluated via a specific fire hazards analysis.

The acceptability of the relay room stairwell seal design for cable tray crossover penetrations is based on fire tests and engineering analysis. This approach was found acceptable in SSER No. 5.

The conduit fire protection research program final report (Reference 11), submitted to the USNRC in 1987 by the Wisconsin Electric Power Company, provides the acceptance criteria to determine if an internal conduit seal is required for electrical conduits routed through rated fire barriers. This acceptance criteria which has been accepted by the USNRC (Reference 9 and Reference 10) is used at Fermi 2 to determine if and when an internal conduit seal is required for those electrical conduits routed through rated fire barriers. This criteria which evaluates each side of the fire barrier separately, is as follows:

a. Conduits that terminate in junction boxes or other noncombustible closure need no additional sealing

b. Conduits that run through an area but do not terminate in that area need not be sealed in that area

c. Conduits smaller than 2" diameter that terminate 1 foot or greater from the barrier need not be sealed

d. Open conduits of 2" diameter that terminate 3 feet or greater from the barrier need not be sealed

Consequently, electrical conduits which do not meet the criteria outlined above, and are routed through rated fire barriers, are provided with rated internal seals as required.

9A.2.3.1.2 Fire Boundaries

Fermi 2 has fire zones that are not enclosed by 3-hr-rated fire barrier boundaries. The barriers were reviewed by the NRC in 1981 and found to provide an acceptable level of protection, as stated in SSER No. 2.

As part of the 10 CFR 50, Appendix R, deviation submittal (Reference 1), additional information and analyses of these unrated boundaries were provided. SSER No. 5 reaffirms the acceptability of the zone boundaries. The unrated boundaries have unsealed openings such as pipe and duct chases, hatches, and open stairwells. Generally, the unrated boundaries are acceptable for one or more of the following reasons:

a. The Fermi 2 design separates Division I and Division II safe-shutdown cables and equipment in the reactor building

b. The lack of combustible materials in the stairwells and open penetrations

c. The large volume of the reactor building wherein heat can be dissipated

d. The installation of automatic sprinklers in areas considered to present a fire hazard and in areas to prevent fire propagation

e. The administrative control of combustible materials and ignition sources within the plant

f. Early-warning smoke detection provides assurance of prompt fire brigade response

g. Cable tray penetrations are fire stopped at boundaries, thereby eliminating cable trays as a means of fire propagation between zones.

The unrated boundaries are: All Reactor Building floors and ceilings; the walls between Reactor Building Fire Zones 01RB and 02RB, 02RB and 03RB, and 03RB and 04RB, as shown in Figures 9A-2 and 9A-3; and the walls between Auxiliary Building zones 14AB and 15AB and the floor between Auxiliary Building zones 13AB and 15AB.

9A.2.3.1.3 One-Hour Protective Envelope

The 1-hr barrier is composed of 3M fire barrier material. Initially, there were some questions whether the 3M material design and installation configuration met NRC requirements. Subsequently, this fire-retardant material was rated by the Underwriters Laboratories as a 1-hr protective envelope. In Reference 4 submittal justification was demonstrated for the 3M material and the design was found acceptable in SSER No. 5.

The 3M material is being used as a 1-hr protective envelope to protect safe-shutdown cables in specific fire zones as delineated in the fire hazards analysis. Also, it has been installed throughout the plant on cables, conduit, and supports of equipment no longer required to be protected for safe shutdown. Therefore, when it is removed for maintenance purposes, it will not be replaced.

3M material has been added to the Auxiliary Building basement to protect cable trays and supports. This protective envelope has been tested by a nationally recognized testing laboratory and qualified as a 1-hour envelope in accordance with current NRC requirements. In addition, tested fire breaks have been added to trays in the Auxiliary Building Basement to ensure that a postulated fire cannot spread through these cable trays in such a manner as to damage redundant safe shutdown components. The specific areas and cable trays protected are described in the fire hazards analysis.

9A.2.3.1.4 TSI Three-Hour Barrier

Thermo-Lag 330-1 material is not used on site as a fire rated material; rather it is used in the following locations as a nonrated continuous smoke and gas barrier as defined in NFPA 101:

a. As a barrier between the Relay room (Fire Zone 03AB) and the control center northeast stairwell on elevation 613’-6” (also Fire Zone 03AB)

b. As a HVAC chase floor on elevation 613”-6” at column H-11 above the cable tray area (Fire Zone 02AB) on 603’-6”

c. As a HVAC chase floor on elevation 630’-6” in the southwest corner of the cable spreading room above the relay room (Fire Zone 05AB)

9A.2.3.1.5 Fire Doors

Doors in rated barriers are either listed or labeled by a nationally recognized laboratory; or have been evaluated via a specific fire hazards analysis. Fire doors R3-13, R3-27, R1-11, and R1-8 have approved deviations as listed in Section 9A.4 and SSERs No. 5 and No. 6.

In this appendix, as related to fire doors, "A" means the door has a 3-hr fire-resistance rating; "B" means the door has a 1-1/2-hr fire-resistance rating; and "C" means the door has a 3/4 hour fire resistance rating.

9A.2.3.1.6 Fire Dampers

Fire dampers installed in fire barrier boundaries at Fermi 2 are 3-hr rated or have been evaluated via a specific fire hazards analysis. In some instances, there are single 1-1/2-hr dampers, two 1-1/2-hr dampers installed in series, and ganged dampers. These conditions and installations have been evaluated and documented (Reference 7 and SSER No. 5).

The fire dampers have been justified based on manufacturer's tests of similar installations, the negligible fire loading on each side of the barrier of concern, and the installation of early-warning fire detection on each side of the barrier of concern.

For more information on fire dampers installed at Fermi 2, see Subsection 9.5.1.2.

9A.2.3.1.7 12-In. Concrete Block Walls

In certain areas of the auxiliary building, 12-in. concrete block walls have been erected to provide separation from other parts of the building. These walls are removable to facilitate equipment changeout and repairs. Edison has evaluated these walls and considers them equal to a 3-hr barrier. Although a specific rating test does not exist for this design, the 12-in. block wall will prevent any postulated fire from spreading and therefore provides protection equivalent to a 3-hr-rated barrier. (See Reference 3.)

9A.2.3.1.8 Solid-Metal Trays With Covers

Solid-metal trays with solid-metal covers are installed throughout the plant. Generally, these trays contain small instrumentation cables, and the trays are usually sparsely filled. Under such conditions, Edison has taken credit for the solid-metal tray with cover as a mechanism that restricts or eliminates the propagation of a fire. The NRC has accepted this as equivalent to a fire break in cable trays. (See SSER No. 5.)

9A.2.3.2 Review of Shutdown Equipment Within Fire Areas/Zones

A shutdown analysis was originally performed as part of the overall fire protection evaluation. With the issuance of 10 CFR 50, Appendix R, Edison performed other shutdown analyses to assess compliance to the requirements of Appendix R. The original shutdown analysis was used as a starting point. The new analyses determined the circuits that needed protection due to required fire protection separation requirements for redundant and associated circuits and for the prevention of spurious operation. A summary is provided in Section 9A.3.

An important aspect of reviewing shutdown equipment is the consideration of its function and the location of redundant or other equipment capable of performing the same function. In some cases, two or more sets of redundant equipment are located in the same fire zone. When this occurs, it is necessary to evaluate actual separation, barriers, combustibles in the immediate vicinity of the equipment, ignition sources, and fire detection and suppression equipment in the fire zone. In cases where other equipment capable of performing the same function is located in a different fire zone, it is necessary to perform an analysis to demonstrate that the equipment in the fire zone under consideration could be destroyed by a fire without adversely affecting plant shutdown capability.

9A.2.3.3 Calculation of Fire Loading

For the original fire hazards analysis and subsequent analyses, combustible materials located within each fire zone have been listed and the fire loading, in Btu/ft^2, has been calculated, and the current loadings are documented in a detailed engineering design calculation.

This loading, along with the type of combustibles and the anticipated rate of burn, is used to verify the adequacy of existing fire barriers. For fire-barrier ratings as related to heat load (Btu/ft^2), see Table 9A.2-1.

9A.2.3.4 Review of Ventilation Systems

Ventilation equipment required to cool rooms containing plant shutdown equipment is considered safe-shutdown equipment. Ventilation systems have been designed and installed as described in Section 9.4.

9A.2.3.5 Examination of Fire Detection and Suppression

The examination of fire detection and suppression consists of determining how a fire within a fire zone will be detected and extinguished. It is assumed that permanently installed fire-detection, fire-suppression, and fire-fighting equipment will function as designed.

The types of combustibles and their fire loadings are reviewed to determine the type of suppression and detection equipment required to provide early warning and contain or extinguish a fire within the zone. The effect of water on electrical components and safe-shutdown equipment is a consideration in the selection of the design and type of suppression system that was or will be installed at Fermi 2.

9A.2.3.5.1 Fire Detection Systems

Fermi 2 fire detection systems consist of the detectors, associated electrical power supplies, and the annunciator panels. The types of detectors used are: ionization, thermal, infrared, and photoelectric. The fire detection systems provide local and remote audible and visual alarms. The remote alarms are in the main control room. The fire detection systems are installed in areas having safety-related equipment and/or safety-related cables.

The fire detection systems are installed in accordance with NFPA 72D except that a permanent recording device is not installed as required. A deviation was granted in SSER No. 5 based on the fact that the operators continually man the control room and log each fire alarm received in the control room. Also, control room alarms can only be reset manually at the local fire alarm panel.

Fire detection systems that are used to actuate suppression systems in the reactor/auxiliary building are Class A systems as defined in NFPA 72D. All other redundant safety-related division areas have a cross-zoned Class B detection system.

Edison performed an evaluation of the fire detection system to verify installation with NFPA 72E. The evaluation included assessing detector spacing, location, ceiling types and construction, interferences by heating, ventilation, and air conditioning (HVAC) airflow patterns, and accessibility for testing and maintenance. As a result, some detectors were added in specific areas as described in Reference 7 and a deviation was requested for spacing of the detectors in the torus area. The deviation was approved in SSER No. 5.

Note: Fire detection in the Security Diesel Generator enclosures utilize both infrared and thermal detectors which actuate a FM-200 clean agent system and sends a signal to the security Central Alarm Station which is continually manned.

For more details on the Fermi 2 fire detection systems, see Subsection 9.5.1.2.

9A.2.3.5.2 Fire Protection Systems

Fermi 2 fire protection systems consist of automatic suppression systems including water sprinkler, CO_2, Clean Agent, and Halon systems, the water supply system, yard hydrants, fire pumps, standpipes, and hose stations. For details on these systems, see Subsection 9.5.1.2.

FM-200 Clean Agent extinguishing systems are used in certain areas of Fermi 2. These systems are activated by a NFPA-72 and NFPA-70 compliant fire detection system. These clean agent systems were designed, installed, and tested in accordance with NFPA-2001 requirements.

Halon 1301 total flooding systems are used in certain areas of Fermi 2. These systems are activated by ionization detectors of a Class A fire alarm circuit or photoelectric detectors. These systems were designed and installed using NFPA 12A as guidance.

Hose stations are located throughout the plant. The hose stations were installed using NFPA 14 as guidance. They are equipped with 1-1/2-in. approved lined hose and adjustable pattern fog nozzles. Pressure reducing devices are not installed as required by NFPA-14 at all hose station outlets where the pressure exceeds 100 psig, to reduce the pressure with required flow at the outlet to 100 psig. This is acceptable because the hose stations and fire hose are only used by trained fire brigade members, and adjustable pattern fog nozzles are provided at all hose stations, except for the fifth (refueling) floor of the reactor building where solid stream nozzles are provided. Pressure reducing devices that significantly reduce pressure are provided for hose station outlets on the fifth floor of the reactor building and on floors below the grade floor of 583 ft 6 in., due to excessively high pressure at those hose stations. The reason for utilizing a higher pressure at hose stations is to be able to more effectively fight fires at the ceiling height where cable trays are located. These reducers maintain pressure at the hose at approximately 130 psi. The higher pressure is needed for the hose stream's reach. A fire at ceiling height, 20 to 30 ft, would otherwise be difficult to extinguish. To compensate for the higher pressures, the fire brigade is trained in handling hose streams with higher pressures and signs have been placed on the hose cabinets in safety-related buildings restricting their use to the fire brigade. General employee training covers the use of and restrictions on the fire hose stations (Reference 8).

9A.2.3.6 Evaluation/Conclusions

An evaluation is performed to determine whether the plant is adequately protected in the event of a design-basis fire within a fire zone. This evaluation is based on all the previously noted information. The primary objective is to determine if a fire will jeopardize plant safe shutdown.

Questions addressed in the fire hazards analysis or evaluation of the safe shutdown fire area/zones are typically the following:

a. Is there safe-shutdown equipment within the fire zone?

b. Can the function be fulfilled by redundant equipment in other fire zones?

c. Is this a single item of equipment or are both divisions of redundant equipment involved in this fire zone?

d. Does the ventilation system contribute to the spread of the fire and/or products of combustion to other fire zones that would be otherwise unaffected?

e. How will a fire in the fire zone be detected?

f. What is the response time of the detection devices or scheme? Is this adequate?

g. How will a fire in the fire area/zone be extinguished?

h. How quickly can the suppression equipment be placed into service and what is its effectiveness? Is this adequate?

i. Can the plant be shut down despite the design-basis fire and fire hazards identified within the fire zone?

If the answer to question i. is YES after all the other questions are addressed, it is concluded that the individual fire zone is adequately protected against fire from the standpoint of plant safe shutdown.

If the answer to question i. based on the preceding analyses is NO, design changes are implemented to ensure that adequate protection is available to allow plant safe shutdown.

9A.2.3.7 Containment of Radioactivity

The reactor, radwaste, and turbine buildings house equipment that normally contains significant concentrations of radioactivity. The methods of containing radioactive leakage and releases within these buildings are as follows:

a. Gaseous activity

   Gaseous release or leakage inside the buildings will be retained and controlled within the buildings by their respective ventilation systems. These systems are described in Section 9.4. Radiation monitors are located in the exhaust points. On detection of high radioactivity in the effluents, these monitors actuate an alarm in the main control room and simultaneously trip the ventilation fans and close the isolation dampers. The consequences of a fire in an area capable of releasing radioactive gases are less severe than the most significant gaseous release from the failure of the offgas system, described in Subsection 15.11.4

b. Liquid activity

Liquid spillage or leakage from equipment within these buildings drains into the respective building floor drain sump. Subsection 9.3.3 provides a description of the floor drain systems in the various buildings. From these sumps, it is pumped to the radioactive waste floor drain collection tank for normal liquid waste processing. Section 11.2 details the handling and containment of liquid radioactive waste. The consequences of a fire in an area capable of releasing radioactive liquids are less severe than the most significant release resulting from failure of the liquid radwaste system described in Subsection 11.2.3.1.

Radioactive liquids and gases are normally contained within piping and process equipment, such as tanks, pumps, demineralizers, filters, and evaporator packages. The major source of radioactivity is process equipment that is located in shielded cubicles having very low fire loadings.

A possible problem resulting from a fire is that water used to fight the fire may become radioactively contaminated. However, such contamination does not result in uncontrolled releases. The fire-fighting water will be contained and controlled in the same manner as spillage or leakage described above.

9A.2 METHODOLOGY – FIRE HAZARDS ANALYSIS

REFERENCES

1. Letter from W. H. Jens, Detroit Edison, to B. J. Youngblood, NRC, Subject: Submittal of Deviations From Staff Interpretations of Fire Protection Features in 10 CFR 50, Appendix R and Justification, dated August 3, 1984 (EF2-72717).
2. American National Standards Institute, 1976. Draft-Generic Requirements for Nuclear Power Plant Fire Protection, ANSI N18.10.
3. Detroit Edison Company, Fermi 2 Project Specification 3071-80, "Special Wire and Cable," March 1972.
4. Letter from W. H. Jens, Detroit Edison, to B. J. Youngblood, NRC, Subject: Qualification of 3M Fire Wrap, dated October 22, 1984 (EF2-72266).
5. Letter from W. H. Jens, Detroit Edison, to B. J. Youngblood, NRC, Subject: Additional Information Concerning "Cross-Over" Cable Fire Stops and Use of Vinyl Tile in the Control Center, dated September 27, 1984 (EF2-72260).
6. Letter from W. H. Jens, Detroit Edison, to B. J. Youngblood, NRC, Subject: Transmittal of Fire Protection Information, dated August 4, 1984 (EF2-69218).
7. Letter from W. H. Jens, Detroit Edison, to B. J. Youngblood, NRC, Subject: Additional Fire Protection Information, dated February 4, 1985 (NE-85-0275).
8. Letter from W. H. Jens, Detroit Edison, to B. J. Youngblood, NRC, Subject: Additional Fire Protection Information, dated February 18, 1985 (EF2-70391).
9. Letter from C. E. McCracken, NRC, to C. W. Fay, Wisconsin Electric Power Company, Subject: Review of Draft Safety Evaluation of Conduit Fire Seal Topical Report for Proprietary Content, dated October 23, 1989.
10. Enclosure to Reference 9, Technical Evaluation Report, Conduit Fire Protection Research Program submitted by Wisconsin Electric Power Company TAC 66623; by Science Applications International Corporation, dated May 12, 1989 under contract NRC-03-87-029, Task 3, SAIC 88/1824.
11. Conduit fire test program final report; prepared by Professional Loss Control, Inc., for the Wisconsin Electric Power Company; dated June 1, 1987. Document number: DTC:TDDATA; DSN: 1797E.
12.

TABLE 9A.2-1 REQUIRED BARRIER RATINGS FOR FIRE LOADINGS[a]

Fire Loading (Btu/ft^2)	Required Barrier Rating
40,000	30 minutes
80,000	1 hr
120,000	1-1/2 hr
160,000	2 hr
200,000	2-1/2 hr
240,000	3 hr

[a] National Fire Protection Association Handbook, 14 Edition, pages 6-81.

9A.3 PLANT SAFE SHUTDOWN

The primary objective of the fire hazards analysis is to evaluate plant design and modifications to ensure the ability to achieve and maintain safe shutdown in the event of a fire in accordance with the fire protection license condition. The safe-shutdown analysis starts with the reactor at normal full power and ends with the reactor in a cold-shutdown condition with long-term cooling in progress, using the residual heat removal (RHR) system.

Safe-shutdown analyses are maintained in controlled engineering documents performed for Fermi 2 to evaluate compliance to 10 CFR 50, Appendix R, Section III.G. These analyses included safe-shutdown capability evaluations and associated circuits of concern, for example, common power supply, common enclosure, spurious operation, and high/low-pressure interfaces. For fires in most of the fire zones, safe shutdown is accomplished from the main control room using one of the divisions of safe shutdown equipment in accordance with the technical requirements of Section III.G.2 of Appendix R. For fires occurring in one of the dedicated shutdown areas of concern (Fire Zones 03AB, 07AB, 08AB, 09AB, 11AB or 13AB), safe shutdown is accomplished from outside the main control room using the alternative shutdown system (including the dedicated shutdown panel) as described in Section 7.5.2.5 in accordance with the technical requirements of Sections III.G.3 and III.L of Appendix R.

Subsection 9A.3.1 outlines the shutdown sequence on which the fire hazards analyses were based. Subsection 9A.3.2 lists the systems required to accomplish plant shutdown. Subsection 9A.3.3 discusses the method of safe-shutdown analysis.

9A.3.1 Shutdown Sequence

9A.3.1.1 Shutdown from the Main Control Room Using One of the Safe Shutdown Divisions

For the fire hazards analysis, the shutdown sequence starts with the detection of a fire of a magnitude such that plant shutdown is required. Depending on the location and magnitude of the fire, the plant may be quickly brought to hot shutdown or tripped by the plant operator. For the fire hazards analysis, it is assumed that plant shutdown is initiated with an automatic or manual scram of the reactor from the main control room. Once a scram is initiated, no further control rod motion is required.

It was also determined that, although fire damage might cause the plant to trip, no fire could negate the ability to manually trip the reactor.

There are two normal offsite ac power sources available as well as two redundant Class 1E power sources. However, for the purpose of the fire hazards analysis, a loss of offsite power is assumed to occur. The emergency diesel generators (EDGs) for the division credited for shutdown are assumed to start and restore the required portions of the emergency onsite electrical system.

It was assumed, for analytical purposes, that control of reactor pressure by the main turbine pressure regulators through the bypass valves to the condenser was lost. Therefore, the reactor was isolated from the normal heat sink and feedwater flow was stopped at the pressure associated with normal full power. In this condition, reactor pressure is relieved through the safety/ relief valves (SRVs) to the suppression pool.

Additional information pertaining to the safe shutdown systems for main control room shutdowns using one of the normal post-fire shutdown divisions, as well as information related to the safe shutdown analysis are provided in Sections 9A.3.2 and 9A.3.3. Analysis results for applicable fire zones are provided in Section 9A.4.

Manual activation of SRVs and the reactor core isolation cooling (RCIC), the HPCI, or manual activation of SRVs and low pressure coolant injection (RHR or Core Spray) system, brings the reactor to a hot-shutdown condition. During this phase of shutdown, the suppression pool is cooled by operating the RHR system in the suppression pool cooling mode. Reactor pressure is controlled and core decay and sensible heat are rejected to the suppression pool by the HPCI or RCIC turbines or by manually relieving steam pressure through the relief valves. Reactor water inventory is maintained by the high-pressure RCIC or HPCI systems or by the Core Spray or RHR system in conjunction with manual operation of two or more SRVs.

The depressurization, caused by operation of the HPCI or RCIC turbines or manual operation of the relief valves, cools the reactor and reduces its pressure at a controlled rate until the reactor pressure becomes so low that the RCIC or HPCI system discontinues operation. This condition is reached at 50 to 100 psig reactor pressure. The RHR system is then operated in a shutdown cooling mode wherein the RHR system heat exchanger is used to bring the reactor to a cold, low-pressure condition. The cooldown process is ended when long-term decay heat removal operation is established.

For fires in the control center complex and other selected zones, the reactor is tripped in the control room and safe shutdown is completed using the alternative shutdown system described in Subsection 7.5.2.5.

The alternative shutdown system has been designed and installed to meet the technical requirements of 10 CFR 50, Appendix R, Sections III.G.3 and L. This system provides safe-shutdown capability separate and remote from the control center complex and other plant fire zones. The system is used when a fire within the complex or other dedicated shutdown areas of concern is determined to have significantly damaged the safe-shutdown equipment/cabling within these zones. The alternative shutdown system consists of a dedicated shutdown panel (past correspondence with the NRC referred to this panel as the 3L panel) and selected systems that were already installed at Fermi 2. For details on alternative shutdown system capability, including the dedicated shutdown panel, system parameter monitoring, and transfer switches, see Subsection 7.5.2.5.

9A.3.1.2 Shutdown from the Dedicated Shutdown Panel Using the Alternative Shutdown System

As with the control room shutdown described in the previous subsection, the reactor is scrammed from the control room before it is abandoned and a concurrent loss of offsite power is assumed for the limiting analysis. However, the emergency diesels, HPCI, RCIC and multiple SRVs for rapid depressurization may not be available due to fire damage. The Standby Feedwater System, powered by CTG 11-1, or an alternate CTG using the standby diesel generator that provides high pressure RPV makeup and controls for a single SRV are available on the dedicated shutdown panel to provide RPV pressure control for hot shutdown conditions.

Additional information pertaining to the systems used to support the alternative shutdown system utilizing the dedicated shutdown panel and the related safe shutdown analysis are provided in Sections 9A.3.2, 9A.3.3 and applicable fire zones in Section 9A.4.

9A.3.2 Shutdown Systems

The following table is a summary of the Fermi 2 plant systems required to achieve and maintain safe shutdown following a fire. The entries in the table differentiate whether the given system is used for hot shutdown, cold shutdown, or both. It should be noted that for a specific fire zone, not all of the systems listed in the table are required. For example, the hot shutdown RPV makeup function can be performed by HPCI, RCIC, SBFW, or RHR in conjunction with SRVs. In addition, separate columns are provided for shutdown from the control room using one of the normal post-fire shutdown divisions and for shutdown from outside the control room using the alternative shutdown capability including the dedicated shutdown panel. The list of systems includes both systems that directly provide a post-fire shutdown function such as RPV makeup, as well as systems that are required to support these "front-line" systems. For example, RHR Service Water is required to support the RHR when it is aligned for shutdown cooling during the cold shutdown phase. The Appendix R safe shutdown system, component, cable list, and the basis for inclusion in the safe shutdown analysis are maintained in a controlled design calculation.

ID	System Name	Divisional Shutdown from the Control Room	Dedicated Shutdown from Outside the Control Room
B21	MSIVs (manual closure)	Hot/Cold	Hot/Cold
B21	SRVs	Hot/Cold	Hot/Cold
B21	RPV pressure & level instrumentation	Hot/Cold	Hot/Cold
B31	Recirculation (valve lineup for shutdown cooling)	Cold	Cold
C11	CRD hydraulic control units	Hot/Cold	Hot/Cold
C36	Dedicated Shutdown Panel Controls	NA	Hot/Cold
C36	Dedicated Shutdown Panel Instrumentation	Hot/Cold	Hot/Cold
C36	Dedicated Shutdown Support Systems & Components	NA	Hot/Cold
E11	RHR - suppression pool cooling	Hot	Hot
E11	RHR - low pressure RPV makeup	Hot	Hot

ID	System Name	Divisional Shutdown from the Control Room	Dedicated Shutdown from Outside the Control Room
E11	RHR - shutdown cooling	Cold	Cold
E11-51	RHR Service Water (RHRSW)	Hot/Cold	Hot/Cold
E11-56	RHRSW Cooling Towers	Hot/Cold	Hot/Cold
E21	Core Spray	Hot	NA
E41	High Pressure Coolant Injection (HPCI)-Div 2	Hot	NA
E51	Reactor Core Isolation Cooling (RCIC)- Div 1	Hot	NA
N21/R11/R32	Standby Feedwater (SBFW), CTG 11-1 and associated BOP ac & dc	NA	Hot/Cold
P44	Emergency Equipment Cooling Water (EECW)	Hot/Cold	Hot/Cold
P45	Emergency Equipment Service Water (EESW)	Hot/Cold	Hot/Cold
P50-02	Control Air for Control Center HVAC air path (dampers)	Hot/Cold	NA
R30/R14/R16	ESF ac distribution for shutdown equipment	Hot/Cold	Hot/Cold
R30-01	Emergency Diesel Generators (EDGs) & auxiliaries	Hot/Cold	NA
R32	ESF dc system	Hot/Cold	Hot/Cold
T41	Control Center HVAC	Hot/Cold	NA
T41	ESF fan coil units	Hot/Cold	Hot/Cold
T47	Drywell Cooler Fans	NA	Hot/Cold
T49	Drywell Pneumatics	Hot/Cold	NA
X41-03	EDG & EDG Switchgear Room HVAC	Hot/Cold	NA

Systems, components and cables that are vulnerable to causing adverse consequences from hot shorts caused by cable damage have been associated with specific scenarios of concern such as loss of RPV inventory, loss of suppression pool inventory, SRV actuation, etc. Such cables and components that are not associated with the safe shutdown systems listed above are analyzed separately in the safe shutdown analysis as described in Section 9A.3.3.

9A.3.3 Method of Safe-Shutdown Analysis

To maintain a safe-shutdown capability, Fermi 2 was designed and built with the concept of keeping Division I cables and equipment separate from those of Division II. The dividing line is column line 12 for the reactor building. Division I cables and equipment are normally routed and located on the north side while those of Division II are normally on the south side of the line. The auxiliary building was designed differently. Therefore, analyses were performed and protection provided as required. In some instances where Division I and II cables cross over into the opposite division's side of the building and the cables/equipment are within 20 ft of their redundant cables, they are provided with a 1-hr-fire-rated protective envelope, to achieve or maintain 20 ft of separation with no intervening combustibles, or an analysis is performed to show that a loss of the interacting redundant divisional circuit(s) will not affect plant safe-shutdown capability.

An important requirement relevant to the fire hazards analysis is that regarding separation of cables and cable trays. Since most of the safety-related cables are also required for plant shutdown, separation of redundant safety-related cables in cable trays has been evaluated within each fire zone.

Each plant area is systematically evaluated for the ability to achieve and maintain safe shutdown, assuming that all of the equipment and cables within it are subject to fire damage. One of three shutdown strategies, Division 1 shutdown from the control room, Division 2 shutdown from the control room, or dedicated shutdown from outside the control room, is assigned to each. The dedicated shutdown strategy in accordance with the technical requirements of Appendix R Section III.G.3 and III.L is used only when divisional shutdown from the control room is not feasible. In general, these strategies were developed as part of the original plant licensing basis, and provide the framework for the NRC-approved deviations documented in docketed NRC correspondence, the plant SER, and its supplements. The inventory of safe shutdown equipment and cables, including associated circuit cables and equipment, is established, and conflicts between the shutdown strategy and the affected equipment are identified. The resolution of each of these shutdown conflicts is documented in a controlled engineering analysis. Examples of acceptable resolutions include protecting shutdown division cables with fire barriers, evaluating the electrical schematics to show that the electrical fault of concern is not applicable for the fire location being evaluated, use of NRC-approved deviations, or removal of certain fuses during power operation.

For spurious operation due to hot shorts, cables and equipment that can adversely affect safe shutdown systems (e.g., flow diversion paths from cooling systems) are evaluated, as are those that can adversely affect the safe shutdown functions or performance requirements independent of the safe shutdown systems (e.g., loss of RPV isolation or spurious SRV opening). In addition to evaluating single hot shorts between two conductors, the analysis includes any number of conductor-to-conductor shorts with a single cable and cable-to-cable shorts for any two cables within the area, in accordance with the NRC Regulatory Issue Summary RIS 2004-03 (Reference 1). For the RHR shutdown cooling letdown path high-low pressure interface, the division 2 outboard containment isolation valve is closed and de-energized.

9A.3 PLANT SAFE SHUTDOWN

REFERENCES

1. NRC Regulatory Issue Summary 2004-03, Risk-Informed Approach for Post-Fire Safe Shutdown Associated Circuit Inspections, dated March 2, 2004

9A.4 FIRE HAZARDS ANALYSIS

9A.4.1 Reactor Building

9A.4.1.1 General Description

The reactor building is a multilevel structure, separated from all other buildings by 3-hr-rated fire barriers. For purposes of this fire hazards analysis, the reactor building has been designated as fire area RB. It is bounded on the north, south, and west by outside walls and on the east by the auxiliary building.

The outage building is located four (4) inches south of the south wall of the reactor and auxiliary building. The outage building is of completely noncombustible construction; additionally no safe shutdown systems or equipment are located in this building. The outage building is structurally separated from plant structures, however, nonstructural flashing is attached to both the reactor and auxiliary building to seal and protect the four-inch gap between it and the outage building.

The north, south, and west exterior walls (below the metal siding on elevation 684′−6″) are constructed of at least 18 inches of reinforced concrete which will prevent an exposure fire in the yard area from propagating into the Reactor Building. Except as detailed below, these three walls are 3-hr-rated fire barriers.

The walls of the personnel airlock (on the south side of the reactor building) are constructed of 18 inches of reinforced concrete. The airlock itself, is separated from the yard area by two 1½-hr rated fire doors (R1-6 and R1-7) which together provide a level of protection at least equivalent to a 3-hr-rated fire door. In addition, as demonstrated above, the airlock walls are 3-hr-rated barriers.

The railroad bay pressure resistant door (also on the south side of the reactor building) is not a rated fire door; however, it is constructed of heavy steel channels covered with metal sheeting on both sides. This door is of much more substantial construction than the typical 3-hr-rated fire doors because of its pressure resistance rating. In addition, heat detectors and an automatic sprinkler system are provided in the railroad bay to further ensure that a fire originating outside the plant will not propagate into the reactor building via the railroad bay. These features and combustible loading in the vicinity of both the inside and outside door have been evaluated and found to provide adequate assurance that a fire will not propagate from outside the building or inside the railroad bay airlock into the southwest corner first floor of the reactor building.

The south and west walls of the reactor building contain six (6) removable plug sleeves which are 1-hr-rated penetration seals. These sleeves are either sealed with solid steel plates or contain steel plates with capped pipes and conduits passing through the penetrations from the interior of the reactor building. The sleeve openings on the exterior of the reactor building are closed with steel blind flanges. In addition, the space between these plates is totally devoid of combustible materials. Therefore, although they are not tested and approved seal configurations they are of substantial steel construction and will prevent flame propagation into the reactor building.

The fifth floor of the reactor building (elevation 684′-6″) is not being provided with fire rated exterior walls because its three exterior walls are constructed of insulated metal siding which is not a tested and rated construction. However, the siding will protect the fifth floor from the heat and smoke which would be generated from a fire in the yard. The base of the metal-sided walls is 100 feet above the yard grade level - well above any postulated exposure fire in the yard areas adjacent to the reactor building. Therefore, the as-built construction of these walls is sufficient to protect the fifth floor of the reactor building from a fire in the yard area.

The reactor building houses the reactor, reactor drywell and suppression pool, fuel handling equipment and storage pool, and other reactor auxiliary equipment.

With the exception of the drywell, ventilation of the reactor building is provided by the reactor/auxiliary building ventilation system. The drywell cooling system is provided for the drywell. These ventilation systems are discussed briefly in the individual zone descriptions. Additional details for these ventilation systems are presented in Subsections 9.4.2 and 9.4.5.

For purposes of this fire hazards analysis, the reactor building has been divided into 10 Fire Zones as follows:

a. Torus room, Fire Zone 01RB, Elevation 540 ft 0 in.

b. Northeast, northwest, southeast, and southwest basement corner rooms, Fire Zone 02RB, Elevations 540 ft 0 in. and 562 ft 0 in.

c. High pressure coolant injection (HPCI) pump and turbine and control rod drive (CRD) pump rooms, Fire Zone 03RB, Elevations 540 ft 0 in. and 562 ft 0 in.

d. Corridor area, Fire Zone 04RB, Elevations 562 ft 0 in and 564 ft 0 in.

e. First Floor, Fire Zone 05RB, Elevation 583 ft 6 in.

f. Second Floor, Fire Zone 06RB, Elevation 613 ft 6 in.

g. Third Floor, Fire Zone 07RB, Elevation 641 ft 6 in.

h. Fourth Floor, Fire Zone 08RB, Elevation 659 ft 6 in.

i. Fifth Floor, Fire Zone 09RB, Elevation 684 ft 6 in. (including the Auxiliary Building stairwell enclosure and duct space)

j. Drywell, Fire Zone 10RB, Elevation 562 ft 0 in. to 684 ft 6 in.

As discussed in Subsection 9A.3.3, the reactor building Division I cables and equipment are normally routed and located on the north side of the building (north of column line 12) and Division II cables and equipment are normally routed and located on the south side of the building (south of column line 12).

Division I is used to achieve plant safe shutdown when a fire occurs south of column line 12. Division II is used to achieve plant safe shutdown when a fire occurs north of column line 12.

9A.4.1.2 Torus Room, Fire Zone 01RB, El. 540 Ft 0 In.

9A.4.1.2.1 Description

The torus room, shown in Figures 9A-2 and 9A-3, is an octagonally shaped room which extends from the reactor building mat at Elevation 540 ft 0 in. up to Elevation 583 ft 6 in. It is bounded on the north by an outside wall; on the northeast by Fire Zone 02RB; on the east by a below-grade wall up to Elevation 551 ft 0 in. and Fire Zone 04RB thereafter; on the southeast by Fire Zone 02RB; on the south by an outside wall; on the southwest by Fire Zone 02RB; on the west by an outside wall; on the northwest by Fire Zone 02RB; and in the center by the drywell (Fire Zone 10RB), which it surrounds.

This zone houses the suppression pool (torus) and piping and cabling.

The walls (36 in.) and floor of this zone are constructed of reinforced concrete. The ceiling is constructed of 24-in.- reinforced concrete over steel beams. All penetrations through that portion of the ceiling separating this zone from the steam tunnel portion of the turbine building fire area are sealed with non-tested fire seals in the fire rated separation barrier. These seals have been evaluated and provide an adequate assurance that a fire in the Reactor Building Fire Zone 01RB will not propagate through these penetrations into the steam tunnel, or from the steam tunnel to the reactor building. Electrical penetrations through the remainder of the ceiling have fire stops. Division I cables, located in the south portion of the room, are enclosed with a 1-hr-rated fire barrier, as are Division II cables, in the north portion of the room. The doors to the corner rooms are 8-in.-thick steel watertight doors and will stop the propagation of any fire foreseen in the torus room.

Ventilation for this zone is provided by air from the four basement corner rooms (Fire Zone 02RB) abutting the northeast, southeast, southwest, and northwest walls of this zone. Air is drawn through 20 in. x 20 in. wall openings into the torus room and is directly exhausted through ductwork to the main exhaust system.

Divisions I and II redundant cables enter the torus room on the east side and traverse the room toward the west and above the center line of the torus. Division I cables are to the north and Division II cables are to the south.

Balance-of-plant (BOP) cable trays enter and traverse parallel to Divisions I and II cable trays around the torus. On the west side, the BOP trays continue around the torus, encircling the drywell above the torus and linking Divisions I and II with intervening combustibles.

Shutdown equipment located within this zone consists of the following:

a. Suppression pool (torus)

b. Divisions I and II cables

c. Divisions I and II, residual heat removal (RHR), core spray, HPCI, suppression pool instrumentation and reactor core isolation cooling (RCIC) valves, racks or equipment.

Fire detection in the torus area consists of eight ionization smoke detectors that are located adjacent to the exhaust duct grills. These detectors do not conform to the spacing requirements of NFPA 72E (beam pocket criteria). See Subsection 9A.4.1.2.4. The torus area has an automatic sprinkler system that protects the entire area. This system will protect any exposed structural steel from thermal degradation during any fire condition. The water flow alarm for the sprinkler system transmits signals to the main control room upon actuation. Fire extinguishers and manual water hose stations are located in adjacent Fire Zones.

9A.4.1.2.2 Analysis

Shutdown is achieved from the main control room. Division I is used to achieve plant safe shutdown when a fire occurs south of column line 12. Division II is used to achieve plant safe shutdown when a fire occurs north of column line 12.

There are no protective envelopes required for cables/equipment in this zone.

Redundant valves that are not backed up by functionally redundant equipment in another Fire Zone are spatially separated by more than 20 ft. The other valves, required for shutdown and located within this zone, are backed up by functionally redundant equipment in other Fire Zones.

Cable trays, which present intervening combustibles between redundant cables, have a fire break installed in them or are solid-metal trays with covers to prevent the propagation of fire within them.

Three 12-in. BOP cable trays interconnecting Divisions I and II on the west side are considered intervening combustibles. The trays are OP-016, OC-790 and OK-097. Two, OP-016 and OC-790, have fire breaks installed at about column line 12±3 ft. Cable tray OK-097 is an instrumentation cable tray and is an enclosed solid-metal tray with cover.

The automatic sprinkler system will protect the exposed steel from being adversely affected by a fire in this zone.

Inadvertent operation of the automatic fire suppression equipment will have no adverse effect on shutdown capability. Combustibles within this zone consist primarily of electrical insulation. Total fire loading for this zone is low.

9A.4.1.2.3 Conclusion

The objective for this zone is to prevent a fire from damaging redundant shutdown valves and cable and from spreading to other zones. This objective is achieved through barriers, the provision of fire detection equipment, an automatic sprinkler system, fire breaks in cable trays, and separation of redundant equipment. In addition, fire extinguishers and manual water hose stations are provided in adjacent zones.

9A.4.1.2.4 Deviations

Deviations have been approved for the following:

a. Intervening combustibles, cable trays OP-016, OC-790, and OK-097 based on area-wide sprinklers and fire stops in cable trays OP-016 and OC-790 at about column line 12 and solid-metal tray and cover for OK-097 (Reference 1, SSER No. 5 VI [1])

b. Early-warning fire detectors are not installed in accordance with NFPA 72E based on area with automatic sprinklers, alarms to the main control room, and response by the fire brigade (Reference 1, Reference 2, SSER No. 5, II.D).

9A.4.1.3 Basement Corner Rooms, Fire Zone 02RB, El. 540 Ft 0 In. and 562 Ft 0 In.

9A.4.1.3.1 Description

The basement corner rooms, shown in Figures 9A-2 and 9A-3, consist of four unconnected, triangular-shaped rooms, one of which is located in each corner of the reactor building. Each room is composed of two floors, one at Elevation 540 ft 0 in., the other at Elevation 562 ft 0 in. An open stairwell in each room connects each floor.

The zone houses the RHR pumps (Division I pumps in the northwest corner room, Division II pumps in the southwest corner room), the RCIC pump and turbine, and Division I core spray pumps (northeast corner room), and the Division II core spray pumps (southeast corner room).

Walls surrounding each room of the zone are constructed of 36-in. reinforced concrete. The doors to the torus room are 8-in.-thick steel watertight doors that will stop the propagation of fire.

The floor of the lower elevation is a reinforced-concrete mat. The floor at Elevation 562 ft 0 in. is constructed of reinforced concrete and contains unsealed penetrations and unprotected openings for stairwells and hatches. The ceilings at both elevations are 24-in. reinforced concrete and contain unsealed penetrations and other unprotected openings. Electrical penetrations through the floor and ceiling are provided with fire stops.

Ventilation air enters each room through stairwells from Elevation 583 ft 6 in. (Fire Zone 05RB). Ventilation air leaves each room through wall openings in the walls abutting the torus room (Fire Zone 01RB) on Elevation 540 ft 0 in. Each corner room has a local air-handling unit (emergency equipment room cooler) for cooling the room ambient air.

Shutdown equipment located in this zone consists of the following:

a. RHR pumps and associated valves (Divisions I and II)

b. RHR instrument racks (Divisions I and II)

c. Emergency equipment room coolers (Divisions I and II)

d. RCIC pump and turbine and associated valves (Division I)

e. Instrument racks (Division I and II)

f. Core spray pumps and associated valves (Divisions I and II)

g. Core spray instrument racks (Divisions I and II).

h. 120 V ac distribution panel (Divisions I and II)

Fire detection equipment in this zone consists of an ionization detection system in each room at each elevation. Fire suppression equipment in this zone consists of an automatic sprinkler system in the northeast room on Elevation 540 ft 0 in. and manual hose and portable fire extinguishers as shown in Figures 9A-2 and 9A-3.

9A.4.1.3.2 Analysis

Shutdown is achieved from the main control room. There is no functionally redundant equipment located in any one room within this zone. Divisions I and II RHR pumps, instrument racks, and associated valves and room coolers are located in separate rooms. Division I RHR equipment is located on Elevation 540 ft 0 in. of the room located in the northwest corner of the building. Division II pumps are located on Elevation 540 ft 0 in. of the room located in the southwest corner of the building. Division II core spray equipment is located on Elevation 540 ft 0 in. of the room located in the southeast corner of the building. Division I core spray equipment is located on Elevation 540 ft 0 in. of the room located in the northeast corner of the building. Functional redundancy for the RCIC pump located in this zone is provided by the HPCI pump located in Zone 3 of this fire area.

Division I will be used to achieve safe shutdown for fires in the southeast and southwest corner rooms and Division II will be used to achieve safe shutdown for fires in the northeast and northwest corner rooms of the zone.

Inadvertent operation of the automatic sprinkler system in the room containing the RCIC pump and turbine will have no adverse effect on shutdown capability.

The oil contained in the RCIC turbine represents a specific fire hazard in this zone due to high operating temperatures of the turbine and related piping.

Combustibles within this zone consist primarily of the following:

a. Electrical insulation

b. Lubricating oil

Total zone fire loading is low, and the fire loading in any one room is low.

9A.4.1.3.3 Conclusion

The objective for this zone is to prevent the spread of a fire in this zone to another zone containing redundant shutdown equipment and/or from damaging redundant shutdown equipment within this zone. Redundant shutdown equipment located within this zone is located in separate rooms, each located in a corner of the building. The ventilation openings to the torus room do not represent a significant potential path for fire spread due to the low fire loading within the rooms. The objective is achieved through barriers, the adequate spatial separation of redundant equipment, and the provision of early-warning detection equipment in each room, and an automatic sprinkler system on the specific fire hazard (RCIC turbine). In addition, manual water hose stations and portable fire extinguishers are provided.

9A.4.1.3.4 Deviations

Deviations have been approved for the following:

a. Installation of partial suppression in the northeast corner room, Elevations 540 ft 0 in. and 562 ft 0 in., based on cables required to achieve a safe shutdown being provided with a 1-hr fire barrier in this zone, fire detection, and low combustible loading (Reference 1, SSER No. 5, VI [13])

b. Lack of suppression in the southeast corner room, Elevations 540 ft 0 in. and 562 ft 0 in., based on low combustible loading and 1-hr fire barriers for cables required to achieve safe shutdown (Reference 1, SSER No. 5, VI [14]).

9A.4.1.4 High Pressure Coolant Injection Pump and Turbine and Control Rod Drive Pump Room, Fire Zone 03RB, El. 540 Ft 0 In. and 562 Ft 0 In.

9A.4.1.4.1 Description

This zone, shown in Figures 9A-2 and 9A-3, consists of two rooms, the HPCI pump and turbine room at Elevation 540 ft 0 in. and the CRD pump room at Elevation 562 ft 0 in. This zone is bounded on the north by a below-grade wall up to Elevation 551 ft and Fire Zone 04RB thereafter; on the east and south by a below-grade wall up to Elevation 551 ft and the auxiliary building above Elevation 551 ft; and on the west by the room containing the Division II core spray pumps (Fire Zone 02RB).

The zone houses the HPCI turbine, pump, and related valves and controls, and an emergency equipment room cooler on Elevation 540 ft 0 in., and the CRD pumps on Elevation 562 ft 0 in.

The walls and ceiling separating this zone from the auxiliary building are constructed of reinforced concrete having a fire-resistance rating of 3 hr. The door to the Division II CS pump room is watertight. The door separating this zone from the auxiliary building is a Class A fire door. Penetrations through the rated walls and the fire-rated portion of the ceiling of the 562 ft 0 in. elevation are sealed to provide a 3-hr fire-resistance rating. The floor at Elevation 540 ft 0 in. is a reinforced-concrete mat. The floor at Elevation 562 ft 0 in. is constructed of reinforced concrete with an unprotected equipment hatch. Electrical cable tray penetrations through the floor between the two elevations are provided with fire stops. Floor drains are provided on both floors.

Ventilation for this zone is provided by the reactor/auxiliary building ventilation system. Air is ducted directly to the CRD pump room and exhausted through ducts from the HPCI pump and turbine room directly to the auxiliary building main exhaust system. The HPCI pump and turbine room has an emergency equipment room cooler for cooling the room ambient air.

Shutdown equipment located in this zone consists of the following:

a. HPCI turbine, pump, and associated valves and instrument rack (Division II)

b. Emergency equipment room cooler (Division II).

No protective envelopes are required for safe-shutdown components in this zone. Fire detection equipment in this zone consists of an ionization detection system at each elevation.

Fire suppression equipment for this zone consists of a partial area automatic sprinkler system for the HPCI turbine and pump room. The hatch and stairwell opening between the two elevations of fire zone 03RB are not protected by automatic sprinklers. Manual hose stations and portable fire extinguishers are provided as shown in Figures 9A-2 and 9A-3.

9A.4.1.4.2 Analysis

Shutdown is achieved from the main control room. All of the equipment and cables in fire zone 03RB are assumed damaged due to a fire. Division I equipment outside this fire zone will be used to achieve safe shutdown for fires in this zone. The RCIC turbine and pump, and the core spray and RHR pumps located in other zones, are functionally redundant to the HPCI turbine, pump, and associated equipment in this zone. A partial area suppression system is provided in the area between the divisions in 04RB.

The lubricating oil in the HPCI turbine represents a specific fire hazard in this zone. This equipment is surrounded by curbing of sufficient height to contain any oil spills. A partial area sprinkler system has been provided for the HPCI turbine and pump room. The sprinkler system is not required for compliance with Appendix R when determining if safe shutdown can be achieved in the event of a fire in 03RB.

Inadvertent operation of the automatic sprinkler system will have no adverse effect on shutdown capability.

Combustibles within this zone consist primarily of the following:

a. Electrical insulation

b. Lubricating oil

Total zone fire loading is low.

9A.4.1.4.3 Conclusion

The objective for this zone is to prevent a fire in this zone from damaging functionally redundant equipment such as RCIC equipment and/or Division I cable located in an adjacent zone. This objective is achieved through the adequate spatial separation of redundant equipment and provision of early-warning detection equipment for the entire zone, a partial area suppression system provided in the area between the divisions in 04RB, and an approved deviation for the intervening combustibles crossing between the divisions in 04RB. In addition, manual hose stations and portable fire extinguishers are provided.

9A.4.1.5 Corridor Area, Fire Zone 04RB, El. 562 Ft 0 In. and 564 Ft 0 In.

9A.4.1.5.1 Description

This zone, shown in Figure 9A-3, consists of a north-south corridor at the Elevation 562 ft 0 in. and an east-west corridor leading to the turbine building at the Elevation 564 ft 0 in. The zone is bounded on the north by the auxiliary building; on the east by the auxiliary and turbine buildings; on the south by the auxiliary building and CRD pump room (Fire Zone 03RB); and on the west by the torus room (Fire Zone 01RB).

The zone houses electrical cables. Divisions I and II cables are all located in the north-south corridor.

The walls, floors, and ceiling separating this zone from the auxiliary and turbine buildings are constructed of reinforced concrete having a fire-resistance rating of 3 hr. The door to the turbine building is a Class A fire door. Penetrations through the rated walls, floors, and ceiling are sealed to provide a 3-hr fire-resistance rating. At the north end of the north-south corridor is a metal pressure-relieving hatch in the ceiling. The hatch is designed for steam venting of a pipe break outside the containment. Because of the light fire loading on each side of the hatch, the partial automatic sprinkler system in this zone, and the availability of manual suppression equipment, the metal hatch provides the necessary fire resistance for the zone.

Ventilation air for this zone is from the reactor/auxiliary building ventilation system. Air is duct exhausted from the zone.

Shutdown equipment located in this zone consists of Divisions I and II cables and a RCIC valve.

No protective envelopes are required for safe-shutdown components in this zone.

Fire detection equipment consists of a photoelectric and ionization detection system. Fire suppression equipment consists of an automatic sprinkler system in the 562-ft corridor, portable fire extinguishers, and manual hose.

9A.4.1.5.2 Analysis

By plant design, the reactor building Division I cables and equipment are normally routed and located on the north side of the building (north of column line 12) and Division II cables and equipment are normally routed and located on the south side of the building (south of column line 12). The RCIC valve is located on the south side of this zone.

Shutdown is achieved from the main control room. Division I will be used to achieve plant safe shutdown for fires on the south side and Division II will be used to achieve plant safe shutdown for fires on the north side of the zone.

Automatic sprinklers are installed in the north-south corridor, (562 ft) in the area of the cable trays (combustible loading for the room is concentrated in this area). There is no automatic sprinkler system in the east-west corridor (combustible loading is insignificant in this area). There are no shutdown cables in the area where automatic sprinkler protection has not been provided.

Cable trays, which present intervening combustibles between redundant cables, have fire breaks installed in them or are solid-metal trays with covers to prevent the propagation of fire. The intervening combustibles in this zone consist of two 12-in. non-Appendix R (non-R) trays (OP-020 and OC-785). Additionally, a 12-in. non-R instrument tray (OK-034) is located approximately 10 ft south of the two 12-in. non-R trays. Since the instrument tray is an enclosed solid-metal tray with cover, it is not considered an intervening combustible. An approximate 10-ft clear space exists between Division II R tray 2K-007 and of the 2 non-R trays. Also, tray 2K-007 is an enclosed solid-metal tray with cover.

All trays run horizontally, which causes a slow-burning fire with smaller heat releases.

These non-R trays represent the only in-situ intervening combustible path between Divisions I and II cables. For a single fire to affect both Divisions I and II cables, a cable tray fire must burn more than 20 ft and must traverse a clear space of approximately 10 ft.

Trays (2) OP-020 and OC-785 have a fire break installed at approximately column line 12 ±5 ft north.

Additional sprinkler heads have been installed below the pipe obstructions to improve sprinkler coverage of the area.

Combustibles located in this zone consist primarily of electrical insulation. The total zone fire loading is low.

9A.4.1.5.3 Conclusion

The objective for this zone is to prevent a fire from affecting both Divisions I and II cables located within this Fire Zone and to prevent a fire from crossing the boundaries of the zone. This is achieved through the provision of an automatic sprinkler system, barriers, fire detection system, portable fire extinguishers, and manual hose.

9A.4.1.5.4 Deviations

Deviations have been approved for the following:

a. Intervening combustibles between redundant trains based on fire stops in trays OP-020 and OC-785 (Reference 1, SSER No. 5, VI[2])

b. Partial automatic sprinklers based on the provisions of additional automatic sprinkler coverage (Reference 1, SSER No. 5, VI[2]).

9A.4.1.6 First Floor, Fire Zone 05RB, El. 583 Ft 6 In.

9A.4.1.6.1 Description

This zone, shown in Figure 9A-4, consists of the large open floor area surrounding the drywell (Fire Zone 10RB), the RHR heat exchanger rooms, railroad bay, drywell access air-lock area, and a partial height equipment room adjacent to and west of the drywell. It is bounded on the north, south, and west by outside walls; and on the east by the auxiliary building and the steam tunnel.

This zone houses the CRD hydraulic controls, RHR heat exchangers, railroad bay, neutron monitoring system (NMS) cabinets, and other auxiliary equipment. The RHR heat exchanger rooms extend up to Elevation 641 ft 6 in.

The walls and ceiling separating this zone from the auxiliary building and the steam tunnel are constructed of reinforced concrete having a 3-hr fire-resistance rating. The door opening between this zone and the steam tunnel is protected by a heavy pressure-resistant metal door. The pressure-resistant door, in combination with the labyrinth access passage, will prevent the spread of a fire from the steam tunnel area to this zone. Penetrations through rated walls and ceiling are sealed to provide 3-hr fire-resistance ratings except for the pressure equalizing line between the steam tunnel and this Fire Zone. The ability of the fire barrier to perform its function has been evaluated and determined to provide an adequate assurance that a fire in this Fire Zone will not propagate to the steam tunnel. The partial height equipment room is accessible from the south portion of the zone, and is separated from the remainder of the zone by a shield wall and ceiling. The portion of the room boundary north of column 12 has been evaluated to provide adequate separation from the north portion of the Fire Zone. The floor and unrated portion of ceiling of this zone are constructed of reinforced concrete and steel beams, and contain open stairwells, unprotected hatches, pipe chases, and unsealed penetrations. Cable tray penetrations through the floor and unrated portion of ceiling, and unrated walls are provided with fire stops.

Ventilation air for this zone is ducted directly from the reactor/auxiliary building ventilation system and is relieved to the neutron monitoring equipment room and to an area outside the personnel air lock. Air also enters the zone through the stairwells from the floor above and from the RHR heat exchanger rooms through pressure relief dampers.

Shutdown equipment located in this zone consists of the following:

a. RHR heat exchangers (Divisions I and II) and associated valves

b. CRD hydraulic control units (HCUs)

c. Instrument racks and motor control centers (Division I and II)

d. The following valves:

   1. RHR to recirculation inboard isolation valve, E1150F015A (Division I) and B (Division II)

   2. Reactor recirculation extraction to outboard isolation valve, E1150F008

   3. EECW system isolation valves, P4400F601A, P4400F603A (Division I) and P4400F601B, P4400F603B (Division II).

e. 120 V ac distribution panel

f. Standby feedwater and CTG 11-1 supervisory cables

Fire detection equipment in this zone consists of an ionization detection system. Fire suppression equipment consists of an automatic sprinkler system in the railroad bay and manual water hose stations and portable fire extinguishers as shown in Figure 9A-4.

NFPA 13 noncompliances with this sprinkler system include sprinkler protection areas exceeding the limit for ordinary hazard occupancy and sidewall sprinklers around the open equipment hoistway not installed in a staggered arrangement (in addition to those discussed and evaluated in 9.5.1.2.3.3). These noncompliances would not adversely affect the required function of this system because the large safety margin in the water supply hydraulic design calculations would adequately compensate for these and provide the required sprinkler performance. In addition, the exceptionally deep beams would result in partially obstructed discharge patterns for some sprinklers, but the sprinkler system would still prevent any fire or fire effects from traveling any significant distance north or south from the point of origin.

9A.4.1.6.2 Analysis

By plant design, the reactor building Division I cables and equipment are normally routed and located on the north side of the building (north of column line 12) and Division II cables and equipment are normally routed and located on the south side of the building (south of column line 12).

One-hour rated protective envelopes are provided for Division I cables when routed south of Column line 12.

Shutdown is achieved from the main control room. Division I will be used to achieve plant safe shutdown for fires on the south side and Division II will be used to achieve plant safe shutdown for fires on the north side of the zone.

Because of a potential high/low-pressure interface (associated circuits), E1150F008 shutdown cooling valve is required to be electrically disabled. The two sets of CRD HCUs, both of which are required for shutdown, are located on opposite sides of the drywell structure. The RHR heat exchangers and related valves are located in separate rooms located on opposite sides of the building. The redundant EECW isolation valves and Division I and II cables located within the zone are separated either by the drywell or steam tunnel structure or are separated spatially by a minimum of 40 ft.

The steel beams installed above the railroad bay area (also known as the truck bay) are evaluated based on the worst case fire in the railroad bay area. This analysis demonstrates that a fire in the truck bay area will not damage the steel beams supporting the Division 1 EECW Heat Exchanger. As a result, fire coating the steel beams in the truck bay area is not required to ensure safe shutdown of the plant during all Appendix R scenarios.

During refueling the railroad bay could represent a possible fire hazard; however, this area is protected by an automatic sprinkler system and a continuous firewatch when a refueling vehicle containing a combustible fuel is parked in the bay.

The automatic sprinkler system is installed in the railroad bay (column A-B, 9-13).

A heat detection system is installed in the railroad bay (column lines A-B, 9-13).

There is a greater than 20 ft separation with no intervening combustibles between Divisions I and II shutdown circuits in the railroad bay within the zone between column lines A-B, 11-13. The drywell and steam tunnel walls provide fire barriers at least equivalent to 3-hr-rated barriers.

Combustibles located within this zone consist primarily of electrical insulation.

The total zone fire loading is low.

9A.4.1.6.3 Conclusion

The objective for this zone is to prevent a fire from affecting both sets of redundant equipment located within this zone, and from spreading to other zones. This objective is achieved through barriers, spatial separation, the location of redundant equipment in separate rooms, the provision of early-warning detection equipment throughout the zone and a partial automatic sprinkler system over the railroad bay, a continuous firewatch when a refueling vehicle containing a combustible fuel is parked in the bay, and low fire loading.

Due to the low fire loading in the areas of both CRD HCUs and the presence of the early-warning detection equipment, it is considered unlikely that the function of the CRD HCUs (i.e., to scram the reactor) would be affected by a fire.

In addition, manual hose and portable fire extinguishers are provided.

9A.4.1.6.4 Deviations

Deviations have been approved for the following:

a. Partial suppression system based on 20-ft combustible free zone on west side of the reactor building at column line 12, high ceilings, and low combustibles (Reference 1, SSER No. 5, VI[3])

b. Lack of 3-hr fire-rated barriers separating redundant equipment based on 20-ft combustible free zone on the west side of the reactor building at column line 12, high ceilings, and low combustibles (Reference 1, SSER No. 5, VI[3]).

c. Non rated doors R1-8 and R1-11 on the first floor reactor building are special-purpose doors constructed of heavy weight, reinforced steel plates and are either blast-resistant (R1-11) or water-tight (R1-8) in addition to providing fire protection. (Reference 1, Reference 3, SSER No. 6, III.B)

9A.4.1.7 Second Floor, Fire Zone 06RB, El. 613 Ft 6 In.

9A.4.1.7.1 Description

This zone, shown in Figure 9A-6, consists of the floor area outside the drywell (Fire Zone 10RB), excluding the RHR heat exchanger rooms, at Elevation 613 ft 6 in.

It is bounded on the north, south, and west by outside walls and on the east by the auxiliary building and the steam tunnel. The west wall of the RHR Heat Exchanger Room on the Reactor Building 2nd Floor provides a three-hour fire barrier between the Division II RHR heat exchanger and the Division I EECW heat exchanger P4400B001A.

This zone houses the reactor water cleanup (RWCU) heat exchangers, phase separators, and pumps; the EECW pumps, heat exchangers, area coolers, makeup tanks and makeup pumps; instrument racks; motor control centers (MCCs); and the H_2-O_2 Division I analyzer and associated test gas cylinders.

The walls separating this zone from the auxiliary building and the steam tunnel are constructed of reinforced concrete having a fire-resistance rating of 3 hr. The door opening leading to the auxiliary building is protected by a Class A fire door. Penetrations through the rated wall are sealed to provide a 3-hr fire-resistance rating. The floor and ceiling are constructed of reinforced concrete and contain open stairwells, unprotected hatches, and unsealed penetrations. Cable tray penetrations through the floor and ceiling are provided with fire stops. Division I shutdown cables within 20 ft of Division II shutdown cables near F-11 are enclosed by a 1-hr-rated fire barrier.

Ventilation air for this zone is provided directly from the reactor/auxiliary building ventilation system supply to the general floor area. Air flows to the RWCU pump rooms, RHR heat exchanger rooms, water sample station, water sludge discharge pump room, holding area, and RWCU heat exchanger room from the general floor area. Air to or from these areas is controlled by backdraft dampers in the walls. Air in these areas is exhausted to the reactor/auxiliary building ventilation system exhaust. The EECW pump areas have local air-handling units (pump room cooling units) to cool the area ambient air.

Shutdown equipment located in this zone consists of the following:

a. Divisions I and II cables

b. Divisions I and II reactor vessel level and pressure instrument racks

c. Divisions I and II EECW pumps, heat exchangers, pump area cooling units, makeup tanks and makeup pumps, nitrogen tanks (Division I only), EESW to EECW makeup lines, and associated valves and MCCs

d. Divisions I and II drywell monitoring instrument racks

e. Divisions I and II MCCs

f. Divisions I and II core spray and RHR valves

g. Standby feedwater and CTG 11-1 supervisory control cables

h. 120 V ac distribution panel (Division I)

i. Emergency Equipment Room Coolers (Division I and II)

j. Swing bus MCC

k. Drywell pneumatic racks (Division II)

One-hour protective envelopes are required for certain cable trays in this zone.

Fire detection equipment in this zone consists of an ionization detection system. Fire suppression equipment consists of automatic sprinklers over cable trays along the east wall between columns 10 and 12 and on the west side between column lines A and C, at column line 12 and in the area near P4400B001A between columns lines A and B and 9 and 10. In addition, manual water hose stations and portable fire extinguishers are provided as shown in Figure 9A-6.

NFPA 13 noncompliances with the west side sprinklers include some sprinkler locations exceeding the maximum allowable distance below the ceiling, lack of baffles between sprinklers that are less than 6 ft apart, and some sprinklers partially obstructed by supports. These noncompliances do not prevent these west side sprinklers from providing the required fire protection for this area.

9A.4.1.7.2 <u>Analysis</u>

By plant design, the reactor building Division I cables and equipment are normally routed and located on the north side of the building (north of column line 12) and Division II cables and equipment are normally routed and located on the south side of the building (south of column line 12).

Shutdown is achieved from the main control room. Division I will be used to achieve plant safe shutdown for fires on the south side and Division II will be used to achieve plant safe shutdown for fires on the north side of the zone.

No protective envelopes are required for cable routed on the north side of the zone. One-hour protective envelopes are provided for cable trays 1C-033, 1P-038, 1P-040, and 1P-051 when routed on the south side of the zone.

Divisions I and II EECW equipment located within this zone is separated spatially by a minimum distance of approximately 50 ft. In addition, the drywell structure functions as a radiant-energy barrier between the redundant pumps.

The Division I EECW Heat Exchanger P4400B001A is located south of Column 12, above the railroad bay hatch at Column 9 between Columns A and B. The backup Division 1 EECW Heat Exchanger P4400B001C is located slightly north of column line 12 between columns A and B. Fire suppression is provided in these areas. In addition, all Division II conduit located within 20 feet of the Division I heat exchanger P4400B001A is protected with a one-hour protective envelope. The Division II RHR heat exchanger is separated from the Division I EECW heat exchanger P4400B001A by a three-hour fire barrier (RHR Heat Exchanger Room West wall between Columns 9 and 10 at Column B).

The abandoned tubing left within the three hour fire resistant penetration to the auxiliary building is evaluated to show that the seal is adequate for fires in the zone.

Reactor vessel level and pressure instrument racks are separated by the drywell structure.

Drywell monitoring instrument racks are located on opposite sides of the heat exchanger vault.

The RWCU equipment located in this zone contains significant amounts of concentrated radioactivity. This equipment is located in separate shielded cubicles with negligible fire loadings.

There are three non-safe-shutdown trays (OP-037, OC-060, and OK-066), which are routed north-south along column line B. Three cable trays (OP-047, OC-793, and OK-069) traverse the Fire Zone along the east wall near column line F. These trays represent the only intervening combustibles that could propogate a fire between Divisions I and II shutdown circuits on the east and west side respectively.

For a single fire to affect both divisions, a cable tray fire would have to burn a minimum of 35 ft.

On the east side of the reactor building, fire breaks have been installed in cable trays OP-047 and OC-793 approximately 3 ft south of column line 12.

On the west side of the reactor building, fire breaks have been installed in cable trays OP-037 and OC-060 approximately 12 ft south of column line 12.

The two instrument trays, OK-069 and OK-066, are solid-metal trays with covers.

Combustibles located within this zone consist primarily of electrical insulation.

The total zone fire loading is low.

9A.4.1.7.3 Conclusion

The objective for this zone is to prevent a fire from affecting redundant equipment, cable, and instrumentation and from spreading to other zones. This objective is achieved through barriers, early-warning detection equipment, spatial separation between redundant equipment, and low fire loading. Automatic sprinklers are provided in the area with concentrated fire loading of Divisions I and II cable trays and in the areas with the Division I EECW Heat Exchangers. In addition, manual water hose stations and portable fire extinguishers are provided.

9A.4.1.7.4 Deviations

Deviations have been approved for the following:

a. Partial suppression at column line 12 based on intervening open cable trays having fire stops and separation of Divisions I and II cables (north and south) within the zone (Reference 1, SSER No. 5, VI[4])

b. Intervening combustibles in cable trays OP-047, OC-793, OP-037, and OC-060 which are provided with fire stops (Reference 1, SSER No. 5, VI[4]).

9A.4.1.8 Third Floor, Fire Zone 07RB, El. 641 Ft 6 In.

9A.4.1.8.1 Description

This zone, shown in Figure 9A-8, consists of the floor area at Elevation 641 ft 6 in., with the exception of the drywell and fuel storage pool.

It is bounded on the north, south, and west by outside walls and on the east by the auxiliary building.

This zone houses the hydrogen recombiners, contaminated equipment storage area, CRD decontamination and repair area, the fuel storage pool heat exchangers and pumps, and the H_2-O_2 Division II analyzer and test gas cylinders.

Safe shutdown equipment located in this zone consists of the following:

a. Division I and II cables

b. Standby Feedwater cables

The wall separating this zone from the auxiliary building is constructed of reinforced concrete having a fire-resistance rating of 3 hr. Penetrations through rated walls are sealed to provide a 3-hr fire-resistance rating. The floor and ceiling are constructed of 12-in. reinforced concrete and contain open stairwells, unprotected hatches, and unsealed penetrations. Floor penetrations are sealed to provide a 3-hr fire barrier for that portion of the floor in the southeast corner which separates this zone from Zone 8 of the auxiliary building. Cable tray penetrations through the floor and ceiling are provided with fire stops.

Ventilation air for this zone is provided directly from the reactor/auxiliary building ventilation system supply to the general floor area and the area north of the fuel storage pool. Air flows to the contaminated equipment storage area, CRD decontamination and repair area, and the fuel storage pool heat exchanger and pump room from the general floor area. Air enters these areas through backdraft dampers located in the room walls and is exhausted through ducts to the reactor/auxiliary building ventilation system exhaust. Air exhausted from the contaminated equipment storage and CRD decontamination and repair areas passes through high-efficiency particulate air (HEPA) filters.

Fire detection equipment located in this zone consists of an ionization detection system. Fire suppression equipment consists of manual water hose stations and portable fire extinguishers as shown in Figure 9A-8.

9A.4.1.8.2 Analysis

By plant design, the reactor building Division I cables and equipment are normally routed and located on the north side of the building (north of column line 12) and Division II cables and equipment are normally routed and located on the south side of the building (south of column line 12).

Shutdown is achieved from the main control room. Division I will be used to achieve plant safe shutdown for fires on the south side and Division II will be used to achieve plant safe shutdown for fires on the north side of the zone.

There are no Division I shutdown cables on the west side of the reactor building. Any large openings that communicate with second floor, Division I shutdown cables, are located approximately 50 ft away. Any fire in this area will affect only Division II equipment. Therefore, protection is not necessary.

No protective envelope is required for safe-shutdown components in this zone.

The fuel storage pool heat exchangers and pumps contain significant amounts of concentrated radioactivity. This equipment is located in a separate shielded cubicle with a negligible fire loading.

Vertical cable tray risers are solid-metal trays with covers. These are located at approximately column lines F-13 (trays OP-123, OC-071, and OP-049).

Combustibles located within this zone consist primarily of electrical insulation. The total zone fire loading is low.

9A.4.1.8.3 Conclusion

The objective for this zone is to prevent the spread of a fire in this zone to another Fire Zone. This objective is achieved through barriers, low zone fire loading, and provision of early-warning detection equipment, manual water hose stations, and portable fire extinguishers.

9A.4.1.8.4 Deviations

Lack of a 3-hr barrier separating the next floor based on metal covers on vertical cable trays near column line F-13, no intervening combustibles, and the low combustible loading of the zone (Reference 1, SSER No. 5, VI[5]) .

9A.4.1.9 Fourth Floor, Fire Zone 08RB, El. 659 Ft 6 In.

9A.4.1.9.1 Description

This zone, shown in Figure 9A-9, consists of two floor areas at Elevation 659 ft 6 in. These floor areas are separated by the drywell, the dryer/separator storage pool and the fuel storage pool.

The western portion of the zone is bounded on the north, south, and west by outside walls and on the east by the drywell, dryer/ separator storage pool, and the fuel storage pool. The eastern portion of the zone is bounded on the north and south by outside walls; on the east by the auxiliary building; and on the west by the drywell, dryer/separator storage pool, and the fuel storage pool.

The western portion of the zone houses motor-generator (M-G) sets and oil cooler, dress-out facilities, and RWCU equipment. The eastern portion of the zone houses the standby liquid control system (SLCS).

The walls separating this zone from the auxiliary building are constructed of reinforced concrete having a fire-resistance rating of 3 hr. Penetrations through rated walls are sealed to provide a 3-hr fire-resistance rating. The floor is constructed of reinforced concrete and contains open stairwells, unprotected hatches, and unsealed penetrations. Floor drains are provided and trapped at the collection sumps. The ceiling is also constructed of reinforced concrete and contains unprotected hatches and unsealed penetrations. Cable tray penetrations through the floor and ceiling are provided with fire stops.

Ventilation air is supplied directly to the area around the M-G sets and the storage areas north and east of the fuel storage pool. Air then flows from these areas to the clean area, the RWCU pump room, and the RWCU south and north demineralizer rooms. Air also flows from the clean area to the personnel change area. Supply air to the RWCU holding pump room and demineralizers is controlled by backdraft dampers. With the exception of air exhausted from the area around the M-G sets, exhaust air is ducted to the reactor/ auxiliary building ventilation system exhaust. The M-G set area is locally cooled by air ducted directly to the M-G sets from three recirculating fancoil units.

Safe shutdown equipment located in this zone consists of the following:

a. Division II cables

b. Standby Feedwater cables

c. Division II 480 V ac distribution panel

Fire detection equipment located in this zone consists of an ionization detection system and heat detectors. Fire suppression equipment consists of an automatic sprinkler system in the area of the M-G sets and oil coolers, manual hose, and portable fire extinguishers as shown in Figure 9A-9.

9A.4.1.9.2 Analysis

Reactor water cleanup equipment located in this zone contains significant amounts of concentrated radioactivity. This equipment is located in separate shielded cubicles with negligible fire loadings.

Shutdown is achieved from the main control room. Division I will be used to achieve safe shutdown for fires in the south side and Division II will be used to achieve safe shutdown for fires in the north side of the zone.

Except for Standby Feedwater flow indication cables located in the south side of the zone, there are no Division I or II Appendix R cables or equipment in the zone.

Lubricating oil in the couplings and cooling units of the two M-G sets located in this zone represents a specific fire hazard. This equipment is surrounded by curbing of sufficient height to contain any oil spills.

Combustibles located within this zone consist of the following:

a. Lubricating oil

b. Electrical insulation

c. Ordinary combustibles

The total fire loading for this zone is low.

9A.4.1.9.3 Conclusion

The objective for this zone is to prevent a fire from spreading to another zone. This objective is achieved through barriers, low fire loading in the area of the SLCS, the provision of early-warning detection systems for the entire zone, curbing and an automatic sprinkler system for the M-G sets and oil coolers, and manual hose and portable fire extinguishers.

9A.4.1.10 Fifth Floor, Fire Zone 09RB, El. 684 Ft 6 In.

9A.4.1.10.1 Description

This zone, shown in Figure 9A-10, consists of the floor area at Elevation 684 ft 6 in., including the fuel storage pool, dryer/ separator pool, and decontamination area, along with the Auxiliary Building stairwell enclosure.

The zone is bounded on the north, south, and west by outside walls and on the east by the auxiliary building.

This zone houses the fuel storage pool and associated equipment, dryer/separator pool, and the decontamination area.

The east wall abutting the auxiliary building is constructed of reinforced concrete up to Elevation 701 ft 0 in. and provides a 3-hr-rated fire barrier. Penetrations in rated walls are sealed to provide a 3-hr fire rating. The east wall above Elevation 701 ft 0 in. and the north, south, and west walls are constructed of steel frame and siding. The stairwell leading to the auxiliary building is enclosed by a 3-hr-rated fire barrier to provide separation between the auxiliary building and the reactor building. The floor is constructed of reinforced concrete and contains unprotected hatches and unsealed penetrations. Cable tray penetrations through the floor are fire stopped. The roof is constructed of steel frame and deck with insulation and builtup roofing that conforms to Factory Mutual Class I requirements.

Ventilation air is supplied directly through ducts to the floor area. Air then flows from the floor area to the dryer/separator pool, reactor well, and fuel storage pool. Air is exhausted from these areas through ducts to the reactor/auxiliary building ventilation system exhaust. The elevator machine room is cooled by an air conditioning unit which rejects waste heat to the refueling area.

Equipment located in this Fire Zone is not required for shutdown.

Safe shutdown equipment located in this zone consists of the following:

a. Division I and II cables

Fire detection equipment located in this zone consists of an infrared detection system. Fire suppression equipment in this zone consists of manual hose with solid stream nozzles and portable fire extinguishers as shown in Figure 9A-10.

The combustible loading in the Auxiliary Building stairwell enclosure is extremely low. In addition future storage of combustibles in this area is not considered for the purpose of this analysis because the storage of combustibles in stairwells is controlled. Based on the extremely low combustible loading in this area, fire detection instrumentation is not installed since it would not be expected to alarm due to the small amounts of smoke/heat that could be produced by a fire in this area. The stairwell contains two (2) Division II cables routed in the same conduit above the 677′-6″ elevation which are required for safe shutdown.

9A.4.1.10.2 Analysis

Shutdown is achieved from the main control room. Division I will be used to achieve safe shutdown for fires on the south side because there are no Appendix R Division I cables located on the south side of this zone. On the north side of this zone, Division II will be used to achieve safe shutdown. There are no Appendix R Division II cables (nor are there Appendix R Division I cables) located on the north side of this zone. Combustibles located in this zone consist primarily of the reactor building and fuel-handling crane and gear box lubricating oil. The total zone fire loading is low.

9A.4.1.10.3 Conclusion

The objective for this Fire Zone is to prevent the spread of a fire in this zone to another Fire Zone. This objective is achieved through low zone fire loading, and the provision of an early-warning detection system and manual hose and portable fire extinguishers.

9A.4.1.11 Drywell, Fire Zone 10RB, El. 562 Ft 0 In. to 684 Ft 6 In.

9A.4.1.11.1 Description

This zone, shown in Figures 9A-3, 9A-4, 9A-6, 9A-8 through 9A-10, consists of a containment vessel in the shape of an inverted light bulb.

The zone is surrounded by reactor building Fire Zones 01RB through 09RB.

This zone houses the reactor pressure vessel (RPV), reactor recirculation pumps, and associated equipment.

The drywell consists of a steel pressure vessel surrounded by reinforced concrete for shielding. External to the drywell vessel but in the Fire Zone above elevation 572 ft. 1 in., the drywell is separated from the concrete biological shield by a gap of approximately 2 inches. The gap is filled with polyurethane foam material. The bottom portion of the shell is totally embedded in concrete, and the transition zone is backed by compacted sand. Access to the drywell is through an air lock located in Zone 4 at Elevation 583 ft 6 in.

Cooling of air within the drywell is provided by 14 fan-coil units located at various elevations within the drywell. These units recirculate and cool the drywell ambient air. Cooling water for these units is normally supplied from the reactor building closed cooling water system (RBCCWS). Under other than normal conditions, cooling water is supplied from the EECW system. Thermocouples located in various drywell areas actuate control room alarms on detection of high temperature.

Shutdown equipment located in this zone consists of the following:

a. Nuclear pressure relief system (NPRS) safety/relief valves (SRVs) B21-F013A, B, C, D, E, F, G, H, J, K, L, M, N, P, and R and instruments

b. Reactor recirculation shutdown cooling to RHR inboard isolation valves E11-F009 and E11-F608

c. Reactor recirculation discharge valves B31-F031A, B31-F031B, B3105F023A and B3105F023B.

d. Division 1 and 2 cables, located in drywell penetrations passing through the drywell gap area.

e. SRV accumulators (Division I and II)

f. Valves (Division I and II)

g. T50 instrumentation (Division I and II)

For maintenance operations, fire suppression equipment, consisting of manual hoses and portable fire extinguishers, is located at the drywell access air lock in Zone 4 at Elevation 583 ft 6 in. The drywell gap area is not provided with either fire detection or automatic suppression. Fire suppression consists of manual hoses located on the first and second floor level.

9A.4.1.11.2 Analysis

The drywell atmosphere is inerted with nitrogen. The concentration of nitrogen is maintained at 97 percent. Oxygen and hydrogen content is monitored. For a more detailed description, refer to Subsection 9.3.6. Fire damage is not assumed to occur under Appendix R Section III.G.2.

Combustibles within this zone consist primarily of the following:

a. Electrical insulation

b. Lubricating oil

c. Polyurethane foam in the drywell gap area

d. Silicone rubber impregnated fiberglass fabric covering permanently installed lead blankets

Because the polyurethane foam is located in the drywell gap outside the steel drywell vessel, the foam does not contribute to the total zone Btu content of the drywell.

Total zone fire loading is low.

If a fire occurs in the drywell gap area, hot shutdown can be maintained using HPCI; cold shutdown can be attained by manual operation of valves in the drywell to achieve shutdown cooling lineup.

9A.4.1.11.3 Conclusion

The objective of this zone is to prevent a fire from occurring. During reactor operation, this is achieved through the maintenance of a nitrogen atmosphere. During maintenance operation, fire suppression equipment is used. Although Division 1 and 2 cables are present in the drywell gap, redundant hot shutdown equipment is not affected by a fire in the gap area. Hot and cold shutdown can be achieved following the assumptions of 10 CFR 50, Appendix R.

9A.4.2 Auxiliary Building

9A.4.2.1 General Description

The auxiliary building is a multilevel structure. For purposes of this fire hazards analysis, the auxiliary building has been designated as fire area AB. It is bounded on the north and south by outside walls; on the east by the turbine building; and on the west by the reactor building.

The outage building is located four (4) inches south of the south wall of the reactor and auxiliary building. The outage building is of completely noncombustible construction; additionally no safe shutdown systems or equipment are located in this building. The outage building is structurally separated from plant structures, however, nonstructural flashing is attached to both the reactor and auxiliary building to seal and protect the four-inch gap between it and the outage building.

The north and south exterior walls are constructed of 24 inches of reinforced concrete which will prevent an exposure fire in the yard area from propagating into the auxiliary building. Except as noted below, these walls are 3-hr-rated fire barriers.

The auxiliary building south wall also contains five (5) non-rated removable plugs filled with at least twelve (12) inches of grout and are acceptable for use as penetration seals in a 3-hr-rated fire barrier based on their construction.

The auxiliary building also contains a sixth removable plug seal. This sleeve has six (6) 1-inch thick steel plates held into the penetration with a locked steel bar such that they are flush with the exterior plane surface of the fire barrier. A seventh 1-inch thick steel plate is bolted into the exterior wall of the auxiliary building. In addition, the eighteen (18) inches between these sets of plates is totally devoid of combustible materials. Therefore, although they are not tested and approved seal configurations they are of substantial steel construction and prevent flame propagation into the auxiliary building.

The metal-sided control center air conditioning intake is located on the south side of the auxiliary building. The base of the air intake is at elevation 643′-6″ while the actual opening into the auxiliary building is a 6′ x 20′ opening at elevation 681′-6″. Since this opening itself is 98′ above grade elevation (583′-6″), an exposure fire threat to the opening itself is not postulated based on the types, amounts, and locations of the combustible materials that could be in close proximity of the air intake either during normal operation or outages. Should the control room operators detect smoke coming into the control center because of a fire in the yard, or receive notification of a fire in the yard, the operators can switch from the air intake on the south side of the auxiliary building to the air intake on the north side of the building. This is done by placing the air conditioning system in the recirculation mode.

The auxiliary building houses reactor auxiliary systems and equipment.

With the exception of the control room, relay room, cable spreading room, standby gas treatment system (SGTS) room, and control center air conditioning equipment rooms, ventilation of the auxiliary building is provided by the reactor/auxiliary building ventilation system. Ventilation for the control room, relay room, cable spreading room, and control center air conditioning equipment room is provided by the control center heating, ventilation, and air conditioning (HVAC) system. These ventilation systems are discussed briefly in the individual Fire Zone descriptions. Additional details for these ventilation systems are presented in Subsections 9.4.1 and 9.4.2.

For the purpose of this fire hazards analysis, the auxiliary building has been divided into the following Fire Zones:

a. Basement, Fire Zone 01AB, Elevations 551 ft 0 in. and 562 ft 0 in.

b. Mezzanine and cable tray area, Fire Zone 02AB, Elevations 583 ft 6 in. and 603 ft 6 in.

c. Relay room, Fire Zone 03AB, Elevation 613 ft 6 in.

d. Switchgear room, Fire Zone 04AB, Elevation 613 ft 8 1/2 in.

e. Cable tunnel, Fire Zone 05AB, Elevation 613 ft 6 in.

f. Second floor, miscellaneous rooms, Fire Zone 06AB, Elevation 613 ft 6 in.

g. Cable spreading room, Fire Zone 07AB, Elevation 630 ft 6 in.

h. Cable tray area, Fire Zone 08AB, Elevation 631 ft 0 in.

i. Control room, Fire Zone 09AB, Elevations 643 ft 6 in. and 655 ft 6 in.

j. Divisions I and II battery rooms, Fire Zone 10AB, Elevation 643 ft 6 in.

k. Miscellaneous rooms, Fire Zone 11AB, Elevation 643 ft 6 in.

l. Switchgear room, Fire Zone 12AB, Elevation 643 ft 6 in.

m. Ventilation equipment area, Fire Zone 13AB, Elevation 650 ft 6 in.

n. Control center ventilation equipment rooms and standby gas treatment rooms, Fire Zone 14AB, Elevation 677 ft 6 in.

o. Ventilation equipment area, Fire Zone 15AB, Elevation 677 ft 6 in.

9A.4.2.2 Basement, Fire Zone 01AB, El. 551 Ft 0 In. and 562 Ft 0 In.

9A.4.2.2.1 Description

The basement, shown in Figure 9A-3, encompasses the entire floor area at Elevation 551 ft 0 in. and the floor area bounding CRD pump room on the east and south at Elevation 562 ft 0 in. The zone is bounded on the north and south by outside walls; on the east by the turbine building; and on the west by the reactor building.

This zone houses Divisions I and II control air equipment and cables. Walls and ceiling separating this zone from the reactor building, turbine building, and other zones of the auxiliary building are constructed of reinforced concrete having a fire-resistance rating of 3 hr. Door openings are protected by Class A fire doors. Penetrations through rated walls and ceilings are sealed to provide 3-hr fire-resistance ratings. Division I and II shutdown cables within 20 ft of the opposite Division's shutdown cables are enclosed with a 1-hr-rated fire barrier or an analysis has been performed to show that loss or misactivation of any interacting redundant divisional circuits does not affect plant safe shutdown. Fire breaks have been installed in trays which contain intervening combustibles in order to ensure that a postulated fire cannot spread through these cable trays in such a manner as to damage redundant safe shutdown components.

Ventilation supply air from the reactor/auxiliary building ventilation system is ducted to both control air equipment areas and to the cable tray space. Exhaust from these spaces is by direct duct connection to an exhaust main passing through these spaces. Both control air equipment areas have local air-handling units for cooling the room ambient air.

Shutdown equipment located in this zone consists of the following:

a. Divisions I and II control air equipment, fan coil units, and associated isolation valves

b. Divisions I and II cable.

For Fire Zone 01AB, Division II is primarily utilized for safe shutdown except for certain Division I areas. Division I is utilized for shutdown between 10-12, and in the southwest corner near G-9.

Fire detection equipment in this zone consists of an ionization detection system. Fire suppression equipment consists of an automatic sprinkler system for floor Elevations 551 ft 0 in. and 562 ft 0 in. and manual water hose stations and portable fire extinguishers as shown in Figure 9A-3.

9A.4.2.2.2 Analysis

Shutdown is achieved from the main control room. Division II cable trays required for shutdown (2C-027, 2C-030, 2C-036, 2P-019, and DC2P-019) are provided with a 1-hr protective envelope when they are within 20 ft of Division I circuits. Division II cable trays 2C-035, 2P-026, and DC2P-026 are partially protected along column line 11. These trays no longer require protection as the Division 1 circuits are protected in this area. Division 1 trays 1P-069, DC1P-069, 1P-024, and 1C-005 are protected between column lines H10 and H13.

The cable tray supports, along the west side, between column lines H12 and H13 are wrapped for their full height. The cable tray supports, along the west side, between column lines H11 and H12 are wrapped to approximately elevation 566'. The cable tray supports, along the west side, between column lines H10 and H11 do not require fire wrap. The cable tray support wrap was evaluated and determined to be required to protect the tray supports from direct flame impingement in the event of a transient combustible fire occurring beneath these trays.

Division II trays 2K-011 and 2K-020 are not protected, between column lines 11 and 12, because these trays are not required since they are in an area where Division I will be used to achieve shutdown.

In areas where Division I is not protected, Division II is used for shutdown.

Intervening combustibles exist between the two shutdown divisions. Between column lines 12 and 13, trays 0C-018, 0C-017, 0C-027, and 0C-028 are provided with fire breaks, and trays 1K-022, 2K-020 and 0K-001 are solid metal bottom trays with covers. Between column lines 10 and 11 trays 0P-005, 0C-018, 0C-017, 0C-027, 0C-028, and 0P-002 constitute intervening combustibles with fire breaks, and tray 1K-022 is a solid metal bottom tray with covers. The empty tray 0P-006 is not an intervening combustible. These fire breaks provide a minimum of 20 feet free of intervening combustibles and therefore meet the requirements for 20 foot separation with no intervening combustibles and with detection and suppression.

At the south end, mezzanine area 562 ft 0 in., of the zone (column line G-H, 9-11) intervening combustibles in the form of cable trays exist within the 20-ft separation zone between the divisions. Cable tray fire breaks have been installed in trays OP-005, OC-017, and OC-018. Cable tray 2K-015 is enclosed within the fire barrier in the vicinity of these breaks and thus is not an intervening combustible.

Specific fire hazards exist in the southeast and northeast portions of the zone where both Divisions I and II cables are concentrated.

The amount of lubricating oil in the control air equipment is not sufficient to allow propagation of a fire between Division I and II equipment through the floor drain system in the zone.

Combustibles located within this zone consist primarily of electrical insulation.

The total zone fire loading is low.

9A.4.2.2.3 Conclusion

The safe-shutdown analysis performed verified that either Division I or II will be available for plant safe shutdown in the event of a fire in this zone. The Division I or II power and control circuits are provided with a 1-hr-rated protective envelope, as listed above, or are separated from the redundant division's unprotected cables by at least 20 ft. Cable tray fire breaks are provided in various Balance of Plant cable trays to provide 20 ft. zones free of intervening combustibles.

9A.4.2.2.4 Deviations

Deviations have been approved for the following: intervening combustibles--based on fire stops in cable trays OP-005, OC-017, and OC-018 at column lines 9 and 11 (Reference 1, SSER No. 5, VI [15]).

9A.4.2.3 Mezzanine and Cable Tray Area, Fire Zone 02AB, El. 583 Ft 6 In. and 603 Ft 6 In.

9A.4.2.3.1 Description

This zone, shown in Figures 9A-4 and 9A-5, is divided into three sections and encompasses two floor elevations, with a common ceiling under Elevation 613 ft 6 in. The first floor elevation is at 583 ft 6 in. and is divided into two sections, a north section and a south section, separated by an extension of the turbine building. The southern section of the zone consists of a cable entry room, which extends partially along the outside of the south wall, and a cable tray area. The northern section of the zone consists of a cable tray area. The mezzanine area, the third section of the zone, is at Elevation 603 ft 6 in. above the turbine building extension. The zone is bounded on the south by an outside wall, except at the cable entry area, where a portion of the zone bounds the reactor building; on the east by the turbine building; on the north by an outside wall; on the west by the reactor building, steam tunnel, and an outside wall at the cable entry area; and is divided by an extension of the turbine building from the 583 ft 6 in. elevation up to the floor of the 603 ft 6 in. elevation.

This zone serves primarily as a cable routing area.

The walls, floor, and ceiling bounding this zone are constructed of reinforced concrete having a fire-resistance rating of 3-hr. Penetrations are sealed to provide 3-hr fire-resistance ratings except for 16 cable tray penetrations in the mezzanine area at the 603 ft 6 in. elevation east wall. These penetrations are open to the enclosed 4-inch gap area between the auxiliary and turbine buildings. Door openings leading to the turbine building extension and between the Divisions I and II cable entry rooms are protected by Class A fire doors. Division II shutdown cables within 20 ft of Division I shutdown cables in the north end of the area are enclosed with a 1-hr-rated fire barrier, as are Division I shutdown cables within 20 ft of Division II shutdown cables in the south end of the area. The equipment hatch in the southern section of the zone is provided with a reinforced-concrete cover.

The HVAC/pipe chase along column H between 10 and 11 extends from the floor opening at elevation 613’-6” to the ventilation equipment area on elevation 677’-6” (Fire Zone 15AB) and is completely devoid of combustibles for is entire 64-foot height. Additionally, the walls of this chase are constructed and sealed as 3-hour rated barriers. Finally, Thermo-Lag material was used to construct the floor of this chase. Given, that as detailed below, automatic sprinkler coverage is provided for the area around the base of this opening and that the combustible loading on the 677’-6” elevation open top of this chase is negligible (reference Section 9A.4.2.16.2), flame propagation via this combustible material free vertical chase is not a credible event. Therefore, the chase itself provides the required separation between auxiliary building Fire Zones 2 and 15. Additionally, the Thermo-Lag material used to seal the chase at elevation 613’-6” is a nonfire rated smoke and gas barrier. For identification purposes, the chase is considered as being part of Fire Zone 02AB.

Ventilation for this zone is provided by the reactor/auxiliary building ventilation system. Supply air is ducted to each section of the zone. Exhaust air returns unducted from the northern section of the zone to the mezzanine area where air is exhausted through ducts to the auxiliary building main exhaust system. Exhaust air from the southern section of the zone is ducted to the auxiliary building main exhaust system.

Shutdown equipment contained in this zone consists of the following:

a. Divisions I and II cables

b. Offsite power cables affecting CTG 11-1 feed to standby feedwater

Division II cable will be used to achieve plant safe shutdown for fires in the north half of the zone. For fires in the south half of the zone, Division I will be used to achieve plant safe shutdown.

Fire breaks have been installed in cable trays within this zone.

Fire detection equipment in this zone consists of an ionization detection system. Fire suppression equipment consists of an area-wide automatic sprinkler system and selected cable tray protection, manual water hose stations, and portable fire extinguishers as shown in Figures 9A-4 and 9A-5.

NFPA 13 noncompliances with this sprinkler system include sprinkler protection areas exceeding the limit for extra hazard occupancy, spacing between branch lines exceeding the 12 ft limit, sprinklers farther from the wall than the 6 ft limit, sprinkler spray patterns partially obstructed, and discrepancies with cable tray sprinklers (in addition to those discussed and evaluated in 9.5.1.2.3.3). These noncompliances would not adversely affect the required function of this system because the extremely conservative extra hazard occupancy water application density would adequately compensate for these and provide the required sprinkler system performance.

9A.4.2.3.2 Analysis

Shutdown is achieved from the main control room. For this zone, Division I and II cables are routed and located on the north side of the building (north of column line 12) and Division I and II cables are routed and located on the south side of the building (south of column line 12). Where redundant shutdown trains are not separated by more than 20 ft, a 1-hour fire wrap is applied to one division.

The sixteen cable tray penetrations in the east auxiliary building wall Fire Rated Separation Barrier have been analyzed. Credit is taken for the sealed turbine building wall penetrations adjacent to the auxiliary building wall, the metallic cover plates over the seismic gap opening between the buildings and the lack of signifi-cant combustibles or ignition sources in the gap as sufficient barriers to prevent the propagation of fire through the unsealed openings in the auxiliary building wall Fire Rated Separation Barrier.

Cable trays 1K-014, 1K-029, 1K-034, 2C-012 and 2C-030, and conduit JA001-1K (north end) and 1C-006, 1P-045, 1P-041, and DC1P-044 (south end) have been provided with a 1-hr protective envelope.

Because of the intervening combustibles in the form of cable trays, fire breaks have been installed in cable trays OC-617, OC-618, OC-611, OC-614, OC-582, OC-585, OC-640, OC-636, OC-916, OC-570, OC-645, OC-592, OC-671, and OC-672 which are located on the north end, Elevation 603 ft 0 in.

Combustibles located within this zone consist primarily of electrical insulation.

The total zone fire loading is moderate.

9A.4.2.3.3 Conclusion

The safe-shutdown analysis performed verified that, for a fire in this zone, plant safe shutdown will be performed using Division II equipment for fires in the north half. For fire in the south half, Division I equipment will be used to achieve plant safe shutdown. The objective for this zone to minimize the potential for the occurrence of a fire and to minimize the spread and damage, should a fire occur, has been achieved through spatial separation of control and instrument components, rated barriers, and the provision of early-warning detection, manual water hose stations, and portable fire extinguishers.

Safe-shutdown capability is protected via the above and provisions of fire breaks and 1-hr protective envelopes as required in the zone.

9A.4.2.3.4 Deviations

Deviations have been approved for the following: intervening combustibles based on area-wide sprinklers, cable tray sprinklers, and fire stops (Reference 1, and SSER No. 5, VI[6]).

9A.4.2.4 Relay Room, Fire Zone 03AB, El. 613 Ft 6 In., 630 Ft 6 In. and 643 Ft 6 In.

9A.4.2.4.1 Description

This zone, shown in Figure 9A-6, consists of the relay room and the control center northeast stairwell located in the northern portion of the building. The zone is bounded on the north by an outside wall; on the east by the turbine building; on the south by Fire Zone 05AB, an extension of the turbine building, and the steam tunnel; and on the west by the reactor building. The relay room is a part of the control center complex.

The zone houses relay cabinets, instrument racks, and cables.

Unless noted below, the walls, floor, and ceiling surrounding this zone are constructed of reinforced concrete having a fire-resistance rating of 3 hr. Penetrations are sealed to provide a 3-hr fire-resistance rating. Door openings are protected by Class A fire doors. The stairwell is enclosed by 3-hr fire-rated walls with a Class A fire door. In the control center stairwell, a 3-hr-rated fire barrier is provided for cables of one division. The access stairway to the cable tray area on Elevation 603’-6” is protected by 3-hr fire walls and a Class A fire door. The barrier wall between the relay room itself and the northeast stairwell is a nonfire rated continuous smoke and gas barrier constructed of Thermo-Lag material. This barrier is used to provide containment as a boundary for the halon suppression system in the relay room.

An HVAC chase is located in the southwest corner of the relay room ceiling which extends up to elevation 654’-0” which is above the control room suspended ceiling (Fire Zone 09AB). There are no combustible materials in this 23-foot vertical chase. The HVAC ducts entering this chase from the relay room are provided with fire and smoke and gas dampers. The 23-foot high walls and the ceiling (at elevation 654’-0”) between the existing metal HVAC ducts of this chase are constructed and sealed as 3-hour rated barriers. However, Thermo-Lag material was used in two (2) places to seal around the HVAC ducts in the floor of this chase at elevation 630’-6” as a nonfire rated smoke and gas seal to prevent the escape of discharged halon. Given, as detailed below, that automatic halon suppression is provided for the relay room and that the combustible loading in the control room ceiling is negligible, flame propagation via this combustible material-free vertical chase and out through the metal HVAC ductwork is not a credible event. At this time, it should be noted that NFPA 90 considers metal HVAC ductwork in walls as equivalent to one-hour rated fire barriers. Therefore, this chase provides the required separation between auxiliary building Fire Zones 03AB and 09AB. Additionally, the Thermo-Lag material used to seal the chase at elevation 630’-6” is a nonfire rated smoke and gas barrier. For identification purposes, the chase is considered as being part of auxiliary building Fire Zone 03AB.

Ventilation for this zone is provided by the control center HVAC system. Conditioned air is ducted directly to the relay room. Air is exhausted by ducts from the relay room.

Shutdown equipment located in this zone consists of the following:

a. Division I and II relay panels and termination cabinets

b. Division I and II cables

c. Standby feedwater and CTG 11-1 related cables

Fire detection equipment located in this zone consists of a Class A cross-zoned ionization smoke detection system and a smoke detector in the stairwell. Fire suppression equipment for this zone consists of an automatic Halon system, manual water hose stations, portable fire extinguishers, and a CO_2 hose reel station located outside the room at the south door, as shown in Figure 9A-6.

9A.4.2.4.2 Analysis

Shutdown is achieved from outside the main control room. An alternative shutdown system, independent of the control center complex, has been designed and installed to achieve plant safe shutdown for a fire in this zone.

Cable tray 1K-034 is provided with a 3-hr barrier in the northeast stairwell area.

Inadvertent operation of the automatic Halon system would have no adverse effect on safe-shutdown equipment located in this zone.

Combustibles located in this zone consist primarily of electrical insulation.

Total zone fire loading is moderate.

9A.4.2.4.3 Conclusion

For a fire in this zone, plant safe shutdown will be achieved using the alternative shutdown system.

The objective for this zone is to prevent a fire within the zone from affecting both Divisions I and II equipment and to prevent a fire from crossing the zone's barriers. This objective is achieved through spatial separation, barriers, the provision of an early-warning detection system, an automatic Halon system, manual hose, portable fire extinguishers, and a CO_2 hose reel station.

9A.4.2.4.4 Deviations

There are no deviations for this zone.

9A.4.2.5 Switchgear Room, Fire Zone 04AB, El. 613 Ft 8-1/2 In.

9A.4.2.5.1 Description

This zone, shown in Figure 9A-6, consists of one room located in the southern portion of the building. The zone is bounded on the north by Fire Zone 06AB of this fire area; on the east by the turbine building; on the south by an outside wall; and on the west by the reactor building. Within this zone, a room is constructed to enclose the Division II cables.

The zone houses Division I switchgear and the Division I remote shutdown panel.

The walls, floor, and ceiling of this zone are constructed of reinforced concrete having a fire-resistance rating of 3 hr. Penetrations are sealed to provide 3-hr fire-resistance ratings. The door opening leading to Fire Zone 06AB is protected by Class A fire doors. The stairwell is enclosed by 2-hr-rated fire walls with a Class B fire door. The room containing the Division II cables is enclosed by a 3-hr-rated fire barrier with a Class A fire door.

Ventilation for this zone is provided by the reactor/auxiliary building ventilation system. Air is ducted directly to the switchgear room and exhausted through ducts to the auxiliary building main exhaust system. In addition, the switchgear room contains two local, recirculating-type cooling units.

This zone contains the following shutdown equipment:

a. Division I switchgear
b. Division I and II cable
c. Offsite power cables affecting CTG 11-1 feed to standby feedwater
d. Switchgear room cooling units (Division I)
e. 120 V ac modular power units (Division I and BOP)
f. 130 V dc distribution panel (Division I)

Fire detection equipment located within this zone (including the Division II cable enclosure) consists of an area ionization detection system. Fire suppression equipment consists of a manual hose and portable fire extinguishers as shown in Figure 9A-6. The manual hose station and CO_2 hose reel are located in Fire Zone 06AB.

9A.4.2.5.2 Analysis

Division II cables and equipment will be used to achieve plant safe shutdown for fires in this zone except for the enclosed room near column line G-9. In this room, Division I equipment and cables are used for safe shutdown.

The abandoned tubing left within the three hour fire resistant penetration to the reactor building is evaluated to show that the seal is adequate for fires in the zone.

Combustibles located within this zone consist primarily of electrical insulation. Total zone fire loading is moderate.

9A.4.2.5.3 Conclusion

The objective for this zone is to prevent a fire in this zone from spreading to other zones and to Division II cable. This objective is achieved through fire barriers between other zones and redundant equipment, an early-warning detection system, a manual hose, portable fire extinguishers, and a CO_2 hose reel.

9A.4.2.6 Cable Tunnel, Fire Zone 05AB, El. 613 Ft 6 In.

9A.4.2.6.1 Description

This zone, shown in Figure 9A-6, consists of one room located in the central portion of this elevation adjacent to the steam tunnel. It is bounded on the north by the relay room (Fire Zone 03AB); on the east and south by Fire Zone 06AB and on the west by the steam tunnel.

This zone serves as a cable routing area for Divisions I, Division II, and BOP cable. The Division I cables are located along the east side of the tunnel while the Division II cables are located along the west wall.

The walls, floor, and ceiling separating this zone from the relay room (Fire Zone 03AB) and the turbine building extension are constructed of reinforced concrete having a fire-resistance rating of 3 hr. Penetrations through rated walls, floor, and ceiling are sealed to provide a 3-hr fire-resistance rating. The door openings leading from the cable tunnel are protected by Class A fire doors. The tunnel is divided by a 3-hr fire-rated gypsum wall that separates Divisions I and II cables.

Ventilation for this zone is provided by the reactor/auxiliary building ventilation system. Air is ducted directly to the cable tunnel and exhausted through ducts to the auxiliary building main exhaust system. Relief air flows unducted from the cable tunnel to the corridor leading to the turbine building. Airflow entering the corridor is controlled by a backdraft damper.

Shutdown equipment located in this zone consists of the following:

a. Division I and II cables

b. Standby feedwater power supply control cables

Fire detection equipment located in this zone consists of an area ionization detection system. Fire suppression equipment located in this zone consists of a manual CO_2 system. Manual water hose stations and portable fire extinguishers are available in adjacent zones, as shown in Figure 9A-6.

9A.4.2.6.2 Analysis

Shutdown is achieved from the main control room. Only Division I and standby feedwater control cables are present in the east cable tunnel. Therefore, Division II will be available for plant safe shutdown in the event of a fire in the east tunnel. Division II circuits are present in the west tunnel. The Division I systems will be used to achieve plant safe shutdown in the event of fire in the west tunnel.

The total quantity of combustibles on both sides of the wall consists primarily of electrical insulation. The resultant fire loading for the west side of the tunnel is high. The east side fire loading is also high.

The inadvertent operation of the CO_2 suppression system will have no adverse effect on the cables.

9A.4.2.6.3 Conclusion

The objective for this zone is to prevent a fire from affecting Divisions I and II cables within the zone and from spreading to another zone. The objective is achieved through the provision of a 3-hr-rated fire barrier, early-warning detection, manual CO_2 suppression equipment, and manual hose and portable fire extinguishers.

9A.4.2.6.4 Deviations

Deviations have been approved for the following: to maintain a 3-hr-rated barrier between redundant divisions and provide a manually actuated CO_2 system. (Reference 1, SSER No. 5, VI [910]).

9A.4.2.7 Second Floor, Miscellaneous Rooms, Fire Zone 06AB, El. 613 Ft 6 In.

9A.4.2.7.1 Description

This zone, shown in Figure 9A-6, consists of the personnel air lock, dress-out area, and corridor space. Generally, it is bounded on the north by the steam tunnel, cable tunnel, and the turbine building extension; on the east by the turbine building extension; on the south by the switchgear room; and on the west by the reactor building and the cable tunnel.

The zone houses instrumentation and control calibration equipment and welding equipment.

The walls, floor, and ceiling separating this zone are constructed of reinforced concrete having a fire-resistance rating of 3 hr. Door openings between this zone and the switchgear room, the turbine building extension, and the reactor building are protected by Class A fire doors. Penetrations through the rated walls, floor, and ceiling are sealed to provide 3-hr fire-resistance ratings.

Ventilation for this zone is provided by the reactor/auxiliary building ventilation system. Air is ducted directly to the personnel change room and the welding equipment area. Exhaust from the personnel change room is ducted directly to the auxiliary building main exhaust system. Relief air flows unducted from the welding equipment area to the personnel change room.

Fire detection equipment located within this zone consists of an ionization detection system. Fire suppression equipment in this zone consists of a manual hose station, a CO_2 hose reel, and portable fire extinguishers as shown in Figure 9A-6.

9A.4.2.7.2 Analysis

Only Division I and BOP instrumentation power supply cables are routed through this zone.

Combustibles located within this zone consist primarily of electrical insulation and protective clothing. The total zone loading is low.

9A.4.2.7.3 Conclusion

Division II will be used to achieve plant safe shutdown for a fire in this zone.

The objective for this Fire Zone is to prevent a fire in this zone from spreading to another Fire Zone. This is accomplished through barriers and provision of an early-warning detection system, and manual hose and portable fire extinguishers.

9A.4.2.8 Cable Spreading Room, Fire Zone 07AB, El. 630 Ft 6 In.

9A.4.2.8.1 Description

This zone, shown in Figure 9A-7, consists of one room. It is bounded on the north by an outside wall; on the east by the turbine building; on the south by the steam tunnel; and on the west by the reactor building. The cable spreading room is a part of the control center complex.

The zone serves as a cable routing area for both Divisions I and II and standby feedwater cables.

Unless otherwise noted below, the walls, floor, and ceiling of this zone are constructed of reinforced concrete with a fire-resistance rating of 3 hr. Penetrations through rated walls, floor, and ceiling are sealed to provide a 3-hr fire-resistance rating. The stairwells are enclosed by 3-hr-rated fire walls with Class A fire doors.

Ventilation for this zone is provided by the control center HVAC system. Conditioned air is ducted to and from the zone.

Shutdown equipment located in this zone consists of both Divisions I and II cables.

Fire detection equipment in this zone consists of two ionization detection systems. One of the detection systems is strictly early warning, with the other a Class A cross-zoned ionization detection system providing automatic actuation of the Halon system. Fire suppression equipment consists of an automatic Halon system, manual fusible link sprinkler system, manual water hose station, and portable fire extinguishers, as shown in Figure 9A-7.

9A.4.2.8.2 Analysis

Shutdown is achieved from outside the control room. The alternative shutdown system, independent of the control center complex, has been designed and installed to achieve plant safe shutdown for a fire in this zone.

No protective envelopes are required in this zone.

Inadvertent operation of the automatic Halon fire suppression system will have no adverse effect on the cables in this zone.

Combustibles within this zone consist primarily of cable insulation. Total zone loading is high.

9A.4.2.8.3 Conclusion

The objective for this zone is to prevent a fire within the zone from affecting both Divisions I and II cables and to prevent a fire from crossing the boundaries of this zone. This objective is achieved through spatial separation, barriers, and the provision of an early-warning detection system, an automatic Halon fire suppression system, manual fusible link sprinkler system, manual water hose station, and portable fire extinguishers.

9A.4.2.9 Cable Tray Area, Fire Zone 08AB, El. 631 Ft 0 In.

9A.4.2.9.1 Description

This zone, shown in Figure 9A-7, consists of one room. It is bounded on the north by the steam tunnel; on the east by the turbine building; on the south by an outside wall; and on the west by the reactor building. The zone serves primarily as a cable routing area for Division II cable. A small amount of Division I cable is routed through this zone.

The walls, floors, and ceiling of this zone are constructed of reinforced concrete having a fire-resistance rating of 3 hr. Penetrations through the walls, floor, and ceiling are sealed to provide 3-hr fire-resistance ratings or have been evaluated to contain an acceptable penetration seal. Penetrations that are not installed in a configuration that provides 3-hr protection are evaluated to be acceptable if the installed detail provides adequate protection to prevent spread of fire across the barrier. The stairwell is enclosed by a 2-hr-rated fire barrier with a Class B fire door.

Ventilation air is provided by the reactor/auxiliary building ventilation system. Supply air is ducted directly to this zone. Exhaust air is ducted to the auxiliary building main exhaust system.

The alternative shutdown system is used to achieve plant safe shutdown for a fire in this zone.

Shutdown equipment located in this zone consists of Divisions I and II and standby feedwater cables.

Fire detection equipment in this zone consists of an ionization detection system. Fire suppression equipment located in this zone consists of an automatic CO_2 system, manual water hose stations, and portable fire extinguishers, as shown in Figure 9A-7.

9A.4.2.9.2 Analysis

Shutdown is achieved from outside the main control room. For a fire in this zone, the alternative shutdown system will be used to bring the plant to a safe-shutdown condition. Conduit RI 005-2P/wireway RI-069 contains circuits required for the alternative shutdown system. When the conduit is routed in the zone, a 1-hr protective envelope has been provided on the circuit/wireway.

Inadvertent operation of the automatic CO_2 fire suppression system will have no adverse effect on the cables.

Combustibles located within this zone consist primarily of cable insulation. Total zone fire loading is low.

9A.4.2.9.3 Conclusion

For a fire in this zone, the alternative shutdown system will be used to achieve plant safe shutdown. The objective for this zone is to prevent a fire within the zone from spreading to another Fire Zone. This objective is achieved through spatial separation, barriers, and the provision of early-warning detection, automatic CO_2 fire suppression, manual water hose stations, and portable fire extinguishers.

9A.4.2.9.4 Deviations

There are no deviations for this zone.

9A.4.2.10 Control Room, Fire Zone 09AB, El. 643 Ft 6 In., 655 Ft 6 In, and 677 Ft 6 In.

9A.4.2.10.1 Description

This zone, shown in Figures 9A-8, 9A-9, and 9A-10 consists of the main control room, office, conference room, kitchen, and lavatory on Elevation 643 ft 6 in.; the computer equipment area on Elevation 655 ft 6 in.; and the small air conditioning room located between columns H-13 to 15 on Elevation 677 ft 6 in. The zone is bounded on the north by an outside wall; on the east by the turbine building; on the south by the turbine building corridor and battery rooms; and on the west by the reactor building.

This zone houses the main control panel, computer, and associated auxiliary equipment.

The outside walls, floor, and ceiling of this zone are constructed of reinforced concrete having a fire-resistance rating of 3 hr. The computer room is cut off from the main control room by a barrier that will prevent the propagation of fire. The remainder of the peripheral rooms to the control room, except for the Shift Supervisor's room, have walls and doors that will prevent a fire from spreading out of the room. Electrical and piping penetrations are sealed to provide the same rating as the fire barrier. Supply and return ducts for control room ventilation are provided with fire dampers at the 3-hr fire barriers. See Fire Zone 13AB and

14AB for a discussion of fire dampers F099, F0100, F0101, and F0102, which interface between the Division II control center HVAC and control rooms. Supply and return ducts for the cable spreading and relay rooms that pass through the control room are not provided with dampers at the floor or ceiling. Door openings leading into the turbine building are protected by 1.5-hr fire doors. The northeast stairwell is enclosed by a 3-hr fire barrier with a Class A fire door. A portion of the ceiling of the northeast stairwell is the underside of the stairwell leading up to the computer equipment area (elevation 655’-6”) which has been provided with a 3- hour protective barrier on the underside only. Refer to Subsection 9A.4.2.4.2 for additional details.

Refer to Subsection 9A.4.2.4.1 for a discussion of the HVAC chase between the southwest corner of the relay room on elevation 613’-6” (Fire Zone 03AB) and the area above the control room ceiling. The chase is located at column F-13.

The surface burning characteristics of the glazed block walls, duct insulation, central workstation counters, and ceiling panels in the control room area are rated 25 or less in accordance with the ASTM E-84 test method. The smoke and fuel contribution of the walls, duct insulation, central workstation counters and ceiling panels is also rated 50 or less in accordance with the ASTM E-84 test method. Both the carpeting and counter top meet the criterion requirements for critical radiant heat flux rating and smoke density rating for Class I materials as defined by NFPA standards.

Ventilation for this zone is provided by the control center HVAC system. Conditioned air is ducted directly to and from the control room and associated offices and facilities.

Shutdown equipment located in this zone consists of Division I and II main control board panels, Division I and II cables and standby feedwater cables. The shutdown circuits in the control room are contained within three pairs of cabinets. The control cabinets are mounted on a 4-in.-high concrete pad. The redundant division is contained in the adjacent cabinet. Each set of cabinets is separated from the other sets by several feet. Redundant components in adjacent cabinets are separated from each other by steel panels that have no unsealed penetrations. On the front of the cabinet, the portion below the operating panel is louvered; however, a panel of 1-in.-thick marinite has been fastened on the inside of the panel to close these openings. The annunciator windows are glass for the panels required for shutdown. The heat load and cooling requirements of the panels are satisfied by natural radiative cooling.

Fire detection for the control room is provided by ionization and photoelectric detectors above the drop ceiling and photoelectric detectors in the computer room under-floor area, ionization and/or heat detectors in the peripheral rooms, ionization detectors behind the control room panels below the drop ceiling, ionization detectors within the control boards and continuous manning of the control room (SSER No. 6). Ionization detectors are also located within the central operators consoles, which also provide detection coverage within the adjacent raised floor area. Fire suppression equipment located in this zone consists of an automatic Halon suppression system for the computer room and underfloor area and portable fire extinguishers, as shown in Figures 9A-8 and 9A-9.

The combustible loading in the air conditioning room on elevation 677′-6″ (columns H-13 to 15) is extremely low. In addition future storage of combustibles in this area is not considered for the purpose of this analysis because the area is heavily congested with non-combustible duct work with little floor space. Based on the extremely low combustible loading in this area, fire detection instrumentation is not installed since it would not be expected to alarm due to the small amounts of smoke/heat that could be produced by a postulated fire in this room.

9A.4.2.10.2 Analysis

Shutdown is achieved from outside the main control room. An alternative shutdown system and dedicated shutdown panel independent of the control center complex has been designed and installed to achieve plant safe shutdown for a fire in this zone.

Inadvertent operation of the automatic Halon suppression system in the computer room would have no adverse effect on equipment located in this zone.

Smoke removal from the control room can be accomplished using the control center HVAC system as described in Subsection 9.5.1.2.2. Total fire loading for this zone is low. Total fire loading for this zone is low. Combustibles located in this zone consist of the following:

a. Permanently installed combustibles in the computer room consist primarily of computer wiring insulation and components. In the control room, permanently installed combustibles consist primarily of wiring insulation and components, fire-retardant carpet, counter tops and paper. Paper in this category includes paper in file cabinets and shelves, and chart, recorder, terminal, and plotter paper in use at their respective machines.

b. Anticipated transient combustibles in the computer room consist primarily of paper. The remaining peripheral rooms contain primarily paper, wood, and plastic. The transient combustibles in the main control room are low. Paper not in use will be stored in enclosed metal cabinets.

9A.4.2.10.3 Conclusion

For a fire in the control room, plant safe shutdown will be achieved using the alternative shutdown system and dedicated shutdown panel. The objective for this zone is to minimize the potential for the occurrence of a fire in this zone and, should a fire occur in the zone, minimize the extent of the fire and also to prevent a fire from another zone from spreading into this zone. This objective is achieved through spatial separation of control and instrument components, barriers, and the provision of early-warning detection, automatic Halon suppression in the computer room and computer underfloor area, manual water hose stations, and portable fire extinguishers.

9A.4.2.10.4 Deviations

Deviations have been approved for the following:

a. Installing 1-1/2-hr versus 3-hr-rated fire doors for doors numbered R3-27 and R3-13 based on early-warning detection in the turbine building extension, the Turbine Building low combustible loading in the vicinity of the doors, and the construction of the doors themselves (Reference 3, Reference 2, Appendix E SSER No. 6 III.B)

b. Lack of a fixed suppression system in the control room based on continuous manning of the control room (Reference 1, SSER No. 5-VI [12] and VII).

9A.4.2.11 Divisions I and II Battery Rooms, Fire Zone 10AB, El. 643 Ft 6 In.

9A.4.2.11.1.1 Description

This zone, shown in Figure 9A-8, consists of two rooms. It is bounded on the north by the main control room; on the east and south by Fire Zone 11AB of this fire area; and on the west by the reactor building.

This zone houses the Divisions I and II engineered safety features (ESF) batteries fuse cabinets and cables.

The walls, floor, and ceiling of this zone are constructed of reinforced concrete having a minimum fire-resistance rating of 3 hr. Penetrations are sealed to provide 3-hr-rated fire barriers. The door openings in the south wall are protected by Class A fire doors.

Ventilation for this zone is provided by the reactor/auxiliary building ventilation system. Supply and exhaust are ducted separately to and from each room. Each room is provided with redundant exhaust fans.

The Division I or II batteries contained in these rooms are required for shutdown.

Fire detection equipment located in this zone consists of an area ionization detection system. Fire suppression equipment consists of portable fire extinguishers and manual water hose stations, as shown in Figure 9A-8.

9A.4.2.11.2 Analysis

Shutdown is achieved from the main control room. Divisions I and II batteries located in this zone are separated by a 3-hr fire barrier.

Combustibles in this zone consist primarily of battery cases, electrical insulation, and shock absorbers between batteries. Total zone fire loading is low.

9A.4.2.11.3 Conclusion

The objective for this zone is to prevent a fire in one battery room from spreading to the other battery room and to prevent a fire outside the zone from spreading into the zone. This objective is achieved through barriers, low fire loading, and the provision of early-warning detection, manual water hose stations, and portable fire extinguishers.

9A.4.2.12 Miscellaneous Rooms, Fire Zone 11AB, El. 643 Ft 6 In.

9A.4.2.12.1 Description

This zone, shown in Figure 9A-8, is bounded on the north by the turbine building corridor; on the east by the turbine building; on the south by the Division II switchgear room; and on the west by the battery rooms and reactor building.

This zone houses the reactor protection system (RPS) M-G sets, battery chargers, dc MCCs, and distribution cabinets. The walls, floor, and ceiling of this zone are constructed of reinforced concrete and are rated as 3-hr fire barriers. Penetrations are sealed to provide a fire-resistance rating equivalent to that of the walls, floor, or ceiling in which they are found or have been evaluated to contain an acceptable penetration seal. Penetrations that are not installed in a configuration that provides 3-hr protection are evaluated to be acceptable if the installed detail provides adequate protection to prevent spread of fire across the barrier. The ceiling has a metal hatch cover. The subject steel hatch cover has been evaluated as adequate, as a part of the fire barrier between fire zones 11ABE and 13AB, to prevent the propagation of fire based on the physical configuration of the subject hatch cover in the ceiling/floor, the very low combustible loadings, the fire detection provided in both fire zones, the automatic suppression system provided in Fire Zone 11ABE and the control of transient combustibles in procedures. Door openings are protected by Class B fire doors except in the walls abutting the turbine building corridor and the Division II switchgear room, which have Class A fire doors. Divisions I and II battery chargers are located outside their respective battery rooms on the south side in Fire Zone 11AB. The battery chargers are separated by a 4-in. concrete brick wall with a Class A door installed in it. The wall provides a minimum fire rating of 1-1/2-hr.

Ventilation for this zone is provided by the reactor/auxiliary building ventilation system. Supply air is ducted directly to the battery room air-conditioning unit and circulated through the area or exhausted to the ventilation system.

Shutdown equipment consists of the Divisions I and II battery chargers, dc MCCs, dc distribution cabinets and cables, SRV control cabinets and fan coil units.

Fire detection equipment in this zone consists of two area ionization detection systems. Fire suppression equipment consists of an automatic CO_2 suppression system in the dc MCC room, manual water hose stations, portable fire extinguishers, and a CO_2 hose reel, as shown in Figure 9A-8.

9A.4.2.12.2 Analysis

The Divisions I and II battery chargers and dc distribution cabinets are located in separate rooms.

Division I will be used to achieve plant safe shutdown from the main control room for fires in the west battery charger room.

The alternative shutdown system will be used to achieve plant safe shutdown from outside the control room for a fire in the east side of the zone.

Inadvertent operation of the automatic CO_2 suppression system would have no adverse effect on equipment located in this zone.

Combustibles within this zone consist primarily of electrical insulation. Total zone fire loading is low.

9A.4.2.12.3 Conclusion

The alternative shutdown system is used to achieve plant safe shutdown for a fire in this zone except for the west battery charger room where Division I will be available for shutdown.

The objective for this zone is to prevent a fire within this zone from spreading to another zone. This objective is achieved through barriers and the provision of early-warning detection, an automatic CO_2 suppression system, manual water hose stations, and portable fire extinguishers.

9A.4.2.12.4 Deviations

Deviations have been approved for the following: lack of a 3-hr-rated barrier separating redundant equipment based on a 4-in. solid concrete brick wall with a 3-hr rated door, smoke detection, CO_2 for Division I side, and low combustible loading (less than six cable trays) (Reference 1, SSER No. 5, VI [11]).

9A.4.2.13 Switchgear Room, Fire Zone 12AB, El. 643 Ft 6 In.

9A.4.2.13.1 Description

This zone, shown in Figure 9A-8, consists of one room. It is bounded on the north by Fire Zone 11AB of this fire area; on the east by the turbine building; on the south by an outside wall; and on the west by the reactor building.

The zone houses the Division II switchgear.

The walls, floor, and ceiling are constructed of reinforced concrete having a fire-resistance rating of 3 hr. The door openings in the north wall are protected by Class A fire doors. The door opening at the stairwell is protected by a Class B fire door. Penetrations in the walls, floor, and ceiling are sealed to provide 3-hr-rated fire barriers.

Ventilation for this zone is provided by the reactor/auxiliary building ventilation system. Air is ducted directly to the switchgear room and exhausted through ducts to the auxiliary building main exhaust system. In addition, the switchgear room contains two recirculating-type cooling units.

Shutdown equipment located in this zone consists of the following:

a. Division II switchgear

b. Division I, Division II and standby feedwater cable

c. Switchgear room cooling units (Division II)

d. 120 V ac modular power unit (Division II)

e. 130 V dc distribution panels (Division II)

Fire detection equipment located in this zone consists of an area ionization detection system. Fire suppression equipment consists of manual water hose stations, portable fire extinguishers, and a CO_2 hose reel, as shown in Figure 9A-8.

9A.4.2.13.2 Analysis

Shutdown is achieved from the main control room. Functional redundancy for the Division II switchgear located in this zone is provided by Division I equipment located in another Fire Zone.

Combustibles located within this zone consist primarily of electrical insulation. Total zone fire loading is low.

9A.4.2.13.3 Conclusion

The objective for this zone is to prevent a fire within the zone from spreading to other zones. This objective is achieved through barriers and the provision of an early-warning detection system, manual water hose stations, and portable fire extinguishers.

Division I will be used to achieve plant safe shutdown for a fire in this zone.

No protective envelope is required in this zone.

9A.4.2.14 Ventilation Equipment Area, Fire Zone 13AB, El. 659 Ft 6 In.

9A.4.2.14.1 Description

This zone, shown in Figure 9A-9, consists of one room. It is bounded on the north by the control room Fire Zone 09AB; on the east by the turbine building; on the south by an outside wall; and on the west by the reactor building.

This zone houses the reactor/auxiliary building ventilation system exhaust unit.

The walls surrounding this zone and the floor of this zone are constructed of reinforced concrete having a fire-resistance rating of 3 hr. Penetrations through rated walls and floors are sealed to provide 3-hr fire-resistance ratings. Dampers FO-85 and FO-90 are 1.5-hr-rated dampers while FO-81A and B, FO-82A and B, FO-83A and B, and FO-84A and B are two 1.5-hr-rated dampers in series. These dampers are located in the zone's west and north 3-hr boundary walls but are acceptable because of low fire loading and the presence of fire detection. Fire damper FO-90 is located in a wall separating Fire Zone 13AB from a pipe/HVAC duct chase in the southwest corner. Fire damper FO-85 is located in the wall separating the control room (Fire Zone 09AB) from Fire Zone 13AB. The floor also has a metal hatch cover which will prevent the propagation of fire. The subject steel hatch cover has been evaluated as adequate, as a part of the fire barrier between Fire Zones 11ABE and 13AB, to prevent the propagation of fire based on the physical configuration of the subject hatch cover in the ceiling/floor, the very low combustible loadings, the fire detection provided in both Fire Zones, the automatic suppression system provided in Fire Zone 11ABE and the control of transient combustibles in procedures. The ceiling is constructed of reinforced concrete and contains unprotected hatches and unsealed penetrations, except that all electrical and piping penetrations are sealed to provide a 3-hr fire barrier for that portion of the ceiling separating this zone from Fire Zone 14AB at Elevation 677’-6” and the reactor building southeast access stairs at Elevation 677’-6”. Cable tray penetrations are provided with fire stops. A radiant energy shield of 1-hr fire-rating construction has been installed from floor to ceiling on the west side of the room, the southwest corner wall of the northwest stairwell, south to approximately 3 ft beyond the south end of the Division II testability cabinets.

The pipe chase is a 12-in. concrete block wall (3-hr equivalent). The wall separating the main control room from the fourth floor auxiliary building is reinforced concrete and has a 3-hr fire rating.

The stairwell in the northwest quadrant of the zone is enclosed by a 3-hr-rated barrier with a Class A door that opens to the reactor building's Fire Zone 09AB.

Ventilation for this building area is provided by the reactor/ auxiliary building ventilation system. Supply and exhaust air is ducted to and from this area.

Shutdown equipment in this zone consists of Divisions I and II cables, and Divisions I and II instrument racks.

Fire detection equipment located in this zone consists of an ionization detection system. Fire suppression equipment consists of manual water hose stations and portable fire extinguishers, as shown in Figure 9A-9.

9A.4.2.14.2 Analysis

Shutdown is achieved from outside the main control room. Safe-shutdown capability for the zone is achieved by use of the alternative shutdown system.

Combustibles located within this zone consist primarily of electrical insulation. Total zone fire loading is low.

A radiant energy shield from floor to ceiling has been installed to separate the Divisions I and II equipment from a common heat source.

9A.4.2.14.3 Conclusion

For fires in this zone, the alternative shutdown system will be used to achieve plant safe shutdown.

The objective for this zone is to prevent a fire from spreading to another Fire Zone. This objective is achieved through adequate spatial separation, low fire loading, rated barriers, and the provision of early-warning detection, manual water hose stations(s), and portable fire extinguishers.

9A.4.2.14.4 Deviations

Deviations have been approved for the following:

a. Lack of automatic suppression based on a 1-hr radiant energy shield being installed in front of the cabinet (Reference 1, SSER No. 5 VI [16]).

b. Installation of 1-1/2-hr fire-rated dampers in 3-hr fire-rated barriers based on negligible fuel load and early-warning detection on each side of the barrier (Reference 1, SSER No. 5 III.B).

9A.4.2.15 Control Room Ventilation Equipment Room and Standby Gas Treatment Rooms, Fire Zone 14AB, El. 677 Ft 6 In.

9A.4.2.15.1 Description

This zone, shown in Figure 9A-10, consists of five rooms located in the northern half of Elevation 677 ft 6 in. of the auxiliary building. It is bounded on the north by an outside wall; on the east by the turbine building; on the south by the ventilation equipment room; and on the west by the reactor building.

This zone houses the SGTS charcoal filter units and the control center ventilation equipment.

The walls surrounding this zone are constructed of reinforced concrete. The east and west boundary walls are rated as 3-hr fire barriers. A 1-hr-rated fire barrier with Class A fire doors separates Division I and II air conditioning equipment. A 1-hr-rated fire barrier separates Divisions I and II cables. Penetrations through rated walls are sealed to provide a fire resistance equivalent to the walls in which they are located. The floor is constructed of reinforced concrete and provides a 3-hr fire-rated barrier. Electrical and piping penetrations in the floor are sealed. Ducts are encased by 3-hr-rated fire barriers. Dampers FO-99, FO-100, FO-101, and FO-102 are 1-1/2-hr rated fire dampers. These dampers separate the control room from this zone. The dampers are acceptable because of low fire loading and the presence of fire detection (see SSER No. 5). The ceiling is constructed of reinforced concrete over unprotected steel.

Ventilation for this zone is provided by the control center air conditioning system (CCACS). Conditioned air is supplied through ducts to the control room air conditioning equipment room and by an extension of the duct to the north standby gas treatment room. Exhaust air from the control room air conditioning equipment room is drawn through a return duct opening to the control center air-conditioning units located in the room. Additionally, local cooling and recirculation units in the control room air conditioning equipment room maintain suitable room ambient temperature when the CCACS is operating in the emergency recirculation mode. During operation in the emergency recirculation mode, flows of supply and return air to and from the control center air conditioning equipment room are stopped. There are 1.2 air changes per hour.

A fire in either ventilation equipment room may result in closure of fire damper T4100F903. This damper is located in common ductwork on the discharge of the Division I and Division II CCACS return air fans and is part of the 3-hour fire barrier between the ventilation equipment room and the Control Room. Closure of this damper will result in loss of CCACS return air flow for both divisions and will result in a reduction of cooling air flow to the various ventilation zones served by the CCACS. Once the fire is extinguished, plant procedures have been established to detect closure of fire damper T4100F903 and to manually open it to reestablish the return air flow path. There is sufficient time to open the damper and to start the CCACS Division that did not experience the fire prior to exceeding maximum temperature limits in the zones served by the CCACS.

This zone contains the following shutdown equipment:

a. Division I and II control center air conditioning equipment

b. Divisions I and II control and power cables for control center HVAC fan coil units and drywell pneumatics.

Cable trays 1P-070 and 1C-037 are provided with a 1-hr rated fire barrier within the Division II control center ventilation equipment room when they are within 20 ft of their redundant cables.

Fire detection equipment located within this zone consists of an area ionization detection system. Fire suppression equipment located in this zone consists of an automatic low-pressure CO_2 system for the SGTS charcoal filters, manual water hose stations, and portable fire extinguishers, as shown in Figure 9A-10.

9A.4.2.15.2 Analysis

Shutdown is achieved from the main control room.

Combustibles located within this zone consist primarily of the following:

a. Lubricating oil

b. Charcoal filter material

c. Electrical insulation

Area fire loading is low.

9A.4.2.15.3 Conclusion

Division I will be used to achieve plant safe shutdown for fires in the Division II control center ventilation equipment room and standby gas treatment rooms.

Division I cable trays required for safe shutdown are protected with a 1-hr rated fire barrier when in the Division II control center ventilation equipment room.

Division II will be used to achieve plant safe shutdown for fires in the Division I control center ventilation equipment room.

The objective for this zone is to prevent a fire in the zone from spreading to another Fire Zone and from affecting both Divisions I and II equipment located within the zone. The objective is achieved through fire barriers, low fire loading, and provision of an early-warning detection system, automatic CO_2 fire suppression equipment, manual water hose stations, and portable fire extinguishers.

9A.4.2.15.4 Deviations

Deviations have been approved for the lack of automatic suppression based on 1-hr wrap being provided and low combustible loading (Reference 1, SSER No. 5 VI [9]).

9A.4.2.16 Ventilation Equipment Area, Fire Zone 15AB, El. 677 Ft 6 In.

9A.4.2.16.1 Description

This zone, shown in Figure 9A-10, consists of one room comprising the southern half of Elevation 677 ft 6 in. of the auxiliary building. It is bounded on the north by Fire Zone 14AB; on the east by the turbine building; on the south by an outside wall; and on the west by the reactor building.

The walls surrounding this zone are constructed of reinforced concrete. The east and west bounding walls are rated as 3-hr fire barriers. Penetrations through these walls are sealed to provide 3-hr-rated fire barriers. The door opening leading to the reactor building is protected by a Class A fire door. The floor is constructed of reinforced concrete with unprotected openings. Cable tray penetrations are provided with fire stops. The ceiling is constructed of reinforced concrete over unprotected steel. Ventilation for this zone is provided by the reactor/auxiliary building ventilation system. Supply air is ducted directly to the zone. Exhaust air is ducted to the auxiliary building main exhaust system.

Refer to Subsection 9A.4.2.3.1 for a discussion of the open chase from the mezzanine and cable tray area on the 603’-6” elevation (Fire Zone 02AB) and this area. The opening is located along column H between 10 and 11.

Shutdown equipment located in this zone consists of Divisions I and II HVAC equipment and cables.

Fire detection equipment located in this zone consists of an ionization detection system. Fire suppression equipment located in this zone consists of a manually actuated water flooding system for the charcoal filters, manual water hose stations, and portable fire extinguishers as shown in Figure 9A-10.

9A.4.2.16.2 Analysis

Shutdown is achieved from the main control room. For a fire in this zone, Division II safe shutdown capability is maintained/protected by the installation of isolation devices (fuses) for Division II associated circuits within the zone.

Combustibles located in this zone consist primarily of charcoal filter material and electrical insulation. Total zone fire loading is low.

9A.4.2.16.3 Conclusion

The objective for this zone is to prevent the spread of a fire within this zone to another zone and from affecting both Divisions I and II equipment located within this zone. This objective is achieved through low fire loading and provision of early-warning detection, a manual water flooding system, manual water hose stations, and portable fire extinguishers and isolation devices.

9A.4.2.16.4 Deviations

Deviations have been approved for the lack of automatic suppression based on a 1-hr rated fire barrier, low combustible loading, and charcoal filters having a suppression system(s) (Reference 1, SSER No. 5 VI [7]).

9A.4.3 Residual Heat Removal Complex

9A.4.3.1 General Description

The RHR complex, shown in Figures 9A-13 through 9A-17 inclusive, is a separate reinforced-concrete structure located 230 ft west of the reactor building. The complex is divided at its east-west centerline by a reinforced-concrete wall that has a minimum fire-resistance rating of 3 hr. Each half of the complex contains essentially the same equipment with Division I equipment in the southern portion and Division II equipment in the northern portion of the complex.

Each half of the complex houses a reservoir, cooling tower and service water pump and equipment rooms which comprise the plant's ultimate heat sink. Each half of the complex also houses one set of emergency diesel generators (EDGs), diesel-fuel-oil storage tanks, and switchgear, which are utilized to provide ac power to the plant during a loss of offsite power.

Rated walls, floors, and ceilings are constructed of reinforced concrete having a fire-resistance rating of 3 hr. Doors in rated walls are Class A fire doors. Penetrations in rated walls, floors, and ceilings are sealed.

Floor drains in rooms containing oil are connected to a common manway which is connected by an overflow line to the liquid waste holding pond. Floor drains in other rooms are connected to a different manway which is connected by an overflow line to the circulating water reservoir.

Ventilation for the north diesel generator rooms is provided by outside air drawn by two fans through a louver in the west wall above the 617 ft 0 in. elevation and from there through a motorized outside air damper in the west wall of the fan room at the same elevation. Each diesel room is then supplied by two fans located above the 617 ft 0 in. elevation. Air is relieved through grating in the diesel room ceiling and then through a motorized damper back to the fan room.

Ventilation for the north service water pump room is provided by outside air drawn through a filter plenum by two fans and distributed to the pump room by ductwork along the room's west wall. Room air is relieved through the roof in the northeast and southeast corners of the room. The filter plenums are located at grade along the northeast and southeast corners of the complex.

Ventilation supply air for the north diesel-fuel-oil storage room is drawn by room exhaust fans through an opening in the north CO_2 storage room wall. Exhaust air from the north diesel-fuel-oil storage room is fan exhausted through ducts.

Ventilation for the north CO_2 storage room is provided by continuous exhaust through the space. Exhaust air from the EDG room enters through dampers in the east wall. Exhaust air leaves the room through a damper located in the west wall of the room.

The north switchgear room and ventilation equipment rooms are cooled by outside air. The switchgear room ventilation air is drawn through a filter plenum by two fans and is distributed to the switchgear room by ductwork located along the west wall. This air also supplies the switchgear ventilation equipment room through an outlet in the supply duct main. Air is relieved from the switchgear room through two separate relief openings in the west wall of the room. One of these openings relieves to the switchgear ventilation equipment room. The second of these openings relieves to an air relief room and the EDG room. Air is relieved from the air relief room through dampers to the outside or to the diesel equipment room for recirculation.

The north ventilation equipment room is ventilated by ducted exhaust air from the diesel-fuel-oil storage tank room.

The north diesel generator air intake filter area is ventilated by outside air drawn through fixed louvers located in the west wall by the switchgear and diesel room ventilation fans. Air flows from the louvers, along the west wall housing the diesel intake filters, to the west wall of the switchgear and diesel room ventilation equipment rooms.

Ducts or openings penetrating rated walls are provided with fire dampers.

Ventilation of the south portion of the RHR complex is the same as that for the north portion of the complex. There are no interconnections between north and south ventilation systems.

Shutdown equipment located in the RHR complex consists of the following Divisions I and II equipment:

a. EDGs and auxiliary equipment

b. EDG fuel-oil storage tanks, day tanks, and transfer pumps

c. RHR service water pumps

d. EESW pumps

e. EDG service water pumps

f. RHR complex ventilation equipment

g. RHR cooling towers

h. Switchgear and MCCs.

Fire detection equipment provided in each half of the RHR complex consists of ionization detection systems for the service water pump rooms, switchgear rooms, and ventilation equipment rooms. Fire suppression equipment consists of an automatic, low-pressure CO_2 system in the EDG rooms, automatic sprinkler systems in the fuel-oil storage tank rooms, and portable fire extinguishers and manual water hoses throughout the complex, as shown in Figures 9A-13 through 9A-15.

NFPA 13 noncompliances with these sprinkler systems include location of sprinklers in excess of the maximum allowable distance below the ceiling and distance between some sprinklers under tanks in excess of the maximum allowable distance for extra hazard occupancies (in addition to those discussed and evaluated in 9.5.1.2.3.3). These noncompliances would not prevent the sprinkler systems from fulfilling their required function of controlling a fire and confining it to the room of origin.

9A.4.3.2 Analysis

Shutdown is achieved from the main control room, using Division I systems for a fire in the north half of the RHR Complex and Division II systems for a fire in the south half of the RHR Complex. Divisions I and II equipment is separated by a 3-hr-rated fire barrier.

Fuel-oil storage within the complex represents a specific fire hazard. Tanks are surrounded by rated walls to contain oil in the event of a tank rupture. In addition, tanks can be remote manually drained. Further details are discussed in Subsection 9.5.4. Fuel oil accounts for the major portion of combustible materials. Other combustibles consist primarily of electrical insulation and lubricating oil. The total fire loading for each half of the complex is greater than the high classification.

Because diesel fuel oil is delivered to the valve station near the northwest corner of the RHR complex at regular intervals, the unlikely possibility exists for a catastrophic failure of one of these delivery trucks resulting in an oil spill fire in close proximity to the RHR complex itself. It should be noted plant personnel escort the truck at all times when it is being driven within the protected area and will provide prompt notification of an oil spill/fire.

The actual exposure fire threat to the RHR complex from an oil spill fire such as described above is very low. The exterior walls are constructed of reinforced concrete with an equivalent fire resistance rating of at least three hours. All openings in the exterior walls above elevation 590′-0″ (which is six feet above grade level and the possible oil spill/fire) are protected by heavy steel plates/doors or are within the reinforced concrete RHR cable vaults. All safety related equipment and cables in the RHR complex are located on or above elevation 590′-0″. Four overflow pipe penetrations are provided below elevation 590′-0″. These openings are not provided with any type of covering. However, there are no combustibles in the RHR complex below the 590′-0″ elevation; thus flame propagation through these openings is not postulated. Finally, any heat postulated to enter the complex via the air intakes or non fire rated penetration assemblies will be quickly dissipated by the HVAC system.

The north side of RHR complex, near a postulated fire at the valve station only contains Division II equipment therefore, no credible exposure to both divisions exists and, Division I equipment would be available for safe shutdown.

Because no other combustible materials are stored or located adjacent to the RHR complex, a diesel fuel oil fire is considered the worst case transient combustible exposure fire that the RHR complex could be postulated to receive therefore, the plant's ability to achieve and/or maintain safe shutdown would not be adversely affected by an exposure fire to the RHR complex.

9A.4.3.3 Conclusion

The objective for the RHR complex is to prevent a fire in one half of the complex from spreading to the other half of the complex. This is accomplished by the rated fire barrier between halves of the complex, existing fire detection and suppression equipment, and the ability to drain fuel oil from the storage tanks to a remote area.

9A.4.4 Radwaste Building

9A.4.4.1 General Description

The radwaste building is structurally part of the turbine building and has, for purposes of this fire hazards analysis, been designated as a single, separate fire area. The building is bounded on the north by an outside wall, on the south and west by the turbine building and office and service building, and on the east by the onsite storage building.

The radwaste building houses the liquid and solid waste processing equipment.

The walls, floor, and ceiling are constructed of reinforced concrete and concrete block. Door openings to the turbine building are equipped with Class A, B, and C fire doors. Penetrations through walls of the turbine building and office service building are sealed to provide a 3-hr barrier. Cable trays passing through floors are fire stopped.

The alternative/dedicated shutdown system panels are located on the second floor of this building.

Shutdown equipment contained in this zone consists of the following:

a. Offsite power cables affecting CTG 11-1 feed to standby feedwater

b. RHR Instrumentation equipment and cable

c. Standby feedwater and CTG 11-1 equipment and cable

Fire detection equipment consists of thermal, photoelectric, and ionization type fire detection instruments throughout the building for early warning. Fire suppression equipment for the radwaste building consists of an automatic sprinkler system for the chemical stores room, the two oil-coalescer rooms, the extruder-evaporator room, the drum-turntable room, the drum-capper room, the drum-transfer-conveyor room (all on the first floor), and the main corridor, the drum-conveyor room, the main corridor west of the drum decontamination room and storage room (both on the third floor); an automatic deluge system for the roof-mounted voltage regulator; Clean Agent extinguishing systems for various administrative areas; and a manual hose and portable fire extinguishers. The radwaste building ventilation system is completely separate from other plant areas or buildings.

9A.4.4.2 Analysis

Shutdown is achieved from the main control room using either Division I or Division II systems. The building is separated from the turbine and the office service buildings by 3-hr-rated fire barriers, except for the opening placed in the south wall of the radwaste building which has wet pipe sprinkler protection installed to separate the office and service building fire zone from the new storage area. The fire barrier separating the Radwaste and Turbine Buildings contains class A, B, and C fire doors. The class B fire doors were constructed without windows and in the exact same manner as class A doors; and are therefore considered equivalent to class A doors. The three (3) class C (3/4 hour fire rated) doors are located along column line K at elevation 583’-6” and form part of the separation between the Radwaste Building control room and office area and the Turbine Building. Because the office and control room area is provided with automatic fire detection and the combustible loading on both sides of these doors is low, these doors do not prevent the fire barrier separating the Turbine and Radwaste Buildings from performing its intended design function. Therefore, fire in this building will not affect plant safe-shutdown capability because of the separation and isolation of plant equipment. This arrangement meets the system interface requirements of BTP-CMEB 9.5-1.

Inadvertent operation of automatic fire suppression systems provided for this fire area will have no adverse effect on the ability to shut down the plant. The floor drain system is contained within the building; therefore, combustible liquid spills cannot travel outside the radwaste building.

Combustibles within the radwaste building have been protected by automatic suppression systems as noted in Subsection 9A.4.4.1.

The Conveyor system area of the radwaste building is converted to a storage are. It is isolated from the radwaste building with 3-hr rated fire walls. A cutout in the south wall connects this room to the office and service building. A sprinkler curtain was installed on both sides of the cutout. Effectively, this room is part of the office and service building. Therefore, the radwaste building compliance with Branch Technical Position APCSB 9.5-1 is not impacted by this change.

9A.4.4.3 Conclusion

A fire in the radwaste building will not adversely affect plant shutdown. The 3-hr fire-resistance rating of the walls separating the turbine and the office and service buildings from the radwaste building is adequate, based on the fire hazards and the protection provided for the specific fire hazards in the radwaste building.

9A.4.5 Turbine Building

9A.4.5.1 General Description

The turbine building, which for purposes of this fire hazards analysis includes the steam tunnel and a portion of the auxiliary building at Elevation 583 ft 6 in., comprises one fire area. This fire area is bounded on the north by the radwaste building; on the east by the office and service buildings; on the south by an outside wall; and on the west by the auxiliary building, reactor building, and transformer area.

The west wall of the turbine building is a 3-hr-rated barrier below elevation 679′-6″. This rated barrier serves to protect the turbine building from an exposure fire originating in one of the adjacent oil-filled transformers. In addition, fixed automatic water spray systems are provided for these transformers to reduce their exposure fire hazard. Therefore, the turbine building is adequately protected from a transformer oil exposure fire.

The turbine building houses the turbine generator and related auxiliary equipment. Also located in the turbine building is equipment for the condenser offgas system.

Walls separating the turbine building from other buildings are constructed of reinforced concrete and concrete block. These walls have a 3-hr fire-resistance rating. Doorways in boundary walls separating the turbine building from the auxiliary and reactor buildings are equipped with Class A fire doors. As detailed in Section 9A.4.4.2, doorways in boundary walls separating the turbine building from the radwaste building contain class A, B, and C fire doors. All other penetrations in these boundary walls are sealed to provide 3-hr-rated fire barriers except for the pressure equalizing line between the first floor of the reactor building and this Fire Zone. The ability of the fire barrier to perform its function has been evaluated and determined to provide an adequate assurance that a fire in this Fire Zone will not propagate to the reactor building first floor. Two penetrations in the west wall at approximately 603 ft elevation that contain the Calvert Cable Buses are not sealed with a tested configuration design. However, the lack of combustibles in the area adjacent to and below these openings, the configuration of the Calvert Cable Buses and the rated seals on the auxiliary building wall have been evaluated and provide adequate assurance that a fire in the turbine building will not propagate through these penetrations into the auxiliary building. The floor penetrations in the steam tunnel are provided with a non-tested configuration in the fire rated separation barrier. These seals have been evaluated and provide an adequate assurance that a fire in the Reactor Building Fire Zone 01RB will not propagate through these penetrations into the steam tunnel, or from the steam tunnel to the reactor building.

Safe shutdown equipment consists of the following:

a. Offsite power cables affecting CTG 11-1 feed to standby feedwater

b. Standby feedwater and CTG 11-1 equipment and cables

c. HPCI and RCIC cables, Division I and Division II

d. RHR instrumentation cables

e. HPCI and RCIC equipment and cables, Division I and Division II, in the TB Steam Tunnel

Fire suppression equipment is provided as follows:

a. Automatic water sprinkler systems for the reactor feed pump turbines and turbine-oil reservoir, main lube-oil reservoir, oil storage and turbine-oil tank rooms, the second floor pipe space, and the equipment hatch area and decontamination room on the first floor

b. Automatic water deluge systems for the hydrogen seal oil unit.

In addition to the above automatic systems, manual fire hoses and portable fire extinguishers are provided.

9A.4.5.2 Analysis

Shutdown is achieved from the main control room. Division II is used to achieve shutdown in the turbine building, except for the steam tunnel. In the turbine building steam tunnel, Division I is used to achieve safe shutdown.

Combustibles within the turbine building are typical for a turbine generator complex. The major fire hazard in this fire area is the large quantity of oil required for turbine bearing lubrication and the oil required for the generator hydrogen seals. This hazard is protected against by the fixed suppression systems noted in Subsection 9A.4.5.1.

Inadvertent operation of automatic fire suppression systems provided for this fire area will have no adverse effect on the ability to shut down the plant.

There are no combustibles in the steam tunnel. The major source of fire in the turbine building is remotely located from the valves in the steam tunnel. This distance, coupled with the fixed fire suppression systems provided, protects against a fire hazard to equipment in the steam tunnel. In addition, both shutdown valves (RCIC and HPCI pump discharge isolation valves) are backed up by the automatic depressurization, LPCI, and core spray systems.

The HWC System introduces hydrogen into the turbine building through supply piping at the north end. This piping is routed along the inner east and north walls of the turbine building, bordering the radwaste building. A barrier installed between the northeast stairwell and the hydrogen skid assembly will provide protection for personnel using the stairs in the event of a fire. The elevator shaft is enclosed by a 12-inch thick hollow concrete block wall, which will provide protection and prevent the spread of a fire into the shaft. The quantity of hydrogen which could be released into the turbine building in the event of a pipe break will be limited to that amount contained in the 1.5-inch hydrogen piping (between the upstream automatic isolation valve module and the downstream automatic isolation valves on the injection skid; these will all close on detection of high hydrogen levels). These valves are located inside the turbine building, and will isolate the piping in the building from the hydrogen supply facility. Because of the highly flammable nature of the gas, local area monitors are installed above each heater feed pump injection point, at the hydrogen skid assembly, and at the isolation module at the turbine building entrance. The detection of small amounts of hydrogen (about 1% concentration in air) will result in a local alarm at the HWC control panel, and the detection of levels above 2% in air will result in a system trip and isolation. Since the flammability limit is 4% hydrogen in air, the leak detection system should provide isolation before a flammable mixture can result.

9A.4.5.3 Conclusion

A fire emergency in the turbine building would not adversely affect the ability to shut down the plant. The 3-hr fire- resistance rating of the walls separating the auxiliary, reactor, and radwaste buildings from the turbine building is adequate, based on the fire hazards and the protection provided against specific fire hazards in the turbine building.

9A.4.5.4 Deviations

Deviations for the steam tunnel have been approved for the following:

a. Lack of automatic suppression based on negligible fuel load, heat monitoring instrumentation in place of detectors, and 7 ft separation of redundant valves (Reference 1, SSER No. 5 VI[8]).

b. Lack of 20 ft separation (Reference 1, SSER No. 5 VI).

9A.4.6 Office and Service Building

9A.4.6.1 General Description

The office and service building is primarily a single story structure; however, the office portion of this building consists of two stories. For purposes of this fire hazards analysis, the office and service building has been designated as a single fire area. This building is bounded on the north by a portion of the radwaste building and an outside wall; on the east and south by outside walls; and on the west by the turbine building.

Housed within the office and service building are office spaces, locker rooms, kitchen and dining areas, shops, and warehouse space.

The walls separating this building from adjoining buildings are constructed of reinforced concrete. Penetrations in these walls are sealed to provide a fire stop. Doorways to adjoining buildings are equipped with metal doors, except for the opening placed in the south wall of the radwaste building which has wet pipe sprinkler protection installed to separate the office and service building fire zone from the new storage area.

Shutdown cables contained in this area include cables associated with diversion of inventory from the Condensate Storage Tank, which is the source of water for the SBFW pumps.

Fire suppression equipment for this fire area consists of an automatic water pre-action sprinkler system for the warehouse loading dock, an automatic water sprinkler system in the office storage and fill areas, tool crib and warehouse, and manual hose and portable fire extinguishers.

9A.4.6.2 Analysis

Safe shutdown is achieved from the main control room using Division I or Division II systems. Shutdown cables lost are associated with SBFW. The SBFW system is not required for a fire in the Office and Service Building. The building is separated from adjacent buildings by fire barriers. Along the northern boundary of the OSB on elevation 589’-6”, row line 13A between column lines S and V, there is an unrated opening to the Radwaste building. This opening has an automatic water curtain sprinkler system installed around it to prevent the passage of fire from one zone into the other. This along with the Radwaste and Office and Service Buildings automatic sprinkler systems, early warning fire detection, and low combustible loading in the vicinity of the opening justify that the unrated boundary is acceptable. Additionally, the adjacent buildings house no shutdown equipment nor is there shutdown equipment nearby.

Inadvertent operation of automatic fire suppression systems provided for this fire area will have no adverse effect on ability to shut down the plant.

Combustibles within the office and service buildings have not been quantified since they consist primarily of transient materials typical of office and service buildings.

9A.4.6.3 Conclusion

The objective for this fire area is to prevent fire in this building from jeopardizing the ability to shut down the plant. This objective is achieved by adequate separation from shutdown equipment by barriers, use of automatic, partial coverage fire suppression systems, and manual hose and portable fire extinguishers.

9A.4.7 Yard Area

9A.4.7.1 General Description

The yard area, shown in Figure 9A-1, includes the open areas of the plant site not occupied by buildings. Equipment located in this area includes, but is not limited to, the following:

a. Condensate storage tanks

b. Auxiliary boiler fuel-oil storage tank

c. Auxiliary boiler house

d. Transformers

e. Storage facility for hydrogen

f. Underground safety related cable ducts

g. HWC gas supply facility

h. CTG 11-1 and auxiliaries and 120 kV Mat Equipment located at Fermi 1

i. Offsite power cables affecting CTG 11-1 feed to SBFW

j. Egress area between Reactor Building and RHR complex

See the following subsections for individual analyses of each of the above.

9A.4.7.2 Condensate Storage Tanks

9A.4.7.2.1 Description

The condensate storage tanks are located approximately 100 ft east of the services building and approximately 112 ft south of the auxiliary boiler house.

The tanks are located inside a lined diked area which is designed to collect the contents of a tank spill/overflow. The dike around the tanks is a three foot high concrete wall.

These tanks are used as the supply of water for SBFW, HPCI and RCIC. HPCI and RCIC pumps can be supplied from the suppression pool as another source of water. Fire suppression equipment in this portion of the yard area consists of a fire hydrant, supplied from the fire service water system, and manual hose.

9A.4.7.2.2 Analysis

Shutdown is achieved from the main control room using either Division I or Division II systems. One of the two condensate storage tanks and associated level instrumentation are used for shutdown operations using HPCI or RCIC. However, should the tanks be damaged as a result of fire, the suppression pool can be used as an alternative water source. SBFW does not have another water source. Safe shutdown for the fires in the yard where these tanks could be damaged does not rely on SBFW.

The three foot high concrete wall surrounding the condensate storage tank (to contain the tank contents) will prevent an exposure fire or the heat from an exposure fire in the yard area adjacent to the storage tanks from affecting the tanks themselves. This includes a postulated oil spill/fire due to a catastrophic failure of an oil truck enroute to the RHR complex. In the case of the oil truck, the concrete walls will prevent the burning oil from getting within 25 feet of the storage tanks. In addition, the oil truck is escorted by plant personnel (while the truck is being driven within the protected area) who will promptly notify the Control Room in the event of an oil spill/fire.

9A.4.7.2.3 Conclusion

The objective for this portion of the yard area is to prevent damage to the condensate storage tanks as a result of fire in nearby equipment or buildings. The minimum spatial separation (approximately 100 ft) between these tanks and nearby buildings is adequate. The objective is achieved by this spatial separation and provision of manual fire protection equipment. Additionally, an alternative source of water is provided through connections between the suppression pool and the RCIC, HPCI, low pressure coolant injection (LPCI), and core spray systems.

9A.4.7.3 Auxiliary Boiler Fuel-Oil Storage Tank

9A.4.7.3.1 Description

The auxiliary boiler fuel-oil storage tank is located approximately 200 ft from the service building and approximately 100 ft north of the auxiliary boiler house.

This tank is above ground and surrounded by a dike; therefore, should leakage occur, it would be contained in the diked area.

This tank is not shutdown equipment.

Fire suppression equipment in this portion of the yard area consists of a fire hydrant, supplied by the fire service water system, and manual hose.

9A.4.7.3.2 Analysis

Since this tank is not required for shutdown operation, functional redundancy is not a consideration. Separation by more than 200 ft between this tank and the condensate storage tanks is adequate.

9A.4.7.3.3 Conclusion

The objective for this portion of the yard is to prevent fire in this area from spreading to buildings housing shutdown equipment. This objective is achieved by a dike surrounding the tank, the remote location of the tank, and the fire hydrant in the vicinity.

9A.4.7.4 Auxiliary Boiler House

9A.4.7.4.1 Description

The auxiliary boiler house is located approximately 90 ft east of the service building and approximately 110 ft north of the condensate storage tanks.

This structure houses the auxiliary boiler. The auxiliary boiler is not required for shutdown.

Fire suppression equipment in this portion of the yard area consists of a fire hydrant, supplied from the fire service water system, and manual hose.

9A.4.7.4.2 Analysis

Shutdown is achieved from the main control room using either Division I or Division II systems. Since the auxiliary boiler is not required for safe shutdown, functional redundancy is not a consideration. Separation of this building from other buildings is adequate.

9A.4.7.4.3 Conclusion

The objective of this portion of the yard area is to prevent a fire in the auxiliary boiler house from spreading to other buildings or adversely affecting the condensate storage tanks. This objective is achieved by spatial separation and the fire hydrant in the vicinity.

9A.4.7.5 Transformers

9A.4.7.5.1 Description

Transformers are located in a portion of the yard area adjacent to the west wall of the turbine building and south of the auxiliary building. The main and auxiliary transformers are located in this area, which is surrounded on the north, south, and west sides by a curb to contain any oil leakage from the transformers. Fire barriers are provided between the transformers.

Except for SS #64, none of these transformers are necessary for shutdown operation since required electrical power can be supplied by the EDGs. SS #64 is utilized as part of the SBFW power supply from CTG 11-1 to the SBFW pumps.

Fire suppression equipment for this portion of the yard area consists of automatic deluge systems for the transformers. Fire hydrants, supplied from the fire service water system, and manual hose are also provided.

9A.4.7.5.2 Analysis

Shutdown is achieved from the main control room utilizing either Division I or Division II. SS #64 can affect the ability to power SBFW pumps from the CTG, but SBFW is not necessary for shutdown in the yard area. Since the transformers located in this portion of the yard area are not required for shutdown, functional redundancy is not a consideration. Separation is adequate in light of the fire suppression systems provided.

9A.4.7.5.3 Conclusion

The objective for this portion of the yard area is to prevent a fire spreading from this area to other buildings or yard areas containing shutdown equipment. This objective is achieved by automatic deluge systems, fire hydrants, and a curb around three sides of the area (the turbine building west wall encloses the fourth side).

9A.4.7.6 Hydrogen Storage Facility

9A.4.7.6.1 Description

The hydrogen storage area is located approximately 80 ft south of the turbine building.

Hydrogen is not required for shutdown.

Fire suppression equipment for this area consists of fire hydrants, supplied from the fire service water system, and manual hoses.

9A.4.7.6.2 Analysis

Shutdown is achieved from the main control room using either Division I or Division II systems. Spatial separation of this area from buildings containing shutdown equipment is adequate. Additionally, gas storage cylinders in this storage area are oriented to minimize the probability of striking a safety-related building should an explosion occur.

9A.4.7.6.3 Conclusion

The objective is to prevent fire in the hydrogen storage area from causing damage to shutdown equipment in other buildings. This objective is achieved by the remote location of the hydrogen storage area, the orientation of gas storage cylinders away from safety-related buildings, and fire hydrants in the vicinity.

9A.4.7.7 Underground Safety Related Cable Ducts

9A.4.7.7.1 Description

There are two sets of Category I 4160-V ductbanks between the RHR complex and the Reactor/Auxiliary building, with a Division I and Division II ductbank in each set.

The first set of ductbanks was installed during plant construction. These two underground safety related cable ducts run parallel to each other and carry safe shutdown cables between the RHR complex and the Auxiliary Building cable vault. The most northerly duct carries Division II safe shutdown cables while the other carries Division I safe shutdown cables. The cables in each of these ducts are routed in approximately 30 fiber pipes. The spaces between and around these pipes are filled with approximately 3″ of concrete and the entire structure is reinforced with steel.

Each of the ducts is provided with a manhole structure which is also of reinforced concrete construction and an integral part of the duct. The opening which is approximately 30″ in diameter, is covered by a tight fitting malleable iron cover with cast iron ring. These underground ducts are separated by at least 10′ of soil and are covered by at least 2 feet of soil. The top of the manhole structures are approximately one foot below grade and the manhole covers are covered with soil and gravel.

Immediately adjacent to each manhole is a handhole structure, which is physically independent of the manhole structure but it does become part of the underground duct as it ties into it on both sides of the manhole structure. These handholes provide access to communication cables which are separated by concrete from fiber pipes carrying safety related cables.

The second set of ductbanks and associated manholes is installed above the maximum ground water elevation of 576.0 ft with ducts sloped to the manholes, such that circuits contained are not subject to continuous wetting. These are cast-in-place, rectangular reinforced concrete ductbanks, located with the ductbank top approximately six inches below the surface and manhole covers at grade level. The spaces around the ducts are filled with a minimum of five inches of reinforced concrete. The portion of the ductbanks located below the ISFSI Transfer Pad is covered by the two foot thick reinforced concrete roadway and are separated by a minimum of 7'-8" of soil and reinforced concrete. In the balance of the ductbanks, the ducts are covered with a minimum of 12 ½" of reinforced concrete above the ducts and 18" of reinforced concrete along the sides of the outside ducts.

Three manholes are provided in each of the two ductbank runs. The manholes are 8'-0" long x 6'-0" wide (inside dimension) with 18" thick reinforced concrete walls and 16" thick bottom slab/mat. The top of the manholes is at the finished grade elevation. The manhole covers consist of a 12 ½" thick reinforced concrete removable top slab with two equal 4'-6" x 7'-0" overlapping sections. The manhole cover interface surfaces are provided with joint sealant at the vertical surface and an additional gasket at the horizontal surfaces to avoid the entry of water or other fluids.

The ductbanks rise above grade for a length of approximately six feet in an area of thickened reinforced concrete at the entrance to the RHR cable vaults and for a length of approximately thirteen feet at the entrance to the Reactor/Auxiliary building cable vault. At the Reactor/Auxiliary building entrance, the ducts are covered with eight inches of reinforced concrete and a 1" thick steel plate.

Category I ductbanks from manholes 16946C and 16947C to the RHR complex terminate in RHR cable vaults with 18" thick reinforced concrete walls and 12 ½" thick reinforced concrete roofs. The cable vaults have access openings measuring 2'-6" x 2'-6" and covered with 1 ½" thick steel plate in the north and south walls. The RHR cable vaults are separated by 80 feet. The walls extend 6" below grade, which has a cover of approximately six inches of bituminous pavement. The cable vault floors are gravel to allow drainage.

9A.4.7.7.2 Analysis

Shutdown is achieved from the main control room using either Division I or Division II systems. The underground ducts are separated from each other by distance, construction and soil and gravel. A fire involving solid combustibles stored outside the posted area does not pose a threat to the safe shutdown cables within the manholes because of the insulating properties of the soil and gravel or concrete and the fact that most of the heat will be dissipated into the atmosphere. A combustible liquid fire is not a viable threat to cables inside the manholes because the burning liquid will be extinguished due to the absence of oxygen, as it soaks into the soil and gravel over the manhole. The manholes with reinforced concrete slab covers are equipped with barriers on both the vertical and horizontal surfaces to minimize the possibility of liquid entry.

In addition, the top of the manhole structure is a reinforced concrete slab approximately 12″ thick and the manhole opening is covered by either a tight fitting iron plate that lays inside of a cast iron ring or a 12 ½" thick reinforced concrete slab in two overlapping sections, provided with sealant and gaskets.

The RHR cable vaults for Division I and Division II cables are separated by 80 feet and are constructed of reinforced concrete, with steel covers for the access openings.

9A.4.7.7.3 Conclusion

The objective is to prevent a fire in the yard area from impacting the safe shutdown cables in manholes 16946 and 16947, manholes 16946A, B, and C and 16947A, B, and C, or the RHR cable vaults, and to prevent a fire in either divisional manhole or cable vault from spreading to a manhole or cable vault of the other division.. These objectives are achieved by the insulating capabilities of soil, gravel, and concrete and by physical separation (location).

9A.4.7.8 HWC Gas Supply Facility

9A.4.7.8.1 Description

The HWC gas supply facility is located approximately 1100 feet northwest of the nearest safety-related structure (RHR Complex).

Neither the HWC system nor the gases at the supply facility are required for safe shutdown.

Fire suppression equipment in the area includes yard area fire hydrants supplied from the fire service water system and manual hoses. The hydrogen supply system contains fire control valves which will isolate the hydrogen supply in the event of a fire.

9A.4.7.8.2 Analysis

Shutdown is achieved from the main control room using either Division I or Division II systems. The HWC gas supply facility is located far enough away to prevent fires or explosions from affecting safety-related structures and to prevent the formation of combustible mixtures at safety-related intakes in the event of a release of tank contents without fire or explosion. Therefore, the spatial separation of the gas supply facility from buildings containing safe shutdown equipment is adequate.

9A.4.7.8.3 Conclusion

The objective is to prevent fire in the HWC gas supply facility area from causing damage to shutdown equipment in other buildings. The objective is achieved by the remote location of the gas supply facility and yard area fire hydrants.

9A.4.7.9 CTG 11-1 and Auxiliaries, 120 kV Mat Breakers at Fermi 1

9A.4.7.9.1 Description

At the 120 kV mat area of Fermi 1 and the Fermi 1 building, the CTG 11-1 and auxiliaries and certain breakers are used to provide power to SBFW if offsite power is lost to Fermi 2.

Safe shutdown equipment contained in the 120 kV mat and Fermi 1 zones are as follows:

a. CTG 11-1 and CTG 11-1 starting diesel engine
b. Peaker fuel oil storage tank and delivery system to the CTGs

c. 120 kV offsite breakers, 13.8 kV and 13.2 kV breakers

d. Battery power supplies for the CTG, breakers and supervisory control equipment

Fire suppression equipment for this portion of the yard area consists of automatic CO_2 suppression on the CTG units, fire hydrants and manual hose.

9A.4.7.9.2 Analysis

Shutdown is achieved from the Fermi 2 main control room using either Division I or Division II equipment. Damage to the equipment identified above can affect the power supply to the SBFW pumps, but will not cause loss of power to other divisional shutdown equipment. Use of SBFW is not required for a fire in the yard zone involving the CTG 11-1 or Fermi 1.

9A.4.7.10 Offsite Power Cables

9A.4.7.10.1 Description

The power cables from the 120 kV mat breakers to SS Transformer #64 are run in underground cable ducts. The power cables from SS Transform #64 run in an underground cable duct into the cable entry vault outside the auxiliary building Fire Zone 02AB, and then in an enclosed cable bus along the outside of the auxiliary building until it enters the Division 1 Switchgear Room (Fire Zone 04AB). This power train of cables provides power from CTG 11-1 to the SBFW pumps if offsite power is lost.

The power cables from SS Transformer #65 run in an enclosed cable bus along the outside of the turbine building and the auxiliary building until it enters the Division 2 Switchgear Room (Fire Zone 12AB). The offsite power feed from the 345 kV Mat and SS Transformer #65 are not credited for required or system shutdown.

9A.4.7.10.2 Analysis

Shutdown is achieved from the main control room using either Division I or Division II. SBFW is not required for shutdown for fires in the yard that damage either SS Transformer #64 or the enclosed cable bus outside the buildings.

9A.4.7.11 Egress Area between Reactor Building and RHR Complex

9A.4.7.11.1 Description

In the process of shutting down the plant due to a fire using the alternative dedicated shutdown system, the operators cross the yard area to the RHR complex.

9A.4.7.11.2 Analysis

Shutdown is achieved from the main control room using either Division I or Division II systems. The yard area is lighted for safeguard purposes but is not battery-backed.

However, backup power is available from the combustion turbine generator (CTG 11-1 or an alternate CTG using the standby diesel generator) which supplies power for alternative shutdown. An analysis showed that the CTG can provide power for the yard lights required for shutdown without adversely affecting plant safe-shutdown capability.

9A.4.7.11.3 Deviations

Justification for a deviation from the technical requirements of Section III.J of Appendix R has been documented in a deviation approval request letter dated February 20, 1986, for yard lighting from CTGs versus 8-hr battery packs (Reference 4).

9A.4.8 General Service Water Pump House

9A.4.8.1 General Description

The general service water (GSW) pump house consists of a metal-clad steel building founded on a reinforced-concrete intake structure. This structure is located on the west shore of Lake Erie, south of the main group of plant buildings.

This structure houses the circulating water makeup pumps, GSW pumps, and associated mechanical and electrical equipment. Also housed in this structure are the two fire service pumps. One fire service pump is diesel-engine driven; the other, electric-motor driven.

The diesel-engine driven fire service pump is located in a cubicle surrounded by a 3-hr-rated barrier. The doorways between the diesel-engine-driven pump cubicle and the remaining floor area of this building are equipped with Class A fire doors. The roof of this building satisfies Factory Mutual Class I requirements.

No shutdown equipment is located within the GSW pump house.

Fire suppression equipment for the GSW pump house consists of an automatic water sprinkler system for the diesel-engine-driven fire service pump cubicle, manual hose, and portable fire extinguishers.

9A.4.8.2 Analysis

Shutdown is achieved from the main control room using either Division I or Division II systems. The electric-motor-driven and diesel-engine-driven fire service pumps are redundant. Separation of these pumps is accomplished by enclosure of the diesel-engine-driven fire service pump within a 3-hr-rated fire barrier. The electric-motor-driven fire service pump is separated from other equipment by a minimum distance of approximately 15 ft.

The diesel-driven fire service pump fuel-oil tank represents the only significant concentration of combustible material. This tank is located outside, at grade, adjacent to the north wall of the building housing the fire service pumps.

9A.4.8.3 Conclusion

The objective for the GSW pump house is to prevent fire from damaging both fire service pumps. The objective is achieved through location of the diesel-engine-driven fire service pump within a 3-hr-rated fire barrier, the provision of an automatic sprinkler system for protection of this pump, and the outdoor location of the fuel-oil tank.

9A.4.9 Office Building Annex and Technical Support Center

9A.4.9.1 General Description

The technical support center (TSC) is described in Subsection 7.8.1. The remainder of the building is a two-story steel frame office service building. This portion of the building houses office space and a computer room.

No shutdown equipment is located within the office building.

Fire detection equipment consists of an ionization detection system.

Fire suppression for the office building annex consists of an automatic Halon extinguishing system for the computer room and portable extinguishers.

In addition to the suppression systems listed above, an automatic sprinkler system is installed in the TSC's records room.

9A.4.9.2 Analysis

Shutdown is achieved from the main control room using Division I or Division II systems. No shutdown equipment is jeopardized by a fire in the annex portion of the office building. Inadvertent operation of the automatic fire suppression system will have no adverse effect on ability to shut down the plant.

Combustibles within the office portion have not been qualified since they consist primarily of transient materials typical of an office building.

9A.4.9.3 Conclusion

The objective for this area is to prevent fire in this building from jeopardizing the ability to shut down the plant. This objective is achieved by spatial separation from necessary safety systems.

9A.4.10 Onsite Storage Building

This building is described in Section 11.7.

9A.4.11 Outage Building

9A.4.11.1 General Description

The outage building is primarily a two story structure; however, a one story breezeway connects the turbine building with the outage building. For the purpose of fire hazard analysis, the outage building is designated as a single fire area. The outage building is a free standing structure located four inches south of the reactor and auxiliary buildings.

The outage building contains a radiation protection control point area and access into the Plant Radiologically Controlled Area (RCA), as well as lunch room and rest room facilities.

The building is of completely noncombustible construction. The walls separating this building from the safety-related areas of the plant are constructed of reinforced concrete and contain fire rated doors.

No shutdown equipment is located within the outage building. The drywell pneumatic valves and connection lines are located in the yard between the reactor building and the one-story breezeway connecting the turbine building and the outage building.

Fire suppression equipment for this structure consists of a fire hydrant, supplied by the fire service water system, and manual hose. Fire detection is also provided in the outage building.

9A.4.11.2 Analysis

Shutdown is achieved from the main control room using Division I or Division II systems. No shutdown equipment is jeopardized by a fire in the outage building. The building is separated by reinforced concrete walls and fire rated doors from the safety-related areas of the plant.

Combustibles within the outage building have not been quantified since they consist primarily of transient materials consistent with lunchrooms, offices, and protective clothing storage areas.

9A.4.11.3 Conclusion

The object for this zone is to prevent fire from spreading to buildings housing shutdown equipment. This objective is achieved by the reinforced concrete walls and fire rated doors between the outage building and the safety-related areas of the plant.

9A.4.12 ISFSI Equipment Storage Building

9A.4.12.1 General Description

The Independent Spent Fuel Storage Installation (ISFSI) equipment storage building is located just north of the 345 KV switchyard, approximately 158 feet west of the RHR Complex.

This structure houses the equipment (e.g. – the Vertical Cask Transporter) required for ISFSI cask loading campaigns when not in use and also provides part-time office space and functions as an ISFSI crew briefing/turnover meeting area. This structure is not required for shutdown.

Fire suppression equipment in this structure consists of a wet pipe sprinkler system, supplied from the fire service water system and portable fire extinguishers.

9A.4.12.2 Analysis

Shutdown is achieved from the main control room using either Division I or Division II systems. Since the ISFSI equipment is not required for safe shutdown, functional redundancy is not a consideration. Separation for this building from other buildings is adequate.

9A.4.12.3 Conclusion

The objective is to prevent a fire in the ISFSI equipment storage building from spreading to other buildings and jeopardizing the ability to shut down the plant. This objective is achieved by spatial separation from necessary safety systems.

9A.4.13 FLEX Storage Facility #1 and #2

9A.4.13.1 General Description

There are two FLEX Storage Facilities (FSF) installed at Fermi. FSF#1 is located inside the protected area approximately 150 feet north of the Reactor Building and approximately 240 feet N-E of the RHR complex. FSF#2 is located outside the protected area in the owner controlled area approximately 200 feet west of the Circulating Water Pump House and approximately 210 feet S-E of the south Cooling Tower.

These structures provide storage for equipment that is designated to mitigate the consequences of a Beyond Design Basis External Event. The buildings are made of reinforced concrete and designed to withstand events including Seismic, External Floods, High Winds, Snow/Ice and High/Low Temperatures. Buildings are heated as required to prevent freezing of wetted components.

Fire suppression equipment consists of a dry pipe sprinkler system.

9A.4.13.2 Analysis

Shutdown is achieved from the main control room using either Division I or Division II systems. The equipment stored in FSF#1 and FSF#2 is not safety related and not required for safe shutdown. Separation between the two FLEX Storage Facilities and other plant buildings is adequate.

9A.4.13.3 Conclusion

The objective is to prevent a fire in either of the two FLEX Storage Facilities from spreading to adjacent buildings/SSC’s jeopardizing the ability of these buildings/SSC’s to bring the plant to safe shutdown. FSF#1 and #2 are sufficiently separated from systems credited with safe shutdown.

9A.4 FIRE HAZARDS ANALYSIS

REFERENCES

1. Letter from W. H. Jens, Detroit Edison, to B. J. Youngblood, NRC, Subject: Submittal of Deviations From Staff Interpretations of Fire Protection Features in 10 CFR 50, Appendix R and Justification, dated August 3, 1984 (EF2-72717).
2. Letter from W. H. Jens, Detroit Edison, to B. J. Youngblood, NRC, Subject: Additional Fire Protection Information, dated February 4, 1985 (NE-85-0275).
3. Letter from W. H. Jens, Detroit Edison, to B. J. Youngblood, NRC, Subject: Additional Clarification Concerning Fire Doors and Fire Detectors, dated June 18, 1985 (VP-85-0142).
4. Letter from F. E. Agosti, Detroit Edison, to E. G. Adensam, NRC, Subject: Deviation Request - Emergency Lighting, dated February 20, 1986 (VP-86-0006).

9A.5 POINT-BY-POINT COMPARISON

This section contains a point-by-point comparison with Appendix A to NRC Branch Technical Position APCSB 9.5-1, dated August 23, 1976.

Position For Plants Under Construction and Operating Plants	EF-2 Response
Positions	
a. Overall Requirements of Nuclear Plant Fire Protection Program	
1. Personnel	
Responsibility for the overall fire protection program should be assigned to a designated person in the upper level of management. This person should retain ultimate responsibility even though formulation and assurance of program implementation is delegated. Such delegation of authority should be to staff personnel prepared by training and experience in fire protection and nuclear plant safety to provide a balanced approach in directing the fire protection programs for nuclear power plants. The qualification requirements for the fire protection engineer or consultant, who will assist in the design and selection of equipment, inspect and test the completed physical aspects of the system, develop the fire protection program, and assist in the fire-fighting training for the operating plant should be stated. Subsequently, the FSAR should discuss the training and the updating provisions such as fire drills provided for maintaining the competence of the station firefighting and operating crew, including personnel responsible for maintaining and inspecting the fire protection equipment. The fire protection staff should be responsible for: (a) Coordination of building layout and systems design with fire area requirements, including consideration of potential hazards associated with postulated design basis fires, (b) Design and maintenance of fire detection, suppression, and extinguishing systems, (c) Fire prevention activities, (d) Training and manual fire-fighting activities of plant personnel and the fire brigade. (NOTE: NFPA 6 - Recommendations for Organization of Industrial Fire Loss Prevention, contains useful guidance for organization and operation of the entire fire loss prevention program.)	Fermi 2 has agreed to implement the fire protection program contained in the staff supplemental guidance, "Nuclear Plant Fire Protection Functional Responsibilities, Administrative Controls and Quality Assurance," dated August 29, 1977, including (1) fire protection organizations (2) fire brigade training (3) control of combustibles (4) control of ignition sources (5) fire-fighting procedures.

Position For Plants Under Construction and Operating Plants	EF-2 Response
2. Design Bases	
The overall fire protection program should be based upon evaluation of potential fire hazards throughout the plant and the effect of postulated design basis fires relative to maintaining ability to perform safety shutdown functions and minimize radioactive releases to the environment.	Section 9A.4 (Fire Hazards Analysis) provides this comparison. Likewise, plant emergency procedures are based on maintaining the plant in a safe condition.
3. Backup	
Total reliance should not be placed on a single automatic fire suppression system. Appropriate backup fire suppression capability should be provided.	In areas where automatic suppression systems are provided, adequate manual suppression equipment, including fire-hose stations and/or portable fire extinguishers, is available.
4. Single-Failure Criterion	
A single failure in the fire suppression system should not impair both the primary and backup fire suppression capability. For example, redundant fire water pumps with independent power supplier and controls should be provided. Postulated fires or fire protection system failures need not be considered concurrent with other plant accidents or the most severe natural phenomena. The effects of lightning strikes should be included in the overall plant fire protection program.	The fire suppression systems satisfy this requirement and are described in Position E.
5. Fire Suppression Systems	
Failure or inadvertent operation of the fire suppression system should not incapacitate safety related systems or components. Fire suppression systems that are pressurized during normal plant operation should meet the guidelines specified in APCSB Branch Technical Position 3-1, "Protection Against Postulated Piping Failures in Fluid Systems Outside Containment."	Failure or inadvertent operation of any fire suppression system will not incapacitate more than one division of safety-related systems or components. Analysis of fire protection piping failures was included in the moderate energy piping break evaluation, UFSAR Subsection 3.6.2.3.
6. Fuel Storage Areas	
Schedule for implementation of modifications, if any, will be established on a case-by-case basis.	The fire protection system as described in the FSAR in the fuel storage areas is operational
7. Fuel Loading	
Schedule for implementation of modifications, if any, will be established on a case-by-case basis.	The Fermi 2 Fire Protection System as described in UFSAR Subsection 9.5.1 and in this appendix in safety-related areas is operational.
8. Multiple-Reactor Sites	
On multiple-reactor sites where there are operating	N/A

Position For Plants Under Construction and Operating Plants	EF-2 Response
reactors and construction of remaining units is being completed, the fire protection program should provide continuing evaluation and include additional fire barriers, fire protection capability, and administrative controls necessary to protect the operating units from construction fire hazards. The superintendent of the operating plant should have the lead responsibility for site fire protection.	
9. Simultaneous Fires	
Simultaneous fires in more than one reactor need not be postulated, where separation requirements are met. A fire involving more than one reactor unit need not be postulated except for facilities shared between units.	N/A
b. Administrative Procedures, Controls and Fire Brigade	
1. Administrative procedures consistent with the need for maintaining the performance of the fire protection system and personnel in nuclear power plants should be provided. Guidance is contained in the following publications: NFPA 4 - Organization for Fire Services NFPA 4A - Organization for Fire Department NFPA 6 - Industrial Fire Loss Prevention NFPA 7 - Management of Fire Emergencies NFPA 8 - Management Responsibility for Effects of Fire on Operations	Fermi 2 has agreed to implement the fire protection program contained in the staff supplemental guidance, "Nuclear Plant Fire Protection Functional Responsibilities, Administrative Controls and Quality Assurance," dated August 29, 1977, including: (1) fire protection organizations (2) fire brigade training (3) control of combustibles (4) control of ignition sources (5) fire-fighting procedures.
NFPA 27 Private Fire Brigades	NFPA codes containing information on the above topics were used for guidance.
2. Effective administrative measures should be implemented to prohibit bulk storage of combustible materials inside or adjacent to safety related buildings or systems during operation or maintenance periods. Regulatory Guide 1.39, "Housekeeping Requirements for Water-Cooled Nuclear Power Plants," provides guidance on housekeeping, including the disposal of combustible materials.	
3. Normal and abnormal conditions or other anticipated operations such as modifications (e.g., breaking fire stops, impairment of fire detection and suppression systems) and refueling activities should be reviewed by appropriate levels of management and appropriate special actions and procedures such as fire watches or temporary fire barriers implemented to assure adequate fire protection and reactor safety. In particular:	

Position For Plants Under Construction and Operating Plants	EF-2 Response
(a) Work involving ignition sources such as welding and flame cutting should be done under closely controlled conditions. Procedures governing such work should be reviewed and approved by persons trained and experienced in fire protection. Persons performing and directly assisting in such work should be trained and equipped to prevent and combat fires. If this is not possible, a person qualified in fire protection should directly monitor the work and function as a fire watch.	
(b) Leak testing, and similar procedures such as air flow determination, should use one of the commercially available aerosol techniques. Open flames or combustion generated smoke should not be permitted.	
(c) Use of combustible material, e.g., HEPA and charcoal filters, dry ion exchange resins or other combustible supplies, in safety related areas should be controlled. Use of wood inside buildings containing safety related systems or equipment should be permitted only when suitable noncombustible substitutes are not available. If wood must be used, only fire retardant treated wood (scaffolding, lay down blocks) should be permitted. Such materials should be allowed into safety related areas only when they are to be used immediately. Their possible and probable use should be considered in the fire hazard analysis to determine the adequacy of the installed fire protection systems.	
4. Nuclear power plants are frequently located in remote areas, at some distance from public fire departments. Also, first response fire departments are often volunteer. Public fire department response should be considered in the overall fire protection program. However, the plant should be designed to be self-sufficient with respect to fire fighting activities and rely on the public response only for supplemental or backup capability.	
5. The need for good organization, training and equipping of fire brigades at nuclear power plant sites requires effective measures be implemented to assure proper discharge of these functions. The guidance in Regulatory Guide 1.101, "Emergency Planning for Nuclear Power Plants," should be followed as applicable.	

Position For Plants Under Construction and Operating Plants	EF-2 Response
(a) Successful fire fighting requires testing and maintenance of the fire protection equipment, emergency lighting and communication, as well as practice as brigades for the people who must utilize the equipment. A test plan that lists the individuals and their responsibilities in connection with routine tests and inspections of the fire detection and protection systems should be developed. The test plan should contain the types, frequency and detailed procedures for testing. Procedures should also contain instructions on maintaining fire protection during those periods when the fire protection system is impaired or during periods of plant maintenance, e.g., fire watches or temporary hose connections to water systems.	
(b) Basic training is a necessary element in effective fire fighting operation. In order for a fire brigade to operate effectively, it must operate as a team. All members must know what their individual duties are. They must be familiar with the layout of the plant and equipment location and operation in order to permit effective fire fighting operations during times when a particular area is filled with smoke or is insufficiently lighted. Such training can only be accomplished by conducting drills several times a year (at least quarterly) so that all members of the fire brigade have had the opportunity to train as a team, testing itself in the major areas of the plant. The drills should include the simulated use of equipment in each area and should be preplanned and post-critiqued to establish the training objective of the drills and determine how well these objectives have been met. These drills should periodically (at least annually) include local fire department participation where possible. Such drills also permit supervising personnel to evaluate the effectiveness of communications within the fire brigade and with the on scene fire team leader, the reactor operator in the control room, and the off-site command post.	
(c) To have proper coverage during all phases of operation, members of each shift crew should be trained in fire protection. Training of the plant fire brigade should be coordinated with the local fire department so that responsibilities and duties are delineated in	

Position For Plants Under Construction and Operating Plants	EF-2 Response
advance. This coordination should be part of the training course and implemented into the training of the local fire department staff. Local fire departments should be educated in the operational precautions when fighting fires on nuclear power plant sites. Local fire departments should be made aware of the need for radioactive protection of personnel and the special hazards associated with a nuclear power plant site.	
(d) NFPA 27, “Private Fire Brigade” should be followed in organization, training, and fire drills. This standard also is applicable to the inspection and maintenance of firefighting equipment. Among the standards referenced in this document, the following should be utilized: NFPA 194, "Standard for Screw Threads and Gaskets for Fire Hose Couplings," NFPA 196, "Standard for Fire Hose," NFPA 197, "Training Standard on Initial Fire Attacks," NFPA 601, "Recommended Manual of Instructions and Duties for the Plant Watchman on Guard." NFPA booklets and pamphlets listed on page 27-11 of Volume 8, 1971-72 are also applicable for good training references. In addition, courses in fire protection and fire suppression which are recognized and/or sponsored by the fire protection industry should be utilized.	

Position For Plants Under Construction and Operating Plants	EF-2 Response
c. Quality Assurance Program	
Quality assurance (QA) programs of applicants and contractors should be developed and implemented to assure that the requirements for design, procurement, installation, and testing and administrative controls for the fire protection program for safety-related areas as defined in this Branch Position are satisfied. The program should be under the management control of the QA organization. The QA program criteria that apply to the fire protection program should include the following:	The Quality Assurance Program for Plant Operation governs all activities which may affect safety-related structures, systems, and components at the plant. This program is described in Section 17.2 (QAPD) In view of the fact that safety-related structures, systems, and components are protected by the fire protection systems, portions of the Quality Assurance Program for Plant Operation are designed to ensure that fire protection in safety-related areas is maintained through requirements on design, procurement, installation, testing, and administrative controls. The QA program is under the management control of the Nuclear Quality Assurance (NQA) Department. The NQA Department verifies that the fire protection program incorporates suitable requirements and is acceptable to the senior onsite nuclear manager and also verifies its effectiveness through review, surveillance, and audits. All portions of the fire protection program that impact safety-related areas of the plant are programmatically defined in the Fermi Conduct Manuals and meet the guidtance as addressed in Appendix A of NRC Branch Technical Position APCSB 9.5-1 with the following stipulation. The fire protection system was not originally designed to be safety related.
1. Design Control and Procurement Document Control	
Measures should be established to assure that all design-related guidelines of the Branch Technical Position are included in design and procurement documents and that deviations there from are controlled.	These measures are part of the QA Program.
2. Instructions, Procedures and Drawings	
Inspections, tests, administrative controls, fire drills and training that govern the fire protection program should be prescribed by documented instructions, procedures or drawings and should be accomplished in accordance with these documents.	These items have been developed in accordance with the Fermi Conduct Manuals.

Position For Plants Under Construction and Operating Plants	EF-2 Response
3. Control of Purchased Material, Equipment and Services	
Measures should be established to assure that purchased material, equipment and services conform to the procurement documents.	This item is included in the QA Program.
4. Inspection	
A program for independent inspection of activities affecting fire protection should be established and executed by, or for, the organization performing the activity to verify conformance with documented installation drawings and test procedures for accomplishing the activities.	This item is included in the QA Program.
5. Test and Test Control	
A test program should be established and implemented to assure that testing is performed and verified by inspection and audit to demonstrate conformance with design and system readiness requirements. The tests should be performed in accordance with written test procedures; test results should be properly evaluated and acted on.	The test program is developed according to the requirements of the QA Program. The test results are reviewed by NQA through inspections, surveillances, or audits.
6. Inspection, Test and Operating Status	
Measures should be established to provide for the identification of items that have satisfactorily passed required tests and inspections.	These measures are part of Edison's tagging system and are part of the QA Program.
7. Non-Conforming Items	
Measures should be established to control items that do not conform to specified requirements to prevent inadvertent use or installation.	These measures are part of Edison's tagging system and are part of the QA Program.
8. Corrective Action	
Measures should be established to assure that conditions adverse to fire protection, such as failures, malfunctions, deficiencies, deviations, defective components, uncontrolled combustible material, and nonconformances are promptly identified, reported and corrected	This item is included in the QA Program.

Position For Plants Under Construction and Operating Plants	EF-2 Response
9. Records	
Records should be prepared and maintained to furnish evidence that the criteria enumerated above are being met for activities affecting the fire protection program.	Fire protection records are being maintained for this purpose according to the requirements of the QA Program.
10. Audits	
Audits should be conducted and documented to verify compliance with the fire protection program including design and procurement documents; instructions; procedures and drawings; and inspection and test activities.	Audits conducted by the NQA Department include the fire protection program.
d. General Guidelines for Plant Protection	
1. Building Design	
(a) Plant layouts should be arranged to:	The fire hazards analysis (Section 9A.4) identifies the fire areas and the safe-shutdown equipment within each area.
(1) Isolate safety related systems and	
(2) Separate redundant safety related systems from each other so that both are not subject to damage from a single fire hazard. Alternatives:	
(a) Redundant safety related systems that are subject to damage from a single fire hazard should be protected by a combination of fire retardant coatings and fire detection and suppression systems, or (b) a separate system to perform the safety function should be provided.	Locations where redundant systems are exposed to a single fire hazard are identified in the fire hazards analysis (Section 9A.4). Adequate fire protection is provided for these areas.
(b) In order to accomplish 1(a) above, safety related systems and fire hazards should be identified throughout the plant. Therefore, a detailed fire hazard analysis should be made. The fire hazards analysis should be reviewed and updated as necessary. Additional fire hazards analysis should be done after any plant modification.	See the fire hazards analysis, Section 9A.4.
(c) Alternative guidance for constructed plants is shown in Section E.3, "Cable Spreading Room."	

Position For Plants Under Construction and Operating Plants	EF-2 Response
(d) Interior wall and structural components, thermal insulation materials and radiation shielding materials and sound-proofing should be noncombustible or listed by a nationally recognized testing laboratory, such as Factory Mutual or Underwriters Laboratory, Inc. for flame spread, smoke and fuel contribution of 25 or less in its use configuration (ASTM E-84 Test, "Surface Burning Characteristics of Building Materials").	Plant structural components satisfy thie criterion or have approved deviations.
(e) Metal deck roof construction should be noncombustible (see the building materials directory of the Underwriters Laboratory, Inc.) or listed as Class I by Factory Mutual System Approval Guide. Where combustible material is used in metal deck roofing design, acceptable alternatives are (i) replace combustibles with non-combustible materials, (ii) provide an automatic sprinkler system, or (iii) provide ability to cover roof exterior and interior with adequate water volume and pressure.	All metal deck roof construction is noncombustible and is listed as Class I by the Factory Mutual System Approval Guide.
(f) Suspended ceilings and their supports should be of noncombustible construction. Concealed spaces should be devoid of combustibles. Adequate fire detection and suppression systems should be provided where full implementation is not practicable.	Plant areas satisfy these criteria.
(g) High voltage - high amperage transformers installed inside buildings containing safety related systems should be of the dry type or insulated and cooled with non-combustible liquid. Safety related systems that are exposed to flammable oil filled transformers should be protected from the effects of a fire by: (i) replacing with dry transformers or transformers that are insulated and cooled with noncombustible liquid; or (ii) enclosing the transformer with a three-hour fire barrier and installing automatic water spray protection.	Inside transformers are dry type.

Position For Plants Under Construction and Operating Plants	EF-2 Response
(h) Buildings containing safety related systems, having openings in exterior walls closer than 50 feet to flammable oil filled transformers should be protected from the effects of a fire by: (i) closing of the opening to have fire resistance equal to three hours (ii) constructing a three-hour fire barrier between the transformers and the wall openings; or (iii) closing the opening and providing the capability to maintain a water curtain in case of a fire.	Outdoor oil-filled transformers are within 50 ft of openings in the turbine building wall. Transformers are adequately protected by fixed automatic water spray systems. A solid metal door is provided for the turbine building west wall
(i) Floor drains, sized to remove expected fire fighting water flow should be provided in those areas where fixed water fire suppression systems are installed. Drains should also be provided in other areas where hand hose lines may be used if such fire-fighting water could cause unacceptable damage to equipment in the area. Equipment should be installed on pedestals, or curbs should be provided as required to contain water and direct it to floor drains. (See NFPA 92M, "Waterproofing and Draining of Floors.") Drains in areas containing combustible liquids should have provisions for preventing the spread of fire throughout the drain system. Water drainage from areas which may contain radioactivity should be sampled and analyzed before discharge to the environment. In operating plants or plants under construction, if accumulation of water from the operation of new fire suppression systems does not create unacceptable consequences, drains need not be installed.	Floor drains are designed to remove the expected fire-fighting water flow from areas where fixed fire suppression systems are installed or where fire hose may be used. Equipment is installed on pedestals. Drains in areas containing combustible liquids are designed to prevent the spread of fire throughout the drain system. Water drainage from areas that may contain radioactivity is collected in the floor drain collection tank for normal liquid waste. Subsection 9.3.3 of the UFSAR describes the floor drain system in all the buildings. Section 11.2 of the UFSAR describes the handling and processing of liquid radioactive waste.

Position For Plants Under Construction and Operating Plants	EF-2 Response
(j) Floors, walls and ceilings enclosing separate fire areas should have minimum fire rating of three hours. Penetrations in these fire barriers, including conduits and piping, should be sealed or closed to provide a fire resistance rating at least equal to that of the fire barrier itself. Door openings should be protected with equivalent rated doors, frames and hardware that have been tested and are approved by a nationally recognized laboratory. Such doors should be normally closed and locked or alarmed with alarm and annunciation in the control room. Penetrations for ventilation system should be protected by a standard "fire door damper" where recognized. (Refer to NFPA 80, "Fire Doors and Windows.") The fire hazard in each area should be evaluated to determine barrier requirements. If barrier fire resistance cannot be made adequate, fire detection and suppression should be provided, such as: (i) water curtain in case of fire, (ii) flame retardant coatings, (iii) additional fire barriers.	The fire hazards analysis identifies the fire barriers and determines the requirements for maintaining their integrity. As detailed in Section 9A.4, door openings are protected with equivalent rated doors, frames, and hardware that have been tested and approved by a nationally recognized laboratory. Such doors are normally closed and alarmed with alarm and annunciation in the control room (a continuously manned location), or checked daily, or alarmed with annunciation to Security (a continuously manned location), or locked and checked weekly, all of which are acceptable monitoring methods described in Branch Technical Position CMEB 9.5-1, Revision 2. Penetrations for ventilation systems are protected by fire dampers where deemed necessary as a result of the fire hazards analysis. Electrical conduits penetrating rated fire barriers are provided with internal seals unless they meet the criteria of 9A.2.3.1.1 for not requiring internal seals for fire.
2. Control of Combustibles	
(a) Safety related systems should be isolated or separated from combustible materials. When this is not possible because of the nature of the safety system or the combustible material, special protection should be provided to prevent a fire from defeating the safety system function. Such protection may involve a combination of automatic fire suppression, and construction capable of withstanding and containing a fire that consumes all combustibles present. Examples of such combustible materials that may not be separable from the remainder of its system are: (1) Emergency diesel generator fuel oil day tanks (2) Turbine-generator oil and hydraulic control fluid systems (3) Reactor coolant pump lube oil system	The fire hazards analysis identifies these hazards and the protection afforded.

Position For Plants Under Construction and Operating Plants	EF-2 Response
(b) Bulk gas storage (either compressed or cryogenic), should not be permitted inside structures housing safety-related equipment. Storage of flammable gas such as hydrogen, should be located outdoors or in separate detached buildings so that a fire or explosion will not adversely affect any safety related systems or equipment. (Refer to NFPA 50A, "Gaseous Hydrogen Systems.")	Bulk gas is stored in outside areas. A fire or explosion will not adversely affect any safety-related systems or equipment.
Care should be taken to locate high pressure gas storage containers with the long axis parallel to building walls. This will minimize the possibility of wall penetration in the event of a container failure. Use of compressed gases (especially flammable and fuel gases) inside buildings should be controlled. (Refer to NFPA 6, "Industrial Fire Loss Prevention.")	High-pressure gas storage containers will be located with the long axis parallel to the adjacent safety-related building wall.
(c) The use of plastic materials should be minimized. In particular, halogenated plastics such as polyvinyl chloride (PVC) and neoprene should be used only when substitute non-combustible materials are not available. All plasticmaterials, including flame and fire retardant materials, will burn with an intensity and BTU production in a range similar to that of ordinary hydrocarbons. When burning, they produce heavy smoke that obscures visibility and can plug air filters, especially charcoal and HEPA. The halogenated plastics also release free chlorine and hydrogen chloride when burning which are toxic to humans and corrosive to equipment.	Plastic materials throughout the plant are negligible.
(d) Storage of flammable liquids should, as a minimum, comply with the requirements of NFPA 30, "Flammable and Combustible Liquids Code."	NFPA 30 was used as a guideline for storage of flammable liquids.
3. Electric Cable Construction, Cable Trays and Cable Penetrations	
(a) Only non-combustible materials should be used for cable tray construction.	Cable trays are of non-combustible metal construction.
(b) See Section F.3 for fire protection guidelines for cable spreading rooms.	

	Position For Plants Under Construction and Operating Plants	EF-2 Response
(c)	Automatic water sprinkler systems should be provided for cable trays outside the cable spreading room. Cables should be designed to allow wetting down with deluge water without electrical faulting. Manual hose stations and portable hand extinguishers should be provided as backup. Safety related equipment in the vicinity of such cable trays, that does not itself require water fire protection, but is subject to unacceptable damage from sprinkler water discharge, should be protected from sprinkler system operation or malfunction. When safety related cables do not satisfy the provisions of Regulatory Guide 1.75, all exposed cables should be covered with an approved fire retardant coating and a fixed automatic water fire suppression system should be provided.	Automatic water sprinkler systems will be provided in areas of concentrated cable loading of redundant channels in accordance with the fire hazards analysis. Manual hose stations and portable hand extinguishers are provided as backup. Potential water damage will be considered where water sprays are used. Safety-related and balance-of-plant (BOP) cables are in compliance with IEEE 383/1974 for flame-retardant cable. This standard is referenced in Regulatory Guide 1.75. As addressed in UFSAR Subsection A.1.75, the noncompliance with Regulatory Guide 1.75 is in the identification of associated circuits only. (NOTE: For Exceptions, See Section 8.3.1.4.2)
(d)	Cable and cable tray penetration of fire barriers (vertical and horizontal) should be sealed to give protection at least equivalent to that fire barrier. The design of fire barriers for horizontal and vertical cable trays should, as a minimum, meet the requirements of ASTM E-119, "Fire Test of the Building Construction and Materials, "including the hose stream test, Where installed penetration seals are deficient with respect to fire resistance, these seals may be protected by covering both sides with an approved fire retardant material. The adequacy of using such material should be demonstrated by suitable testing.	Cable penetrations in fire barriers are sealed with silicone foam consistent with fire barrier fire resistance requirements.
(e)	Fire breaks should be provided as deemed necessary by the fire hazards analysis. Flame or flame retardant coatings may be used as a fire break for grouped electrical cables to limit spread of fire in cable ventings. (Possible cable derating owing to use of such coating materials must be considered during design.)	Fire breaks are provided where electrical cables penetrate walls and floors. Also, fire breaks are installed in cable trays of intervening combustibles. Instrument cable trays are enclosed solid-metal trays with covers which serve as radiant energy barriers.

	Position For Plants Under Construction and Operating Plants	EF-2 Response
(f)	Electric cable constructions should as a minimum pass the current IEEE No. 383flame test. (This does not imply that cables passing this test will not require additional fire protection.) For cable and plants under construction that do not meet the IEEE No. 383 flame test requirements, all cables must be covered with an approved flame-retardant coating and properly derated.	Safety-related and BOP cable* satisfies Edison Specification 3071-80 flame test requirements. This specification required a flame test setup on both ladder and solid bottom trays at a horizontal/vertical joint. The test used a 120,000 Btu, 14-in. wheel-type propane burner with a contact flame at 1500°F. Trays were loaded with a single layer of cable spread 1/2 diameter apart. On the ladder tray, the fire could not be self-propagating nor could the cable fail electrically after 5 minutes. On the solid bottom tray, the fire could not be self-propagating after 10 minutes of burner operation. In December 1988, Detroit Edison Specification 3071-080 was revised to require flame tests in accordance with IEEE 383-1974.
(g)	To the extent practical cable construction that does not give off gases while burning should be used. Applicable to new cable installations.	New cables will satisfy Edison Specification 3071-80 test requirements. (NOTE: For Exceptions, See Section 8.3.1.4.2)
(h)	Cable trays, raceways, conduit, trenches, or culverts should be used only for cables. Miscellaneous storage should not be permitted, nor should piping for flammable or combustible liquids or gases be installed in these areas. Installed equipment in cable tunnels or culverts, need not be removed if they present no hazard to the cable runs as determined by the fire hazards analysis.	This criterion is satisfied.
(i)	The design of cable tunnels, culverts and spreading rooms should provide for automatic or manual smoke venting as required to facilitate manual fire fighting capability.	The cable spreading areas are not provided with automatic or manual smoke venting. A low-pressure carbon dioxide system or Halon system is installed to provide extinguishment prior to generation of any appreciable amount of smoke. Portable fans would be used to exhaust smoke from affected areas.
(j)	Cables in the control room should be kept to the minimum necessary for operation of the control room. All cables entering the control room should terminate there. Cables should not be installed in floor trenches or culverts in the control room. Existing cabling installed in concealed floor and ceiling spaces should be protected with an automatic total flooding halon system.	Cables in the control room come from the cable spreading area and terminate in control panels, consoles, or equipment. However, some cabling is installed in the concealed floor of the computer area. An automatic Halon suppression system is provided for the protection of the concealed floor and the computer room.

Position For Plants Under Construction and Operating Plants	EF-2 Response
4. Ventilation	
(a) The products of combustion that need to be removed from a specific fire area should be evaluated to determine how they will be controlled. Smoke and corrosive gases should generally be automatically discharged directly outside to a safe location. Smoke and gases containing radioactive materials should be monitored in the fire area to determine if release to the environment is within the permissible limits of the plant Technical Specifications. The products of combustion which need to be removed from a specific fire area should be evaluated to determine how they will be controlled.	Ventilation for critical areas is evaluated in Sections 9A.2 and 9A.4 of this report. Areas having potential for release of radioactive material are also outlined. Monitoring of radioactive contamination is discussed in UFSAR Subsection 12.2.4.
(b) Any ventilation system designed to exhaust smoke or corrosive gases should be evaluated to ensure that inadvertent operation or single failures will not violate the controlled areas of the plant design. This requirement includes containment functions for protection of the public and maintaining habitability for operations personnel.	No systems are designed solely for smoke removal. Existing ventilation systems that would be used for smoke removal satisfy these criteria.
(c) The power supply and controls for mechanical ventilation systems should be run outside the fire area served by the system.	The power supply and controls for the mechanical ventilation systems used to cool redundant safe-shutdown equipment have been run in the same area as the applicable equipment. These controls satisfy the separation requirements
(d) Fire suppression systems should be installed to protect charcoal filters in accordance with Regulatory Guide 1.52, "Design Testing and Maintenance Criteria for Atmospheric Cleanup Air Filtration."	Charcoal filters are protected with manual deluge or carbon dioxide suppression systems.
(e) The fresh air supply intakes to areas containing safety related equipment or systems should be located remote from the exhaust air outlets and smoke vents of other fire areas to minimize the possibility of contaminating the intake air with the products of combustion.	Fresh air supply intakes are remotely located with respect to exhaust air outlets. Thus the possibility of contaminating the intake air with the products of combustion is minimized.

	Position For Plants Under Construction and Operating Plants	EF-2 Response
(f)	Stairwells should be designed to minimize smoke infiltration during a fire. Staircases should serve as escape routes and access routes for fire fighting. Fire exit routes should be clearly marked. Stairwells, elevators and chutes should be enclosed in masonry towers with minimum fire rating of three hours and automatic fire doors at least equal to the enclosure construction, at each opening into the building. Elevators should not be used during fire emergencies. Where stairwells or elevators cannot be enclosed in three hours fire rated barrier with equivalent fire doors, escape and access routes should be established by a pre-fire plan and practiced in drills by operating and fire brigade personnel.	Some of the stairwells are enclosed. (See the fire protection layout drawings attached to this report.) Stairwells serve as escape routes and access routes for fire fighting. Escape and access routes will be established by pre-fire plan and will be practiced in drills by operating and fire brigade personnel.
(g)	Smoke and heat vents may be useful in specific areas such as cable spreading rooms and diesel fuel oil storage areas and switchgear rooms. When natural-convection ventilation is used, a minimum ratio of 1 sq. foot of venting area per 200 sq feet of floor area should be provided. If forced-convection ventilation is used, 300 CFM should be provided for every 200 sq feet of floor area. See NFPA No. 204 for additional guidance on smoke control.	Natural convection heat venting of 1 ft^2 per 200 ft^2 is used in the turbine room floor area. Forced convection ventilation is provided in all other areas with a minimum design of one air change per hour. The control center smoke purge mode provides 250 cfm per 200 ft^2 floor area for the cable spreading room.

	Position For Plants Under Construction and Operating Plants	EF-2 Response
(h)	Self-contained breathing apparatus, using full face positive pressure masks, approved by NIOSH (National Institute for Occupational Safety and Health - approval formerly given by the U.S. Bureau of Mines) should be provided for fire brigade, damage control and control room personnel. Control room personnel may be furnished breathing air by a manifold system piped from a storage reservoir if practical. Service or operating life should be a minimum of one-half hour for the self-contained units. At least two extra air bottles should be located onsite for each self-contained breathing unit. In addition, an onsite 6-hour supply of reserve air should be provided and arranged to permit quick and complete replenishment of exhausted supply air bottles as they are returned. If compressors are used as a source of breathing air, only units approved for breathing air should be used. Special care must be taken to locate the compressor in areas free of dust and contaminants.	The plant will use full-face positive-pressure breathing masks, approved by NIOSH. Masks will be available for the fire brigade, damage control, or other control room personnel. The plant breathing air system provides a manifold on the south wall of the control room which will supply breathing air to five connection points. Each self-contained breathing unit will have at least two extra fully charged bottles onsite at all times. The plant will have an onsite air compressor for charging the breathing air bottles.
(i)	Where total flooding gas extinguishing systems are used, area intake and exhaust ventilation dampers should close upon initiation of gas flow to maintain necessary gas concentration. (See NFPA 12, "Carbon Dioxide Systems," and 12A, "Halon 1301 Systems.")	Where required, ventilation dampers close on actuation of gaseous extinguishing systems to maintain the necessary gas concentration.

5. Lighting and Communication

Lighting and two way voice communication are vital to safe shutdown and emergency response in the event of fire. Suitable fixed and portable emergency lighting and communication devices should be provided to satisfy the following requirements:

	Position	EF-2 Response
(a)	Fixed emergency lighting should consist of sealed beam units with individual 8-hour minimum battery power supplies.	Fixed emergency lighting with 8-hr battery power supplies is provided for the control room, safety-related equipment areas, and means of egress except in the yard area route to the residual heat removal (RHR) complex where yard security lights are used to provide a lighted pathway.
(b)	Suitable sealed beam battery powered portable hand lights should be provided for emergency use.	Automatically operated, sealed-beam battery-powered lights and sealed-beam battery-powered portable hand lights will be provided for emergency use.

Position For Plants Under Construction and Operating Plants	EF-2 Response
(c) Fixed emergency communication should use voice powered head sets at preselected stations.	Emergency communications capability is provided by telephones, public address systems, and radio communications equipment powered from redundant power sources.
(d) Fixed repeaters installed to permit use of portable radio communication units should be protected from exposure to fire damage.	Repeater stations are installed to improve the quality of radio communication. Loss of a particular repeater will not result in a loss of communication capability in the area adjacent to the repeater.
e. Fire Detection and Suppression	
1. Fire Detection	
(a) Fire detection systems should as a minimum comply with NFPA 72D, "Standard for the Installation Maintenance and Use of Proprietary Protective Signaling Systems." Deviations from the requirements of NFPA 72D should be identified and justified.	Fire detection systems were installed using NFPA 72D as guidance. No recorder is provided in the main control room. This deviation has been approved because adequate records are kept.
(b) Fire detection system should give audible and visual alarm and annunciation in the control room. Local audible alarms should also sound at the location of the fire.	Plant fire detectors will alarm in the control room on the fire protection control panel that will designate general fire location (detector subpanels). Local alarms will sound at the sub-panels that will pinpoint individual room and/or detector location.
c) Fire alarms should be distinctive and unique. They should not be capable of being confused with any other plant system alarms.	Fire alarms will be distinctive and unique and should not be confused with any other plant system alarms.
(d) Fire detection and actuation systems should be connected to the plant emergency power supply.	Fire detection and actuation systems are connected to the plant emergency power supply.
2. Fire Protection Water Supply Systems	
(a) An underground yard fire main loop should be installed to furnish anticipated fire water requirements. NFPA 24 - Standard for Outside Protection - gives necessary guidance for such installation. It references other design codes and standards developed by such organizations as the American National Standards Institute (ANSI) and the American Water Works Association (AWWA). Lined steel or cast iron pipe should be used to reduce internal tuberculation. Such tuberculation deposits in an unlined pipe over a period of years can significantly reduce water flow through the	The underground yard fire main loop was installed using NFPA 24 for guidance. Subsection 9.5.1.2.1 of the UFSAR gives a detailed description of the system. Underground carbon steel pipe is coated, wrapped and provided with cathodic protection. Above-ground pipe is carbon steel. Flushing is accomplished using Fire hydrants. No means for treatment is available. Sectional control valves (post indicator valves) are provided to isolate portions of the fire main for maintenance or repair without shutting down the entire system. Position indicators are provided with the sectional control valves. Branch lines outside the protected area

	Position For Plants Under Construction and Operating Plants	EF-2 Response
	combination of increased friction and reduced pipe diameter. Means for treating and flushing the systems should be provided. Approved visually indicating sectional control valves, such as Post Indicator Valves, should be provided to isolate portions of the main for maintenance or repair without shutting off the entire system. Visible location marking signs for underground valves is acceptable. Alternative valve position indicators should also be provided.	include coated, wrapped and cathodically protected carbon steel, cement lined ductile iron, asbestos-cement and poly vinyl chloride pipe.
	The fire main system piping should be separate from service or sanitary water system piping. For operating plants, fire main system piping that can be isolated from service or sanitary water system piping is acceptable.	The fire main system piping is connected to the general service water system. Isolation valves are provided.
(b)	A common yard fire main loop may serve multi-unit nuclear power plant sites, if cross-connected between units. Sectional control valves should permit maintaining independence of the individual loop around each unit. For such installations, common water supplies may also be utilized. The water supply should be sized for the largest single expected flow. For multiple reactor sites with widely separated plants (approaching 1 mile or more), separate yard fire main loops should be used. Sectionalized systems are acceptable.	N/A
(c)	If pumps are required to meet system pressure or flow requirements, a sufficient number of pumps should be provided so that 100% capacity will be available with one pump inactive (e.g., three 50% pumps, two 100% pumps). The connection to the yard fire main loop from each fire pump should be widely separated, preferably located on opposite sides of the plant. Each pump should have its own driver with independent power supplies and control. At least one pump (if not powered from the emergency diesels) should be driven by non-electrical means, preferably diesel engine. Pumps and drivers should be located in rooms separated from the remaining pumps and equipment by a minimum three-hour fire wall. Alarms indicating pump running, driver availability, or failure to start should be provided in the control room.	Two fire pumps (2500 gpm at 150 psig; one diesel driven and one electric motor driven) are provided for the plant. Connections to the yard fire main loop are 2.68 ft apart. The diesel-driven fire pump is separated from the electric-motor-driven fire pump by a 3-hr-rated fire barrier in the general service water pump house. Alarms indicating pump running, driver availability, and failure to start are provided in the control room.

	Position For Plants Under Construction and Operating Plants	EF-2 Response
	Details of the fire pump installation should as a minimum conform to NFPA 20, "Standard for the Installation of Centrifugal Fire Pumps."	The fire pump installation conforms to the intent of NFPA 20, except for certain deviations, with supporting justifications, identified in section 9.5.1.2.3.2.
(d)	Two separate reliable water supplies should be provided. If tanks are used, two 100% (minimum of 300,000 gallons each) system capacity tanks should be installed. They should be so interconnected that pumps can take suction from either or both. However, a leak in one tank or its piping should not cause both tanks to drain.	Water supply is from Lake Erie.
	The main plant fire water supply capacity should be capable of refilling either tank in a minimum of eight hours. Common tanks are permitted for fire and sanitary or service water storage. When this is done, however, minimum fire water storage requirements should be dedicated by means of a vertical standpipe for other water services.	N/A
(e)	The fire water supply (total capacity and flow rate) should be calculated on the basis of the largest expected flow rate for a period of two hours, but not less than 300,000 gallons. This flow rate should be based (conservatively) on 1,000 gpm for manual hose streams plus the greater of: (1) all sprinkler heads opened and flowing in the largest designed fire area; or (2) the largest open head deluge system(s) operating.	The maximum flow demand is estimated to be less than 1500 gpm to the most remote deluge system, plus 500 gpm for manual hose streams. A single pump is designed to operate at 150 percent of rated capacity and provide 3750 gpm. The capabilities of the Diesel Fire Pump and diesel engine driver are described in section 9.5.1.2.3.2.
(f)	Lakes or fresh water ponds of sufficient size may qualify as sole source of water for fire protection, but require at least two intakes to the pump supply. When a common water supply is permitted for fire protection and the ultimate heat sink, the following conditions should also be satisfied:	Lake Erie is the source of fire service water.
	(1) The additional fire protection water requirements are designed into the total storage capacity; and	N/A
	(2) Failure of the fire protection system should not degrade the function of the ultimate heat sink.	N/A
(g)	Outside manual hose installation should be sufficient to reach any location with an effective hose stream. To accomplish this	Fire hydrants are located not more than 300 ft apart around the perimeter of the plant. The lateral to each fire hydrant is provided with a

Position For Plants Under Construction and Operating Plants	EF-2 Response
hydrants should be installed approximately every 250 feet on the yard main system. The lateral to each hydrant from the yard main should be controlled by a visually indicating or key operated (curb) valve. A hose house, equipped with hose and combination nozzle, and other auxiliary equipment recommended in NFPA 24, "Outside Protection," should be provided as needed but at least every 1,000 feet.	valve. The system is designed so that the sectional control valves (post-indicator valves) can isolate one, two, or three fire hydrants. Selected fire hydrants are provided with hose houses which contain 250 ft of 2-1/2 in. hose, 200 ft of 1-1/2 in. hose, combination fog nozzle, and auxiliary equipment, as deemed necessary.
Threads compatible with those used by local fire departments should be provided on all hydrants, hose couplings and standpipe risers.	The thread size used on hydrants, hose couplings, and standpipe risers is compatible with the Frenchtown Township Fire Department.
3. Water Sprinklers and Hose Standpipe Systems	
(a) Each automatic sprinkler system and manual hose station standpipe should have an independent connection to the plant underground water main. Headers fed from each end are permitted inside buildings to supply multiple sprinkler and standpipe systems. When provided, such headers are considered an extension of the yard main system. The header arrangement should be such that no single failure can impair both the primary and backup fire protection systems.	Underground connections are provided to various buildings to supply standpipe and sprinkler systems as shown on Figure 9A-1. Headers fed from both ends are not provided in the buildings. In the reactor/auxiliary building, two connections (feeds) are provided from the plant underground water main. All standpipes are fed from one connection; all sprinkler systems are fed from the other connection. Isolation valves are provided to separate the primary (automatic) sprinkler systems from the secondary (standpipe) systems.
Each sprinkler and standpipe system should be equipped with OS&Y (outside screw and yoke) gate valve, or other approved shut off valve, and water flow alarm. Safety related equipment that does not itself require sprinkler water fire protection, but is subject to unacceptable damage if wetted by sprinkler water discharge should be protected by water shields or baffles.	Each sprinkler and standpipe system is equipped with an OS&Y gate valve. Each sprinkler system is equipped with a water flow alarm. Standpipe systems are equipped with a water flow alarm. Safety-related equipment has been protected from water damage.
(b) All valves in the fire water systems should be electrically supervised. The electrical supervision signal should indicate in the control room and other appropriate command locations in the plant. (See NFPA 26, "Supervision of Valves.") When electrical supervision of fire protection valves is not practicable, an adequate management supervision program should be provided. Such a program should include locking valves open with strict key control; tamper proof seals; and periodic, visual check of all valves.	Shutoff valves controlling sprinkler and deluge systems are electrically supervised and actuate alarms in the control room or other normally manned security area. Sectional and divisional valves of the underground fire main and major valves inside the building will be locked open. Routine fire inspection by the plant operations engineer delegate will check valve positions, status, and seals.

	Position For Plants Under Construction and Operating Plants	EF-2 Response
(c)	Automatic sprinkler systems should as a minimum conform to requirements of appropriate standards such as NFPA 13, "Standard for the Installation of Sprinkler Systems," and NFPA 15, "Standard for Water Spray Fixed Systems."	Sprinkler systems throughout the plant were installed using NFPA 13 and/or NFPA 15 for guidance. Certain noncompliances to NFPA 13 have been evaluated in accordance with Generic Letter 86-10 and are referenced in section 9.5.1.1.2.
(d)	Interior manual hose installation should be able to reach any location with at least one effective hose stream. To accomplish this, standpipes with hose connections equipped with a maximum of 75 feet of 1-1/2 inch woven jacket lined fire hose and suitable nozzles should be provided in all buildings, including containment, on all floors and should be spaced at not more than 100-foot intervals. Individual standpipes should be at least 4-inch diameter for multiple hose connections and 2-1/2-inch diameter for single hose connections. These systems should follow the requirements of NFPA No. 14 for sizing, spacing and pipe support requirements (NELPIA).	Hose reels are provided throughout the plant as indicated on the fire protection layout drawings. Fire hose is approved 1-1/2 in. lined hose. Individual standpipes are 4-in.-diameter for multiple hose connections and 2-1/2-in.-diameter for single hose connections. NFPA 14 was used for guidance for sizing, spacing, and pipe supports.
	Hose stations should be located outside entrances to normally unoccupied areas and inside normally occupied areas. Standpipes serving hose stations in areas housing safety-related equipment should have shutoff valves and pressure-reducing devices (if applicable) outside the area.	Hose stations are mainly located outside entrances to normally unoccupied areas. Shutoff valves are provided at each hose station where required. Pressure-reducing devices are provided on the 5th floor of the reactor building and below grade, 583 ft 6 in., due to excessive system pressure. Since fog nozzles, which act as effective pressure-reducing devices, are used throughout the remainder of the plant and since fire brigade members who use the hose stations are trained to use the higher outlet pressures in excess of 100 psi, pressure-reducing devices are not provided elsewhere.
(e)	The proper type of hose nozzles to be supplied to each area should be based on the fire hazard analysis. The usual combination spray/straight-stream nozzle may cause unacceptable mechanical damage (for example, the delicate electronic equipment in the control room) and be unsuitable. Electrically safe nozzles should be provided at locations where electrical equipment or cabling is located.	All areas are provided with adjustable pattern fog nozzles, except for the refueling floor, which has solid stream nozzles. Personnel are adequately trained to make proper use of hose stations.
(f)	Certain fires such as those involving flammable liquids respond well to foam suppression. Consideration should be given to use of any of the available foams for such	There are no major flammable liquid hazards in the plant. Areas involving combustible liquids are adequately protected with a sprinkler or deluge system.

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specialized protection application. These include the more common chemical and mechanical low expansion foams, high expansion foam and the relatively new aqueous film forming foam (AFFF).	
4. Halon Suppression Systems	
The use of Halon fire extinguishing agents should as a minimum comply with the requirements of NFPA 12A and 12B, "Halogenated Fire Extinguishing Agent Systems-Halon 1301 and Halon 1211." Only UL or FM approved agents should be used.	NFPA 12A was used for guidance for the Installation of Halon systems.
In addition to the guidelines of NFPA 12A and 12B, preventative maintenance and testing of the systems, including check weighing of the Halon cylinders should be done at least quarterly. Particular consideration should also be given to:	Liquid level measurement of the cylinders and testing of the system will conform to the fire protection conditions for operation, Section 9A.6.
(a) minimum required Halon concentration and soak time (b) toxicity of Halon (c) toxicity and corrosive characteristics of thermal decomposition products of Halon.	Consideration will be given to items (a), (b), and (c).
5. Carbon Dioxide Suppression Systems	
The use of carbon dioxide extinguishing systems should as a minimum comply with the requirements of NFPA 12, "Carbon Dioxide Extinguishing Systems."	Carbon dioxide systems are provided for protection of certain cable tray areas outside the control center complex, the EDG rooms, and SGTS charcoal filters. The carbon dioxide systems are designed using NFPA Standard 12 for guidance.
Particular consideration should also be given to: (a) minimum required CO_2 concentration and soak time; (b) toxicity of CO_2; (c) possibility of secondary thermal shock (cooling) damage; (d) offsetting requirements for venting during CO_2 injection to prevent over-pressurization versus sealing to prevent loss of agent; (e) design requirements from over-pressurization; and (f) possibility and probability of CO_2 systems being out-of-service because of personnel safety consideration. CO_2 systems are disarmed whenever people are present in an area so protected. Areas entered frequently (even though duration time for any visit is short) have often been found with CO_2 systems shut off.	Consideration has been given to items (a) through (f).

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6. Portable Extinguishers	
Fire extinguishers should be provided in accordance with guide lines of NFPA 10 and 10A, "Portable Fire Extinguishers, Installation, Maintenance and Use." Dry chemical extinguishers should be installed with due consideration given to cleanup problems after use and possible adverse effects on equipment installed in the area.	Portable fire extinguishers are provided using NFPA 10 as guidance.
F. Guidelines for Specific Plant Areas	
1. Primary and Secondary Containment	
(a) Normal Operation	
Fire protection requirements for the primary and secondary containment areas should be provided on the basis of specific identified hazards. For example: a. Lubricating oil or hydraulic fluid system for the primary coolant pumps b. Cable tray arrangements and cable penetrations c. Charcoal filters	
Fire suppression systems should be provided based on the fire hazards analysis. Fixed fire suppression capability should be provided for hazards that could jeopardize safe plant shutdown. Automatic sprinklers are preferred. An acceptable alternate is automatic gas (Halon or CO_2) for hazards identified as requiring fixed suppression protection. An enclosure may be required to confine the agent if a gas system is used. Such enclosure should not adversely affect safe shutdown, or other operating equipment in containment. Automatic fire suppression capability need not be provided in the primary containment atmospheres that are inerted during normal operation. However, special fire protection requirements during refueling and maintenance operations should be satisfied as provided below.	The fire hazards analysis outlines the protection for containment areas.

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(b) Refueling and Maintenance	
Refueling and maintenance operations in containment may introduce additional hazards such as contamination control materials, decontamination supplies, wood planking, temporary wiring, welding and flame cutting (with portable compressed fuel gas supply). Possible fires would not necessarily be in the vicinity of fixed detection and suppression systems. Management procedures and controls necessary to assure adequate fire protection are discussed in Section 3a. In addition, manual fire fighting capability should be permanently installed in containment. Standpipes with hose stations, and portable fire extinguishers, should be installed at strategic locations throughout containment for any required manual fire fighting operations. Equivalent protection from portable systems should be provided if it is impractical to install standpipes with hose stations. Adequate self-contained breathing apparatus should be provided near the containment entrances for fire fighting and damage control personnel. These units should be independent of any breathing apparatus or air supply systems provided for general plant activities	It is impractical to provide a standpipe system inside the plant Mark I containment. During refueling, portable extinguishers and self-contained breathing apparatus will be located outside primary containment and portable extinguishers will be located inside containment at various work locations. Hose stations with hose reels are located nearby in the reactor building.
2. Control Room	
The control room is essential to safe reactor operation. It must be protected against disabling fire damage and should be separated from other areas of the plant by floors, walls and roofs having minimum fire resistance ratings of three hours.	The control room is separated from other areas of the plant by fire rated floor, walls, and ceiling. Section 9A.4 discusses fire-resistance ratings of these barriers and outlines the protection for the control room.
Control room cabinets and consoles are subject to damage from two distinct fire hazards: (a) Fire originating within a cabinet or console; and (b) Exposure fire involving combustibles in the general room area	
Hose stations adjacent to the control room with portable extinguishers in the control room are acceptable.	A hose station is provided adjacent to the control room. Fire extinguishers are provided adjacent to or in the control room.
Nozzles that are compatible with the hazards and equipment in the control room should be provided for the manual hose station. The nozzles chosen should satisfy actual fire fighting needs, satisfy electrical safety and minimize physical damage to electrical equipment from hose stream impingement.	Adjustable pattern fog nozzles are provided. Personnel are trained in their safe use.

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Fire detection in the control room cabinets, and consoles should be provided by smoke and heat detectors in each fire area. Alarm and annunciation should be provided in the control room. Fire alarms in other parts of the plant should also be alarmed and annunciated in the control room.	Ionization detectors are provided in the ceiling of the room as well as in the control room cabinets and consoles. Additional protection is outlined in the fire hazards analysis. Fire alarms in other plant locations are annunciated and actuate alarms in the control room.
Breathing apparatus for control room operators should be readily available. Control room floors, ceilings, supporting structures, and walls, including penetrations and doors, should be designed to a minimum fire rating of three hours. All penetration seals should be air tight.	Breathing apparatus for the control room operators will be readily available in the control room. Control room floors, ceiling, supporting structures, and walls, including penetrations and doors, are fire rated as discussed in Section 9A.4. All penetration seals will be airtight.
Manually operated ventilation systems are acceptable.	The ventilation system will automatically be placed in the smoke purge mode by confirmed activation of the Halon system in the cable spreading room or relay room. The smoke purge mode can also be manually initiated.
Cables should not be located in concealed floor and ceiling spaces. If such concealed spaces are used, however, they should have fixed automatic total flooding halon protection. All cables that enter the control room should terminate in the control room. That is, no cabling should be simply routed through the control room from one area to another.	The concealed space beneath the computer room subfloor will be provided with a Halon system.
3. Cable Spreading Room	
(a) The preferred acceptable methods are:	
(1) Automatic water system such as closed head sprinklers, open head deluge, or open directional spray nozzles.	The cable spreading room is protected by an automatic Halon system.
Deluge and open spray systems should have provisions for manual operation at a remote station; however, there should also be provisions to preclude inadvertent operation. Location of sprinkler heads or spray nozzles should consider cable tray sizing and Arrangements to assure adequate water coverage. Cable should be designed to allow wetting down with deluge water without electrical faulting. Open head deluge and open directional spray systems should be zoned so that a single failure will not deprive the entire area of automatic fire suppression capability. The use of foam is acceptable, provided it is of a type capable of being delivered by a sprinkler or deluge system, such as an Aqueous Film Forming Foam (AFFF).	In addition, a manually actuated automatic sprinkler system is installed for backup capability.

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(2) Manual hoses and portable extinguishers should be provided as backup.	Manual hose and portable fire extinguishers are provided.
(3) Each cable spreading room of each unit should have divisional cable separation, and be separated from the other and the rest of the plant by a minimum three-hour rated fire wall (refer to NFPA 251 or ASTM E-119 for fire test resistance rating).	Section 9A.4 discusses the fire rating of barriers
(4) At least two remote and separate entrances are provided to the room for access by fire brigade personnel; and	Two remote entrances are provided to the room. (See Figure 9A-7.)
(5) Aisle separation provided between tray stacks should be at least three feet wide and eight feet high.	Aisles 3 ft wide and 8 ft high are not provided.
(b) For cable spreading rooms that do not provide divisional cable separation of a(3), in addition to meeting a(1), (2), (4), and (5) above, the following should also be provided:	Cable separation has been provided adequately to permit safe plant shutdown in case of a fire in the cable spreading room. See Subsection 9A.4.2.8.
(1) Divisional cable separation should meet the guidelines of Regulatory Guide 1.75, "Physical Independence of Electric Systems."	
(2) All cabling should be covered with a suitable fire retardant coating.	
(3) As an alternate to a(1) above, automatically initiated gas systems (Halon or CO_2) may be used for primary fire suppression, provided a fixed water system is used as a backup.	
(4) Plants that cannot meet the guidelines of Regulatory Guide 1.75, in addition to meeting a(1), (2), (4), and (5) above, an auxiliary shutdown system with all cabling independent of the cable spreading room should be provided.	
4. Plant Computer Room	
Safety related computers should be separated from other areas of the plant by barriers having a minimum three-hour fire resistant rating. Automatic fire detection should be provided to alarm and annunciate in the control room and alarm locally. Manual hose stations and portable water and halon fire extinguishers should be provided.	Plant computers are not safety related.

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5. Switchgear Rooms	
Switchgear rooms should be separated from the remainder of the plant by minimum three-hour rated fire barriers to the extent practicable. Automatic fire detection should alarm and annunciate in the control room and alarm locally. Fire hose stations and portable extinguishers should be readily available.	Safety-related switchgear rooms are separated from the remainder of the plant by walls, floors, and ceilings which have fire-resistant barriers. (See Section 9A.4, which discusses the fire rating of the barriers.) Automatic fire detection devices, which actuate alarms and annunciate in the control room, are provided. Fire hose and portable fire extinguishers are readily available.
Acceptable protection for cables that pass through the switchgear room is automatic water or gas agent suppression. Such automatic suppression must consider preventing unacceptable damage to electrical equipment and possible necessary containment of agent following discharge.	
6. Remote Safety Related Panels	
The general area housing remote safety related panels should be provided with automatic fire detectors that alarm locally and alarm and annunciate in the control room. Combustible materials should be controlled and limited to those required for operation. Portable extinguishers and manual hose stations should be provided.	Areas housing remote safety-related panels are provided with automatic fire detectors that alarm in the control room. Combustible materials are controlled in these areas. Manual fire suppression equipment is provided for these areas. The fire hazards analysis details these areas.
7. Station Battery Rooms	
Battery rooms should be protected against fire explosions. Battery rooms should be separated from each other and other areas of the plant by barriers having a minimum fire rating of three hours inclusive of all penetrations and openings. (See NFPA 69, "Standard on Explosion Prevention Systems.") Ventilation systems in the battery rooms should be capable of maintaining the hydrogen concentration well below 2 vol. % hydrogen concentration. Standpipe and hose and portable extinguishers should be provided.	The battery rooms are separated from other areas by at least 1-1/2 hr fire-resistance-rated walls, floors, and ceiling. The fire hazards analysis outlines the protection provided for these areas. The ventilation system will maintain the hydrogen concentration well below 2 percent by volume. Portable fire extinguishers and a hose reel are provided.
Alternatives:	
(a) Provide a total fire rated barrier enclosure of the battery room complex that exceeds the fire load contained in the room.	
(b) Reduce the fire load to be within the fire barrier capability of 1-1/2 hours.	
OR	
(c) Provide a remote manual actuated sprinkler	

Position For Plants Under Construction and Operating Plants	EF-2 Response
system in each room and provide the 1-1/2 hour fire barrier separation.	
8. Turbine Lubrication and Control Oil Storage and Use Areas	
A blank fire wall having a minimum resis-tance rating of three hours should separate all areas containing safety related systems and equipment from the turbine oil system. When a blank wall is not present, open head deluge protection should be provided for the turbine oil hazards and automatic open head water curtain protection should be provided for wall openings.	N/A
9. Diesel Generator Areas	
Diesel generators should be separated from each other and other areas of the plant by fire barriers having a minimum fire resistance rating of three hours.	Emergency diesel generators of opposite divisions are separated by a 3-hr fire barrier.
When day tanks cannot be separated from the diesel-generator one of the following should be provided for the diesel generator area:	Day tanks are separated from the diesel generator by 3-hr fire barrier walls. The day tanks are also protected by a wet pipe sprinkler system.
(a) Automatic open head deluge or open head spray nozzle system(s)	
(b) Automatic closed head sprinklers	
(c) Automatic AFFF that is delivered by a sprinkler deluge or spray system	
(d) Automatic gas system (Halon or CO_2) may be used in lieu of foam or sprinklers to combat diesel generator and/or lubricating oil fires.	
10. Diesel Fuel Oil Storage Areas	
Diesel fuel oil tanks with a capacity greater than 1100 gallons should not be located inside the buildings containing safety related equipment. They should be located at least 50 feet from any building containing safety related equipment, or if located within 50 feet, they should be housed in a separate building with construction having a minimum fire resistance rating of three hours. Buried tanks are considered as meeting the three hour fire resistance requirements. See NFPA 30, "Flammable and Combustible Liquids Code," for additional guidance.	Diesel fuel-oil tanks are separated from the EDG by construction having a 3-hr fire-resistance rating. The fire hazards analysis (Section 9A.4) discusses the diesel fuel storage room fire protection.

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When located in a separate building, the tank should be protected by an automatic fire suppression system such as AFFF or sprinklers.	
In operating plants where tanks are located directly above or below the diesel generators and cannot reasonably be moved, separating floors and main structural members should, as a minimum, have fire resistance rating of three hours. Floors should be liquid tight to prevent leaking of possible oil spills from one level to another. Drains should be provided to remove possible oil spills and fire fighting water to a safe location.	
One of the following acceptable methods of fire protection should also be provided: (a) Automatic open head deluge or open head spray nozzle system(s) (b) Automatic closed head sprinklers; or (c) Automatic AFFF that is delivered by a sprinkler system or spray system	
11. Safety Related Pumps	
Pump houses and rooms housing safety related pumps should be protected by automatic sprinkler protection unless a fire hazards analysis can demonstrate that a fire will not endanger other safety related equipment required for safe plant shutdown. Early warning fire detection should be installed with alarm and annunciation locally and in the control room. Local hose stations and portable extinguishers should also be provided.	The fire hazards analysis outlines fire protection for safety-related pumps.
Equipment pedestals or curbs and drains should be provided to remove and direct water away from safety related equipment.	Equipment is installed on concrete pads. Adequate water drainage is provided.
Provisions should be made for manual control of the ventilation system to facilitate smoke removal if required for manual fire fighting operation.	Smoke removal will be provided by portable fans, if required.
12. New Fuel Area	
Hand portable extinguishers should be located within this area. Also, local hose stations should be located outside but within hose reach of this area. Automatic fire detection should alarm and annunciate in the control room and alarm locally. Combustibles should be limited to a minimum in the new fuel area. The storage area should be provided with a drainage system to preclude accumulation of water.	Manual suppression equipment, such as hose stations and portable fire extinguishers, is provided. Automatic fire detection is provided.
The storage configuration of new fuel should always be so maintained as to preclude criticality for any	

Position For Plants Under Construction and Operating Plants	EF-2 Response
water density that might occur during fire water application.	
13. Spent Fuel Pool Area	
Protection for the spent fuel pool area should be provided by local hose stations and portable extinguishers. Automatic fire detection should be provided to alarm and annunciate in the control room and to alarm locally.	Manual suppression equipment, such as hose stations and portable fire extinguishers, is provided. Automatic detection is provided.
14. Radwaste Building	
The radwaste building should be separated from other areas of the plant by fire barriers having at least three-hour ratings. Automatic sprinklers should be used in all areas where combustible materials are located. Automatic fire detection should be provided to annunciate and alarm in the control room and alarm locally. During a fire, the ventilation systems in these areas should be capable of being isolated. Water should drain to liquid radwaste building sumps. Acceptable alternative fire protection is automatic fire detection to alarm and annunciate in the control room, in addition to manual hose stations and portable extinguishers consisting of hand held and large wheeled units.	Except as noted in section 9A.4.4.2, the radwaste building is separated from the turbine building by fire barriers having a 3-hr fire-resistance rating. For a discussion of the onsite storage building, see Section 11.7 of the UFSAR. Automatic sprinklers are provided as discussed in Subsection 9A.4.4. Automatic fire detection annunciates and alarms in the control room. The ventilation system can be isolated during a fire. The building water drains are discussed in Section 9A.4.4.2
15. Decontamination Areas	
The decontamination areas should be protected by automatic sprinklers if flammable liquids are stored. Automatic fire detection should be provided to annunciate and alarm in the control room and alarm locally. The ventilation system should be capable of being isolated. Local hose stations and hand portable extinguishers should be provided as backup to the sprinkler system.	No significant quantity of flammable liquids is stored in the decontamination areas. Automatic fire detection alarms and annunciates in the control room. Hose stations and portable extinguishers are provided.
16. Safety Related Water Tanks	
Storage tanks that supply water for safe shutdown should be protected from the effects of fire. Local hose stations and portable extinguishers should be provided. Portable extinguishers should be located in nearby hose houses. Combustible materials should not be stored next to outdoor tanks. A minimum of 50 feet of separation should be provided between outdoor tanks and combustible materials where feasible.	Subsection 9A.4.7 of the fire hazards analysis outlines the protection for this area.

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17. Cooling Towers	
Cooling towers should be of noncombustible construction or so located that a fire will not adversely affect any safety related systems or equipment. Cooling towers should be of non-combustible construction when the basins are used for the ultimate heat sink or for the fire protection water supply. Cooling towers of combustible construction, so located that a fire in them could adversely affect safety related systems or equipment should be protected with an open head deluge system installation with hydrants and hose houses strategically located.	Residual heat removal cooling towers are of noncombustible construction. Circulating water cooling towers are located such that a fire will not affect safety related equipment.
18. Miscellaneous Areas	
Miscellaneous areas such as records storage areas, shops, warehouses, and auxiliary boiler rooms should be so located that a fire or effects of a fire, including smoke, will not adversely affect any safety related systems or equipment. Fuel oil tanks for auxiliary boilers should be buried or provided with dikes to contain the entire tank contents.	The record storage areas, shops, outage building and warehouse are separated from safety-related systems or equipment by fire barriers. Therefore, fire or smoke would not affect safety-related systems or equipment. The fuel-oil tank for the auxiliary boiler is provided with a dike.
G. Special Protection Guidelines	
1. Welding and Cutting, Acetylene-Oxygen Fuel Gas Systems	
This equipment is used in various areas throughout the plant. Storage locations should be chosen to permit fire protection by automatic sprinkler systems. Local hose stations and portable equipment should be provided as backup. The requirements of NFPA 51 and 51B are applicable to these hazards. A permit system should be required to utilize this equipment. (Also refer to 2f herein.)	Storage of welding and cutting acetylene-oxygen gas bottles will be in the warehouse areas protected by automatic sprinklers. A permit system is used to control open flames in the plant as explained previously in Section B.3(a).
2. Storage Areas for Dry Ion ExchangeResins	
Dry ion exchange resins should not be stored near essential safety related systems. Dry unused resins should be protected by automatic wet pipe sprinkler installations. Detection by smoke and heat detectors should alarm and annunciate in the control room and alarm locally. Local hose stations and portable extinguishers should provide backup for these areas. Storage areas of dry resin should have curbs and drains. (Refer to NFPA 92M, "Waterproofing and Draining of Floors.")	Dry ion exchange resins will be stored in the warehouse which is removed from safety-related areas and protected by an automatic wet pipe sprinkler system. The warehouse area is also provided with a fire detector system that provides local and control room alarms. Local hose stations and portable extinguishers are provided in the warehouse as backup to the sprinkler system. A curb and drain system is not necessary in the warehouse as the entire area is sprinkled.

Position For Plants Under Construction and Operating Plants	EF-2 Response
3. Hazardous Chemicals	
Hazardous chemicals should be stored and protected in accordance with the recommendations of NFPA 49, "Hazardous Chemicals Data." Chemicals storage areas should be well ventilated and protected against flooding conditions since some chemicals may react with water to produce ignition.	Minor amounts of hazardous chemicals may be stored in the laboratory or shop areas. NFPA 49, "Hazardous Chemicals Data," is used as a guideline for storage. Portable extinguishers and hose stations are provided in these areas.
4. Materials Containing Radioactivity	
Materials that collect and contain radioactivity such as spent ion exchange resins, charcoal filters, and HEPA filters should be stored in closed metal tanks or containers that are located in areas free from ignition sources or combustibles. These Materials should be protected from exposure to fires in adjacent areas as well. Consideration should be given to requirements for removal of isotopic decay heat from entrained radioactive materials.	Materials that collect and contain radioactivity are stored in the radwaste area until processed. Spent resins are stored (wet) in the phase separator tanks until processed. Spent charcoal filter material and HEPA filters will be stored in metal containers in the radwaste bailed waste storage room. This room removes the material from other areas of the radwaste building. This area is provided with fire detectors.

9A.6 FIRE PROTECTION CONDITIONS FOR OPERATION

The Fire Protection Conditions For Operation portion of Appendix 9A is in the Technical Requirements Manual.

Figure Intentionally Removed
Refer to Plant Drawing A-2400

Fermi 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 9A-1

FIRE PROTECTION EVALUATION PLOT PLAN

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Refer to Plant Drawing A-2401

Fermi 2

UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 9A-2

FIRE PROTECTION EVALUATION
REACTOR BUILDING SUBBASEMENT PLAN
(ELEVATION 540.0 FT)

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Refer to Plant Drawing A-2402

Fermi 2

UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 9A-3

FIRE PROTECTION EVALUATION
REACTOR AND AUXILIARY BUILDINGS
BASEMENT PLAN (ELEVATION 562.0 FT)

Figure Intentionally Removed
Refer to Plant Drawing A-2403

Fermi 2

UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 9A-4

FIRE PROTECTION EVALUATION
REACTOR AND AUXILIARY BUILDINGS
FIRST FLOOR PLAN
ELEVATION 583.5 FT

Figure Intentionally Removed
Refer to Plant Drawing A-2404

Fermi 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 9A-5

FIRE PROTECTION EVALUATION
REACTOR AND AUXILIARY BUILDINGS
CABLE TRAY AREA PLAN (ELEVATION 603.5 FT)

Figure Intentionally Removed
Refer to Plant Drawing A-2405

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FIGURE 9A-6

FIRE PROTECTION EVALUATION
REACTOR AND AUXILIARY BUILDINGS
SECONG FLOOR PLAN (ELEVATION 613.5 FT)

Figure Intentionally Removed
Refer to Plant Drawing A-2406

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FIGURE 9A-7

FIRE PROTECTION EVALUATION
REACTOR AND AUXILIARY BUILDINGS
CABLE SPREADING AREA PLAN
(ELEVATION 630.5 FT)

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Refer to Plant Drawing A-2407

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FIGURE 9A-8

FIRE PROTECTION EVALUATION
REACTOR AND AUXILIARY BUILDINGS
THIRD FLOOR PLAN
ELEVATION 641.5 FT AND 643.5 FT

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Refer to Plant Drawing A-2408

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FIGURE 9A-9

FIRE PROTECTION EVALUATION
REACTOR AND AUXILIARY BUILDINGS
FOURTH FLOOR (ELEVATION 659.5 FT)

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Refer to Plant Drawing A-2409

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FIGURE 9A-10

FIRE PROTECTION EVALUATION
REACTOR AND AUXILIARY BUILDINGS
FIFTH FLOOR PLAN
(ELEVATIONS 677.5 FT AND 684.5 FT)

Figure Intentionally Removed
Refer to Plant Drawing A-2410

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FIGURE 9A-11

FIRE PROTECTION EVALUATION
REACTOR AND AUXILIARY BUILDINGS
ROOF PLAN (ELEVATION 697.5 FT AND 735.5 FT)

Figure Intentionally Removed
Refer to Plant Drawing A-2411

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FIGURE 9A-12

FIRE PROTECTION EVALUATION
REACTOR AND AUXILIARY BUILDINGS
SECTION D-D

Figure Intentionally Removed
Refer to Plant Drawing A-N-2040

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FIGURE 9A-13

FIRE PROTECTION EVALUATION
RESIDUAL HEAT REMOVAL COMPLEX
BASEMENT FLOOR PLAN (ELEVATION 554.25 FT)

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Refer to Plant Drawing A-N-2041

FIGURE 9A-14

FIRE PROTECTION EVALUATION
RESIDUAL HEAT REMOVAL COMPLEX
GRADE FLOOR PLAN (ELEVATION 590.0 FT)

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Refer to Plant Drawing A-N-2042

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FIGURE 9A-15

FIRE PROTECTION EVALUATION
RESIDUAL HEAT REMOVAL COMPLEX
UPPER FLOOR PLAN (ELEVATION 617.0 FT)

Figure Intentionally Removed
Refer to Plant Drawing A-N-2043

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FIGURE 9A-16

FIRE PROTECTION EVALUATION
RESIDUAL HEAT REMOVAL COMPLEX
ROOF PLAN (ELEVATIONS 617.0 FT AND 637.0 FT)

Figure Intentionally Removed
Refer to Plant Drawing A-N-2044

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FIGURE 9A-17

FIRE PROTECTION EVALUATION
RESIDUAL HEAT REMOVAL COMPLEX
SECTION A-A AND SECTION B-B

Figure Intentionally Removed
Refer to Plant Drawing A-N-2045

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FIGURE 9A-18

FIRE PROTECTION EVALUATION
RESIDUAL HEAT REMOVAL COMPLEX
SECTION C-C

CHAPTER 10: STEAM AND POWER CONVERSION SYSTEM

10.1 SUMMARY DESCRIPTION

The steam and power conversion system for Fermi 2 includes a tandem-compound, single-stage reheat, six-flow exhaust, 1800-rpm turbine with nominal 43-in. (8th stage) last-stage buckets (blades). The turbine nominal rating at the generator terminals is 1235 MWe at 1.5 in. Hg abs, 100 percent reactor flow, and zero percent makeup. The design rating of the generator coupled to the turbine is 1,350,000 kVA at 22,000 V, 60-Hz frequency, and 0.90 power factor. Steam at 981.0 psia, 544°F, and 0.46 percent moisture is provided by the nuclear steam supply system (NSSS) at the turbine throttle to drive the main turbine generator.

Moisture separation with one stage of reheat is provided between the high-pressure and the low-pressure turbines for all steam entering the low-pressure turbines. Steam from the low-pressure turbines is condensed in a single-pressure condenser of divided water-box design. Condensate is collected in the condenser hot-wells and pumped through the condensate/feedwater cycle to the NSSS. Heater drains are cascaded into the condenser, except for the heater drains from heaters 5 and 6. The condensate/feedwater from these is pumped forward into the reactor feed pump (RFP) suction.

The condensate and feedwater system supplies feedwater to the NSSS through a condensate cleanup system and then through six stages of extraction feedwater heating.

Circulating water from a circulating water reservoir is pumped through the main condenser and returned to the cooling towers. There, the heat rejected from the steam conversion system is dissipated into the atmosphere. Makeup water for the circulating water system is taken from Lake Erie.

The heat balance at design rating is shown in Figure 10.1-1. Key cycle characteristics are shown in Table 10.1-1.

Normally, the turbine and auxiliary equipment use all the steam being generated by the NSSS; however, an automatic pressure-controlled 23.5 percent-capacity turbine bypass system discharges excess steam directly into the condenser. The capacity of this system is 23.5 percent of the rated reactor flow.

The steam and power conversion system is designed to use the energy available from the NSSS. It has the capability of accepting at least rated reactor flow and reactor pressure for safe, continuous operation. The necessary biological shielding for the main turbines, RFP turbines, moisture separators and reheaters, and condenser is provided for personnel protection.

The individual components of the steam and power conversion system are based on a proven conventional design acceptable for use in large central-station power plants. All auxiliary equipment has been sized on the basis of the design flow rating and pressure rating with turbine valves providing adequate margin for pressure control in accordance with the heat balance shown in Figure 10.1-1. Design margins have been included to ensure adequate capacity under all operating circumstances.

The steam turbine is provided with an electro-hydraulic control (EHC) system having three electrical speed inputs. Speed logic is redundantly processed in both electronic and hydraulic channels. Turbine steam supply valves are provided in serial pairs; a stop valve is actuated by either of two redundant overspeed trip systems followed by a controlling valve modulated by the speed governing system. The latter valve is tripped by either of the two overspeed trip systems. Failure of a single component in the speed control system does not lead to excessive overspeed.

Logic circuits are provided for turbine protection and operation. Additionally, testing circuits for the turbine steam valves are provided. Emergency trip devices include a manual trip, a mechanical overspeed trip, an electrical overspeed trip, and an electrical vacuum trip.

None of the components of the power conversion systems are required to operate to ensure a safe reactor shutdown. This is because reactor safety systems are provided that are designed to protect the reactor under all conditions, including complete isolation from the power conversion systems. Therefore, reliability of these power conversion systems, except where concerned with control of radioactivity, is primarily a function of system operating requirements.

Redundant equipment is provided, wherever feasible, to prevent excessive loss of plant output or excessive frequency of reactor scram.

The safety-related aspects of several postulated failures that might occur within the power conversion system have been considered. The following specific situations have been analyzed:

a. Breaks in the feedwater system that allow discharge of contaminated feedwater into the turbine building

b. Failure of the air-ejection line resulting in discharge of activity directly into the turbine building

c. Missiles generated by a postulated turbine failure

d. Introduction of contaminants into the reactor vessel via the condensate/feedwater system.

Feedwater system breaks and failure of the air-ejection line are both discussed in Chapter 15. These analyses indicate that the amount of radiation released into the environment following any one of these studied incidents is within acceptable limits.

The effects of turbine missiles are analyzed in Subsections 10.2.3 and 3.5.1.2.2. The conclusion is that postulated turbine missiles are not a plausible event.

Regulatory Guide 1.56, Maintenance of Water Purity in Boiling Water Reactors, will be met to ensure that contaminants from the feedwater entering the reactor vessel are kept at acceptably low levels.

TABLE 10.1-1 SUMMARY OF IMPORTANT NOMINAL AND PERFORMANCE CHARACTERISTICS OF THE POWER CONVERSION SYSTEM

Turbine Data	
Manufacturer	General Electric Company Turbine Generator, LTD.[a] GE for HP and LP Steam Path replacement components
Type / LSB length, in.	43 (8th stage)
Number of cylinders	One higher pressure, three low pressure
Gross electrical output at the generator terminals (MWe)	1235
Condenser pressure, in. Hg abs	1.5
Final feedwater temperature, °F	426.5 (nominal)
Steam conditions at throttle valves inlet	
Flow, lb/hr	13,722.820
Pressure, psia	981.0
Temperature, °F	544
Enthalpy, Btu/lbm	1190.6
Moisture content, percent	0.46
Turbine cycle arrangement	
Number of steam reheat stages	One
Number of feedwater heating stages	Six
Heater drain system	Heaters 5 and 6 pumped forward
Feedwater heaters in condenser neck	Numbers 1 and 2
Type of condensate demineralizer	Mixed-powdered-resin type
Main steam bypass capacity, percent of rated reactor flow	23.5

[a] Formerly English Electric Co,

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Refer to Plant Drawing C1C OUT

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FIGURE 10.1-1

HEAT BALANCE AT 100 PERCENT
REACTOR FLOW

10.2 TURBINE GENERATOR

10.2.1 Design Bases

The turbine generator is designed to meet the following conditions:

a. Gross electrical output at the generator terminals at 100 percent reactor flow is 1235 Mwe.

b. Steam conditions at the turbine throttle valves inlet

1.	Flow, lb/hr	13,722,820
2.	Pressure, psia	981.0
3.	Temperature, °F	544
4.	Enthalpy, Btu/lbm	1190.6
5.	Moisture content, percent	0.46

c. Exhaust pressure, in. Hg abs 1.5

d. Final feedwater temperature, °F 426.5

e. Stages of feedwater heating Six

f. Stages of steam reheating One

These figures represent the 100 percent reactor flow heat balance conditions shown in Figure 10.1-1.

The unit is to be operated initially in a base-loaded manner but has the provision to be operated in a load-following manner when this becomes beneficial from the standpoint of system reliability and economics.

The nuclear steam supply system (NSSS) and turbine have the ability to provide continuous load-following capability over a range of approximately 31.5 percent of rated power. This power change via recirculation flow can be accomplished at the rate of 1.5 percent/sec for both load increases and decreases. Step-change electrical load reductions that do not exceed 23.5 percent of rated power are handled by operation of the main steam bypass system without requiring an associated change in reactor power.

10.2.2 Description

10.2.2.1 Turbine Generator

The General Electric Company Turbine Generator, Ltd. (formerly English Electric Co.) turbine is a four-casing, tandem-compound, six-flow, 1800-rpm unit that has been modified. During RF05, the LP Turbine Steam Path consisting of rotors, buckets (blades), diaphragms and steam flow guides was replaced with GE designed components. The HP Turbine Steam Path was replaced during RF07 with GE designed components. The major components replaced were the rotor, diaphragms, associated seals, and coupling spacers. An inlet snout was added to provide the steam flow path into the first stage nozzles. An ac generator is connected to the turbine shaft. The excitation system consists of an automatic voltage regulator and excitation transformer.

The turbine consists of one double-flow high-pressure element in tandem with three double-flow low-pressure elements.

Turbine-generator bearings are lubricated by a conventional pressurized oil system. Two 100 percent electric (ac) motor-driven pumps supply bearing oil to the turbine generator under normal operation. Normally one ac pump is running and one is a spare. One electric (dc) motor-driven backup pump is provided in the event both ac pumps fail as a result of a loss of ac power.

Steam from the NSSS enters the high-pressure turbine through four 24-in. stop valves and governing control valves. One stop valve and one control valve form a single assembly. After expanding through the high-pressure turbine, the steam flows through the moisture separators and reheaters to the six intermediate stop valves and six intercept valves into steam lines leading to the three low-pressure turbines. Steam from each low-pressure turbine is then exhausted into the main condenser.

Moisture separation and reheating of the steam are provided between the high-pressure and low-pressure elements in two parallel shells, each of which contains combined moisture-separator-reheater assemblies. A separator-reheater assembly is located on each side of the turbine parallel to the turbine shaft.

The turbine generator is protected from excessive overspeed by two emergency overspeed trip protection systems, the mechanical overspeed trip system and the electrical overspeed trip system. The mechanical overspeed trip system consists of two redundant systems using two separate spring-loaded throwout plungers mounted on the turbine shaft. Should the turbine accelerate to its over-speed trip set point, each plunger strikes its respective position limit switch mounted adjacent to each of the plungers, energizing a system of protective relays that will trip the turbine.

The electrical overspeed system uses four separate and redundant channels of speed measurement. The four channels are fed through a network of comparative logic gates. This comparative logic system monitors the speed input signals and alerts the operator with an alarm if any one of the four inputs fails to match the others. The system ac power supply is redundant with automatic throwover to the backup ac supply. The power supplies, main, backup, and test, are monitored for loss of potential and alarmed for operator corrective action. Figure 10.2-1 is the block diagram of the electrical overspeed system.

The generator is sized to accept the gross rated output of the turbine at rated reactor pressure and reactor flow at the throttle. The generator is a direct-coupled, 60-Hz, three-phase, 22,000-V unit designed at 1,350,000 kVA at 0.90 power factor, and has a short-circuit ratio of 0.58, at a maximum hydrogen pressure of 75 psig. The generator shaft seals are oil-sealed to prevent hydrogen leakage. The static excitation system has been sized for a rated field current of 5,189 A at a rated field nominal voltage of 575 VDC.

Excitation power for the generator rotor is supplied from the excitation transformer through thyristor bridges in a configuration to allow continuous operation with a minimum of two bridges in service at full power, with the excitation being controlled by the excitation control cubicle.

10.2.2.2 Cycle Description

Steam is fed from the reactor, through four lines and associated isolation valves, into a 52-in. common manifold. From the manifold, steam is supplied to the high-pressure turbine through four 24-in. lines. Each line contains a turbine stop valve and a turbine control valve. The control valves adjust the quantity of steam admitted to the turbine and thus control the reactor steam pressure and the electrical power output.

If operation with one control valve out of service is necessary, steam is supplied to the high-pressure turbine through three 24-in. lines. An evaluation of the limiting transients and issues associated with one turbine stop or control valve out of service for Fermi 2 has been documented in Reference 2. The evaluation is qualitative and independent of fuel type through GE14. The conclusions are generic and can be applied to both current and future cycles of Fermi 2. Reference 3 confirms that the Reference 2 evaluation is applicable to GNF3 fuel with the power and steam flow capacity updates for 1 Turbine Control Valve Out of Service (TCVOOS) at 3486 MW. The assessment with one turbine stop or control valve out-of-service in Reference 2 along with Reference 3 covers the adequacy of the current power and flow dependent MCPR and MAPLHGR limits and the impact on ECCS/LOCA and ATWS. The assumptions for the assessments and conclusions are that operation with one steam feed to the main turbine isolated by a TCV or TSV is acceptable if:

a. Core thermal power will be at or below 91.5 percent

b. Operating dome pressure is maintained at or above normal off-rated operating dome pressure but below the LCO maximum dome pressure

c. The turbine bypass system is operable

d. The moisture separator reheaters are operable

e. Operating with normal feedwater heating

f. Reactor Flow Limiter Setpoint is at 115 percent or higher.

g. Maximum Steam Flow Available is 109.4% rated steam flow.

During an electrical load reduction, steam may be bypassed directly to the condenser to maintain constant reactor pressure. The capacity of the bypass system is 23.5 percent of rated reactor flow.

After passing through the high-pressure turbine, steam is exhausted to the moisture separators and reheaters, where it is reheated by steam taken from the main steam lines ahead of the turbine stop valves. The reheated steam then passes into the low-pressure turbines. There, the steam is equally divided among the three low-pressure turbines and is eventually exhausted into the condenser. The condensed heating steam is drained to the No. 6 feedwater heaters.

Steam is extracted from six points on the turbine for feedwater heating. There is one extraction point from the high-pressure turbine, one from the high-pressure turbine exhaust, and four from the low-pressure turbines, as shown in Figure 10.2-2.

Steam is supplied to the reactor feed pump (RFP) turbines from two sources: (1) the main steam manifold during startup and low-load operation and (2) the hot reheat line during normal operation.

10.2.2.3 Instrumentation Application

The turbine generator uses an electro-hydraulic control (EHC) system that controls the speed, load, pressure, and flow for startup and planned operation, and trips the unit when required. The EHC system operates the high-pressure stop valves, bypass valves, control valves, low-pressure stop and intercept valves, and other protective devices. Turbine-generator supervisory instrumentation is provided for operational analysis as well as for pre- and postmalfunction diagnosis.

The automatic control functions of the turbine generator are correlated with the reactor pressure control and recirculation control. For details, see Subsection 7.7.1.

The turbine EHC system uses solid-state electronics and high-pressure hydraulics to control the nuclear steam flow from the reactor.

Four major functions are performed by the turbine EHC system, as follows:

a. Speed control

b. Pressure control

c. Valve position control

d. Supervisory control.

Speed control is accomplished by comparing a turbine shaft speed signal to a speed reference to produce a speed error signal. In addition, a digital technique is used to produce a turbine acceleration signal from the turbine shaft speed pickup pulses. This acceleration signal is compared to a reference to produce an acceleration error signal that is summed with the speed error signal to produce a speed/acceleration error. The speed/ acceleration error is modified by an adjustable proportional constant to produce a valve position demand. The speed governing system has been designed using three redundant systems.

Pressure control is accomplished by comparing turbine inlet steam pressure to a pressure reference and thereby producing a pressure error signal. This pressure error is modified by an adjustable electronic regulator to obtain a valve position demand.

Unitized actuators at each turbine steam valve accept the electrical signals from the pressure control, speed control, or the supervisory control and position the valve in the required manner. Each valve is provided with an individual valve actuator, which eliminates the need for extensive high-pressure control oil piping. The unitized actuator is a self-contained, electro-hydraulic valve positioner that converts the electrical control signals to valve position. Each unitized actuator is designed to perform a specific valving function.

Supervisory control is provided to maintain the turbine in a safe controlled state or to initiate a rapid shutdown in case of an emergency.

Rapid shutdown is achieved by initiating the fast closure mode of valve control. Under this mode of control, the maximum closure rate is obtained. Fast-closure full-stroke travel time of the turbine stop valves is 0.20 to 0.22 sec. The fast-closure full-stroke travel time of the turbine control valves is 0.20 to 0.22 sec. Low-pressure stop and intercept valves close in approximately 1.0 sec when operating in the fast closure mode.

10.2.2.4 Emergency Control Operations

Loss of electrical load with respect to subsequent interactions should be considered under three conditions (a., b., and c. below). For these three conditions, the turbine-generator emergency overspeed will not exceed 120 percent of rated speed (1800 rpm).

a. Generator breakers (two) trip

   The generator has a system of protective devices that protect the generator from damage. This protection is achieved by tripping open the generator breakers. The generator breakers have position switches that will initiate a direct turbine trip when both breakers are tripped open.

b. System disturbances resulting in sustained loss of electrical load

   If the turbine generator has been running at maximum load and the load on the generator is suddenly lost (not the result of generator breaker trips), the following events will occur in controlled rapid succession:

   1. The turbine will accelerate at a rate proportional to loss in electrical load until the turbine control system starts to close the control valves
   2. The turbine control will initiate the fast closure mode of the turbine control valves (TCV) when the turbine acceleration exceeds a prescribed trip setpoint
   3. The operation of the HP stop valve and the associated RPS turbine stop valve closure limit switch initiates fast closure mode which will initiate a direct reactor scram
   4. The control valves will close at the maximum closure rate by means of the fast-acting solenoid valves
   5. The entrained steam between the valves and the turbine, in the turbine steam casing, and in the extraction lines will expand. Some of the accumulated water will flash into steam, supplying energy to the turbine at a relatively moderate rate
   6. The turbine speed will cease to increase when the entrained steam has stopped expanding. The turbine will trip on reverse power when its speed is less than synchronous
   7. Generator breaker and turbine trips will be initiated on reverse power to the generator if the loss of electrical load has not already isolated the generator from the system
   8. The turbine will coast down until turning gear speed is established. The turning gear will maintain slow rotation of the turbine to allow even cooling during the desoaking period.

c. Partial loss of electrical load

   On a small loss of load, the turbine will accelerate slowly. Assuming that the fast closure mode is not initiated, the bypass valves will divert the nuclear steam supply to the condenser until the steam supply can be decreased.

The emergency trip system closes all valves (turbine stop valves, control valves, intercept valves, and reheat stop valves), shutting down the turbine on the following signals:

NOTE: Setpoints are approximate and are for illustration only.

a. Turbine speed approximately 7 to 10 percent above rated speed by
   1. Magnetic speed pickups - four provided (106 to 108 percent speed)
   2. Overspeed trip plungers - two provided (107 to 110 percent speed).
b. Vacuum less than a preselected value (7.5 in. Hg abs)
c. Excessive thrust-bearing wear (±0.050 in.)
d. Low flow of generator stator water coolant (600 gpm or less after a time delay of 60 seconds)
e. High stator-coolant outlet temperature (195°F)
f. Generator protection, including reverse-power sustained and both generator breakers tripped
g. Low lube-oil pressure - below 10 psig after a 20-sec time delay
h. Loss of two speed-sensing signals (failure of two of three computing channels)
i. Loss of both main and emergency power supplies to the EHC cubicle
j. High pressure in separator-reheaters - 256 psia
k. High reactor water level
l. Manual trip from control room panel
m. Deleted
n. High shaft or pedestal vibration after a 7.5 second (maximum) time delay with
   1. "Hi Hi" (12 mils shaft or 10 mils pedestal) on any bearing and
   2. "Hi" (<10 mils) on an adjacent bearing
o. Hydrogen-seal oil-pressure differential low - 10 psig after a 20-sec time delay
p. Hydrogen gas temperature high - 185°F
q. Both main lube-oil reservoir emergency valves open.

10.2.2.5 Turbine-Generator Supervisory Instruments

The turbine supervisory instrumentation is located in the main control room and is sufficient to detect malfunctions.

The turbine-generator supervisory instrumentation includes monitors for the following:

a. Electrical load
b. Shaft speed
c. Control valve position
d. Vibration and eccentricity
e. Thrust-bearing wear
f. Exhaust hood temperature and spray pressure
g. Oil system pressures, levels, and temperatures
h. Bearing metal and oil drain temperatures
i. Shell temperatures
j. Valve positions
k. Shell and rotor differential expansion
l. Hydrogen temperature, pressure, and purity
m. Stator-coolant temperature and conductivity
n. Stator winding temperature
o. Excitation equipment area temperature
p. Steam seal pressure
q. Gland steam condenser vacuum
r. Steam chest pressure
s. Hydrogen-seal oil pressure.

10.2.2.6 Testing Provisions

Provisions are made for testing each of the following devices while the turbine generator is operating:

a. Main stop and control valves
b. Intermediate stop and intercept valves
c. Overspeed governor
d. Turbine extraction nonreturn valves (excluding small valves)
e. Vacuum trip
f. Lubricating oil system backup pumps.

The following testing and inspection activities are performed in accordance with the manufacturer's recommendations and operational experience or constraints:

a. The mechanical and electrical overspeed trip systems are operated and checked

b. The main steam stop valves, main steam control valves, low pressure stop valves, and intercept valves are dismantled and inspected

c. The main steam stop valves, main steam control valves, low pressure stop valves, and intercept valves are exercised.

10.2.3 Turbine Missiles

Fermi 2 was designed with barriers to resist potential turbine missiles. These barriers were designed to protect the safety related plant components from a design basis turbine missile which, prior to the replacement of the LP turbines during RF05, was a 120° segment of the largest main low-pressure turbine wheel. That missile weighed 8650 lbs. and had an initial velocity of 383 mph.

During the fifth refueling outage, the three built-up low pressure rotors, including blades and diaphragms, for Fermi 2 LP turbines were replaced. The maximum attainable speed of the new rotors will be approximately 218-222% of rated speed. At this point, the steam flow through the rotating steam path is well away from design conditions with some stages being driven by the steam while the remainder absorb energy. This scenario assumes that all the buckets remain intact on the rotor, the generator does not loosen retaining rings, wedges or field bars, and that the unit does not experience severe rubbing, all of which would keep the rotor at lower speeds.

Considering the minimum rotor material specification strength values, and assuming all buckets remain attached, the minimum overspeed capability of the rotors is about 219-225%. Using typical strength values, the overspeed capability of the rotors is considerably higher than the shrunk-on designs and exceeds the maximum overspeed the rotors can attain. However, the turbine overspeed control system is designed to limit maximum turbine overspeed of 120% of the turbine rated speed.

A complete failure of the control system and safety-related items is required to reach the event described. The probability of this occurring is well below 10 to the -8 power. In conclusion, the rotor stress levels are quite low; the probability of missiles being generated by the low pressure rotors is not present.

During the seventh refueling outage, the high pressure rotor, including blades and diaphragms for Fermi 2 HP turbine, was replaced. Although the HP rotor was replaced after the LP rotors, the LP rotor document regarding nuclear turbine missile analysis still governs. This concluded that blades will not penetrate outer casings. The minimum speed at which the HP blades fail is bounded by the LP turbine analysis performed for RF05.

The generator is not being replaced. The existing calculations indicate that missiles emanating from the generator rotor will be stopped before they can completely breach their respective outer casings. Concluding, with the low-pressure rotor replacement, there will no longer be a design basis turbine missile at Fermi 2, however the originally designed missile barriers remain intact.

The probability of a failure of a rotor or bucket (blade) is further minimized by the selection of materials, manufacturing process, preservice inspections and established inservice inspection programs.

The LP rotors are a GE proven monoblock design, whereby a rotor is machined from a single forging that accounts for bucket (blade) attachment points, as well as the coupling configuration; thus, eliminating the need for shrunk on discs and couplings. The new rotors are forged out of a GE proprietary NiCrMoV material that is similar to ASTM A470 Class 6 which meets the requirements specified in the purchase specification. The monoblock forging material chemistry is optimally balanced to have high hardenability, to achieve good fracture toughness at the required tensile strength, low tramp elements to minimize temper embrittlement and low sulfur to minimize harmful segregation. The rotors have the bucket (blade) wheel dovetails machined directly into the rotor forgings. The first six stages utilize tangential entry “pinetree” dovetails to attach the buckets, the last two stages utilize radial entry finger dovetails with pins.

The buckets (rotor blades) are either fabricated from bar stock or forged. The material is a GE proprietary material that consists of nominal 12% Cr. and is similar to ASTM A479, except with more stringent quality requirements. To protect against moisture erosion of the blade tips, GE uses flame hardening in lieu of stellite shields to provide an equivalent resistance to erosion, and to minimize the addition of cobalt into the primary system. The last four bucket stages (5, 6, 7 and 8) will be flame hardened. In addition to flame hardening, stages 5, 6 and 7 have moisture removal grooves that help direct water to drainage paths through the diaphragms. This design helps prevent water build-up, and that will reduce bucket’s loading during turbine operation.

The first six bucket stages have standard GE shot peened pinetree dovetails for attachment to the rotor wheels. The last two stages have finger dovetails with shot peened pins for attachment to the rotor wheels. Shot peening reduces concentrated stresses, therefore significantly improving the material resistance to stress corrosion cracking and improving the dovetail reliability.

The last stage bucket is what GE refers to as a 43C design. The bucket length is only 43 inches as compared to the original last stage blade which was approximately 45 inches. The 43C bucket is based on GE proven designs and latest technology utilizing, at its outer periphery, a two-piece over-under continuous cover connecting each bucket (blade) in its row together. This helps maintain the space at the bucket tips where the steam flows through and helps resist blade twisting, thus allowing for a more efficient bucket design.

The turbine supervisory instrumentation is used as a continuous inservice monitoring process of the turbine and associated equipment performance.

Edison performed the inspection of the low-pressure turbine disks during the second refueling outage in accordance with the Technical Specifications. This inspection consisted of volumetric examination of the disk bore area using ultrasonic techniques. Future inspection requirements will be per the turbine manufacturer’s recommendation.

10.2.4 Evaluation

The primary source of activity in the steam and power conversion system is radiation from ^{16}N, formed by activation in the reactor. Nitrogen-16 has a half-life of approximately 7 sec. The activated nitrogen is carried with the steam to the turbine. Fission-product noble gases and other activation gases, such as ^{19}O, ^{17}N, and ^{13}N, are also carried with the steam to the turbine. Some nongaseous fission and activation products are present in the turbine as a result of moisture carryover in the steam from the NSSS.

The activity entering the low-pressure turbine is reduced because of the presence of moisture separation and transit time between the high-pressure and low-pressure turbines, which permits the ^{16}N to decay.

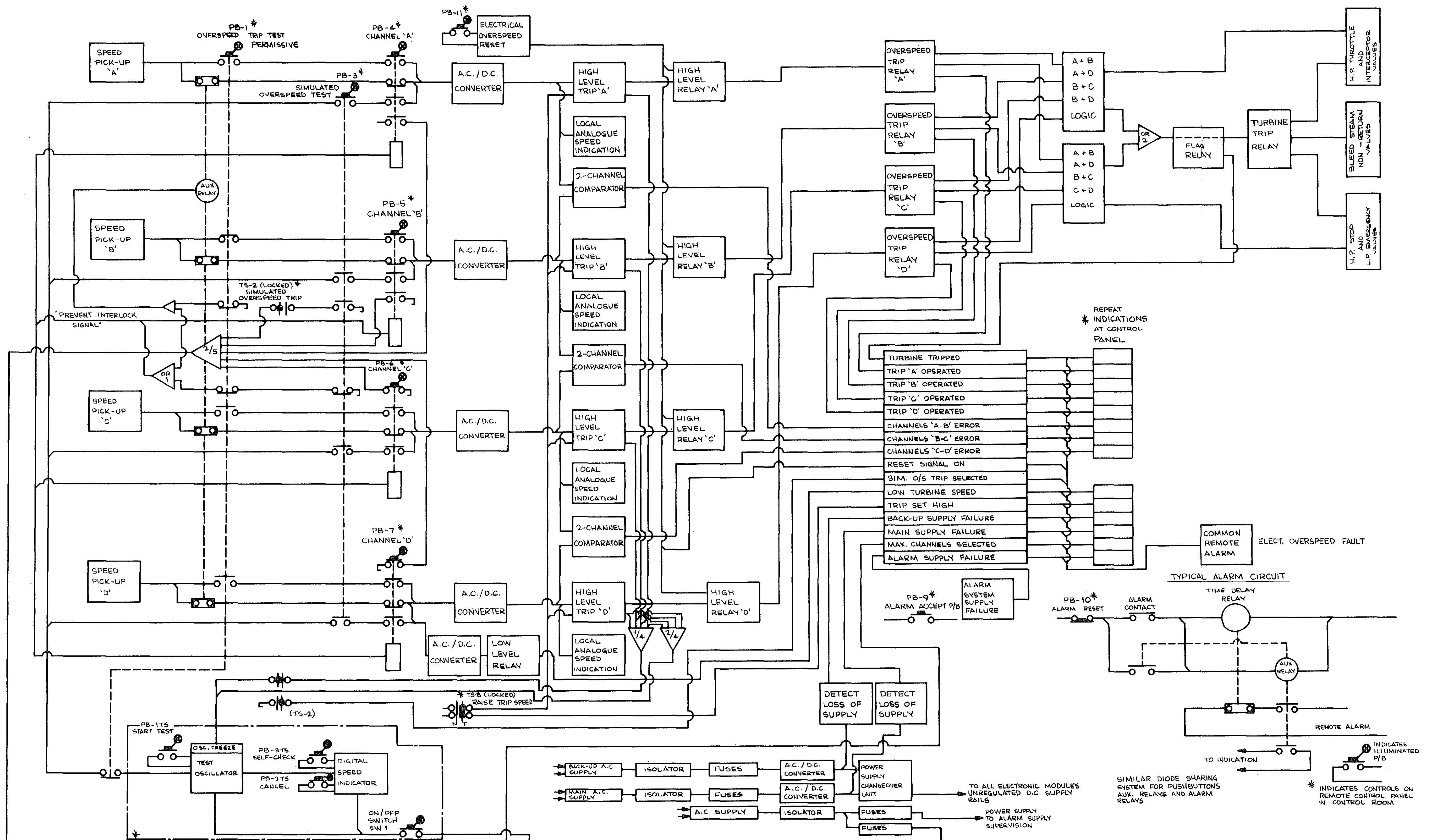
Most of the noncondensible gases in the condenser are removed by the steam-jet air ejectors to the offgas system, which is described in Section 11.3. The activity remaining in the condensate is reduced significantly by the nominal 4-minute holdup time in the condenser hotwell.

Shielding requirements are discussed in Section 12.1. The turbine generator is in an administratively controlled access area.

10.2 TURBINE GENERATOR

REFERENCES

1. USAEC/ACRS subcommittee meeting minutes, March 2, 1971, Enrico Fermi Atomic Power Plant - Unit 2, AEC Docket No. 50-341
2. GNF DRF: GE-NE-J11-03920-07-01, "Turbine Control Valve Out-of-Service for Enrico Fermi Unit-2," Revision 0, October 2001.
3. TRVEND 24MCGNF3FTRT1104, "GNF3 Fuel Design Cycle-Independent Analyses for Fermi 2 Power Plant," Revision 0, November 2019. (GEH File: 004N7423), (Edison File# T19-158).



GEC DRAWING NO. TDRI 1312, REV. D

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FIGURE 10.2-1

TURBINE GENERATOR ELECTRICAL OVERSPEED PROTECTION SYSTEM BLOCK DIAGRAM

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Refer to Plant Drawing M-2003

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FIGURE 10.2-2

EXTRACTION STEAM SYSTEM

10.3 MAIN STEAM SUPPLY SYSTEM

10.3.1 Design Bases

10.3.1.1 Safety Design Bases

To satisfy the safety design bases, the main steam lines from the reactor up to the second isolation valves are designed according to the following piping classification, which is in accordance with the ASME Boiler and Pressure Vessel Code:

a. From the reactor to the drywell wall - ANSI B31.7, Class A, Category I

b. From the drywell wall to the outer main steam isolation valve - Section III, Class 1, Category I

c. The outer isolation valve to the third isolation valve is seismically qualified and designed to ANSI B31.1.0, Group D, Category II/I.

10.3.1.2 Power Generation Design Bases

The main steam supply system is designed to fulfill the following functions:

a. To deliver steam from the nuclear steam supply system (NSSS) up to the turbine generator

b. To provide steam for the reheater and the steam-jet air ejectors

c. To provide steam for the reactor feed pump (RFP) turbines during startup and low-load operations

d. To provide steam for the turbine seal system and flange warming during startup

e. To deliver excess steam produced in the NSSS to the condenser during startup and transients whenever the steam used by the turbine is less than that produced by the NSSS.

10.3.2 Description

The main steam supply system is shown in Figure 10.3-1.

The main steam piping consists of four 24-in. lines from the outboard (second) main steam isolation valves (MSIVs) to the 52-in. manifold (including the motor-operated [third] MSIVs), and then to the locations described in Subsection 10.3.1.2. The turbine stop valves and MSIVs may be tested independently during plant operation.

The main steam line pressure relief system, main steam line flow restrictors, and MSIVs are described in Subsections 5.2.2, 5.5.4, and 5.5.5, respectively.

The design pressure-temperature rating of the main steam piping is 1250 psig/575°F, the same as the design pressure-temperature of the NSSS. The Category I design requirements are placed (1) on the main steam piping from the reactor up to the second isolation valve and (2) on all branch lines up to and including the first valve, which is either normally closed or capable of automatic closure during all modes of normal NSSS operation. The main steam line is also analyzed for the dynamic loadings caused by fast closure of the turbine stop valves. For further information on the design of the main steam piping and valves, see Subsection 6.2.6.6.

A 52-in. manifold is installed ahead of the turbine stop valves. This provides a common point for the four steam lines from the reactor, the four steam lines to the turbine, the two bypass steam lines, the steam line to the RFP turbines, and plant auxiliaries.

A drain line is connected to the low points of each main steam line, both inside the drywell and outside the containment. Both sets of drains are headered and connected by valving to permit steam line isolation and drainage to the main condenser hotwell. To permit draining the lines for maintenance, an additional drain is provided from the low points of the drains to the radwaste system.

The drains inside and outside the containment are capable of equalizing pressure across the MSIVs prior to restart following steam line isolation. Assuming all MSIVs are closed, and the steam lines outside the drywell have been depressurized, the isolation valves outside the drywell are opened first. Then the drain lines are used to warm up and pressurize the outside steam lines. Finally, the MSIVs inside the drywell are opened.

10.3.3 Evaluation

The seismic and quality group requirements of all main steam lines and components are defined in Section 3.2. This design ensures conformance with the intent of Regulatory Guide 1.26.

Per Subsection 6.2.6, a re-analysis of the Loss-of-Coolant Accident (LOCA) using an Alternative Source Term (AST) methodology made it no longer necessary to credit the Main Steam Isolation Valve Leakage Control System (MSIVLCS) for post-LOCA activity leakage mitigation. Conformance with Regulatory Guide 1.96 was superseded by License Amendment 160, which approved the use of the AST methodology and the deletion of the MSIVLCS (Ref. Subsection A.1.96). The main steam lines from the RPV to the third MSIVs are seismically qualified as indicated in License Amendment 160.

10.3.4 Inspection and Testing Requirements

Inspection and testing are carried out in accordance with the requirements of Regulatory Guide 1.68 and ANSI N18.7. The mainsteam line is hydrostatically tested to confirm leaktightness. All welding in the above steam line is 100 percent volumetrically inspected.

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Refer to Plant Drawing M-2002

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FIGURE 10.3-1

MAIN STEAM SYSTEM

10.4 OTHER FEATURES OF THE STEAM AND POWER CONVERSION SYSTEM

10.4.1 Main Condenser

10.4.1.1 Design Bases

10.4.1.1.1 Performance Requirements

The main condenser provides the heat sink for the turbine exhaust steam, turbine bypass steam, and other turbine cycle flows, and receives and collects flows for return to the nuclear steam supply system (NSSS).

The main condenser accommodates or provides for the following at rated (nominal) full load (see Figure 10.1-1):

a.	Total turbine exhaust steam	8.10×10^6 lb/hr
b.	Total condensate outflow	10.88×10^6 lb/hr
c.	Total condenser heat duty	7.81×10^9 Btu/hr
d.	Number of condenser shells	One
e.	Condenser pressure	1.5 in. Hg abs
f.	Exhaust pressure limit	5.0 in. Hg abs
g.	Circulating water	
	1. Flow(Nominal)	836,700 gpm
	2. Number of passes	One
	3. Temperature to limit condenser pressure to 4.5 in. Hg abs	100°F
	4. Condenser temperature rise	18°F

10.4.1.1.2 Turbine Bypass Steam

The main condenser is designed to accept up to 23.5 percent rated reactor steam flow from the turbine bypass system, as described in Subsection 10.4.4 (also see Figure 10.3-1). This condition is accommodated without increasing the condenser backpressure to the turbine trip setpoint or exceeding the allowable turbine exhaust temperature.

10.4.1.1.3 Condensate Deaeration

One purpose of the main condenser is to deaerate the condensate. More specifically, it is designed to reduce the dissolved oxygen level in the condenser hotwell effluent to 7 ppb or less under normal full-load operation. This level is undesirable from a carbon steel corrosion standpoint. However, experience has shown that the normal dissolved oxygen level will be 10 to 50 ppb. If the main condenser deaerates the condensate values consistently less than 10 ppb dissolved oxygen, actions must be promulgated to restore oxygen levels and/or evaluate the consequences consistent with Owners' Group guidelines and site programs. An Oxygen Injection System has been provided to inject oxygen gas into the condensate system to restore oxygen to normal levels. (See UFSAR Figure 10.4-8(1)).

10.4.1.1.4 Air Leakage

The main condenser is designed to minimize air inleakage. Welded construction is used for the condenser shell and for condenser shell connections and penetrations. Equipment and piping connected to the condenser shell are also designed to minimize air inleakage to the main condenser. The design of the evacuation system is described in Subsection 10.4.2.

10.4.1.1.5 Condensate Detention

The condenser hotwell is designed to store a sufficient volume of condensate to provide a nominal of 4 minutes' effective detention of the condensate to allow for radioactive decay.

10.4.1.1.6 Design Codes

Condenser construction is in accordance with the requirements of Heat Exchange Institute (HEI) standards for steam surface condensers.

10.4.1.2 System Description

During plant operation, steam from the last stage of the low-pressure turbine is exhausted directly downward into the condenser shell through exhaust openings in the bottom of each of the three turbine casings and is condensed. The condenser consists of one shell serving three double-flow, low-pressure turbines. The condenser also serves as a heat sink for several other flows: the two reactor feed pump (RFP) turbine exhausts, cascading heater drains, steam line drains, pump vents and recirculation lines, heater vents, and condensate system makeup.

During transient conditions, the condenser is designed to receive bypass steam, feedwater heater drainage, and moisture-separator drainage. The condenser is also designed to receive relief valve discharges from the feedwater heater shells, steam seal regulator, and the various steam supply lines. The moisture-separator relief valves discharge to the turbine room. These valves are backed up by rupture disks.

The condenser is cooled by the circulating water system, which removes the heat rejected to the condenser as described in Subsection 10.4.5.

The condensate is pumped from the condenser hotwell by the condenser pumps, described in Subsection 10.4.7, and is returned to the feedwater and steam cycle.

The main condenser is a single-pressure, single-shell, single-pass, deaerating-type condenser with divided water boxes. The condenser tubes are 1 in. in diameter, 50 ft in length, and are made of titanium.

The condenser shell is solidly supported on the turbine foundation mat. It has expansion joints provided between each turbine exhaust opening and the steam inlet connections of the condenser shells.

The condenser hotwell has horizontal and vertical baffles. They improve deaeration and ensure a nominal detention of 4 minutes for all condensate from the time it enters the hotwell until it is removed by the condenser pumps.

Valves in the circulating water system permit one-half of the condenser to be removed from service. This might be required in case of a condenser tube leak.

The air leakage and noncondensible gases include hydrogen and oxygen gases contained in the turbine exhaust steam as a result of dissociation of water in the NSSS. These gases are collected in the condenser and passed through the air-cooling section of the condenser, where they are removed by the main condenser evacuation system, described in Subsection 10.4.2.

10.4.1.3 Safety Evaluation

During operation, radioactive steam, gases, and condensate are present in the shell of the main condenser. The anticipated inventory of radioactive contaminants during operation is discussed in Sections 11.1 and 11.3. Shielding for the main condenser is provided as discussed in Section 12.1.

Condensate is retained in the main condenser for a nominal of 4 minutes to permit radioactive decay before the condensate enters the condensate system.

Hydrogen buildup during operation is not a problem because of the provisions for continuous evacuation of noncondensibles from the main condenser. During shutdown, significant hydrogen buildup in the main condenser does not occur because the main condenser is then isolated from the NSSS.

The main condenser is not required to cause or support the safe shutdown of the NSSS or to perform in the operation of NSSS safety features.

Exhaust hood overheating protection is provided by the low-pressure exhaust hood spray systems located just downstream from the last-stage blades of the turbine.

The loss of main condenser vacuum causes the turbine to be tripped. This transient and its effect on the reactor are discussed in Chapter 15.

Four rupture diaphragms on each turbine exhaust hood open at a few pounds per square inch, gage, to protect the condenser and turbine exhaust hoods (15 psig design) against overpressure. Failure of a rupture diaphragm results in radionuclides being admitted directly to the turbine building rather than passing to the offgas system. This specific failure is not analyzed but the results of a more significant event, i.e., failure of the air ejector line, are analyzed in Chapter 15.

Any leakage of circulating water into the condensate is detected by continuous monitoring of conductivity. Leakage of condensate out to the circulating water is detected by radioactivity monitoring in the circulating water reservoir decant line.

10.4.1.4 Tests and Inspections

The condenser shell received a field hydrostatic test prior to initial operation. This test consisted of filling the condenser shell with water and, while at the resulting static head, inspecting all tube joints, accessible welds, and surfaces for visible leakage and/or excessive deflection.

Each condenser water box received a field hydrostatic test and a visual inspection of all joints and external surfaces.

10.4.1.5 Instrumentation Application

The condenser shell is provided with local and remote indications of hotwell level and pressure, including alarms in the main control room.

Condensate temperature is measured in the suction lines to the condenser pumps.

Water-box pressure and temperature are measured.

Conductivity instruments detect leakage of circulating water into the condenser steam space.

Air leakage is monitored at the offgas system.

The condensate level in the condenser hotwell is maintained within proper limits by automatic controls. The controls provide for transfer of condensate to and from the condensate storage tank as needed to satisfy the requirements of the thermal cycle.

The condenser hotwell has heating coils in each of the four hotwell sections, however they are not used at Fermi 2.

Turbine exhaust temperature is monitored and controlled with water sprays to protect the turbine blading and exhaust hood from overheating.

A high condenser backpressure alarm is provided at a nominal 4.5 in. Hg abs.

Turbine trip is activated on loss of main condenser vacuum, when condenser backpressure reaches or exceeds a setpoint of a nominal 7.5 in. Hg abs.

10.4.2 Main Condenser Evacuation System

10.4.2.1 Design Bases

The main condenser evacuation system during normal operation removes the noncondensible gases from the condenser, including air inleakage and dissociation products originating in the NSSS, and exhausts them to the offgas system (see Section 11.3).

10.4.2.2 System Description

The main condenser evacuation system consists of four 25 percent-capacity, two-stage steam-jet air ejector units, complete with intercondensers for normal plant operation and mechanical vacuum pumps for use during startup. Typically, only two of the four steam-jet air ejector units are required for normal operation.

The mechanical vacuum pumps are used to remove the air and offgases from the main condenser. The discharge from the vacuum pumps is routed to the reactor building vent stack via the 2-minute holdup pipe. The offgases from the vacuum pump are discharged directly to the environment. This is acceptable because the vacuum pump is in service when little or no radioactive gases are present. However, the gas is monitored for radioactivity and pumps will be shut down if Technical Specifications limits are exceeded. In addition, the mechanical vacuum pumps are tripped automatically on main steam line high radiation.

When suitable steam is available, the steam-jet air ejectors are put into service to remove the gases from the main condenser after 6 in. Hg abs vacuum has been established in the main condenser by the mechanical vacuum pumps. Main steam, reduced in pressure to a nominal value of 200 psig by an automatic steam-pressure-reducing station, is supplied as the driving medium to the two-stage air ejectors. The first stages take suction from the main condenser and exhaust the gas vapor mixture to the intercondensers. The second stages exhaust the suction gas vapor mixture from the intercondensers to the offgas system. The steam-jet inter-condensers are drained back to the main condenser.

10.4.2.3 Safety Evaluation

The treatment of radionuclide releases from the main condenser via the offgas system is discussed in Section 11.3. Prolonged shutdown of the offgas system can cause significant hydrogen buildup in the condenser and require shutdown of the unit within 5 to 10 minutes, if condenser backpressure warrants.

Failure of the air ejector line leading to the release of radionuclides directly to the turbine building is discussed in Chapter 15.

Automatic trip of the mechanical vacuum pumps on main steam line high radiation mitigates the potential release of radionuclides through this pathway during a control rod drop accident as described in Chapter 15.

10.4.2.4 Tests and Inspections

All tests and inspections of the equipment that is part of the main condenser evacuation system are performed in accordance with ANSI N18.7.6 and the applicable section of Regulatory Guide 1.68.

10.4.2.5 Instrumentation Application

Process instrumentation applying to the evacuation system is described in Section 11.4. High radiation at the main steam line radiation monitors will trip and isolate the vacuum pumps. High radiation at the 2-minute holdup pipe or from the offgas system causes an alarm signaling the operator to take corrective action.

10.4.3 Main Turbine Gland Sealing System

10.4.3.1 Design Bases

The main turbine gland sealing system prevents air leakage into, or radioactive steam leakage out of, the main turbine.

The main turbine gland sealing system is designed to seal the main and RFP turbine shaft glands and valve stems (high-pressure stop, control, low-pressure stop, intercept, and bypass valves).

10.4.3.2 System Description

The turbine gland sealing system (Figure 10.4-1) consists of a startup steam supply from the 52-in. manifold or from the auxiliary boiler, steam seal pressure regulators, steam seal header, one full-capacity gland steam condenser, two full-capacity exhauster blowers, and the associated piping, valves, and instrumentation.

Sealing steam for turbine shaft packing glands and valve stem packing glands is supplied from the steam seal header, which is maintained at a positive pressure of approximately 2 psig. During startup and low load, the header is supplied with live steam from the 52-in. manifold or from the auxiliary boiler. At normal load, the turbine becomes self-sealing as the seal header is then supplied with steam from the high-pressure turbine center gland.

The outer pockets of all glands are routed through the gland steam condenser, which is maintained at a slight vacuum of approximately 20 in. H_2O by the exhauster blowers. This positively prevents escape of steam from the glands into the turbine room. Instead, air is drawn into the outer glands at these points, and the steam/air mixture is routed to the gland steam condenser. The gland steam condenser, which is cooled by the main condensate flow, condenses the gland steam and returns this to the main condenser, while allowing saturated air and noncondensible gases to be drawn out by the exhauster.

The gland steam exhauster discharges to the reactor building vent by way of the 2-minute holdup pipe. This flow is throttled by valve VR3-2578 to keep the discharge as low as possible but still maintain proper vacuum. The exhausters are tripped automatically on main steam line high radiation.

10.4.3.3 Safety Evaluation

The turbine gland sealing system provides a continuous supply of steam to the turbine shaft glands and the valve stems.

The high-pressure turbine shaft packing can accommodate a range of turbine shell pressures from zero to full-load pressure. The low-pressure turbine shaft packing seals against vacuum at all times. The sealing steam enters the high- and low-pressure turbine shaft packings and the valve stem packings through the inner annulus pocket. Steam is positively prevented from leaking into the turbine room by maintaining a vacuum at each gland outer pocket at all times. This vacuum is provided by the gland steam exhauster. A standby exhauster is provided.

If exhauster vacuum falls below approximately 10 in. H_2O, caused for example by loss of ac power, a vacuum switch initiates the closing of the live steam supply to the gland steam header.

An analysis of possible failure modes of the turbine gland sealing system is presented in Chapter 15.

Automatic trip of the gland seal exhausters on main steam line high radiation mitigates the potential release of radionuclides through this pathway during a control rod drop accident as described in Chapter 15. This trip is only required at the low power levels analyzed in the control rod drop accident and is therefore bypassed above the low power setpoint associated with the rod worth minimizer (see Subsection 7.7.1.3.3.5) to minimize the potential for spurious exhauster trips that could result in a malfunction of the turbine glad sealing system.

10.4.3.4 Tests and Inspections

Normal manufacturers' tests are performed on all equipment. The following tests are required for the gland steam condenser: leak test for tube-to-tube-sheet joints, hydrostatic test, and eddy current tube tests.

10.4.3.5 Instrumentation Application

The liquid level in the gland steam condenser is maintained by a control valve connected to the main condenser. Local pressure-control valves are provided to maintain the gland steam header pressure constant at approximately 2 psig, by either supplying or dumping steam as required. If pressure rises above 5 psig, excess steam is discharged to the condenser by a relief valve.

Temperature and pressure gages are installed in a local panel. Test flow orifices are provided to monitor operation of the system.

10.4.4 Turbine Bypass System

10.4.4.1 Introduction

The Fermi 2 bypass system is a composite of passive and active components that provides a steam path following a turbine- generator trip.

The Fermi bypass system has two key features: the live steam supply to the turbine reheaters, which has a nominal flow of 8 percent of nuclear boiler rating, and the electro-hydraulic control (EHC) redundant bypass valves, which are each designed to bypass a nominal 11.75 percent (23.5 percent total) rated reactor flow to the condenser.

Immediately following a turbine or generator trip from rated power, the bypass system will have a nominal capacity of 31.5 percent of nuclear boiler rating (reheater steam supply plus bypass valves). Following a typical trip, the live steam supply is eventually isolated and the pressure control system maintains the setpoint pressure by modulating the bypass valves.

10.4.4.2 Summary

The Fermi bypass system is designed in such a manner that the loss of the bypass system would require multiple random failures in the system. However, as identified in Table 10.4-1, loss of the BOP dc feeding the system causes both bypass valves to close. Because this is very unlikely, the turbine trip without bypass transient was analyzed as the turbine trip with a single bypass valve failure prior to initial fuel load. This event was not the limiting transient with respect to minimum critical power ratio (MCPR) limits.

Edison maintained that the design of the Fermi 2 bypass system obviates the need to consider the turbine trip without bypass to be part of the design basis. Currently, Fermi performs the turbine trip event and the load reject event assuming that all bypass valves fail to open during the transient. The analysis was based on input parameters specified in Table 15.0-1 and used the TRACG computer code. The results are summarized in Subsection 15.2.3. The technical specification for MCPR is frequently based on these results.

The analysis of reheater steam flow, which is important in the turbine trip analysis, is described further in Subsection 10.4.4.3.

10.4.4.3 Passive Bypass (Live Steam to Reheaters)

10.4.4.3.1 Design Bases

The primary purpose of piping the live steam to the reheater is to improve cycle efficiency by drying and superheating the high-pressure turbine exhaust before it enters the low-pressure turbines. In addition, piping live steam to the reheater minimizes the mechanical damage to turbine blades due to erosion by water droplets and the tearing of sealing surfaces due to leakage of wet steam. The reheat steam quality and flow at rated load are illustrated in the heat balance shown in Figure 10.1-1. As a secondary result of live-steam-reheat flow, a passive bypass system exists and continues to operate following a turbine stop and/or throttle valve closure. The length of time this passive system operates is a function of the time required to close the motor-operated isolation valve in the supply line. The rate of decay of flow following the turbine trip is controlled primarily by the thermodynamic response of the reheater's heat-exchange process until the isolation valve closes.

10.4.4.3.2 System Description

Each moisture separator reheater (MSR) is a cylindrical vessel located on either side of the main turbine generator on the turbine floor. The pressure vessel (shell) is approximately 12 ft in diameter and 111 ft long. Each MSR is equipped with a heating bundle at each end of the MSR vessel. The heating bundle consists of 1195 U-tubes configured in two sets of vertically arranged U-tubes, one located on top of the other to provide a "four pass" heating geometry. Each U-tube is 3/4 in. in outer diameter (nominal) with finned surface to promote more efficient heat transfer. Heating/live steam from the reactor enters the bottom bundle of the U-tubes, completes the first two passes, exits to the top bundle and completes the third and fourth passes. The drains from second pass are routed to the Reheater Seal Tank. Whereas the drains from the fourth pass are routed to the shell of the MSR. Cold reheat steam from the high-pressure turbine exhaust enters the bottom of the separator reheater through four inlet connections. The steam is directed upward through the moisture separators, and passes the reheater tube bundles. The reheated steam then leaves the reheater and passes through the low-pressure turbine-stop and intercept valves and into the low-pressure turbines.

Live steam is supplied as shown in Figure 10.3-1. The steam source is the 52-in.-diameter pressure-equalizing manifold which supplies steam to the four turbine inlet connections through the high-pressure turbine-stop valves. The EHC-controlled bypass valves are also connected to this manifold. The live steam passes through two parallel motor-operated isolation valves (N3018F607) and bypass valve (N3018F609) and then through the parallel combination of two pressure-control valves (N30F006 and N30F007) and a full-flow valve (N3018F608). During normal operation at rated load, the isolation valve and the full-flow valve are fully open. On a turbine or generator trip, valve N3018F607 is closed automatically at a nominal 12-inch-per-minute rate. The bypass valve (N3018F609) is used for warmup purposes only. The two automatic pressure control valves are used during initial startup to maintain a controlled heatup rate. These valves are held completely open during normal operation to prevent the lines from forming/collecting condensate. The live steam then flows through the tube bundles inside each reheater where the heat is transferred to reheat the cold steam from the high-pressure turbine.

In addition to reheating the high pressure turbine exhaust steam, the MSRs provide the passive bypass capability to the reactor steam supply system following a main turbine/generator trip. UFSAR section 10.4.4.3.4 discusses the evaluation of the MSR passive bypass flow adequacy during a postulated turbine trip.

10.4.4.3.3 Single-Failure Analysis

Because the amount of live steam flow following a turbine or generator trip, for the time period of interest, does not depend on the action or inaction of an active component, none of the single failures identified can terminate this flow.

10.4.4.3.4 Transient Analysis

During Fermi 2 initial licensing process, the assumed passive bypass flow capability through the Moisture Separator Reheaters (MSRs), following a turbine trip was documented in Detroit Edison Letter to the NRC dated April 27, 1982 (Reference 1). The NRC acceptance of Fermi 2 analysis was based on reviewing the results generated using the NRC approved version of the RETRAN computer code. The NRC Safety Evaluation Report, NUREG-0798, (Reference 2), Supplement 1, September 1981 Section 15. 1, p. 15-1 and NUREG-0798, Supplement 3, January, 1983, Section 15.1, p 15-1(Reference 2) documented the NRC review and acceptance of Fermi 2 methodology. The model included the following physical entities:

a. Main steam and reheat steam lines, isolation valves, and MSR drains

b. High pressure turbine-stop and throttle valves

c. High-pressure turbine

d. Extraction flows to heaters 5 and 6

e. Shell side of reheater

f. Reheater heat transfer

g. Low pressure turbine intercept valves

h. Low-pressure turbines

i. Reheater seal tanks

j. Heaters 5 and 6.

Significant physical entities that affect the passive bypass flow during a turbine trip transient are as follows:

a. The configuration of the reheat steam supply piping

b. The physical characteristics of the MSRs

c. The configuration of the reheater drain piping upstream of the reheater seal tanks

The analysis showed that the passive bypass flow through the MSRs was in excess of the assumed 8% of the nuclear boiler rating (NBR) flow during the first two seconds following a turbine trip.

The original MSRs were replaced during the 2006 Refueling Outage (RF11). The above transient analysis to demonstrate the passive bypass capability was repeated for the replacement MSRs using the NRC approved version of the RETRAN computer code, as documented in "RETRAN02 Analysis for a Moisture Separator Reheater Flow Distribution", Dated October 18, 2005 (Reference 3). The new transient analysis models the steam cycle including the physical entities a through j listed above in order to establish initial steady state conditions. For conservatism, the above RETRAN02 Analysis (Reference 3) did not include the third and fourth passes of either of the two new MSRs. This RETRAN02 analysis (Reference 3) showed that the passive bypass flow through the replacement MSRs remains in excess of the assumed 8% of the nuclear boiler rating (NBR) flow during the first two seconds following a turbine trip.

Additional sensitivity analyses were performed to determine the parameters that may affect the assumed passive bypass flow through the MSRs following a hypothetical turbine trip event, as documented in "RETRAN02 Analysis for a Moisture Separator Reheater Flow Distribution", Dated October 18, 2005 (Reference 3). These sensitivity analyses show that the required passive bypass flow capability through the MSRs can be maintained when: (1)180 tubes are plugged in each of the MSR's first and second passes even after excluding the third and fourth passes in each MSR; and (2) when the volumes of the nearest and the next to the nearest nodes upstream and down stream of the MSRs are varied by plus or minus 10 percent. Therefore, future tube plugging and changes in nodal volumes that are within the bounds of the above sensitivity analysis (Reference 3) can be performed without further analysis.

A bounding (conservative) flow characteristic, documented in "RETRAN02 Analysis for a Moisture Separator Reheater Flow Distribution", (Reference 3) is used as an input to Subsection 15.1.2, Feedwater Controller Failure transient analysis, Subsection 15.2.2 Generator Load Rejection transient analysis and Subsection 15.2.3 Turbine Generator Trip transient analysis, as shown in Figure 15.0-2.

The RETRAN02 Analysis was repeated for operation at 3486 MWt. The revised RETRAN02 Analysis (Reference 8) showed that the passive bypass flow through the MSRs remains in excess of the assumed 8% of the NBR flow during the first two seconds of a trip.

10.4.4.4 Active Bypass (EHC-Controlled Bypass System)

10.4.4.4.1 Design Bases

The EHC-controlled (electro-hydraulic control) bypass system is designed to control reactor pressure whenever the turbine throttle valves are not able to maintain control. This includes startup and shutdown operations. The bypass system possesses an emergency open mode of operation in which the bypass valves are opened at a full-stroke rate equal to the full-stroke, trip- closure rate of the high-pressure turbine-stop and throttle valves.

The bypass system control logic is designed with triple redundant channels to be compatible with the English Electric (EE) philosophy used on the turbine-governor portion of the system. Each of the two bypass valves operates independently and each has its own self-contained hydraulic (unitized actuator) system. Each valve is sized to pass a nominal 11.75 percent rated reactor flow in the full-open position for a controlled total bypass of 23.5 percent rated reactor flow. The system is designed so that any postulated failure will not cause both valves to fail to open in the fast-opening mode of operation coincident with the closure of the turbine-stop or throttle valves. The controlled bypass failure analysis is discussed in Subsection 10.4.4.4.3 and the failure mode and effects analysis is presented on a systems basis in Table 10.4-1.

10.4.4.4.2 System Description

The pressure control system used on Fermi 2 is a solid-state electronic system, designed by English Electric Company Elliot Automation. The system is a three-channel design operating with a two-out-of-three logic. A simplified sketch of the pressure control system is shown in Figure 10.4-3. The positioning of each bypass valve is achieved by using an individual, unitized actuator for each valve. Each module of each channel has its own power supply, which is connected to two independent ac sources. Each module power supply can use either source to supply its requirements. Consequently, a fault in one module cannot affect the other module power supplies.

The total power requirement for the governor/pressure control system (approximately 2.5 kVA) is supplied entirely by twenty- nine ±15-V dc and three ±5-V dc power supplies. Each of these supplies provides operating potential for one module/control function such as a bypass valve control module. These precision-regulated power supplies are not interconnected with the other module supplies and are fed from redundant and independent 110-V ac power feeds.

The sources for these two independent power feeds are the reactor pressure system buses A and B, which would supply ac power to the system following a loss of offsite power for a period of at least 2 sec. Isolation within a power supply is accomplished using diodes, and each redundant portion of an individual supply is sized to carry the entire module power requirement. A loss of either ac power feed to an individual power supply is alarmed in the control room.

A 480-V ac supply is provided for each valve actuator oil pump. These feeds are common from one power supply. The oil pumps operate in an on-off fashion to replenish the hydraulic accumulators in the actuators as demand dictates.

The 130-V dc power supply that energizes the valve actuator solenoid valves is supplied from the plant battery system. All the turbine valves and the bypass valve solenoids are supplied by BOP battery.

Referring to Figure 10.4-3, in each pressure module the pressure signal from the associated pressure transmitter is compared with the pressure-regulator setpoint. The resulting difference is the pressure error signal. The pressure error signal is operated on by the control algorithm of the pressure regulator and steam line resonance filter to produce a pressure demand signal.

The pressure demand from each pressure regulator is auctioneered against the other demands in three independent, high-value gates. This results in the selection of the pressure demand that will produce the largest bypass valve flow demand. The output of each of the three gates is modified by the flow limiter, which is adjustable and consists of a three-gang potentiometer. The resulting signal is the pressure-steam signal, which is transmitted to the three computing channel modules. At this point, each signal is compared on a per-channel basis in a low-value gate with the other signals controlling the turbine-stop, throttle, and intercept valves.

The low-value gates send the lowest signal back to the pressure control modules. A turbine and/or generator trip sets the low- value gates to a minimum, which results in the generation of a large, opening-demand signal at the input to each of the bypass valve control modules. This error signal is sent from each pressure module and the pressure control module to the input- averaging amplifier of each bypass valve control module. The input amplifier in the bypass valve module averages the three signals and detects and removes any signal that deviates from the average.

The average-demand signal is compared to the actual bypass valve position as measured by redundant valve position transducers (LVDTs) to generate a control signal to drive the bypass servovalve through a power amplifier. The spool valve of the servovalve is mechanically biased to open the bypass valve if the control current through the servovalve is zero. A position-error detection circuit is provided to activate the fast-opening mode of operation when the bypass valve position error (in the open direction) exceeds approximately 8 percent. A contact from the comparator output relay energizes the fast-opening solenoid valve (c) shown in Figure 10.4-4. The solenoid valve allows high-pressure oil from the accumulators to operate the fast- opening valve. The fast-opening valve admits high-pressure oil directly into the bypass valve servocylinder to achieve an opening time of 0.2 sec for full stroke.

An independent one-out-of-two-times-two condenser pressure logic also interfaces with the close solenoid of each actuator to trip the valves closed on low condenser vacuum. When the fast-opening solenoid and the close solenoid are operated at the same time, the close solenoid will override the fast-opening solenoid, and the bypass valve will close. The station battery powers the control solenoids on the bypass valve unitized actuators. Alarms are provided on loss-of-actuator pressure, pressure-module failure, pressure-control-module failure, computing-channel failure, excessive valve-position error, power-supply failure, low fluid level, LVDT failure, or a single condenser switch failure.

10.4.4.4.3 Controlled Bypass Failure Analysis

Due to the redundancy of the control logic and the hydraulic actuator hardware, no identified hardware failure can result in the fast closure of the turbine stop and/or throttle valves and prevent the fast opening of both the bypass valves. In addition, external failures such as loss of condenser vacuum have been considered. A protection logic using separate and redundant condenser-pressure trip strings for both turbine-trip and bypass-trip functions has been provided. The trip setpoint for closure of the turbine control valve and stop valve occurs at a much lower condenser pressure than the bypass valve condenser pressure trip. This allows ample time for the fast opening of the bypass valves to mitigate the effects of the fast stop and/or control valve closure during a condenser vacuum loss.

The control power for the stop and control valve unitized actuators is separate from the bypass valve control power, thereby preventing a single battery failure from closing all the valves through the loss of power to the trip solenoids.

In the unlikely event that all offsite power is lost, the turbine stop and throttle valves will close in the fast closure mode. The bypass system will function in the fast opening mode as intended in this situation. Each unitized actuator has two accumulators that store enough hydraulic energy to stroke each valve approximately three times. Battery control power is provided for the critical control solenoid valves and a supply of ac power to the pressure control module is provided for the duration of the transient. Refer to Table 10.4-1 for a summary of EHC- controlled bypass failure mode and effects analyses.

10.4.4.4.4 Transient Analysis

To exhibit an additional degree of conservatism for the turbine- trip transient analysis, it is assumed that one of the redundant bypass valves fails to open in the fast mode and therefore credit has been taken for only one-half of the controlled bypass capability. The one bypass valve is analyzed with an opening delay of 0.1 sec and a full-stroke time of 0.2 sec. The capacity of one valve at full-open is a nominal 12-1/2 percent rated steam flow.

10.4.5 Circulating Water System

10.4.5.1 Design Bases

The circulating water for cycle heat rejection from the main condenser is provided by a closed cycle circulating water system using two parallel natural draft cooling towers. The cooling towers remove the design heat load from the circulating water for all weather conditions.

10.4.5.2 System Description

The circulating water system supplies the main condenser with the necessary cooling water at temperatures ranging from nominal 55°F to 94°F. In the winter, the water temperature may be as low as 35°F; however, if that is the case, the cooling towers are bypassed. The system consists of the main condenser, cooling towers, circulating water reservoir, and circulating water pumps, as shown in Figure 10.4-5. Data on specific components are given in Table 10.4-2.

The circulating water reservoir is sized to support limited operation of Fermi 2 following loss of makeup water, which might occur with simultaneous conditions of sustained strong westerly winds and low Lake Erie water level, or damage to or blockage of the intake structure. The reservoir base area is nominally 5.5 acres. Approximately 23 x 10^6 gal are available at sufficient head for the circulating water pumps and are sufficient for the evaporative losses expected during a limited period of operation and plant shutdown. Following this, if makeup water is still not available, approximately 7.9 x 10^6 gallons would still remain in the reservoir to supply general service water (GSW) following shutdown of the circulating water pumps.

Five 20 percent (180,000 gpm each), motor-driven, vertical, wet- pit circulating water pumps are located in the circulating water pump house. These pumps take suction from the circulating water reservoir and discharge the circulating water via two 12-ft- diameter pipes to the main condenser where the water temperature is raised 18°F (nominal). The heated water is discharged from the two outlet water boxes into two circulating water pipes, which are 12 ft in diameter and are interconnected so that a cooling tower may be removed from service during operation.

The natural draft cooling towers are designed for a wet-bulb temperature of 74°F. The design range and the design approach are both 18°F. The design range and design approach may vary slightly due to the installation of wind vanes and replacement fill which improve performance under wind conditions. ("Range" is the amount the water is cooled. "Approach" is the difference between cooled water temperature and air wet-bulb temperature.) Each tower is approximately 450 ft in diameter at the base; the maximum elevation is 400 ft above the grade elevation.

After passing through the cooling tower fill, the circulating water flows into the circulating water reservoir and then to the circulating water pump house located at the south end of the reservoir.

A decanting blowdown system is provided on the circulating water system. This is required to maintain water quality because the evaporative process in the cooling tower tends to increase the dissolved solids content in the circulating water. Blowdown (approximately 10,000 to 30,000 gpm) is taken from the circulating water reservoir by one, two, or three decanting pumps, monitored, and discharged to Lake Erie through the 36-in.-diameter decanting line.

A makeup water system replaces the circulating water losses caused by evaporation and blowdown. Makeup water is fed into the circulating water system from the GSW system discharge or from the circulating water makeup pumps (normal and standby). Approximately 22,000 to 28,000 gpm of makeup water are required, depending upon the season of the year.

A biocide can be added to the circulating water to prevent growth of algae and slime on the inner surfaces of the condenser tubes. Regular monitoring of residual halogens at the decanting line is done to comply with environmental regulations. The biocide injection system and dehalogenation system are shown in Figure 10.4-6. A chemical scale inhibitor that has been evaluated to be compatible with materials in the Circulating Water System is added to minimize formation of scale on internal system surfaces. Sulfuric acid is added as needed to adjust the system pH.

The circulating water system is designed with cross-connected discharge piping from the circulating water pumps. The pumps are equipped with separate butterfly valves that permit any circulating water pump or pumps to be isolated while the remaining pumps continue to operate.

Appropriate valving allows the plant to operate on one train of condenser water boxes (one longitudinal half of the condenser can be taken out of service). The system piping is designed in accordance with ANSI B31.1.0.

Cooling water pumps are tripped on high pressure to prevent over-pressurization of the 12-ft lines. Relief valves are provided at the cooling towers to prevent overpressurization by the GSW system.

10.4.5.3 Safety Evaluation

The closest cooling towers are located at least one tower height away from the NSSS containment and auxiliary and turbine buildings complex. It is extremely unlikely that the towers will collapse because they were designed for a wind velocity of 90 mph. If a cooling tower were to collapse, however, it would fall inward, because its base is wider than its top. Therefore, the potential for the debris to damage any plant structure is minimal.

Circulating water is not required for safe shutdown of the plant.

The potential for water hammer in the circulating water piping and the associated rupture of expansion joints has been minimized by using motor-operated valves in place of fast-acting hydraulic or pneumatic positioners. A postulated rupture of the expansion joint in the system may flood the basement of the turbine building; however, even this would not result in any risk to the health and safety of the public because there is no engineered safety feature equipment located in the turbine building.

The reactor/auxiliary building houses safety-related components and is designed against site flooding to Elevation 588 ft, as described in Subsection 2.4.2.2.2. It would therefore withstand turbine building flooding to first floor and grade Elevation 583 ft, at which point the water would run out of the building.

Even though flooding of the turbine building does not pose a safety threat, the following additional information has been provided to describe some aspects of such an event.

First, if the failure were to occur in a circulating water line because of a pressure surge, that same surge would probably trip off the circulating water pumps by means of the pressure switches that protect the system. Flooding would thus not occur.

Second, if the joint should completely fail in either the 9- or 12-ft-diameter circulating water lines, and the pumps did not trip, water would be forced out the resulting 3.5-in. gap at an estimated rate of about 200,000 gpm and would take about 45 minutes to fill the turbine building to grade level. However, the operator would be made aware of the problem due to variations in process parameters and would trip the circulating water pumps long before flooding to grade level would occur.

10.4.5.4 Tests and Inspections

All active components of the system (except the main condenser) are accessible for inspection during station operation. Cooling tower tests, if deemed necessary, are in accordance with the ASME power test code for atmospheric water cooling equipment, PTC-23.

The circulating water pump house (CWPH) will be sampled every spring and fall for the presence of Mollusks. The Fermi 2 Mollusk Monitoring Implementation and Treatment Plan requires that the inlet and outlet water boxes to the main condenser be inspected during the next scheduled outage following the detection of Mollusks in the CWPH. Also, the inlet and outlet water boxes of the main condenser will be inspected if performance decreases significantly.

10.4.5.5 Instrumentation Application

The condenser shell water boxes are equipped with isolation valves that enable either half of the condenser to be isolated. All isolation valves are operated by remote switches in the main control room. Temperature and pressure are measured at the condenser. Circulating water flow and reservoir level are monitored. Also, analysis of the circulating water for pH, biocide residual, and radioactivity is performed.

10.4.6 Condensate Polishing Demineralizer System

Condensate polishing is performed by a full flow polishing demineralizer of the mixed-powdered-resin type.

10.4.6.1 Design Bases

10.4.6.1.1 Fraction of Condensate Flow Treated

The condensate polishing demineralizer system processes all of the condensate from the condenser hotwell (approximately 10.5 x 10^6 lb/hr at full load). The heater drains are pumped forward from the No. 5 heaters to the feedwater stream and are not demineralized (approximately 4.3 x 10^6 lb/hr at full load). These drains, however, are continuously recycled and deaerated to less than 70 ppb dissolved oxygen prior to forward pumping. They are also continuously monitored for oxygen and conductivity to provide additional assurance of no adverse impact to final feedwater quality. Turbidity is monitored on an as-needed basis by local grab during periods when corrosion product concentrations are expected to be higher than normal.

10.4.6.1.2 Effluent Impurity Levels To Be Maintained

Operating procedures ensure that the effluent from the condensate polishing demineralizer system results in reactor impurity levels that meet the requirements of Regulatory Guide 1.56 (see Subsection A.1.56). Further limits on condensate composition and electrical conductivity are established in GE Specification 22A2707, BWR Plant Requirements, Part 7, Water Quality.

The condensate polishing demineralizer maintains the required purity of feedwater flowing to the reactor. During normal operation, the system removes dissolved and suspended solids from the feedwater and maintains a high effluent quality based on the following design values:

a. Specific conductivity (μmho/cm) at 25°C ≤ 0.1

b.	pH at 25°C	6.5 to 7.5
c.	Metallic impurities, as the metal (ppb)	≤ 10 (of which copper shall not exceed 2 ppb)
d.	Silica, as SiO_2 (ppb)	≤ 5
e.	Chloride (ppb)	≤ 2

The limit of metallic impurities in the feedwater measured at the outboard isolation valve is 15 ppb, including a maximum of 2 ppb of copper. During initial plant testing and startup, the normal limit of metallic impurities may be exceeded for the first 500 hr of effective full-power operation. During such a period, the average concentration of metallic impurities shall not exceed 50 ppb at greater than 50 percent power, nor shall it exceed 100 ppb at less than or equal to 50 percent power.

During restarts or periods of operational disturbance, the normal limit of 15 ppb may be exceeded for up to 14 days in any 12-month period. However, the average concentration during this period shall not exceed 50 ppb.

10.4.6.1.3 Design Codes

The condensate cleanup system pressure vessels are constructed in accordance with the ASME Boiler and Pressure Vessel (B&PV) Code Section VIII, Division I. All piping is in accordance with the ANSI B31.1.0 Code for Pressure Piping.

10.4.6.2 System Description

The condensate polishing-demineralizer system is shown in Figure 10.4-7. It consists of eight parallel-operating demineralizers. Normally, all eight demineralizers are in operation except when one is in backwash/precoat or down for maintenance. The number of demineralizers in service may be varied to accommodate the varying differential flow and pressure requirements of the system. The system includes the associated piping, effluent strainers, backwash, precoat system (with backwash tank and pumps), as well as the necessary valves, instrumentation, and controls required to provide proper operation and protection against malfunction.

The body feed system (with body feed tank pumps) has been abandoned in place and no longer in service.

Instrumentation includes an automatic flow-balancing control that can be used to maintain equal flow (approximately 3000 gpm) through each onstream unit. The valves, pumps and flow can also be controlled manually from local panels.

In the event that a high pressure differential occurs across the condensate cleanup system, an automatic bypass valve opens to prevent damage to the demineralizer. It is highly unlikely that the bypass valve will open during normal operation. However, if this were to occur, appropriate steps would be taken to minimize the introduction of untreated water to the reactor.

10.4.6.3 Safety Evaluation

The condensate demineralizers provide high purity water to the reactor pressure vessel (RPV). Any loss of performance of the demineralizers would be immediately detected by process instrumentation. Buildup of impurities in the RPV is restrained by Technical Specifications limits such that the reactor is shut down well before unacceptable limits are reached. Additionally, more conservative limits and corrective actions are maintained and administered by the plant chemistry section. Subsequent safe shutdown of the reactor does not require the condensate demineralizers.

Resins are not regenerated at Fermi 2. However, they are replaced before the differential pressure of an individual demineralizer or the conductivity of a demineralizer effluent reaches detrimental levels. The alarm setpoint for the influent conductivity meter is 0.2 μS/cm. At this point, the plant chemistry section is notified to acquire samples of influent to check the possibility of a condenser leak. If analysis indicates that a leak exists, corrective action is taken before the 0.5 μS/cm high-high alarm is reached. The alarm setpoints for the effluent conductivity meter are 0.1 and 0.09 μS/cm for the individual and the combined demineralizer outlet, respectively. Corrective action is initiated at 0.1 μS/cm but before 0.2 μS/cm for all individual demineralizer effluents.

The conductivity meter in the condensate cleanup system will be calibrated by comparing it with an in-line laboratory cell once a week. The flow rate through each demineralizer is measured at the outlet from the pressure drop across an orifice plate.

The initial total capacity of condensate polishing and reactor water cleanup demineralizer resins will be measured at least once per year before demineralizer vessel loading. Capacity determinations will be performed by one of the following:

a. Plant Chemistry Section, Fermi 2

b. Engineering Services Organization, Edison

c. Resin vendor/supplier.

The chemistry performed to determine the total resin ionic capacity is outlined by ASTM D-2187. If the type or the supplier of cation and anion resins is changed, a measurement of initial total capacity will be performed before vessel loading. Excess capacity exists in the condensate treatment system to provide for the orderly shutdown of the reactor in the event of a postulated condenser leak of 50 gpm.

The condensate quality guidelines of condensate influent, effluent, final feedwater, and reactor water are summarized in Table 10.4-3.

10.4.6.4 Tests and Inspections

The condensate polishing demineralizer system is tested and inspected in accordance with ANSI N18.7.6 and applicable sections of Regulatory Guide 1.68. All pressure vessels and piping are hydrostatically tested at a pressure 1.5 times the design pressure. Additionally, before the equipment was put into service, a performance test was run to ascertain that the equipment is performing according to the specifications.

10.4.6.5 Instrumentation Application

The performance of the condensate polishing demineralizer system is monitored by conductivity instrumentation at the inlet and outlet and downstream of each demineralizer. Small condenser leaks as low as 6 gpm will be detected. Other instrumentation on the feedwater and reactor water checks for dissolved oxygen, pH, and conductivity. Differential pressure measurements are made to detect solids buildup on the filtering elements. Both local alarms and main control room alarms alert the plant operators whenever undesirable limits are reached. The alarm setpoint at the inlet of the demineralizers in the condensate system is 0.2 μS/cm, and the setpoints for the individual and overall demineralizer outlet are 0.1 and 0.09 μS/cm, respectively.

10.4.7 Condensate and Feedwater System

10.4.7.1 Design Bases

The condensate and feedwater system provides a dependable supply of feedwater to the NSSS, provides feedwater heating, and maintains high feedwater quality. The system provides the required flow at the required pressure to the NSSS and allows sufficient margin to provide continued flow under anticipated transient conditions.

10.4.7.1.1 Performance Requirements

The system provides feedwater at a nominal pressure of 1173 psia from the two RFPs. It has sufficient capacity with appropriate margin to provide feedwater flow for the unit design-basis rating. The feedwater heaters provide feedwater at the required temperature to the NSSS with six stages of closed feedwater heating. The final feedwater temperature is 426.5°F at 100 percent reactor flow.

10.4.7.1.2 Feedwater Quality

Feedwater quality limits are established to prevent adverse effects to fuel, material integrity, and equipment performance. Corrosion product generation/transport and chemical intrusions are controlled and minimized so that a suitable environment is provided for high reliability of plant components.

During startup, condensate is recirculated to the main condenser hotwell until water quality specifications are met. The recirculation line is located downstream of the high-pressure feedwater heaters, and thus full-cycle recirculation is accomplished prior to introduction to the reactor. Guidelines for feedwater quality are listed in Tables 10.4-3 and 10.4-4.

Operating practices limit the conductivity of purified condensate during power operation to the reactor vessel to 0.07 μmho/cm. The control program for dissolved and suspended solids, including sampling frequency and chemical analysis, is described below.

Suspended and dissolved-solids samples are part of an integrated on-line sample collection, which consists of collecting both filterable and dissolved species in one filter housing that contains a membrane filter and ion exchange filter. The on-line filters are checked routinely for flow rate. Integrated on-line samples for feedwater are collected continuously during operation. There are three sample collection intervals weekly.

Filters collected are analyzed for certain metals necessary to conform to fuel warranty specifications. Metal species of interest are typically iron (Fe), copper (Cu), nickel (Ni), chromium (Cr), and zinc (Zn).

Suspended-solids samples are acquired by grab sampling for qualitative analysis by filter color comparison during periods when corrosion product concentrations are expected to be higher than normal.

Control program limits are imposed within the limitations of fuel warranty specifications. Total metals are limited during power operation to <15 ppb with no more than 2 ppb copper.

The basis for these limits is to minimize deposit buildup on fuel heat transfer surfaces and the transport of corrosion products from the core surfaces. Consequently, high heat transfer is maintained, and out-of-core radiation levels are at a minimum.

Zinc is added to the feedwater to control radiation buildup in out-of-core primary coolant piping. The zinc will compete with the cobalt for deposition sites. This will have the end effect of reducing out-of-core radiation dose rates. The additional zinc will add to the dissolved metals and total metals in the feedwater. The amount of zinc to be added to the feedwater is much less than 1 ppb. The zinc will provide the beneficial outcome of controlling radiation build-up on out-of-core surfaces; however, overall metals concentration will still be maintained within the fuel warranty limits to ensure no impact on fuel performance.

Forward-pumped heater drains are untreated and account for approximately 30 percent of total feedwater flow. These drains are monitored for dissolved oxygen and conductivity prior to and during introduction to the feedwater. Turbidity is monitored on an as-needed basis by local grab during periods when corrosion product concentrations are expected to be higher than normal.

10.4.7.1.3 Design Codes

All components of the condensate and feedwater system, except the main condenser and the feedwater piping from the second valve outside the containment to the reactor, are designed and constructed in accordance with the applicable requirements of the following codes:

a. ANSI Code for Pressure Piping, B31.1.0 - Power Piping

b. ASME B&PV Code Section VIII, Division I - Unfired Pressure Vessels.

10.4.7.2 System Description

The condensate and feedwater system consists of the piping, valves, pumps, heat exchangers, controls, instrumentation, and the associated equipment and subsystems that supply the NSSS with heated feedwater in a closed steam cycle using regenerative feedwater heating. The system described in this section extends from the main condenser to the second valve outside the primary containment. The remainder of the system, extending to the reactor, is described in Subsection 5.5.9.

The main portion of the feedwater flow (approximately 70 percent) is condensate pumped from the main condenser. The remaining portion, which comes from the moisture-separator drains, steam reheater drains, and drains from the fifth- and sixth-stage feedwater heaters, is pumped forward from the fifth stage of feedwater heating into the feedwater stream. Turbine extraction steam provides six stages of closed feedwater heating, with the drains from the first four stages of feedwater heating being cascaded through successively lower pressure feedwater heaters to the main condenser.

The condenser pumps take the deaerated condensate from the main condenser hotwell and deliver it through the steam-jet air ejector condensers, the gland steam condenser, and offgas condenser to the condensate polishing demineralizers (see Figure 10.4-8). Demineralizer effluent then passes to the heater feed pumps, which discharge through the first-, second-, third-, fourth-, and fifth-stage low-pressure feedwater heaters to the RFPs.

Additional drain flow comes to the RFPs from the fifth-stage drains, and then is pumped forward and injected into the feedwater stream at the RFP suction header. These drains originate as shown in Figure 10.4-9. The shell drains from the sixth-stage high-pressure feedwater heaters are directed to the shells of the fifth-stage low-pressure feedwater heaters. The shell drainage from the fifth-stage feedwater heaters is collected in the heater drain flash tanks, and then is pumped into the feedwater system by the heater drain pumps.

The RFPs discharge the total feedwater flow through the sixth-stage high-pressure feedwater heaters to the NSSS, as shown in Figure 10.4-10.

10.4.7.2.1 Condenser Pumps

Three condenser pumps operate in parallel (see Figure 10.4-8). Each is a motor-driven, vertical, multistage, centrifugal pump installed at an elevation that allows operation at low condensate level in the main condenser hotwell. The condenser pumps are sized to provide the necessary suction head at the heater feed pumps, even with one condenser pump out of service.

Isolation valves allow each condenser pump to be removed from service individually while maintaining full system capability with the remaining two condenser pumps; however, maintenance must be performed on the pumps during shutdown, with the condenser drained. Condenser pump capacities are given in Table 10.4-5.

10.4.7.2.2 Heater Feed Pumps

Three heater feed pumps operate in parallel (see Figures 10.4-8 and 10.4-9), taking suction from the polishing demineralizer outlet piping and discharging through the low-pressure feedwater heaters. Each is a motor-driven, horizontal, single-stage, centrifugal pump. The heater feed pumps are sized to provide the necessary suction head to the RFPs even with one heater feed pump out of service.

Isolation valves allow each heater feed pump to be removed from service individually while maintaining full system capability with the remaining heater feed pumps. Capacities are given in Table 10.4-6.

Controlled condensate recirculation to the main condenser hotwell is provided downstream of the condensate polishing demineralizer. This ensures that the minimum safe flow through the condenser pumps, steam-jet air ejectors, gland steam condenser, and offgas condenser, is maintained during operation. This recirculation path also provides cleanup during startup since flow is through the demineralizer. Separate minimum flow bypass lines are provided for the heater feed pumps. A Heater Feed Pump (HFP) running signal is taken from the auxiliary contact off of the switchgear breaker feeding each HFP. The use of auxiliary contacts prevents HWC System operation from impacting HFP operation.

10.4.7.2.3 Feedwater Heaters

The first- and second-stage low-pressure feedwater heaters are identically arranged in three parallel streams. The third, fourth, fifth, and sixth stages of feedwater heating are arranged in two parallel streams. The first- and second-stage feedwater heaters are located in the necks of the three steam inlets of the main condenser.

Integral drain-cooling sections are included in the second-, third-, fourth-, and sixth-stage feedwater heaters. External drain coolers are provided for the first-stage heaters and are located on the first floor of the Turbine Building.

Each feedwater heater and drain cooler is of the horizontal, closed type, installed at an elevation that allows proper shell drainage at all loads. Each feedwater heater uses U-tube construction. All feedwater heater and drain cooler tubes are made of stainless steel.

Isolation valves and bypasses allow the feedwater heaters and the drain coolers to be removed from service in groups. System operability is maintained with the remaining feedwater heaters, drain coolers, and bypasses.

The startup and operating vents from the steam side of the feedwater heaters are piped directly to the main condenser. Discharges from shell relief valves on the steam side of the feedwater heaters are piped directly to the main condenser.

10.4.7.2.4 Heater Drain Flash Tank

A heater drain flash tank receives deaerated drainage from the shells of the fifth-stage feedwater heaters. The drain tank provides reservoir capacity for the heater drain pumps suction. The heater drain flash tank is installed at an elevation beneath the fifth-stage feedwater heaters that allows the heaters to drain freely by gravity flow. Remote indicator light is provided to annunciate low tank level switch actuation. When necessary, the fifth-stage heater drains may be diverted to the main condenser instead of the drain tank.

10.4.7.2.5 Heater Drain Pumps

Two one-half capacity heater drain pumps operate in parallel, each taking suction from the heater drain flash tank and discharging to the feedwater stream before the RFPs. A third one-half capacity pump is provided as a spare. Each is a motor-driven, vertical, multistage, centrifugal-type pump located below the heater drain flash tank and designed for the available suction conditions. Nominal sizes, capacities, and other information are given in Table 10.4-7.

The piping arrangement allows a heater drain pump to be removed from service individually while maintaining system operability.

Controlled drain recirculation is provided from the discharge side of each heater drain pump to the heater drain flash tank. This ensures that the minimum required flow through each heater drain pump is maintained during operation at low throughput.

10.4.7.2.6 Reactor Feed Pumps

Two one-half capacity RFPs operating in parallel (see Figure 10.4-10), act in series with the condenser pumps and heater feed pumps and heater drain pumps. The RFPs take suction from the fifth-stage low-pressure feedwater heaters and discharge through the sixth-stage high-pressure feedwater heaters to provide the pressure head required at the NSSS. Each pump is a turbine-driven, horizontal, single-stage, centrifugal unit. Isolation valves allow either RFP to be removed from service individually while maintaining system operability with the remaining RFP. Data for these pumps are given in Table 10.4-8.

Controlled feedwater recirculation is provided from the discharge side of each RFP to the main condenser hotwell. This ensures that the minimum required flow through each RFP is maintained during operation at low throughput.

10.4.7.2.7 Reactor Feed Pump Turbine Drives

Each of the two one-half capacity RFPs is driven by an individual steam turbine. The turbine drives are the dual-admission type, each equipped with two sets of main stop and control valves. One set of valves regulates the low-pressure steam flow extracted from the main turbine hot reheat piping. The other set regulates the high-pressure steam flow from the main steam supply. During normal operation, the turbine drives run on the low-pressure reheat steam. Main steam is used during plant-startup, low-load, or transient conditions when reheat steam either is not available or is of insufficient pressure. The turbine drives exhaust to the main condenser.

Isolation valves allow either turbine drive to be removed from service individually while maintaining system operability with the remaining turbine-driven RFP.

Total turbine output is 14,200 bhp at 4355 rpm with a low-pressure steam pressure of 225 psia and back-pressures of 1.5 in. Hg abs. Further data are given in Table 10.4-9.

10.4.7.3 Safety Evaluation

During operation, radioactive steam and condensate are present in the feedwater heating portion of the system, which includes the extraction steam piping, feedwater heater shells, heater drain piping, and heater vent piping. Shielding and restricted access are provided as necessary (Section 12.1). The condensate and feedwater system is designed to minimize leakage with welded construction being predominantly used. Relief discharges and operating vents from heater shells are treated through closed systems and piped to the condenser. System components are designed for pump shutoff pressures.

The condensate and feedwater system is not required to cause or support the safe shutdown of the NSSS or to perform in the operation of NSSS safety features.

If it is necessary to remove a component such as a feedwater heater, pump, or control valve from service, continued operation of the system is possible by use of the multistream arrangement and the provisions for isolating and bypassing equipment and sections of the system. The isolation capability of the system limits the magnitude of radioactive releases from failed components.

An analysis is presented in Chapter 15 for a feedwater system piping break, which results in the massive leakage of contaminated feedwater directly to the turbine building.

10.4.7.4 Tests and Inspections

During manufacture, shop performance tests on all pumps were carried out. Each feedwater heater, drain cooler, heater drain tank, and pump received a shop hydrostatic test performed in accordance with applicable codes. All tube joints of feedwater heaters and drain coolers were individually shop leak tested. Prior to initial operation, the complete condensate and feedwater system received a field hydrostatic test and inspection in accordance with ANSI N18.7.6 and applicable sections of Regulatory Guide 1.68. Periodic tests and inspections of the system will be performed in conjunction with scheduled maintenance outages.

10.4.7.5 Instrumentation Application

Feedwater flow-control instrumentation measures the feedwater flow rate from the condensate and feedwater system. This measurement is used by the feedwater control system that regulates the feedwater flow to the NSSS to meet system demands. The feedwater control system is described in Sections 7.1 and 7.7.

Instrumentation and controls are provided for regulating pump recirculation flow rate for the condenser pumps, heater feed pumps, and RFPs.

Measurements of pump suction and discharge pressures are provided for all pumps in the system.

Sampling means are provided for monitoring the quality of the final feedwater, as described in Table 9.3-1.

In the feedwater heating portion of the system, temperature measurements are provided for each stage of heating. Steam pressure measurements are provided at each feedwater heater.

Instrumentation and controls are provided for regulating the heater drain flow rate in order to maintain the proper condensate level in each feedwater heater shell or heater drain tank. High-level alarm and automatic emergency drain action on high level are also provided.

A feedwater flowrate signal is taken from the Feedwater Flow Loop and isolated to prevent HWC equipment from affecting the loop. The circuit is similar to the Integrated Plant Computer System (IPCS) input circuit, which is already used in this loop.

10.4.8 Standby Feedwater System

10.4.8.1 Design Basis

The standby feedwater (SBFW) system provides condensate from the condensate storage tank to the feedwater system downstream of the No. 6 feedwater heater. It is a manually initiated system to provide additional assurance of the capability to maintain reactor core cooling and to prevent the uncovering of the core. No credit for the SBFW system has been assumed in the accident analyses in Chapters 6 or 15. The system may be initiated by the control room operator in response to an operational transient, e.g., loss of normal feedwater. This minimizes demands on other high-pressure core cooling systems. The system is not safety related and is nonseismic.

10.4.8.2 System Description

The SBFW system consists of piping, valves, pumps, motors, controls, instrumentation, and associated equipment that supply the feed- water system with condensate from the condensate storage tank. There are two SBFW pumps with a nominal capacity of 1300 gpm and 1247 psig. Each pump is driven by a 700-hp motor; the motors are independently fed from the SS64 and SS65 transformers. The pumps discharge to two parallel motor-operated (dc) modulating flow control valves. The larger valve (6 in.) is used when reactor pressure is near 1120 psi; the other (4-in.) valve is used when reactor pressure is low. There is a motor-operated (dc) isolation valve before tying into the feedwater system. This valve will automatically open when either pump is started and will close at RPV Level 8. The system diagram is shown in Figure 10.4-11.

10.4.8.3 Safety Evaluation

The SBFW system is not required to support the safe shutdown of the reactor except for its use in the alternate shutdown system to meet 10 CFR 50, Appendix R, Section III.L. See Subsection 7.5.2.5. (Inadvertent initiation of the system is bounded by the inadvertent high-pressure-coolant-injection (HPCI) transient, discussed in Subsection 15.5.1, since HPCI flow is approximately five times SBFW flow.)

10.4.8.4 Tests and Inspections

Normal manufacturer's tests were performed on the SBFW pumps and motors. Prior to initial operation, the system received a field hydrostatic test and inspection in accordance with ANSI N18.7.6.

10.4.8.5 Instrumentation Application

Controls are located in the main control room. Measurement of pump discharge flow is provided in the main control room. Pump, motor bearing, and winding temperatures are displayed and alarmed in the main control room.

10.4.9 Zinc Injection System

10.4.9.1 Design Basis

The zinc injection system is designed to allow Fermi 2 to continuously inject a dilute solution of zinc oxide into the reactor feedwater system. Zinc has been shown to reduce radiation fields coming from various primary coolant pipes (primarily in the drywell) by competing for the sites that ^{60}Co would occupy. The system utilizes the differential pressure developed across the reactor feed pumps to provide motive force for the system and is completely manual. It is designed with a low flow bypass line in order to prevent thermal shock.

The zinc injection system is nonsafety related, QA level Non-Q, seismic category none. The system and associated piping and valves meet ANSI B31.1 requirements. The piping and components connected to the reactor feed pump discharges are designed for 1750 psig and 450ºF. The piping and components connected to the reactor feed pump suctions are designed for 950 psig and 430ºF. The dissolution column is designed to hold enough sintered zinc oxide pellets to last a fuel cycle.

10.4.9.2 System Description

The zinc injection system consists of piping, valves controls, instrumentation, and associated equipment that dissolves a dilute solution of zinc oxide into the reactor feedwater system. The system is provided water from the discharge of one of the reactor feed pumps through connections on the pumps minimum flow lines. It enters the skid and passes through a flow straightening vane to ensure a fully developed flow. The flow is measured by a local flow element and then passes through the dissolution column. Dissolution column vessel temperature is measured locally by a thermometer attached to the dissolution vessel. Temperature is measured so that the vessel is not opened for maintenance until it has cooled sufficiently. Flow passes through an outlet strainer which prevents large particles of sintered zinc oxide from entering the feedwater stream. The differential pressure across the column and strainer is measured by a local ΔP indicator. The solution then exits the skid through a manual flow control valve and is returned to the suction of the reactor feedwater pumps. The system flow is manually controlled between zero and 100 gallons per minute. It is based on reactor water zinc concentrations. Zinc dissolution rate is controlled by flow through the vessel, by feedwater temperature, and by the amount of zinc pellets in the column.

To prevent thermal shock of mechanical components and the zinc oxide pellets, a low flow, heat up, bypass loop is provided around the main flow control valve. This bypass loop has a filter that will prevent small zinc oxide pellet fragments or other particles from lodging in the bypass flow control valve. The skid is provided with vents, drains, and test connections for maintenance purposes. Skid isolation valves are also provided. No pumps are installed in the system. All valves are manual and all instruments are local indication only. Therefore, the new system is passive and has no active components. The skid is bolted to the floor on the southeast corner of the TB-1 steam tunnel near column N-3. The system diagram is on drawing M-2012.

10.4.9.3 Safety Evaluation

The zinc injection system is not required for safe shutdown or operation of the reactor. The zinc injection system is not required for plant operation. The addition of this new system does not change the operation or function of the condensate or feedwater systems.

10.4.9.4 Tests and Inspections

The manufacturer performed testing to verify that the equipment operated prior to shipment. They also perform a hydrostatic test of the skid equipment. Prior to initial operation, the system received a pressure test, instrumentation calibration check, and system flow testing.

10.4.9.5 Instrumentation Application

All indications are local. There is local flow indication on the zinc skid for better control of zinc injection rate. Differential pressure indication for the dissolution vessel and outlet strainer is provided to indicate when strainer cleaning or dissolution vessel basket maintenance is required. The dissolution column vessel has local temperature indication provided such that the vessel is not opened for maintenance before the water has cooled to less than 212°F. All system control is local. There are no indications or controls in the control room.

10.4.10 Hydrogen Water Chemistry (HWC) System

10.4.10.1 Design Basis

The purpose of the Hydrogen Water Chemistry (HWC) system is to inject hydrogen into the feedwater system at rates sufficient to allow the noble metal applied to stainless steel reactor vessel internals surfaces to control intergranular stress corrosion cracking (IGSCC) of the vessel internals. IGSCC control is accomplished by the addition of H_2 gas to the final feedwater in an effort to reduce the dissolved O_2 concentration due to the radiolytic decomposition of water in the reactor core. By reducing the O_2 concentration in the reactor water, the corrosion potential of the water is reduced.

With a few exceptions, the HWC system has been designed in accordance with the BWR Owners Group “Guidelines for Permanent BWR Hydrogen Water Chemistry Installation - 1987 Revision” (Reference 4). The HWC system is designed to meet the following design bases:

1. To supply hydrogen for feedwater injection at rates up to approx. 7-15 scfm, which corresponds to feedwater concentration of approx. 0.14 – 0.31 ppm.
2. To supply oxygen to the Off-Gas system at a rate equal to 50% of the hydrogen injection rate to ensure a stoichiometric mixture for recombination of hydrogen and oxygen.
3. To supply oxygen into the Condensate system to keep the oxygen levels in the condensate and feedwater systems high enough to minimize general corrosion.
4. To automatically isolate hydrogen and oxygen injection in the event of system or component failures.

The HWC System injects sufficient hydrogen into the feedwater system to allow the noble metal applied to stainless steel reactor internal surfaces via the On Line NobleChem (OLNC) System to catalytically recombine oxygen and hydrogen peroxide in the reactor coolant. OLNC is a technology developed by General Electric (GE) for applying noble metal to stainless steel reactor internals. This technology has successfully reduced the electrochemical corrosion potential (ECP) of internals below -230mV$_{SHE}$ (Standard Hydrogen Electrode). It has been shown that at this ECP and below, IGSCC is successfully mitigated in a BWR.

In addition to the EPRI Guidelines (Reference 4), the HWC system was designed to meet the following codes and standards:

OSHA 29 CFR 1910.103	Hydrogen
OSHA 29 CFR 1910.104	Oxygen
OSHA 29 CFR 1990.119	Process Safety Management of Highly Hazardous Chemicals
NFPA 50, 1990	Bulk Oxygen Systems at Consumer Sites
NFPA 50A, 1994	Gaseous Hydrogen Systems at Consumer Sites
NFPA 50B, 1994	Liquefied Hydrogen Systems at consumer Sites
CGA G-4	Oxygen
CGA-4.1, 1985	Cleaning Equipment for Oxygen Service
CGA G-4.3	Commodity Specification for Oxygen
CGA G-4.4, 1993	Industrial Practices for Gaseous Oxygen Transmission and Distribution Piping
CGA G-5	Hydrogen
CGA G-5.3	Commodity Specification for Hydrogen
CGA G-5.4, 1992	Hydrogen Piping Systems at Consumer Locations

The piping at the Gas Supply Facility is designed to ASME B31.3, Chemical Plant and Petroleum Refinery Piping. The underground yard piping and the piping inside the Turbine Building is designed to the requirements of ANSI/ASME B31.1, Power Piping.

All liquid and gas storage vessels are designed, fabricated and stamped as ASME Boiler and Pressure Vessel Code, Section VIII, Division I, Unfired Pressure Vessels.

System wiring, grounding and cathodic protection is designed in accordance with NFPA 70, the National Electric Code. In addition, lightning protection for the GSF has been designed per NFPA 780-92, “Lightning Protection Code.”

10.4.10.2 System Description

The HWC system continuously injects hydrogen gas into the heater feed pump suction to reduce the dissolved oxygen concentration in the Reactor. Oxygen gas is continuously injected into the Off-Gas system at the common 18” manifold to recombine with hydrogen to maintain the stoichiometric balance for recombination. Oxygen gas is also added to the

Condensate system at the condensate pump suction to make up for the reduced oxygen concentration in the condenser. The operating modes of the HWC system are startup, operation, and shutdown. For overall system piping configuration, see drawing 6M721-2013.

Liquid hydrogen is stored in a cryogenic tank at the gas supply facility. The hydrogen is stored under its own vapor pressure until withdrawn by the compressor system. Two 100% capacity parallel compressor trains are provided for system reliability. One compressor operates while the other acts as a backup. The operating compressor withdraws a combination of cold gas from the tank head space and liquid from the tank bottom and compresses it to a pressure several hundred psig above the required pressure. This allows the supply system to preferentially withdraw gaseous hydrogen from the tank head space, reducing system losses. After compression, the hydrogen is sent through ambient air vaporizers which evaporate it to within 20°F of ambient temperature. Each compressor train has two, 100% capacity vaporizers with automatic switching to allow de-icing. Gaseous hydrogen flows to a pressure control manifold which reduces the supply pressure to the operating pressure.

Hydrogen gas then flows via underground piping to the Turbine Building and through piping in the Turbine Building to the injection skid. The injection skid contains a flow element and three injection legs, each equipped with a flow control valve and isolation valve. Each injection leg from the skid is piped to the suction of one of the heater feed pumps. The isolation valve in each injection leg closes on a system shutdown signal, or individually, if the respective pump is tripped. There is a check valve at each heater feed pump suction connection to prevent backflow of water into the hydrogen piping. Each pump suction connection also contains a manual isolation valve and purge connection.

Liquid oxygen is stored in a cryogenic tank at the gas supply facility. The oxygen is stored under its own vapor pressure. Upon demand, oxygen is withdrawn from the tank and passed through an ambient air vaporizer. An economizer circuit preferentially withdraws oxygen vapor from the tank head space, reducing system losses. There are two 100% capacity vaporizers piped in parallel with automatic switching to allow de-icing. Gaseous oxygen flows to a pressure control manifold which reduces the supply pressure to the operating pressure.

Oxygen gas then flows via underground piping to the Turbine Building and through piping in the Turbine Building to the injection skid. The injection skid contains a flow element and two parallel flow control valves. The skid outlet is piped to the common 18” manifold in the Off-Gas system. There is a check valve in the oxygen piping, upstream of the Off-Gas connection, to prevent backflow from the Off-Gas into the oxygen piping. (For system configuration details, see drawing 6M721-2013.)

Oxygen gas is also injected into the Condensate pumps suction common header to make up for the reduced oxygen concentration in the condenser. Injection can be accomplished through the supply piping routed from the gas supply facility, or through an alternate bottled gas station.

Liquid nitrogen is stored at the gas supply facility for use in purging, instrumentation, and valve actuation as required in the design of the gas supply facility. Prior to use, the liquid nitrogen is converted to gas by an ambient vaporizer.

10.4.10.3 Safety Evaluation

The HWC system is non-safety related, QA level non-Q, seismic category none. The electrical components are not Class 1E or environmentally qualified. The HWC system is not required to mitigate the consequences of any accident or malfunction, nor to achieve safe shutdown of the reactor or safe plant operation.

The HWC system has been designed and sited in accordance with the requirements of Reference 1. Where full compliance could not be achieved, technical justification was provided. The liquid hydrogen storage tank is located at a distance greater than 800 feet from the nearest safety related structure (RHR Complex). This separation distance assures that a worst case hypothetical detonation of the liquid hydrogen storage tank will not endanger safety-related structures and equipment. An explosion of the liquid hydrogen tank may cause damage to the roof and siding of the Reactor Building above the elevation of the Refuel Floor, and the roof and siding of the Turbine Building above the elevation of the Operating Deck. However, due to the large separation distance, the force on these structures would be less than those generated by design-basis tornadoes or earthquakes. Therefore, the effects of a hydrogen tank explosion on the upper floors of the Turbine and Reactor Buildings is bounded by the analysis for the design basis tornado.

All hydrogen and oxygen storage vessels have sufficient separation from safety-related intakes in the event of vessel failure without fire or explosion. The liquid hydrogen storage tank and piping over 0.4-inch diameter are seismically designed to prevent failure during a safe shutdown earthquake. The liquid hydrogen and oxygen tanks and the gaseous hydrogen tube banks are designed to remain in place during a design basis tornado, earthquake, or flood so that any releases would originate from that source location. The storage vessels are also designed to be adequately protected from lightning and transportation accidents.

Excess flow protection devices at the gas supply facility and Turbine Building entrance will provide rapid isolation in the event of a line break. Area hydrogen detectors are installed in the Turbine Building near HWC equipment to detect hydrogen leakage and initiate system isolation. Once hydrogen injection is isolated by the system trip signals identified in the section below (Instrumentation and Controls), oxygen injection isolation will lag the hydrogen injection isolation by a pre-set time to ensure the maximum recombination of hydrogen in the Off-Gas system.

10.4.10.4 Instrumentation and Controls

The hydrogen injection rate is initiated with a low flow that is sufficient for establishing IGSCC mitigation during heatup. This rate is maintained until reactor power reaches approximately 25% at which point the injection rate increases proportionally with reactor power level. The oxygen flow is approximately half the hydrogen flow rate. The flow control valve in each injection leg is controlled from a single flow control signal. The flow element on the skid provides feedback to the flow control loop. Once activated, injection will be isolated under any of the following actions/conditions:

a. Manual Shutdown

b. Reactor Protection System Trip

c. Hi-Hi Hydrogen (From Area H_2 Monitor)

d. High Hydrogen Flow

e. Off-Gas Flow Restriction (Valves not Fully Open)

f. Deleted

g. Low Percent Oxygen in Off-Gas

h. High Hydrogen Supply Pressure

i. Deleted

j. Supply Facility Trip

Local instruments are provided at the gas supply facility and at the HWC control panels in the Turbine Building. System shutdown and trouble annunciators are provided in the Control Room. In addition, hydrogen injection enable/trip control is provided in the Control Room.

All signals from safety related circuits are isolated to prevent the HWC system from adversely affecting the operation of safety related systems.

10.4.11 On-Line Noble Chemistry Injection System

10.4.11.1 Design Basis

The On-Line Noble Chemistry (OLNC) Injection System is designed to allow Fermi 2 to inject a dilute solution of platinum or other noble metals into the reactor feedwater system. The injection results in a fine layer of noble metal being deposited onto the wetted surfaces of the reactor and associated piping.

As documented in Reference 6, surfaces with noble metal compound in a low hydrogen coolant environment have been shown to reduce the potential of intergrannular stress corrosion cracking (IGSCC) and mitigate existing IGSCC in the reactor vessel by reducing the electrochemical corrosion potential (ECP). Based on laboratory data, when the ECP is below 230 mV_{SHE}, (SHE = Standard Hydrogen Electrode) IGSCC crack initiation is mitigated and crack growth rates are lowered. Noble metal coating on the wet surfaces of the reactor coolant system piping has been shown to slow or mitigate IGSCC in the reactor vessel and attached reactor coolant system piping. The noble metal penetrates existing cracks to help slow or mitigate crack growth.

The OLNC application is performed after a sufficient time of power operation after a refueling outage to ensure oxide layer is developed on newly inserted fuel assemblies and within the vendor recommended range of power and core flow necessary to ensure adequate noble metal deposition. The online injection results in a more even distribution of metals throughout the system and deeper penetration in to the existing cracks and crevices.

References 5 and 6 evaluated the effects of injection noble metal into the reactor coolant system. The evaluation reviewed effects on the reactor fuel, reactor fuel performance, reactor coolant piping, the Reactor Recirculation System, and the Reactor Water Clean-up System.

The OLNC injection system is non-safety related, QA level Non-Q, seismic category II/I. The system and associated piping and valves meet ANSI B31.1 requirements. The piping and components connected to the reactor fed water system are designed for 1275 psig and 450°F. The system is designed to inject sufficient noble metal solution to reduce the ECP of reactor coolant surfaces below -230 mV_{SHE}, as measured at the mitigation monitoring system in the Reactor Water Clean-up System, when the injected noble metals, the zinc injection system, and the Hydrogen Water Chemistry system work concurrently.

10.4.11.2 System Description

The OLNC injection system consists of piping, valves, controls, instrumentation, and associated equipment that injects a dilute solution of noble metal into the reactor feedwater system. The system pumps solution from a temporarily staged OLNC injection skid on the north-east corner of the Reactor Building First Floor by the steam tunnel entrance. The injection skid is connected to the injection lines viaflexible hose connections. The flow and the injection pressure are indicated at the injection skid.

The injection skid is provided with vents, drains, and test connections for maintenance purposes. Skid isolation valves are also provided. All valves are manual and all instruments are local indication only. Therefore, the new system is passive and has no active components. When not in use, the injection skid will be stored on Reactor Building Third Floor. The system tie-ins to the feedwater system are indicated in Figure 10.4-10.

The Mitigation Monitoring System (MMS) is a one-pass-through system that provides a series of tubing samples to monitor and analyze the amount of noble metal remaining on the tubing interior surfaces, which is representative of the amount of noble metal remaining on the internal surfaces of the reactor vessel during and following an OLNC application. The MMS consists of a Durability Monitor Panel, a Data acquisition System Panel, and an Automatic Flow Control Module Panel. The MMS includes sensors that are installed to measure the ECP of the reactor water.

The MMS skid is provided with vents, drains, and test connections for maintenance purposes. Skid isolation valves are also provided. All valves are manual and all instruments are local indication only. Therefore, the new system is passive and has no active components. The system tie-ins to the Reactor Water Cleanup System are shown in Figures 5.5-19 and 5.5-20.

10.4.11.3 Safety Evaluation

The OLNC injection system is not required for safe shutdown or operation of the reactor. The OLNC injection system is not required for plant operation. The addition of this new system does not change the operation or function of the Reactor Water Clean-up, condensate or feedwater systems.

10.4.11.4 Tests and Inspections

The manufacturer performed testing to verify that the equipment operated prior to shipment, including a hydrostatic test of the skid equipment. Prior to initial operation, the system received a pressure test, instrumentation calibration check, and system flow testing.

10.4.11.5 Instrumentation Application

All indications are local. There is local flow indication on the OLNC injection skid for control of noble metal injection rate. Local indicators are provided on the durability monitor panel for flow and water temperature. All system control is local. There are no indications or controls in the control room.

10.4 OTHER FEATURES OF THE STEAM AND POWER CONVERSION SYSTEM

REFERENCES

1. Detroit Edison Letter to the NRC, EF2-57,134, Dated April 27, 1982.
2. The NRC Safety Evaluation Report, NUREG-0798, Supplement 1, dated September 1981, and Supplement 3 Dated January 1983.
3. DECo File No. T14-006, "RETRAN02 Analysis for a Moisture Separator Reheater Flow Distribution", Dated October 18, 2005.
4. EPRI NP-5283-SR-A, “Guidelines for Permanent BWR Hydrogen Water Chemistry Installations,” 1987 Revision.
5. BWRVIP-143, BWR Vessel and Internals Project, “On-Line Noble Metal Chemical Application Generic Technical Safety Evaluation.”
6. DECo File No. R1-8056, GEH OLNC 0000 0099 7942 02 RO, “On-Line NobleChem™ (OLNC) Application Technical Safety Evaluation For Fermi Unit 2.”
7. DECo File No. R1-8196, 0000 0155 8335 R1, GEH OLNC evaluation, Dated July 3, 2013.
8. DTE CP 003, DECo File No. T14-006, “Revised RETRAN02 Model for Moisture Separator Reheater for Uprate Conditions”, Dated August 30, 2013.

TABLE 10.4-1 EHC-CONTROLLED BYPASS FAILURE MODE AND EFFECTS ANALYSES

SUBSYSTEM: AUXILIARY SYSTEMS

No.	Component	Failure Mode	Cause	Effect	Method of Detection	Disable Bypass Fast Opening	Initiate Fast Closure of Turbine Stop or Throttle Valves	Comments
1.	120-V ac supply to EHC cabinet	Loss of potential	Fuse failure, short, bus trip	No effect	Alarms on failure	No	No	Load pickup by backup supply feeder
2.	130-V dc battery supply	Loss of potential	Fuse failure, short	Deenergizes both closure solenoids in bypass valve actuators	Alarms, pump duty	Yes	No	Solenoid power supply for turbine valves is obtained from the other plant 130-V dc battery
3.	Actuator cooling water	Loss of flow	Line fails, trip of TBCCW system	Temperature increase in actuator	Alarms on high temperature	No	No	Temperature rise is slow, addition of heat due to pump that is not operating continuously
4.	Condenser	Loss of vacuum	Condenser failure, loss of circulating water, loss of steam-jet air ejectors	Trips bypass and turbine valves closed via actuator solenoids	Alarms on decreasing vacuum; alarms on equipment loss	Yes	Yes	Separate vacuum switch logic with redundant devices is provided for each trip (bypass valve and turbine valve vacuum trips); the setpoint for each trip is different, allowing the turbine to be tripped before the bypass valves are finally tripped as the condenser vacuum is lost
5.	Equipment cabinet environment	Loss of cooling	Loss of fan power, filters plugged, ambient temperature high	Possibly failure system, progressive failure most probable	Alarms on high temperature	Yes	Yes	System has been operated continuously in a test ambient of 40°C as part of acceptance test
6.	Actuator oil pumps	Manual trip of all actuator oil pumps	Operator error	Trip of turbine and bypass valves after 2-minute time delay	Alarms	Yes	Yes	This trip is normally used to lock valve closed during maintenance on turbine

SUBSYSTEM: UNITIZED ACTUATOR

No.	Component	Failure Mode	Cause	Effect	Method of Detection	Disable Bypass Fast Opening	Initiate Fast Closure of Turbine Stop or Throttle Valves	Comments
1.	Valve control module	Output zero	Electronic failure	Deenergizes solenoid valve	Alarms on failure of module	Yes on one bypass valve	No	None
2.	Valve control module	Position error detector	Electronic failure	Fails to energize solenoid valve	Alarms, test of valve	Yes on one valve	No	None
3.	Bypass valve position transducer (LVDT)	Output zero	Mechanical or electrical failure	Deenergizes solenoid valve	Alarms on failure	Yes on one valve	No	Redundant LVDTs provide check circuit for alarm

TABLE 10.4-1 EHC-CONTROLLED BYPASS FAILURE MODE AND EFFECTS ANALYSES

SUBSYSTEM: AUXILIARY SYSTEMS

No.	Component	Failure Mode	Cause	Effect	Method of Detection	Disable Bypass Fast Opening	Initiate Fast Closure of Turbine Stop or Throttle Valves	Comments
4.	Control cabling from EHC (valve control module) cabinet to actuator	Shorted or open	Mechanical damage	Renders valve inoperable	Failure obvious	Yes	No	Cabling to bypass valves not common due to physical location of actuator on each valve
5.	Pressure module No. 1, 2, and control module	Output zero	Electronic failure	No effect on operation of valves	Alarms on failure	No	No	Two-out-of-three taken twice analog control logic, failed channel is disconnected from control
6.	Computing channel No. 1, 2, or 3 low value gates	Output saturated	Electronic failure	No effect on operation of valves	Alarms on failure	No	No	Two-out-of-three taken twice analog control logic, outputs of each channel are compared with the remaining two to detect this type of failure
7.	Power supply (any module)	Output zero	Electronic failure	No effect on operation of module	Alarms on failure	No	No	Redundant supplies are provided for each module

SUBSYSTEM: UNITIZED ACTUATOR

No.	Component	Failure Mode	Cause	Effect	Method of Detection	Disable Bypass Fast Opening	Initiate Fast Closure of Turbine Stop or Throttle Valves	Comments
1.	Servo- cylinder	Leakage	Seal failure	Fast opening of bypass valve not obtained	Level alarm on loss of fluid	Yes on one valve	No effect	Oil line failure not considered, control hardware mounted actuator manifold ports directly
2.	Servo-cylinder	Blockage	Foreign substance in oil	Fast opening of bypass valve not obtained	Test of valve	Yes on one valve	No effect	Each actuator has integral oil supply
3.	Dump valve	Leakage	Foreign substance in valve	Fast opening of bypass valve not obtained	Test of valve	Yes on one valve	No effect	None
4.	Servo-valve	Drain port open	Defect, failure of valve control module	Possibly prevent fast opening of valve	Test of valve	Yes on one valve	No effect	Servovalve is spring biased to admit oil to the servocylinder if the control signal is lost
5.	Accumulator	Loss of nitrogen	Diaphragm leak, valve leak	Reduces stored energy available	Gage readings on each accumulator	No	No effect	Capacity of one actuator is ample for one valve operation
6.	Fast- open valve	Jammed	Defect, leakage, foreign material in oil	Fast opening oil supply not available at the servo-cylinder	Test of hardware	Yes	No effect	None

TABLE 10.4-1 EHC-CONTROLLED BYPASS FAILURE MODE AND EFFECTS ANALYSES

SUBSYSTEM: AUXILIARY SYSTEMS

No.	Component	Failure Mode	Cause	Effect	Method of Detection	Disable Bypass Fast Opening	Initiate Fast Closure of Turbine Stop or Throttle Valves	Comments
7.	Oil dump solenoid valve	Opens to drain	Loss of dc control voltage, coil open, condenser vacuum trip	Dump valve operates draining oil from servo-cylinder	Alarms on power supply, cycling of oil pump increases	Yes	No effect	Control power for both bypass valve solenoids is independent of control power for turbine valves; condenser vacuum trip logic for bypass valves (1/2) x 2 logic; control power for bypass valve solenoidsis independent of control power for turbine valves
8.	Oil dump solenoid valve	Fails to operate	Loss of dc control voltage, coil open, valve stuck	Fast open valve does not receive operating oil pressure	Alarm on power supply loss, test of circuit	Yes	No effect	None

TABLE 10.4-2 CIRCULATING WATER SYSTEM COMPONENTS

Circulating water pumps	
Number	Five
Type	Vertical, wet pit
Capacity (each), gpm	180,000
Head, ft	92
Cooling tower	
Number	Two
Type	Natural draft
Design wet-bulb temperature, °F	74
Design range, °F	18*
Design approach, °F	18*
Relative humidity, percent	58
Dimensions, ft	450 x 400 approximately
Design capacity, each	450,000 gpm

* NOTE: The design range and design approach may vary slightly due to the installation of wind vanes and replacement fill which improve performance under wind conditions.

TABLE 10.4-3 CONDENSATE QUALITY GUIDELINES, NORMAL OPERATION

		Influent to Cond. Demin.	Effluent from Cond. Demin.	Feedwater to Reactor	Reactor Water
1.	Specific conductivity at 25 °C, maximum	0.5 µmho/cm[c]	0.1 µmho/cm[c]	0.1 µmho/cm	1.0 µmho/cm[b]
2.	pH at 25 °C		6.5 to 7.5	6.5 to 7.5	5.6 to 8.6[b]
3.	Chloride (as CL^-), maximum				200 ppb[b]
4.	Dissolved O_2		30-50 ppb	200 ppb max. 20 ppb min.	-
5.	Total metallic impurities			15 ppb (max.)[a]	-

[a] No more than 2 ppb copper.
[b] These are limits from Regulatory Guide 1.56, Table 1
[c] These are limits from Regulatory Guide 1.56, Table 2

TABLE 10.4-4 CONDENSATE QUALITY GUIDELINES, STARTUP

	Influent to Cond. Demin.	Effluent from Cond. Demin.	Feedwater to Reactor	Reactor Water
Specific conductivity at 25 °C, maximum	0.5 µmho/cm[e]	0.1µmho/cm[e]	-	2 µmho/cm[a,d] 10 µmho/cm[b,d]
pH at 25 °C			-	5.6 to 8.6[d] 5.3 to 8.6[b,d]
Chloride (as Cl^-), maximum			-	200 ppb[d] 100 ppb [a,d] 500 ppb[b,d]
Dissolved O_2		200 ppb max. 20 ppb min.	-	
Total metallic impurity, maximum		100 ppb (max.)[c]	-	

[a] Steaming rates less than 1 percent of rated steam flow.
[b] Reactor depressurized (<100 °C).
[c] No more than 2 ppb copper.
[d] These are limits from Regulatory Guide 1.56, Table 1.
[e] These are limits from Regulatory Guide 1.56, Table 2.

TABLE 10.4-5 CONDENSER PUMPS

Number	Three	
Type	Vertical	
	Three Pumps, 100 Percent Reactor Flow	Two Pumps, 100 Percent Reactor Flow
Capacity per pump, gpm	7130	10,695
Suction temperature, °F	91.7	91.7
Suction pressure, psia	5.37	5.37
Discharge pressure, psia	243	183

TABLE 10.4-6 HEATER FEED PUMPS

Number	Three	
Type	Horizontal, single-stage, double volute	
Manufacturer	Byron Jackson	
Horsepower	3000	
Shaft speed, rpm	3574	
Driver	Westinghouse, horizontal, three-phase, 60-Hz electric motor	
Applicable code	ASME B&PV Code Section III, Division I	
	ASTM A193 and A194 (Nuts and Bolts)	
	ASME Pump Test Code	
	ANSI B1.4 and B18.2 (Nuts and Bolts)	
Location	First floor, turbine building	
	Three Pumps, 100 Percent Reactor Flow	Two Pumps, 100 Percent Reactor Flow
Capacity per pump, gpm	7083	10,624
Suction temperature, °F	94.2	94.2
Suction pressure, psia	151	151
Discharge pressure, psia	693	548

TABLE 10.4-7 HEATER DRAIN PUMPS

Number	Three
Type	Vertical, nine stage, centrifugal
Manufacturer	Ingersoll-Rand
Horsepower	1750
Shaft speed, rpm	1780
Driver	Westinghouse, 4000-V, 60-Hz, three-phase
Applicable Code	ASME B&PV Code Section VIII, Division I ASTM A193 and A194 (Nuts and Bolts) ANSI B1.1 and B18.2.1 (Nuts and Bolts) ASME Pump Test Code
Location	First floor, turbine building
	Two Pumps, 100 Percent Reactor Flow
Capacity per pump, gpm	5000
Suction temperature, °F	391.6
Suction pressure, psia	225
Discharge pressure, psia	705

TABLE 10.4-8 REACTOR FEED PUMPS

Number	Two
Type	Horizontal, single-stage, centrifugal
	Two Pumps, 100 Percent Reactor Flow
Capacity per pump, gpm	17,100
Suction temperature, °F	388
Suction pressure, psia	513
Discharge pressure, psia	1173

TABLE 10.4-9 REACTOR FEED PUMP TURBINES

Number	Two
Type	Horizontal, dual- admission, multistage
	Two Turbines, 100 Percent Reactor Flow
Speed, rpm	4355
Total Output, bhp	14,200
Low-pressure steam pressure, psia	225 125 °F of superheat (h = 1274 Btu/lbm)
Low-pressure steam temperature, °F	517
High-pressure steam pressure, psia	947 Saturated (h = 1190.4 Btu/lbm)
High-pressure steam temperature, °F	538
Total Low-pressure steam consumption, lb/hr	140,000

Figure Intentionally Removed
Refer to Plant Drawing I-2336-05

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FIGURE 10.4-1

TURBINE GLAND SEALING SYSTEM

FIGURE 10.4-2 HAS BEEN INTENTIONALLY DELETED

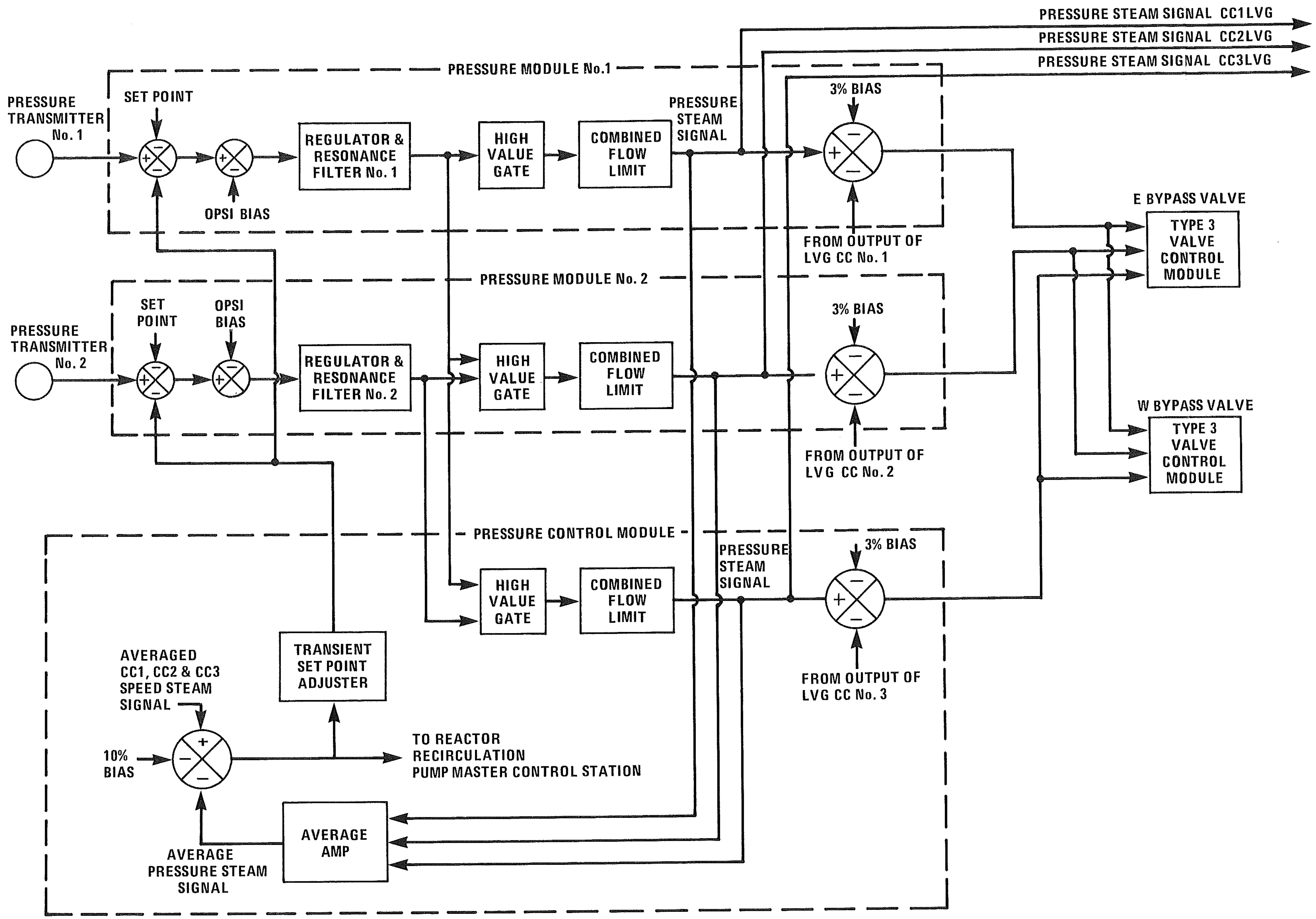

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FIGURE 10.4-3

SIMPLIFIED GOVERNOR/PRESSURE CONTROL BLOCK DIAGRAM

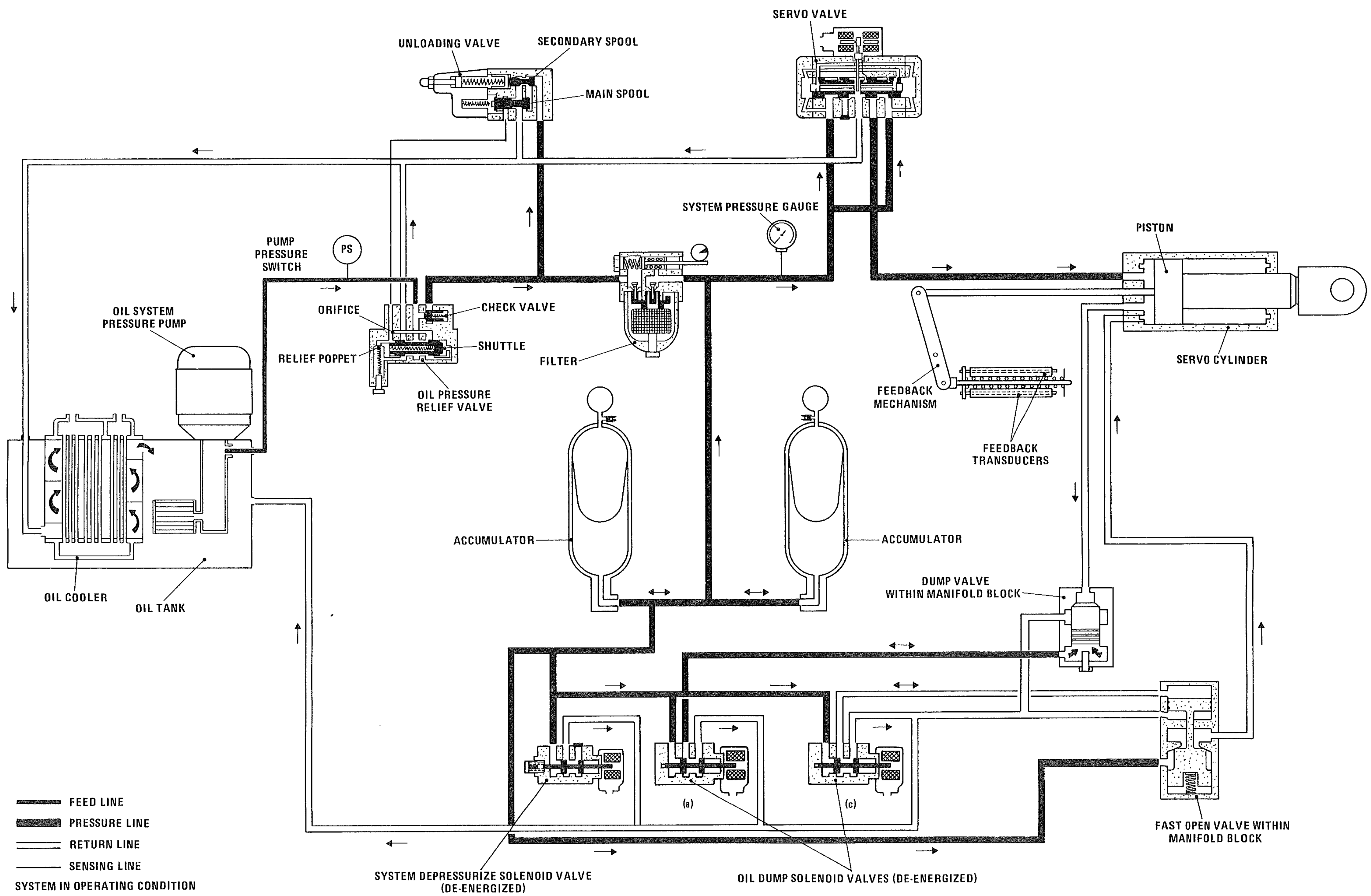

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FIGURE 10.4-4

SERVO OIL SYSTEM BYPASS VALVE ACTUATOR

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Refer to Plant Drawing M-2007

FIGURE 10.4-5

CIRCULATING WATER SYSTEM

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Refer to Plant Drawing M-5743

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FIGURE 10.4-6

CIRCULATING WATER SYSTEM
BIOCIDE INJECTION/ DEHALOGENATION SYSTEMS

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Refer to Plant Drawing M-2011

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FIGURE 10.4-7, SHEET 1

CONDENSATE POLISHING DEMINERALIZER SYSTEM

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Refer to Plant Drawing M-2011-1

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FIGURE 10.4-7, SHEET 2

CONDENSATE POLISHING DEMINERALIZER SYSTEM

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Refer to Plant Drawing M-2004

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FIGURE 10.4-8, SHEET 1

CONDENSATE SYSTEMS

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Refer to Plant Drawing M-2004-1

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FIGURE 10.4-8, SHEET 2

CONDENSATE SYSTEMS

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Refer to Plant Drawing M-2005

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FIGURE 10.4-9, SHEET 1

HEATER DRAIN SYSTEMS

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Refer to Plant Drawing M-2005-1

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FIGURE 10.4-9, SHEET 2
HEATER DRAIN SYSTEMS

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Refer to Plant Drawing M-2023

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FIGURE 10.4-10

FEEDWATER SYSTEM

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Refer to Plant Drawing M-5083

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FIGURE 10.4-11

STANDARD FEEDWATER SYSTEM
P&ID

CHAPTER 11: RADIOACTIVE WASTE MANAGEMENT

In September 1992, the NRC issued Amendment 87 to the Fermi 2 Operating License authorizing a change in the thermal power limit from 3293 MWt to 3430 MWt (References 1 and 2). The data provided in Chapter 11 for the original power level (3293 MWt) was calculated at 3430 MWt for source terms, activity releases, and doses to the public. As a result of the power uprate, source terms, activity releases, concentrations, and doses have been adjusted linearly to correspond to 102 percent of 3430 MWt or 3499 MWt. Flow rates, masses, and volumes are also scaled linearly for the uprated conditions. Table 11.1-1 provides the scale-up factors used in Sections 11.2, 11.3, 11.5, and Appendix 11A, Compliance with Appendix I. The Appendix I evaluation showed that the radiation doses associated with power uprate operation meet the Appendix I objectives.

The values in Table 11.1-2 have not been adjusted for power level because they are derived from the standard annual average design basis release rate of 0.1 Ci/sec at t=30 minutes. However, activities, concentrations, releases, and doses based on 11.1-2 are adjusted for power level. While the inconsistency in this approach is recognized, the calculations are reasonably conservative and the methodology is consistent with the General Electric Licensing Topical Report, NEDC-31897P-1 "Generic Guidelines for General Electric Boiling Water Reactor Power Uprate," June 1991.

On February 10, 2014, the NRC issued Amendment 196 to the Fermi 2 operating license authorizing a change in the thermal power limit from 3430 MWt to 3486 MWt, a 1.64 percent increase in thermal power. This Measurement Uncertainty Recapture (MUR) power uprate was performed in accordance with 10 CFR 50, Appendix K and the analyses performed at 102% of the pre-MUR licensed thermal power (3430 MWt) remain applicable at the MUR uprated thermal power (3486 MWt) because the 2% uncertainty is effectively reduced by the improvement in feedwater flow measurement. As such, the source terms, activity releases, concentrations, and doses were not adjusted as a result of the MUR power uprate.

11.1 SOURCE TERMS

The General Electric Company (GE) has evaluated radioactive material sources (activation products and fission product release from fuel) in operating BWRs over the past decade. These source terms are reviewed and periodically revised to incorporate up-to-date information. Release of radioactive material from operating BWRs has generally resulted in doses to offsite persons that have been only a small fraction of permissible doses or of natural background dose.

The information provided in this section defines the design-basis radioactive material levels in the reactor water, steam, and offgas. The various radioisotopes listed have been grouped as coolant activation products, noncoolant activation products, and fission products. The fission product levels are based on measurements of BWR water and offgas at several stations through mid-1971. Emphasis was placed on observations made at KRB and Dresden 2. The design-basis radioactive material levels do not necessarily include all the radioisotopes observed or theoretically predicted to be present. The radioisotopes included are considered significant to one or more of the following criteria:

a. Plant equipment design

b. Shielding design

c. Understanding system operation and performance

d. Measurement practicability

e. Evaluating radioactive material releases to the environment.

For halogens, radioisotopes with half-lives of less than 3 minutes were omitted. For other fission product radioisotopes in reactor water, radioisotopes with half-lives of less than 10 minutes were not considered.

11.1.1 Fission Products

11.1.1.1 Noble Radiogas Fission Products

The noble radiogas fission product source terms observed in operating BWRs are generally complex mixtures whose sources vary from minuscule defects in cladding to tramp uranium on external cladding surfaces. The relative leakage rate of amounts of noble radiogas isotopes can be described as follows:

a. Equilibrium: $R_g \approx k_1 Y$ (11.1-1)

b. Recoil: $R_g \approx k_2 Y\lambda$ (11.1-2)

The nomenclature in Subsection 11.1.1.4 defines the terms in these and succeeding equations. The constants k_1 and k_2 describe the fractions of the whole fission product that are involved in each of the releases.

The equilibrium and recoil mixtures are the two extremes of the mixture spectrum that are physically possible. The equilibrium mixture results when a sufficient time delay occurs, between the fission event and the time of release of the radiogases from the fuel to the coolant, for the radiogases to approach equilibrium levels in the fuel. When there is no delay or impedance between the fission event and the release of the radiogases, the recoil mixture is observed.

Prior to the Vallecitos BWR and Dresden 1 experience, it was assumed that noble radiogas leakage from the fuel would be the equilibrium mixture of the noble radiogases present in the fuel.

The Vallecitos BWR and early Dresden 1 experience indicated that the actual mixture most often observed approached a distribution that was intermediate in character to the two extremes. This intermediate decay mixture was termed the diffusion mixture. It must be emphasized that this diffusion mixture is merely one possible point on the mixture spectrum, ranging from the equilibrium to the recoil mixture, and does not have the absolute mathematical and mechanistic basis for the calculational methods possible for equilibrium and recoil mixtures. However, the diffusion distribution pattern that has been described is as follows (Reference 3):

Diffusion: $R_g \approx k_3 Y\lambda^{0.5}$ (11.1-3)

The constant k_3 describes the fraction of total fissions involved in the release. As can be seen, the value of the exponent of the decay constant λ is midway between that of equilibrium (0) and recoil (1). The diffusion pattern value of 0.5 was originally derived from diffusion theory, but the assumptions have become discredited.

Although the previously described diffusion mixture was used by GE as a basis for design since 1963, the design-basis release magnitude used has varied from 0.5 Ci/sec to 0.1 Ci/sec as measured after 30-minute decay (t = 30 minutes).*

Since about 1967, the design-basis release magnitude used, including the 1971 source terms, has been established at an annual average of 0.1 Ci/sec at t = 30 minutes. This design basis is considered as an annual average, with some time above and some time below this value.

This design value was selected on the basis of operating experience rather than predictive assumptions. Several judgment factors-including the significance of environmental release, reactor water radioisotope concentrations, liquid waste handling and effluent disposal criteria, building air contamination, shielding design, and turbine and other component contamination affecting maintenance-have been considered in establishing this level.

Experience in the operation of open-cycle BWRs has indicated that in-plant contamination and other operating restrictions may limit plant operation at levels well below emission rates that would correspond to the 10 CFR 20 dose limit of 500 mrem/yr to any offsite person.

Although noble radiogas source terms from fuel above 0.1 Ci/sec at t = 30 minutes can be tolerated for reasonable periods of time, long-term operation at such levels may be undesirable. Continual assessment of this value is made on the basis of actual operating experience in BWRs. There is no experimental or operational basis for changing this design-basis value because of increased reactor size or fuel power density, since limiting conditions are largely independent of these parameters.

While the noble radiogas source-term magnitude was established at 0.1 Ci/sec at t = 30 minutes, it was recognized that there may be a more statistically applicable distribution for the noble radiogas mixture. Sufficient data were available from KRB operations from 1967 to mid-1971 along with Dresden 2 data from operation in 1970 and several months in 1971 to more accurately characterize the noble radiogas mixture pattern for an operating BWR.

The basic equation for each radioisotope used to analyze the collected data is

$$R_g = K_g Y \lambda^m (1 - e^{-\lambda T}) (e^{-\lambda \tau}) \qquad (11.1\text{-}4)$$

With the exception of ^{85}Kr with a half-life of 10.74 years, the noble radiogas fission products in the fuel are essentially at an equilibrium condition after an irradiation period of several months (rate of formation is equal to rate of decay). Therefore, for practical purposes the term $(1 - e^{-\lambda T})$ approaches unity and can be neglected when the reactor has been operating at a steady state for long periods of time. The term $(e^{-\lambda t})$ is used to adjust the releases from the fuel at t = 0 to the decay time for which values are needed. Historically, t = 30 minutes has been used. When discussing long steady-state operation and leakage from the fuel, the

* The noble radiogas source-term rate after 30-minute decay has been used as a conventional measure of the design-basis fuel leakage rate, since it is conveniently measurable and was consistent with the nominal design-basis 30-minute offgas holdup system used on a number of plants.

following simplified form of Equation 11.1-4 can be used to describe the leakage of each noble radiogas isotope:

$$R_g = K_g Y \lambda^m \qquad (11.1\text{-}5)$$

The constant K_g describes the magnitude of leakage. The rate of noble radiogas leakage with respect to each other (composition) is expressed in terms of m, the exponent of the decay constant term λ.

Dividing both sides of Equation 11.1-5 by y and taking the logarithm of both sides results in the following equation:

$$\log(R_g/Y) = m \log(\lambda) + \log(K_g) \qquad (11.1\text{-}6)$$

Equation 11.1-6 represents a straight line when $\log(R_g/y)$ is plotted versus $\log(\lambda)$; m is the slope of the line. This straight line is obtained by plotting R_g/y versus λ on logarithmic graph paper. By fitting actual data from KRB and Dresden 2, using least squares techniques, to the equation, the slope m can be obtained. This can be estimated on the plotted graph. With radiogas leakage at KRB over the nearly 5-year period varying from 0.001 to 0.056 Ci/sec at t = 30 minutes, and with radiogas leakage at Dresden 2 varying from 0.001 to 0.169 Ci/sec at t = 30 minutes, the average value of m was determined. The value form is 0.4 with a standard deviation of ±0.07. This is illustrated in Figure 11.1-1 as a frequency histogram. As can be seen from this figure, variations in m were observed in the range m = 0.1 to m = 0.6.

After establishing the value of $\bar{m} = 0.4$, the value of K_g can be calculated by selecting a value for R_g or, as has been done historically, by setting the total design-basis source-term magnitude at t = 30 minutes. With ΣR_g at 30 minutes equal to 100,000 µCi/sec, K_g can be calculated as being 2.6×10^7. Equation 11.1-4 then becomes

$$R_g = 2.6 \times 10^7 Y \lambda^{0.4} (1 - e^{-\lambda t}) (e^{\lambda t}) \qquad (11.1\text{-}7)$$

This updated noble radiogas source-term mixture has been termed the 1971 mixture to differentiate it from the diffusion mixture. The noble gas source term for each radioisotope can be calculated from Equation 11.1-7. The resultant source terms are presented in Table 11.1-2 as leakage from fuel at t = 0, at t = 7 sec, and at t = 30 minutes. While ^{85}Kr can be calculated using Equation 11.1-7, the number of confirming experimental observations was limited by the difficulty of measuring the very low release rates of this isotope. Therefore, the table provides an estimated range for ^{85}Kr based on a few actual measurements.

11.1.1.2 Radiohalogen Fission Products

Historically, the radiohalogen design-basis source term was established by the same equation as that used for noble radiogases. In a fashion similar to that used with gases, a simplified equation can be shown to describe the release of each halogen radioisotopes:

$$R_h = K_h Y \lambda^n \qquad (11.1\text{-}8)$$

The constant K_h describes the magnitude of leakage from fuel. The rate of halogen radioisotope leakage with respect to each other (composition) is expressed in terms of n, the exponent of the decay constant λ. As was done with the noble radiogases, the average value was determined for n. The value for $\bar{n}$ is 0.5 with a standard deviation of ±0.19. This is illustrated in Figure 11.1-2 as a frequency histogram. As can be seen from this figure, variations in n were observed in the range of n = 0.1 to n = 0.9.

As mentioned above, it appeared that the use of the previous method of calculating radiohalogen leakage from fuel was overly conservative. Figure 11.1-3 relates KRB and Dresden 2 noble radiogas and ^{131}I leakage. It can be seen from Dresden 2 data, during the period August 1970 to January 1971, that there is a relationship between noble radiogas and ^{131}I leakage under one fuel condition. However, there was no simple relationship for all fuel conditions experienced. Also, it can be seen that during this period, high radiogas leakages were not accompanied by high radioiodine leakage from the fuel. Except for one KRB datum point, all steady-state ^{131}I leakages observed at KRB or Dresden 2 were equal to or less than 505 μCi/sec. Even at Dresden 1 in March 1965, when severe defects were experienced in stainless-steel-clad fuel, ^{131}I leakages greater than 500 μCi/sec were not experienced. Figure 11.1-3 shows that these higher radioiodine leakages from the fuel were related to noble radiogas source terms of less than the design-basis value of 0.1 Ci/sec at t = 30 minutes. This may be partially explained by inherent limitations due to internal plant operational problems that caused plant derating.

In general, one would not anticipate continued operation at full power for any significant time period with fuel-cladding defects. These defects would be indicated by ^{131}I leakage from the fuel in excess of 700 μCi/sec. When high radiohalogen leakages are observed, other fission products will be present in greater amounts. This may increase potential radiation exposure to operating and maintenance personnel during plant outages following such operation.

Using these judgment factors and experience to date, the design-basis radiohalogen source terms from fuel were established based on an ^{131}I leakage of 700 μCi/sec. This value, as seen in Figure 11.1-3, accommodates the experience data and the design-basis noble radiogas source term of 0.1 Ci/sec at t = 30 minutes. With the ^{131}I design-basis source term established, K_h can be calculated as being 2.4 x 10^7, and halogen radioisotope release can be expressed by the following equation:

$$R_h = 2.4 \times 10^7\, Y\lambda^{0.5}\,(1 - e^{-\lambda T})\,(e^{-\lambda t}) \qquad (11.1\text{-}9)$$

Concentrations of radiohalogens in reactor water can be calculated using the following equation:

$$C_h = \frac{R_h}{(\lambda + \beta + y)M} \qquad (11.1\text{-}10)$$

Although carryover of most soluble radioisotopes from reactor water to steam is observed to be <0.1 percent (<0.001 fraction), the observed carryover for radiohalogens has varied from 0.1 percent to about 2 percent in newer plants. The average of observed radiohalogen carryover measurements has been 1.2 percent by weight of reactor water in steam with a standard deviation of ±0.9. In our present source-term definition, we have used a radiohalogen carryover of 2 percent (0.02 fraction).

The halogen release rate from the fuel can be calculated from Equation 11.1-9. Concentrations in reactor water can be calculated from Equation 11.1-10. The resultant concentrations are presented in Table 11.1-3.

11.1.1.3 Other Fission Products

The observations of other fission products and transuranic nuclides, including ^{239}Np, in operating BWRs are not adequately correlated by simple equations. For these radioisotopes, design-basis concentrations in reactor water have been estimated conservatively from experience data and are presented in Table 11.1-4. Carryover of these radioisotopes from the reactor water to the steam is estimated to be <0.1 percent (<0.001 fraction). In addition to carryover, however, decay of noble radiogases in the steam leaving the reactor results in production of noble gas daughter radioisotopes in the steam and condensate systems.

Some daughter radioisotopes, such as yttrium and lanthanum, were not listed as being in reactor water. Their independent leakage to the coolant is negligible. However, these radioisotopes may be observed in some samples in equilibrium or approaching equilibrium with the parent radioisotope.

Except for ^{239}Np, trace concentrations of transuranic isotopes have been observed in only a few samples where extensive and complex analyses were carried out. The predominant alpha emitter present in reactor water is ^{242}Cm at an estimated concentration of 10^{-6} μCi/g or less, which is below the maximum permissible concentration in potable water applicable to continuous use by the general public. The concentration of alpha-emitting plutonium radioisotopes is more than one order of magnitude lower than that of ^{242}Cm. Plutonium-241, a beta emitter, may also be present in concentrations comparable to the ^{242}Cm level.

11.1.1.4 Nomenclature

The following nomenclature defines the terms used in equations for source-term calculations:

R_g = Leakage rate of noble gas radioisotope, μCi/sec

R_h = Leakage rate of halogen radioisotope, μCi/sec

y = Fission yield of radioisotope, atoms/fission

λ = Decay constant of radioisotope, per sec

T = Fuel irradiation time, sec

t = Decay time following leakage from fuel, sec

m = Noble radiogas decay constant exponent, dimensionless

n = Radiohalogen decay constant exponent, dimensionless

K_g = Constant establishing level of noble radiogas leakage from fuel

k_h = Constant establishing level of radiohalogen leakage from fuel

C_h = Concentration of halogen radioisotope in reactor water, μCi/g

M = Mass of water in operating reactor, g

β = Reactor water cleanup system removal constant, per sec

$$\beta = \frac{\text{Reactor water cleanup system flow rate, g/sec}}{\text{M,g}} \qquad (11.1\text{-}11)$$

$\gamma =$ Halogen steam carryover removal constant, per sec

$$\gamma = \frac{\left[\frac{\text{con.of halogen radiosotope in steam,}\mu\text{Ci/g}}{C_h}\right][\text{steam flow,g/sec}]}{M} \quad (11.1\text{-}12)$$

11.1.2 Activation Products

11.1.2.1 Coolant Activation Products

The coolant activation products are not adequately correlated by simple equations. Design-basis concentrations in reactor water and steam have been estimated conservatively from experience data. The resultant concentrations are presented in Table 11.1-5. For plant operation with Hydrogen Water Chemistry, in-plant tests have shown that the N-16 steam activity values will increase by a maximum factor of six.

11.1.2.2 Noncoolant Activation Products

The activation products formed by activation of impurities in the coolant or by corrosion of irradiated system materials are not adequately correlated by simple equations. The design-basis source terms of noncoolant activation products have been estimated conservatively from experience data. The resultant concentrations are presented in Table 11.1-6. Carryover of these isotopes from the reactor water to the steam is estimated to be <0.1 percent (<0.001 fraction).

11.1.3 Tritium

The estimated amount of tritium released from Fermi 2 is calculated using the GALE code contained in NUREG-0016, Rev. 1. Actual amounts released are determined by sampling and included in the Annual Radioactive Effluent Release Report. The portions of this section discussing specific amounts of tritium released have been left in for historical reference.

In a BWR, tritium is produced by three principal methods:

a. Activation of naturally occurring deuterium in the primary coolant

b. Nuclear fission of UO_2 fuel

c. Neutron reactions with boron used in reactivity control rods.

With regard to tritium, which may be released from a BWR in liquid or gaseous effluents, the tritium formed in control rods which is released is believed to be negligible. A prime source of tritium available for release from a BWR is that produced from activation of deuterium in the primary coolant. Some fission product tritium may also transfer from fuel to primary coolant. This discussion is limited to the uncertainties associated with estimating the amounts of tritium generated in a BWR which are available for release.

All of the tritium produced by activation of deuterium in the primary coolant is available for release in liquid or gaseous effluents. The tritium formed in a BWR can be calculated using the equation

$$R_{act} = \frac{\Sigma\phi V\lambda}{3.7 \times 10^4 P} \quad (11.1\text{-}13)$$

where

R_{act}	=	tritium formation rate by deuterium activation, μCi/sec/MWt
Σ	=	macroscopic thermal neutron cross section, cm^{-1}, for deuterium
ϕ	=	thermal neutron flux, neutrons/cm^2/sec
V	=	coolant volume in core, cm^3
λ	=	tritium radioactive decay constant, 1.78 x 10^{-9} sec^{-1}
P	=	reactor power level, MWt

For recent BWR designs, R_{act} is calculated to be 1.3 ± 0.4 x 10^{-4} μCi/sec/MWt. The uncertainty indicated is derived from the estimated errors in selecting values for the coolant volume in the core, coolant density in the core, abundance of deuterium in light water (some additional deuterium will be present because of the H(n,γ) D reaction), thermal neutron flux, and macroscopic cross section for deuterium.

The fraction of tritium produced by fission which may transfer from fuel to the coolant, and which will then be available for release in liquid and gaseous effluents, is much more difficult to estimate. However, since zircaloy-clad fuel rods are used in BWRs, essentially all fission product tritium remains in the fuel rods unless defects are present in the cladding material (Reference 4).

The study made at Dresden 1 in 1968 by the U.S. Public Health Service (USPHS) (Reference 5) suggests that essentially all of the tritium released from the plant could be accounted for by the deuterium activation source. For purposes of estimating the leakage of tritium from defective fuel, the assumption can be made that it leaks in a manner similar to the leakage of noble radiogases. Thus, the empirical relationship described as the diffusion mixture can be used for predicting the source term of individual noble gas radioisotopes as a function of total noble gas source term. The equation that describes this relationship is

$$R_{dif} = Ky\sqrt{1} \qquad (11.1\text{-}14)$$

where

R_{dif}	=	leakage rate of radioisotope, μCi/sec
y	=	fission yield fraction
λ	=	radioactive decay constant, sec^{-1}
K	=	constant related to total leakage rate

If the total noble radiogas source term is 10^5 μCi/sec after a 30-minute decay, leakage from fuel is calculated to be about 0.24 μCi/sec of tritium. To place this value in perspective in the USPHS study, the observed rate of ^{85}Kr, which has a half-life similar to that of tritium, was 0.06 to 0.4 times that calculated using the diffusion mixture relationship. This would suggest that the actual tritium leakage rate might range from 0.015 to 0.10 μCi/sec. Since the annual average noble radiogas leakage from a BWR is expected to be less than 0.1 Ci/sec at t = 30 minutes, the annual average tritium release rate from the fission source can be conservatively estimated at 0.12 ± 0.12 μCi/sec.

For a 3293-MWt reactor, the estimated total tritium appearance rate in reactor coolant and release rate in the effluent are about 17 Ci/yr.

Tritium formed in the reactor is generally present as tritiated oxide (HTO) and to a lesser degree as tritiated gas (HT). Tritium concentration in the steam formed in the reactor is the same as that in the reactor water at any given time. This tritium concentration is also present in condensate and feedwater. Since radioactive effluents generally originate from the reactor and power cycle equipment, radioactive effluents also have this tritium concentration. Condensate storage receives treated water from the radwaste system and rejects water from the condensate system. Thus, all plant process water should have a common tritium concentration.

Offgases released from the plant contain tritium, which is present as tritiated gas (HT) resulting from reactor water radiolysis as well as tritiated water vapor (HTO). In addition, a lesser amount present in ventilation air due to process steam leaks or evaporation from sumps, tanks, and spills on floors also contains tritium. The remainder of the tritium leaves the plant in liquid effluents.

Recombination of radiolysis gases in the offgas system forms water, which is condensed and returned to the main condenser. This tends to reduce the amount of tritium leaving in gaseous effluents. Reducing the gaseous tritium release results in a slightly higher tritium concentration in the plant process water. Reducing the amount of liquid effluent discharged also results in a higher process coolant equilibrium tritium concentration.

Essentially all tritium entering the primary coolant is eventually released to the environs, either as water vapor and gas to the atmosphere or as liquid effluent to the plant discharge. Reduction due to radioactive decay is negligible due to the 12-year half-life of tritium.

The USPHS study at Dresden 1 estimated that approximately 90 percent of the tritium release was observed in liquid effluent, with the remaining 10 percent leaving as gaseous effluent. Efforts to reduce the volume of liquid effluent discharges may change this distribution so that a greater amount of tritium leaves as gaseous effluent. The fraction of tritium leaving as liquid effluent may vary between 60 percent and 90 percent, with the remainder leaving in gaseous effluent.

11.1.4 Fuel Fission Product Inventory and Fuel Experience

11.1.4.1 Fuel Fission Product Inventory

Fuel rod and fuel plenum radioisotopic inventory, along with escape rate coefficients and release fractions, is not used in establishing BWR design-basis source-term coolant activities. Fuel fission product inventory information is used in establishing fission product source terms for accident analysis and is therefore discussed in Chapter 15.

11.1.4.2 Fuel Experience

A discussion of fuel experience gained for BWR fuel, including failure experience, burnup experience, and thermal conditions under which the experience was gained, is available in two GE topical reports (References 6 and 7).

11.1.5 Process Leakage Sources

The release of radioactive material from operating BWRs has generally resulted in doses to offsite persons which have been only a small fraction of permissible doses. With greater emphasis being placed on keeping doses from radioactive material in effluents as low as reasonably achievable, Edison utilizes augmented systems for further reduction of doses to offsite persons. Release paths such as process leaks into ventilation, which were previously negligible relative to normal effluents, become prominent although still negligible with respect to doses to offsite persons when augmented systems are provided on the principal process release pathways.

General Electric had a measurement program to identify and quantify these low-level release paths. Concurrently, analytical and mathematical model studies were performed to provide a description of the transport, residence, and release of various radionuclides in and from an operating BWR. This BWR Radiochemical Mode has been supplied in NEDO-10871 (Reference 8).

Expected sources of liquid and gaseous radwaste releases are described in Sections 11.2 and 11.3, respectively.

Process leakage measurements and control methods are further discussed in Subsections 5.2.7 and 7.1.2.

11.1 SOURCE TERM

REFERENCES

1. Detroit Edison Company, "Proposed License Amendment - Uprated Power Operation," NRC 91-0102, September 24, 1991.
2. Nuclear Regulatory Commission, "Fermi 2 - Amendment 87 to Facility Operating License No. NPF-43" (TAC M82101), September 9, 1992.
3. F. J. Brutschy, "A Comparison of Fission Product Release Studies in Loops and VBWR," Paper presented at the Tripartite Conference on Transport of Materials in Water Systems, Chalk River, Canada, February 1961.
4. J. W. Ray, "Tritium in Power Reactors," Reactor and Fuel-Processing Technology, 12(1), pp. 19-26, Winter, 1968-1969.
5. B.Kahn et al., Radiological Surveillance Studies at a Boiling Water Nuclear Power Reactor, BRH/DER 70-1, U.S. Public Health Service, March 1970.
6. H. E. Williamson and D. C. Ditamore, Current State of Knowledge of High Performance BWR Zircaloy Clad UO_2 Fuel, NEDO-10173, General Electric Company, May 1970.
7. H. E. Williamson and D. C. Ditamore, Experience With BWR Fuel Through September 1971, NEDO-10505, General Electric Company, May 1972.
8. General Electric Company, Technical Derivation of BWR 1971 Design Basis Radioactive Source Terms, NEDO-10871, March 1973.

TABLE 11.1-1 SCALE-UP FACTORS FOR RADIOACTIVE WASTE MANAGEMENT-EFFECT OF POWER UPRATE

	Scale-up Factor, F*				
	Source Terms	Liquid Effluents	Gaseous Effluents	Offgas Effluents	Solid Radwaste
Reactor Water Activity, F1	1.02				
Main Steam Activity Mass Concentration, F1	1.02				
Reactor Coolant Activity, F1		1.02			1.02
Reactor Coolant Mass Flow Rate, F2		1.02			1.02
Combined Release to Environment and Doses to Public F1 x F2		1.04			1.04
Mainstream Activity Mass Concentration, F1			1.02		
Mainsteam Flowrate, F2			1.02		
Combined Gasesous Release Rate, Released Activity, Resultant Dose, F1 x F2			1.04		
Reactor Steam Activity Mass Concentration, F1				1.02	
Reactor Steam Mass Flow Rate, F3				1.024	
Offgas System Activities, F1 x F3				1.044	

* Calculation of F1, F2, F3

Thermal Power Level, Original power, Uprated power, MWt	3430
102% of Uprated Power, MWt	3499
Scale-up Factor, F1 = 3499/3430	1.02
Scale-up Factor, F2 = 3499/3430	1.02
Scale-up Factor, F3 = Linear Extrapolation of Steamflow Rate	1.024

[14,156 lbm/hr @ 3293 MWt; 14,864 lbm/hr @ 3430; 15,220 lbm/hr @ 3499]

TABLE 11.1-2 NOBLE RADIOGAS SOURCE TERMS

Isotope	Half-Life	Release Rate at t = 0 (μCi/sec)	Release Rate[a] at t = 7 sec (μCi/sec)	Release Rate at t = 30 minutes (μCi/sec)
Kr-83m	1.86 hr	3.4(3)[b]	3.4(3)	2.9(3)
Kr-85m	4.4 hr	6.1(3)	6.1(3)	5.6(3)
Kr-85	10.74 years	10 to 20[c]	10 to 20[c]	10 to 20[c]
Kr-87	76 minutes	2.0(4)	2.0(4)	1.5(4)
Kr-88	2.79 hr	2.0(4)	2.0(4)	1.8(4)
Kr-89	3.18 minutes	1.3(5)	1.27(5)	1.8(2)
Kr-90	32.3 sec	2.8(5)	2.41(5)	
Kr-91	8.6 sec	3.3(5)	1.88(5)	
Kr-92	1.84 sec	3.3(5)	2.36(4)	
Kr-93	1.29 sec	9.9(4)	2.30(3)	
Kr-94	1.0 sec	2.3(4)	1.80(2)	
Kr-95	0.5 sec	2.1(3)	1.28(-1)	
Kr-97	1 sec	1.4(1)	1.09(-1)	
Xe-131m	11.96 days	1.5(1)	1.5(1)	1.5(1)
Xe-133m	2.26 days	2.9(2)	2.9(2)	2.8(2)
Xe-133	5.27 days	8.2(3)	8.2(3)	8.2(3)
Xe-135m	15.7 minutes	2.6(4)	2.59(4)	6.9(3)
Xe-135	9.16 hr	2.2(4)	2.2(4)	2.2(4)
Xe-137	3.82 minutes	1.5(5)	1.47(5)	6.7(2)
Xe-138	14.2 minutes	8.9(4)	8.85(4)	2.1(4)
Xe-139	40 sec	2.8(5)	2.48(5)	
Xe-140	13.6 sec	3.0(5)	2.1(5)	
Xe-141	1.72 sec	2.4(5)	1.43(4)	
Xe-142	1.22 sec	7.3(4)	1.37(3)	
Xe-143	0.96 sec	1.2(4)	7.66(1)	
Xe-144	9 sec	5.6(2)	3.27(2)	
	TOTAL	~2.5(6)	~1.40(6)	~1.0(5)

[a] Source term to steam-jet air ejector.

[b] $3.4(3) = 3.4 \times 10^3$.

[c] Estimated from experimental observations.

TABLE 11.1-3 HALOGEN ISOTOPES IN REACTOR WATER (3499 MWt)

Isotope	Half-Life	Concentration (μCi/g)
Br-83	2.40 hr	1.5(-2)[a]
Br-84	31.8 minutes	2.8(-2)
Br-85	3.0 minutes	1.7(-2)
I-131	8.065 days	1.3(-2)
I-132	2.284 hr	1.2(-1)
I-133	20.8 hr	9.1(-2)
I-134	52.3 minutes	2.4(-1)
I-135	6.7 hr	1.3(-1)

[a] 1.5(-2) = 1.5 x 10^{-2}.

TABLE 11.1-4 OTHER FISSION PRODUCT ISOTOPES IN REACTOR WATER (3499 MWt)

Isotope	Half-Life	Concentration (µCi/g)
Sr-89	50.8 days	3.2(-3)[a]
Sr-90	28.9 years	2.3(-4)
Sr-91	9.67 hr	7.0(-2)
Sr-92	2.69 hr	1.1(-1)
Zr-95	65.5 days	4.1(-5)
Zr-97	16.8 hr	3.3(-5)
Nb-95	35.1 days	4.3(-5)
Mo-99	66.6 hr	2.2(-2)
Tc-99m	6.007 hr	2.9(-1)
Tc-101	14.2 minutes	1.4(-1)
Ru-103	39.8 days	1.9(-5)
Ru-106	368 days	2.7(-6)
Te-129m	34.1 days	4.1(-5)
Te-132	78 hr	5.0(-2)
Cs-134	2.06 years	1.6(-4)
Cs-136	13 days	1.1(-4)
Cs-137	30.2 years	2.4(-4)
Cs-138	32.2 minutes	1.9(-1)
Ba-139	83.2 minutes	1.6(-1)
Ba-140	12.8 days	9.2(-3)
Ba-141	18.3 minutes	1.7(-1)
Ba-142	10.7 minutes	1.7(-1)
Ce-141	32.53 days	4.0(-5)
Ce-143	33.0 hr	3.6(-5)
Ce-144	284.4 days	3.6(-5)
Pr-143	13.58 days	3.9(-5)
Nd-147	11.06 days	1.4(-5)
Np-239	2.35 days	2.4(-1)

[a] 3.1(-3) = 3.1 x 10^{-3}.

TABLE 11.1-5 COOLANT ACTIVATION PRODUCTS IN REACTOR WATER AND STEAM (3499 MWt)

Isotope	Half-Life	Steam Concentration (μCi/g)	Reactor Water Concentration (μCi/g)
N-13	9.99 minutes	6.6(-3)[a]	4.1(-2)
N-16	7.13 sec	1.0(2)	6.2(1)
N-17	4.14 sec	1.6(-2)	6.4(-3)
O-19	26.8 sec	8.2(-1)	7.0(-1)
F-18	109.8 minutes	4.1(-3)	4.1(-3)

[a] 6.5(-3) = 6.5 x 10^{-3}.

Note: With Hydrogen Water Chemistry in operation, the N-16 steam concentration will increase by a maximum factor of six.

TABLE 11.1-6 NONCOOLANT ACTIVATION PRODUCTS IN REACTOR WATER (3499 MWt)

Isotope	Half-Life	Concentration (μCi/g)
Na-24	15 hr	2(-3)[a]
P-32	14.31 days	2(-5)
Cr-51	27.8 days	5(-4)
Mn-54	313 days	4(-5)
Mn-56	2.582 hr	5(-2)
Co-58	71.4 days	5(-3)
Co-60	5.258 years	5(-4)
Fe-59	45 days	8(-5)
Ni-65	2.55 hr	3(-4)
Zn-65	243.7 days	2(-6)
Zn-69m	13.7 hr	3(-5)
Ag-110m	253 days	6(-5)
W-187	23.9 hr	3(-3)

[a] 2(-3) = 2×10^{-3}.

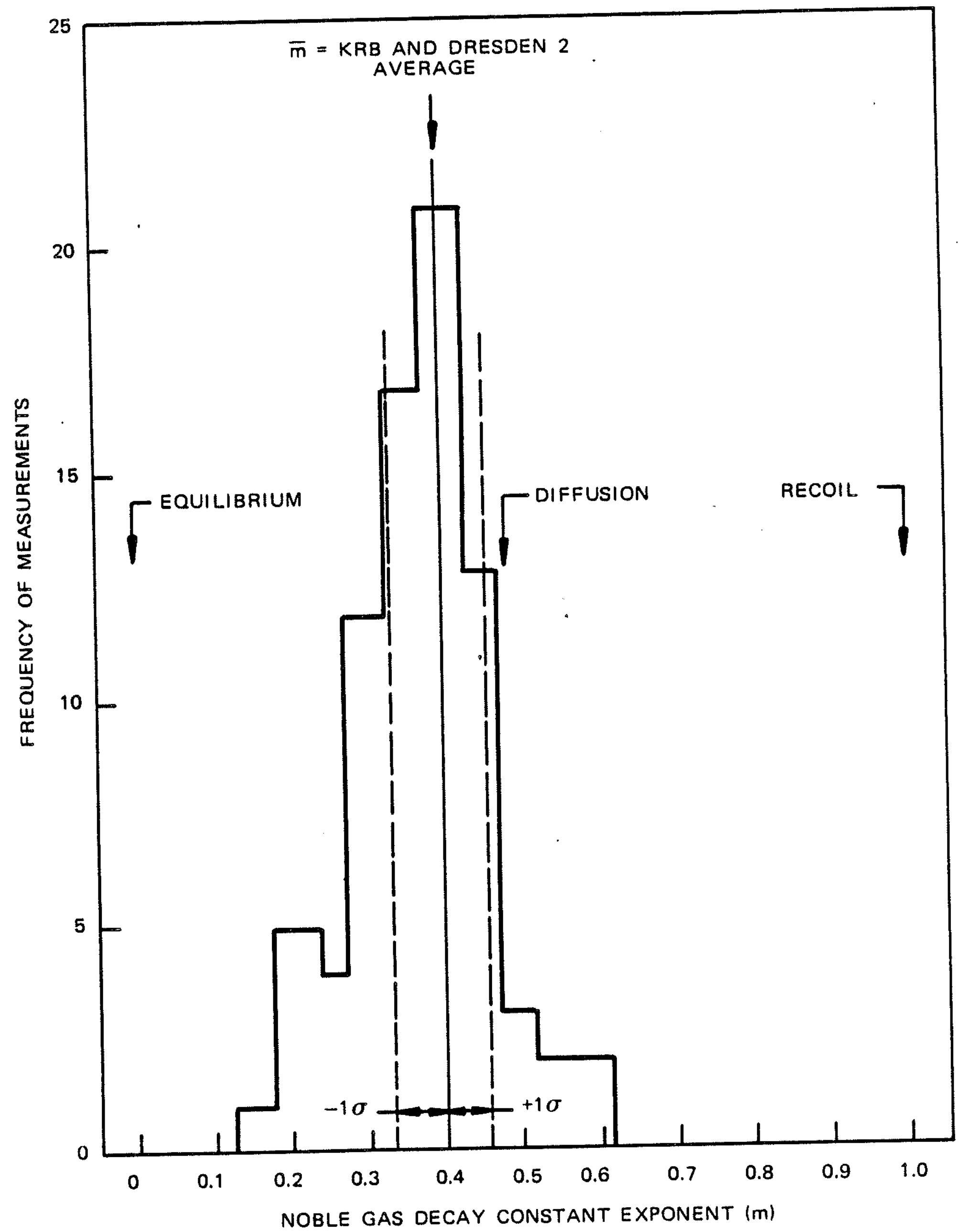

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FIGURE 11.1-1

NOBLE RADIOGAS DECAY CONSTANT EXPONENT FREQUENCY HISTOGRAM

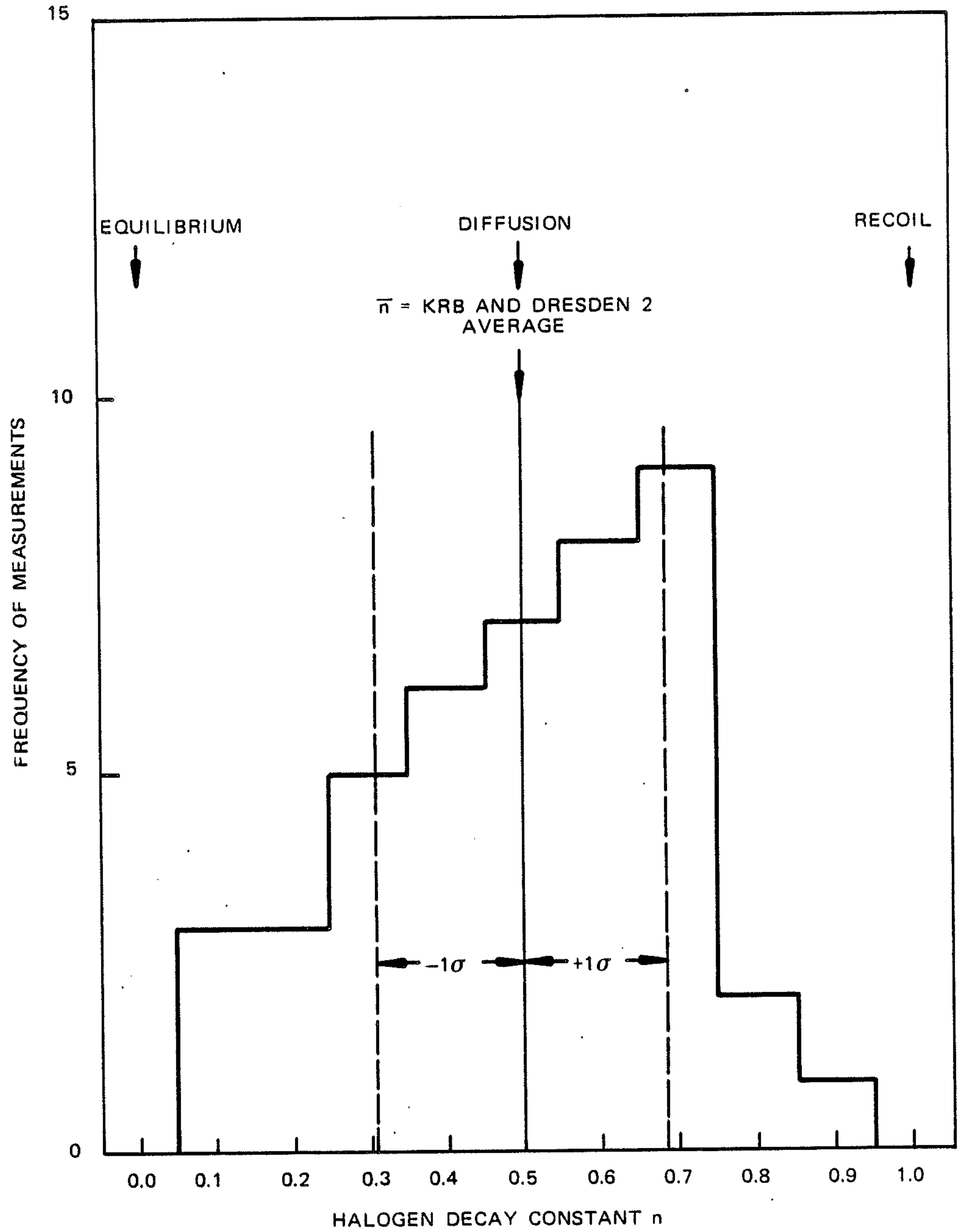

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FIGURE 11.1-2

RADIOHALOGEN DECAY CONSTANT EXPONENT FREQUENCY HISTOGRAM

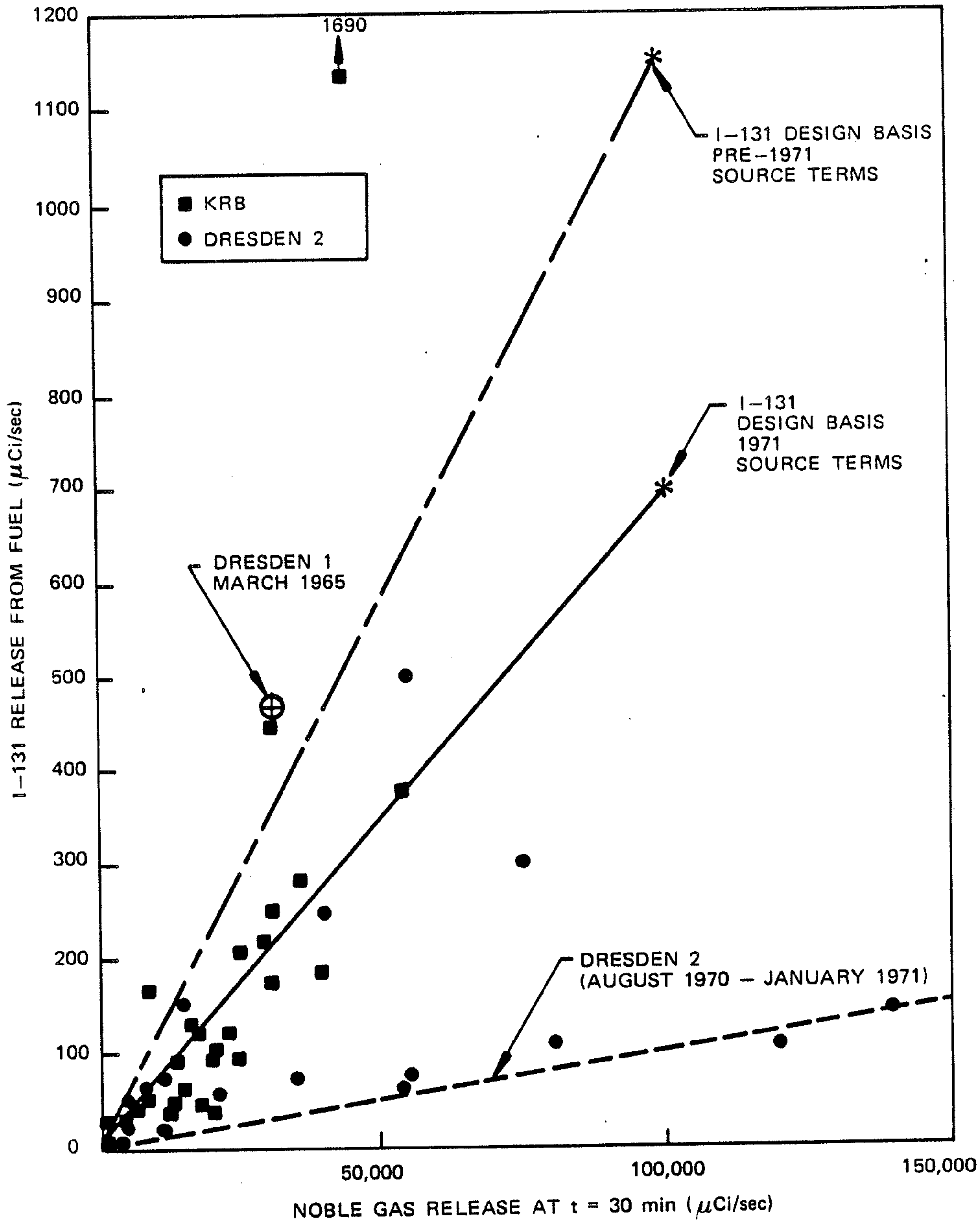

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FIGURE 11.1-3

NOBLE RADIOGAS VERSUS IODINE-131 LEAKAGE

11.2 LIQUID RADWASTE SYSTEM

The liquid radwaste system collects, monitors, processes, stores, and returns radioactive liquid wastes to the plant for reuse, or to the circulating-water reservoir blowdown line for controlled discharge. The collection and processing are done in a controlled, preplanned manner in compliance with established regulatory requirements. Any leakage or spillage due to equipment failure or malfunction will be contained and re-collected in the system. The system is capable of handling anticipated quantities of liquid radwaste without affecting the normal operation or availability of the plant.

11.2.1 Design Objectives

The liquid radwaste system is designed to function as follows:

a. Produce effluents that meet the limits of 10 CFR 20 and the design objectives of 10 CFR 50, Appendix I

b. Control and monitor releases of radioactive materials to the environment per the requirements of 10 CFR 50, Appendix A, General Design Criteria (GDC) 60 and 64

c. Produce treated waste of condensate quality for reuse within the plant

d. Provide the capacity to process liquid radioactive wastes produced in the plant during normal operation and during anticipated operational occurrences

e. Handle anticipated quantities of liquid radwaste without affecting the normal operation or availability of the plant

f. Segregate wastes into subsystems for more efficient processing

g. Provide alternative methods and redundancy of major items of equipment for processing radioactive liquids to ensure the flexibility of operation and maintenance

h. Use the plant drainage system to collect radioactive leakage or spillage due to equipment failure or malfunctions during normal plant operations

i. Provide for the transfer of liquid radwaste system processed waste by-products (evaporator bottoms, filter backwashes, tank sludge letdown, and spent resin) to the solid radwaste system

j. Protect plant personnel from radiation exposure and incorporate the basic as-low-as-reasonably-achievable (ALARA) objectives by the use of automated systems, shielding, and remotely operated instrumentation and controls.

Note: The following Section 11.2 description of the Liquid Radwaste System details the as-designed and as-installed design basis system. However, three of the described portions or subsystems are not presently being used, for various reasons. These subsystems remain in place and have not been isolated by any plant modifications, except as discussed in each section. They (and all components of them) have not officially been retired, or abandoned, and they could be made operational at some time in the future. Therefore, the full original design-basis description, usage, and tables for these items has been retained in Section 11.2 and all other pertinent sections of this UFSAR. These statements describing the system design are all technically correct; however, these items (and therefore their flow paths) are not considered operational at this time. These three subsystems or components are:

a. Radwaste Evaporator and supporting components

b. Two radwaste Etched-Disc Filters and supporting components

c. Two radwaste Oil Coalescers and supporting components

11.2.2 System Description

The liquid radwaste system is composed of two major subsystems--the floor drain collector (FDC) subsystem and the waste collector subsystem. The overall radwaste system's piping and instrumentation diagram is included as Figures 11.2-1 through 11.2-14, Figure 11.2-15 depicts the process flow diagram and Figure 11.2-16 (Sheets 1 through 3) depicts the sump pump diagrams.

Tables 11.2-1, 11.2-2, and 11.2-3 list the estimated design inputs to the liquid radwaste system along with the corresponding process flow diagram stream numbers (Figure 11.2-15).

At times the liquid radwaste system may produce water that may not be required for reuse in the station's water balance, in which case the system effluent could be discharged in a controlled manner to the circulating-water reservoir blowdown line. Processed liquid not meeting the criteria for either discharge or reuse is normally returned to the system for reprocessing.

The liquid and solid radwaste systems have a number of piping connections for use by portable waste-processing systems. (See Table 11.2-4 and Figure 11.2-15.) Vendor-contract services are available onsite for waste processing and solidification. These services meet applicable regulations and are more fully described in Subsections 11.2.10 and 11.5.6.

11.2.2.1 Floor Drain Collector Subsystem

The FDC subsystem will receive periodic and uncontrolled inputs from a variety of plant floor drain sources. The sources to this subsystem have been segregated from the waste collector subsystem because their water quality will probably be poor, will have high conductivity, and will normally contain higher contents of suspended and dissolved solids. The activity content will generally be lower than that of the waste collector subsystem. The estimated chemical characteristics of liquid radwaste input streams for this subsystem are listed in Table 11.2-5.

The chemical nature of the FDC subsystem inputs will also be highly variable. The effluent from the chemical waste tank will be particularly important to the overall stream process requirements because it is a source of high concentrations of dissolved solids. Periodic and variable quantities of oil and grease must also be accommodated by this subsystem. Most of this type of contaminant will be removed by the FDC oil coalescer when it is in service. Otherwise, but to a lesser extent, removal is accomplished by the precoat filters.

The FDC subsystem has an expected higher concentration of both dissolved and suspended solids, with a lower activity level and lower flow rate, than the waste collector subsystem.

Evaporators can be used to separate the FDC subsystem low-purity liquid by evaporation and condensation into a concentrated liquid that is fed to the solid radwaste system and a high-purity distillate that is fed to the FDC and waste collector demineralizers. Both the FDC and waste collector streams are normally passed through both demineralizers in series. Both subsystems offer independent etched-disk filters and oil coalescers to remove suspended solids and oil from the input liquids. In addition, precoat filters are provided for each stream but are not as volume-efficient because of the larger amount of solid radwaste they generate. The two streams are connected by a cross tie to allow the precoat filter or the etched-disk filter in the other stream to be used as a backup.

Each major input to the FDC subsystem is listed in Table 11.2-1 along with its corresponding stream number from Figure 11.2-15. Table 11.2-2 provides a summary of the design daily input to the chemical waste tank, which is in turn directed to the FDC tank for further processing.

The estimated design-basis daily volume inputs for the FDC subsystem total 15,219 gal, whereas the maximum daily volume input to this subsystem is calculated to be 42,284 gal. For the maximum volume input, it is assumed that the probability of the simultaneous occurrence of two or more volume input maximums is extremely low. Thus, the maximum is assumed to be the largest of the individual stream maximums plus the design daily inputs of the other streams. For this subsystem, the largest maximum daily volume input is estimated as 28,800 gal from the drywell floor drain sump. This amount, when added to the design daily volume inputs from the other FDC subsystem inputs, yields the maximum daily volume input value of 42,284 gal.

The normal collection point of the inputs to the FDC subsystem is the FDC tank, which has a working volume of about 20,000 gal. The design basis daily input of 15,219 gal can be accommodated for 1 day in the unlikely event of simultaneous failure of the redundant tank pumps. During the infrequent periods of anticipated maximum inputs, the waste surge tank will serve as an alternative collection point. This tank has a working volume of 65,700 gal and could contain the entire volumetric input (42,284 gal) to the FDC subsystem for 1 day during the maximum anticipated operational occurrence. Flow to the waste surge tank is accomplished by pumping from the FDC tank using the FDC pumps and the cross tie between the FDC subsystem and the waste collector subsystem.

Liquid radwaste system processing will normally be expected to be performed any time of day, 7 days a week; thus, for the design daily input case, an average FDC subsystem process rate of only 10.5 gpm would be required. For periods of maximum inputs, the FDC subsystem is capable of processing at a rate of at least 30 gpm. The processing rates account for periods of equipment unavailability during filter backwashes, resin replacement, and equipment maintenance. Generous liquid radwaste system subsystem interconnects, process equipment redundancy, and bypass capabilities provide maximum operational flexibility during periods of large input surges or unexpected equipment failures.

The FDC subsystem process equipment is discussed in Subsection 11.2.3.2.

11.2.2.2 Waste Collector Subsystem

The waste collector subsystem will receive periodic inputs from a variety of plant equipment drain sources. The equipment drain sources have been segregated from the FDC subsystem (and other sources) because the waste collector inputs will probably be of a higher purity (lower conductivity and suspended solids) than the FDC inputs. The activity concentration in the waste collector subsystem will tend to be higher than in the FDC subsystem. The estimated chemical characteristics of the liquid radwaste input streams for this subsystem are listed in Table 11.2-5.

Like the FDC subsystem, the chemical nature of the waste collector subsystem inputs will be variable, but should not be subject to the large fluctuations that may occur in the FDC subsystem. It is assumed that oil and grease will be present in the waste collector subsystem input, although this should occur much less frequently than in the FDC subsystem. Oil coalescers are included to provide for oil removal before ion exchange.

The waste collector subsystem process equipment is designed to also handle liquid input from the solid radwaste system. This consists of the discharge from the waste surge tank, whose primary function is to collect clarified liquid from the waste clarifier tank. Most of the clarified liquid is produced by the phase separator tank decant operation within the solid radwaste system. The solid radwaste system input to the waste collector subsystem enters downstream of the waste collector tank and, therefore, has no bearing on the size of the waste collector tank. Table 11.2-3 lists the design-basis daily volume input to the waste collector subsystem.

The combined result of all equipment drain inputs to the waste collector subsystem is represented by the waste collector tank effluent.

The estimated design-basis daily volume inputs for the waste collector subsystem total 28,805 gal. The maximum daily equipment drain volume input to this subsystem is calculated to be 48,846 gal. It is assumed that the probability of the simultaneous occurrence of two or more input maximums is extremely low; therefore, the maximum input is assumed to be the largest of the individual stream maximums plus the design daily volume inputs of the other streams. For this subsystem, the largest maximum daily equipment drain volume input will be 28,800 gal from the drywell equipment drain sump. This amount, when added to the design daily volume inputs from the other waste collector subsystem inputs, yields the maximum daily volume input value of 48,846 gal.

The collection point for the equipment drain volume input to the waste collector subsystem is the waste collector tank, which has a working volume of about 23,400 gal. The waste surge tank (which has a working volume of about 65,700 gal) will serve as the backup collection point for excessive equipment drain volume input to the waste collector subsystem.

The waste collector subsystem process equipment is discussed in Subsection 11.2.3.2.

11.2.2.3 Side Stream Liquid Radwaste Processing Subsystem

The Side Stream Liquid Radwaste Processing Subsystem (SSLRPS) processes primarily Chemical Waste Tank (CWT) contents prior to forwarding to the Floor Drain Collector Tank (FDCT). In addition, it processes liquids, such as: sludge from various building sumps, water collected in 55 gallon drums from the Standby Liquid Control System rinses during refueling outages and water from mopping of the building floors.

The SSLRPS includes two 45 kW evaporators, and two 20 gpm trains of Post Treatment System (PTS). Each train of PTS consists of a Granulated Active Charcoal Filter, an Ultra

Violet (UV) Total Organic Carbon (TOC) reducing System, and a Mixed Bed Filter, and associated Tanks, pumps and other system components as shown in Figure 11.2-18, Sheets 1, 2, and 3.

Each evaporator processes liquids in 55 gallons batches at a nominal rate of 0.2 gpm. The vapors from the evaporator will be condensed in a water-cooled condenser and collected in the Post Treatment Inlet Batch (PIB) Tank. The evaporator bottoms will be processed and shipped as solid radwaste. Liquids from the PIB Tank will be processed in one or both trains of the Post Treatment System, at a nominal rate of 20 gpm per train. PTS can process FDCT liquids at a nominal 40 gpm rate, when needed, using both streams of the system.

The Post Treatment System processes consist of carbon adsorption columns, photo-chemical oxidation of soluble organics using Ultraviolet (UV) light reactors and mixed bed filtration in succession. Particles above 5 microns in size and approximately, 90 percent of the Total Organic Carbon (TOC) will be removed by the Carbon filters. The effluents from the Carbon Bed Filters will flow through one or both of the UV Reactors. The UV reactors oxidize soluble organics into organic acids that can be more effectively removed by adsorption or ion exchange. The UV also kills bacteria, if present, in the liquid stream. The effluents from either of the UV reactors will flow through one or both mixed bed filters. The mixed bed filters remove the soluble organic acids generated by the UV reactors via adsorption and ion exchange.

The processed liquid will be collected in the Sample Batch Tank and returned to the FDCT via Radwaste Building basement floor drain system.

11.2.3 System Design

The liquid radwaste system is designed to ensure that system operation can be accomplished in a safe manner and to minimize the accumulated radiation exposure to system operators. Design practices that result in the achievement of the ALARA philosophy are used throughout. Where appropriate, redundant pump capacity is provided. Shielding is located to protect workers from operating equipment radiation.

The liquid radwaste system is designed to accommodate ease of maintenance in a radiation area, and, to the extent practicable, components are separated by shield walls to reduce radiation exposure to maintenance personnel. Clearance provisions are adequate for in-place maintenance activities and for the removal or replacement of components.

All normal liquid release pathways to the environment are continuously monitored to ensure that the dose to the general public will be well within the allowable limits of 10 CFR 20 and 10 CFR 50, Appendix I.

11.2.3.1 System Classifications

The following documents govern the codes, regulatory classifications, and regulatory requirements of the liquid radwaste system:

a. 10 CFR 20, Standards for Protection Against Radiation

b. 10 CFR 50, Appendix A, General Design Criteria for Nuclear Power Plants (GDC 60 and 64)

c. 10 CFR 50, Appendix I, Numerical Guides for Design Objectives and Limiting Conditions for Operation to Meet the Criterion "As Low As Is Reasonably Achievable" for Radioactive Material in Light-Water-Cooled Nuclear Power Reactor Effluents

d. Regulatory Guide 1.143, Design Guidance for Radioactive Waste Management Systems, Structures, and Components Installed in Light-Water-Cooled Nuclear Power Plants (Revision 1, October 1979)

e. Regulatory Guide 1.26, Quality Group Classifications and Standards for Water, Steam, and Radioactive Waste Components of Nuclear Power Plants

f. Regulatory Guide 8.8, Information Relevant to Ensuring That Occupational Radiation Exposure at Nuclear Power Stations Will Be As Low As Is Reasonably Achievable.

The initial design classification of the liquid radwaste system was Quality Group D per Regulatory Guide 1.26. The current design, which is based on Regulatory Guide 1.143, retains the Quality Group D classification (Table 11.2-6).

Table 11.2-6 lists both ASTM and ASME Section II materials for use in atmospheric and 0- to 15-psig storage tanks rather than ASME Section II materials only. The reasons for this are as follows:

a. API-650 and AWWA-D100 specify materials conforming to ASTM specifications

b. ASTM material specifications and ASME Section II material specifications are essentially identical.

For the Fermi 2 radwaste modification, the materials employed for the fluid-retaining boundaries of new atmospheric tanks and modifications to existing atmospheric tanks conform to ASME Section II material specifications as listed, respectively, in Tables 11.2-7 and 11.5-2. The single exception to the conformance is the material for the new, conical bottom of the spent resin tank. ASTM A36 material is used rather than ASME SA-36. However, material specifications for ASTM A36 and ASME SA-36 are essentially identical.

Table 11.2-6 lists manufacturers' standards for welder qualification and procedures as well as ASME Section IX for welding employed in the manufacture of pumps. In this respect, Table 11.2-6 conforms to Table 4-1 of ANSI/ANS-55.1 and Table 2 of ANSI/ANS-55.6. The reason for not excluding manufacturers' standards in Table 11.2-6 is that the pumps used in radwaste systems are frequently of a standard commercial design, and welding that meets the requirements of ASME Section IX is not always available.

Regulatory Guide 1.143 also requires that foundations of walls and structures housing the liquid radwaste system be designed to specified seismic criteria to a height sufficient to contain the liquid inventory expected to be in the building. Seismic calculations previously performed by Edison show that the radwaste building satisfies Category I requirements; therefore, it meets the criteria of Regulatory Guide 1.143.

Regulatory Guide 1.143 and Standard Review Plan 15.7.3 require an analysis to assess the consequences of a hypothetical uncontrolled release of radioactive liquids and the effect of the release on the health and safety of the public. The initiating event for this accident sequence would be a seismically induced total failure of the liquid radwaste system. This assumption is conservative compared with the requirements in Regulatory Guide 1.29. Subsection 15.7.3 describes the basic method and results of this analysis. The results of the analysis indicate offsite radioactivity concentrations that are well within the NRC requirements stated in Appendix B of 10 CFR 20.

11.2.3.2 Process Equipment Description

The process equipment for the liquid radwaste system is capable of processing several combinations of chemical and/or radioactive inputs.

One component of the FDC system is the evaporator subsystem (two redundant low-pressure, single-shell, submerged-tube units). The use of the evaporators is optional (at the discretion of the plant, based upon such considerations as economics, ALARA, input-stream characteristics, offsite releases and doses, etc.), and the system design has provided evaporator bypasses directly to the radwaste demineralizers. The evaporators are preceded in the FDC system by either the precoat filter or the etched-disk filter and oil coalescer train. The etched-disk filter serves several functions: (1) it removes particulates larger than 5 µm in order to minimize plugging and changeout of the oil coalescer; (2) it removes particulates that would lead to fouling and scaling of the evaporators; and (3) if the evaporators are bypassed, the etched-disk filter will remove particulates that could affect the downstream demineralizers. The oil coalescer removes emulsified oil and grease that would foul the downstream demineralizers or cause foaming and carryover from the evaporators.

If the evaporators are in use, evaporator distillate is pumped through two mixed-bed demineralizers normally aligned in series. The demineralizers serve to polish the evaporator distillate in order to achieve condensate-quality effluent. Processed water qualifies as condensate-grade water and can be reused within the plant if it meets the specifications listed in Table 11.2-8.

Because the specific conductivity of input streams to the waste collector subsystem is normally expected to be low (less than 50 µmho/cm), demineralization was selected as the primary processing method. The demineralizers are also preceded by a 5-µm etched-disk filter and an oil coalescer to remove particulates, oil, and grease that could foul the demineralizer resin. The waste collector subsystem precoat filter, located in parallel with the etched-disk filter/oil coalescer train, can otherwise be placed in service. Two mixed-bed demineralizers, normally aligned in series, remove dissolved solids. Although one demineralizer is assigned to the FDC subsystem and the other to the waste collector subsystem, they are normally used in series and process the FDC or waste collector streams.

The principal design parameters for the major liquid radwaste system components are given in Table 11.2-7.

11.2.3.2.1 Floor Drain Collector Tank

The FDC tank collects drainage containing high concentrations of dissolved and suspended solids from the drywell, reactor building, turbine building, radwaste building, and onsite storage facility. The system is designed so that liquid can be normally processed through combinations of etched-disk filters, oil coalescers, precoat filters, evaporators, and demineralizers.

The expected normal design-basis volume input is 15,219 gal, as shown in Figure 11.2-15, stream number 23. The tank working volume is about 20,000 gal. The estimated normal processing rate from this tank is about 50 gpm.

The FDC tank is provided with a slant bottom and sludge well to enhance sludge blowdown. The sludge blowdown is augmented by spray nozzles at the tank bottom to direct settled solids to the sludge well. The tank is provided with a bottom sludge connection located in the tank floor at the sludge well and also a decant connection located in the vertical tank wall about 2 ft above the sludge connection. The lines from these two connections join into a three-way diverter valve whose position can be set to allow pump suction to be taken from either connection. During the bottoms mode of operation, the tank contents will be pumped out through the bottom sludge connection. The decant connection can be used either for normal operations or when large quantities of wastes containing high concentrations of suspended solids are input to the tank. In this case, suspended solids would be allowed to settle to the tank bottom, and liquid would be drawn off the top and out the decant connection for processing through the downstream filter. The settled solids (sludge) in the tank bottom can be directed to the sludge well and then pumped out through the bottom sludge connection to the condensate phase separators. The drain to the tank is blind flanged outside the cubicle. Tank overflow is directed to the radwaste building floor drain sump. The tank is vented to the building vent system through a 4-in. connection.

11.2.3.2.2 Floor Drain Collector Pumps

The purpose of the FDC pumps is to transfer liquid waste from the FDC tank through one of the following:

a. Floor drain etched-disk filter and oil coalescer to the evaporator feed tank
b. Floor drain precoat filter to the evaporator feed surge tank
c. Waste collector precoat filter or etched-disk filter and oil coalescer to the evaporator feed tank
d. Spray nozzles in the FDC tank (recirculation line)
e. Waste surge tank.

The pumps are also used on an infrequent basis to pump the FDC tank sludge letdown to the phase separator tanks in the solid radwaste system.

The capacity of these pumps is determined from the overall processing rate requirements of the FDC subsystem. For design daily inputs, the stream should be able to process at a minimum rate of 10.5 gpm and at a rate of 29.3 gpm during peak input surges. The actual pumps used for this service are sized to deliver flow in a range of 100 to 150 gpm. Two 100 percent-capacity pumps are provided for this purpose.

11.2.3.2.3 Floor Drain and Waste Collector Etched-Disk Filters

Floor drain and waste collector etched-disk filters are designed to remove suspended solids particles down to 5 μm in size. The particulate removal serves the following three purposes:

a. To prevent premature plugging of the downstream oil coalescers

b. To prevent large particulates from entering the evaporators

c. To remove particulates that could plug the downstream demineralizers.

The floor drain and waste collector etched-disk filters are estimated to remove most of the suspended solids that enter the liquid radwaste system via the FDC and waste collector subsystems. When the FDC tank effluent (stream 23) is processed, the flow rate will normally be about 50 gpm and the average suspended solids content is estimated to be about 129 ppm. Since the floor drain etched-disk filter was designed as a backup to the waste collector etched-disk filter, it should also be capable of processing the combined flows of the waste collector subsystem for streams 24 and 40. The average suspended solids input from the waste collector subsystem is estimated at 20 ppm.

The etched-disk filters for the floor drain and the waste collector are identical. Since the normal flow rate through the floor drain etched-disk filter is less than that through the waste collector etched-disk filter, it should have a higher dirt-holding capacity before reaching the automatic differential pressure cutoff prior to backwashing. When operated at 50 gpm, the etched-disk filter is calculated to hold 2.64 lb of suspended solids before reaching 75 psid across the filter. At 140 gpm, the etched-disk filter is calculated to hold 1 lb of suspended solids before reaching 75 psid. These values are based upon the assumed water/crud characteristics (5 percent suspended solids smaller than 5 μm).

The etched-disk filter was selected for this service because it was thought to require little or no filter-aid material that would otherwise add to the ultimate volume of the solid radwaste system. The filters require primarily air for backwashing; they add minimal backwash water for processing by the liquid radwaste system.

The etched-disk filter consists of stacks of hundreds of individual disks, each of which is chemically etched on the top surface. When the disks are stacked, the top surface of one disk against the bottom surface of another forms pores around the perimeter of the stack. The etching is controlled so that the pore size is equal to the minimum particle size to be removed. These stacks of disks are placed inside a vessel, and wastewater is pumped into the vessel, where it flows perpendicular to the stacks, through the pores into the center of the stacks, and out the top of the filter vessel. Suspended solids in the wastewater are trapped in the pores and retained on the exterior of the stacks.

The backwash sequence proceeds automatically after being initiated by a high differential pressure signal across the filter as sensed by a pressure element or by manual initiation. Backwashing takes about 2 minutes.

Filter backwash for both the waste collector and floor drain etched-disk filters is directed to the condensate phase separator tank A. The total backwash volume is about 21 gal.

11.2.3.2.4 Floor Drain and Waste Collector Oil Coalescers

The oil coalescers remove mechanically emulsified oil from the floor drain and waste collector subsystems to maintain the optimal performance of the downstream process equipment. If sufficient oil is present in the wastewater, the downstream demineralizer resins will be coated with oil, degrading the demineralizing capacity and necessitating more frequent resin-bed changeout. The upstream etched-disk filters should normally be in service at all times when the oil coalescers are operating.

Although it is not possible to quantify all experience with oil in radwaste systems, oil has historically presented serious operational problems. Some plants have instituted strict administrative controls to prevent oil from entering the radwaste system.

These controls have included careful surveillance for oil leaks, immediate isolation of leaks, and the isolation of any oil-contaminated sumps. These measures require the dedication of manpower and the collection of spilled or leaked oil by makeshift means. Oil may enter the radwaste collection tanks if the source is not discovered and isolated quickly.

Oil in the radwaste system could affect the performance of demineralizers and evaporators. Any goal of maximum recycle of processed water to the condensate system requires that oil be minimized or removed.

The assumed design oil concentrations in the collector tanks are somewhat subjective and actual values will depend on administrative control procedures and general housekeeping. A survey of floor and equipment drains at Fermi 2 showed that oil sources were fairly well segregated from the equipment drains that flow to the waste collector subsystem. Therefore, the higher concentrations of oil would be in the floor drain subsystem. In design work for oil-removal systems for coal-fired generating stations, the designer had considered 100 ppm of oil in the influent stream as the design basis. Sample data available to the designer for the FDC tank at another BWR averaged approximately 66 ppm over a 6-month period and almost 9 ppm for the waste collector tank. For Fermi 2, design-basis averages of 5 ppm and 20 ppm for the waste collector and FDC subsystems, respectively, were selected.

The option to use oil coalescers was based only on the assumed use of etched-disk prefilters. Otherwise, the oil coalescers would experience rapid pressure buildup and plugging, since they have a 3-μm rating for other suspended solids.

The floor drain oil coalescers will be used as backup for the waste collector subsystem coalescers and vice versa. Hence, both oil coalescers are designed to handle maximum flows of 150 gpm.

11.2.3.2.5 Waste Oil Tank

The waste oil tank collects the oily wastes from the two liquid radwaste system oil coalescers. Since the flow of oil to the tank is small, long-term oil storage is also provided by this tank.

The tank is sized to provide a minimum of 1 year of oil storage from the oil coalescers. The maximum expected oil flow is less than 300 gal per year; therefore, a tank size of 1000 gal provides both storage and a contingency for carryover from the coalescers and unexpected oil spills.

11.2.3.2.6 Waste Oil Pump

The waste oil pump transfers the waste oil from the waste oil tank to a portable disposal container.

The pump capacity (10 gpm) is based on emptying the waste oil tank (1000-gal capacity) in about 100 minutes. The pump differential pressure will be about 150 psi when the oil temperature is near 40°F. If the oil temperature is 60°F, the differential pressure is about 75 psi.

11.2.3.2.7 Evaporator Feed Surge Tank

This tank is for collection of the water from the FDC subsystem after filtration. Because the FDC subsystem is designed for a nominal 50 gpm processing rate and the evaporator system is designed for a nominal 30 gpm rate, the evaporator feed surge tank provides surge capacity.

The input to the tank contains minimal suspended solids, and the tank is therefore not provided with either a slant bottom or a sludge-drawoff line.

The tank is designed to be at least large enough to contain 15,219 gal, the design daily input from the FDC subsystem. The evaporator feed surge tank has a capacity of 25,000 gal, which will accommodate the design inputs for 1 day assuming the failure of the redundant tank discharge (evaporator feed) pumps. Downstream processing from this tank can normally occur 24 hr per day. It can be emptied of the design daily input in about 8 hr, assuming there are no further inputs to it.

11.2.3.2.8 Evaporator Feed Pumps

The evaporator feed pumps process water from the evaporator feed tank under different operating modes, as follows:

a. From the evaporator feed tank to the evaporator

b. From the evaporator feed tank through the floor drain and waste collector demineralizers to the waste sample tank when the evaporators are bypassed

c. Recycle or recirculation back to the evaporator feed tank through an eductor

d. From the evaporator feed tank to portable demineralization equipment in the onsite storage facility.

e. From evaporator feed tank to the Side Stream Liquid Radwaste Processing System distillation inlet batch tank

The capacity of the pumps is determined from the nominal evaporator-processing capacity of 30 gpm. The pump head is based on the head requirements for the above modes of operation. Two 100 percent-capacity pumps are provided.

11.2.3.2.9 Evaporators

The two redundant evaporators can process the prefiltered FDC subsystem low-purity waste by evaporation and condensation to produce concentrated liquid bottoms and a high-purity distillate.

The dissolved solids in the wastewater, including dissolved radioactive material, are concentrated in the evaporator bottoms. The evaporators provide the function of concentration or volume reduction of radioactive and nonradioactive material in the floor drain wastewater. The evaporators are sized to process floor drain water at a 30-gpm flow rate in each unit.

The concentrates (refuse liquid) are concentrated to an assumed practical density of less than 8 percent by weight and are normally discharged at a nominal temperature of 165°F.

Two 100 percent-capacity radwaste evaporators are provided. Normally, only one is used to process floor drain wastewater.

The evaporators operate on a semibatch basis. Under this type of operation, feed and distillate production is a continuous process, but the removal of concentrates occurs only after the desired bottoms concentration is reached.

The evaporators are of the low-pressure, single-shell, submerged-tube type. The units are heated by steam supplied by the main plant auxiliary boilers (through pressure-reducing stations) to tube bundles. Each unit contains a distiller condenser cooled by general service water. The units operate under a partial vacuum (about 20-in. Hg vacuum). Vacuum is maintained by a liquid-ring type mechanical vacuum pump that removes noncondensibles from the shell. Each unit is provided with a single vacuum pump, distillate pump, and concentrates pump. Each unit is also fitted with a single distillate cooler (which is cooled by general service water) as well as the required valves and instrumentation. Internal baffles and demisters are provided for the removal of entrained water droplets from the vapor. The evaporators are skid mounted, with the vacuum pumps and the concentrates and distillate pumps located off the skids behind shield walls to minimize radiation exposure to maintenance and operations personnel. All equipment that is in contact with process fluid is constructed of stainless steel (except for the Incoloy tube bundles).

During steady-state operation, feed to the evaporator is continuous and is controlled automatically by the level in the shell. The concentrates pump operates automatically in the recirculation mode. A chemical metering pump pumps additives to continuously adjust the pH in the recirculation line of the concentrates pump so that frothing in the evaporator and scaling of heat transfer surfaces are avoided. The chemical metering pump is electrically interlocked to the concentrates pump; this permits the operation of the chemical injection system only when the concentrates pump is in operation recirculating bottoms. The vacuum pump is in continuous operation. The distillate pump also operates continuously and discharges to the distillate surge tank as long as distillate purity meets the conductivity limit (about 2 μmho/cm). Cavitation of the distillate pump is prevented by maintaining a minimum level in the pump suction pipe. Suction pipe level instrumentation ensures this level by throttling a flow control valve in the pump discharge line.

The distillate surge tank may be operated in the batch or continuous mode. In the batch mode, the tank is allowed to fill before the transfer of its contents is initiated. Once full, the evaporator distillate pump discharge is shifted to the standby evaporator's distillate surge tank by means of the distillate crossover piping. The contents of the full tank can then be sampled and, if within conductivity limits for further processing by the demineralizer train, can be pumped through the demineralizers. It is also possible to return the contents of the distillate surge tank to the evaporator feed surge tank for recycling if required. When the tank contents have been transferred and the standby evaporator's distillate surge tank has been filled, the distillate pump discharge can be shifted back to the operating evaporator's distillate surge tank. The surge tanks can continue to be alternated in this manner.

In the continuous mode of operation, the distillate may be transferred from the operating evaporator's distillate surge tank at the same rate that it is filling. The transfer rate is adjusted to match the fill rate by correctly selecting the flow setpoint of the distillate transfer flow control valve. In this mode of operation, primary reliance for distillate purity must be placed on the evaporator distillate conductivity instrumentation. Periodic grab samples may be obtained from the sample tap on the distillate transfer pump recirculation line or directly from the tank. The continuous mode of distillate transfer is also possible using the standby evaporator's distillate surge tank and distillate transfer pump in case the operating evaporator's distillate transfer pump is out of service.

System analysis indicates that about 8 days of operation would be required to reach 6 percent to 10 percent by weight dissolved solids in the concentrates. The evaporator is not required to be completely shut down if there are short time periods (within a long-term evaporator run) when the unit is not processing FDC subsystem water; rather, the evaporator can be kept in standby. In the standby mode, the evaporator concentrates are kept at the approximate operating temperature by a submersible heater in the evaporator shell. The heater is thermostatically controlled and has a low-level cutout.

Once the desired concentration of the evaporator bottoms has been reached, the bottoms are transferred to the concentrates feed tank either directly from the evaporator shell or indirectly via the evaporator drains holdup tank. From the concentrates feed tank, the bottoms are transferred to the extruder/evaporator for solidification in the solid radwaste system. The evaporator drains holdup tank and concentrates feed tank and associated piping are electrically heated to maintain the temperature of the concentrates and to prevent possible crystallization of the dissolved material.

11.2.3.2.10 Concentrates Pumps

The concentrates pumps transfer concentrates from the evaporator shell to the evaporator drains tank or the concentrates feed tank. They also circulate evaporator concentrates through the evaporator shell during normal operation to prevent solution precipitation.

These pumps are capable of emptying the full evaporator shell of concentrates (800 gal) within about 1 hr. The pumps are conservatively sized to have a capacity of about 50 gpm. One pump is provided for each evaporator subsystem.

11.2.3.2.11 Evaporator Drains Holdup Tank

This tank serves as an emergency backup tank to the concentrates feed tank (described in Subsection 11.5.3.2.16). During normal evaporator operation this tank is bypassed. The tank can be used when it is necessary to drain the evaporator and the concentrates feed tank is unavailable.

The tank is designed to hold the volume of one evaporator batch (about 800 gal) in the event that draining is necessary. During normal evaporator operation, the evaporator drains discharge directly to the concentrates feed tank.

11.2.3.2.12 Evaporator Drains Pump

The evaporator drains pump mixes and maintains a uniform temperature of the contents in the evaporator drains holdup tank.

The pump capacity is determined by the tank-mixing requirements. The evaporator drains tank has a capacity of about 1500 gal and should be completely recycled at least once per hour; thus, a pump capacity of 30 gpm is adequate.

11.2.3.2.13 Distillate Pumps

The purpose of these pumps is to deliver distillate from the evaporator to the distillate surge tank through the seal water/ distillate cooler.

The capacity of the pumps is determined from the evaporator capacity plus reflux (about 35 gpm). The head requirement for the pump is based on the system resistance for the above operating mode.

11.2.3.2.14 Distillate Surge Tanks

The two distillate surge tanks provide a surge capacity between the evaporators and the floor drain and waste collector demineralizers. Provision is made for sampling the distillate collected in these tanks. After sampling, the distillate can be pumped through the demineralizers or returned to the evaporator feed tank through a recycle line.

The evaporators are designed to operate at a nominal flow rate of 30 gpm. Each tank has a volume of 5100 gal which would provide an operating time of over 2.5 hr before the distillate has to be transferred. This is enough time to sample the distillate and to pump to either of the demineralizers for polishing or back to the evaporator feed tank for reprocessing.

11.2.3.2.15 Distillate Transfer Pumps

The distillate transfer pumps transfer liquid from the evaporator distillate surge tank to one of the following:

a. A waste sample tank through the floor drain and waste collector demineralizers

b. The waste surge tank (or waste collector or floor drain collector tanks) through the floor drain and waste collector demineralizers (recycle mode)

c. Directly to the evaporator feed tank (recycle mode).

This pump also provides recirculation to mix the evaporator distillate surge tank liquid to acquire a representative sample.

These pumps are capable of discharging the evaporator distillate surge tank contents at a rate that ensures that one surge tank can be sampled and emptied while the other surge tank is being filled. Since the nominal evaporator system capacity is 30 gpm, the pumps are conservatively sized to have a nominal capacity of 50 gpm. Two 100 percent-capacity pumps are provided. The distillate surge tanks are provided with crossover inlet connections that allow one tank to fill while the other is being sampled and discharged.

11.2.3.2.16 Floor Drain and Waste Collector Demineralizers

The demineralizers remove, by ion exchange, the dissolved solids contained in the floor drain collector subsystem and the waste collector subsystem. The goal of demineralization is to produce water of sufficient quality to be recycled to the plant via the condensate storage tank or the condensate return tank.

The nominal combined simultaneous flow rate from the waste collector subsystem and the floor drain system through the demineralizers should be about 140 gpm.

The demineralizers are designed to reduce the dissolved solids concentrations such that the conductivity is less than 1 μmho/cm. It is calculated that on the average, a resin bed will require replacement about every 8 days for the design daily inputs.

The floor drain demineralizer holds approximately 49 ft^3, and the waste demineralizer approximately 49 ft^3 of mixed cation and anion resin and activated carbon. Each vessel has type 304 stainless steel internals, including an inlet distributor and a wire-wrapped underdrain collector that prevents the escape of resins. During service, water enters the demineralizers through the inlet distributor, is distributed over and passes down through the resin bed, and discharges through the underdrain collector. When resin exhaustion is indicated by high conductivity in the effluent, the spent resins are dumped by manual initiation to the spent resin tank, and new resins are added to the demineralizers.

Under normal conditions, these two demineralizers will operate in series to process combined wastes from the FDC and waste collector subsystems. If required, the demineralizers can be used individually for either subsystem to process liquid wastes. Each demineralizer is sized to operate at a flow rate of about 140 gpm, if necessary. Using the demineralizers in series provides maximum loading of the ion exchange resins before they have to be replaced with new resins. The piping system is designed such that either demineralizer can be used as the lead or follow unit. As the liquid wastes are processed through the demineralizers, the effluent is continuously monitored. If the conductivity out of the second demineralizer is below a preset value, then the processed liquid is directed to the waste sample tanks. If the conductivity of the processed liquid exceeds the preset value, then the flow is automatically diverted and returned to a selected subsystem (normally to the waste surge tank) for reprocessing.

11.2.3.2.17 Waste Sample Tanks

The purposes of the waste sample tanks are the following:

a. To collect treated water processed by the demineralizers from the floor drain and waste collector subsystems

b. To allow analysis of the tank contents for radioactivity and conductivity after the tank contents have been mixed

c. To discharge the water to either the condensate storage tank, to the blowdown discharge, or to the waste collector or waste surge tanks for recycling, depending on the radiochemical analysis of the water.

The calculated design daily input from the FDC subsystem is 15,219 gal. The calculated design daily input from the waste collector subsystem is about 34,173 gal. The three waste sample tanks have a capacity of about 24,300, 24,300, and 21,000 gal, respectively. The treated water will be sampled before discharge to the condensate storage tank, the blowdown line, or the waste collector or waste surge tank. At any given time, one sample tank will be receiving a batch while the second one can be in the sample mode and the third can be in the discharge mode. Therefore, the three tanks together meet the design requirements. During periods of maximum operational occurrences, one of these three tanks can provide surge capacity.

11.2.3.2.18 Waste Sample Pumps

Three waste sample pumps are provided. Two are normally associated with sample tanks G1101-A004 A and B. The third is normally associated with sample tank G1101-A009. One pump is provided for each tank, but a manual valve alignment will allow pumping from the A tank with the B pump or C pump and vice versa.

These pumps transfer water from the waste sample tanks to the following:

a. Condensate storage tank

b. Waste surge tank (off-standard water quality)

c. Blowdown discharge line

d. Waste sample tank (recirculation line).

The capacity of the waste sample pumps is determined by providing a reasonable rate for the tank to empty to accommodate overall system inputs. Since the waste sample tanks can be filled at a rate of about 140 gpm via the waste collector subsystem, the waste sample pumps should be capable of discharging to the condensate storage, waste surge, or waste collector tanks at a similar rate.

Flow to the blowdown discharge line will be throttled back to a level of 5 to 50 gpm. Excess pump flow while discharging through throttling valves will be recycled to the waste sample tank.

11.2.3.2.19 Chemical Waste Tank

The chemical waste tank collects wastewater, including decontamination solutions and laboratory drains that may require pH or other suitable adjustment before processing. Provisions exist for the addition of an acid or base to the tank to adjust the pH, and the wastes are then sent to the floor drain collector tank for further processing.

The design-basis maximum daily input to this tank is from the periodic evaporator cleaning rinse operation (stream 13, Figure 11.2-15). This is assumed to produce about 3350 gal of solution twice a year.

11.2.3.2.20 Chemical Waste Pumps

The purpose of these pumps is to mix the contents of the chemical waste tank and to transfer neutralized waste to the FDC tank. These pumps also transfer the Chemical Waste Tank Contents to the Side Stream Liquid Radwaste Processing System Distillation Inlet Batch Tank. The capacity of the pumps is based on the mixing requirement of the chemical waste tank, which has a 5200-gal capacity, and the capability to empty a full tank within one shift. The selected size of 60 gpm would allow one complete turnover of the tank contents followed by tank emptying, within one 8-hr shift. Two 100 percent-capacity pumps are provided.

11.2.3.2.21 Precoat Filters

The floor drain precoat filter and the waste-collector precoat filter provide processing paths that are in parallel with the etched-disk filter/oil coalescer trains. The removal efficiency for particulate is based on the amount of filter aid used and is generally found to be 0.1 lb of crud removed for each pound of filter aid. The floor drain precoat filter is designed to handle 50 gpm with a 64-ft^2 filter area and a 210-gal filter vessel volume. The waste collector precoat filter is designed to handle 125 gpm with a 115-ft^2 filter area and a 460-gal filter vessel volume.

Precoating is accomplished by recirculating a powdered resin/ fiber mixture through the vessel where it collects and forms a layer on filter elements. A holding pump provides minimum flow through the filter to prevent the material from falling off after precoating or when the filter is taken out of service upon the completion of a batch. During service, wastes flow into the filter, suspended solids and oil are retained on the filter resin layer, and liquid passes through the layer out of the vessel. As the filter cycle continues, solids build up on the surface of the filter elements and cause the differential pressure across the filter to increase. The filter can be left in service until the differential pressure reaches about 30 psi, at which time it will automatically be taken out of service and put into a hold condition. It must then be backwashed before it can be put back into service. If the differential pressure cutoff is not reached but the filter is no longer required for service, it can be manually put into a hold condition. During service, a filter aid solution can be injected into the incoming wastes as body feed to prevent the filter cake from blinding, which would cause the filter to rapidly reach differential pressure cutoff. This body feed is particularly important with oily wastes. When differential pressure is reached or the filter is no longer required for filtration, it is removed from service and backwashed by using an air bump method. After backwashing, it is left cleaned and full of water, ready for the next precoating and service cycles.

11.2.3.2.22 Waste Precoat Tank

The waste precoat tank mixes the powdered resin/fiber into a uniform slurry before precoating the precoat filters. The tank services both the floor drain and waste collector precoat filters.

The precoat tank is designed to contain enough powdered resin/ fiber solution to allow the precoating of one filter before refilling the tank.

11.2.3.2.23 Filter Aid Tank

The filter aid tank mixes the filter aid into a slurry before feeding it to the floor drain or waste collector precoat filters along with the incoming wastes.

The filter aid tank supplies filter aid to both the floor drain and waste collector precoat filters. The tank is sized to feed sufficient filter aid to each filter for one batch run before refilling is necessary.

11.2.3.2.24 Waste Collector Tank

This tank collects waste from different sources, which include the reactor water cleanup system, drywell and reactor building equipment drain sumps, waste and floor drain demineralizer drains, distillate surge tank drain and overflow, the turbine building equipment drain sump, and the radwaste building equipment drain sump. These inputs are periodic in nature. The wastewater collected in the tank can be pumped from either the bottom-sludge well connection or from the decant nozzle (2 ft above the bottom suction). Any sludge collected over time can be let down via the bottom-sludge well connection to the phase separator tanks. The volume to overflow of the waste collector tank is approximately 23,400 gal. This capacity, combined with the processing rate through the filters, will be adequate to handle the flows to the waste collector tank. Excessive inputs during surge periods will be pumped to the waste surge tank.

The waste collector tank is modified to provide a sludge well with a slant bottom. Spray nozzles are provided at the bottom of the tank to direct solids to the sludge well. The tank is vented to the building vent system, and the tank overflow is directed to the radwaste building floor drain sump. The tank drain is blind flanged outside the cubicle.

11.2.3.2.25 Waste Collector Pumps

The purpose of these pumps is to pump water from the waste collector tank through one of the following:

a. Waste collector etched-disk filter, oil coalescer, and floor drain and waste collector demineralizers to waste sample tank

b. Waste collector precoat filter and floor drain and waste collector demineralizers to waste sample tank

c. Floor drain precoat filter or etched-disk filter and oil coalescer, and floor drain and waste collector demineralizers to waste sample tank

d. Recirculation lines back to the waste collector tank.

The pumps are also used infrequently to pump, through a system-balancing valve, the waste collector tank sludge letdown to the phase separator tanks in the solid radwaste system.

The capacity of these pumps is determined by the overall processing rate requirements for the waste collector subsystem. Waste collector tank contents should normally be processed at a minimum rate of 100 gpm in order to accommodate the design daily inputs. The actual pumps used in this service are sized to deliver a flow range of 100 to 160 gpm. Two 100 percent-capacity pumps are provided. These pumps are vertical, in-line, centrifugal pumps capable of operating under several modes of operation.

11.2.3.2.26 Waste Surge Tank Pumps

These pumps pump water from the waste surge tank through one of the following:

a. Waste collector etched-disk filter, oil coalescer, and floor drain and waste collector demineralizers to the waste sample tank

b. Waste collector precoat filter and floor drain and waste collector demineralizers to the waste sample tank

c. Floor drain precoat filter or etched-disk filter, oil coalescer, and floor drain and waste collector demineralizers to the waste sample tank

d. System-balancing valve to the condensate phase separator tanks (sludge letdown)

e. Spray nozzles to the waste surge tank (recirculating line).

The capacity of these pumps is based on the overall processing rate requirements dictated by the inputs to the waste surge tank. The waste surge tank contents should normally be processed at a minimum rate of 100 gpm in order to accommodate the design daily input.

Two 100 percent-capacity pumps are provided. The pumps are vertical, in-line, centrifugal pumps capable of operating under different operating modes. During the sludge blowdown mode, a system-balancing valve is utilized to generate the necessary pressure drop.

The waste surge tank is described in Subsection 11.5.3.2.4 as a solid radwaste system component.

11.2.3.2.27 Ultraviolet (UV) Total Organic Carbon Reduction System

Organically contaminated water produced by plant operation is drained into the liquid radwaste system for treatment. Total organic carbon (TOC) can be treated using UV radiation. Certain wavelength UV radiation has the capability to destroy TOC by breaking bonds and oxidizing the organic compounds. The process passes the waste stream past UV radiation emitting lamps. The effluent from the unit can then be demineralized to remove the products of the TOC breakdown.

To treat various liquid radwaste streams, a portable UV water treatment unit will be used as necessary to reduce organics from the liquid radwaste process waste streams.

11.2.3.3 Side Stream Liquid Radwaste Processing System Equipment Description

The Side Stream Liquid Radwaste processing System is depicted in Figure 11.2-18. Major components are briefly described below and their design capabilities are summarized in Table 11.2-7.

11.2.3.3.1 Distillation Inlet Batch (DIB) Tank

The DIB tank stores liquids forwarded from the Chemical Waste Tank and from 55 drums that collect water from building floor mopping operations. The Tank's working volume is 800 gallons. Water from the Fermi 2 Condensate System is provided to clean the tank, when needed. The tank level is monitored and controlled from the local control panel. The over flow line is routed to the Radwaste Building Floor Drain. The tank vent is hard piped to the Radwaste Building Ventilation system.

11.2.3.3.2 High and Low Radwaste Evaporators

The high and low Radwaste Evaporators are both capable of processing liquid radwaste in 55 gallon batches at a nominal rate of 0.2 gpm. The vapor from the evaporators is conveyed to the condenser using Station Air stream. Return air is discharged to the Radwaste Building Ventilation System. Solids will remain in the 55 gallon drum. When sufficient amount of solid is collected or when the radiation level reaches a predetermined level, the drum is released for offsite shipment.

11.2.3.3.3 High and Low Radwaste Condensers

Each evaporator is provided with a water cooled condenser. The station air drives the vapors across the condenser tubes carrying General Service Water. The condenser liquids are collected in the Condensate Receiver. The condensate thus collected is forwarded Post treatment Inlet Batch Tank via the condensate forwarding pump.

11.2.3.3.4 Post Treatment Inlet Batch (PIB) Tank

The PIB Tank collects the condensate from the high and low Radwaste Evaporators for processing via the Post Treatment System. The tank's working volume is about 800 gallons. The tank level is monitored and controlled from the local control panel. The over flow line is routed to the Radwaste Building Floor Drain. The tank vent is hard piped to the Radwaste Building Ventilation system.

11.2.3.3.5 PIB Tank Forwarding Pump

The contents of the PIB Tank are forwarded to the Post Treatment System using a 10 gpm pump. This pump can also be aligned for tank recirculation.

11.2.3.3.6 Granular Activated Carbon Bed Filters

Two adsorption columns each capable of holding over 20 cubic feet of Granular Activated Carbon (GAC) are designed to remove particles above 5 microns in size from the liquid streams flowing at or below 20 gpm. The tank vent is hard piped to the Radwaste Building Ventilation system.

11.2.3.3.7 Ultraviolet (UV) Light Reactors

Two 1.5 kW medium pressure UV Reactors are provided to oxidize the effluents from the Carbon Bed Filters. The UV rays also kill bacteria, if present in the effluent stream. Each UV reactor is capable of handling up to 20 gpm effluent flow.

11.2.3.3.8 Mixed Bed Filters

Two mixed bed filters each capable of holding 20 cubic feet of Cation and anion resin beads. The mixed Bed Filter removes the organic acids produced by the UV reactor by oxidizing soluble organics in the effluent stream. Each Mix Bed Filter can handle flows up to 20 gpm. The tank vent is hard piped to the Radwaste Building Ventilation system.

11.2.3.3.9 Sample Batch (SB) Tank

The effluents from the mixed bed filters are collected in the Sample Batch Tank. The tank's working volume is 1000 gallons. The tank level is monitored and controlled from the control panel. The over flow line is routed to the Radwaste Building Floor Drain. The tank vent is hard piped to the Radwaste Building Ventilation system.

11.2.3.4 Pipe Routing

To aid the routing of piping normally carrying radioactive fluids, a shielded pipe tunnel runs along the north, south, and west walls of the radwaste building at an elevation of 564 ft. Whenever possible, pipes carrying radioactive fluids are routed through this tunnel and exit at the tunnel when required to connect to a piece of process equipment. When a pipe cannot be routed via the tunnel, proper care, including the installation of shielding material, is taken to reduce the radiation levels to acceptable values.

11.2.4 Operating Procedure

The liquid radwaste system is basically a manual-start/automatic-stop processing system that does not require continuous on-line operation. The system is designed around large collecting tanks that accept inputs from a variety of sources. As tank levels increase, an operator selects the appropriate system lineup and manually initiates treatment by manipulating control panel switches. Upon completion of system lineup, the operator starts the appropriate pump to draw down the collecting tank. The pump will stop automatically on low tank level and will remain de-energized unless manually restarted.

If radioactive liquid must be discharged from the site, it is treated by the liquid radwaste system and transferred to a waste sample tank for sampling. The treated water is sampled before discharge to verify compliance with discharge criteria; if the criteria are not satisfied, the water is recycled through the liquid radwaste system. Liquid radwaste discharge monitoring is further described in Section 11.4.

11.2.5 Performance Tests

Since the liquid radwaste system is operated as required during the operation of the power plant, its ongoing operability is demonstrated without recourse to special testing. Operating logs, records, and sample results reflect the day-to-day performance of the system. Conditions such as high-volume processing, short filter or demineralizer runs, or high wastewater conductivity or activity are evaluated when they occur.

11.2.6 Estimated Releases

The liquid radwaste system is designed so that, with proper water management techniques, minimal or zero discharge of liquid waste should be needed. It is recognized that during some operating conditions, such as startup, the discharge of excess water may be desirable or even necessary.

The total design-basis liquid releases (excluding tritium) are estimated to be about 0.14 Ci per year. Tritium releases are estimated to be about 52.5 Ci per year. The radwaste system is designed to effectively capture the majority of incoming radionuclides (and ultimately process them as solid wastes) and to so reduce the radioactivity levels in the radwaste sample tanks to minimal values (for discharge). Therefore, the exact configuration of the radwaste equipment/trains utilized or in use is not so important as long as the end-point (discharge) isotopic-concentration criteria are maintained. This is illustrated by the results shown in Tables 11.2-9 and 11.2-10, where estimated design-basis releases have been calculated for two different modes of operating the radwaste equipment. It is seen that the resultant release quantities are virtually the same.

All releases to the environment from the liquid radwaste system are discharged past a radiation monitor that isolates the discharge line if high radioactive concentrations in the discharged liquid should occur. This monitor and the isolation valve are located so that, if a high radiation level is detected, the line is isolated before any liquid can be discharged. The flow is rerouted back to the system for reprocessing. The monitor and discharge lines would then be decontaminated by flushing.

11.2.7 Release Points

Any release of liquid radwaste is directed to the circulating water reservoir blowdown line. This discharge is from the Fermi 2 circulating water pump house and is directed to Lake Erie. The discharge path is shown in Figure 2.1-5.

11.2.8 Dilution Factors

If small amounts of liquid radwaste are to be released from Fermi 2, they will be released to Lake Erie via the circulating water reservoir blowdown line. The minimum dilution flow will be about 10,000 gpm. Further dilution of the blowdown is provided by the natural mixing characteristics of Lake Erie in the vicinity of the discharge. Section III of Appendix 11A provides an evaluation of dilution factors to the nearest individual receptors both northeast and south of Fermi 2 and at the Monroe and Toledo potable water intakes. These dilution factors are as follows:

a. 45 at nearest shoreline northeast of Fermi 2 (1770 m)

b. 67 at nearest shoreline south of Fermi 2 (1530 m)

c. 77 at 3200 m south of Fermi 2 (Monroe potable water intake)

d. 100 at distances greater than 3200 m.

11.2.9 Estimated Doses From Liquid Effluents

The possible pathways for radiation exposure to Man from plant effluents are presented in Figure 11.2-17. The following general pathways have been evaluated for liquid effluents:

a. Drinking water

b. Aquatic food chains

c. Direct radiation from water and shores.

These pathways can be divided into internal exposures resulting from pathways a. and b. and external exposures resulting from pathway c.

The radiation doses described in this section are predicated upon design-basis source terms, radwaste throughput values, and annual releases into Lake Erie. They were updated for power uprate conditions, and are considered to be conservative upper-limit values, and are being retained as such in the UFSAR for "historical" purposes. It is understood that the actual releases, source terms, and offsite dose values will be different than these UFSAR values, will be estimated via the Offsite Dose Calculation Manual, and will be periodically reported to the NRC.

A detailed design-basis evaluation of the potential doses from liquid effluents to an individual is presented in Appendix 11A, Section III. The maximum exposure from liquid effluents to an individual was assumed to be located, as discussed in Subsection 11.2.8 above, at 1770 m northeast of Fermi 2 and 1530 m south of Fermi 2. The resident south was assumed to drink potable water obtained from the Monroe water intake located 3200 m south of Fermi 2. The resident north was assumed to obtain his potable water from the Detroit municipal water system, which will be unaffected by Fermi 2 operation. Table III-1 of Appendix A presents conservative usage factors for liquid exposures. The activities usage factors represent 2 hr/day for boating, swimming, and shoreline use, each for a period of 90 days/yr for the teenager and child, while the adult will participate 1 hr/day in each activity. The ingestion rates are those recommended by Regulatory Guide 1.109 (Reference 2). The individual doses are summarized in Table 11.2-11 for the mode of radwaste operation with evaporators and the etched-disk filters in service.

Doses to the maximum exposed individual were calculated based on Mode One Operation (i.e., normal operation with the evaporators and etched disk filters in use). These doses are tabulated in Table 11.2-11. A comparison of Mode One annual liquid effluent releases with those corresponding to Mode Two operation (i.e., normal operation without the radwaste evaporators and with the precoat filters in use) shows that both sets of releases are almost identical. Therefore, it is reasonable to expect that doses to the maximum individual based on Mode Two operation, if they were to be calculated, would be approximately equal to those tabulated in Table 11.2-11. The total body doses tabulated in Table 11.2-11 are within the guidelines established by Appendix I and 10CFR20, and are less than the value calculated by the NRC (1.6 mrem/year total body, as reported in the Safety Evaluation Report, Table 11-5, NUREG-0798, July 1981).

The population exposures from both internal and external pathways were evaluated using the guidance provided in Regulatory Guide 1.109, Revision 1 (Reference 3). The exposures were calculated using the LADTAP II computer code (Reference 4). LADTAP II is a computer code received from the Radiation Shielding Information Center at Oak Ridge National Laboratory, which implements the models in Reference 3.

The population exposures from internal and external pathways were reviewed for the mode of operation without the evaporators and etched disk filters. As shown in Tables 11.2-9 and 11.2-10, there is no significant difference in the source terms between operation in mode one and mode two. It can be expected that the population exposure from internal and external pathways would not change significantly and that any differences would be due to changes in the assumptions in Subsections 11.2.9.1 and 11.2.9.2 used to evaluate the doses rather than from the radiological source term.

11.2.9.1 Internal Population Exposure

Internal population exposure will arise from the ingestion of potable water and from the ingestion of fish.

The locations of all municipal potable water intakes within 50 miles of Fermi 2 are presented in Table 2.1-12. The population data of each municipality were extrapolated to represent the population in the year 2000. The growth rates used for the U.S. locations were based on the assumption that the country growth rate established from 1970 to 1980 (Reference 5) would be maintained and would be applicable to the appropriate municipality. For the Canadian locations, a provincial growth rate from 1976 to 1980 (Reference 6) was assumed to be maintained until the year 2000. The dilution factors presented in Subsection 11.2.8 were assumed to be applicable. Table 11.2-12 presents the data on the municipal potable water intake locations, populations, and dilution factors.

For the expected population exposure from fish ingestion, an upper limit was estimated from the following assumptions:

a. The commercial fish catch from Lake Erie landed in Michigan is assumed to be affected by plant releases (Reference 7). The 1980 catch amounted to 280,000 kg

b. The sport fish catch described in Reference 7 is affected by plant activity releases. It was assumed to consist of 70 percent yellow perch and 30 percent walleye and amounts to 1,837,000 kg

c. The applicable dilution factor is conservatively taken to be 100 in all cases

d. The edible portion of the fish was assumed to be 60 percent

e. The population doses for fish ingestion are based on the estimated 50-mile population for the year 2000 (Reference 8).

Table 11.2-13 provides the internal population exposure by pathway and various organs.

11.2.9.2 External Population Exposure

External population exposure resulting from liquid effluents can arise from swimming, boating, and other shoreline activities.

The population of concern in the evaluation of the dose due to external exposure is residents of the nearby communities along the Lake Erie beachfront. It is estimated that 50 percent of the persons living in beachfront communities in Monroe County, Michigan, and the Toledo area use the beach for recreational purposes (Reference 5). The communities of interest, 50 percent of their year 2000 populations, their distances from the plant, and dilution factors are given in Table 11.2-14. The estimated year 2000 populations were calculated by extrapolating the 1980 population (Reference 8) to the year 2000, assuming that the country growth rates established from the year 1970 to the year 1980 will be maintained.

Other communities are either at greater distances from the plant or have beachfronts that are generally unsuitable for recreational activity. For the purpose of estimating population doses, it was assumed that a resident using the beach would spend 200 hr per year engaging in beach activities. Of this total time, it was assumed that 50 hr would be spent for swimming, 50 hr for water-surface activities (fishing, boating, waterskiing, and sailing), and 100 hr for shoreline activities such as sunbathing or walking along the shore (listed as shoreline in Table 11.2-14, which presents the external population doses from the liquid effluents by pathway and various organs).

11.2.10 Vendor-Supplied Liquid Processing System

If the permanent Fermi 2 liquid processing system is not available due to system malfunction, or if needed for any other reason, a vendor-supplied portable system can be utilized. The system normally will be operated by the vendor and will be closely monitored by Edison personnel. The types and quantities of waste to be processed are the same as for the permanent radwaste systems (as described in Subsection 11.2.2). Fermi 2 specific operating procedures or approved vendor procedures will be used for operating the portable system interfaced with the Fermi liquid radwaste system.

This vendor-supplied portable system would normally be installed in the areas immediately adjacent to the truck bay in the onsite storage facility. These areas of the onsite storage facility were specifically designed and constructed to contain and handle mobile process systems (see Subsection 11.7.2.2.11). Concrete floors and walls in this region are coated, and all drains are routed back to the liquid radwaste system. The remote-operated overhead crane is available to move the process equipment. The design of these onsite storage facility areas and the methods of operation have incorporated features to maintain personnel exposures ALARA. Permanent piping installed in the shielded onsite storage facility pipe tunnel will transport the radioactive process fluid to the vendor's equipment.

The interface connections between the mobile system and the Fermi 2 system are shown in Figure 11.2-15 and described in Table 11.2-4. A typical portable radwaste system operates by passing the contaminated water through a series of pressure vessels, as necessary, containing filtration media or ion-exchange resins. When these vessels are removed from service, the media are sluiced to a disposal container and processed further or dewatered or solidified in situ and then shipped to an approved burial site for disposal. In both cases, the resulting end products comply with all federal and state disposal regulations. The processed water is, in turn, routed to the waste sample tanks when established conductivity limits are met.

11.2 LIQUID RADWASTE SYSTEM

REFERENCES

1. U.S. Nuclear Regulatory Commission, Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents for Boiling Water Reactors, BWR-GALE Code, NUREG-0016, Rev. 1, January 1979.
2. U.S. Nuclear Regulatory Commission, Calculation of Annual Doses to Man From Routine Release of Reactor Effluents for the Purpose of Evaluating Compliance With 10 CFR Part 50, Appendix I, Regulatory Guide 1.109, U.S. Nuclear Regulatory Commission, March 1976.
3. U.S. Nuclear Regulatory Commission, Calculation of Annual Doses to Man From Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance With 10 CFR Part 50, Appendix I, Regulatory Guide 1.109, Rev. 1, October 1977.
4. Oak Ridge National Laboratory, Users Manual for LADTAP II - A Computer Program for Calculating Radiation Exposure of Nuclear Reactor Laboratory Effluents, NUREG/CR-1276, May 1980.
5. 1980 Census of Population and Housing, Preliminary Reports, for Ohio - PHC 80-P-37, February 1981; for Michigan - PHC 80-P-24, February 1981.
6. The World Almanac and Book of Facts, 1981.
7. U.S. Nuclear Regulatory Commission, Draft Environmental Impact Statement Related to the Operation of the Enrico Fermi Atomic Power Plant, Unit 2 - Docket 50-341, NUREG-0769, April 1981.
8. U.S. Department of Commerce, Bureau of the Census, 1980 Census data by tract for Monroe County, Michigan (unpublished data).

TABLE 11.2-1 DESIGN DAILY INPUT VOLUMES FOR THE FLOOR DRAIN COLLECTOR SUBSYSTEM

Stream No.[a]	Description	Fermi 2 Design Daily Volume (gpd)
1	Turbine building, oil separator effluent	3,060
2	Drywell floor drain sump	1,785
3	Reactor building floor drain sump	5,100
4	Turbine building floor drain sump	2,040
5	Loadout building drains	200
7	Personnel decontamination drains	100
8	Cask-cleaning drains	14
9	CRD and fourth-floor drains	Infrequent
10	Radwaste building drains	2,550
26	Chemical waste tank[b]	370
23	Total floor drain collector tank effluent	15,219

a Refer to Figure 11.2-15.
b Refer to Table 11.2-2.

TABLE 11.2-2 DESIGN DAILY VOLUMES FOR CHEMICAL WASTE TANK INPUT TO THE FLOOR DRAIN COLLECTOR SUBSYSTEM

Stream No.[a]	Description	Fermi 2 Design Daily Volume (gpd)
6	Regulated shop drains	50
11	Laboratory drains	200
12	Decontamination solutions	100
13	Evaporator cleaning solutions	17
81	Neutralization chemicals	3
26	Total chemical waste tank effluent	370

[a] Refer to Figure 11.2-15.

TABLE 11.2-3 DESIGN DAILY VOLUMES FOR MAJOR INPUTS TO THE WASTE COLLECTOR SUBSYSTEM

Stream No.[a]	Description	Fermi 2 Design Daily Volume (gpd)
14	Drywell equipment drain sump	8,738
15	Reactor building equipment drains	9,509
16	Radwaste building equipment drains	2,827
17	Turbine building equipment drains	7,710
24	Total waste collector tank effluent	28,784
40	Waste surge tank liquid effluent[b]	6,000
	Total input to waste collector filter	34,784

[a] Refer to Figure 11.2-15.

[b] Stream 40 joins stream 24 downstream of the waste collector pumps.

TABLE 11.2-4 VENDOR PROCESSING CONNECTIONS

Connection	Size (in.)	Material	Design Pressure (psig)	Design Temperature (°F)
Demineralization, floor drains	2	Carbon steel	150	150
Demineralization, waste collector	3	Carbon steel	150	150
Wet slurries to solidification	2	Stainless steel	150	150
Decant water from solidification process	2	Stainless steel	150	150
Purified water from demineralization process	3	Stainless steel	150	150

TABLE 11.2-5 ESTIMATED CHEMICAL CHARACTERISTICS OF LIQUID RADWASTE INPUT STREAMS

Input	Suspended Solids (ppm)	Dissolved Solids (ppm)	Oil and Grease (ppm)	pH
FDC subsystem	120	165	20	6-8
Chemical waste tank inputs to FDC	500	15,700	<1	7-9
Waste collector subsystem	20	35	5	6-8

TABLE 11.2-6 RADWASTE EQUIPMENT DESIGN REQUIREMENTS

	Codes			
Equipment	Design and Fabrication	Materials[a]	Welder Qualification and Procedure	Inspection and Testing
Pressure vessels	ASME Code Section VIII, Division 1	ASME Code Section II	ASME Code Section IX	ASME Code Section VIII, Division 1
Atmospheric or 0-15 psig tanks	ASME Code[b] Section III, Class 3, or API 620 or 650, or AWWA D-100[c]	ASME Code Section II or ASTM	ASME Code Section IX	ASME Code[b] Section III, Class 3, or API 620 or 650, or AWWA D-100[c]
Heat Exchangers	ASME Code Section VIII, Division 1, and TEMA	ASME Code Section II	ASME Code Section IX	ASME Code Section VIII, Division 1
Piping and valves	ANSI B31.1	ASTM or ASME Code Section II	ASME Code Section IX	ANSI B31.1
Pumps	Manufacturer's Standards[d]	ASME Code Section II or Manufacturer's Standards	ASME Code Section IX or Manufacturer's Standards	ASME Code[b] Section III, Class 3 or Hydraulic Institute

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[a] Material manufacturer's certified test reports should be obtained whenever possible.

[b] ASME Code stamp and material traceability are not required.

[c] API-650 and AWWA D-100 apply to atmospheric tanks, whereas API-620 applies to 0- to 15-psig tanks. ASME Section III, Class 3, has rules .pertaining to both atmospheric (Subarticle ND-3800) and 0- to 15-psig (Subarticle ND-3900) tanks.

[d] Manufacturer's standard for the intended service. Hydrotesting should be 1.5 times the design pressure.

TABLE 11.2-7 LIQUID RADWASTE SYSTEM – COMPONENT DESIGN PARAMETERS

Component	Number	Capacity (gal)	Material	Design Pressure (psig)	Design Temperature (°F)	Design Code
Floor drain collector tank	1	20,000	Carbon steel[a]	Atmospheric	150	API-650[b]
Evaporator feed surge tank	1	25,000	Carbon steel (SA-285, Grade C)	Atmospheric	150	ASME III, Class 3
Waste oil tank	1	1,000	Carbon steel (SA-285, Grade C)	Atmospheric	150	ASME III. Class 3
Waste precoat tank	1	180	Carbon steel	Atmospheric	150	Manufacturer's Standard
Waste clarifier tank	1	16,500	Carbon steel Plasite 7155	Atmospheric	150	API-650[b]
Filter aid tank	1	400	Carbon steel	Atmospheric	150	Manufacturer's Standard
Distillate surge tank	2	5,100	Aluminum	Atmospheric	150	ASME III
Chemical waste tank	1	5,200	Stainless steal	Atmospheric	150	API-650
Evaporator drains holdup tank	1	1,500	Carbon steel	Atmospheric	150	ASME III
Waste collector tank	1	23,400	Carbon steel[a]	Atmospheric	150	API-650[b]
Waste sample tank	2	24,300	Aluminum	Atmospheric	150	ANSI B96.1-1967
Waste sample tank	1	21,000	Aluminum	Atmospheric	150	ANSI B96.1-1967
Waste surge tank	1	65,700	Carbon steel[a]	Atmospheric	150	API-650[b]

[a] Except for a new SA-240-304/stainless steel bottom.

[b] Design code for tank modifications is ASME III, Class 3

Component	Number	Liquid Pumped	Flow Rating (gpm)	Total Dynamic Head (ft)	Materials (Casing/ Shaft/ Impeller)	Type	Design Code
Floor drain collector pump A	1	Wastewater	150	264	SS SS SS	Single stage, vertical, in-line	Manufacturer's Standard
Floor drain collector pump B	1	Wastewater	150	264	SS SS SS	Single-stage, vertical, in-line	Manufacturer's Standard
Evaporator feed pump	2	Evaporator surge tank effluent	40	126	316 SS/ 316 SS/ 316 SS	Single-stage, vertical, in-line	Manufacturer's Standard
Distillate pump	2	Evaporator distillate	35	92	SS CF-3/ CS/ SS CF-3	Single stage, centrifugal	Manufacturer's Standard

TABLE 11.2-7 LIQUID RADWASTE SYSTEM – COMPONENT DESIGN PARAMETERS

Component	Number	Liquid Pumped	Flow Rating (gpm)	Total Dynamic Head (ft)	Materials (Casing/ Shaft/ Impeller)	Type	Design Code
Distillate transfer pump	2	Evaporator distillate	50	80	316 SS/ 316 SS/ 316 SS	Single stage, horizontal	Manufacturer's Standard
Evaporator drains pump	1	Evaporator drainage	30	35	316 SS/CS 316 SS	Single stage, horizontal	Manufacturer's Standard
Concentrates pump	2	Wastewater	50	90	CS/ 304 L SS/ SS CF-3	Single stage, horizontal,	Manufacturer's Standard
Chemical waste pump	2	Wastewater	60	90	316 SS/ 316 SS/ 316 SS	Single stage, one vertical, in-line and one horizontal	Manufacturer's Standard
Chloride waste pump	1	Chloride wastewater	35	40	Monel/ Monel/ Monel	Single stage, vertical, in-line	Manufacturer's Standard
Waste oil pump	1	Waste oil	10	352	CS/ CS/ CS	Rotary gear	Manufacturer's Standard
Waste collector pump A	1	Wastewater	150	350	Cast iron/ stainless steel/ bronze	Single stage, vertical, in-line	Manufacturer's Standard
Waste collector pump B	1	Wastewater	150	350	Cast iron/ stainless steel/ bronze	Single stage, vertical, in-line	Manufacturer's Standard
Waste surge pump A	1	Wastewater	150	326	316 SS/ 316 SS/ 316 SS	Single stage, vertical, in-line	Manufacturer's Standard
Waste surge pump B	1	Wastewater	150	326	316 SS/ 316 SS/ 316 SS	Single stage, vertical, in-line	Manufacturer's Standard
Waste sample pump	2	Radwaste	150	97	316 SS/ 316 SS/ 316 SS	Single stage, in-line	Manufacturer's Standard
Waste sample pumps	1	Radwaste	150	190	316 SS/ 316 SS/ 316 SS	Single stage, vertical, in-line	Manufacturer's Standard
Floor drain sump pumps	2	Wastewater	55	35	Cast iron/ stainless steel/ bronze	Horizontal, self-priming	Manufacturer's Standard
Equipment drains sump pumps	2	Wastewater	55	35	Cast iron/ stainless steel/ bronze	Horizontal, self-priming	Manufacturer's Standard
Evaporator Condensate Forwarding Pumps	2	Condensate	10	100	Cast iron/ stainless steel/ bronze	Horizontal	Manufacturer's Standard

TABLE 11.2-7 LIQUID RADWASTE SYSTEM – COMPONENT DESIGN PARAMETERS

Component	Number	Liquid Pumped	Flow Rating (gpm)	Total Dynamic Head (ft)	Materials (Casing/ Shaft/ Impeller)	Type	Design Code
PIB Tank Forwarding Pump	1	Condensate	10	170	316 SS	Horizontal 4-Stage Centrifugal	Manufacturer's Standard
Sample Batch Tank Forwarding Pump	1	Water	40	170	316SS	Horizontal 4-Stage Centrifugal	Manufacturer's Standard

Floor Drain Demineralizer

Type - Mixed-bed, anion and cation resin, nuclear grade, nonregenerative, with stainless steel wire mesh underdrain

Capacity - 140 gpm, batch process

Resin bed - 49 ft^3

Vessel size - 4 ft 6 in. O.D. by 4 ft 9 in. vertical shell and ASME heads

Design temperature - 150°F

Design pressure - 150 psig

Pressure drop - 7 psid

Design code - ASME Section VIII, Division I, 2010

Material – Shell, heads, nozzle pipes, flanges and internals – stainless steel

Waste Demineralizer

Type - Mixed-bed, anion and cation resin, with stainless steel wire mesh underdrain

Capacity - 140 gpm, batch process

Resin bed - 49 ft^3, resin depth 3 ft minimum, 5 ft maximum

Vessel size - 4 ft 6 in. O.D. by 9 ft 6 in. shell height

Design temperature - 150°F

Design pressure - 150 psig

Material - Shell, heads, flanges, and nozzle pipes - carbon steel

Internals - 304 stainless steel

Tank lining - 1/4-in. EPDM (ethylene propylene)

Pressure drop - 10 psid

Design code - Demineralizer Vessel - ASME Section III, Class C, 1968

TABLE 11.2-7 LIQUID RADWASTE SYSTEM – COMPONENT DESIGN PARAMETERS

Post Treatment System Mixed Bed Demineralizer

Type – Mixed-bed, anion and cation resin, nuclear grade, nonregenerative, with stainless steel wire mesh underdrain

Number of Demineralizers - 2

Capacity - 20 gpm, batch process

Resin bed - 20 ft^3

Vessel size – 30 in. O.D. by 5 ft 8 in. vertical shell and ASME heads

Design Temperature - 150°F

Design Pressure - 150 psig

Pressure drop - 5 psid

Material - Shell, heads, flanges, and nozzle pipes - 316 SS

Internals - 304 Stainless steel

Design Code - ASME Section VIII, Division I, 2001

Post Treatment System Granulated Activated Charcoal Bed Filter

Type - Granular Activated Carbon Bed Filter

Number of Filters - 2

Capacity - 20 gpm, batch process

GAC bed – 24 ft^3

Vessel size - 30 in. O.D. by 5 ft 8 in. shell height

Design Temperature - 150°F

Design Pressure - 150 psig

Material - Shell, heads, flanges, and nozzle pipes - 316 SS

Internals - 304 Stainless steel

Pressure drop - 10 psid

Design Code - ASME Section VIII, Division I, 2001

Floor Drain and Waste Collector Etched-Disk Filters (two)

Type - Etched disk

Capacity - 190 gpm maximum

Materials - Shell and heads - 304 stainless steel

Internals - 316L stainless steel

Design pressure - 350 psig

Design temperature - 150°F

Design code - ASME Section VIII, Division I

TABLE 11.2-7 LIQUID RADWASTE SYSTEM – COMPONENT DESIGN PARAMETERS

Floor Drain and Waste Collector Oil Coalescers (two)

Type - Oil separator vessel with oil-coalescing cartridges

Capacity - 150 gpm design

Material - 316 stainless steel

Design pressure - 150 psig

Design temperature - 150°F

Design code - ASME Section VIII, Division 1

Process Evaporators (two)

Type - Low-pressure, horizontal batch type with submerged U-tube heating bundle - single shell, with continuous spray demister

Capacity - 30 gpm of distillate

Steam pressure to tube bundle - 10 psig

Cooling water pressure - 100 psig

Overpressure protection - 3 in. rupture disk to discharge

Condensing space vacuum - 20 in. Hg

Distillate temperature - 190°F

Operating temperature - 160°F (evaporator and condenser)

Distillate temperature at cooler discharge - 125°F

Shell size - 8 ft 6 in. diameter by 11 ft 4 in. long over elliptical heads

Material and thickness - 304 stainless steel, 1/2-in.-thick plate

Tubes and tube sheets - Incoloy-825, 3/4 in., 17-gage tubes; 2-1/16-in.-thick tube sheets

Decontamination factor - 3×10^5 bottoms to distillate (gross activity basis)

Max. activity of concentrated waste liquid - 5×10^{-2} μCi/ml

Volume of concentrated waste liquid - 800 gal

Design codes - Evaporator shell - ASME Section III, Class C, 1968

Evaporator tube bundles - ASME Section VIII, Division 1, 1980

Channel sections of tube bundles - ASME Section VIII, Division 1, 1968

Process piping - ANSI B31.7, 1969 Class III for stainless steel

Pumps and valves - ASME Draft Code for Pumps and Valves for Nuclear Power, Class III, 1968, and March 1970 Addenda

Distillate cooler - ASME Section VIII, Division 1, 1968, and TEMA Class C

Piping for steam and cooling water - Carbon steel ANSI B31.1

TABLE 11.2-7 LIQUID RADWASTE SYSTEM – COMPONENT DESIGN PARAMETERS

Precoat Filters (two)

Surface area - Waste collector filter: 115 ft^2

- Floor drain filter: 64 ft^2

Max. differential pressure - Waste collector filter: 30 psid

- Floor drain filter: 30 psid

Amount of precoat - 0.2 lb/ft^2 (each filter)

Filter vessel volume - Waste collector filter: 460 gal

-Floor drain filter: 210 gal

Total backwash air required - Waste collector filter: 61 scf

- Floor drain filter: 28 scf

Materials - Vessel - carbon steel

- Internals - 304 stainless steel

- Lining – Plasite

---

[a] Except SA-240-304/stainless steel bottom.

[b] Design code for tank modifications is ASME III, Class 3.

TABLE 11.2-8 ESTIMATED CONDENSATE STORAGE WATER QUALITY

Parameter	Value
Specific conductivity at 25 °C	≤ 1µmho/cm
pH at 25 °C	6 to 8
Silica (as SiO_2)	≤50 ppb
Chloride (as Cl^-)	≤25 ppb
Boron (as BO_3)	≤0.1 ppm
Total Organic Carbon (TOC)	≤500 ppb

Note: pH and conductivity apply after correction is made for dissolved carbon dioxide.

TABLE 11.2-9 ESTIMATED ANNUAL RELEASES FROM LIQUID EFFLUENT FOR MODE ONE[a,b,c] (3499 MWt)

Nuclide	Total (Ci/yr)[d]
Corrosion and Activation	
Na-24	0.00460
P-32	0.00011
Cr-51	0.00345
Mn-54	0.00004
Mn-56	0.01007
Fe-55	0.00058
Fe-59	0.00002
Co-58	0.00011
Co-60	0.00023
Ni-65	0.00006
Cu-64	0.01329
Zn-65	0.00011
Zn-69m	0.00091
Zn-69	0.00076
W-187	0.00015
Np-239	0.00380
Fission Products	
Br-83	0.00120
Br-84	0.00030
Br-85	0.00001
Rb-89	0.00098
Sr-89	0.00006
Sr-91	0.00163
Y-91m	0.00084
Y-91	0.00002
Sr-92	0.00209
Y-92	0.00278

TABLE 11.2-9 ESTIMATED ANNUAL RELEASES FROM LIQUID EFFLUENT FOR MODE ONE[a,b,c] (3499 MWt)

Nuclide	Total (Ci/yr)[d]
Y-93	0.00167
Nb-98	0.00028
Mo-99	0.00109
Tc-99m	0.00715
Tc-101	0.00161
Ru-103	0.00001
Tc-104	0.00185
Ru-105	0.00058
Rh-105m	0.00058
Rh-105	0.00005
Te-129m	0.00002
Te-129	0.00001
Te-131m	0.00005
I-131	0.00226
I-132	0.01152
I-133	0.02621
I-134	0.00736
Cs-134	0.00018
I-135	0.01903
Cs-136	0.00046
Cs-137	0.00011
Cs-138	0.00421
Ba-139	0.00114
Ba-140	0.00023
La-140	0.00001
Ba-141	0.00023
La-141	0.00018
Ce-141	0.00002
Ba-142	0.00008

TABLE 11.2-9 ESTIMATED ANNUAL RELEASES FROM LIQUID EFFLUENT FOR MODE ONE[a,b,c] (3499 MWt)

Nuclide	Total (Ci/yr)[d]
La-142	0.00072
Ce-143	0.00001
Pr-143	0.00002
Total (except tritium)	0.13718
Tritium release	52.5

---

a Nuclides having an annual release of less than 10^{-5} Ci/yr have been excluded.
b Calculated according to NUREG-0016, Revision 1.
c Mode one represents normal operation with both the radwaste evaporator and the etched-disk-filter/oil coalescer trains in use.
d See Table 5 of Annex A of Appendix 11A.

TABLE 11.2-10 ESTIMATED ANNUAL RELEASES FROM LIQUID EFFLUENTS FOR MODE TWO[a,b,c] (3499 MWt)

Nuclide	Total (Ci/yr)[d]
Corrosion and Activation	
Na-24	0.00460
P-32	0.00011
Cr-51	0.00345
Mn-54	0.00004
Mn-56	0.01008
Fe-55	0.00058
Fe-59	0.00002
Co-58	0.00011
Co-60	0.00023
Ni-65	0.00006
Cu-64	0.01330
Zn-65	0.00011
Zn-69m	0.00091
Zn-69	0.00076
W-187	0.00015
Np-239	0.00380
Fission Products	
Br-83	0.00120
Br-84	0.00030
Br-85	0.00001
Rb-89	0.00098
Sr-89	0.00006
Sr-91	0.00163
Y-91m	0.00084
Y-91	0.00002
Sr-92	0.00209
Y-92	0.00278
Y-93	0.00167
Nb-98	0.00028
Mo-99	0.00109
Tc-99m	0.00715
Tc-101	0.00161
Ru-103	0.00001
Tc-104	0.00185
Ru-105	0.00058
Rh-105m	0.00058

TABLE 11.2-10 ESTIMATED ANNUAL RELEASES FROM LIQUID EFFLUENTS FOR MODE TWO[a,b,c] (3499 MWt)

Nuclide	Total (Ci/yr)[d]
Rh-105	0.00005
Te-129m	0.00002
Te-129	0.00001
Te-131m	0.00005
I-131	0.00226
I-132	0.01153
I-133	0.02622
I-134	0.00736
Cs-134	0.00018
I-135	0.01904
Cs-136	0.00046
Cs-137	0.00011
Cs-138	0.00421
Ba-139	0.00114
Ba-140	0.00023
La-140	0.00001
Ba-141	0.00023
La-141	0.00018
Ce-141	0.00002
Ba-142	0.00008
La-142	0.00072
Ce-143	0.00001
Pr-143	0.00002
Total (except tritium)	0.13723
Tritium release	52.5

---

[a] Nuclides having an annual release of less than 10^{-5} Ci/yr have been excluded.
[b] Calculated according to NUREG-0016, Revision 1.
[c] Mode one represents normal operation with both the radwaste evaporator and the etched-disk-filter/oil coalescer trains in use.
[d] See Table 5 of Annex A of Appendix 11A.

TABLE 11.2-11 ESTIMATED MAXIMUM DOSES TO AN INDIVIDUAL RESULTING FROM FERMI 2 LIQUID EFFLUENT FOR MODE ONE OPERATION[a] (3499 MWt)

	Dose to a Child (mrem/year)	
Pathway	Total Body	Bone (Maximum Organ)
	Resident 1770 meters NE	
Fish ingestion	0.00343	0.07305
Invertebrate ingestion	0.00029	0.00385
Shoreline	0.00006	0.00006
Swimming	0.00004	0.00004
Boating	0.00003	0.00002
Total	0.00386	0.07703
	Resident 1530 meters S	
Fish ingestion	0.00229	0.04912
Invertebrate ingestion	0.0002	0.0026
Drinking water	0.00223	0.00019
Shoreline	0.00004	0.00004
Swimming	0.00002	0.00002
Boating	0.00001	0.00001
Total	0.00480	0.05198

[a] See Table 11.2-9 for definition of mode one.

TABLE 11.2-12 MUNICIPAL POTABLE WATER INTAKES

Municipality	Year 2000 Population	Dilution Factor
Monroe	56,000	77
Toledo	466,200	100
Kingsville	1,800	100
Leamington	12,600	100
Port Clinton	14,900	100
Wheatley	1,300	100
Sandusky	53,400	100

TABLE 11.2-13 ESTIMATED POPULATION DOSES WITHIN A 50-MILE RADIUS RESULTING FROM FERMI 2 LIQUID EFFLUENTS FOR THE YEAR 2000 (Internal and External) (3499 MWt)

	Dose (man-rem/yr)	
Pathway	Total Body	Thyroid
Internal		
Sport fish ingestion	0.08533	0.02602
Commercial fish ingestion	0.00066	0.00017
Drinking water	0.35798	1.61299
External		
Shoreline	0.00291	0.00291
Swimming	0.00094	0.00094
Boating	0.00047	0.00047
Total	0.45	1.64

TABLE 11.2-14 LAKE ERIE SHORELINE COMMUNITIES

Community	Year 2000 Population[a]	Approximate Distance From Plant (miles)	Dilution Factor
Monroe County			
Estral Beach	294	2.5	45
Stony Point	936	1.5	45
Woodland Beach	1,514	3	77
Detroit Beach	1,327	4	77
Avalon Beach	495	9	77
Toledo Beach	79	11	77
Luna Pier	3,828	14	77
Toledo area	168,645	26	100

[a] Numbers in this column represent 50 percent of the projected population for the year 2000.

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Refer to Plant Drawing M-2033

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FIGURE 11.2-1

WASTE COLLECTOR P&ID

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Refer to Plant Drawing M-2040

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FIGURE 11.2-2

FLOOR DRAIN COLLECTOR P&ID

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FIGURE 11.2-3
DEMINERALIZERS P&ID

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Refer to Plant Drawing M-4798

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FIGURE 11.2-4

EVAPORATOR FEED "B" P&ID

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FIGURE 11.2-5

EVAPORATOR FEED "A" P&ID

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FIGURE 11.2-6

CHEMICAL WASTE
P&ID

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Refer to Plant Drawing M-2222

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FIGURE 11.2-7

WASTE SLUDGE P&ID

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FIGURE 11.2-8

CENTRIFUGE FEED P&ID

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Refer to Plant Drawing M-4942

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FIGURE 11.2-9

SPENT RESIN SLURRY P&ID

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Refer to Plant Drawing M-4943

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FIGURE 11.2-10

ASPHALT FEED P&ID

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Refer to Plant Drawing M-4944

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FIGURE 11.2-11

**EXTRUDER/EVAPORATOR
P&ID**

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Refer to Plant Drawing M-4945

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FIGURE 11.2-12

FILL STATION AUXILIARIES AND COOLING WATER BOOSTER PUMPS P&ID

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FIGURE 11.2-13

CAUSTIC FEED SYSTEM ISOLOK SAMPLING SYSTEMS AND MISCELLANEOUS SERVICE PIPING

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Refer to Plant Drawing M-5122

Figure Intentionally Removed
Refer to Plant Drawing M-2028

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FIGURE 11.2-15, SHEET 1

RADWASTE SYSTEM PROCESS FLOW DIAGRAM

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FIGURE 11.2-15, SHEET 2

RADWASTE SYSTEM PROCESS FLOW DIAGRAM

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FIGURE 11.2-15, SHEET 3

RADWASTE SYSTEM PROCESS FLOW DIAGRAM

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Refer to Plant Drawing M-2032

FIGURE 11.2-16, SHEET 1

RADWASTE SYSTEM
SUMP PUMP DIAGRAM

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Refer to Plant Drawing M-2032-1

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FIGURE 11.2-16, SHEET 2

RADWASTE SYSTEM SUMP PUMP DIAGRAM

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Refer to Plant Drawing M-2031

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FIGURE 11.2-16, SHEET 3

RADWASTE SYSTEM SUMP PUMP DIAGRAM

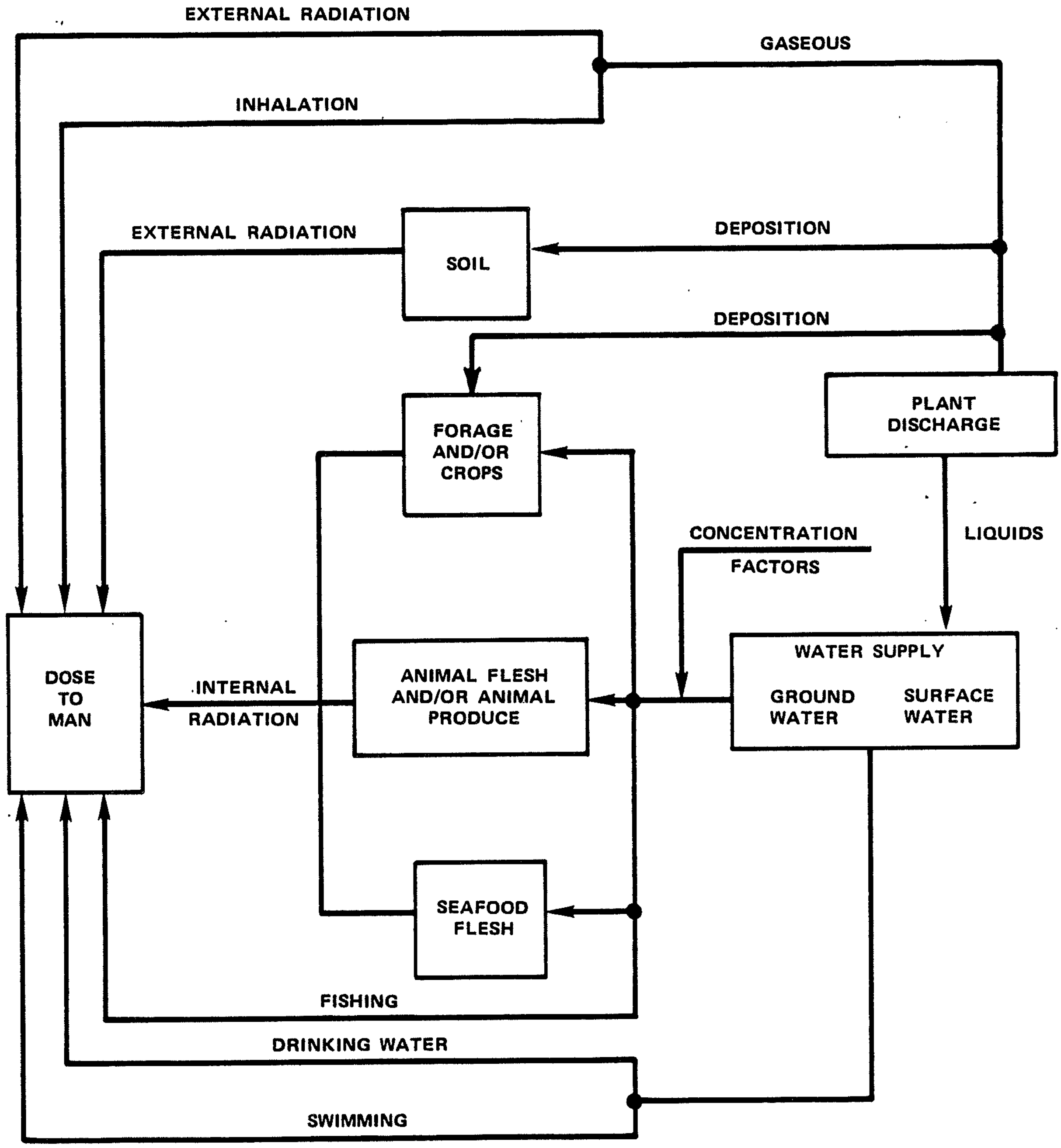

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FIGURE 11.2-17

EXPOSURE PATHWAYS TO MAN

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FIGURE 11.2-18, SHEET 1

SIDE STREAM LRWP SYSTEM P&ID

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Refer to Plant Drawing M-2512

FIGURE 11.2-18, SHEET 2

SIDE STREAM LRWP SYSTEM P&ID

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Refer to Plant Drawing M-2513

Fermi 2

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FIGURE 11.2-18, SHEET 3

SIDE STREAM LRWP SYSTEM P&ID

11.3 GASEOUS RADWASTE SYSTEM

11.3.1 Design Objectives

The design objectives of the gaseous radwaste system are to process and control the release of gaseous radioactive effluents to the site environs so that the releases are a small fraction of the concentration limits as defined in 10 CFR 20, Appendix B, and are as low as reasonably achievable, as required by 10 CFR 50, Appendix I; to keep iodine releases within the total yearly release limit of Regulatory Guide 1.42;* and to operate within the emission rates established in the Offsite Dose Calculation Manual radiological effluent controls.

Subsections 11.3.6 and 11.3.9 establish that the gaseous radwaste system adequately meets the above design objectives.

11.3.2 System Description

The largest single source of gaseous radwaste from the Fermi 2 plant is the offgas removed from the main condenser. For the treatment of this source of gaseous radwaste, the gaseous waste processing system, referred to as the offgas system, has been incorporated in the plant design. This system is discussed in Subsection 11.3.2.7.

Other sources of gaseous radwaste include releases from the turbine gland seal steam condenser and releases to the various plant ventilation systems from potential leakage of main steam and primary coolant. Although attempts are made to limit leakage to a minimum, small leaks at rates which make their detection difficult are expected. These other sources of gaseous waste are discussed in Subsections 11.3.2.1 through 11.3.2.6.

11.3.2.1 Turbine Gland Seal Steam

Steam is provided to the turbine gland seal to prevent air inleakage to the condenser during operation. Steam to the gland seal is provided from the main steam line or from the auxiliary boiler during startup and from the high-pressure turbine inner steam seal leakoffs during operation. The steam from the turbine gland seal and air inleakage is exhausted to the gland steam condenser where the steam is condensed. The condensate is returned to the main condenser. Subsection 10.4.3 provides a detailed description of the turbine gland sealing system.

The noncondensibles from the gland steam condenser contain a source of radioactive gaseous effluents from Fermi 2. Estimated sources from the gland steam condenser were based upon the parameters given in Appendix A of Regulatory Guide 1.42.

In order to reduce the concentration of short-lived radionuclides in offgas from the gland seal condenser, additional piping has been incorporated in the gland seal condenser exhaust system to provide a minimum 2-minute delay. Estimated releases from the turbine gland seal condenser are given in Table 11.3-1.

---

* Regulatory Guide 1.42 was withdrawn March 18, 1976, with the adoption of Appendix I to 10 CFR 50 and the development of a series of implementing guides.

11.3.2.2 Sources to Turbine Building Ventilation System

The source of radionuclides to the turbine building atmosphere is small potential leaks from valves in piping systems carrying main steam. Although attempts are made to limit this potential leakage to a minimum, small leaks are expected to occur. For calculational purposes, the total steam leakage into the turbine building is assumed to be 1700 lb/hr consistent with Regulatory Guide 1.42, Revision 1. Noble gas concentrations in the steam are presented in Table 11.1-2. Assumptions for iodine releases are the same as those provided in Appendix A of Regulatory Guide 1.42, Revision 1. The total main steam line flow is 15,221,000 lbm/hr for the design basis of 102 percent of uprated reactor power.

Due to the extremely high turbine building ventilation exhaust flow rates, treatment of this release path is not practicable. Within the turbine building area, ventilation flow is controlled by maintaining pressure differentials between the various turbine building areas. This ensures proper ventilation flow patterns and also prevents releases of radioactive gases to areas of the turbine building normally accessible during plant operation. In evaluating the ventilation system in the steam piping area (that is, the valve area and east and west reheater bays at Elevation 641 ft 6 in.), it was conservatively determined that a minimum 10-minute holdup is provided by the ventilation system. This allows adequate decay for short-lived isotopes. Monitoring of the turbine building ventilation exhaust is performed, and if the radioactivity concentration exceeds the monitor setting as described in Section 11.4, turbine building ventilation is terminated. The turbine building ventilation system is described in Subsection 9.4.4. The expected releases from the turbine building are listed in Table 11.3-1.

11.3.2.3 Sources to Reactor Building Ventilation System

Since the noble gas concentrations are negligible in the primary coolant liquid present in fluid systems located in the reactor building, only the release of radiohalogens from primary coolant leakage into the reactor building represents a source of radioactivity to the reactor building ventilation. A primary coolant leakage rate of 500 lb/hr was used in estimating a conservative radiohalogen source term. This value is the total of a number of minor leaks assumed to exist. The assumptions used in determining the quantity of radiohalogen releases are those presented in Appendix A of Regulatory Guide l.42, Revision 1. The estimated releases from the reactor building are given in Table 11.3-l.

Normally, ventilation of the reactor building is performed by the reactor/auxiliary building ventilation system, which does not process the ventilation effluent. However, if the radioactivity concentration in the release exceeds the associated exhaust radiation monitor setpoint (Section 11.4), ventilation by the reactor/auxiliary building ventilation system is terminated and the reactor building is ventilated and maintained under negative pressure with respect to outside atmosphere by the standby gas treatment system (SGTS). The reactor/auxiliary building ventilation system is described in Subsection 9.4.2.

11.3.2.4 Sources to Drywell Purge System

Neutron activation of air around the reactor pressure vessel (RPV) and potential small system leaks could provide sources of radioactive gases to the drywell atmosphere. Since the drywell is a closed system and is not normally vented, most isotopes will have decayed out prior to initiation of ventilation of the drywell. The atmosphere can be sampled prior to purging and is also monitored during purging. If high radiation levels are detected, the purge can be terminated or processed by the SGTS. Therefore, any release from the Fermi 2 drywell is expected to be negligible. The drywell purge system is described in Subsection 6.2.3.

11.3.2.5 Sources to Radwaste Building Ventilation System

The source of radioactive gases in the radwaste building could be from evaporation of leakage from equipment, from valves, or from the ventilation of atmospheric storage tanks. The iodine concentration in the liquid radwaste system is significantly lower than that in the primary coolant due to removal by processing and to dilution of the iodine by noncontaminated water entering the system from sumps. Assuming an average reduction of 100 for iodine in the liquid radwaste system, the radiohalogen release to the radwaste building atmosphere has been determined to be negligible.

11.3.2.6 Other Potential Sources of Radioactive Gaseous Waste

It will be necessary to vent certain tanks and discharge gases from specific laboratories and building service areas to a reactor building, turbine building, or radwaste building ventilation exhaust system. These additions are of a low level and add insignificant increments to the total radioactive gas releases.

11.3.2.7 Offgas System

The noncondensibles removed from the main condenser are the largest source of radioactive gaseous waste from the plant. In order to reduce the releases from this source, the offgas system has been incorporated in the plant. The offgas system consists of two effluent streams, one from the mechanical vacuum pump and the second from the steam-jet air ejectors. The offgas system is described in Figure 11.3-1 and shown schematically in Figure 11.3-2.

11.3.2.7.1 Mechanical Vacuum Pump Offgas

The mechanical vacuum pump is used before startup to reduce the condenser pressure to approximately 4 in. Hg abs, at which point the mechanical vacuum pumps stop and the steam-jet air ejectors are started manually.

The mechanical vacuum pump is also used for normal shutdowns, SCRAM related shutdowns, and during periods of low power operations when the Offgas system is not available. The expected quantity of gaseous radwaste released from these operations of the mechanical vacuum pump are also small. Controls for the release path contained in the Offsite Dose Calculation Manual (ODCM) are designed to prevent exceeding ODCM limits. An active mechanical vacuum pump trip on high radiation in the main steam lines will ensure that 10 CFR 50.67 limits are not exceeded on transient or “puff” releases. These controls prevent the release limits from being exceeded.

Since the mechanical vacuum pump is normally used only under the conditions stated above, it is an infrequent source of gaseous releases. The expected quantity of gaseous radwaste released from this source is dependent upon the chronology of events from initiation of shutdown to startup.

An estimate of the expected concentrations of gaseous radwaste from the mechanical vacuum pump during a startup can be made assuming that:

a. The plant operates with an 80 percent plant capacity factor

b. The average duration per shutdown is 18 days, assuming four shutdowns per year and a total of 20 percent downtime per year

c. The volume of the condenser is estimated to be 1.8 x 10^5 ft^3

d. For noble gases, offgas from the reactor is assumed to be carried to the condenser, at the full power rate, for 2 hr following shutdown of the steam-jet air ejectors

e. For iodine, the partition coefficient within the turbine condenser is taken as 10^{-4} $\frac{\mathrm{mCi/cm^3\ noncondensible}}{\mathrm{mCi/cm^3\ water}}$

Other parameters for iodine are as given in Appendix A to Regulatory Guide 1.42.

During startups, the rate of air removal by the mechanical vacuum pump is greater than the offgas flow rate through the steam-jet air ejector during normal operation. As a result, the offgas from the mechanical vacuum pump does not permit processing through the portion of the offgas system designed to process air ejector effluents. Also, since startup using the mechanical vacuum pump follows an outage period that is long enough to allow significant decay of most gaseous isotopes in the condenser, no processing is provided other than a 2-minute delay of the mechanical vacuum pump offgas. Estimated releases from this effluent stream are given in Table 11.3-1.

During mechanical vacuum pump operation for normal shutdowns, SCRAM related shutdowns, and operations during periods of low power operations when the Offgas system is not available, the release rate of the mechanical vacuum pump offgas is expected to be low. The controls applied to this release path will ensure that ODCM limits on instantaneous release, quarterly dose and annual dose due to untreated release are met. These limits are significantly below the levels originally estimated in Table 11.3-1. This allows mechanical vacuum pump operations for normal shutdowns, SCRAM related shutdowns, and during periods of low power operations when the Offgas system is not available.

11.3.2.7.2 Steam-Jet Air Ejector Offgas

In order to reduce backpressure on the turbine and to maintain turbine efficiency, noncondensible gases must be continuously exhausted from the condenser during plant operation. This is accomplished by the main condenser steam-jet air ejectors. The condenser offgas, which is the major source of the gaseous radwaste, contains hydrogen and oxygen generated by the radiolysis of water, air that leaks into the condenser, and radioactive gases consisting of activation and fission gases. About 98.5 percent of the radioactive gases that exit the RPV with the steam are very short-lived activation gases that have less than a 30-sec half-life, such as ^{16}N and ^{19}O. Additional activation gases are present in much smaller amounts, with half-lives of 10 minutes (^{13}N) and 110 minutes (^{18}F). The remaining radioactive gases, krypton and xenon, are noble gases and result from fissioning. The concentration of these noble gases depends on the amount of tramp uranium in the coolant and on the cladding surfaces, which is usually extremely small, and on the number and size of fuel-cladding leaks. Estimated concentrations of radioactive gases exiting the RPV and entering the offgas system are provided in Table 11.1-1.

In addition to the radiogases removed from the condenser, there are also radioiodines and radioactive particulate daughters due to the decay of krypton and xenon isotopes.

11.3.2.7.3 Radionuclide Inventories in the Offgas System

The calculated design-basis radionuclide inventories in components within the offgas system are presented in Table 11.3-2. Components identified in Table 11.3-2 are shown schematically in Figure 11.3-2.

11.3.2.7.3.1 Noble Gas Inventories

Noble gas inventories have been calculated by using equipment volume, condenser offgas release rate as listed in Table 11.1-2, and decay during residence in the equipment. Decay during transit between equipment was not considered. Residence time in equipment other than the charcoal beds was determined by:

$$T = \frac{V}{F} \qquad (11.3\text{-}1)$$

where

T = residence time

V = equipment volume

F = flow rate (see Subsection 11.3.3.1)

The residence times for the various equipment in the offgas system are:

a. Preheater - 0.2 sec

b. Recombiner - 0.5 sec

c. Condenser - 18 sec

d. Aftercooler - 30 sec

e. Precooler - 15 sec

f. Holdup pipe - 130 sec

g. Sand filter - 30 sec

h. Chiller - 18 sec

i. First charcoal bed - 2.66 days (Xe); 4 hr (Kr)

j. All charcoal beds - 16 days(Xe); 24 hr (Kr)

k. Afterfilter - 60 sec

The residence time for the noble gases in the charcoal delay beds was determined by

$$T = \frac{K_D M}{F} \quad (11.3\text{-}2)$$

where

K_D = dynamic adsorption coefficient, cm^3/g

M = mass of adsorbing material (charcoal), g

F = volumetric flow rate, cm^3/sec (see Subsection 11.3.3.1)

The values of K_D were determined experimentally for the installed Fermi system at the following conditions:

a. Percent moisture of charcoal - approximately 1.4 percent

b. Temperature of charcoal - 70°F

c. Gas pressure - 12.5 psia.

These are the nominal operating conditions in the charcoal delay portion of the offgas system. The derived test data obtained per design calculation were:

Gas	K_D Measure as cm^3/g	Residence Time
Kr	37.6	24.8 hours
Xe	629 – 688	17.3 – 18.9 days

These test results showed charcoal residence times longer than the design basis values of 24 hours and 16 days.

11.3.2.7.3.2 Daughter Product Inventory

Unlike noble gases, the daughter products are either washed out of the free volume in equipment such as condensers and directed to the liquid radwaste system, washed out and trapped on frost in equipment such as the chiller where they are later directed to the liquid radwaste system after the chiller is defrosted, or trapped in equipment such as the sand filter and charcoal beds. A daughter product removal of 100 percent was assumed for the following components:

a. Offgas condenser

b. Aftercooler

c. Precooler

d. Holdup pipe

e. Chiller

f. Sand filter

g. Charcoal beds

h. Afterfilter.

Daughter product activities in each piece of equipment were determined by calculating the quantity produced by decay of the parent during residence in the component, and then calculating the amount removed by decay. For equipment that removes these radionuclides by washout or retention, the concentration in the equipment effluent discharge was assumed to be zero. The equation used to calculate the daughter product inventories was the modified Bateman Equation for decay chain activity computation:

$$N_i(t) = P(\lambda_1.\lambda_2 \ldots \lambda_{i-1}).\sum_{j=1}^{i} \frac{\left(1-e^{-\lambda_j T}\right)}{\lambda_j \prod_{k \neq j}(\lambda_k - \lambda_j)} \qquad (11.3\text{-}3)$$

where

$N_i(t)$ = activity of ith isotope after time (t), lCi

T = equipment residence time, sec

P = continuous release rate, lCi/sec

In equipment that retains these daughter products, the concentrations increase until an equilibrium is reached or until the retention material is changed. The operating times assumed for equipment that retains these products are

a. Chiller (assumed to require defrosting after 6 hr of operation) - 6 hr

b. Charcoal beds - 10 years

c. Afterfilter - 10 years.

The inventories in such components were calculated using the following equation:

$$N_i(t) = P(1 - e^{-\lambda_1 T}) \left[(\lambda_1.\lambda_2 \ldots.\lambda_{i-1}) \sum_{j=1}^{i} \frac{\left(1-e^{-\lambda_j t}\right)}{\lambda_j \prod_{k \neq j}(\lambda_k - \lambda_j)} \right] \qquad (11.3\text{-}4)$$

where

$N_i(t)$ = activity of ith daughter isotope after time t in microcuries

t = operation or accumulation time, sec

T = equipment residence time, sec

11.3.2.7.3.3 Radioiodine Inventory

Major components in the offgas system were provided by Kraftwerk Union. Data on similar process streams of offgas systems provided by Kraftwerk Union and operating in West Germany have been obtained. These data show no detectable iodine entering the charcoal adsorbers. The iodine removal is not assumed to occur due to washout in the recombiner condenser, but rather is assumed to result from iodine reacting with the recombiner catalyst. The iodine inventory in the offgas system given in Table 11.3-2 reflects the data available through Kraftwerk Union and assumes that all iodine is removed in the recombiner.

11.3.2.7.4 Design Bases of the Offgas System

The design bases for the offgas system are

a. To process an annual average offgas rate equivalent to 100,000 μCi/sec after a 30-minute delay (See subsection 11.3.6)

b. To maintain the concentration of hydrogen in the gases from the air ejectors below its flammable limit

c. To provide protection against inadvertent release of significant quantities of gaseous and particulate radioactive material to the environs

d. To ensure that in-plant occupational radiation exposures due to operation of the offgas system are as low as practicable.

11.3.2.7.5 Process Description

Basically, the offgas system processes the condenser offgas by delaying the offgas so that significant decay of radionuclides is allowed before it is released from the plant. The delay is provided by charcoal, which impedes the flow of all gases; however, heavy gases such as krypton and xenon are affected more than are lighter gases. The charcoal provides about a 1-day delay for krypton and about a 16-day delay for xenon.

During plant operation, offgas discharged from the steam-jet air ejector is diluted with steam to keep hydrogen concentrations below 4.0 percent. The gas is heated by steam in the preheater, and enters the recombiner, where the hydrogen and oxygen are recombined catalytically into water. Diluting the gas with steam controls the hydrogen concentration and also provides control over temperature rise during the recombination. After recombination, the gases are cooled and dehumidified. The gas then enters a 2.2 minute (nominal) delay pipe which is followed by a sand filter. The gas is further cooled and enters the ambient temperature charcoal adsorbers. Chilling and drying the air improves the charcoal adsorbers' performance. The discharge from the adsorber system is filtered mainly to remove any charcoal fines that may have been carried out of the last charcoal bed. The gas is then pumped into the offgas discharge piping. The system vacuum pump is used to maintain a slightly negative pressure throughout the system, thus ensuring that any leakage would be into the system. The effluent from the offgas system is discharged from the plant after dilution in the reactor building ventilation system exhaust.

The condenser offgas system removes most of the activity from activation gases and reduces the activity due to fission gases by a factor of at least 90 (when compared to the 30-minute mixture). Essentially all of the hydrogen is removed from the offgas.

The ability to continuously process condenser offgas in the case of equipment failure is ensured by providing redundant standby equipment for each component in the offgas system, except for the six charcoal beds. Since the charcoal beds are passive equipment at ambient temperature and are at a slightly negative pressure, failure of a charcoal bed is unlikely.

The hydrogen concentration in the system is controlled by the addition of dilution steam upstream of the recombiner. Oxygen is injected into the 18" offgas manifold to ensure that hydrogen injected into the feedwater system via the Hydrogen Water Chemistry (HWC) System is recombined. Free hydrogen is essentially nonexistent at the outlet of the recombiner. Increased hydrogen concentration, which is measured in the 2.2-minute delay pipe, and the lack of a ΔT across the recombiner would provide indication of a recombiner failure. A switchover to the redundant hydrogen recombiner subsystem would be made.

Protection against inadvertent release of significant quantities of gaseous waste during system operation is accomplished by the following measures:

a. The system is maintained at a negative pressure, which ensures that air leakage is into the system

b. The system is designed to withstand the maximum pressure transient which would result from an instantaneous combination of a stoichiometric hydrogen-oxygen mixture

c. Radiation monitors on the delay line from the mechanical vacuum pumps would alarm should high radioactivity concentrations occur while these pumps are in use. Following an alarm, the plant operator can take proper action to correct/mitigate the situation. The mechanical vacuum pumps are also automatically tripped on main steam line high radiation.

d. The Reactor Building Exhaust Plenum Radiation Monitoring System measures the radioactivity in the Reactor Building exhaust plenum prior to discharge from the Reactor Building vent stack. This monitor will alarm in the main control room should high radioactivity concentrations be present in the Reactor Building or Offgas System exhausts. Following a high-radiation alarm, the plant operator can take proper action to correct the situation.

In-plant occupational radiation exposures due to system operation are maintained as low as practicable as follows:

a. Shielded rooms and a pipe tunnel are provided for the routing of piping, including field-routed piping carrying radioactive fluids

b. Adequate shielding is provided around the offgas system

c. The redundant equipment trains are completely isolated from each other so that if equipment servicing is required, offgas processing can be switched to the standby equipment, and maintenance can be performed on the off-line equipment.

11.3.2.7.6 System Availability

The offgas system operation is required during the operation of the plant. There are two independent 100 percent-capacity trains of equipment consisting of water separators, preheaters, recombiners, condensers, aftercoolers, and precoolers; there is also redundancy in the number of sand filters, chillers, mechanical filters, and water ring pumps. Upon failure of any component in one subsystem, a switchover is made to the redundant subsystem. Although the charcoal adsorbers are not redundant, system availability is protected since charcoal adsorber tanks can be bypassed individually. This arrangement ensures the operation of the offgas system at all times during the operation of the plant.

While there are redundant trains of the Offgas System equipment, the steam jet air ejector line, 2.2 minute delay piping, and the Offgas vent pipe are not redundant and are not required to be redundant. The limiting failure is that of the delay piping and this abnormal operating occurrence is addressed in the analysis in UFSAR Section 15.7.1.

11.3.2.7.7 Decontamination Factors

11.3.2.7.7.1 Particulate Removal

Since, in processing, the offgas is first passed through a sand filter followed by six activated charcoal adsorber beds, none of the particulate activity entering the system is expected to be discharged. Particulate daughter products of noble gas decaying within the charcoal beds are entrapped there. To further prevent particulate releases, charcoal fines in particular, the charcoal beds are followed with a high-efficiency particulate air (HEPA) filter rated at 99.9 percent efficient for all particles 0.3 μm and larger.

11.3.2.7.7.2 Radiogas Removal

Since radiogases are removed by decay, the decontamination factor will vary from isotope to isotope. Table 11.3-3 presents the estimated decontamination factor for each radiogas isotope, assuming a 24-hr holdup for krypton isotopes and a 16-day holdup for xenon isotopes.

11.3.3 System Design

The offgas system shown in Figure 11.3-1 is considered to consist of four subsystems: (1) the recombiner subsystem; (2) the air drying subsystem; (3) the charcoal adsorption subsystem; and (4) the water ring exhaust pump subsystem.

11.3.3.1 Design Parameters

Design parameters of the offgas system are:

a. Hydrogen - 186 cfm nominal at 14.7 psia and 130°F

b. Oxygen - 93 cfm nominal at 14.7 psia and 130°F

c. Air - 40 cfm nominal at 14.7 psia and 70°F

d. Steam - sufficient to reduce hydrogen concentration to ≤4.0 percent by volume at preheater inlet.

Carrier gas is the air inleakage from the main condenser after the radiolytic hydrogen and oxygen are removed by the recombiner. The sixth edition of Heat Exchange Institute Standards for Steam Surface Condensers, Paragraph S-16 c(2), indicates that, with certain conditions of stable operation and suitable construction, noncondensibles (not including radiolytic dissociation and trace gases) should not exceed 6 scfm for large condensers. The air inleakage for Fermi 2 has been considered as 40 scfm (nominal). However the plant can operate at an air inleakage flow higher than 40 scfm as long as the offsite dose rates do not exceed the applicable limits specified in the Technical specifications, and the offgas equipment does not exceed its capacity.

11.3.3.2 Design Pressure Transients

The most severe pressure transient that the system is postulated to experience would proceed as follows. The system is functioning normally; however, condenser air inleakage is so low as to be nondetectable. A recombiner failure occurs, but system switchover to the standby hydrogen removal train is not complete until a considerable quantity of H_2-0_2 gas, in stoichiometric proportions, has entered the vessels downstream of the condenser. Combustion cannot occur upstream of the condenser due to the presence of dilution steam and noncondensed air ejector steam. An ignition source that causes an instantaneous constant-volume combustion of gases is alleged to exist. The calculated pressure is postulated to exist everywhere in the offgas system exhaust pipe. The maximum pressure transient is 3l8 psig. To withstand this pressure transient, the offgas system (except for the water ring exhaust pumps) is designed for an upset pressure of 375 psia.

The recombiner is provided with a rupture disk for overpressure protection of the water separator, the tube side of the preheater, the recombiner, the shell side of the condenser, and the aftercooler. There are no isolating valves between these components and interconnecting piping. This is in accordance with the code requirement for overpressure protection in Article UG 125, ASME Boiler and Pressure Vessel Code Section VIII, Division 1.

In addition, safety valves are provided at the shell side of the preheater and relief valves are provided for the tube side of the condenser, aftercooler, and water ring cooler, for protection of the system piping and components against overpressurization.

11.3.3.3 Component Description

Each major component of the offgas system is described in the following subsections. Design parameters of offgas system components are listed in Table 11.3-4.

11.3.3.3.1 Water Separator

There is one water separator provided per train. The water separator is a vertical tank-shaped vessel. Gas enters near the bottom by way of a tangential nozzle. Water is removed by utilizing the cyclone principle. The gas passes through a stainless steel mesh demister before exiting through the top of the vessel. Detained water is drained to the condensate receiver tank by way of the loop seal.

11.3.3.3.2 Offgas Preheater

There is one offgas preheater provided per train. The purpose of the offgas preheater is to superheat the offgas. This is conducive to more efficient and dependable recombiner performance. The preheaters are flanged-head straight tube-type vessels. The shell side receives main steam which has been throttled to 160 psia. The steam condenses, giving up heat to the offgas that flows through the tubes. The shell-side water level is sensed and controlled, and the shell side is drained directly to the condenser. The tube side drains to the condensate receiver through the loop seal. A shell-side safety valve is provided that discharges into the offgas stream at the preheater inlet.

11.3.3.3.3 Catalytic Recombiner

There is one catalytic recombiner provided per train. The recombiners are vertical tank-shaped vessels. Offgas enters through the side of the vessel near the top. The gas passes down through a bed of homogeneous palladium catalyst that is supported on an aluminum oxide carrier material (pellet). The catalyst causes an exothermic reaction when the free hydrogen and oxygen in the offgas are being recombined into water. Normally, hydrogen concentration in the recombiner outlet will not exceed 20 ppm by volume. Hydrogen concentrations may exceed this value during system transients. The gas is discharged through a nozzle located in the bottom of the vessel. Each recombiner is equipped with thermocouples located at different depths in the catalyst so that a temperature profile for the bed can be continuously observed during operation. This allows the operator to monitor continuously for catalyst attrition.

Each recombiner is equipped with thermostatically controlled electric heaters located in the catalyst bed. These are used to maintain catalyst temperature in the standby recombiner so that system switchover can be accomplished without loss of recombination efficiency. Each recombiner is equipped with a rupture disk rated at 345 psig.

11.3.3.3.4 Offgas Condenser

There is one offgas condenser provided per train. The offgas condensers are horizontal U-tube flanged-head vessels. The tubes are free riding to minimize thermal stresses. Offgas entering the shell side is cooled and some of the moisture is condensed. The condensate drains into the condensate receiver tank through the four-inch loop seal manifold. Condensate from the condensate system is supplied to the tube side. Condensate flow is maintained only in the operating condenser.

11.3.3.3.5 Offgas Aftercooler

There is one offgas aftercooler provided per train. The offgas aftercoolers are straight-tube horizontal flanged-head heat exchangers. Turbine building closed cooling water (TBCCW) flows through the tubes. Offgas from the offgas condenser flows through the shell side, where additional moisture is condensed. The aftercooler drains, by way of the four-inch loop seal manifold, into the condensate receiver tank. Aftercooler discharge is essentially humid air. A demister is provided on the aftercooler outlet.

11.3.3.3.6 Precooler

There is one precooler provided per train. The precooler is a vertical vessel with a removable shell. The tubing design is serpentine with baffle plates. Throttled freon gas from a refrigeration system flows on the tube side. Offgas passes through the shell side and is cooled. The precooler discharges through a demister. Since the precoolers are the last vessels in the recombiner trains (hydrogen removal trains), they are followed by an isolation valve. Offgas passes from the operating precooler through the 2.2 minute delay pipe into the sand filter.

11.3.3.3.7 Sand Filters

There is one sand filter provided per train. Discharge from the delay pipe flows into a sand filter. The sand filters are vertical tanks. The offgas flows up through the sand. The purposes of the sand filters are to remove the nongaseous decay daughters and to attenuate a transient pressure wave, thus providing protection for the vessels downstream.

11.3.3.3.8 Chillers

There are three chillers shared between two trains. The chillers are vertical heat exchangers, flanged with a removable shell. The tubing is serpentine in design. Throttled freon gas from a refrigeration system circulates through the tubes. Offgas circulates through the shell side and is cooled. The tubing will become covered with frost during operation. Switchover to another chiller occurs automatically on a timed cycle, and the first chiller is automatically defrosted by heated freon circulating through the chiller coils. A third chiller is available as a standby unit. Each chiller is equipped with its own refrigeration subsystem. In the event of higher air-inleakage flows, chillers may be operated in manual mode (operating them in parallel) to lower the temperature of the offgas at the chiller outlet.

11.3.3.3.9 Charcoal Adsorbers

There are six charcoal adsorbers provided. The charcoal adsorbers are vertical tanks, each containing approximately 20,000 lb of activated charcoal adsorbent. All molecules, such as those of chemically inert krypton and xenon, and molecules, such as N_2 and O_2 gases, interact mechanically with the charcoal, the net result of which is that the flow of heavy gases is delayed. The delay of the radionuclides of krypton and xenon in the charcoal beds allows a significant portion of these gases to decay, thus reducing the activity of the offgas. Offgas flows up through the charcoal beds. All six adsorbers are piped together in a series arrangement. Because of their size and building space requirements, as well as the passive nature of these vessels, no standby adsorbers are provided. Bypass piping around each adsorber along with isolation valves are provided so that any adsorber can be isolated without inhibiting the use of the other adsorbers. Administrative controls preclude the possibility of bypassing the entire adsorber chain.

Each of the six bypass valves has a keylock switch in the main control room. The keys cannot be removed when bypass has been initiated. The keys are under the administrative control of the Shift Manager or his delegate. Administrative control ensures that no more than one charcoal adsorber can be bypassed at any one time when reactor power is greater than 5 percent.

11.3.3.3.10 Absolute Filter

There is one absolute filter provided per train. Two trains are provided, one of which is standby. The filters are housed in tank-type vessels. The filters are HEPA type, rated at 99.9 percent efficiency for all particles 0.3 μm and larger. The filters are replaceable cartridge-type units, with three cartridges in parallel per absolute filter.

11.3.3.3.11 Water Ring Exhaust Pumps

There is one water ring exhaust pump provided per train. The water ring pumps are used to maintain the system at a slightly negative gage pressure. Thus, should leaks occur, they would leak into the system. One water ring pump operates; the other is a standby unit. Associated with each water ring pump is a ring water buffer tank and a ring water cooler. In operation, a two- phase air/water mixture is discharged by the pumps. This mixture enters the buffer tank where the water is separated and the air is discharged to the reactor building vent. Water drains from the buffer tank through the cooler and returns to the pump.

A water ring pump of proven reliability is used here to hold a slight negative pressure in the offgas system. In the event of higher air inleakage flows, the two water ring exhaust pumps may be operated in parallel to maintain the vacuum in the main condenser.

11.3.3.3.12 Component Drains

The water separators, preheaters (tube side), condensers, and aftercoolers drain into a drain receiver tank by way of a loop seal manifold. Each vessel drain is routed individually to the four-inch loop seal manifold and is equipped with a hand-operated shutoff valve. The receiver tank is vented to the offgas condenser gas outlet. Each vent has a motor-operated shutoff valve. The drain receiver tank is drained, by means of a level controller, into the condensate receiver tank. The condensate tank is vented to the main turbine condenser, and is drained by means of pumps that transport the condensate back to the main turbine condenser.

The steam-jet air ejector intercondensers are drained by means of a manifold and loop seal that are connected directly to the condensate receiver tank. Condensate in the steam-jet air ejector exhaust manifold is drained directly into a collector tank. Condensate in the delay pipes is drained into collector tanks that are drained via level controllers into the condensate receiver tank.

Condensate in the vacuum manifold is drained into a collector tank. When the tank is full, the pipe connecting the tank and manifold is valved shut. The tank is vented to the steam-jet air ejector exhaust manifold and then drained into the condensate receiver tank. After draining, the vent is closed and the valve in the connecting pipe is opened.

Condensate does not form in the sand filter, absolute filter, or adsorbers.

11.3.3.3.13 Component Isolation

Each of the two hydrogen removal trains (i.e., those components from the water separator up to and including the precooler) is located in a separate cell. The trains are completely isolated from each other. One system operates continuously and the other serves as a standby. Because of the high activity of the offgas, it is impossible to perform any service on the operating train. Thus, upon malfunction, operation can be shifted to the standby train without interrupting plant operation. Because either train may be isolated, service can be performed on one train while the other operates.

11.3.3.4 Quality Group Classification

A detailed discussion of equipment Quality Group classification is presented in Subsection 3.2.2. This classification meets the criterion of Regulatory Guide 1.26 since the single failure of any component does not result in an offsite dose in excess of 0.5 rem. This is demonstrated in Subsection 15.11 where the analysis of the offgas system failure is presented.

11.3.3.5 Seismic Classification

Since an assumed seismically induced total failure of the offgas system would not result in an offsite dose in excess of 0.5 rem as specified in Regulatory Guide 1.29, the offgas system does not require Category I design. The analysis of the offgas system failure is provided in Section 15.11.

11.3.3.6 Offgas System Instrumentation and Control

The offgas system is monitored for radiation level at two locations: at the discharge of the 2.2 minute delay pipe and in the reactor building exhaust plenum. The radiation monitor at the discharge of the 2.2 minute delay pipe continuously monitors radioactivity release from the reactor and therefore continuously monitors the degree of fuel leakage. This radiation monitor is used to provide an alarm on high radiation in the offgas. The monitor has no control function.

The radiation monitor for the reactor building exhaust plenum continuously monitors the effluents released from the charcoal beds. If high radiation levels should occur in the discharge of the offgas system, this monitor would alarm in the main control room. Upon receipt of a high radiation alarm, the plant operator can evaluate the situation and initiate the proper action.

The discharge from the mechanical vacuum pump downstream of the 2-minute delay pipe is also monitored as discussed in Subsection 11.4.3.8.2.13.

Offgas system process radiation monitors are discussed further in Subsection 11.4.3.8.2.2.

This system is also monitored by flow, temperature, and pressure instrumentation. In addition, it is monitored by a hydrogen analyzer to ensure correct operation and control and to ensure that hydrogen concentration is maintained below the flammable limit. Oxygen concentration is monitored at the inlet to the delay piping. The Hydrogen Water Chemistry System is tripped on high or low oxygen concentrations. Process monitors are shown in Figure 11.3-1. The offgas system is normally operated automatically; upon operator initiative, however, the equipment can be operated from the main control room. The operator is thus in control of the system at all times, regardless of system operating mode.

System monitors are discussed in Subsection 7.7.2.6. The principal system instrumentation for significant monitored process parameters is listed in Table 11.3-5.

11.3.4 Operating Procedures

11.3.4.1 Startup

As the reactor is pressurized, steam is supplied to the preheater. The recombiner is preheated by means of electric heaters. With the recombiners preheated, charcoal adsorbers are valved in, or initially bypassed to prevent moisture damage below 5 percent power and the main condenser at approximately 4 in. Hg abs, the steam-jet air ejectors are started. As the condenser is pumped down and the reactor power is increased, the recombiner inlet stream is diluted to less than 4.0 percent H_2 (by volume) by a regulated steam supply and the recombiner outlet is maintained at less than 20 ppm hydrogen.

11.3.4.2 Normal Operation

After startup, the noncondensibles pumped by the steam-jet air ejector stabilize. Recombiner performance is closely followed by means of the recorded temperature profile of the recombiner catalyst bed. The hydrogen effluent concentration is measured by a hydrogen analyzer. Below 5 percent power as an option to the above stated method, the mechanical vacuum pumps may be used.

Normal operation is terminated when steam pressure to the steam jet air ejectors is insufficient for operation by closing off steam to the steam-jet air ejectors and preheaters.

11.3.4.3 Charcoal Bypass Mode

There is a charcoal adsorber bypass line that can be used to bypass any single charcoal adsorber. The activity is monitored by a process radiation monitor upstream of the reactor building vent that produces a high radiation alarm. The alarm setting is covered in Subsection 11.4.3.8.2.2.

11.3.5 Performance Tests

This system is in continuous operation during normal plant operation and does not require specific testing to ensure operability. Process equipment is continuously monitored to determine if process parameters are within design limits, as shown in Figure 11.3-1. Monitor equipment is calibrated and maintained according to a specific schedule and upon indication of monitor malfunction.

Process radiation monitors located downstream of the 2.2-minute delay line and downstream of the charcoal beds in the reactor building exhaust plenum provide adequate indication of the system's ability to reduce the radiogas concentration in this effluent.

To ensure that the hydrogen concentration is within design limits, the recombiner performance is continuously monitored by catalyst bed thermocouples monitoring bed temperature profiles and by a hydrogen analyzer measuring the hydrogen concentration of the recombiner effluent.

11.3.6 Estimated Releases

The potential sources of gaseous radwaste releases have been discussed in Subsections 11.3.2.1 through 11.3.2.7. Calculated releases from these potential sources are tabulated in Table 11.3-1. Anticipated operational occurrences would not signifi-cantly vary the total yearly release value because the 100,000 μCi/sec offgas rate after 30 minutes decay is an annual average value. The value of 100,000 μCi/sec is a conservative annual average, and offgas rate is expected to be above this value only for short periods of time.

Table 11.3-6 provides the calculated yearly average radionuclide concentrations at the restricted boundary of the site using the maximum yearly average χ/Q. The information in this table demonstrates that the design objectives of the gaseous radwaste system are met.

11.3.7 Release Points

The two release points for normal gaseous radwaste effluents from Fermi 2 are the reactor building vent and the turbine building vent. These release points are indicated in Appendix 11A Figure III-1.

The reactor building vent is cylindrical in shape, extends 22.5 ft above the top of the reactor building and is 7 ft 2 in. in diameter. The vent centerline is 8 ft 6 in. from the east wall of the reactor building and 9 ft 3 in. from the south wall of the reactor building. The top of the vent is at Elevation 761 ft (New York Mean Tide, l935) and the grade is 583 ft. The exhaust from this vent is approximately 101,940 cfm at a velocity of 2529 fpm.

The turbine building vent is rectangular in shape, extends 4 ft above the upper roof over the turbine building and has a cross-sectional area of approximately 416 ft^2. The top of the vent is at Elevation 714.5 ft (New York Mean Tide, 1935). The exhaust from the vent is approximately 315,900 cfm at a velocity of 759 fpm.

The greatest fraction of the gaseous activity released from the plant will be from the offgas system and the turbine gland seal exhaust. Both of these releases are mixed with the reactor building ventilation exhaust before they leave the plant. Assuming the zero enthalpy for air is fixed at 32°F, the normal heat value of the gland seal exhaust is 248,000 Btu/hr and the normal heat value for the offgas system exhaust is 1650 Btu/hr.

The radwaste building vent is a third ventilation release point (see Figure 9.4-5). The radwaste building ventilation system exhaust is discharged via the radwaste building vent under normal operating conditions through HEPA filters to remove particulate radioactive material.

The radwaste building vent is rectangular in shape, extends 54 ft above the lower roof of the turbine building, and has a cross-sectional area of approximately 16.65 ft^2. The vent centerline is approximately 383 ft from the south wall and 78 ft from the east wall of the turbine building. The top of the vent is at Elevation 729 ft (New York Mean Tide, 1935). The exhaust from the vent is approximately 38,519 cfm at a velocity of 2313 fpm.

11.3.8 Dilution Factors

Estimates of annual average offsite atmospheric dilution factors are presented in Section 2.3. Calculations are provided of the estimated values of χ/Q for 16 radial sectors to a distance of 50 miles from the plant for ground-level releases. The maximum annual average site boundary χ/Q value has been determined to be to the NNW site boundary and is 1.15×10^{-6} sec/m^3.

11.3.9 Estimated Doses

From Table 11.3-1, it can be observed that the calculated radioactive gaseous releases are composed mostly of noble gases with halogens contributing only a small fraction. Since the noble gases do not react chemically with other substances under normal conditions, there is no physical basis for their transport through food chains or reconcentration within the human body. Thus, the most significant exposure pathway for released noble gases is direct external radiation to the skin and whole body.

The opposite is true of the released radioiodines for which inhalation and food chain transport are the critical pathways.

External radiation from iodine is generally insignificant in comparison with the internal dose derived through inhalation and ingestion.

11.3.9.1 External Dose From Gaseous Cloud Immersion

The determination of the external dose from gaseous cloud immer-sion for the "maximum-exposed individual" and the population can be performed using the International Commission on Radiological Protection (ICRP) recommended semi-infinite sphere model (Reference 1). The following relationship was used to determine the dose rate from this source:

$$D(rem/yr) = (0.259)(\chi/Q) \begin{cases} \sum_i \overline{E}_{\gamma,i} Q_i \text{ (for whole body dose)} \\ \text{or} \\ \sum_i \left(\overline{E}_{\gamma,i} + \overline{E}_{\beta,i}\right) Q_i \text{ (for skin dose)} \end{cases} \quad (11.3\text{-}4)$$

where

χ/Q = applicable annual average effluent concentration normalized by source strength, sec/m^3

$E_{\gamma,i}$ = average energy of gamma disintegration of ith radionuclide, MeV

$E_{\beta,i}$ = average energy of beta disintegration of ith radionuclide, MeV

Q_i = annual average activity release for ith radio- nuclide, Ci/yr

0.259 = constant necessary to yield dose rate rems/yr

The normalization constant 0.259 is developed from the following equation:

$$0.259 = (0.5)\left(1.6 \times 10^{-6}\,\frac{\text{ergs}}{\text{MeV}}\right)\left(10^{-2}\,\frac{\text{g-rads}}{\text{erg}}\left(1\,\frac{\text{rem}}{\text{rad}}\right)\right)(1.13)\left(3.7 \times 10^{10}\,\text{dis}/_{\text{sec} - \text{Ci}}\right)\left(\frac{1}{1.29\times10^{3}\text{gair/m}^{3}}\right) \qquad (11.3\text{-}5)$$

where

0.5 = geometry factor accounting for the fact that receptor is irradiated from half the whole available solid angle

1.13 = factor to account for increased stopping power of tissue relative to air for β's and secondary electrons produced by x- and δ- radiation (Section 11.2 and Reference 1)

The basic assumption of this model is that the energy absorption at any point inside an infinite medium of homogeneous material of uniform radioactivity concentration is equal to the energy source from that point. Use of the infinite sphere model provides conservative results because:

a. The surrounding cloud of radioactivity is not infinite in dimension

b. The concentration is not uniform, but is a maximum at the centerline

c. The spatial flux depression caused by the presence of the source-free body in the infinite medium is not accounted for.

Direct exposure to a cloud of radioactivity results in a dose to the skin or to the whole body depending upon the type of radiation emitted. The radiation of interest in this report consists of beta and gamma components. Beta particles and gamma rays are assumed to contribute to the skin dose; however, only gamma rays are assumed to contribute to the total-body dose.

11.3.9.1.1 Maximum Individual External Exposure From Cloud Immersion

For the purpose of estimating the potential annual dose, a hypothetical maximum-exposed individual is assumed to reside at the NNW site boundary continuously over a period of 1 full year, unshielded by housing and clothing. These conservative assumptions resulted in a maximum individual whole-body dose rate of 4.6 mrem/yr and an external skin dose rate of 8.9 mrem/yr.

11.3.9.1.2 Population Exposure From Cloud Immersion

The general relationship presented earlier for the skin dose and external whole-body dose was employed to determine the population dose. The estimated population distributions within 50 miles of the plant, for the years 1980, 2000, and 2020, as defined in Figures 2.1-7, 2.1-9, and 2.1-11, were used for this purpose. The annual segment population exposures, the product of the segment populations and the sector average dose rates, are summed over all 160 segments to evaluate the total population exposure within 50 miles.

The results are summarized as follows:

Year	Population Within 50 Miles of the Site	Annual Man-Rem Within 50 Miles of the Site	
		Whole Body	Skin

1980	6,100,000	1.5×10^2	3.1×10^2
2000	8,200,000	2.2×10^2	4.2×10^2
2020	12,000,000	3.0×10^2	5.8×10^2

11.3.9.2 External Dose From Contaminated Land Surface

An individual downwind from the plant can receive external radiation from material deposited on the ground by a passing radioactive cloud. Airborne radioactive material can be deposited on the ground by dry deposition, rainout and washout, and can consist of any material in the cloud except for the noble gases and tritium (Reference 2).

The whole-body dose from deposited activity was calculated using the equation:

$$D(\mathrm{mrem/yr}) = \sum Q_i(\chi/Q)(V_{gi})(T_i/0.693)(DCF)_i \ldots \left(10^6\,\frac{\mu\mathrm{Ci}}{\mathrm{Ci}}\right)\left(10^{-4}\,\frac{\mathrm{m}^2}{\mathrm{cm}^2}\right)\left(10^3\,\frac{\mathrm{mrem}}{\mathrm{rem}}\right) \tag{11.3-6}$$

where

Q_i	=	release rate of isotope i, Ci/yr
χ/Q	=	annual average effluent concentration normalized by source strength, sec/m^3
V_{gi}	=	deposition velocity of radionuclide is 0.01 m/sec (Reference 3)
T_i	=	radiological half-life of radionuclide i, years
$(DCF)_i$	=	dose conversion factor of radionuclide i, rem/yr per μCi/cm^2

The dose conversion factors for gamma and beta radiation were obtained from Reference 4. The calculated beta exposure rates were reduced by a factor of two to account for the self-shielding of the human body against fission product beta radiation.

The whole-body dose to the maximum-exposed hypothetical individual at the NNW site boundary was calculated using an effective deposition velocity of 0.015 m/sec for the iodines, the only significant contributors. It was calculated that an annual whole-body dose of 0.08 mrem from gamma radiation would result. Including the beta contribution, a body surface dose of 0.23 mrem/yr was calculated.

11.3.9.3 Internal Exposure From Gaseous Effluents

Release radionuclides must be either inhaled or ingested in order to yield internal radiation exposure. Ingestion requires that the physical transport of the radioactivity be through some form of food chain. This is possible for the radioactive halogen isotopes. Inhalation is a significant pathway for the radioactive halogens and tritium.

11.3.9.3.1 Internal Exposure From Released Noble Gases

Since the noble gases do not react chemically with other substances, there is no physical basis for their transport through food chains or reconcentration within the human body.

In terms of continued inhalation and absorption in the body, both krypton and xenon may develop in physical solution, chiefly in the body water and fat (Reference 5). Several human exposure experiments revealed that inhalation of relatively large amounts of radioactive noble gases resulted in very low tissue exposures (References 6 and 7). In general, it may be estimated that the internal dose from radioactive noble gases dissolved in body tissue following inhalation from a cloud is negligible (i.e., less than 1 percent of the associated external whole-body dose) (Reference 8).

11.3.9.3.2 Internal Exposure From Released Radioactive Halogens

In addition to the noble gases, small amounts of radioactive halogens are anticipated to be released as gaseous effluent from Fermi 2. Iodine is an insignificant contributor to the external whole-body dose, but may produce potentially significant internal doses due to the preferential concentration of iodine in the human thyroid gland. Iodine may enter the body either through inhalation or by ingestion. The most critical pathway for environmental transport of the routine release of radioiodine is the pasture-cow-milk-Man pathway.

11.3.9.3.2.1 Iodine Inhalation Thyroid Dose

Exposure rates have been computed for the inhalation of iodine. The dose rate has been estimated using Regulatory Guide 1.42 (Reference 9). For the infant, the inhalation dose is given by the following formula:

$$D(\text{mrem/yr}) = [4.8 \times 10^5\ Q_{131} + 1.2 \times 10^5\ Q_{133}]\ (\chi/Q)R \qquad (11.3\text{-}7)$$

where

Q_{131}, Q_{133} = release rate of ^{131}I and ^{133}I, Ci/yr

χ/Q = applicable annual average effluent concentration normalized by source strength, sec/m^3

R = dimensionless iodine cloud depletion factor, assumed to equal 1

4.8×10^5, 1.2×10^5 = constant terms that take intoaccount breathing rate of infant and dose conversion factor $\frac{\text{mrem} - \text{m}^3}{\text{Ci} - \text{sec}}$

For the adult, the dose due to inhalation is determined from the equation

$$D(\text{mrem/yr}) = [4.0 \times 10^5\ Q_{133} + 9.8 \times 10^4\ Q_{133}]\ (\chi/Q)R \qquad (11.3\text{-}8)$$

The constant terms in this equation take into account the breathing rate of the adult and dose conversion factor for each isotope. The cloud depletion factor is assumed equal to 1. The maximum annual iodine-induced thyroid inhalation exposure to an adult was calculated to be 0.37 mrem/yr. For the child, the corresponding exposure is 0.46 mrem/yr.

11.3.9.3.2.2 Thyroid Milk Ingestion Dose

Although the radioiodines will be released initially in gaseous forms, they may be deposited on grass, ingested by a grazing cow, and subsequently secreted in milk. Various mathematical models have been devised to estimate the dose to the thyroid via this route. In all cases, the exposure is inversely proportional to the mass of the thyroid gland. The most sensitive receptor in the population, in terms of whole thyroid dose per unit intake, is therefore a young child or infant who would have a very small thyroid. Also, the relative radiosensitivity of the thyroid decreases markedly with age. Since the rate of milk ingestion is important in determining the dose, the most critical receptor is not a newborn infant but is more likely to be a child 6 months to 1 year in age.

For the child, the dose was calculated using Regulatory Guide 1.42 (Reference 9). The following formula gives the child dose:

$$D(\text{mrem/yr}) = [1.15 \times 10^8\, Q_{131} + 2.12 \times 10^6\, Q_{133}]\,(\chi/Q)R \qquad (11.3\text{-}9)$$

where

R = dimensionless iodine cloud depletion factor, assumed equal to 1

Q_{131}, Q_{133} = release rate of iodine ^{131}I and ^{133}I, Ci/yr

χ/Q = applicable annual average effluent concentration normalized by source strength at location of nearest cow (sec/m^3)

1.15×10^8, 2.12×10^6 = constant terms that take into account milk ingestion rate of the child, fractional thyroid deposition value from human ingestion, and dose conversion factor $\frac{\text{mrem} - \text{m}^3}{\text{Ci} - \text{sec}}$

The site nearest Fermi 2 at which milk is known to be produced from grazing cows is located about 3 miles to the north-northwest. The applicable χ/Q value for this location has been determined to be 1.27×10^{-7} sec/m^3. It was assumed that the cows graze 5 months per year. The maximum potential thyroid dose to a child from this milk source was calculated to be 2.2mrem/yr.

11.3.9.3.2.3 Adult Thyroid Milk Ingestion Dose

The following model (References 10 and 11) was employed to compute the adult thyroid milk dose from the release of radioiodines:

$$D(\text{rem/yr}) = (\chi/Q)\frac{V_{g_i}K_c I_d}{\lambda_{g_i}} A_i Q_i (2.74 \times 10^3) \qquad (11.3\text{-}10)$$

where

2.74×10^3 = conversion factor changing Ci/yr to µCi/day

V_{gi} = deposition velocity of radionuclide onto pasture 0.015 m/sec; (Reference 3)

K_c = (µCi/l)/(µCi/m^2); milk/grass activity ratio

I_d = adult milk ingestion rate, 1.0 1/day

A_i = dose conversion factor for adult, $\frac{rem}{yr} / \frac{\mu C_i}{day}$

λ_{gi} = mean lifetime for i^{th} isotope on the ground, $days^{-1}$

The maximum potential thyroid dose to an adult was calculated to be 0.44 mrem/year.

11.3.9.3.2.4 Adult Human Thyroid Dose Via Leafy Vegetables

The model for calculation of doses due to ingestion of leafy vegetables having radioiodine deposited on them is taken from Reference 9 with the exception that no cloud depletion is assumed. The model assumes the consumption of 18 kg of fresh leafy vegetables over a period of 3 months. The resulting equation for dose rate due to ingestion of leafy vegetables is:

$$D(mrem/yr) = [2.1 \times 10^6\ Q_{131} + 8.3 \times 10^4\ Q_{133}]\ (\chi/Q)(R) \qquad (11.3\text{-}11)$$

where

R = dimensionless iodine cloud depletion factor, assumed equal to 1

χ/Q = applicable annual average effluent concentration normalized by source strength, sec/m^3

2.1×10^6, 8.3×10^4 = constant term which takes into account amount of leafy vegetables ingested, fractional thyroid deposition dose from human ingestion, and dose concentration factor, $\frac{\mathrm{mrem - m^3}}{\mathrm{Ci - sec}}$

For Fermi 2, it was assumed that the nearest garden was located at the site boundary in the direction with the highest χ/Q value, north-northwest. The total dose via the ingestion of leafy vegetables is 0.95 mrem/yr.

11.3.9.3.3 Internal Exposure From Released Tritium (Released As Vapor)

It is anticipated that approximately 52.5 Ci/yr of tritium will be released from Fermi 2. For tritium, the inhalation dose has been estimated using the following equation:

$$D(\mathrm{rem/yr}) = \sum / Q_i\ (\chi/Q)\ (\mathrm{BR})(\mathrm{DCF})_i \left(10^6 \frac{\mu\mathrm{Ci}}{\mathrm{Ci}}\right)\left(\frac{1\ \mathrm{yr}}{365\ \mathrm{days}}\right) \qquad (11.3\text{-}12)$$

where

Q_i = release rate of tritium, Ci/yr

BR = breathing rate, m^3/sec

$(DCF)_i$ = dose conversion factor for tritium, $\frac{\mathrm{rem}}{\mathrm{yr}} / \frac{\mu\mathrm{Ci}}{\mathrm{day}}$

Since the tritium can rapidly be taken into the body by skin absorption (Reference 12), the total tritium uptake by the body was assumed to be twice the rate due to inhalation alone as recommended by the ICRP (Reference 1). The conversion factor was assumed to be 4.627 x 10^{-2} rem/yr per μCi/day, as derived from Reference 5.

The resultant whole-body dose is 3.6×10^{-3} mrem/yr.

11.3.9.4 Summary of Estimated Doses

Table 11.3-7 presents a summary of the doses to the hypothetical maximum-exposed individual by release pathway.

11.3 GASEOUS RADWASTE SYSTEM

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TABLE 11.3-1 EXPECTED GASEOUS RELEASES FROM FERMI 2 (ACTIVITY RELEASE RATES BASED ON 3499 MWt)

		SOURCE OF RELEASE						SOURCE OF RELEASE				
		Reactor Building Ventilation (R.B. Vent)		Turbine Building* Ventilation (R.B. Vent)		Mechanical Vacuum Pump (R.B. Vent)		Turbine Gland Seal Condenser (R.B. Vent)		Offgas System (R.B. Vent)		
Isotope	Half-Life	µCi/sec	Ci/yr	µCi/sec	Ci/yr	µCi/sec	Ci/yr	µCi/sec	Ci/yr	µCi/sec	Ci/yr	Total Curies/Year
Kr-83m	1.86 hr			4.04E-01	9.68E+00			3.12E+00	7.91E+01	4.62E-01	1.14E+01	1.0E+02
Kr-85m	4.4 hr			7.09E-01	1.77E+01			6.24E+00	1.56E+02	1.45E+02	3.64E+03	3.8E+03
Kr-85	10.74 year			2.33E-02	6.04E-02	1.04E+01	6.35E-01	1.04E-02	2.60E-01	2.08E+01	5.20E+02	5.2E+02
Kr-87	76 minutes			2.31E+00	5.52E+01			2.08E+01	5.20E+02	4.12E-02	1.04E+00	5.8E+02
Kr-88	2.79 hr			2.24E+00	5.83E+01			2.08E+01	5.20E+02	5.36E+01	1.35E+03	1.9E+03
Kr-89	3.18 minutes			1.77E+00	4.47E+01			8.74E+01	2.19E+03			2.2E+03
Kr-90	32.3 sec			8.44E-05	2.08E-03			2.29E+01	5.72E+02			5.7E+02
Kr-91	8.6 sec							2.19E-02	5.52E-01			5.0E-01
Xe-131m	11.96 days			1.80E-05	4.47E-02	2.91E+00	1.67E-01	1.56E-02	3.95E-02	6.17E+00	1.56E+02	1.6E+02
Xe-133m	2.26 days			3.47E-02	2.50E-01	6.56E-01	3.75E-02	3.02E-01	7.60E+00	2.23E+00	5.62E+01	6.4E+01
Xe-133	5.27 days			9.67E-01	2.50E-01	4.27E+02	2.39E+01	8.53E+00	2.19E+02	1.04E+03	2.60E+04	2.6E+04
Xe-135m	15.7 minutes			2.00E+00	5.00E+01			2.50E+01	6.24E+02			6.7E+02
Xe-135	9.16 hr			2.36E+00	6.56E+01			2.29E+01	5.72E+02			6.4E+02
Xe-137	3.8 minutes			2.95E+00	7.39E+01			1.04E+02	2.60E+03			2.7E+03
Xe-138	14.2 minutes			6.54E+00	1.67E+02			8.43E+01	2.08E+03			2.2E+03
Xe-139	41 sec			1.02E-03	2.60E-02			2.91E+01	7.39E+02			7.4E+02
Xe-140	13.6 sec							6.76E-01	1.67E+01			1.7E+01
N-13	9.99 minutes			7.43E-01	1.87E+01			1.04E+01	2.60E+02			2.8E+02
F-18	109.8 minutes			8.25E-01	2.08E+01			7.80E+00	1.98E+02			2.2E+02
O-19	26.8 sec							4.27E+01	1.04E+03			1.0E+03
Br-83	2.4 hr	3.81E-04	1.25E-02	1.24E-02	3.12E-01			1.11E-03	2.81E-02			3.5E-01
Br-84	31.8 minutes	6.85E-04	2.19E-02	1.85E-02	4.68E-01			1.95E-03	4.89E-02			5.4E-01
Br-85	3.0 minutes	4.32E-04	1.35E-02	1.45E-02	3.64E-01			7.85E-04	1.98E-02			4.0E-01
I-131	8.065 days	3.30E-04	1.04E-02	1.11E-02	2.81E-01			9.91E-04	2.39E-02			3.2E-01
I-132	2.284 hr	3.03E-03	9.57E-02	9.90E-02	2.50E+00			8.67E-03	2.19E-01			2.8E+00
I-133	20.8 hr	2.25E-03	7.08E-02	7.43E-02	1.87E+00			6.61E-03	1.67E-01			2.1E+00

TABLE 11.3-1 EXPECTED GASEOUS RELEASES FROM FERMI 2 (ACTIVITY RELEASE RATES BASED ON 3499 MWt)

		SOURCE OF RELEASE						SOURCE OF RELEASE				
		Reactor Building Ventilation (R.B. Vent)		Turbine Building* Ventilation (R.B. Vent)		Mechanical Vacuum Pump (R.B. Vent)		Turbine Gland Seal Condenser (R.B. Vent)		Offgas System (R.B. Vent)		
Isotope	Half-Life	μCi/sec	Ci/yr	μCi/sec	Ci/yr	μCi/sec	Ci/yr	μCi/sec	Ci/yr	μCi/sec	Ci/yr	Total Curies/Year
I-134	52.3 minutes	6.09E-03	1.87E-01	1.81E-01	4.58E+00			1.74E-02	4.37E-01			5.2E+00
I-135	6.7 hr	3.29E-03	1.04E-02	1.11E-01	2.81E+00			9.50E-03	2.39E-01			3.1E+00
H-3***	12.262 years											5.25E+01
Sr-89	50.8 days			7.02E-04	1.77E-02							1.8E-02
Sr-90	28.9 years			5.37E-05	1.25E-03							1.2E-03
Sr-91	9.67 hr			1.53E-02	3.85E-01							3.9E-01
Sr-92	2.69 hr			2.35E-02	5.93E-01							5.9E-01
Zr-95	65.5 days			9.08E-06	2.29E-04							2.3E-04
Zr-97	16.8 hr			7.02E-06	1.77E-04							1.8E-04
Nb-95	35.1 days			9.50E-06	2.39E-04							2.4E-04
Mo-99	66.6 hr			9.07E-03	2.29E-01							2.3E-01
Tc-99m	6.007 hr			6.19E-02	1.56E+00							1.6E+00
Tc-101	14.2 minutes			1.95E-02	4.79E-01							4.8E-01
Ru-103	39.8 days			4.13E-06	1.04E-04							1.0E-04
Te-132	78 hr			1.11E-02	2.71E-01							2.7E-01
Cs-134	2.06 years			3.59E-05	8.95E-04							8.9E-04
Cs-136	13 days			2.48E-05	6.24E-04							6.2E-04
Cs-137	30.2 years			5.37E-05	1.35E-03							1.4E-03
Cs-138	32.2 minutes			3.42E-02	8.64E-01							8.6E-01
Ba-139	83.2 minutes			3.30E-02	8.33E-01							8.3E-01
Ba-140	12.8 days			2.02E-03	5.10E-02							5.1E-02
Ba-141	18.3 minutes			2.60E-02	6.56E-01							6.6E-01
Ba-142	10.7 minutes			1.98E-02	5.00E-01							5.0E-01
Ce-141	32.53 days			8.67E-06	2.19E-04							2.2E-04
Ce-143	33 hr			7.85E-06	1.98E-04							2.0E-04
Ce-144	284.4 days			7.85E-06	1.98E-04							2.0E-04

TABLE 11.3-1 EXPECTED GASEOUS RELEASES FROM FERMI 2 (ACTIVITY RELEASE RATES BASED ON 3499 MWt)

		SOURCE OF RELEASE						SOURCE OF RELEASE				
		Reactor Building Ventilation (R.B. Vent)		Turbine Building* Ventilation (R.B. Vent)		Mechanical Vacuum Pump (R.B. Vent)		Turbine Gland Seal Condenser (R.B. Vent)		Offgas System (R.B. Vent)		
Isotope	Half-Life	µCi/sec	Ci/yr	µCi/sec	Ci/yr	µCi/sec	Ci/yr	µCi/sec	Ci/yr	µCi/sec	Ci/yr	Total Curies/Year
Pr-143	13.58 days			8.46E-06	2.19E-04							2.2E-04
Np-239	2.35 days			5.33E-02	1.35E+00							1.4E+00

NOTES:

1. The drywell purge, radwaste building ventilation, and other potential sources of radioactive gaseous waste are discussed in UFSAR Subsections 11.3.2.4, 11.3.2.5, and 11.3.2.6. These potential sources have been evaluated, and it has been determined that the potential releases are negligible.

2. Isotopes with total released activities in excess of 1.0E-04 curies are listed.

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* The source of radionuclides released to the turbine building is assumed to be steam leakage, and since this is the only source of steam leakage, only the turbine building releases will contain particulate radionuclides other than halogens.

** This release will occur following a plant shutdown lasting longer than 10 hr. The mCi/sec represent an average concentration over a 4-hour pump down period.

*** A total of 105 Ci of tritium is expected to be released yearly with 52/5 Ci released via liquid effluents and 52.5 released via gaseous effluents. The gaseous tritium releases are not attributed to any particular source.

TABLE 11.3-2 RADIONUCLIDE INVENTORY IN OFFGAS SYSTEM (ACTIVITIES BASED ON 3499 MWt)

Isotope	Half-Life	Preheater (ci)	Recombiner (ci)	Condenser (ci)	After-Cooler (ci)	Precooler (ci)	Delay Pipe (ci)	Sand Filter (ci)	Chiller (ci)	First Charcoal Units (ci)	All Charcoal Units (ci)	Absorber Filter (ci)	Radionuclide Inventory in System (ci)
Xe-131m	11.9 days	3.1E-06	7.8E-06	2.8E-04	4.7E-04	2.4E-04	2.1E-03	4.7E-04	2.8E-04	3.3E+00	1.4E+01	3.7E-04	1.4E+01
Xe-133m	2.3 days	6.1E-05	1.6E-04	5.4E-03	9.2E-03	4.5E-03	4.0E-02	9.1E-03	5.4E-03	4.7E+01	8.3E+01	1.1E-04	8.3E+01
Xe-133	5.27 days	1.7E-03	4.3E-03	1.6E-01	2.6E-01	1.3E-01	1.1E+00	2.6E-01	1.6E-01	1.7E+03	5.0E+03	6.5E-02	5.0E+03
Xe-135m	15.6 min	5.4E-03	1.4E-02	4.8E-01	7.9E-01	3.9E-01	3.2E+00	6.9E-01	4.1E-01	3.0E+01	3.0E+01		3.6E+01
Xe-135	9.2 hr	4.6E-03	1.1E-02	4.2E-01	7.0E-01	3.4E-01	3.0E+00	6.9E-01	4.1E-01	1.0E+03	1.0E+03	3.4E-13	1.1E+03
Xe-137	3.8 min	3.0E-02	7.6E-02	2.7E+00	4.2E+00	1.8E+00	1.4E+01	2.5E+00	1.4E+00	2.5E+01	2.5E+01		5.1E+01
Xe-138	14.0 min	1.9E-02	4.6E-02	1.7E+00	2.7E+00	1.4E+00	1.0E+01	2.3E+00	1.4E+00	9.3E+01	9.3E+01		1.1E+02
Xe-139	41.0 sec	5.2E-02	1.3E-01	4.0E+00	4.5E+00	1.5E+00	4.6E+00	2.3E-01	6.1E-02	2.6E-01	2.6E-01		1.5E+01
Xe-140	13.7 sec	4.4E-02	1.0E-01	2.5E+00	1.3E+00	1.9E-01	1.6E-01	1.6E-04	2.6E-05	1.8E-05	1.8E-05		4.3E+00
Xe-141	1.6 sec	2.8E-03	6.1E-03	2.8E-02	1.8E-05	7.7E-11	1.8E-13	1.8E-36	9.1E-42				3.7E-02
Xe-142	1.2 sec	2.5E-04	5.1E-04	1.6E-03	4.7E-08	1.1E-15	2.0E-19						2.3E-03
Xe-143	0.96 sec	1.9E-05	3.7E-05	8.7E-05	3.3E-10	2.5E-19	7.7E-24						1.4E-04
Xe-144	8.8 sec	6.7E-05	1.7E-04	3.0E-03	8.9E-04	6.3E-05	2.7E-05	8.9E-10	7.0E-11	2.2E-11	2.2E-11		4.2E-03
Cs-135	3.0E06 yr	1.6E-12	4.0E-12	4.8E-13	9.8E-12	3.7E-13	1.8E-12	1.6E-07	1.3E-11	2.5E-04	2.5E-04	7.8E-20	2.5E-04
Cs-137	30.2 min	1.6E-10	4.1E-10	3.2E-08	1.3E-07	8.4E-08	1.4E-06	5.6E-02	2.2E-05	5.7E-01	5.7E-01		6.3E-01
Cs-138	32.2 min	4.7E-05	1.3E-04	9.8E-03	4.0E-02	2.9E-02	5.1E-01	2.3E+00	1.4E+00	9.3E+01	9.3E+01		9.7E+01
Cs-139	9.0 min	4.5E-04	1.1E-03	8.6E-02	2.1E-01	8.1E-02	6.8E-01	2.3E-01	9.2E-02	2.6E-01	2.6E-01		1.6E+00
Cs-140	65.0 sec	2.7E-03	7.0E-03	4.2E-01	3.4E-01	3.2E-02	7.0E-02	1.6E-04	2.6E-05	1.8E-05	1.8E-05		8.7E-01
Cs-141	24.0 sec	1.7E-04	4.2E-04	1.3E-02	5.3E-05	5.8E-12	2.3E-14	1.8E-36	9.1E-42				1.3E-02
CS-142	2.3 sec	2.9E-05	6.7E-05	4.4E-04	4.3E-11	2.0E-22	2.2E-28						5.3E-04
Cs-143	1.6 sec	1.3E-06	2.8E-06	1.3E-05	1.3E-14	2.0E-29	9.2E-37						1.7E-05
Cs-144	1.0 sec	4.3E-05	1.0E-04	2.0E-03	1.4E-04	8.6E-07	1.1E-07	8.9E-10	7.0E-11	2.2E-11	2.2E-11		2.3E-03
Ba-137m	153.0 sec	2.4E-12	6.6E-12	1.4E-09	1.1E-08	1.1E-08	3.8E-07	5.6E-02	2.1E-05	5.7E-01	5.7E-01		6.3E-01
Ba-139	83.0 min	2.3E-07	6.2E-07	1.1E-04	7.0E-04	4.3E-04	9.4E-03	2.3E-01	8.7E-02	2.6E-01	2.6E-01		5.9E-01
Ba-140	12.8 days	6.4E-09	1.8E-08	2.8E-06	6.7E-06	1.3E-06	8.9E-06	1.6E-04	3.6E-07	1.8E-05	1.8E-05		1.9E-04
Ba-141	18.0 min	5.8E-07	1.6E-06	1.4E-04	2.2E-07	6.1E-13	1.4E-14	1.8E-36	9.1E-42				1.4E-04

TABLE 11.3-2 RADIONUCLIDE INVENTORY IN OFFGAS SYSTEM (ACTIVITIES BASED ON 3499 MWt)

Isotope	Half-Life	Preheater (ci)	Recombiner (ci)	Condenser (ci)	After-Cooler (ci)	Precooler (ci)	Delay Pipe (ci)	Sand Filter (ci)	Chiller (ci)	First Charcoal Units (ci)	All Charcoal Units (ci)	Absorber Filter (ci)	Radionuclide Inventory in System (ci)
Ba-142	11.0 min	3.7E-07	9.4E-07	4.1E-05	1.4E-09	1.7E-17	2.3E-20						4.2E-05
Ba-143	12.0 sec	1.1E-06	2.9E-06	7.2E-05	7.8E-11	7.2E-21	1.6E-25						7.6E-05
Ba-144	12.0 sec	1.5E-05	3.8E-05	1.8E-03	3.9E-04	6.1E-06	1.6E-06	8.9E-10	7.0E-11	2.2E-11	2.2E-11		2.2E-03
La-140	40.2 hr	2.1E-08	5.0E-08	1.1E-06	2.3E-07	6.9E-09	4.9E-10	1.6E-04	1.8E-08	1.8E-05	1.8E-05		1.8E-04
La-141	3.9 hr	1.3E-09	2.7E-09	4.6E-08	2.6E-10	1.1E-15	6.9E-17	1.8E-36	5.7E-42				5.0E-08
La-142	92.0 min	4.3E-09	8.7E-09	3.6E-08	6.5E-12	1.3E-19	4.1E-22						4.8E-08
La-143	14.0 min	9.3E-09	1.6E-08	9.8E-07	7.1E-12	2.9E-21	7.5E-25						1.0E-06
La-144	41.0 sec	1.4E-03	3.1E-03	6.1E-02	4.3E-03	3.8E-05	1.7E-06	8.9E-10	7.0E-11	2.2E-11	2.2E-11		6.9E-02
Ce-141	32.4 days	9.8E-16	2.1E-15	9.9E-14	1.0E-15	6.9E-21	1.0E-21	1.8E-36	1.7E-44				1.0E-13
Ce-143	33.7 hr	1.7E-13	4.0E-13	5.2E-11	1.0E-15	7.5E-25	5.1E-28						5.3E-11
Ce-144	284.0 days	4.7E-10	1.1E-09	2.1E-08	1.3E-09	6.3E-12	7.7E-11	5.2E-10	4.0E-14	1.4E-11	1.4E-11		2.4E-08
Pr-143	13.6 days	6.1E-19	6.4E-19	1.9E-16	9.6E-21	1.0E-29	2.0E-32						1.9E-16
Pr-144	17.3 min	4.0E-12	9.7E-12	1.9E-10	1.4E-11	3.2E-13	3.9E-12	5.2E-10	4.0E-14	1.4E-11	1.4E-11		7.6E-10
Nd-144	2.4E15 yr	1.6E-27	2.0E-26	7.1E-25	2.7E-25	1.3E-26	3.2E-26	1.7E-23	1.5E-24	4.8E-25	4.8E-25		2.0E-23
I-131	8.065 days	9.4E-08	4.8E-01									4.8E-01	
I-132	2.284 hr	1.5E-06	8.9E-02									8.9E-02	
I-133	20.8 hr	1.0E-06	6.0E-01									6.0E-01	
I-134	52.3 min	3.0E-06	6.9E-02									6.9E-02	
I-135	6.7 hr	1.6E-06	2.9E-01									2.9E-01	
Kr-83m	1.86 hr	7.1E-04	1.8E-03	6.4E-02	1.0E-01	5.3E-02	4.6E-01	1.0E-02	6.3E-02	2.6E+01	3.4E+01	3.3E-05	3.5E+01
Kr-85m	4.4 hr	1.3E-03	3.1E-03	1.1E-01	1.9E-01	9.5E-02	8.3E-01	1.9E-01	1.1E-01	6.3E+01	1.1E+02	3.1E-03	1.2E+02
Kr-85	10.76 yr	3.1E-06	7.8E-06	2.8E-04	4.7E-04	2.4E-04	2.1E-03	4.7E-04	2.8E-04	2.3E-01	1.4E+00	9.4E-04	1.4E+00
Kr-87	76.0 min	4.2E-03	1.0E-02	3.8E-01	6.3E-01	3.1E-01	2.6E+00	6.1E-01	3.7E-01	1.1E+02	1.4E+02	2.4E-06	1.4E+02
Kr-88	2.8 min	4.2E-03	1.0E-02	3.8E-01	6.3E-01	3.1E-01	2.7E+00	6.2E-01	3.7E-01	1.9E+02	3.0E+02	3.2E-03	3.1E+02
Kr-89	3.2 min	2.6E-02	6.5E-02	2.2E+00	3.4E+00	1.6E+00	1.0E+01	1.8E+00	9.8E-01	1.5E+01	1.5E+01		3.5E+01
Kr-90	33.0 sec	5.0E-02	1.3E-01	3.7E+00	3.8E+00	1.1E+00	2.7E+00	8.3E-02	2.9E-02	6.1E-02	6.1E-02		1.2E+01
Kr-91	10.0 sec	3.9E-02	9.3E-02	1.7E+00	4.6E-01	2.9E-02	1.1E-02	2.4E-07	1.7E-08	5.0E-09	5.0E-09		2.3E+00

TABLE 11.3-2 RADIONUCLIDE INVENTORY IN OFFGAS SYSTEM (ACTIVITIES BASED ON 3499 MWt)

Isotope	Half-Life	Preheater (ci)	Recombiner (ci)	Condenser (ci)	After-Cooler (ci)	Precooler (ci)	Delay Pipe (ci)	Sand Filter (ci)	Chiller (ci)	First Charcoal Units (ci)	All Charcoal Units (ci)	Absorber Filter (ci)	Radionuclide Inventory in System (ci)
Kr-92	3.0 sec	1.4E-02	3.1E-02	2.5E-01	4.0E-03	3.4E-06	1.1E-07	1.0E-20	9.8E-24	1.6E-25	1.6E-25		3.0E-01
Kr-93	2.0 sec	1.8E-03	3.9E-03	2.1E-02	4.0E-05	1.0E-09	6.0E-12	1.6E-31	4.6E-36	8.9E-39	8.9E-39		2.7E-02
Kr-94	1.0 sec	3.4E-05	6.8E-05	1.7E-04	5.8E-10	4.1E-19	1.1E-23						2.7E-04
Kr-95	0.5 sec	2.4E-08	3.9E-08	3.9E-08	6.3E-19	4.4E-37	4.5E-46						1.0E-07
Kr-97	1.0 sec	2.1E-08	4.2E-08	1.0E-07	3.9E-13	2.9E-22	9.0E-27						1.6E-07
Rb-87	4.7E10 yr	1.3E-17	3.2E-17	1.1E-15	1.9E-15	9.5E-16	8.1E-15	9.0E-12	5.1E-15	1.8E-09	1.9E-09	3.6E-17	1.9E-09
Rb-88	17.8 min	1.9E-05	5.0E-05	4.1E-03	1.7E-02	1.3E-02	2.3E-01	6.2E-01	2.7E-01	1.9E+02	3.0E+02	3.2E-03	3.0E+02
Rb-89	15.0 min	1.4E-04	3.7E-04	2.8E-02	1.0E-01	6.9E-02	1.0E+00	1.8E+00	9.8E-01	1.5E+01	1.5E+01		1.9E+01
Rb-90	2.6 min	1.5E-03	3.8E-03	2.6E-01	5.4E-01	1.7E-01	1.0E+00	8.3E-02	2.9E-02	6.1E-02	6.1E-02		2.2E+00
Rb-91	57.0 sec	2.4E-03	6.2E-03	3.2E-01	1.3E-01	4.0E-03	4.7E-03	2.4E-07	1.7E-08	5.0E-09	5.0E-09		4.7E-01
Rb-92	4.4 sec	3.9E-03	9.6E-03	1.6E-01	1.9E-04	1.5E-09	4.8E-12	1.0E-20	9.8E-24	1.6E-25	1.6E-25		1.7E-01
Rb-93	5.9 sec	3.2E-04	7.9E-04	1.4E-02	2.9E-06	1.9E-12	2.2E-15	1.6E-31	4.6E-36	8.9E-39	8.9E-39		1.5E-02
Rb-94	2.7 sec	3.3E-06	7.6E-06	5.6E-05	1.3E-12	3.6E-25	2.3E-31						6.7E-05
Rb-95	0.36 sec	5.3E-12	8.5E-12	8.6E-12	8.8E-34	4.2E-70	4.4E-88						2.2E-11
Rb-97	0.14 sec	1.5E-10	3.9E-10	9.2E-10	8.4E-21	4.8E-39	4.5E-48						1.5E-09
Sr-89	50.6 days	7.9E-11	2.2E-10	4.3E-08	3.7E-07	3.7E-07	1.3E-05	1.8E+00	3.1E-03	1.4E+01	1.4E+01		1.5E+01
Sr-90	28.8 yr	4.1E-12	1.1E-11	2.0E-09	1.0E-08	5.4E-09	9.4E-08	2.3E-03	4.8E-07	1.5E-03	1.5E-03		3.4E-03
Sr-91	9.7 min	1.9E-07	5.1E-07	7.3E-05	8.7E-05	5.5E-06	2.3E-05	2.4E-07	6.0E-09	5.0E-09	5.0E-09		1.9E-04
Sr-92	2.7 hr	1.8E-06	4.6E-06	3.1E-04	8.9E-06	4.1E-09	1.0E-09	1.0E-20	7.8E-24	1.6E-25	1.6E-25		3.3E-04
Sr-93	8.3 min	2.9E-06	7.6E-06	5.0E-04	1.8E-06	2.2E-11	9.3E-13	1.6E-31	4.6E-36	9.1E-39	8.9E-39		5.1E-04
Sr-94	1.3 min	3.4E-07	8.8E-07	3.7E-05	1.1E-10	3.2E-20	4.6E-24						3.8E-05
Sr-95	26.0 sec	4.6E-10	1.1E-09	3.2E-08	1.8E-19	3.3E-38	6.7E-47						3.4E-08
Sr-97	0.4 sec	3.2E-10	6.4E-10	1.6E-09	1.4E-20	8.0E-39	7.5E-48						2.5E-09
Y-90	64.4 hr	8.1E-11	2.0E-10	6.1E-09	4.1E-09	6.3E-10	1.0E-09	2.0E-03	1.6E-08	1.5E-03	1.5E-03		3.4E-03
Y-91m	50.0 min	1.3E-07	3.0E-07	5.5E-06	4.4E-08	3.7E-08	4.3E-07	2.4E-07	4.9E-09	5.0E-09	5.0E-09		6.7E-06
Y-91	59.0 days	2.1E-13	5.1E-13	9.4E-12	1.1E-12	1.0E-13	3.1E-12	2.4E-07	6.4E-12	4.9E-09	4.9E-09		2.5E-07
Y-92	3.53 hr	1.3E-06	2.9E-06	2.4E-05	9.9E-09	1.1E-11	7.5E-12	1.0E-20	4.0E-24	1.6E-25	1.6E-25		2.8E-05

TABLE 11.3-2 RADIONUCLIDE INVENTORY IN OFFGAS SYSTEM (ACTIVITIES BASED ON 3499 MWt)

Isotope	Half-Life	Preheater (ci)	Recombiner (ci)	Condenser (ci)	After-Cooler (ci)	Precooler (ci)	Delay Pipe (ci)	Sand Filter (ci)	Chiller (ci)	First Charcoal Units (ci)	All Charcoal Units (ci)	Absorber Filter (ci)	Radionuclide Inventory in System (ci)
Y-93	10.1 min	1.1E-07	2.4E-07	1.3E-06	9.2E-10	2.2E-14	2.3E-15	1.6E-31	1.5E-36	8.9E-39	8.9E-39		1.6E-06
Y-94	20.0 min	5.8E-13	5.6E-10	2.6E-07	2.7E-12	1.4E-21	5.7E-25						2.6E-07
Y-95	10.5 min	3.3E-12	8.7E-12	6.6E-10	1.4E-20	5.5E-39	5.4E-47						6.7E-10
Y-97	1.11 sec	1.9E-08	3.7E-08	8.7E-08	2.4E-19	2.9E-36	5.3E-45						1.4E-07
Zr-93	9.5E05 yr	1.3E-16	2.3E-17	3.3E-18	1.5E-21	1.8E-24	1.9E-26	1.1E-37	3.8E-46	6.5E-45	6.5E-45		1.5E-16
Zr-95	65.5 days	1.1E-18	3.3E-18	7.3E-16	3.9E-26	2.7E-44	7.1E-52						7.4E-16
Zr-97	16.8 min	6.8E-13	1.6E-12	3.6E-11	1.4E-16	5.1E-26	1.4E-29						3.8E-11
Nb-95	3.51 days	9.8E-22	7.1E-22	8.1E-22	1.4E-31	1.5E-49	1.0E-56						2.5E-21
Nb-97	74.0 min	1.3E-16	4.0E-16	6.7E-14	7.7E-19	4.7E-28	2.7E-31						6.7E-14
N-13	9.99 min	2.5E-03	6.2E-03	2.2E-01	3.7E-01	1.8E-01	1.4E+00	2.9E-01	1.7E-01	7.6E+00	8.1E+00	3.0E-08	1.1E+01
N-16	7.13 sec	1.8E+01	4.3E+01	7.1E+02	1.5E+02	6.1E+00	1.9E+00	5.6E-06	2.7E-07	5.6E-08	5.6E-08		9.3E+02
N-17	4.14 sec	1.7E-03	3.9E-03	4.3E-02	2.2E-03	1.3E-05	1.1E-06	4.3E-16	2.7E-18	1.5E-19	1.5E-19		5.1E-02
O-19	26.8 sec	2.4E-01	6.1E-01	1.8E+01	1.6E+01	4.3E+00	8.7E+00	1.7E-01	5.3E-02	9.0E-02	9.0E-02		4.8E+01

Note: With Hydrogen Water Chemistry in operation, the conservative calculated N-16 estimates will increase by a maximum factor of six.

TABLE 11.3-3 OFFGAS SYSTEM DECONTAMINATION FACTORS[a]

Isotope	Decontamination Factor[c]	Isotope	Decontamination Factor[c]
Kr-83m	7,660	Xe-131m	2.5
Kr-85m	44	Xe-133m	136
Kr-85	1	Xe-133	8.2
Kr-87	50,000	Xe-135m	b
Kr-88	388	Xe-135	b
Kr-89	b	Xe-137	b
Kr-90	b	Xe-138	b
Kr-91	b	Xe-139	b
Kr-92	b	Xe-140	b
Kr-93	b	Xe-141	b
Kr-94	b	Xe-142	b
Kr-95	b	Xe-143	b
Kr-97	b	Xe-144	b

The decontamination factor provided by the offgas system for noble gases only is approximately 1160. If all gases and particulates entering the offgas system were considered in determining the decontamination factor, this would be much higher.

[a] Decontamination Factor equals:

$$\frac{\text{Concentration at inlet to offgas system}}{\text{Concentration at outlet to offgas system}}$$

[b] Extremely large--essentially all of the isotope has been removed.

[c] Values are based on condenser offgas rate equivalent to 100,000 mCi/sec after 30 minutes delay and condenser air inleakage rate of 40 scfm (nominal).

TABLE 11.3-4 DESIGN PARAMETERS[t] FOR STEAM-JET AIR EJECTOR OFFGAS SYSTEM COMPONENTS

Component Parameters	Preheater	Condenser	Aftercooler	Precooler	Chiller	Ring Water Cooler
Shell side						
Design pressure, psia	210	375	375	375	375	156
Design temperature, °F	480	840	390	212	212/-22	176
Material	Carbon steel	ASTM-A-387	Stainless steel	Stainless steel	Stainless steel	Stainless steel
Fluid	Steam	Offgas	Offgas	Offgas (air)	Offgas (air)	Closed cooling water
Flow rate	1100 lb/hr	15,142 lb/hr	40.0 scfm	40.0 scfm	40.0 scfm	27 gpm
Pressure drop, psi	-	0.15	0.3	0.3	0.3	3.0
Outlet pressure, psia	160	13	13	12.8	12.5	128 max.
Outlet temperature, °F	364	≤ 203	≤ 109	57-61	14 (nom)	82-92
Tube side						
Design pressure, psia	375	420	156	210	210	375
Design temperature, °F	480	480	390	120	176	176
Material	Stainless steel	Stainless steel	Stainless steel	Stainless steel	Stainless steel	Stainless steel
Fluid	Offgas/Steam	Condensate	TBCCW	Freon	Freon	Demin. water
Flow rate	15,142 lb/hr	2700 gpm	780 gpm	-	-	13 gpm
Pressure drop, psi	0.142	8.55	5.0	-	-	0.71
Outlet pressure, psia	14.2	356	114	-	-	-
Outlet temperature, °F	≥ 320	144	104	-	-	-
Heat exchanger area, ft^2	1130	1560	840	-	-	64.5
Duty, Btu/hr approx.	0.94×10^6	22.0×10^6	0.52×10^6	6.0×10^3	6.0×10^3	71×10^3
Empty weight, lb approx.	7000	13,000	5500	3100	3100	1100
Operating weight, lb approx	15,000	18,000	9000	3100	3100	1500

TABLE 11.3-4 DESIGN PARAMETERS[t] FOR STEAM-JET AIR EJECTOR OFFGAS SYSTEM COMPONENTS

Component parameters	Water Separator	Recombiner	Sand Filter	Adsorbers	Absolute Filter	Ring Water Buffer Tank	Drain Receiver Tank	Condensate Receiver Tank	Water Ring Pump
Design pressure, psia	375	375	375	375	375	375	375	375	80
Design temperature, °F	390	840	122	122	122	176	650	650	160
Material	Carbon steel	Low alloy	Carbon steel	Carbon steel	Carbon steel	Stainless steel	Carbon steel	Carbon steel	Stainless steel or mfg std.
Fluid	Offgas and steam	Offgas and steam	Air	Air	Air	Air	Water	Water	Air
Nominal flow rate, scfm	5330[a]	5330[a]	40	40	40	40	-	-	40
Pressure drop, psi	0.3	0.7	0.7	1.2	0.3	0.2	-	-	-
Operating pressure, psia	14.2	14.2	12.5	12.5	11.8	14.5	13.0	0.75	15.7
Maximum operating temperature, °F	284	≤ 788	95	68	95	100	190	91	104
Duty, Btu/hr	-	2.7×10^6	-	-	-	-	-	-	-
Empty weight, lb approx.	4600	20,000	3600	34,000	800	600	-	-	-
Operating weight, lb	7000	32,000	7600	55,000	800	1000	-	-	-

[a] The flow rate for steam = 14,500 lb/hr, H_2 - 52 lb/hr, O_2 - 410 lb/hr, and air - 180 lb/hr.

NOTE: The data given in this table is based on condenser air inleakage of 40 scfm (nonimal). Under certain conditions, the air inleakage will be higher and the related data will vary.

[t] This table contains both design and expected operating parameters. Design parameters are designated explicitly (e.g., “design temperature”, “design pressure”).

TABLE 11.3-5 GASEOUS RADWASTE SYSTEM INSTRUMENTATION DESIGN PARAMETERS

Flow Transmitters

Number	Service	Range (scfm)	Accuracy[a] ±percent
N426	Offgas and gland stem exhaust to reactor/auxiliary building vent	0-3100	0.25
N530	Offgas leaving charcoal filters	0-100 (80 in. WC)	0.64

Level Indicators

Number	Service	Design Pressure (psig)	Design Temperature (°F)	Range, in. Water Column	Accuracy[a], ± % of Span
R411 A	Offgas north ring water buffer tank	0	150	0-20	0.5
R411 B	Offgas south ring water buffer tank	0	150	0-20	0.5

Pressure Transmitters

Number	Service	Type	Range (psia)	Accuracy[a] ±percent
N400	Offgas system 18-in. manifold	Bourdon Tube	11.8 to 26.8	0.4
N457 A	Offgas after delay piping	Bourdon Tube	7 to 15	0.4
N457 B	Offgas after delay piping	Bourdon Tube	7 to 15	0.4
N489 A	Offgas entering ring water pump north	Bourdon Tube	0 to 15	0.4
N489 B	Offgas entering ring water pump south	Bourdon Tube	0 to 15	0.25
N491	Offgas system exhaust	Bourdon Tube	0 to 16	0.25
N525	Offgas charcoal units to adsorber filters	Diaphragm	0 to 12.2	0.25

[a] The instrument accuracy information provided in the UFSAR tables is a bounding value.

TABLE 11.3-5 GASEOUS RADWASTE SYSTEM INSTRUMENTATION DESIGN PARAMETERS

Thermocouples

Number	Service	Design Temperature (°F)	Type
N408 A	Offgas east water separator to east preheater	480	Dual element swaged chromel alumel ungrounded MGO insulated
N408 BB	Offgas west water separator to west preheater	480	Dual element swaged chromel alumel ungrounded MGO insulated
N409 A	Offgas preheater east discharged to recombiner west	480	Dual element swaged chromel alumel ungrounded MGO insulated
N409 B	Offgas preheater west discharged to recombiner west	480	Dual element swaged chromel alumel ungrounded MGO insulated
N418 A N419 A	Offgas east recombiner	850	Dual element swaged chromel alumel ungrounded MGO insulated
N418 B N419 B	Offgas west recombiner	850	Dual element swaged chromel alumel ungrounded MGO insulated
N424 A	Offgas east recombiner discharge to condenser	850	Dual element swaged chromel alumel ungrounded MGO insulated
N424 B	Offgas west recombiner discharge to condenser	850	Dual element swaged chromel alumel ungrounded MGO insulated
N441 A	Offgas system vapor from east aftercooler to precooler	150	Dual element swaged chromel alumel ungrounded MGO insulated
N441 B	Offgas system vapor from west aftercooler to precooler	150	Dual element swaged chromel alumel ungrounded MGO insulated
N442 A	Offgas system east precooler	---	Dual element swaged chromel alumel ungrounded MGO insulated
N442 B	Offgas system west precooler	---	Dual element swaged chromel alumel ungrounded MGO insulated
N448	2-minute delay line to reactor/ auxiliary building vent	150	Dual element swaged copper-constantan ungrounded MGO insulated
N462 A, B & C	Offgas chiller (one for each chiller)	---	Dual element swaged copper-constantan ungrounded MGO insulated

Number	Service	Design Temperature (°F)	Type
N468, N469 and N470	Offgas system charcoal bed 1	---	Dual element swaged copper-constantan ungrounded MGO insulated
N471	Offgas system charcoal bed 2	---	Dual element swaged copper-constantan ungrounded MGO insulated
N472	Offgas system charcoal bed 3	---	Dual element swaged copper-constantan ungrounded MGO insulated
N473	Offgas system charcoal bed 4	---	Dual element swaged copper-constantan ungrounded MGO insulated
N474	Offgas system charcoal bed 5	---	Dual element swaged copper-constantan ungrounded MGO insulated
N475	Offgas system charcoal bed 6	---	Dual element swaged copper-constantan ungrounded MGO insulated

TABLE 11.3-6 EXPECTED YEARLY AVERAGE RADIONUCLIDE CONCENTRATIONS AT SITE BOUNDARY[a] (3499 MWt)

Isotope	Concentration (μCi/cm^3)	Isotope	Concentration (μCi/cm^3)
Kr-83m	3.6(-12)[b]	Sr-89	6.5(-16)
Kr-85m	1.4(-10)	Sr-90	4.9(-17)
Kr-85	1.9(-11)	Sr-91	1.4(-14)
Kr-87	2.3(-12)	Sr-92	2.2(-14)
Kr-88	5.3(-11)	Zr-95	8.3(-18)
Kr-89	7.9(-11)	Zr-97	6.5(-18)
Kr-90	2.1(-11)	No-95	8.7(-18)
Kr-91	2.0(-14)	Mo-99	4.6(-15)
Xe-131m	5.7(-12)	Tc-99m	5.7(-14)
Xe-133m	2.4(-12)	Tc-101	1.8(-14)
Xe-133	9.5(-10)	Ru-103	3.7(-18)
Xe-135	2.4(-11)	Te-132	1.0(-15)
Xe-137	2.3(-11)	Cs-134	3.3(-17)
Xe-138	9.9(-11)	Cs-136	2.3(-17)
Xe-139	2.7(-11)	Cs-137	4.9(-17)
Xe-140	6.0(-13)	Cs-138	3.1(-14)
		Ba-139	3.0(-14)
N-13	1.0(-11)	Ba-140	1.9(-15)
F-18	8.3(-13)	Ba-141	2.4(-14)
O-19	3.7(-11)	Ba-142	1.8(-14)
		Ce-141	7.9(-18)
Br-83	1.2(-14)	Ce-143	7.2(-18)
Br-84	2.0(-14)	Ce-144	7.2(-18)
Br-85	1.4(-14)	Pr-143	7.9(-18)
I-131	1.1(-14)	Np-239	4.9(-14)
I-132	1.0(-13)		
I-133	7.6(-14)		
I-134	1.9(-13)		
I-135	1.1(-13)		
H-3	7.6(-14)		

a Corresponding to a condenser offgas rate of 100,000 μCi/sec after 30 minutes delay. This value has not been adjusted for 102 percent of uprated power (refer to introductory paragraphs to Chapter 11, page 11.1-1).

b 3.6(-12) = 3.6 x 10^{-12}.

TABLE 11.3-7 MAXIMUM INDIVIDUAL EXPOSURE FROM GASEOUS RELEASES[a] (3499 MWt)

Pathway	Whole-Body Dose (mrem/yr)	Skin Dose (mrem/yr)	Thyroid Dose (mrem/yr)	
			Child	Adult
1. From cloud immersion	4.6	8.9		
2. From radiaoiodine inhalation			0.46	0.37
3. From radioiodine ingestion via cow-milk-Man pathway			2.2	0.44
4. From contaminated land surfaces	0.08	0.23		
5. From leafy vegetables				0.95
6. From tritium exposure	0.0037			
Total from gaseous releases	4.68	9.13	2.66	1.76

a Values are based on condenser offgas rate equivalent to 100,000 μCi/sec after 30 minutes delay and condenser air inleakage rate of 40 scfm (nominal). The value for the offgas rate has not been adjusted for 102 percent uprated power (refer to introductory paragraphs to Chapter 11, page 11.1-1).

Figure Intentionally Removed
Refer to Plant Drawing M-2017-1

Fermi 2
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FIGURE 11.3-1, SHEET 1

OFFGAS SYSTEM P&ID

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Refer to Plant Drawing M-2017-1A

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FIGURE 11.3-1, SHEET 2

OFFGAS SYSTEM P&ID

Figure Intentionally Removed
Refer to Plant Drawing M-2017-2

Fermi 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 11.3-1, SHEET 3
OFFGAS SYSTEM P&ID

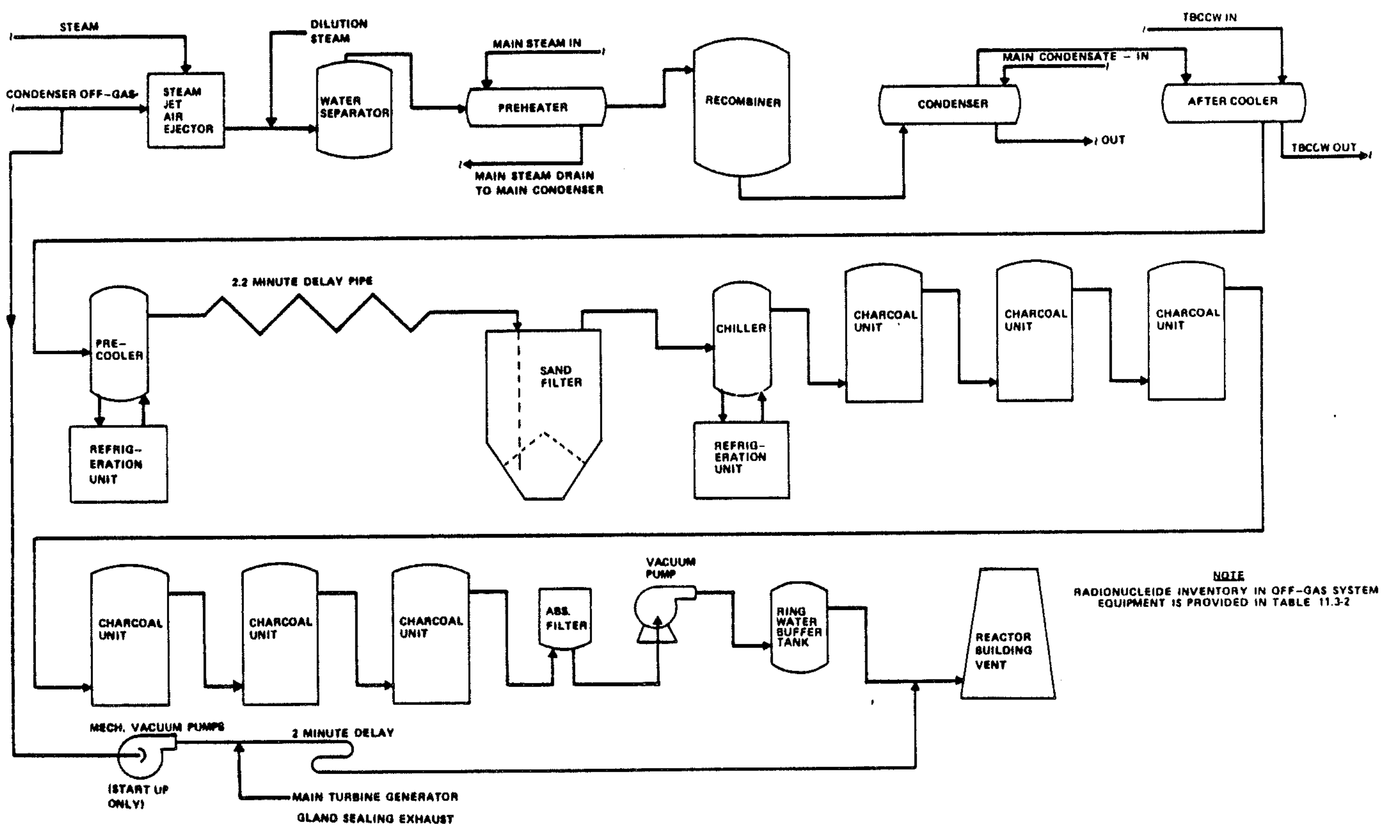

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FIGURE 11.3-2

CONDENSER OFFGAS SYSTEM FLOW DIAGRAM

11.4 PROCESS AND EFFLUENT RADIATION MONITOR SYSTEMS

11.4.1 Introduction

The process and effluent radiation monitor systems are contained in the process radiation monitoring system. The process radiation monitoring system furnishes information to operations personnel regarding the levels of radioactivity in effluent and selected process streams. This information is used to maintain radiation levels as low as reasonably achievable and to verify compliance with applicable governmental regulations for the containment, control, and release of radioactive liquids, gases, and particulates generated as a result of normal or emergency operation of the plant.

The process radiation monitoring system is composed of the following process and effluent radiological monitoring systems:

a. Gaseous and airborne monitors

    1. Offgas radiation monitor system
    2. Main steam line radiation monitor system
    3. Reactor building ventilation exhaust radiation monitor system
    4. Offgas vent pipe radiation monitor system (installed spare)
    5. Radwaste building ventilation exhaust radiation monitor system
    6. Turbine building ventilation exhaust radiation monitor system
    7. Deleted
    8. Standby gas treatment system (SGTS) radiation monitor system
    9. Reactor building exhaust plenum radiation monitor system
    10. Fuel pool ventilation exhaust radiation monitor system
    11. Control center makeup air radiation monitor system
    12. Two-minute holdup pipe exhaust radiation monitor system
    13. Control center emergency air inlet radiation monitor system
    14. Onsite storage facility ventilation exhaust radiation monitor system
    15. Standby gas treatment system postaccident radiation monitor system
    16. Primary containment monitor system.

b. Liquid monitors

    1. Radwaste effluent radiation monitor system
    2. General service water effluent radiation monitor system

3. Reactor building closed cooling water (RBCCW) radiation monitor system
4. Emergency equipment cooling water (EECW) radiation monitor system
5. Residual heat removal service water (RHRSW) radiation monitor system
6. Circulating water reservoir decant line radiation monitor system.

c. Containment area high-range monitor.

d. Post Accident Gaseous Effluent Radiation Monitors
   1. Noble gas effluent monitor system
   2. Radioactive iodine and particulate effluent monitor system
   3. Torus hardened vent radiation monitor system

The process radiation monitoring system described in the following sections serves in conjunction with a comprehensive sampling program. The sampling program is the primary method for quantitatively and qualitatively evaluating system and effluent activity levels to comply with Regulatory Guide 1.21, Revision 1.

11.4.2 Design Objectives

The process radiation monitoring system is designed to measure and record radioactivity levels, to alarm on high radioactivity levels, and to control, as required, the release of radioactive liquids, gases, and particulates produced during operation of the plant. It is also designed to comply with the requirements of 10 CFR 50, 10 CFR 20, and Regulatory Guide 1.21, Revision 1. The process radiation monitoring system aids in protection of the general public and plant personnel from exposure to radiation or radioactive materials in excess of those allowed by the applicable regulations of governmental agencies. All the building gaseous effluent monitors have been upgraded to meet the range requirements of NUREG-0737 (refer to Subsection 11.4.3.11).

The design objectives of the process radiation monitoring system for normal operation are:

a. To provide continuous surveillance of radioactivity levels in process and effluent streams from minimum detectable levels to levels commensurate with Offsite Dose Calculation Manual radiological effluent control limits by indicating and recording these levels and by alarming at abnormal activity levels

b. To provide data for estimating total released activity to comply with Regulatory Guide 1.21, Revision 1

c. To give early warning of increasing radioactivity levels indicative of equipment failure, system malfunction, or deteriorating system performance

d. To initiate prompt corrective action, either automatically or through operator response.

For some anticipated operational occurrences resulting from accidents or malfunctions, the process radiation monitoring system activates necessary isolation or diversion valves, thereby terminating releases if radioactivity levels exceed alarm setpoints, as indicated in Tables 11.4-1 and 11.4-2.

11.4.3 Continuous Monitoring

11.4.3.1 Design Criteria

The following design criteria were employed in the design of the process radiation monitoring system:

a. To facilitate compliance with applicable regulations and guides (10 CFR 50 and Regulatory Guide 1.21), monitors and detectors were selected with sensitivities and ranges in accordance with radiation levels anticipated at specific detector locations

b. Independence of redundant monitors that are safety related is maintained by providing adequate separation of detectors, signal cabling, power supplies, and actuation circuits for isolation and diversion valves to meet IEEE-279 criteria

c. Radioactivity levels are continuously indicated in the relay room or at local panel H21P284 (PCRMS only) and recorded in the main control room

d. Main control room alarms annunciate high radioactivity levels and signal, circuit, or power failures

e. For selected detectors, alarms and recorders are provided in the radwaste control room

f. Access to the alarm setpoints is under the administrative control of the Executive Director – Nuclear Production or his authorized delegate

g. Adequate lead shielding is provided for detectors when the ability to sense low activity levels requires that background radiation have a minimum effect on the instruments

h. Monitor components requiring maintenance and inspection are readily accessible or spare equipment is available in the plant

i. Environmental design conditions for the components are listed in Table 11.4-3. In addition, those safety- related components of the system are protected from the effects of extreme winds, floods, tornadoes, or missiles because they are housed in a structure designed to withstand the above environmental conditions as described in Chapter 3

j. None of the monitors are designed to Category I requirements unless specifically stated in the section describing the particular monitor

k. All in-line monitors have detector housings of the same quality level and category as the system being monitored. Off-line monitors are provided with valves to permit manual isolation of monitors from the process.

11.4.3.2 Basis for Detector Location Selection

An aid for the selection of each location to be continuously monitored is found in Regulatory Guide 1.21, which suggests "all normal and potential paths for release of radioactive material during normal reactor operation, including anticipated operational occurrences and accidents should be monitored." Based on the above, monitors are provided for:

a. Process lines that may discharge radioactive fluids to the environment, in order to indicate the radioactivity level and to alarm in the main control room when preestablished limits for the release of radioactive materials are reached or exceeded

b. Process lines that do not discharge directly to the environment, in order to indicate possible process system malfunctions by detecting increases in radioactivity levels.

11.4.3.3 Expected Radiation Levels

Expected radioactivity concentrations in the process and effluent streams will be such that radiation levels at the site boundary are a small fraction of 10 CFR 20 limits and will be as low as reasonably achievable. The expected concentrations each monitor will be measuring are listed in Tables 11.4-1 and 11.4-2.

11.4.3.4 Quantity To Be Measured

The principal radionuclides that are monitored are indicated in Tables 11.4-1 and 11.4-2. All channels measure gross radioactivity.

11.4.3.5 Detector Type, Sensitivity, and Range

The detectors are Geiger-Mueller tubes, ionization chambers, or scintillation crystals that detect beta radiation or gamma radiation over an energy range of at least 0.07 to 2.5 MeV. The sensitivity and range have been selected so that the alarm setpoint is at least an order of magnitude higher than the detector threshold, and so that the instrument reads on scale during normal operation. If it does not read on scale, a small "bug" source, attached to the detector, is used to clear the low (failure/operate) alarm. Detector type, estimated sensitivity, and nominal ranges of each process and effluent monitor are indicated in Tables 11.4-1 and 11.4-2.

11.4.3.6 Setpoints

Setpoints for effluent monitors are established to meet Offsite Dose Calculation Manual radiological effluent control limits that encompass 10 CFR 20 limits and 10 CFR 50, Appendix I, limits. Setpoints for process monitors are established to provide a warning of increased system activity and to take corrective action where appropriate.

Two independently adjustable radiation setpoints are provided for most monitors. The lower, or high setpoint, normally activates only an alarm, while the upper, or high-high setpoint, activates an alarm and initiates corrective action where appropriate. Setpoints are at least twice the background level to reduce the number of spurious trips. High setpoints when used in conjunction with high-high setpoints are between background and the high-high setpoints. The setpoints are under the administrative control of the Executive Director – Nuclear Production or his authorized delegate, and can be changed if needed as long as Offsite Dose Calculation Manual radiological effluent control limits are not exceeded.

11.4.3.7 Annunciators and Alarms

All process and effluent radiation monitors are annunciated in the main control room on panel H11-P603. A specific annunciator window alarms for low (failure/operate), alert, high or high-high (high) radiation alarm or low-sample-flow alarm, as shown in Tables 11.4-1 and 11.4-2.

An operator can acknowledge and silence the audible alarm but cannot clear the annunciator window until the alarm has been cleared. General Atomics alarms must be reset in the relay room to clear the annunciator window and the Eberline alarms must be reset in the main control room.

For the process radiation monitoring system, the channel that alarmed and the type of alarm are determined by the lights associated with the three types of alarms. These alarms are as follows:

a. A high (or alert) alarm light illuminates when the radioactivity exceeds preset limits that have been selected to provide an early warning

b. A high-high (or high) alarm light illuminates when radioactivity levels exceed a preset limit that is set at or slightly below the Offsite Dose Calculation Manual radiological effluent control limits. This initiates prompt corrective action either automatically or through operator response

c. A low (failure/operate) alarm light is activated when the meter reaches a downscale trip point that indicates that there is a detector signal, circuit, flow, or power failure. In certain cases, as discussed in Subsections 11.4.3.8 and 11.4.3.9, this downscale trip also initiates action.

11.4.3.8 Description of Gaseous and Airborne Monitors

Each channel of the system contains a completely integrated modular assembly as described below. Specific details of each monitor are described in Subsections 11.4.3.8.2.1 through 11.4.3.8.2.16.

11.4.3.8.1 General

11.4.3.8.1.1 Sampling Devices

For each off-line monitor, a sample is drawn from the vessel or system through a sample line. For the Eberline Sping 3/Sping 4/AXM-1 and the containment system (which have detectors viewing the filters) and the GE offgas vent pipe monitor (spare detector), the sample air stream then passes through a paper filter to collect particulates and then through an iodine-adsorbent cartridge. The air stream next passes through a shielded, internally polished chamber (or chambers), where the air is monitored for any radioactive gases by a scintillation detector and/or an energy- compensated Geiger-Mueller tube. The air is then drawn through a sample pump and returned to the vessel or system from which it was sampled.

Each sample pump is capable of drawing 2 cfm of air through the monitor (with the exception of the AXM-1s). Each monitor has a flow out of limits alarm. A local flow indicator is also provided for vent stack monitors that have particulate and iodine filters so that the total volume that has passed through the filters can be determined.

The filter papers used to collect particulates have a collection efficiency of at least 90 percent for 0.3-μm particulates. The iodine-adsorbent cartridges used to collect iodine have been tested and shown to have an efficiency of at least 90 percent for elemental and organic iodine. The filters and cartridges are replaced periodically and are counted in the counting room to determine particulate and iodine activity.

Each monitor has manually operated sample valves, and several types also have solenoid-operated valves. This allows room air to be purged through the gas monitor to check the background radiation level and allows for samples to be taken, or calibrated gas to be introduced, to check the monitor calibration.

The location of sample probes and off-line monitors has been chosen to minimize sample plateout. Unavoidable bends are made with gradual radii of approximately five times the tubing diameter. Stainless steel lines and ball valves are used to further minimize plateout.

11.4.3.8.1.2 Detector-Preamplifier Unit

The detectors are Geiger-Mueller tubes, solid-state, ionization chambers, or scintillation detectors. The General Atomic (Gulf) scintillation detectors, either beta (plastic) or gamma (NaI), generally have preamplifiers mounted on top of the detectors. The Eberline detectors use an interface box (IB-X) to provide this function. The detectors are designed to remain fully operational over a wide range of temperatures, as listed in Table 11.4-3.

Solenoid-operated check sources are provided to check detector response on all General Atomic (Gulf) supplied monitors (nine μCi ^{137}Cs for gamma detectors and 0.5 μCi ^{36}Cl for beta detectors), on the Eberline Sping 3/Sping 4 (30 μCi ^{137}Cs for the beta particulate detector, 0.5 μCi ^{133}Ba for the iodine detector, 30 μCi ^{137}Cs for the beta gas detector, 0.5 μCi ^{90}Sr/Y for the gamma gas detectors, and 0.5 μCi ^{90}Sr/Y for the gamma area detector), on the Eberline AXM-1 (30 μCi ^{137}Cs for the intermediate-range detector and 0.5 μCi ^{90}Sr/Y for the high-range detector), and on the GE-supplied offgas vent pipe radiation monitor (installed spare - 5 μCi ^{137}Cs). Each source is operated from the respective radiation analyzer in the relay room for the General Atomic monitors and from a panel in the main control room for the Eberline monitors (with the exception of the offgas vent pipe radiation ratemeter, which was removed and support equipment abandoned in place). One method of performing effluent monitor source checks is by local activation of the check source mechanism. Other approved check sources may be used if needed.

Off-line detectors are mounted as close as practicable to the system being monitored in a low-radiation area so that the detectors have maximum sensitivity and there is minimum sample plateout.

11.4.3.8.1.3 Radiation Monitor

The radiation analyzer for General Atomic, Mirion, and GE units, which is located in the relay room on panel H11-P604, P606, P883, P884, P914, or P915, is typically composed of an amplifier, a single channel analyzer (if used), a count rate meter (if used), a trip unit, and power supplies as described below:

a. The amplifier accepts pulses from the detector or preamplifier, performs a log integration (if required), and amplifies the output

b. The single channel analyzer, if used, has an adjustable pulse height window and a low-level discriminator for high- and low-level energy discrimination of gamma scintillation detector outputs

c. The meter displays the output in counts per minute, counts per second, or milliroentgens per hour on a four to seven-decade log scale

d. The trip unit provides adjustable trips that can be set for alarm control functions over the entire range of the unit. One low (failure/operate), one high, and one high-high trip are provided for most monitors

e. The Mirion power supply provides the necessary AC and DC voltages for the radiation analyzer and the detector-preamplifier unit. A separate power supply unit provides the necessary DC voltage for the associated trip units. Power for these units and other auxiliary equipment is supplied from the reactor protection system (RPS) buses A and B (120 VAC), the instrument power supply (120 VAC), or the plant 48/24 VDC battery.

All of the analyzer, monitor, and trip functions of the Eberline systems are performed remotely in the Sping units.

11.4.3.8.1.4 Recorder

A recorder is provided in the main control room or radwaste control room to record the output of required channels. Alarms are displayed out on the sequence-of-events recorder. The Eberline instrument channels are displayed in digital format on a control room terminal.

11.4.3.8.2 Specific Gaseous and Airborne Monitor Details

11.4.3.8.2.1 Primary Containment Radiation Monitor System

The primary containment radiation monitor system measures the activity in the drywell and suppression chamber and, in doing so, complies with Regulatory Guide 1.45 and General Design Criterion (GDC) 30. It is designed to detect leakage from the reactor coolant pressure boundary during normal operation (Subsection 5.2.7).

The monitor subsystem includes a noble gas detector. Primary containment atmosphere source terms are discussed in Section 11.1.

A continuous representative sample is extracted from either the drywell or the suppression chamber and is passed through the monitor. The sample is then returned to the suppression chamber through 1-in. stainless steel sample lines. The drywell sample system has five inlet lines of approximately equivalent flow rates that carry the sample from various locations in the drywell to a manifold located outside the containment. A single line routes the sample from the manifold to the monitors and then returns it to the suppression chamber. A single line from the suppression chamber branches into the line above before it enters the monitor, and another line on the discharge of the monitors returns to the suppression chamber as shown in Figure 11.4-1. Valves are provided on these lines to prevent flow when a sample of the suppression chamber is not desired. Normally, the five drywell lines are open to provide an averaged, representative sample. Electrically controlled air operated valves are provided on each of the six inlet lines and the one discharge line so that any one of the drywell sample lines or the suppression chamber sample line can be selected. The valve selector station is located in the main control room on panel H11-P808.

The sample selected is first passed through a coalescer, which removes moisture, and a filter paper to collect particulates. Capability to perform a laboratory analysis of the sample media is retained. The sample is then passed through an impregnated charcoal cartridge to a shielded chamber, where the noble gases are viewed by a shielded beta-sensitive scintillation detector mounted in the top of the chamber. The sample stream then passes through a flow-regulating valve, through a sample pump, and finally returns to the suppression chamber. Table 11.4-1 lists the sensitivity and range of the detectors.

The Primary Containment Radiation Monitoring channel consists of the local detector-preamplifier unit, a radiation analyzer at local panel H21P284, and one pen on a recorder in the main control room. The recorder is a three-pen, six-decade strip-chart recorder located on panel H11-P812. The system provides no control function but is a diagnostic tool that enables the main control room operator to take appropriate action. Power is supplied from the 120-V ac inductive bus for the channel components and 120-V dc instrument bus for the recorder.

This monitor subsystem can withstand the changes of the atmosphere expected for normal conditions as listed in Table 11.4-3. This subsystem is a part of the primary containment monitor system described in Subsection 7.6.1.12. Arrangement details are shown in Figure 11.4-1.

This monitoring subsystem is provided with remotely controlled check-source features to allow on-line operability tests to be performed from the local control panel H21P284.

11.4.3.8.2.2 Offgas Radiation Monitor System

This monitor subsystem measures the radioactivity in the condenser offgas at the discharge of the 2.2-minute delay pipe after it has passed through the steam-jet air ejector and the recombiner. The monitor detects the radiation level that is attributable to the fission gases produced in the reactor and transported in the steam through the turbine to the condenser. It complies with GDC 13.

A continuous representative sample is extracted from the offgas pipe via a 1-in. stainless steel sample line. It is then passed through a sample chamber and a flow indicator and returned to the offgas system. The sample chamber is a 3-ft long section of a 4-in. Schedule 40 stainless steel pipe, which is internally polished to minimize plateout. It can be purged with room air to check detector response to the background radiation by using a three-way solenoid-operated valve. The valve can be controlled locally or from a switch located under the recorder on panel H11-P601 in the main control room. Three gamma-sensitive ion chambers are positioned adjacent to the vertical sample chamber. Two of the chambers are connected to channels that have logarithmic readouts, and the third is connected to a channel with a linear readout. These chambers are listed in Table 11.4-1 for sensitivity and range.

The linear channel consists of a local detector (gamma-sensitive ion chamber), current to frequency converter, and digital ratemeter in the relay room, and a recorder in the main control room. A linear readout with a range of 1 to 10^6mR/hr is used in conjunction with a recorder. The recorder is located on panel H11-P601 in the main control room. The channel has no trip functions and no alarms. Power is supplied from the 48/24-V dc battery for the channel and the 120-V ac instrument bus for the recorder. The auxiliary trip unit is powered from a 24/12 VDC power supply. This channel is classified Quality Level NQ and nonseismic.

The radiation level detected by the logarithmic channels can be directly correlated to the concentration of the noble gases. This concentration can be determined by using the semiautomatic sample system incorporated as part of this monitor. To use this system, a septum bottle is inserted into a sample chamber so that a hypodermic needle pierces the rubber cap. A vacuum pump is used to evacuate the bottle and then a solenoid-operated sample valve is opened to allow offgas to enter the bottle. The bottle is then removed and counted in the counting room with a multichannel gamma pulse height analyzer to determine the concentration of the various noble gas radionuclides. The correlation of sample activity and monitor reading can then be used by the operators to determine what activity is being discharged from the steam-jet air ejectors and ultimately from the roof vent.

Each of the two logarithmic channels consists of a local detector (gamma-sensitive ion chamber), current to frequency converter, a digital ratemeter in the relay room, and a recorder in the main control room. The recorder is a six-decade recorder located on panel H11-P601. The system provides no control function but is a diagnostic tool that enables the main control room operator to take appropriate action. Power is supplied from RPS bus A for one channel, from RPS bus B for the second channel, and from the 120-V ac instrument bus for the recorder. The auxiliary trip unit is powered from a 120 VAC/12 VDC power supply. These channels are classified Quality Level 1M and nonseismic. Arrangement details are shown in Figures 11.4-2 and 11.4-3 and in Sheet 3 of Figure 11.3-1.

11.4.3.8.2.3 Main Steam Line Radiation Monitor System

This monitor subsystem measures the radioactive gases coming from the reactor through the main steam lines. These gases are activation gases that come mainly from activation of oxygen, and fission gases that come from small fuel leaks and tramp uranium impurities. If the reactor fuel fails and a gross release of fission products occurs, the monitoring subsystem provides signals to trip the gland seal exhausters (when reactor power is below the low power setpoint associated with RWM), trip the condenser mechanical vacuum pumps and line valves, and isolate the reactor water sample system to contain the released fission products, thus mitigating the potential for release through these pathways as described in Chapter 15. The main steam line radiation monitoring system complies with Regulatory Guide 1.22 and GDC 13, 20, 21, 23, and 24.

The six detectors are located near the main steam lines just downstream of the outboard main steam line isolation valves in the space between the primary containment and secondary containment walls. The detectors are geometrically arranged so that this system is capable of detecting significant increases in radiation level with any number of main steam lines in operation. Their location along the main steam lines allows the earliest practical detection of a gross fuel failure. Two of the detectors are installed spares that can be electrically connected, if needed, outside the main steam tunnel. Table 11.4-1 lists the sensitivity and range of the detectors, as well as the alarm and trip setpoints.

The subsystem consists of four separate, redundant instrument channels. Each channel consists of a local detector (gamma- sensitive ion chamber) and a radiation analyzer in the relay room. A two-pen, six-decade strip-chart recorder on panel H11-P601 in the main control room is used to record two of the four channels. There are two selector switches located under the recorder, one to select channel A or C and the other to select channel B or D for recording.

A "one-out-of-two-taken-twice" logic is used to provide a trip signal to the gland seal exhausters (when reactor power is below the low power setpoint associated with RWM) and condenser mechanical vacuum pumps and line valves. Two “two-out-of-two” logics are used to provide an isolation signal to the reactor water sample system valves, with one logic closing the inboard valve and the other closing the outboard valve. Power is supplied from RPS bus A for two channels, from RPS bus B for two channels and from the 120-V ac instrument bus for the recorder. This subsystem is Quality Level 1 and Category I. Arrangement details are shown in Figure 11.4-3.

The alarms for this monitor subsystem are set to 1.5 times the “full power background” to allow for prompt sampling of the reactor coolant to determine possible sources of contamination and the need for corrective/mitigative actions.

11.4.3.8.2.4 Reactor Building Ventilation Exhaust Radiation Monitor System

This monitor subsystem measures the radioactivity in the reactor building ventilation system exhaust duct prior to its discharge from the building and, in doing so, complies with GDC 13, 23, and 64. The exhaust duct is in the form of a "T" with north and west legs that come together into a common line prior to passing through the building isolation dampers. During normal operation and during refueling operation (including criticality tests), the monitors act to detect a high activity level in the ductwork. Two independent redundant monitors are located on the common line downstream of the isolation dampers.

A continuous representative sample is extracted from the common duct through the gas monitor, a low-flow alarm switch, and then through a sample pump prior to being returned to the ventilation duct.

The shielded gas monitor has a beta-sensitive scintillation detector mounted in the top of a stainless steel chamber. Table 11.4-1 lists the sensitivity and range of the detector. In the event that this chamber becomes highly contaminated, it can be disassembled for cleaning or replacement.

Each channel consists of the local detector and preamplifier and a radiation analyzer in the relay room. No recorder is provided. One high-high trip or two low alarms (one from each detector) start the SGTS, close the primary containment vent valves, trip and isolate the reactor building vent system, isolate the control center, and initiate emergency recirculation mode for the control center ventilation system. A low trip also initiates all the above actions because the trip circuit has been designed to fail safe in the event of loss of power. Power is supplied from the 120-V ac instrument bus for each channel. This system is Quality Level 1M and seismic II/I. Arrangement details are shown in Figures 11.4-2, 11.4-4, 11.4-5, and 9.4-4, Sheets 1 and 2.

11.4.3.8.2.5 Offgas Vent Pipe Radiation Monitor System

This monitor system is not required since the reactor building exhaust plenum monitor measures the activity leaving the reactor building stack and is therefore not in operation. The system measures the activity in the offgas vent pipe before it discharges into the reactor building ventilation exhaust plenum. The activity this monitor detects is the effluent from the offgas system, which is composed of fission gases from the reactor. During startup, the condenser offgas passes through the mechanical vacuum pumps, through a 2-minute delay line, at the discharge end of which is a monitor, as described in Subsection 11.4.3.8.2.13, and into the common vent pipe.

A continuous representative sample is extracted from the vent pipe through an isokinetic probe, passed through a filter paper to collect particulates, and through an impregnated charcoal cartridge to collect iodine. The sample continues past a pressure switch used as a low-flow alarm, through the sample pump, through two gas monitors in series, and then through a rotameter prior to being returned to the vent pipe. Table 11.4-1 lists the location, sensitivity, and range of the monitors.

Each gas monitor has a sample chamber viewed by a shielded gamma-sensitive (NaI) scintillation detector. Each channel consists of a local detector and preamplifier, a radiation analyzer in the relay room (ratemeter removed and supporting components abandoned in place), and a recorder in the main control room. The recorder is a seven-decade recorder located on panel H11-P601. A switch located under the recorder is used to operate solenoid valves to stop the sample flow and admit room air to purge the detectors. Two other switches, also under the recorder, can be used to move solenoid- operated check sources into position to check detector response. Three local control switches are also provided for the same purposes at the rack where all the local equipment is mounted.

This subsystem provides no control function but is a diagnostic tool that enables the main control room operator to take appropriate action. Power is supplied from the 48/24-V dc batteries for the channels and from the 120-V ac instrument bus for the recorder. This subsystem is Quality Level NQ and seismic II/I. Arrangement details are shown in Figures 11.4-2 and 11.4-3 and in Sheet 3 of Figure 11.3-1.

11.4.3.8.2.6 Radwaste Building Ventilation Exhaust Radiation Monitor System

This monitor subsystem measures the radioactivity in the building exhaust prior to its discharge to the environment and, in doing so, complies with Regulatory Guide 1.21, Revision 1, and GDC 23 and 64. The activity this monitor detects is from samples in the laboratory fume hoods, tank vents, and the extruder fill station and ventilation exhaust from contaminated cubicles. The gaseous activity is normally expected to be below detectable levels. The particulate and iodine activity is accumulated on filters. These filters are periodically changed-out for counting. The filters are counted using certified equipment to aid in determining the quantities of specific radionuclides released. The gaseous activity is monitored by a beta scintillator and energy-compensated Geiger-Mueller tube viewing the same gas sample volume. The analysis results, combined with the data files and printouts from the detectors, provide a record of the activity released to the environment.

A continuous representative sample is extracted from the exhaust vent through an isokinetic probe. The sample first passes through a filter paper to collect particulates. Next the sample passes through an iodine-adsorbent cartridge. The sample then passes through the gas monitor, a combined high/low-flow alarm switch and indicator, and then a regulated sample pump before being returned to the exhaust vent.

The shielded gas monitor has a beta scintillator and energy-compensated Geiger-Mueller tube viewing a common sample plenum. A second Geiger-Mueller tube embedded in the shield exterior serves as a spare detector. Background compensation for both detector channels is performed using fixed background subtraction. Table 11.4-1 lists the sensitivity and ranges of these detectors. In the event that the sample chamber or detector housings should become highly contaminated, the units can be disassembled for cleaning or replacement.

This Sping 3 Radwaste Building Ventilation Exhaust Radiation Monitor (D11-N503/D11-P281) is a self-contained microprocessor-based detection system for sampling of particulates and iodines, and for monitoring of noble gases. The microcomputer performs the tasks of data acquisition, history file management, operational status check, and alarm determination. The monitor is powered from 120-V ac instrumentation and control (I&C) panel H21-P515. All data are accessed and printed out from the Eberline SS-1 system server located in the control room complex. A high- or low-flow condition, a high or low failure of a detector channel or a channel reading above setpoint results in an audible and visual alarm in the control room. In addition, a high channel alarm on the noble gas channel will initiate a trip of the radwaste building ventilation fans and automatically close the isolation dampers.

This system is Quality Level 1M and nonseismic. Arrangement details are shown in Figures 11.4-2, 11.4-4, and 9.4-5.

11.4.3.8.2.7 Turbine Building Ventilation Exhaust Radiation Monitor System

This monitor subsystem measures the radioactivity in the turbine building exhaust prior to its discharge to the environment and, in doing so, complies with Regulatory Guide 1.21, Revision 1, and GDC 23 and 64. The activity this monitor detects is from fission products in the steam that may leak from the turbine or other components in the building. The gaseous activity is normally expected to be below detectable levels. The particulate and iodine activity is accumulated on filters. These filters are normally changed out weekly. The filters are counted using certified equipment to aid in determining the quantities of specific radionuclides released. The gaseous activity is monitored by a beta scintillator and energy-compensated Geiger-Mueller tube viewing the same gas sample volume. The analysis results, combined with the data files and printouts from the detectors, provide a record of the activity released to the environment.

A continuous representative sample is extracted from the exhaust vent through an isokinetic probe. The sample first passes through a filter paper to collect particulates. Next the sample passes through an iodine-adsorbent cartridge. The sample then passes through the gas monitor, a combined high/low-flow alarm switch and indicator, and then a regulated sample pump before being returned to the exhaust vent.

The shielded gas monitor has a beta scintillator and energy- compensated Geiger-Mueller tube viewing a common sample plenum. A second Geiger-Mueller tube embedded in the shield exterior serves as a spare detector. Background compensation for both detector channels is performed using fixed background subtraction. Table 11.4-1 lists the sensitivity and ranges of these detectors. In the event that the sample chamber or detector housings should become highly contaminated, the units can be disassembled for cleaning or replacement.

This Sping 3 Turbine Building Ventilation Exhaust Radiation Monitor (D11-N504/D11-P279) is a self-contained microprocessor- based detection system for sampling particulates and iodines and monitoring noble gases. The microcomputer performs the tasks of data acquisition, history file management, operational status check, and alarm determination. The monitor is powered from 120-V ac I&C panel H21-P563. All data are accessed and printed out from the Eberline SS-1 system server located in the control room complex. A high- or low-flow condition, a high or low failure of a detector channel or a channel reading above setpoint results in an audible and visual alarm in the control room. In addition, a high channel alarm on the noble gas channel will initiate a trip of the turbine building ventilation fans. This system is Quality Level 1M and nonseismic. Arrangement details are shown in Figures 11.4-2, 11.4-4, and 9.4-7.

11.4.3.8.2.8 Deleted

11.4.3.8.2.9 Standby Gas Treatment System Radiation Monitor System

This monitor subsystem measures the radioactivity in the exhaust vent lines from the SGTS prior to its discharge to the environment and, in doing so, complies with Regulatory Guide 1.21, Revision 1, and GDC 23 and 64. There is a monitor on both SGTSs. The activity these monitors are designed to detect is composed of fission products from the reactor building that have been treated by the SGTS. The gaseous activity in the exhaust is normally expected to be below detectable levels. Particulate and iodine activity is accumulated on filters. These filters are normally changed-out weekly. The filters are counted using certified equipment to aid in determining the quantities of specific radionuclides released. The gaseous activity is monitored by a beta scintillator and energy-compensated Geiger-Mueller tube viewing the same gas sample volume. The analysis results, combined with the data files and printouts from the detectors, provide a record of the activity released to the environment.

A continuous representative sample is extracted from the exhaust vent through an isokinetic probe. The sample first passes through a filter paper to collect particulates. Next the sample passes through an iodine-adsorbent cartridge. The sample then passes through the gas monitor, a combined high/low-flow alarm switch and indicator, and then a regulated sample pump before being returned to the exhaust vent.

The shielded gas monitor has a beta scintillator and energy- compensated Geiger-Mueller tube viewing a common sample plenum. A second Geiger-Mueller tube embedded in the shield exterior serves as a spare detector. Background compensation for both detector channels is performed using fixed background subtraction. Table 11.4-1 lists the sensitivity and ranges of these detectors. In the event that the sample chamber or detector housings should become highly contaminated, the units can be disassembled for cleaning or replacement.

These Sping 3 SGTS System Exhaust Radiation Monitors (D11-N510A/ D11-P275 and D11-N510B/D11-P276) are both self-contained microprocessor-based radiation detection systems for sampling particulates and iodines and monitoring noble gases. The microcomputer performs the tasks of data acquisition, history file management, operational status check, and alarm determination. The monitors are powered from 120-V ac I&C panels. All data are accessed and printed out from the Eberline SS-1 system server located in the control room complex. A high- or low-flow condition, a high or low fail of a detector channel or a channel reading above setpoint results in an audible and visual alarm in the control room. The system provides no control function but is a diagnostic tool that enables the main control room operator to take appropriate action. This system is Quality Level 1M and seismic II/I. Arrangement details are shown in Figures 11.4-2 and 11.4-4.

See Subsection 11.4.3.8.2.16 for a discussion of the SGTS post-accident radiation monitor system.

11.4.3.8.2.10 <u>Reactor Building Exhaust Plenum Radiation Monitor System</u>

This monitor subsystem measures the activity in the reactor building exhaust plenum prior to its discharge to the environment and in doing so complies with Regulatory Guide 1.21, Revision 1, and GDC 64. The activity this monitor is designed to detect is due to corrosion and fission products from the reactor/auxiliary building ventilation system (Subsection 11.4.3.8.2.4) and from the offgas system (Subsection 11.4.3.8.2.5). The gaseous activity in the exhaust is mainly due to the condenser offgas. The particulate and iodine activity is accumulated on filters. These filters are normally changed-out weekly. The filters are counted using certified equipment to aid in determining the quantities of specific radionuclides released. The gaseous activity is monitored by a beta scintillator and energy-compensated Geiger-Mueller tube viewing the same gas sample volume and a high-range noble gas monitor using another energy-compensated Geiger-Mueller tube. The analysis results, combined with the data files and printouts from the detectors, provide a record of the activity released to the environment.

A continuous representative sample is extracted from the exhaust vent through an isokinetic probe. The sample first passes through a filter paper to collect particulates. Next the sample passes through an iodine-adsorbent cartridge. The sample then passes through the gas monitor, a combined high/low-flow alarm switch and indicator, the high-range noble gas monitor, and then a regulated sample pump before being returned to the exhaust vent.

The shielded gas monitor has a beta scintillator and energy- compensated Geiger-Mueller tube viewing a common sample plenum. A second Geiger-Mueller tube embedded in the shield exterior serves as a spare detector. Background compensation for both detector channels is performed using fixed background subtraction. The high-range noble gas monitor consists of an energy-compensated Geiger-Mueller tube viewing a shielded 1-in. stainless steel tube as its sample volume. Table 11.4-1 lists the sensitivity and ranges of these detectors. In the event that the sample chamber or detector housings should become highly contaminated, the units can be disassembled for cleaning or replacement.

This Sping 4 Reactor Building Exhaust Plenum Radiation Monitor (D11-N507/D11-P280) is a self-contained microprocessor-based radiation detection system for sampling particulates and iodines and monitoring noble gases. The microcomputer performs the tasks of data acquisition, history file management, operational status check, and alarm determination. The monitor is powered from a 120-V ac I&C panel. All data are accessed and printed out from the Eberline SS-1 system server located in the control room complex. A high- or low-flow condition, a high or low failure of a detector channel or a channel reading above setpoint results in an audible and visual alarm in the control room. The system provides no control function but is a diagnostic tool that enables the main control room operator to take appropriate action. This system is Quality Level 1M and seismic II/I. Arrangement details are shown in Figures 11.4-2, 11.4-4, and 9.4-4, Sheets 1 and 2.

11.4.3.8.2.11 Fuel Pool Ventilation Exhaust Radiation Monitor System

This monitor subsystem measures the activity from the fuel pool area ventilation exhaust ducts that discharge into the east and west legs of the reactor building ventilation exhaust system. The fuel pool contains gaseous activity due to mixing with the reactor coolant system during each refueling. Diffusion of this activity from the pool generates airborne activity that is swept into the spent fuel pool area ventilation system. Gaseous activity released during a fuel-handling accident is also swept into this ventilation system. Two detectors are located on each leg of the ventilation system downstream of all the spent fuel exhaust ducts. During refueling operation (including criticality tests), the monitors act to detect a high radiation level in the ductwork that could be due to fission gases from a refueling accident or a control rod drop accident. Two independent redundant monitors are provided on the east and west exhaust duct legs. The detectors are located as far upstream of the building isolation valve as practicable to allow for reaction time to close the valve to prevent the release of activity. Table 11.4-1 lists the range and sensitivity of the detectors. Subsection 15.7.4 contains a discussion of the accident analyses.

Each channel consists of a local sensor-convertor unit (gamma- sensitive detector and associated circuitry as discussed in Subsection 12.1.4), a radiation analyzer mounted in the relay room, and one pen on a recorder in the main control room. There are two, two-pen, four-decade strip-chart recorders provided, one on panel H11-P601 for channels A and B and one on panel H11-P812 for channels C and D. A high-high trip on any channel starts the SGTS, closes the primary containment vent valves, trips and isolates the reactor building vent system, isolates the control center, and initiates emergency recirculation mode for the control center ventilation system. The radiation monitors' maximum allowable value is 6mR/hr.

Two failure alarms (one from each detector on one leg) also initiate all the above actions because the trip circuit has been designed to fail safe in the event of loss of power, downscale/inop condition. Power is supplied from RPS bus A for one channel on each leg, from RPS bus B for the second channel on each leg, and from the 120-V ac instrument bus for the recorders. This system is Quality Level 1 and Category I. Arrangement details are shown in Figures 11.4-2, 11.4-3, and 9.4-4, Sheets 1 and 2.

11.4.3.8.2.12 Control Center Normal Makeup Air Radiation Monitor System

This monitor system measures the activity in the makeup air to the main control room. No measurable activity is expected to be present in the makeup air. However, in the event of a design- basis accident, fission gases could escape from the main coolant system and be drawn into the makeup air intake. There are two independent monitors at each normal makeup air intake. The system complies with GDC 13 AND 19.

A representative sample for each monitor is extracted from the ventilation duct and passes through the gas monitor, a low-flow alarm switch, and finally through a sample pump before being returned to the ventilation duct. Four source taps are located in the normal air intake prior to the normal air-intake isolation valves.

Each shielded gas monitor has a beta-sensitive scintillation detector mounted in the top of a stainless steel chamber.

Table 11.4-1 lists sensitivity and range for this detector. In the event the chamber becomes contaminated, it can be disassembled for cleaning or replacement.

Each channel consists of the local detector and preamplifier and a radiation analyzer in the relay room. No recorder is provided. One high-high or two low alarms (one from each detector) isolate the control center and initiate emergency recirculation mode for the control center ventilation system. Power is supplied from the 120-V ac instrument bus for the channel components. This system is Quality Level 1M and seismic II/I. Arrangement details are shown in Figures 11.4-2, 11.4-3, and 9.4-2.

11.4.3.8.2.13 Two-Minute Holdup Pipe Exhaust Radiation Monitor System

This monitor system measures the activity from the mechanical vacuum pumps after the discharge from the 2-minute delay pipe. In addition, it also monitors the turbine gland sealing system exhaust that enters the offgas system at the discharge of the mechanical vacuum pumps. The mechanical vacuum pumps are used during startup to remove large quantities of air from the system at high flow rates. After the offgas flow rate is reduced to normal levels, the flow is rerouted through the offgas treatment system and the mechanical vacuum pumps are shut off. The mechanical vacuum pump is also used for normal shutdowns, SCRAM related shutdowns, and during periods of low power operations when the Offgas system is not available. The mechanical vacuum pumps are shutdown when Shutdown Cooling is placed in service for normal shutdowns and SCRAM related shutdowns. The operating time for low power operations when the Offgas system is not available is generally shorter than three to five days. The monitors initially detect the activity due to fission gases produced in the reactor and transported in the steam through the turbine to the condenser. Later, the monitors detect the same gases that come through the turbine gland sealing system. Two independent redundant monitors are provided with the detectors mounted adjacent to the discharge line. The system complies with GDC 13, 23, and 64.

Each shielded monitor has a gamma-sensitive scintillation detector mounted adjacent to the offgas pipe. Table 11.4-1 lists the sensitivity and range of this detector.

Each channel consists of the local detector and preamplifier, and a radiation analyzer in the relay room. No recorder is provided. The system provides no control function, but the alarms for this monitor subsystem are set to 1.5 times the “full power background” to allow for prompt sampling of the reactor coolant to determine possible sources of contamination and the need for corrective/mitigative actions. Power is supplied from the 120-V ac instrument bus for the channel components. This system is Quality Level NQ and nonseismic. Arrangement details are shown in Figures 11.4-2, 11.4-3, and in Sheets 1 and 2 of Figure 11.3-1.

11.4.3.8.2.14 Control Center Emergency Air Inlets Radiation Monitor System

This monitor system measures the activity in the emergency air supply ducts to the main control room. No measurable activity is expected in the emergency air supply. A secondary emergency air makeup intake is provided on the north side of the auxiliary building, along with radiation detectors in both the existing air makeup intake and the second air intake. Therefore, either inlet for makeup air to the control center can be selected from either side of the potential release points, depending on the relative activity. The system is in compliance with GDC 13 and 19.

A representative sample for each of the four monitors is extracted from the emergency ventilation duct through a stainless steel sample tube, which passes through the gas monitor, a low- flow alarm switch, and a sample pump before being returned to the duct. The source taps (four each) are located in the north and south emergency air intakes upstream of the emergency intake isolation valves.

The sampling assembly consists of an off-line gas monitor, a beta-sensitive scintillation detector mounted on top of a stainless steel chamber, and a preamplifier and radiation analyzer in the relay room panel. High-radiation and low-flow or inoperative alarms are provided in the main control room. The sensitivity and range of these detectors are listed in Table 11.4-1. Recorders are not provided.

This system makes an initial automatic selection of emergency air inlets during a radiation-release accident. The monitors would sample the air for 5 minutes; after 5 minutes, if there were high radiation at either the north or south inlet, the corresponding damper with the lower radiation would stay open. The operators then would assume manual control of the selection process following the radiation release, using the radiation monitors to determine which inlet has the lowest radiation level.

This system is Quality Level 1 and Category I. For redundancy, two detectors are provided for each intake (north and south). Arrangement details are shown in Figures 11.4-2, 11.4-5, and 9.4-2.

11.4.3.8.2.15 Onsite Storage Facility Ventilation Exhaust Radiation Monitor System

This monitor subsystem measures the radioactivity in the radwaste onsite storage facility exhaust prior to its discharge to the environment and, in doing so, complies with Regulatory Guide 1.21, Revision 1, and GDC 23 and 64. The activity this monitor detects is a result of the storage and handling of radwaste and equipment in the building. Resultant radioactivity is normally expected to be below detectable levels. The particulate and iodine activity is accumulated on filters. These filters are periodically changed out for counting. The filters are counted using certified equipment to aid in determining the quantities of specific radionuclides released. The gaseous activity is monitored by a beta scintillator and energy-compensated Geiger-Mueller tube viewing the same gas sample volume. The analysis results, combined with the data files and printouts from the detectors, provide a record of the activity released to the environment.

A continuous representative sample is extracted from the exhaust vent through an isokinetic probe. The sample first passes through a filter paper to collect particulates. Next the sample passes through an iodine-adsorbent cartridge. The sample then passes through the gas monitor, a combined high/low-flow alarm switch and indicator, and then a regulated sample pump before being returned to the exhaust vent.

The shielded gas monitor has a beta scintillator and energy-compensated Geiger-Mueller tube viewing a common sample plenum.

A second Geiger-Mueller tube embedded in the shield exterior serves as a spare detector. Background compensation for both detector channels is performed using fixed background subtraction. Table 11.4-1 lists the sensitivity and ranges of these detectors. In the event that the sample chamber or detector housings should become highly contaminated, the units can be disassembled for cleaning or replacement.

This Sping 3 Onsite Storage Building Ventilation Exhaust Radiation Monitor (D11-N508/D11-P299) is a self-contained microprocessor-based radiation detection system for sampling particulates and iodines and monitoring noble gases. The microcomputer performs the tasks of data acquisition, history file management, operational status check, and alarm determination. The monitor is powered by a 120-V ac I&C panel. All data are accessed and printed out from the Eberline SS-1 system server located in the control room complex. A high- or low-flow condition, a high or low failure of a detector channel or a channel reading above setpoint results in an audible and visual alarm in the control room. This system provides no trip or control function but is a diagnostic tool that enables operations personnel to take appropriate action. This system is Quality Level 1M and nonseismic. Arrangement details are shown in Figures 11.4-2, 11.4-4, and 9.4-7.

11.4.3.8.2.16 Standby Gas Treatment System Postaccident Radiation Monitor System

This monitor subsystem measures the radioactivity in the exhaust vent lines from the SGTS after an accident has occurred and prior to discharge to the environment. In doing so, the subsystem complies with Regulatory Guide 1.97 and GDC 60 and 64. The activities these monitors are designed to detect are fission products (following an accident) from the reactor building that have been treated by the SGTS. The activity in the exhaust is expected to be high levels of noble gases resulting from a breach of primary system integrity. The gaseous activity of the SGTS unit exhaust is monitored by two shielded energy-compensated Geiger-Mueller tubes. In addition, a grab sample pallet (GSP-1) contains a particulate filter and charcoal cartridge in a removable shielded holder to allow count room analysis of particulates and iodine in the exhaust using certified equipment. The GSP-1 also has hose-barbed sample taps for removal of a gaseous sample for count room analysis. The analysis results, combined with the data files and printouts from the units, provide a record of the activity released to the environment.

A continuous representative sample is extracted from the exhaust vent through an isokinetic probe. The sample passes through a heat-traced line and bulk filter assembly (BFA-1) to remove any particulates. The filtered sample then passes through a regulated sample pump that provides a continuous sample flow rate of 5.43 liter/minute and a local flow indicator on the noble gas pallet (NGP-1). A flow switch tapped into the sample line at this point provides a loss-of-flow alarm trip to the unit. On the NGP-1 the sample passes through two shielded detector assemblies in series, the intermediate-range noble gas detector (SA-14), and the high-range noble gas detector (SA-15). Both the SA-14 and the SA-15 consist of an energy-compensated Geiger- Mueller tube viewing a shielded polished stainless steel sample volume. The SA-15 also has a second Geiger-Mueller tube embedded in its shield exterior which serves as a spare detector. Background compensation is provided using fixed background subtraction. The sample then returns to the SGTS exhaust header.

In addition to the NGP-1, another isokinetic probe in the sample line upstream of the BFA-1 splits off a portion of the sample flow (1/73.2) for the grab sample pallet assembly (GSP-1). The grab sample pallet flow driving head is provided by a manual throttling valve (V-3). The sample flow of ≥ 74.1 cm^3/minute passes through a shielded, removable particulate filter and iodine cartridge holder (SA-16), a visual flow indicator before returning to the sample line upstream of the BFA-1. The SA-16 contains an energy-compensated Geiger-Mueller tube to indicate the relative amount of radiation present in the filter and cartridge.

The detector outputs are translated by interface boxes and the resultant signal is transmitted to the data acquisition module (DAM-4) for each monitor (D11-N520A/D11-P300A and D11-N520B/D11-P300B). The DAM-4s are both self-contained microprocessor-based radiation detection systems for monitoring accident-range noble gases. The microcomputer performs the tasks of data acquisition, history file management, operational status check, and alarm determination. The monitors are powered from 120-V ac I&C panels. All data are accessed and printed out from the Eberline SS-1 system server located in the control room complex. A low-flow condition, a high or low failure of a detector channel or a channel reading above setpoint results in an audible and visual alarm in the control room. This system provides no control functions but is a diagnostic tool that enables the main control room operator to take appropriate action. This system is Quality Level 1M and seismic II/I. Arrangement details are shown in Figures 11.4-2 and 11.4-4.

The SGTS radiation monitor system for normal operation is described in Subsection 11.4.3.8.2.9.

11.4.3.9 Description of Liquid Monitors

Each channel of the system contains a completely integrated modular assembly as described below. Specific details of each monitor are described in Subsections 11.4.3.9.2.1 through 11.4.3.9.2.6.

11.4.3.9.1 General Liquid Monitor Details

11.4.3.9.1.1 Sampling Devices

For each off-line monitor except the circulating water decant line monitor, a sample is drawn from a process line through a sample tap, passed through a shielded sample chamber, through the sample pump, and returned to the system. The circulating water decant line radiation monitor does not have a sample pump (see Subsection 11.4.3.9.2.6).

Each sample pump is capable of drawing 1 gpm of liquid through the monitor. The sample flow rate is controlled with a manual flow-control valve. Each monitor has a low sample-flow alarm.

The monitor inlet and outlet lines are flanged and have isolation valves so that the monitor can be disassembled if decontamination is necessary. Sample valves are provided so that clean water can be purged through the chamber to check the background radiation level, and so that samples can be taken for analysis, or calibrated liquids introduced, to check the monitor calibration.

Each in-line monitor has a polished stainless steel well bolted to a flange on the line being monitored. The pressure and temperature limits and the Category and Quality Level for the well are the same as that for the line in which the well is mounted.

11.4.3.9.1.2 Detector-Preamplifier Unit

Each detector is a NaI gamma-sensitive scintillation detector. A preamplifier is mounted on top of the detector. The detectors are designed to remain fully operational over a wide range of temperatures, as shown in Table 11.4-3. If they are exposed to high radiation transients exceeding the channel range, the channel maintains full-scale deflection and returns to normal functioning when the transient has subsided. Since gamma detectors are used, comparison of monitor readout with the results of grab samples is easily made. The grab samples are counted in the plant multichannel gamma pulse height spectrometer to check monitor calibration. Solenoid-operated check sources are provided to check detector response on the General Atomics-supplied monitors. Each check source is operated from the respective radiation analyzer in the relay room.

Off-line detectors are mounted as close as practicable to the system being monitored, and yet are still in a low-radiation area (γ<0.5 mR/hr in most cases) so that the detectors have maximum sensitivity and so there is minimum sample plateout.

11.4.3.9.1.3 Radiation Analyzer

Subsection 11.4.3.8.1.3 contains a description of the radiation analyzer.

11.4.3.9.1.4 Recorder

Subsection 11.4.3.8.1.4 contains a description of the recorder.

11.4.3.9.2 Specific Liquid Monitor Details

11.4.3.9.2.1 Radwaste Effluent Radiation Monitor System

This monitor subsystem measures the activity in the radwaste effluent discharge line to comply with Regulatory Guide 1.21 and GDC 23 and 64. The radwaste effluent line discharges through the blowdown discharge line into the circulating water decant line, which dilutes the waste prior to its discharge to Lake Erie. This monitor detects the activity in the blowdown discharge line to prevent the concentration in the circulating water decant line from exceeding the 10 CFR 20, Appendix B, Table II, Column 2, activity limits. Waste liquid can be discharged from any of the three waste sample tanks. The liquid radwaste system for Fermi 2 is designed to be a closed-loop system which does not normally discharge effluent to Lake Erie. As discussed above, provision is made for a discharge should it be required, and instrumentation that satisfies the requirements of NUREG-0473, Revision 2, is provided on the decant line.

Prior to discharge, the liquid in the appropriate waste sample tank is sampled and analyzed in the laboratory for radioactivity to comply with Regulatory Guide 1.21. Based upon this analysis, a discharge permit is issued specifying the release rate, the dilution rate, and the tank to be discharged. The release rate and dilution rate are used to determine the alarm setpoints. Prior to the release, the radwaste control room operator or other authorized personnel on approval of radiochemistry may reset the High alarm point for a flow rate that will be lower than the maximum for which the alarm is normally set. The Shift Manager or his authorized delegate verifies that it is set correctly and initials the permit to signify that he has checked the setting.

The shielded detector is located in a well in the common discharge line from the liquid radwaste system through which all liquid radwaste discharges to the blowdown line must pass. Table 1.4-2 lists the sensitivity and range of this detector. The piping arrangement is designed so that the section of pipe in which the well is located can be flushed to remove crud to lower the background radiation levels or to remove a slug of highly radioactive liquid to clear the high alarm. The flanged stainless steel well, which protrudes into the liquid flow path, is bolted to the blowdown pipe. If the well becomes highly contaminated, it can be removed for decontamination after draining the line.

The channel consists of the local detector and preamplifier, a digital ratemeter in the relay room, and a recorder in the radwaste control room. The recorder is a seven-decade recorder located in the radwaste control room on panel G11-P604. A high alarm also sounds in the radwaste control room and light annunciator window 4D30 on panel G11-P604. A high-high trip or downscale failure initiates closure of the radwaste discharge isolation valve. A low trip also initiates an alarm. Power is supplied from the 48/24-V dc battery for the channel components and from the 120-V ac instrument bus for the recorder. The auxiliary trip unit is powered from a 24/12 VDC power supply. This subsystem is Quality Level 1M and nonseismic. Arrangement details are shown in Figures 11.4-2 and 11.4-3.

11.4.3.9.2.2 General Service Water Radiation Monitor System

This monitor subsystem measures the activity in the general service water line to comply with GDC 64. The general service water line discharges into the main condenser circulating water discharge line. Some of this liquid is evaporated, and the remainder is discharged to the circulating water reservoir where a portion is decanted through the circulating water decant line to Lake Erie. No activity attributable to reactor operation is expected to be present in this line. To have activity in this line, a leak would have to develop simultaneously in equipment cooled by the reactor building closed cooling water system (RBCCWS) and in the RBCCW heat exchanger, or simultaneously in equipment cooled by the turbine building closed cooling water system (TBCCWS) and TBCCW heat exchanger. Samples of the closed cooling water systems are checked periodically for activity that would warn if a leak had developed in a component. In addition, there is an in-line radiation monitor on the RBCCWS (Subsection 11.4.3.9.2.3), which would warn of any gross leak from a component cooled by that system between analyses.

The service water monitor provides a backup for the above detection methods and detects gross leaks of radioactive liquid into the service water.

The shielded detector is located in a well in the service water discharge line. Table 11.4-2 lists the sensitivity and range of this detector. The flanged stainless steel well, which protrudes into the liquid flow path, is bolted to the service water pipe. If the well should become contaminated, it can be removed for decontamination.

The channel consists of the local detector and preamplifier, a digital ratemeter in the relay room, and a recorder in the main control room. The seven-decade recorder is located in the main control room on panel H11-P601. The recorder is shared with the RBCCW monitor. The system provides no control function but is a diagnostic tool that enables the main control room operator to take appropriate action. Power is supplied from the 48/24-V dc battery for the channel and from the 120-V ac instrument bus for the recorder. The auxiliary trip unit is powered from a 24/12 VDC power supply. This subsystem is Quality Level NQ and nonseismic. Arrangement details are shown in Figures 11.4-2, 11.4-3, and 9.2-1, Sheet 1.

11.4.3.9.2.3 Reactor Building Closed Cooling Water Radiation Monitor System

This monitor subsystem measures the activity in the RBCCWS and, in doing so, complies with GDC 64. The RBCCWS cools components that contain radioactive liquids, but does not normally have any activity unless one of these components develops a leak. Samples of the RBCCWS are checked periodically for activity to determine if a leak is starting in a component. A laboratory analysis has much greater sensitivity than a radiation monitor, and therefore can detect smaller leaks. Since leaks usually start small and develop gradually, the radiological analyses performed in the laboratory normally detect the leak prior to the monitor. If a leak should increase dramatically between samples, or if a gross failure should occur, the monitor would detect it. Each RBCCW supplemental cooling loop and the associated EECW loop it services form a separate flow circuit that does not circulate fluid past the RBCCW radiation monitor. These circulation loops (one for each EECW division) are provided with sample points. As stated above, laboratory analysis has a better sensitivity for detecting small leaks. For larger leaks into a RBCCW supplemental cooling circuit, the extra fluid added to the circuit upsets the hydraulic balance between the RBCCW circulation inside and outside of RBCCW supplemental cooling. This hydraulic imbalance forces fluid into the flow of RBCCW outside of the RBCCW supplemental cooling which does pass by the RBCCW radiation monitor. The RBCCW radiation monitor will then detect the increase in activity as it does when the RBBCW supplemental cooling loops are not in operation.

This design meets the criteria stated above that small leaks are detected by sampling and large leaks are detected with the radiation monitor.

The shielded detector is located in a well in the 20-in. discharge header of the RBCCW pumps. Table 11.4-2 lists sensitivity and range of this detector. The flanged stainless steel well, which protrudes into the liquid flow path, is bolted to the cooling water pipe. If the well should become contaminated, it can be removed for decontamination.

The channel consists of the local detector and preamplifier, a digital ratemeter in the relay room, and a recorder in the main control room. The recorder is a seven-decade recorder located on panel H11-P601. The recorder is shared with the general service water effluent monitor. The RBCCWS monitor system provides no control function but is a diagnostic tool that enables the main control room operator to take appropriate action. Power is supplied from the 48/24-V dc battery for the channel and from the 120-V ac instrument bus for the recorder. The auxiliary trip unit is powered from a 24/12 VDC power supply. This subsystem is Quality Level NQ and seismic II/I. Arrangement details are shown in Figures 11.4-2 and 11.4-3.

11.4.3.9.2.4 Emergency Equipment Cooling Water Radiation Monitor System

This monitor subsystem measures the activity in the emergency equipment cooling water system (EECWS) and, in doing so, complies with GDC 64. The EECWS cools certain vital components in the reactor building if use of the RBCCWS is lost. When this system is used, the components it cools have water that contains radioactive contaminants. This monitor is used to determine if a leak occurs. One detector is located on each of the two redundant systems.

Each shielded detector (Table 11.4-2 lists the sensitivity and range of this detector) is located in a well in the 8-in. EECW line downstream of the components that have been cooled. The flanged stainless steel well, which protrudes into the liquid flow path, is bolted to the pipe. If the well should become contaminated, it can be removed for decontamination.

Each channel consists of the local detector and preamplifier and radiation analyzer in the relay room. No recorder is provided. The system provides no control function but is a diagnostic tool that enables the main control room operator to take appropriate action. Power is supplied from the 120-V ac instrument bus for each channel. This subsystem is Quality Level NQ and seismic II/I. Arrangement details are shown in Figures 11.4-2, 11.4-3, 9.2-3, and 9.2-4.

11.4.3.9.2.5 Residual Heat Removal Service Water System Radiation Monitor System

This monitor subsystem measures the activity in the residual heat removal service water system (RHRSWS) and, in doing so, complies with GDC 23 and 64. The RHRSWS cools the RHR system, which is used when the reactor is shut down to remove decay heat from the reactor coolant system. The RHRSWS is discussed in detail in Subsection 9.2.5. This cooling water is discharged to the RHR cooling tower and then into the RHR reservoir. This monitor detects gross leaks to warn of contamination. One detector is located on each of the two redundant systems downstream of the respective RHR heat exchanger.

A representative sample is extracted from each 24-in. line through a sample tap, the liquid monitor, a low-flow alarm switch, and then a sample pump prior to being returned to the RHRSW line downstream.

The shielded detector is mounted in the top of a stainless steel chamber. Table 11.4-2 lists the location, sensitivity, and range of this detector. In the event that this chamber becomes contaminated, it can be disassembled for cleaning or replacement.

Each channel consists of the local detector and preamplifier and radiation analyzer in the relay room. No recorder is provided. Power is supplied from the 120-V ac instrument bus for each channel. This subsystem is Quality Level NQ and seismic II/I and has been upgraded to Quality Level 1 and Seismic I for pressure boundary integrity only. Arrangement details are shown in Figures 11.4-2 and 11.4-3.

11.4.3.9.2.6 Circulating Water Reservoir Decant Line

This monitor subsystem measures the activity in the circulating water decant line and, in doing so, complies with Regulatory Guide 1.21, Revision 1, and GDC 64. The decant line is the blowdown line from the circulating water reservoir to Lake Erie and provides dilution for the liquid radwaste that discharges into this line upstream of the monitor. This is the final point at which a measurement can be made prior to discharge into Lake Erie. This monitor provides a permanent record of this discharge.

A continuous sample flows from the decant line through a tap, the liquid monitor, and a low-flow alarm switch prior to being discharged into the circulating water reservoir downstream.

The shielded detector is mounted in the top of a stainless steel chamber. Table 11.4-2 lists the sensitivity and range of this detector. In the event this chamber becomes contaminated, it can be disassembled for cleaning or replacement.

The channel consists of the local detector and preamplifier, a radiation analyzer in the relay room, and one pen on a recorder in the main control room. The recorder is a two-pen, six-decade strip-chart recorder located on panel H11-P812.

The system provides no control function but is a diagnostic tool that enables the main control room operator to take appropriate action. Power is supplied from the 120-V ac instrument bus. This subsystem is Quality Level 1M and nonseismic. Arrangement details are shown in Figures 11.4-2 and 11.4-3.

11.4.3.10 Containment Area High Range Monitors

Redundant monitors manufactured by General Atomic have been installed to meet the requirements of NUREG-0578, NUREG-0737, and Regulatory Guide 1.97, Revision 2.

These monitors are General Atomic Model RP-2C, and the detectors are Model RD-23 units. This system hardware, including cables, has been designed and qualified to meet the requirements contained in Table II.F.1-3 of NUREG-0737, with the exception of the upper decade criteria for "special environmental qualifications." This exception has been presented to the NRC and approved in Supplement 6 to the Fermi 2 Safety Evaluation Report, NUREG-0798, July 1985.

Radiation levels resulting from gamma photons in the general area of the detectors are indicated in the relay room and displayed on strip-chart recorders in the main control room. The two detectors are located in the primary containment, one at drywell azimuth 302 degrees, Elevation 605 ft 0 in., approximately 6 ft from the shield wall, and the other at drywell azimuth 125 degrees, Elevation 605 ft 0 in., 7 ft from the shield wall. The area chosen is relatively free of massive shielding and is accessible for maintenance.

The monitors and power supplies are located in the plant relay room and are powered from divisional ac power supplies.

11.4.3.11 Postaccident Gaseous Effluent Radiation Monitoring

11.4.3.11.1 Noble Gas Effluent Monitor

Extended range requirements for noble gas effluent monitors have resulted in the installation of an Eberline Company Sping-3/4 series digital monitor on each gaseous effluent discharge point. The effluent channels affected are listed in Table 11.4-4.

All of the normal range channels will trip their respective ventilation system on high-radiation level and/or downscale failure. Following a postulated design-basis accident, the reactor building's ventilation system is tripped, and the SGTS exhaust becomes the single primary discharge vent for the entire secondary containment air space. For this reason, only the SGTS discharge has been provided with Eberline AXM monitors.

Each Sping monitor is a self-contained unit that uses a multisensor approach to meet the broad-range requirements. The Sping employs a local microprocessor to perform the necessary control and digital signal conversion and processing. A history file of the data from each detector is maintained by the processor. This file consists of the last 4 hr of 10-minute averages, the last 24 hr of 1-hr averages, and the last 24 days of 1-day averages.

A control and display are provided in the main control room to allow bidirectional communication with any of the individual radiation channels. This same data base is accessible in the technical support center. Radiation data are reported to operating personnel via both alarms and typewritten data summaries.

The AXM channels are installed in the discharge of the SGTS and use a low-flow isokinetic sample of approximately 5.43 liters/ minute. The accident monitor meets the range requirement of 1 x 10^5 μCi/cm^3 imposed by NUREG-0737 for noble gas accident monitors in this application. The AXM monitors are environmentally qualified by the vendor to meet IEEE 323-1974.

The Sping and AXM monitors have backup local battery power supplies that are part of the instrument system. These batteries are continuously maintained in a state of full charge by self- contained chargers. The battery has a capacity of 8 hr of operation without recharge. The sampling pump power is derived from the power feed supplying the particular ventilation system fan being monitored.

These monitors provide an activity release rate in units of μCi/sec by direct comparison with the results of actual samples of the effluent that have been analyzed on a gamma isotopic analysis system. All monitor calibrations are performed using approved site procedures developed from the vendor instructions.

The flow rate of each stack/vent is initially determined by measurement to a reasonable degree of accuracy. Each of the Sping monitors includes an isokinetic sample provision. In the case of the SGTS, the actual process airflow is automatically controlled to a design value within a tolerance of ±10 percent. Since the AXM channels include an isokinetic sample system and the process flow is maintained at a constant value, no additional provisions are required to maintain system accuracy.

11.4.3.11.2 Radioactive Iodine and Particulate Effluent Monitoring

Each of the Eberline Sping monitors installed on the plant ventilation discharge stacks provides continuous sampling of both radioactive iodine and particulates. Following a design-basis postulated accident, the SGTS becomes the single primary discharge vent; hence the AXM monitors, which are installed on the SGTS, use a special particulate filter and iodine cartridge assembly that is designed for easy retrieval and incorporates integral shielding. Procedures for retrieval of the samples have been developed with Eberline assistance. The accessibility of the sample locations has been considered, and the GDC 19 requirements are satisfied during retrieval of the samples.

All of the sample probes are designed to take isokinetic samples. In the case of the SGTS, the flow is controlled, which obviates any concern with regard to the adequacy of the sampling system.

The AXM system sample lines have been analyzed and correction factors identified to address potential sample line losses attributable to the plate-out of radioiodines.

None of the effluent streams measured have water entrained in the gas, and moisture degradation is not considered a problem.

11.4.3.11.3 Torus Hardened Vent Radiation Monitor System

This monitor subsystem measures the radioactivity in the exhaust vent line from the torus after a severe accident has occurred and prior to discharge to the environment. Torus venting is used only during accidents which are beyond the plant design basis. This release path is not required to be used during normal or design basis accident conditions, and therefore, need not comply with Regulatory Guide 1.97. When used, the torus vent will prevent rupture of the primary containment by permitting direct vent to the environment. If fuel damage occurs concurrent with the loss of all containment cooling, the effluent would consist primarily of noble gases. The majority of the iodines and particulates would be removed by scrubbing action in the wetwell.

The THVRMS consists of a Process Radiation Detector and Ratemeter. The radiation monitor is mounted adjacent to the 24-inch vent pipe on RB4. The radiation monitor covers a range of 1E-4 R/hr to 1E+5 R/hr.

The THVRMS provides no control function but does provide an alarm and indication in the control room that alerts the operator of a radioactive release in progress. The monitor is also interfaced with the emergency response function of the Integrated Plant Computer System (IPCS). The THVRMS is classified as QA Level 1M and Seismic II/I. The system is powered from an Uninterruptable Power System (UPS). During normal plant operation input power will be from a BOP 120 VAC Distribution Panel (from BOP MPU #3). During a BDBEE the UPS provides input power to the HCVS Radiation Monitoring System for the first 24 hours of the Hardened Containment Venting scenario. After 24 hours into a Hardened Containment Venting scenario, power is shifted to a Class 1E Distribution Panel (from Class 1E MPU #2). Arrangement details are shown in Figure 11.4-4.

For further information on primary containment venting see Section 6.2.5.2.5.1.

11.4.3.12 In-Plant Iodine Radiation Monitoring

In-plant iodine radiation monitoring is implemented to accurately determine the airborne iodine concentration in areas within the facility where plant personnel may be present following an accident.

An adequate number of in-plant iodine monitoring instruments are available for the four vital areas necessary for postaccident operation of the plant. These areas are the operational support center, the technical support center, the postaccident sampling facility, and the postaccident sample analysis area.

Three separate laboratory facilities with gamma isotopic analysis capability are available: one in the chemistry laboratory counting room (located in the radwaste building), one in the Radiation Protection Count Room (located in the plant office service building), and one remote laboratory facility (located at the Nuclear Operations Center in the Emergency Operations Facility).

To perform rapid postaccident in-plant determinations of the airborne iodine concentration, a stabilized sodium iodide detector coupled to an analyzer will be used to continuously evaluate an iodine adsorbent cartridge. This cartridge will be coupled to a flow-stabilized air sampler. These entire units are cart-mounted and portable. Procedures for the use and calibration of the unit are available. Personnel are trained in the use and calibration of the unit.

To evaluate air samples, health physics routinely uses gamma isotopic analysis to identify and quantify the results. This analyzer will be backed up by two units in the chemistry laboratory. In addition, if both the chemistry and health physics counting rooms are unavailable (such as might occur during worst-case accident conditions), a remote laboratory facility located at the emergency operations facility will be available for air sample analysis. This remote facility will basically use the same analysis equipment and procedures as those normally used by health physics and chemistry.

In addition, a supply of silver zeolite, or equivalent, adsorbent cartridges is available to allow the determination of the airborne iodine concentrations in the presence of noble gas.

11.4.4 Sampling

The following sections present a detailed description of the radiological sampling procedures, frequencies, and objectives for all plant process and effluent sampling. This sample program provides the means to comply with the Offsite Dose Calculation Manual radiological effluent controls for the process radiation monitoring system and radwaste system.

11.4.4.1 Process Sampling

Subsection 9.3.2 presents a detailed description of the design of sampling facilities provided for general sampling. The sample frequency, type of analyses, analytical sensitivity, and the purpose of the sample are summarized in Table 11.4-5 for each liquid process sample location, and in Table 11.4-6 for each gas process sample location. The analytical procedures used in sample analysis are presented in Subsection 11.4.4.3. These samples monitor activity levels within various plant systems.

11.4.4.2 Effluent Sampling

Effluent sampling of all potentially radioactive liquid and gaseous effluent paths is conducted on a regular basis in order to verify the adequacy of effluent processing to meet the discharge limits to unrestricted areas. This effluent sampling program provides the information for the effluent measuring and reporting programs required by 10 CFR 50.36a in annual reports to the NRC. The frequency of the periodic sampling and analysis described herein is nominal and may be increased if the effluent levels approach the Offsite Dose Calculation Manual (ODCM) Radioactive effluent control limits. Radioactive effluent sampling and analysis requirements are given in the ODCM Radiological Effluent Controls.

11.4.4.3 Analytical Procedures

Samples of process and effluent gases and liquids may be analyzed for alpha, beta, and gamma radiation.

Instrumentation available on-site for the measurement of radioactivity includes:

a. 2-π proportional counter

b. Liquid scintillation counter

c. Gamma isotopic analysis

Gross beta analyses of liquid process samples are performed with a proportional counter. These samples are evaporated to dryness on planchets prior to counting. Sample volume, counting geometry, and counting time are chosen to achieve the required measurement sensitivities. Correction factors are applied for sample-detector geometry, self-absorption, and counter-resolving time, as needed.

Gross beta and gross alpha analyses are performed with the proportional counter. The samples are prepared for counting by evaporation onto planchets. Sample volume and counting times are chosen to achieve the required measurement sensitivity. Correction factors are applied for self-absorption.

Gross beta and alpha analyses of air particulate composite samples will be performed by counting using the proportional counter.

Gamma isotopic analysis will be used exclusively for the radionuclide analysis of gaseous, air particulate, and liquid samples. The detectors are calibrated against gamma energy for a variety of sample detector geometries.

Gaseous tritium samples are collected by the use of bubblers, condensation, or adsorption (silica gel). Liquid samples for tritium analysis are purified prior to analysis by either passing the samples through mixed-bed ion-exchange columns or by distilling the samples, or both. The liquid scintillation counter is used to count the samples.

Radiochemical separations and gas proportional counting are used for the routine analysis of ^{89}Sr and ^{90}Sr.

Depending on initial experience, either activated charcoal, impregnated charcoal, or silver zeolite will be employed as the adsorption media in gaseous radioiodine sampling devices.

11.4.4.4 Postaccident Sampling System

The postaccident sampling system (PASS) provides the capability of obtaining reactor coolant and containment atmosphere samples under accident conditions. To ensure the ability to sample under post-LOCA environments, the design incorporates sufficient safeguards (shielding/ventilation) to keep the radiation exposure to individuals within the limits of 10 CFR 50, Appendix A, General Design Criteria 19. Compliance to these limits was verified by performance of a time and motion study covering sampling, transport and analysis.

This system has the capability for dilution and remote operation in order to safely obtain representative reactor coolant, suppression pool and containment atmosphere samples.

The design and operation of the Fermi 2 PASS was approved by the NRC in Supplement 5 of the Fermi 2 Safety Evaluation Report and NRC Safety Evaluation dated June 12, 2001.

11.4.4.4.1 Sampling System

A schematic of the PASS is shown in Figure 11.4-6. The general arrangement of the postaccident sample station is shown in Figure 11.4-7 and a schematic diagram of the station is shown in Figure 11.4-8.

The PASS isolation valves and sampling panel are supplied with Class 1E power and on-site backup power, respectively. Both can be operated within 30 minutes of an accident in which there is a loss of offsite power.

The system is installed in the auxiliary building adjacent to the secondary containment, and consists of liquid- and air-sampling subsystems. Appropriate procedures have been written to ensure proper operation.

From the sample station, samples are transported to the analytical laboratory or to an exit for offsite analysis. The short transport route within the building ensures that radiation doses received during transport are minimal.

The PASS will be operated periodically to ensure operability and to provide the opportunity for training. Nuclear Chemistry technician proficiency in PASS operation is verified and maintained in accordance with the Chemistry Technician Training and Qualification Program Description, which includes initial classroom and on-the-job (OJT) training. Documentation of this training is maintained as part of training department records.

The PASS has the capability to obtain:

a. Reactor coolant samples via RHR, when in the shutdown cooling mode, or via jet pumps #5 and #15 when the reactor is at pressure.

b. Containment atmosphere samples

c. Suppression pool atmosphere samples

d. Suppression pool liquid samples from the RHR system when in the suppression pool cooling mode

e. Reactor building (secondary containment) atmosphere.

The ability to obtain these samples does not rely on the use of any isolated contaminated auxiliary system.

Sample lines tie in upstream of automatic isolation systems and are provided with isolation valves operated from the control room. Routing is as direct as possible, and gas lines are heat traced. Long sweep bends and continuous pitch minimize plate- out, blockage, and dissociation of dissolved gases. Shielding is provided in areas where personnel exposure may occur.

Restriction devices are not being used because they are potential crud traps. The small size of the sample lines essentially serves as a flow limiter in case of line rupture.

The PASS sample station, as well as the sample return lines, are purged with either demineralized water or nitrogen gas after taking samples. This reduces the chance of system plugging, reduces radiation buildup by minimizing plate-out, and provides assurance of obtaining representative samples.

Return lines provide a closed loop and return any unused liquids to the suppression pool, and any unused gases to the suppression pool or secondary containment. Refer to Figure 11.4-6.

Postaccident containment sampling is accomplished by connecting into the primary containment monitoring system lines. These lines are routed from opposite sides within containment. The elevation and location on opposite sides of containment permit representative sampling of the upper portion of containment where gases could accumulate. The upper elevation also minimizes the probability of blockage should flooding of the containment occur. Sample nozzle blockage is reduced by pointing the nozzles downward, having the nozzles the same size as the pipes, and not installing traps or filters on the inlet. Recirculation is accomplished by a metal-bellows-type pump at the sample station that draws containment samples through the sample station and returns the sample back to containment.

Suppression pool atmosphere is sampled by tying into two 1-in. primary containment monitoring system lines that connect to suppression pool penetrations X-230 and X-231. The elevation, locations, and nozzle designs similar to primary containment sampling aid in ensuring a representative sample and in minimizing blockage. A pump separate from the primary containment sampling pump recirculates the sample from and back to the suppression pool.

The gas sample system is designed to operate at pressures ranging from subatmospheric to the maximum design pressures of the primary and secondary containments. Heat-traced sample lines are used to prevent the precipitation of moisture and to minimize plate-out.

The gaseous sample flow is chilled to remove entrained moisture, and a nominal grab sample can be taken for the determination of gaseous activity and for hydrogen or oxygen analysis by gas chromatography. A standard sample vial has been adopted for all gas samples to be consistent with present offgas sample vial counting factors. Provision has been made in the laboratory to aliquot fractions of the initial vial contents to other vials if the activity is too high to count directly.

A sample line is provided to obtain reactor coolant samples from two points (jet pumps 5 and 15) in the jet pump pressure instrument system when the reactor is at pressure. This sample location is recommended over the normal reactor sample points as the reactor cleanup system is expected to be isolated under accident conditions, and it is possible that the recirculation line containing the normal reactor water sample lines may be secured. The jet pump pressure system has been determined to be an optimum sample point for accident conditions. The pressure taps are well protected from damage and debris. If the recirculation pumps are secured, there is normally excellent circulation of the bulk of the coolant past these taps. The pressure taps are located sufficiently low to permit sampling at a reactor water level even below the lower core support plate.

In order to ensure that these pressure taps provide a representative sample, two conditions should exist:

a. Enough core flow to allow circulation of water from inside the shroud to the jet pump intake

b. No significant dilution by makeup water.

Two assumptions were made for this determination:

a. Reactor water level can be maintained at or near normal water level after the accident

b. Reactor power level is greater than 1 percent rated, up to approximately 10 percent rated, when the water sample is taken.

Regarding condition (a), after a small break or non-break accident, the reactor water level will be maintained at or near normal water level by the operator using emergency procedures. For decay power above 1 percent of rated power, the core flow is estimated to be greater than 10 percent rated recirculation flow due to natural circulation. This amount of core flow ensures the existence of a flow route from the core to the sampling points; it takes about 3 to 4 minutes to circulate the entire reactor water inventory through the jet pumps. Therefore, a representative sample of the core water will be available at the jet pumps.

Regarding condition (b), for small steam line breaks or non-break accidents, makeup water is pumped in to remove decay heat and to make up for steam loss through the break. This makeup water amounts to approximately 2 percent of the core flow present. Even for small liquid line breaks, the makeup water flow rate is estimated to be less than 18 percent of the core flow present. Therefore, it can be concluded that no significant dilution would occur; the bulk of the water going through the jet pump comes from the reactor core.

A single sample line is also connected to both loops in the RHR system. This provides a means of obtaining a reactor coolant sample when the reactor is depressurized and at least one of the RHR loops is operated in the shutdown cooling mode. To ensure that the sample is representative under these conditions, samples will be acquired after the reactor water level has been raised (approximately 18 in.) to the point where water flows from the steam separators. Similarly, a suppression pool liquid sample is obtained from the RHR loop lined up in the suppression pool cooling mode. These lines are installed on the discharge side of the RHR pumps, downstream of the pump check valves. The representativeness of the suppression pool sample is ensured by the following:

a. No safety/relief valves discharge directly into RHR suction

b. The selected RHR loop will be recirculated approximately 30 minutes prior to taking a sample

c. Sample lines are installed on the discharge side of the RHR pumps, downstream of the pump check valves.

Suppression pool atmospheric samples are taken from taps on opposite sides of the pool proper. Each tap location is selected to maximize the distance to either a downcomer or safety/relief valve discharge sparger.

The sample station is provided with a sump to collect spillage, should it occur. The sump drains into the collector, which is then emptied back into the suppression pool. The collector contains provisions for purging. Should contamination take place, the spread of the contamination is precluded by the fact that it is enclosed and shielded and returned via a closed loop to the suppression pool and the collector has the capability to be purged to eliminate any further contamination.

The PASS isolation valves are independent of automatic isolation or safety injection signals. These isolation valves are always maintained in a closed position by administratively controlled, key-locked pushbuttons in the control room and are opened only when required for sampling, training, maintenance, or testing. Valve position is indicated on the control panel and operability is ensured by the use of Class 1E power. The Target Rock isolation valves conform to IEEE 323-1974 and IEEE 382-1972, and are environmentally qualified. It is estimated that conformance to these requirements ensures the operability of the valves for the period when secondary containment is inaccessible.

11.4.4.4.2 Radiological and Chemical Analysis

Onsite radiological and chemical analysis is provided (in accordance with the guidelines of NUREG-0737 and Reg. Guide 1.97) to quantify source-term radionuclides in the nuclide categories as discussed in Regulatory Guide 1.3. In conjunction with gamma isotopic analysis, selected radionuclides are quantified for use in procedure 78.000.15 (determination of extent of core damage). Analysis of hydrogen levels in the containment and suppression pool atmosphere is performed by gas chromatograph. The PASS can provide diluted liquid samples, which will subsequently minimize personnel exposure during analysis. The sensitivity of onsite liquid sample analysis will permit the measurement of nuclide concentration from approximately 1 μCi/g to 10 Ci/g. Background radiation levels in the onsite laboratory are such that an acceptably small error, less than a factor of 2, will result during sample analysis. The instruments will provide the operator with the radiological and chemical status of the reactor coolant. A remote analysis facility is provided and has the same capabilities as outlined above. Confirmatory analysis may also be performed by an offsite facility.

Automatic, on-line, analytical-type monitors are not used in the PASS. The sample station control panel contains indicators for pressure, temperature, flow, radiation, and conductivity.

A Fermi 2 Radiation Chemistry procedure has been developed for estimating core damage based on the concentrations of volatile and nonvolatile radionuclides. By appropriately normalizing actual Fermi plant data with reference plant data under postulated LOCA conditions, an estimation of core damage can be provided.

11.4.4.4.3 Evaluation

The sample lines up through the second isolation valve are designed to the nuclear classification of the process lines to which they connect. Remote manual isolation valves are provided on these lines. The PASS system is not safety related.

11.4.4.4.4 Testing

The PASS is operated periodically to ensure operability. Operability is demonstrated by obtaining a liquid and gas sample consistent with plant operating mode.

11.4.4.4.5 Procedures

Procedures for sample collection, sample transfer or transport, and sample analysis have been prepared and are summarized below.

All liquid samples are taken into septum bottles mounted on sampling needles. The sample panel is basically a bypass loop on the sample purge line. In the diluted sample lineup, the sample flows through a conductivity cell (readable range 0.1 to 1000 µmho/cm) and then through a ball valve. Flow through the sample panel is established, the valve is rotated 90°, and a syringe is used to flush the sample plus a measured volume of diluent through the valve and into the sample bottle. This provides an initial dilution and supplies a sample for further dilution and subsequent counting on a gamma spectrometer. Alternatively, the flow can be diverted through a sample bomb to obtain a large, pressurized volume. This volume can be circulated and depressurized into a gas sampling chamber where the dissolved gases are stripped from the coolant sample. A gas sample can then be obtained for gas chromatography and quantitative analysis of the dissolved gases associated with the liquid volume. Aliquots of this degassed liquid can also be taken for offsite chemical analyses requiring a relatively large sample. A radiation monitor in the liquid sample enclosure monitors liquid flow from the sample station to provide immediate assessment of the sample activity level. This monitor also provides information as to the effectiveness of the demineralized-water flushing of the sample system following sample operation.

For gas samples, appropriate sample-handling tools are used within the sample station. A gas sampler vial positioner and gas vial cask are also used. The gas vial is installed and removed by the use of the vial positioner through the front of the gas sampler. The vial is then manually dropped into the cask with the positioner, which allows the vial to be maintained about 3 ft from the individual performing the operation.

For liquid samples, a small-volume liquid sample is remotely obtained through the bottom of the sample station by the use of the small-volume cask and cask positioner. The cask positioner holds and positions the cask directly under the liquid sampler. The sample vial is manually raised within the cask to engage the hypodermic needles. When the sample vial has been filled, the bottle is manually withdrawn into the cask. The sample vial is always contained within lead shielding during this operation. The cask is then lowered and sealed before transport to the laboratory.

A large-volume cask and cask positioner containing a nominal 25 ml bottle within a lead-shielded cask are also provided. This sample bottle is raised from its location in the cask to the sample station needles for bottle filling. The sample station will deliver approximately 10 ml to this sample bottle. When filled, the bottle is withdrawn into the cask. The sample bottle is always shielded by lead when in position under the sample station and during the fill and withdraw cycles; thus operator exposure is controlled.

The cask is transported to the required position under the sample station by a dolly cask positioner. When in position, this cask is hydraulically elevated by a small handpump for contact with the sample station shielding under the liquid sample enclosure floor. The sample bottle is raised, held, and lowered by a simple push-pull cable. The cask is sealed by a threaded top plug that inserts above the sample bottle. The weight of this large-volume cask is approximately 700 lb.

Sample radionuclide analysis is performed in a counting laboratory that is shielded to limit exposure rates under accident conditions. Prepared samples are introduced into a gamma isotopic analysis system for automatic peak search and identification. It is calibrated for geometries required for PASS samples under accident conditions.

A wet analysis/sample preparation facility is employed to prepare the sample. Equipment is provided to minimize exposure to personnel.

For extended storage of samples, a shielded facility is available in the laboratory.

The analytical laboratory has the capability to perform the following postaccident analyses on samples acquired from primary coolant, suppression pool and containment air. The analysis of post-accident samples utilize established, routinely-performed analytical procedures to ensure chemistry laboratory technician proficiency.

<u>Primary coolant</u>

Total activity

Gamma isotopic analysis

Dissolved hydrogen

pH

Conductivity

Dissolved oxygen (performed if chloride is greater than 0.15 ppm and dissolved hydrogen is less than 10 cm^3/kg)

Boron (performed if boron is injected)

Chlorides

Containment air

Hydrogen

Oxygen

Gamma isotopic analysis

A more specific discussion of each analysis is given below.

11.4.4.4.5.1 Gamma Isotopic and Total Activity Analysis

Gamma isotopic analysis of postaccident samples will follow normal counting room procedures. Gas samples will be counted in standard offgas sample vials, and liquid samples will be counted in standard sample bottles.

Previously established geometries and calibration curves for liquids and gases will be readily available and regularly updated. Gamma isotopic analysis will handle the acquired samples.

A total activity determination based on the gamma isotopic analysis will be used for the gross beta and gamma activity. The determination of total activity from the gamma isotopic analysis will minimize personnel exposure.

11.4.4.4.5.2 Dissolved-Hydrogen Analysis

Dissolved hydrogen will be determined by gas chromatography. Gas chromatography has been demonstrated to be successful in the determination of hydrogen in the presence of gamma radiation through testing and analysis by Babcock & Wilcox on TMI-2 post-accident gas samples.

11.4.4.4.5.3 pH Analysis

The pH will be determined by micro-pH probe. Confirmatory analysis may be performed by an offsite analytical laboratory.

11.4.4.4.5.4 Conductivity Analysis

The PASS is equipped with a 0.1-cm^{-1} conductivity cell. The conductivity meter has a linear scale with a six-position range- selector switch to give a conductivity range from 0.1 to 1000 μs/cm.

11.4.4.4.5.5 Dissolved-Oxygen Analysis

The dissolved oxygen concentration will be assumed to be less than 0.1 ppm if the measured positive hydrogen residual is greater than 10 cc/kg. If necessary or desirable, the oxygen concentrations will be measured directly, when ALARA conditions so permit.

11.4.4.4.5.6 Boron Analysis

Boron analysis will be performed by using the carminic acid colorimetric method, if boron injection is initiated.

11.4.4.4.5.7 Chloride Analysis

Chloride analysis may be performed by an offsite analytical laboratory.

11.4.5 Inservice Inspection, Calibration, and Maintenance

11.4.5.1 Inspections and Tests

During reactor operation, daily checks of monitor operability are made by observing channel behavior. At monthly intervals during reactor operation, the detector response of each monitor to remotely positioned check sources supplied as specified in the Offsite Dose Calculation Manual radiological effluent controls is recorded together with the instrument background count rate to ensure proper functioning of the monitors.

Some channels have electronic testing and calibrating equipment, which permits channel testing without relocating or dismounting channel components. An internal trip test circuit, adjustable over the full range of the readout meter, is normally used for testing. Each channel is tested at an interval specified in the Offsite Dose Calculation Manual radiological effluent controls prior to performing a calibration check. Verification of valve operation, ventilation diversion, or other trip function is done at this time if it can be done without jeopardizing plant safety. The tests are documented.

11.4.5.2 Calibration

Continuous radiation monitor calibrations are traceable to certified National Bureau of Standards or commercial radionuclide standards. The source-detector geometry during primary calibration approximates the sample-detector geometry in actual use. Secondary standards that were counted in reproducible geometry during the primary calibration are supplied with each continuous monitor for calibration after installation. The check sources have also been related to the primary standard. Each continuous monitor is calibrated every once per fuel cycle during plant operation, or during the refueling outage if the detector is not readily accessible, using the secondary radionuclide standard. A calibration can also be performed by using liquid or gaseous radionuclide standards or by analyzing liquid, particulate, iodine, or gaseous grab samples with laboratory instruments.

11.4.5.3 Maintenance

The channel recorders are serviced and maintained on a periodic basis or per manufacturers' recommendations to ensure reliable operation. Such maintenance includes cleaning, lubrication, and assurance of free movement of the recorder in addition to the replacement or adjustment of any components required after performing a test or calibration check. If any work is performed that could affect the calibration, a recalibration is performed at completion of the work.

11.4.5.4 Laboratory Radiation Detectors

Counting efficiencies of all laboratory radiation detectors are determined with certified radionuclide standards having accuracy better than 6 percent. The gamma isotopic analysis detectors are calibrated in terms of photopeak efficiency versus gamma energy and counting efficiencies for individual gamma emitters.

The response of each laboratory detector to alpha, beta, or gamma check sources is recorded during the primary calibration with the certified radionuclide standards. These check sources are fabricated to maintain their integrity during repeated handling. The response of each counter to the appropriate check source and the background count rate of each detector are determined at least weekly. A control chart showing check source response is maintained for each laboratory counter. A control chart showing counter background is maintained for each laboratory counter for which no automatic background correction of results is performed. Instrument responses falling outside statistical limits imposed by counting statistics are investigated and the instruments serviced as required.

TABLE 11.4-1 PROCESS RADIATION MONITORING SYSTEM (GASEOUS AND AIRBORNE MONITORS)

PRM Number	Monitor	Configuration	Type	Detector Sensitivity	Readout Range	Principal Radionuclides Measured	Expected Activity	Alarms & Trips	Control Function
1.	Primary Containment Radiation Monitor (GA)[a]	Offline						Low Flow	
	Gas (T50-N003)		β-Scint.	30 cpm/pCi/cm^3	10^1-10^7 cpm	Xe-133[b] Kr-85		Failure High	None
2.	Off-Gas Radiation Monitor (GE/Mirion)	Offline						Low Flow	
	Gas - Log Scale (N004A, N004B)		γ-Ion Chamber	3.7 x 10^{-10} Amp/R/h	10^0-10^6 mR/h	Xe-133 Xe-135 Xe-138	Off-gas activity defined in Table 11.3-1	Failure High High-High = (c)	None
	Gas - Linear Scale (N005)		γ-Ion Chamber	3.7 x 10^{-10} Amp/R/h	10^0-10^6 mR/h	Kr-85M Kr-87 Kr-88		None	
3.	Main Steam Line Radiation Monitor (GE) Steam (N006A, N006B, N006C, N006D) (N006E, N006F - Spares)	Adjacent to steam lines	γ-Ion Chamber	3.7 x 10^{-10} Amp/R/h	10^0-10^6 mR/h	N-16 O-19 Xe-133 Xe-135 Xe-138	Steam line activity defined in Section 11.1	Failure High = 1.5 x background High - High = 3 x background	1 High-High alarm in each trip system trips the gland seal exhausters and trips the condenser mechanical vacuum pumps and line valves. 2 High-High alarms in one trip system close the associated reactor water sample system valve.
4.	Reactor Building Ventilation Exhaust Radiation Monitor (GA)[a] Air (N408, N410)	Offline	β-Scint.	30 cpm/pCi/cm^3	10^1-10^7 cpm	Xe-133[b] Kr-85	Reactor Building activity defined in Table 11.3-1	Low Flow Failure High High-High = (c)	1 High-High or 2 (one from each detector) Low alarms start the SGTS, close the P/C vent valves, trip & isolate R/B vent system, isolate control center and initiate emergency recirculation mode for the control center ventilation system.
5.	Off-Gas Vent Pipe Radiation Monitor (GE) Gas (N105, N106)[e]	N/A	N/A	N/A	N/A			N/A	N/A
6.	Radwaste Building Ventilation Exhaust Radiation Monitor (Eber)[d] Air (N503A through N503G)	Offline	Part. Filter Iodine Filter α-Solid-State β-Scint. γ-Scint. GM Tube GM Tube	60 cpm/mR/h	0-1.2E6 cpm 0-1.2E6 cpm 0-1.2E6 cpm 0-1.2E6 cpm	Radon-Thoron Kr-85[b] I-131 Xe-133/Kr-85[b] Cs-137[b]	Negligible activity discussed in Section 11.3	Failure (external, channel high, or channel low) High radiation level or flow out of limits Alert radiation level	1 High radiation level alarm trips radwaste bldg. vent fan.
7.	Turbine Building Ventilation Exhaust Radiation Monitor (Eber)[d] Air (N504A through N504G)	Offline	Part. Filter Iodine Filter α-Solid-State β-Scint. γ-Scint. GM Tube GM Tube	60 cpm/mR/h	0 to 1.2E6 cpm 0 to 1.2E6 cpm 0 to 1.2E6 cpm 0 to 1.2E6 cpm	Radon-Thoron Kr-85[b] I-131 Xe-133/Kr-85[b] Cs-137[b]	Turbine Building activity defined in Table 11.3-1	Failure (External, channel High, or channel low) High Radiation Level or Flow Out of Limits [c] Alert Radiation Level [c]	1 High radiation level alarm trips turbine bldg. vent fan.
8	Deleted								
9.	Standby Gas Treatment System Radiation Monitor (Eber)[d] Air (N510A through N516A) and N510B through N516B)	Offline	Part. Filter Iodine Filter α-Solid-State β-Scint. γ-Scint. GM Tube GM Tube	60 cpm/mR/h	0 to 2.4E6 cpm 0 to 1.2E6 cpm 0 to 1.2E6 cpm 0 to 1.2E6 cpm 0 to 1.2E6 cpm	Radon-Thoron Kr-85[b] I-131 Xe-133/Kr-85[b] Cs-137[b]	Activity discussed in Chapter 6	Failure (External, channel High, or channel Low) High Radiation Level or Flow Out of Limits [c] Alert Radiation Level [c]	None
10.	Reactor Building Exhaust Plenum Radiation Monitor (Eber)[d]	Offline	Part. Filter Iodine Filter α-Solid-State		0 to 1.2E6 cpm	Radon-Thoron	Reactor Building Activity defined in Table 11.3-1	Failure (External, channel High, or channel Low) High Radiation Level or Flow Out of	None

TABLE 11.4-1 PROCESS RADIATION MONITORING SYSTEM (GASEOUS AND AIRBORNE MONITORS)

PRM Number	Monitor	Configuration	Type	Detector Sensitivity	Readout Range	Principal Radionuclides Measured	Expected Activity	Alarms & Trips	Control Function
	Air (N507A through N507H)		β-Scint. γ-Scint. GM Tube GM Tube	 80 cpm/mR/h	0 to 1.2E6 cpm 0 to 1.2E6 cpm 0 to 1.2E6 cpm 0 to 1.2E6 cpm	Kr-85[(b)] I-131 Xe-133/Kr-85[(b)] Cs-137[(b)]		Limits[(c)] Alert Radiation Level[(c)]	
11.	Standby Gas Treatment System Postaccident Radiation Monitor System (N520A through N523A and N520B through N523B)	Offline	GM Tube (SA-14) GM Tube (SA-15) GM Tube (SA-16) GM Tube (background)	40 cpm/γ-Bq-MeV/cc 1.1E-2 cpm/γ-Bq-MeV/cc 80 cpm/mR/h 80 cpm/mR/h	0 to 1.2E6 cpm 0 to 1.2E6 cpm 0 to 1.2E6 cpm	Xe-133/Kr-85 Xe-133/Kr-85 I-131 Cs-137	Postaccident Noble Gas Activity	Failure (External, channel High, or channel Low) High Radiation Level or Flow Out of Limits[(c)] Alert Radiation Level[(c)]	None
12.	Fuel Pool Ventilation Exhaust Radiation Monitor (GE) Air (N010A, N010B, N010C, N010D)	Adjacent to Vent Lines	GM Tube	28 mR/h per μ Ci/cm^3	10^{-2}-10^{2} mR/h	Xe-133[(b)] Xe-135 I-131 Kr-85M	Activity discussed in Chapter 6	Failure (Downscale/Inop) High High-High	1 High-High or 2 Failure alarms (1 from each detector on one leg) start the SGTS, close the P/C vent valves, trip & isolate R/B Vent System, isolate control center and initiate emergency recirculation mode for the control center ventilation system.
13.	Control Center Makeup Air Radiation Monitor (GA)[(a)] Air (N409, N413)	Offline	β-Scint.	30 cpm/pCi/cm^3	10^{1}-10^{7} cpm	Xe-133[(b)] Kr-85	Activity discussed in Chapter 6	Failure High High-High = (c)	1 High-High or 2 Low alarms (1 from each detector) isolate the control center and initiate emergency recirculation mode for the control center ventilation system
14.	Two Minute Holdup Pipe Exhaust Radiation Monitor (GA)[(a)] Gas (N414, N415)	Adjacent to Line	γ-Scint.	10 cpm/pCi/cm^3	10^{1}-10^{7} cpm	Xe-133[(b)] Kr-85	Activity defined in Table 11.3-2	Failure High = 1.5 x background High-High	None
15.	Control Center Emergency Air South Inlet Radiation Monitor (GA)[(a)] (N436A, N436B)	Offline	β-Scint.	40 cpm/pCi/cm^3	10^{1}-10^{7} cpm	Xe-133[(b)] Kr-85	Activity discussed in Chapter 6	Low Flow Failure High[(c)]	Trip isolation damper of non selected inlet
16.	Control Center Emergency Air North Inlet Radiation Monitor (GA)[(a)] (N437A, N437B)	Offline	β-Scint.	40 cpm/pCi/cm^3	10^{1}-10^{7} cpm	Xe-133[(b)] Kr-85	Activity discussed in Chapter 6	Low Flow Failure High[(c)]	Trip isolation damper of non selected inlet
17.	Onsite Storage Facility (OSSF) Ventilator Exhaust Radiation Monitor (N508A through N508G)	Offline	Part. Filter Iodine Filter α-Solid-State β-Scint. γ-Scint. GM Tube GM Tube	 60 cpm/mR/h	 0 to 1.2E6 cpm 0 to 1.2E6 cpm 0 to 1.2E6 cpm 0 to 1.2E6 cpm	 Radon-Thoron Kr-85[(b)] I-131 Xe-133/Kr-85[(b)] Cs-137[(b)]	Radwaste Building Activity defined in Table 11.3-1	Failure (External, channel High, or channel Low) High Radiation Level or Flow Out of Limits[(c)] Alert Radiation Level[(c)]	None
18.	Containment High Range Radiation Monitor	Area environment	γ-Ion Chamber	1 x 10^{-11} amp/R/h	10^{0}-10^{8} R/h	Xe-133[(b)] Kr-85 I-131	Post-LOCA Source Term	Failure Alert High	Primary containment postaccident monitor (NUREG-0737, II.F.1-3)

[a] (GA) = General Atomic Technologies (Gulf).

[b] Sensitivity based upon this radionuclide.

[c] The alarm point will be set, based upon the activity, radionuclides, and dilution factor, so that the discharge concentration in the decant line is less than 10 CFR Part 20 Appendix B, Table II, column 2 limits.

[d] Alarm point to be determined in field.

[e] Ratemeter removed and supporting components abandoned in place.

TABLE 11.4-2 PROCESS RADIATION MONITORING SYSTEM (LIQUID MONITORS)

PRM Number	Monitor	Configuration	Type	Detector Sensitivity	Readout Range	Principal Radioniclides Measures	Expected Activity	Alarms and Trips	Control Function
19.	Radwaste Effluent Radiation Monitor (N007) (GE/Mirion)	Inline	γ-Scint.	1 x 10^{-4} µCi/ml estimated	10^{-1} – 10^{6} cps	Cs-137[b] Co-60	Discussed in Section 11.2	Failure High-High[c]	High-High alarm closes discharge valve
20.	General Service Water Effluent Radiation Monitor (N008) (GE/Mirion)	Inline	γ-Scint.	5 x 10^{-9} µCi/em^{3} estimated	10^{-1} – 10^{6} cps	Cs-137[b] Co-60	Less than minimum detector sensitivity	Failure High = (d)	None
21.	Reactor Building Closed Cooling Water Radiation Monitor (N009) (GE/Mirion)	Inline	γ-Scint.	1 x 10^{-4} µCi/ml estimated	10^{-1} – 10^{6} cps	Cs-137[b] Co-60	Less than minimum detector sensitivity	Failure High = (d)	None
22.	Emergency Equipment Cooling Water Radiation Monitor (N400A, N400B) (GA)[a]	Inline	γ-Scint.	100 cpm/pCi/ml	10^{-1} – 10^{7} cpm	Cs-137[b] Co-60	Less than minimum detector sensitivity	Failure High = (d)	None
23.	Residual Heat Removal Service Water Radiation Monitor (N401A, N401B) (GA)[a]	Offline	γ-Scint.	200 cpm/pCi/ml	10^{-1} – 10^{7} cpm	Cs-137[b] Co-60	Less than minimum detector sensitivity	Low Flow Failure High = (d) High-High = (d)	None
24.	Circulating Water Reservoir Decant Line Radiation Monitor (N402) (GA)[a]	Offline	γ-Scint.	200 cpm/pCi/ml	10^{-1} – 10^{7} cpm	Cs-137[b] Co-60	Less than minimum detector sensitivity	Low Flow Failure High = (d) High-High = (d)	None

[a] (GA) = General Atomic Technologies (Gulf).

[b] Sensitivity based upon this radionuclide.

[c] The alarm point will be set, based upon the activity, radionuclides, and dilution factor, so that the discharge concentration in the decant line is less than 10 CFR Part 20 Appendix B, Table II, column 2 limits.

[d] Alarm point to be determined in field.

TABLE 11.4-3 PROCESS RADIATION MONITORING SYSTEM ENVIRONMENTAL DESIGN CONDITIONS

Radiation Monitor System	Pressure (psig)	Temperature (°F)	Relative Humidity (%)
Primary containment (GA)[a]			
sample systems	-2 to 56	135 to 340	40 to 100
equipment and instruments	0	65 to 130	40 to 95
Main steam line detectors (GE)[b]	0 to 250	392 max	-
Offgas vent pipe (GE)			
sample systems[c]	0 to 375	480 max	-
All remaining GE and Mirion subsystems			
equipment and instruments	0	32 to 140	20 to 98
All remaining Gulf subsystems			
sample systems	0 to 156	32 to 120	-
equipment and instruments	0	50 to 135	0 to 95
Eberline Sping 3/Sping 4	-	32 to 122	-
Eberline AXM-1			
sample systems	10 in. Hg to 30 psia	32 to 120	-
electronics	-	32 to 122	-

[a] GA = General Atomics Technologies (Gulf).
[b] GE = General Electric Company.
[c] Ratemeter removed and supporting components abandoned in place.

TABLE 11.4-4 AFFECTED EFFLUENT CHANNELS

Location	Instrument Number	Noble Gas Required Range ($\mu Ci/cm^3$ ^{133}Xe)		Eberline Model	Noble Gas Channel – Eberline Equipment Range		
Radwaste building ventilation exhaust	D11-N503A through D11-N503G	1×10^{-7}	1×10^{2}	Sping 3	1×10^{-7}	1×10^{3}	$\mu Ci/cm^3$ for ^{133}Xe
Turbine building ventilation exhaust	D11-N504A through D11-N504G	1×10^{-7}	1×10^{3}	Sping 3	1×10^{-7}	1×10^{3}	$\mu Ci/cm^3$ for ^{133}Xe
Reactor building exhaust plenum	D11-N507A through D11-N507H	1×10^{-7}	1×10^{4}	Sping 4	1×10^{-7}	1×10^{5}	$\mu Ci/cm^3$ for ^{133}Xe
Standby gas treatment system (Divisions I and II)	D11-N510A through D11-N516A D11-N510B through D11-N516B D11-N520A through D11-N523A D11-N520B through D11-N523B	1×10^{-7}	1×10^{5}	Sping 3 AXM-1 with particulate and iodine collector to 10^{2} $\mu Ci/cm^3$	1×10^{-7} 1×10^{-4}	4×10^{2} 1×10^{5}	$\mu Ci/cm^3$ for ^{133}Xe $\mu Ci/cm^3$ for ^{133}Xe

TABLE 11.4-5 RADIOLOGICAL ANALYSIS SUMMARY OF LIQUID PROCESS SAMPLES

Sample Description	Grab Sample Frequency	Analysis	Lower Limit of Detection (LLD) (μCi/ml)	Purpose
1. Reactor coolant	7 days	Dose equivalent ^{131}I	10^{-7}[b]	Evaluate fuel-cladding integrity
2. Reactor water cleanup system	Weekly	Gamma isotopic	10^{-6}[a]	Evaluate cleanup efficiency
3. Condenser demineralizer				
Influent and effluent	Monthly	Gamma isotopic	10^{-6}[a]	Evaluate decontamination factor
4. Condensate storage tank	Weekly	Gamma isotopic	10^{-6}[a]	Tank inventory
5. Condensate return tank	Weekly	Gamma isotopic	10^{-6}[a]	Tank inventory
6. Fuel pool filter-demineralizer				
Inlet and outlet	Periodically	Gamma isotopic	10^{-6}[a]	Evaluate decontamination factor
7. Evaporator bottoms	Periodically	Gamma isotopic	10^{-6}[a]	Evaluate performance
8. Evaporator distillate	Periodically	Gamma isotopic	10^{-6}[a]	Evaluate evaporator performance

[a] The principal gamma emitters for which the LLD value applies are: Mn-54, Fe-59, Co-58, Co-60, Zn-65, Mo-99,Cs-134 Cs-137, Ce-141 and Ce-144.

[b] The LLD value applies to I-131.

TABLE 11.4-6 RADIOLOGICAL ANALYSIS SUMMARY OF GASEOUS PROCESS SAMPLES

Sample Description	Sample Frequency	Analysis	Sensitivity ($\mu Ci/cm^3$)	Purpose
Offgas pretreatment	Weekly	Gamma isotopic	10^{-10}	Determine offgas activity

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Refer to Plant Drawing I-2679-01

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UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 11.4-1

PRIMARY CONTAINMENT MONITORING SYSTEM

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Refer to Plant Drawing I-2181-01

FIGURE 11.4-2

PROCESS RADIATION MONITORING SYSTEM
GENERAL DESCRIPTION

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Refer to Plant Drawing I-2181-02

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UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 11.4-3

PROCESS RADIATION MONITORING SYSTEM
GE SUPPLIED SUBSYSTEMS

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Refer to Plant Drawing I-2181-06

Fermi 2

UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 11.4-4

PROCESS RADIATION MONITORING SYSTEM
SUBSYSTEM DIAGRAM

Figure Intentionally Removed
Refer to Plant Drawing I-2181-03

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FIGURE 11.4-5

PROCESS RADIATION MONITORING SYSTEM
GULF SUPPLIED SUBSYSTEM

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Refer to Plant Drawing I-2400-25

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FIGURE 11.4-6, SHEET 1

POSTACCIDENT SAMPLING SYSTEM

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Refer to Plant Drawing I-2400-26

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FIGURE 11.4-6, SHEET 2

POSTACCIDENT SAMPLING SYSTEM

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Refer to Plant Drawing I-2400-15

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FIGURE 11.4-7

GENERAL ARRANGEMENT OF POSTACCIDENT SAMPLE STATION

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Refer to Plant Drawing I-2400-11

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FIGURE 11.4-8

SIMPLIFIED POSTACCIDENT SAMPLE
FLOW DIAGRAM

11.5 SOLID RADWASTE SYSTEM

The Fermi 2 Solid Radwaste System is intended primarily to process and package radwaste for ultimate burial/disposal. It could be considered as three separate systems. The first is for handling dry waste (DAW), whereas the other two are for handling waste resulting from processing liquids. One of these is a vendor supplied system, located in the radwaste onsite storage facility (OSSF), which normally processes liquid radwaste by dewatering or solidification, etc. The second is the asphalt-extruder process system, located in the radwaste building. Each of these systems would produce end products which can be shipped and disposed of in full compliance with the appropriate state and federal regulations.

Note: Section 11.5 describes the as-designed and as-installed design basis of the Radwaste Solidification System (asphalt extruder system). However, this system has never been operational. Pre-operational testing of this system was suspended in 1987 before testing was completed (see Section 14.1.1). Part of the system remains in place. Equipment was removed by modification (e.g., drum turntable, Drum Capper/Seamer, Transfer car, conveyors and conveyor drive units). The centrifuge feed line from the centrifuge feed tank is also capped by a modification. The original design-basis description, design data, figures, and tables for the solidification system are being retained in Section 11.5 and in other pertinent sections of this UFSAR as historical information. Currently, full-time “solid radwaste” processing takes place in the Onsite Storage Facility with a vendor-supplied system, as described in UFSAR Sections 11.5 and 11.7.

The installed Fermi 2 solid radwaste system is the radwaste volume reduction and solidification system, which was designed by the Werner-Pfleiderer Corporation; the volume reduction and solidification system is described in detail in a topical report (WPC-VRS-1) through Amendment II, approved for use as a reference by the NRC on April 12, 1978. This system, which includes the VRS-T 120 extruder/evaporator, is described in Subsection 11.5.3.2.16.7.

The key difference between the design described in the referenced topical report and the Fermi 2 design is the feed concept. The topical report describes a slurry feed, whereas the Fermi 2 plant was originally designed to use a centrifuge feed concept with a slurry feed as a backup. Subsection 11.5.3.2.16.2 describes the primary method of feed.

Three subsystems described in the topical report are not included in the Fermi 2 scope of supply. First, the distillate skid has been replaced by a process that returns the water to other parts of the radwaste system for cleanup. Second, the lubrication oil skid was eliminated by using an extruder gear box design with integral lube oil circulation capability. Third, the overhead bridge crane listed in the topical report has been replaced with a monorail.

11.5.1 Design Objectives

The objectives of the solid radwaste system are to collect, process (solidify or dewater), and package liquid and wet solid wastes and slurries from the liquid radwaste system, the reactor water cleanup (RWCU) system, the fuel pool cooling and cleanup system, and the condensate demineralizer system. The solid radwaste system collects and processes the increased volumes of wastes and slurries that are produced during anticipated operational occurrences without affecting the operation or availability of the plant. It processes, packages, handles, and temporarily stores radioactive wastes and provides a means to transfer solidified or dewatered wastes to vehicles for transport ultimately to an offsite burial facility.

A subsystem also packages, stores, and prepares for transport compressible dry wastes generated during operation of the plant. These wastes include paper, rags, and other disposables that are normally processed conveniently by compaction.

The process equipment and disposable containers prevent the release of significant quantities of radioactive material, and keep the radiation exposure of plant personnel and the general public as low as reasonably achievable (ALARA).

The system is designed to:

a. Collect and solidify or otherwise process radioactive wastes, which consist primarily of evaporator bottoms, filter backwash, tank sludge letdown, and spent resins

b. Provide for the transfer of decantate, resin sluice water, etc., to the liquid radwaste system for processing and eventual reuse or controlled discharge

c. Package, handle, and temporarily store processed, solidified, and compressed radioactive wastes generated as a result of normal operation of the plant, including those from anticipated operational occurrences

d. Provide a means to transfer the packaged wastes to vehicles for transport ultimately to an offsite burial facility

e. Package radioactive wastes in a manner that will allow shipment and burial in accordance with all applicable federal and state regulations

f. Provide means for processing or the solidification of wet wastes that results in freestanding water in the final product less than that required for disposal

g. Provide means to transfer wet wastes to the vendor-supplied system in the OSSF

h. Compact dry waste in a container that is suitable for transportation and eventual burial

i. Protect plant personnel from radiation exposure and incorporate the basic ALARA principles through the use of automated systems, shielding, and remotely operated instrumentation and controls.

Fermi 2 is operated in accordance with its process control program (PCP). The purpose of this PCP is to provide reasonable assurance of the complete solidification, encapsulation, or dewatering of processed wastes and the absence of free water in excess of required limits in the processed waste. For vendor-supplied processing services, a PCP approved by Edison in accordance with Section 17.2 will be utilized. This is described in greater detail in Subsection 11.5.6.

11.5.2 System Inputs

Table 11.5-1 lists the conservative values for all major inputs to the solid radwaste system. This table shows that the majority of the input to the solid radwaste system is from the condensate filter-demineralizer backwash when the two etched-disk filters are in use. On the other hand, when the precoat filters are used in place of the etched-disk units, their inputs would be the largest contributor to the totals.

11.5.3 System and Equipment Description

11.5.3.1 System Description

11.5.3.1.1 General

The solid radwaste system collects, processes, and packages the liquid wastes, wet solid wastes, and slurries from the liquid radwaste system, the RWCU system, the fuel pool cooling and cleanup system, and the condensate demineralizer system. The solid waste package produced by the process must be suitable for transportation to an offsite burial facility. In the course of processing liquid inputs, the solid radwaste system must be able to separate solids from the incoming slurries, which maximizes the amount of liquid that can be returned to the liquid radwaste system for recycling to the plant.

The solid radwaste system will receive periodic inputs from a variety of plant sources. Since the operator should know in advance of major impending inputs of waste batches to the solid radwaste system, system operation can usually be planned before most inputs are received.

The design and classification of the solid radwaste system is essentially the same as the liquid system, and therefore the general discussion of Subsection 11.2.3.1 applies also to the solid system. The principal design parameters for the major components are listed in Table 11.5-2.

The inputs to the solid radwaste system consist of filter backwashes of several types, evaporator concentrates, and spent bead resin. By volume, most of this input is liquid. A major goal of the solid radwaste system is to allow solids in the liquid inputs to settle, leaving a relatively clear decantate, which is sent to the liquid radwaste system for processing. The remaining solids are pumped to an intermediate set of collection tanks from which the sludge (resin beads, powdered resin, and tank sludge) is pumped for final processing, either to the vendor system in the OSSF or to the asphalt solidification system. With the centrifuge currently in a non-functional configuration, the wet waste can be forwarded directly to the solidification process, where the liquid is driven from the waste, leaving only a dry, solid product. One exception to this process is the evaporator concentrates source, which is pumped directly to the solidification process without an intermediate solids settling step. The drains from the high-chloride laboratory are also fed directly to the extruder/ evaporator via the chloride waste tank and the concentrates feed tank.

For the installed system, asphalt is used as the solidification binder. The asphalt and waste are heated and mixed in an extruder/evaporator that simultaneously removes the remaining moisture from the waste while producing a homogeneous product. When the asphalt/waste mixture cools, it forms a solid, homogeneous product that has no freestanding water. The asphalt storage tank is located at grade, on the north side of the radwaste building, opposite the floor drain filter. The radiation zone in this area is designed to be less than 1 mrem/hr and is therefore in compliance with Branch Technical Position (BTP) ETSB 11-3, which states that solidification agents should be stored in low-radiation areas that are less than 2.5 mrem/hr.

11.5.3.1.2 Solid Radwaste System Process Rates

The solid radwaste system uses a batch-type process. Individual batches of inputs from the sources listed in Table 11.5-1 are delivered to the solid radwaste system collection tanks. The radwaste operator will be aware of an expected input for the etched-disk filter backwash, which occurs automatically, and also for the waste collector and floor drain precoat filter backwashes. Thus, the minimum processing rates required for the solid radwaste system components are based on the system's ability to pump out a tank of its decantate, sludge, or bead and powdered resin in a time frame consistent with the incoming batch frequency.

In several cases, the solid radwaste system processing rate and pump size are determined by the recirculation conditions needed to mix tanks or by the flow rate needed to avoid plugging. Design parameters for components of the solid radwaste system are given in Table 11.5-2.

11.5.3.1.3 Chemistry of Inputs

The chemical characteristics of the solid radwaste system sources are dominated by their high concentrations of suspended and dissolved solids. Most of the suspended solids consist of spent powdered and bead resin particles, which usually are fairly large, at least 45μ. Dissolved-solids concentrations from the evaporator are expected to average less than 8 percent by weight. Table 11.5-1 lists the assumed batch solids content of each stream.

The pH of all streams except the evaporator concentrates is expected to be fairly neutral, between 6 and 8. The pH of the waste in the chloride waste tank is neutral because it will be preneutralized in the laboratory before draining to the tank. The evaporator-concentrates stream pH could fluctuate extensively, and therefore can be adjusted to the range 7 to 9 before processing by the extruder/evaporator. The pH of the feed to the extruder/evaporator process is controlled only to protect the machine's construction materials.

11.5.3.1.4 Dry Wastes

Typical values of the radionuclide content and volumes of dry solid waste for BWRs are provided in the table below:

Radionuclide Content and Volumes of Dry Solid Waste

Radionuclide	Activity (percent)	Total Annual Activity (Ci)
58_{Co}	24.0	0.96
60_{Co}	7.2	0.29
51_{Cr}	62.0	2.48

Radionuclide Content and Volumes of Dry Solid Waste

Radionuclide	Activity (percent)	Total Annual Activity (Ci)
^{95}Nb	6.8	0.27
^{137}Cs	traces	--
Total	100.0	4.00

The data in the table were obtained from AIF/NESP-0800, "A Survey and Evaluation of Handling and Disposing of Solid Low- Level Nuclear Fuel Cycle Wastes," October 1976. An average gross curie content of 1.0 Ci/1000 ft^3 was used in the above estimate. This was obtained from a range of 0.001 to 4.0 Ci/1000 ft^3 (obtained from the above reference). The average volume of compacted trash is given in the above reference as 6000 ft^3/yr. If the data are corrected for skewing, an average of 4000 ft^3/yr is obtained; this average was used. The volume of trash generated per year is primarily a function of housekeeping activities and is not heavily influenced by plant size. It should be noted that the Fermi 2 design includes a high-efficiency compactor. The 6000 ft^3/yr number is suspect, and it probably includes dry trash that has not been compacted. The 4000 ft^3/yr number agrees fairly well with the annual upper limit of 500 drums (3700 ft^3) from "A Study of Nuclear Fuel Cycle Radioactive Solid Waste Management," NESP Low-Level Waste Handling and Disposal Alternatives, March 1976.

Dry wastes (usually of low activity) can normally be handled by direct contact. These wastes are collected in bags or containers located in appropriate zones at certain locations within the plant, as determined by the volume of waste generated during plant operation and maintenance. The filled waste containers are sealed and transported for further processing.

Compressible, dry, low-activity wastes can be compacted into standard 55-gal drums by a hydraulic compactor. First, an empty drum is placed on the support plate at the front of the compactor and is moved into position under the ram by a hydraulic cylinder. Then a hinged work table is swung into position against the drum, clamping it in place and providing a seal for the air space above the drum that holds loose waste in place for compaction. Loose waste is deposited in the drum through an access door above the work table. Finally, the access door is closed and locked, and the loose waste is compacted.

An air evacuation system provided by a built-in fan prevents the escape of airborne contaminants generated during the compaction cycle. The fan directs the air trapped above the drum through a roughing filter and 0.3-μm high-efficiency particulate air (HEPA) filters. Differential pressure gages on the compactor control panel indicate when the filters require replacement. Used filters are normally dropped into a drum and compacted.

Noncompressible wastes are normally packaged in strong, tight containers. Because of its low activity, this waste can be stored until enough is accumulated to permit its economical transport to an offsite burial ground for final disposal. During outages or other heavy trash-generating periods, or for packaging of large pieces of noncompactible materials, boxes may also be used to limit handling and ensure packaging efficiency.

Activated charcoal, HEPA filters, and other dry wastes are treated as radioactively contaminated solids. Those that normally do not require solidification processing are packaged and disposed of in accordance with applicable regulations.

11.5.3.1.5 Wet Wastes

Wet wastes consist of spent bead and powdered resins, filter sludge, and evaporator concentrates (when running). They normally result as by-products from liquid processing systems and contain liquid components that require immobilization or removal. By evaporating the liquid components and combining the residues with the asphalt binding agent when the asphalt-extruder system is used, a homogeneous solid matrix of reduced volume and free of water is developed prior to offsite shipment. When the vendor-supplied system is used, wastes can be dewatered or solidified.

Spent cartridge-filter elements may be packaged in a shielded receptacle containing a suitable absorber. If necessary, they will be stored and shipped in the same manner as other radwaste in accordance with applicable regulations.

11.5.3.1.6 Irradiated Reactor Components

Because of its high activation and contamination levels, used reactor equipment is normally stored in the spent-fuel storage pool to allow sufficient radioactive decay before its removal to in-plant or offsite storage and its final disposal in shielded containers or casks.

11.5.3.2 Equipment Description

11.5.3.2.1 General

The selection of the solid radwaste system process components was based on the primary process requirement to dewater solid-laden waste inputs. The process of removing the moisture from the solid waste streams provides a volume reduction of the incoming feed, thus reducing the ultimate amount of waste to be disposed of. The liquid generated by the dewatering processes is returned to the liquid radwaste system for further processing.

Solid wastes are collected in several different ways. Liquid wastes with a low solid content are received in the condensate phase separators, where they are allowed to settle; then the clarified decantate is pumped to the waste clarifier tank. Over-flow from the clarifier tank is directed into the waste surge tank and finally into the liquid radwaste system (waste collection subsystem). The sludges from all three tanks are normally fed to the centrifuge feed tank. Other wastes with higher solids content are added to this basic line at intermediate points. The sludge from the RWCU phase separator is fed directly to the centrifuge feed tank. The spent-resin tank feeds either the centrifuge feed tank or the spent-resin slurry feed tank, which feeds directly into the extruder/ evaporator. The evaporator bottoms and the chloride wastes are fed to the concen-trate feed tank, where a caustic is added for neutralization, before they are pumped into the extruder/evaporator.

The two condensate phase separators perform a primary clarification of the waste sources that contain high suspended solids (excluding evaporator bottoms and exhausted demineralizer bead resins). After collection, the wastes are allowed to settle, clarified liquid is decanted off the top, and sludge is drawn off the bottom.

The waste clarifier tank performs a secondary clarification of condensate phase separator decantate and other wastes with low concentrations of suspended solids. The influent wastes flow through the waste clarifier tank, where the solids settle to the bottom and the clarified liquid overflows into the waste surge tank. From the waste surge tank, the clarified liquid is forwarded to the waste collector subsystem for processing. Sludge collected in the bottom of the clarifier tank is pumped out periodically to the centrifuge feed tank. Any solids that might collect in the waste surge tank can be blown down to the condensate phase separators. The waste clarifier tank also provides a source of relatively clear water, which is used for diluting the contents of the centrifuge feed tank and transporting resins from the spent-resin tank.

The spent-resin tank receives bead-type ion-exchange resins and demineralizer flushes that are produced by dumping the exhausted floor drain and waste collector demineralizer beds. The spent resins and flush water are forwarded to the centrifuge feed tank.

To summarize, the centrifuge feed tank receives concentrated sludges from the condensate phase separators, waste clarifier tank, cleanup phase separators, and spent-resin tank. The feedtank contents are mixed by recirculation and mechanical agitation to give a consistent concentration; a side stream is taken off the recirculation loop for ultimate processing, either to the vendor equipment in the OSSF or to the asphalt-extruder system. When the extruder system is used, high dissolved-solid waste from the concentrates feed tank is sent to the unit, where the waste is dried and mixed with asphalt. The asphalt/solid mixture is emptied into drums that are capped and sent to storage for eventual offsite disposal. Distillate from the evaporation process is returned to the waste clarifier tank. The sludge, originally routed to the centrifuge for dewatering, can be routed directly to the extruder/evaporator. Similarly, spent resin can be routed to the alternative spent-resin slurry feed tank for forwarding to the extruder/evaporator.

11.5.3.2.2 Normal Waste Generation and Holdup Rates

For normal waste generation rates, the holdup capacity provided in the radwaste system for spent resins and filter-demineralizer sludges is described below.

11.5.3.2.2.1 Sludge Collection

The RWCU system has two phase separators, each designed to hold the sludge from 10 RWCU filter-demineralizer backwashes (a total of about 580 lb of sludge).

In addition to the RWCU phase separators, there are two condensate phase separators in the radwaste building, each estimated to have a sludge holdup capacity of approximately 5400 gal, or 2250 lb of solids at a 5 weight-percent concentration.

Total input to the condensate phase separators will depend upon whether the precoat filters or the etched-disk filters are in use, since the precoat filters generate more waste volume. Based upon the conservative design values for input water quality (TSS, TDS), the estimated design inputs are as follows:

Condensate filter-demineralizer backwashes	214 lb/1.3 days	4940 lb/30 days
Fuel pool filter-demineralizer backwash	65 lb/10 days	195 lb/30 days
Floor drain precoat filter backwashes	17 lb/batch 11 batches/day 187 lb/day	5610 lb/30 days
Waste collector precoat filter backwashes	28 lb/batch 1.5 batches/day 42 lbs/day	1260 lb/30-days
Floor drain etched-disk filter backwashes	2.64 lb/batch 6 batches/day 15.9 lb/day	475 lb/30-days
Waste collector etched-disk filter backwashes	1.0 lb/batch 3.7 batches/day 3.7 lb/day	111 lb/30-days
Total solids generated for 30 days		5,721 or 12,000 lb

Conservatively estimated, overall solids input (over 30 days) to the condensate phase separators averages 12,000 lb when the precoat filters are used, and 5,721 lb if the etched-disk filters are used (in their un-precoated design condition).

With the etched-disk filters in use at the estimated normal solids-generation rates, both condensate phase separators would be full in approximately 23 days (about 12 days each per separator). At this time, the contents of one of the condensate phase separators would be transferred to the centrifuge feed tank in preparation for processing through the volume reduction and solidification system. The centrifuge feed tank has a working capacity of approximately 6000 gal, which is equivalent to about 2500 lb of solids at 5 weight-percent concentration. The phase separator just emptied would then have a solids-accumulation capacity of approximately 12 days at normal sludge-generation rates. Thus, the total solids holdup capacity of the two condensate phase separators and centrifuge feed tank is approximately 35 days.

11.5.3.2.2.2 Spent-Resin Collection

Spent resins are produced in the floor drain and waste collector demineralizers. Each of the two demineralizers is estimated to produce about 2250 lb of spent resin once every 16 days, or a total of about 8500 lb of spent resin every 30 days. The spent-resin tank and the spent-resin slurry feed tank can each accommodate two batches of spent bead resin, or a total of about 9000 lb.

11.5.3.2.3 Waste Clarifier Tank and Condensate Phase Separator Tanks

The waste clarifier tank collects decantates primarily from the condensate and RWCU phase separators and the centrifuge to allow solids carried over to settle. It also provides the source of the dilution water for adjusting the solids concentration in the centrifuge feed tank and the source of carrier waste for sluicing resin from the spent-resin tank.

The condensate phase separators provide for an undisturbed period during which the solid materials that enter the vessels as slurries can settle to the bottom. After the settling period, the clarified water can be decanted off to allow enough volume for the receipt of the next slurry input. The units are designed to enable measurements of the quantities of sludge and water they contain, to adjust (by decanting) the sludge concentration, and to mix the water and sludge to a uniform slurry so it can be transferred to the centrifuge feed tank for further processing. To accomplish these functions, additional auxiliary equipment including: level instrumentation, decant pumps, sludge discharge and mixing pumps, and an internal arrangement of mixing educators is provided.

11.5.3.2.4 Waste Surge Tank

The 65,700-gal-capacity waste surge tank accumulates input surges from the waste collector and floor drain collector subsystems. However, its primary function is to receive the overflow from the waste clarifier tank. Periodically, it receives the wastewater from the reactor well drain, one of the radwaste emergency drain sumps, and off-standard recycle from the waste sample tanks.

The waste surge tank also can receive inputs from the RWCU system during reactor startup.

The waste surge tank can hold the maximum daily input from the floor drain collector subsystem, the waste collector subsystem, or the solid radwaste system via the waste clarifier tank. The largest of these inputs is from the waste clarifier tank, from the condensate filter-demineralizer backwash during reactor startup. Including other design daily inputs, the estimated maximum daily input would then be 52,368 gal.

11.5.3.2.5 Centrifuge Feed Tank (See also Subsection 11.5.3.2.16.2)

This tank collects the sludge and wastewater containing high suspended solids from the condensate phase separators, waste clarifier tank, RWCU phase separators, and spent-resin tank and, if required, adjusts the solids content in the water in the range of 5 percent by weight by diluting it with decant water from the waste clarifier tank.

The contents of this tank are processed to the vendor solidification system located in the OSSF. With the isolation of the centrifuge, the contents of the tank can be processed directly by the solid radwaste system extruder/evaporator after decanting the contents to approximately 15 percent by weight.

The centrifuge feed tank is equipped with a mechanical agitator which, together with the mixing flow provided by the centrifuge feed/recirculation pumps, ensures a uniform slurry concentration in the tank.

The largest batch input to the centrifuge feed tank-5400 gal- is from the condensate phase separator. The contents of the tank are processed in a batch operation. The tank has a capacity of approximately 6000 gal.

11.5.3.2.6 Spent-Resin Tank (See also Subsection 11.5.3.2.16.4)

This tank collects the spent resin from the floor drain and waste collector demineralizers. The collected spent resin is transferred either to the centrifuge feed tank or to the slurry feed tank for further processing.

The spent-resin tank is sized to accommodate two batches of spent resin and sluicing water from either the floor drain or the waste collector demineralizer. One resin bed, including wastewater, occupies approximately 700 gal. The tank has a capacity of 1400 gal, which allows a contingency for accommodating an additional batch.

11.5.3.2.7 Chloride Waste Tank

The chloride waste tank can collect laboratory waste containing chlorides, mainly hydrochloric acid. Chloride waste can be segregated from other chemical wastes and drained directly to this tank. The waste is normally preneutralized in the laboratory before drainage. This waste can be segregated from others in the liquid radwaste system because its high chloride content could have a deleterious effect on equipment and stainless steel materials, particularly the evaporator.

The estimated monthly input to the tank is about 300 gal, reflecting the design daily volume of 10 gal. The tank volume of 250 gal requires pumping out the contents to the concentrates feed tank about once per month.

11.5.3.2.8 Condensate Phase Separator Decant Pumps

The condensate phase separator decant pumps decant the clear liquid from the condensate phase separator tanks and transfer it either to the waste clarifier tank or to the condenser hotwell (during startup only).

The pumps are designed to pump the volume of condensate demineralizer backwash decantate to the waste clarifier tank in about 0.5 hr. Either pump can also be used to pump back to the condenser hotwell, as determined by reactor-startup conditions. This ensures that the decantate can be removed before receipt of the next batch. These two pumps are shared by the two condensate phase separator tanks.

11.5.3.2.9 Condensate Phase Separator Sludge Discharge Mixing Pumps

The condensate phase separator pumps transfer the sludge from the condensate phase separators to the centrifuge feed tank and, at the same time, recirculate part of the sludge through mixing eductors in the condensate phase separator to keep the sludge mixed homogeneously.

The capacity of the pumps is based on the recirculation flow requirements to keep powdered resin in suspension and to transfer sludge to the centrifuge feed tank. The solids content during sludge transfer is in the general range of 5 percent by weight. Two 100 percent-capacity pumps are shared by the two condensate phase separator tanks.

11.5.3.2.10 Chloride Waste Pump

The chloride waste pump transfers the chloride waste collected in the chloride waste tank to the concentrates feed tank. The pump rating of 35 gpm was based on emptying the chloride waste tank in less than 10 minutes.

11.5.3.2.11 Centrifuge Feed and Recirculation Pumps

The centrifuge feed and recirculation pumps perform the following functions:

a. Mix the contents of the centrifuge feed tank by recirculating the slurry back to the tank through the mixing eductors

b. Decant the clear liquid from the centrifuge feed tank to the waste clarifier tank

c. Provide a constant flow and slurry concentration when feeding to the vendor station in the OSSF or the waste-slurry metering pump.

The capacity of the pumps is determined by the flow through eductors that is needed to keep the powdered and bead resin in suspension.

11.5.3.2.12 Slurry Dilution Pump

The slurry dilution pump provides dilution water to either the centrifuge feed tank or the spent-resin tank, taking suction from the waste clarifier tank. It can also be used to spray the waste clarifier tank bottom to assist in sludge removal. The pump capacity is based on the maximum dilution-water requirement for centrifuge feed tank operation. (The spent-resin tank requires approximately 30 gpm of dilution water.)

11.5.3.2.13 Waste Clarifier Sludge Pump

The waste clarifier sludge pump transfers sludge from the waste clarifier tank to the centrifuge feed tank. It is also used as a backup to the spent-resin transfer pump to pump the contents of the spent-resin tank to the centrifuge feed tank.

11.5.3.2.14 Spent-Resin Transfer Pump

The spent-resin transfer pump transfers the spent resin from the spent-resin tank either to the centrifuge feed tank or to the slurry feed tank. It can also be used as a backup for the waste clarifier sludge pump to pump clarified sludge to the centrifuge feed tank.

11.5.3.2.15 Centrifuge

The centrifuge, in its design configuration, dewaters the slurry of either spent bead resin or powdered resin fed by the centrifuge feed/recirculation pump so that dry solid is fed to the extruder/evaporator. Dewatering the slurry by centrifuging will maximize the solids processing rate through the extruder/evaporator.

The centrifuge is designed to dewater slurries consisting of either bead resin or spent precoat-filter cake to 40 percent to 50 percent of dry solids in the cake. The estimated recovery of solids in the cake is about 98.5 percent. The water content in the centrifuge cake has an upper limit to match the evaporative capacity of the extruder-evaporator (rated at 0.53 gpm). The centrifuge feed rate is controlled, on the basis of the percent of solids in the feed, to achieve this maximum moisture input to the extruder/evaporator, thereby ensuring that its nominal evaporative capacity is not exceeded.

11.5.3.2.16 Extruder/Evaporator Volume Reduction and Solidification System

11.5.3.2.16.1 General

The extruder/evaporator volume reduction and solidification system (VRS) is designed to perform the following functions:

a. Accepts waste inputs from the liquid radwaste system evaporator and chloride waste tank via the concentrates feed tank as well as waste in slurry form from the centrifuge feed tank

b. Accepts dewatered solid waste inputs from the centrifuge or slurry inputs (approximately 50 percent by weight) from the slurry feed tank

c. Removes moisture from waste feed while homogeneously mixing the waste with asphalt

d. Discharges the asphalt/waste mixture into 55-gal drums where the waste product cools to form a solid mass with no freestanding water

e. Crimps the 55-gal drums to form suitable containers for offsite disposal

f. Returns the cooled distillate resulting from the evaporative process to the waste clarifier tank.

The nominal rated capacity (120 liters per hr) of the VRS-T 120 is for evaporative liquid. A weight percent of solid to liquid is present in each incoming stream so that the amount of incoming water does not exceed the capacity of the extruder/evaporator. The mass flow rate into the centrifuge, by design, is controlled so that the moisture input to the extruder/evaporator, in the form of chemical-bound and surface-bound water, does not exceed its evaporative capacity.

The VRS is designed to process the radioactive wastes from the solid radwaste system collection tanks described above. The principal types and quantities of wastes processed have been estimated in the design as follows:

a. Concentrates Feed Tank

Volume/batch	800 gal
Annual volume	34,679 gal

b. Bead Resin

Volume/batch, dewatered	49 ft^3
Resin type	Rohm & Haas IRN-150 or equivalent
Annual volume	6500 ft^3 (50,000 gal)

c. Powdered Resin

1. Condensate Phase Separators

Batch weight, dewatered	2250 lb
Annual quantity, dewatered	64,800 - 137,000 lb
	(10,300 - 21,800 gal)

2. Reactor Water Cleanup Phase Separators

Batch weight, dewatered	580 lb
Annual quantity, dewatered	3480 lb
	(575 gal)

The volume reduction and solidification system includes the following subsystems:

a. Centrifuge feed system (when functional)
b. Concentrate feed system
c. Spent-resin slurry feed system
d. Asphalt feed system
e. Auxiliary steam system
f. Extruder/evaporator and utility manifold
g. Steam-dome boilout system
h. Cooling water booster pumps
i. Fill station/drum-handling system (Equipment removed by modification)
j. pH adjustment system.

Figures 12.1-3, Sheet 2, and 12.1-4 show the general layout of this equipment.

11.5.3.2.16.2 Centrifuge Feed System

The centrifuge feed system feeds radwaste resin and sludge to the extruder/evaporator, normally in a dewatered form. The slurry feed system acts as a backup.

A homogeneous solution of radwaste resin and sludge slurry, ranging from 2 percent to 15 percent by weight, is recirculated around the centrifuge feed tank. A tap is taken from this recirculation line to feed the extruder, directly in slurry form. The designed primary extruder feed method is to distribute the slurry to the centrifuge, where all free water is removed. The slurry cake is then gravity fed to the extruder/ evaporator. A valve in this gravity line diverts all washdown during flushing operations to the waste clarifier tank. The backup extruder feed method is to feed the recirculated radwaste slurry solution directly to the extruder/evaporator via the waste slurry metering pump. In both feed methods, asphalt is fed simultaneously; flow rates are proportioned.

11.5.3.2.16.3 Concentrates Feed System

The concentrates feed system collects and feeds concentrates from the evaporator and the chloride waste tank when these systems are in use.

The 1500-gal concentrates feed tank receives the radwaste concentrate directly from the evaporator, from the evaporator drain holdup tank, and from the chloride waste tank. This solution is recirculated by the concentrates recirculation pump back to the tank to keep a homogeneous solution. Caustic can be injected into the solution in the recirculation line to adjust the pH.

A tap is taken from this recirculation line to feed the extruder/evaporator through the concentrates metering pump. Asphalt is also fed to the extruder/evaporator simultaneously to provide the correct mix.

The concentrates feed tank has electrical strip heaters on its bottom head, and all lines are electrically heat traced to keep the solution at about 165°F.

11.5.3.2.16.4 Spent-Resin Slurry System

The spent-resin slurry feed tank collects bead resin from the spent-resin tank, prepares the resin slurry to a fixed concentration (normally 50 percent by weight), and feeds the slurry to the extruder/evaporator.

A slurry containing approximately a 25 percent by weight concentration of spent bead resin is transferred from the existing spent-resin storage tank to the spent-resin slurry feed tank. A decanting operation is performed to increase the slurry concentration. This operation reduces the carrier water before the resin slurry is fed to the extruder. Due to the distance between the spent-resin slurry feed tank and the extruder/evaporator, a resin recirculation loop is provided to maintain the bead resin in a homogeneous slurry form. This loop is routed from the spent-resin slurry feed tank to near the extruder and back to the tank; a positive displacement progressive cavity pump is provided for this recirculation.

The spent-resin slurry feed tank is equipped with decant screens. A vertical in-line centrifugal decant pump removes water from the resin to adjust the concentration of resin in the tank to the normal value of about 50 weight percent.

A turbine agitator supplied with the tank keeps the contents thoroughly mixed. The tank also has connections for flushing and for fluffing the resin bed, if required.

A line tap is taken from the recirculation line for feeding the extruder/evaporator through the spent-resin slurry metering pump.

11.5.3.2.16.5 Asphalt Feed System

Asphalt is used as the binder material for the radwaste resins and evaporator concentrates. It is fed to the asphalt storage tank from a tanker through the duplex fill strainer. The 9000-gal bulk-storage asphalt tank is equipped with four externally mounted steam-heating panels. These removable panels maintain the temperature in the tank at approximately 325°F so the asphalt is a pumpable liquid.

The asphalt storage tank is located at grade, outside the radwaste building. Its radiation zone is designed to be less than 1 mrem/hr. The tank is located on the north side of the radwaste building, opposite the floor-drain filter.

A positive displacement pump recirculates the asphalt through a duplex recirculation strainer back to the storage tank to keep a homogeneous, clean flow. A backup positive displacement recirculation pump acts as an operational spare.

Two lines are tapped into the recirculation line to feed the asphalt metering pumps, which are positive displacement pumps that feed directly to the extruder/evaporator. A flow element exists in the feedline. A signal from any of the three radwaste slurry flow elements is sent to a flow ratio controller to establish automatically a proper waste/asphalt mix ratio, via asphalt pump speed control.

All lines in this system are steam traced, and all pumps and strainers are steam jacketed. The steam comes from the solid radwaste system electric auxiliary boiler.

All asphalt valves in this system are the plug type.

11.5.3.2.16.6 Auxiliary Steam System

The auxiliary steam system supplies steam at approximately 400°F and 230 psig to the following:

a. The extruder/evaporator steam domes and barrels

b. The asphalt tank and asphalt supply system (at reduced pressure).

This steam is used to heat the extruder/evaporator to promote the evaporation of water from the radwaste feed. Steam at a reduced pressure is used to heat the asphalt storage tank and to heat trace the asphalt transfer and metering lines so that the asphalt is maintained at approximately 325°F. The auxiliary boiler system is a packaged unit. Demineralized makeup water is provided from plant sources. The blowdown of the boiler is via a flash tank; subsequent discharge is directed to the floor drain sump. Twin boiler feed pumps ensure reliable system operation.

11.5.3.2.16.7 Extruder/Evaporator and Utility Manifold

The heated extruder/evaporator mixes the liquid radioactive wastes with asphalt. It also evaporates free and chemically bound water from the mixture and homogeneously disperses the waste residues in the asphalt matrix. The utility manifold distributes steam to heat each barrel section and distributes cooling water to the feed barrels, discharge barrel, and vapor condensers in the steam domes.

The extruder/evaporator and utility manifold consist of three basic sections, as follows:

a. The drive section provides counter-rotating torque to the screw shafts of the extruder/evaporator

b. The process section evaporates water and transports and mixes the waste/asphalt mixture

c. The extruder/evaporator manifold, a skid-mounted assembly, has cooling water, steam, and condensate supply and return headers, distribution piping, associated temperature control valves, solenoids, and manually operated valves. Flow rates of cooling water and steam required to maintain the operating temperature in the extruder/ evaporator barrels are controlled by temperature elements in the extruder/evaporator. These elements modulate the steam or water control valves, as required. There are two levels of steam pressure on the manifold. The first is for the extruder/evaporator process section heating, which is about 230-psig steam, supplied from the auxiliary boiler; the second, for cleaning the dome devolatizing ports, is about 150-psig steam supplied from a self-contained pressure regulator mounted on the manifold.

   A condensate collection system is provided with associated valves, strainers, and steam traps. The condensate is returned to the condensate return tank on the auxiliary boiler skid, and from there it is returned to the auxiliary boiler.

11.5.3.2.16.8 Steam-Dome Boilout System

The steam-dome boilout system cleans and removes any salt sediment that might accumulate in the steam-dome ports.

This system supplies a predetermined amount of demineralized water through the respective port connection to the steam domes. It consists of a wall-mounted frame supporting a feed tank, a piping manifold, and remotely operated valves. It is operated from the main control panel. The tank is filled with water when the operator opens the tank inlet valve. When the water reaches a preset level, the valve is closed automatically by a signal from the level switch. The operator starts the boilout of one of the three steam domes by opening the valve in the distribution line to the dome to be cleaned. The boilout water flows by gravity to the selected dome. When the operator releases a pushbutton, the boilout cycle terminates automatically by closing the same valve. This sequence is repeated for the domes remaining to be cleaned.

11.5.3.2.16.9 Cooling Water Booster Pump System

This system increases the supply pressure of cooling water to approximately 105 psig (at a temperature of 85°F) to the following equipment via the utility manifold:

a. The extruder/evaporator domes

b. The extruder/evaporator feed and discharge barrels.

Note: This system has been deactivated. The Turbine Building Closed Cooling Water (TBCCW) supply line has been terminated in the turbine building and the wall penetrations have been reused to supply General Service Water (GSW) to the Side Stream Liquid Radwaste System.

11.5.3.2.16.10 Fill Station and Drum-Handling System (Equipment removed by modification)

The fill station and drum-handling system

a. Positions a drum under the extruder for filling
b. Provides ventilation of the drum being filled
c. Provides visual monitoring of the drum-filling process
d. Provides a remote indication of the drum level
e. Provides temporary storage for cooling on the turntable
f. Provides an automatic/manual indexing operation
g. Provides a drum-capping and drum-seaming operation
h. Provides for measuring drum radiation level at the capper/seamer
i. Provides drum handling, which consists of a monorail, a drum grab, conveyors, and a capper/seamer.

The fill station subsystem collects the final product from the extruder/evaporator. The fill station contains a vent hood, filter train, and exhauster, which provide ventilation of the fill area to prevent loose surface contamination of drums and the buildup of vapors. A drip-pan mechanism is provided for product collection during drum-indexing operations. The pan with drippings is put in the next drum available after indexing. The drum-handling system is designed to transport drums to and from the six-drum turntable via the monorail, hoist, and drum grab. The drums are filled on the turntable after being indexed, either manually or automatically. Filled drums are remotely transported via monorail and hoist to the capping station. They are capped, seamed closed, and put on the transfer cart.

The drum-handling system provides a means by which 55-gal drums filled with the solidified radwaste can be remotely moved, transported, and stored. It consists of a transfer cart, an accumulation conveyor, and a 10-ton remotely operated bridge crane equipped with a drum grab for transport of drums to onsite storage. Drums are retrieved from onsite storage by means of the same bridge crane. They are discharged to a truck dock designed to accommodate offsite shipments to a burial repository.

Except for the drum-transfer cart, these actions occur in the onsite storage facility, a separate structure adjacent to the radwaste building. This facility, its systems and equipment, and its operations are described in Section 11.7.

One method of movement of drums is as follows: Filled and seamed drums are moved from the drum capper-seamer area, by means of the transfer cart, to the onsite storage facility. There they are transferred to the accumulation conveyor to await transport offsite or to their storage location. Closed-circuit television (CCTV) cameras throughout the system permit surveillance of the drum's movement.

Drums can also be stored on the solid-radwaste storage conveyors in the radwaste building (first floor). The storage system consists of the transfer cart, 13 reciprocating gravity storage conveyors, 13 drum escapement devices, and a chain-driven live roller drum-exit conveyor.

All components of this system are remotely operated, and visual surveillance of the total system is provided by CCTV cameras, periscopes, and viewing ports. Drums are discharged from the transfer cart onto any one of the 13 reciprocating gravity storage conveyors. The reciprocating gravity storage conveyors can store approximately 380 drums.

11.5.3.2.16.11 pH Adjustment System

The pH adjustment system consists of a caustic holding tank, pumps, and a distribution system. It is used to adjust the pH in the three slurry feed tanks to protect the extruder/evaporator. The caustic is fed from the caustic tank and distributed through the caustic addition pumps to one of the three slurry tanks:

a. The centrifuge feed tank

b. The spent-resin slurry feed tank

c. The concentrates feed tank.

When the pH in the selected tank is within the allowable range, the operator manually shuts down the caustic addition pump.

The system also provides for the injection of caustic for neutralizing the contents of the chemical waste tank.

11.5.4 Estimated Quantities

Estimated design values of the principal radionuclides processed yearly through the radwaste system are presented in Table 11.5-3. This table covers system operation with the evaporator and the etched-disk filter/oil coalescer trains in service. Calculations have also been made for normal system operation with both precoat filters in use and the evaporators not in service. It was found that the total curies processed were nearly identical, which is as expected. The radioactivity inputs to the radwaste system come from various external sources, such as leakage into sumps, laboratory drains, various cleanup resins, and sludges. These input sources are independent of how the internal radwaste equipment/trains are configured. Therefore, since the radwaste systems are designed to essentially capture (and ultimately ship for burial) the majority of radionuclides, rather than releasing them in liquid discharges, it is expected that the final solid-system totals would be essentially independent of system configuration. Source quantities will be redistributed throughout various pieces of radwaste equipment, depending upon specific system configurations. The nuclide distribution for each type of solid waste was calculated by assuming that all waste initially had the same distribution of nuclides as reactor water, and by applying appropriate decay factors for utilization, collection, or processing times involved with each type of solid waste.

The estimated yearly quantity (volume, weight) of wastes to be generated and shipped, however, does depend upon the specific configuration of the overall liquid and solid system. When vendor processing is performed in the OSSF, quantities will depend upon the specific vendor being utilized, fill efficiencies, etc. If the asphalt-extruder system is utilized, results and quantities will depend on such things as drum-fill efficiencies, achievable waste-to-asphalt ratios and extruder throughput, etc. One nominal design example is given in Table 11.5-4 for the situation of waste processed with the evaporators, etched-disk filters/oil coalescers, and asphalt extruder in operation.

11.5.5 Packaging and Shipment

The solid waste system product will be packaged and shipped in accordance with current federal regulations. The majority of normal radwaste will be staged in the onsite storage facility for shipment. Waste quantities, activities, and economics will dictate shipment frequency.

11.5.6 Vendor-Supplied Solidification or Dewatering System

The Fermi 2 solid radwaste system has been set up and hard-piped so that either a full-time (mobile) vendor system can be used or the asphalt system could be used.

The portable solid waste management system is supplied and operated by the vendor. The types and quantities of waste to be processed are the same as for the Fermi solidification system. System operation will be closely monitored by Edison personnel. The vendor will utilize a process control program (PCP), which is reviewed and approved by Edison in accordance with Section 17.2. Conformance to 10 CFR 61 criteria is discussed in the vendor-supplied documentation. Fermi 2 or contractor operating procedures are used for operating this system as interfaced with the Fermi 2 solid radwaste system.

Depending upon the particular system and the expected radiation levels, portable (vendor) radwaste processing in the OSSF can take place in the pallet-loading room, in the storage bays, in the laydown areas immediately adjacent to the truck bay, or in the shielded container-processing room. It is expected that primarily this latter room will be used for such processing. If large bulk cement and chemical containers are used for such processing, however, they may be located outside of the truck bay door. These areas of the onsite storage facility were specifically designed and constructed to contain and handle mobile process systems (see Subsection 11.7.2.2.11). Concrete floors and walls of this region are coated, and drains are routed back to the liquid radwaste system. The remote-operated overhead crane is available to move equipment onto or from trucks located in the truck bay. The basic design of these areas and the methods of system operation have incorporated features to maintain operator exposures ALARA. Permanent piping installed in the shielded onsite storage facility pipe tunnel transports the radioactive process fluid directly to the vendor's equipment.

The interface connections between the portable system and the Fermi 2 system are shown in Figure 11.2-15 and described in Table 11.2-4. In general, liquid from the centrifuge feed tank is transported directly to the vendor equipment, and clarified liquid is returned to the waste clarifier tank. The waste is normally pumped to a disposable liner or high-integrity container (HIC).

If solidification of waste is performed, pretreatment of the waste with chemical additives may be conducted in accordance with values derived from a PCP. Solidification agents are then added and the waste is allowed to cure to complete the solidification process.

If dewatering of the waste is performed, the waste is transferred into a steel liner or HIC containing an internal underdrain assembly. Vacuum is applied to the underdrain system. Liquid from the underdrain system is sent back to the liquid radwaste system by a dewatering pump while the solids are trapped in the container. Some vendors provide additional accelerated dewatering capability. This accelerated capability is achieved by recirculating air at high velocity through a liner or HIC. Procedures ensure no drainable liquid at the time of shipment and <1 percent drainable liquid in HICs or <0.5 percent drainable liquid in steel liners upon receipt at the burial site.

The liners or HICs are suitable for transportation and burial at an approved burial facility. Additionally, the liners and HICs are compatible with numerous approved shipping casks if the liner or HIC requires shipment in a cask.

TABLE 11.5-1 SUMMARY OF ESTIMATED DESIGN INPUTS TO THE SOLID RADWASTE SYSTEM

Stream[a] Number	Description	Design Daily Volume (gpd)	Solids Content per Batch	Maximum Volume per Batch (gal)	Batch Frequency	
					Normal	Maximum
20	Reactor water cleanup phase separator decantate	635	200 ppm	2000	2/6.3 day	2/day
21	Condensate filter – demineralizer backwash	4838	214 lb	6400	1/2 day	8 day
22	Fuel pool filter backwash	216	65 lb	2160	1/10 day	1/10 day
27[b]	Floor drain precoat filter backwash	5170	17 lb	470	11/day	N/A
28[b]	Waste collector precoat filter backwash	1380	28 lb	920	1.5/day	N/A
29, 31, 32	Waste surge tank, FDC tank, waste collector tank sludge letdown	Infrequent (not included in mass balance)				
30	Reactor water cleanup phase separator sludge	23	580 lb	1400	1/60 day	1/60 day
35[b]	Floor drain etched-disk filter backwash	124	2.64 lb	21	6/day	6/day
36[b]	Waste collector etched-disk filter backwash	78	1.0 lb	21	4/day	15.5/day
58	Spent-resin tank	126	45 ft^3	1011	1/8 day	1/1.7 day
59	Evaporator concentrates	103	<8% by weight	800	1/8 day	1/4.5 day

[a] Refer to Figure 11.2-15.

[b] The precoat filters and the etched-disk filters are not in operation at the same time.

TABLE 11.5-2 SOLID RADWASTE SYSTEM – COMPONENT DESIGN PARAMETERS

Component	Number	Capacity (gal)	Material	Pressure (psig)	Temperature (°F)	Design Code
Condensate phase separator tank	2	12,000	Carbon steel Lastiglas 78	Atmospheric	--	(a)
Waste clarifier tank	1	16,500	Carbon steel Plasite 7155	Atmospheric	150	API-650[a]
Waste surge tank	1	65,700	Carbon steel[b] Plasite 7155	Atmospheric	150	API-650[a]
Centrifuge feed tank	1	6,000	Stainless steel, 1/8 in. corrosion allowance (SA-240-304)	Atmospheric	150	ASME Section III, Class 3
Spent-resin tank	1	1,400	Carbon steel Plasite 7155	Atmospheric	150	API-650[a]
Chloride waste tank	1	250	Monel 400, 1/8 in. corrosion allowance (SB-127-400)	Atmospheric	150	ASME Section III, Class 3
Concentrates feed tank	1	1,500	Stainless steel (SA-240-316L)	15	200	ASME Section[e] VIII, Div. 1
Spent-resin slurry feed tank	1	1,500	Stainless steel (SA-240-304)	15	150	ASME Section[e] VIII, Div. 1
Asphalt storage tank	1	9,000	Carbon steel (SA-285-Grade C)	Atmospheric	425	API-650

TABLE 11.5-2 SOLID RADWASTE SYSTEM – COMPONENT DESIGN PARAMETERS

Component	Number	Liquid	Flow Rating (gpm)	Head Across Pump (ft)	Materials (casing/shaft/impeller)	Type	Design Code
Condensate phase separator decant pump A	1	Liquid radwaste	475	60	Steel, mfg. std./ 316 SS/316 SS.	Single stage, vertical, inline	Manufacturer's standard
Condensate phase separator decant pump B	1	Condensate (water)	250	25	316 SS/steel, mfg. std./316 SS	Single stage, vertical, inline	Manufacturer's standard
Condensate phase separator sludge pump	2	Condensate and powdered resin slurry	410	115	316 SS/steel, mfg. std./316 SS	Single stage, vertical, inline	Manufacturer's standard
Centrifuge feed/recirculation pumps	2	Resin and water slurry	300	210	316 SS/steel, mfg. std./316 SS	Single stage, vertical, inline	Manufacturer's standard
Slurry dilution pump	1	Clarifier effluent water	150	32	316 SS/316 SS/316 SS	Single stage, vertical, inline	Manufacturer's standard
Waste clarifier sludge pump[c]	1	Wastewater with resin particles and beads	50	25[d]	316 SS/316 SS/316 SS	Progressive cavity	Manufacturer's standard
Spent-resin transfer pump[c]	1	Wastewater with resin particles and beads	50	25[d]	316 SS/316 SS/316 SS	Progressive cavity	Manufacturer's standard
Spent-resin decant pump	1	Liquid radwaste	85	42	316 SS/316 SS/316 SS	Single stage, vertical, inline	Manufacturer's standard
Cooling water booster pumps	2	Demineralized water	70	104	316 SS/316 SS/316 SS	Single stage, vertical, inline	Manufacturer's standard
Concentrates recirculation pump	1	Liquid radwaste	50	37	316 SS/316 SS/316 SS	Single stage, vertical, inline	Manufacturer's standard
Asphalt metering pumps	2	Asphalt	0.03 to 1.5	-21 to 53	Steel/steel/chrome-plated steel	Rotary gear	Manufacturer's standard
Spent-resin slurry recirculation pump	1	Resin and water slurry	80	69	316 SS/316 SS/chrome-plated 316 SS	Progressive cavity	Manufacturer's standard
Spent-resin slurry metering pump	1	Resin and water slurry	0.2 to 1.5	37	316 SS/316 SS/chrome-plated 316 SS	Progressive cavity	Manufacturer's standard

TABLE 11.5-2 SOLID RADWASTE SYSTEM – COMPONENT DESIGN PARAMETERS

Component	Number	Liquid	Flow Rating (gpm)	Head Across Pump (ft)	Materials (casing/shaft/impeller)	Type	Design Code
Waste slurry metering pump	1	Resin and water slurry	0.2 to 1.5	-158	316 SS/316 SS/chrome-plated316 SS	Progressive cavity	Manufacturer's standard
Concentrates metering pump	1	Liquid radwaste	0.2 to 1.5	28	316 SS/316 SS/chrome-plated 316 SS	Progressive cavity	Manufacturer's standard
Asphalt recirculation pumps	2	Asphalt	20	74	Ductile iron/steel/cast iron	Rotary gear	Manufacturer's standard

Centrifuge
- Type - Bowl with screw conveyor
- Capacity - 20 gpm, 98 percent recovery
- Material - 316 stainless steel
- Design Pressure - Atmospheric
- Design Temperature - 40 to 140 °F
- Design Code - Manufacturer's standard

Extruder/Evaporator (VRS)
- Type - Twin screw
- Capacity - Variable depending on input

Design Pressures
- Barrel heating jackets - 300 psig
- Barrel cooling jackets - 300 psig
- Steam dome jackets - 43 psig
- Steam dome condensers, tube side - 150 psig

Design Temperatures
- Barrel heating jackets – 410 °F
- Barrel cooling jackets – 410 °F
- Steam dome jackets – 330 °F
- Steam dome condensers, tube side – 150 °F

Materials
- Barrels, screw elements - DIN 1.8519 double nitrided
- Screw shafts - DIN 1.8550
- Steam domes, wetted surfaces - DIN 1.4571
- Steam dome condenser tubing - DIN 1.4571
- Interfacing connection - See nozzle schedule

Design Code - Manufacturer's standard

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[a] The design code for tank modification is ASME III, Class 3.

[b] SA-240-304 stainless steel bottoms.

[c] Identical pumps.

[d] Total differential pressure.

[e] These vessels function as atmospheric storage tanks and are vented. However, they are designed as pressure vessels under the rules of ASME VIII and so are more conservatively designed than called for in the code.

TABLE 11.5-3 ESTIMATED PRINCIPAL NUCLIDES TO BE SHIPPED FOR EACH TYPE OF WASTE, IN CURIES PER YEAR, FOR OPERATION WITH EVAPORATORS AND ETCHED-DISK FILTERS (3499 MWt)

Nuclide	Reactor Water Cleanup Resins	Radwaste Demineralizer Resins	Condensate Demineralizer Resins[a]	Evaporator Concentrates	Total Annual Curies
Br-83	0.00000E+00	1.21664E+00	1.86470E-01	1.31683E-06	1.40311E+00
Kr-83m	0.00000E+00	2.32973E+00	3.71962E-01	5.34344E-06	2.70170E+00
Br-84	0.00000E+00	3.95113E-03	7.52364E-04	1.53842E-21	4.70349E-03
Br-85	0.00000E+00	1.22181E-29	3.09385E-28	0.00000E+00	3.21603E-28
Kr-85m	0.00000E+00	1.77480E-02	3.33742E-03	7.25000E-07	2.10861E-02
Kr-85	1.71561E-04	4.33713E-06	2.37419E-05	1.20272E-08	1.99652E-04
Rb-89	0.00000E+00	2.39082E-06	7.55779E-07	0.00000E+00	3.14660E-06
Sr-89	1.61945E+01	1.33132E+00	6.08000E+00	3.47949E-03	2.36093E+01
Sr-90	3.73375E+00	9.74186E-02	5.12877E-01	2.59424E-04	4.34430E+00
Y-90	3.73376E+00	5.47956E-02	4.62144E-01	1.80549E-04	4.24088E+00
Sr-91	0.00000E+00	4.73841E+00	1.31733E+00	1.67715E-03	6.05742E+00
Y-91m	0.00000E+00	2.94110E+00	8.19728E-01	1.04730E-03	3.76188E+00
Y-91	1.26800E+01	8.58308E-01	4.13896E+00	2.32876E-03	1.76796E+01
Sr-92	0.00000E+00	2.57518E+00	4.05440E-01	7.02357E-06	2.98063E+00
Y-92	0.00000E+00	6.91087E+00	1.29632E+00	1.86235E-04	8.20737E+00
Y-93	0.00000E+00	5.05576E+00	1.46743E+00	2.04213E-03	6.52524E+00
Zr-95	1.653899+00	9.99088E-04	5.61256E-01	2.79479E-06	2.20125E+00
Nb-95m	1.72016E+00	4.93084E-04	4.60199E-01	1.68922E-06	2.18086E+00
Nb-95	2.72212E+00	1.01431E-03	5.83751E-01	2.79089E-06	3.30689E+00
Zr-97	1.12879E-27	1.08275E-04	9.24027E-03	9.80370E-08	9.34864E-03
Nb-97	1.21520E-27	1.14682E-04	9.87488E-03	1.05530E-07	9.98960E-03
Nb-98	0.00000E+00	2.89202E-04	1.19590E-02	1.58257E-16	1.22482E-02
Mo-99	1.88183E-05	1.12081E-01	2.14073E+01	2.31930E-04	2.15196E+01
Tc-99m	1.94672E-05	1.52650E+01	2.46800E+01	2.00516E-03	3.99470E+01
Tc-101	0.00000E+00	1.88649E+05	6.33655E-06	0.00000E+00	2.52014E-05
Ru-103	2.29446E+00	2.40077E-03	1.30303E+00	6.74186E-06	3.59990E+00
Tc-104	0.00000E+00	2.99290E-04	8.12049E-05	2.94650E-35	3.80494E-04
Ru-105	0.00000E+00	9.67894E-03	4.46495E-01	4.21898E-07	4.56174E-01
Ru-106	1.60141E+00	4.09813E-04	2.38384E-01	1.11197E-06	1.84020E+00
Rh-106	1.60141E+00	4.09813E-04	2.38384E-01	1.11197E-06	1.84020E+00
Te-129m	3.91072E+00	5.15091E-01	2.23808E+00	1.33601E-03	6.66522E+00
Te-129	2.46783E+00	3.24264E-01	1.41177E+00	8.42827E-04	4.20471E+00
I-129	1.68343E-06	1.34848E-06	1.07673E-05	1.07673E-09	1.38094E-05
Te-131m	5.49768E-15	3.34942E-01	2.05763E-01	4.38708E-04	5.41144E-01
I-131	2.17482E+00	3.77431E+01	1.02743E+01	8.85583E-02	1.42750E+02
Te-131	1.22654E-15	7.47231E-02	4.59050E-02	9.78749E-05	1.20726E-01
Te-132	1.14346E-06	6.87227E-02	9.81369E-02	1.35304E-04	1.66996E-01
I-132	1.17780E-06	1.11330E+01	1.77977E+00	1.47565E-04	1.29129E+01
I-134	0.00000E+00	8.75434E-01	1.40171E-01	6.74317E-13	1.01560E-01
I-133	9.61304E-19	1.21167E+02	5.65057E+01	1.21723E-01	1.77794E+02
Xe-133m	1.49775E-07	2.74539E+00	3.98745E+00	6.42260E-03	6.73927E+00
Xe-133	2.46914E-01	6.21781E+01	1.71109E+02	1.65710E-01	2.33700E+02
I-135	9.61304E-19	1.21167E+02	5.65057E+01	1.21723E-01	1.77794E+02
Xe-135m	1.85923E-19	2.34345E+01	1.09286E+01	2.35420E-02	3.43867E+01
Xe-135	1.70706E-18	1.13804E+02	7.27860E+01	1.83134E-01	1.86773E+02
Cs-135	3.87751E-05	4.26465E-06	1.87470E-05	2.66833E-08	6.18134E-05

TABLE 11.5-3 ESTIMATED PRINCIPAL NUCLIDES TO BE SHIPPED FOR EACH TYPE OF WASTE, IN CURIES PER YEAR, FOR OPERATION WITH EVAPORATORS AND ETCHED-DISK FILTERS (3499 MWt)

Nuclide	Reactor Water Cleanup Resins	Radwaste Demineralizer Resins	Condensate Demineralizer Resins[a]	Evaporator Concentrates	Total Annual Curies
Cs-134	1.48180E+01	4.15622E-01	2.16844E+00	1.10679E-03	1.74031E+01
Cs-136	1.34777E-01	2.28170E-01	7.70842E-01	5.62091E-04	1.13435E+00
Cs-137	4.26805E+01	1.11197E+00	5.86270E+00	2.96549E-03	4.96582E+01
Ba-137m	4.03758E+01	1.05193E+00	5.54613E+00	2.80535E-03	4.69767E+01
Cs-138	0.00000E+00	6.13834E-03	1.16369E-03	3.81325E-21	7.30203E-03
Ba-139	0.00000E+00	5.10282E-01	7.56031E-02	1.66680E-09	5.85885E-01
Ba-140	2.44702E+00	4.53902E+00	1.52215E+01	1.11698E-02	2.22187E+01
La-140	2.81654E+00	3.24415E+00	1.59568E+01	9.80443E-03	2.20273E+01
Ba-141	0.00000E+00	4.23285E-05	1.13901E-05	8.71513E-36	5.37186E-05
La-141	0.00000E+00	3.82517E-01	6.79274E-02	8.47010E-06	4.50453E-01
Ce-141	2.83846E+00	5.16454E-02	2.09002E+00	1.39330E-04	4.98027E+00
Ba-142	0.00000E+00	1.03381E-09	5.00343E-09	0.00000E+00	1.53415E-08
La-142	0.00000E+00	5.54537E-02	1.28712E-01	8.68227E-10	1.84166E-01
Ce-143	3.73270E-14	9.84920E-04	1.19133E-01	1.51206E-06	1.20120E-01
Pr-143	3.36046E-01	4.41148E-03	2.00167E+00	1.21255E-05	2.34214E+00
Ce-144	1.28730E+00	3.99895E-04	2.31491E-01	1.09679E-06	1.51919E+00
Pr-144	1.28735E+00	3.99912E-04	2.31501E-01	1.09684E-06	1.51925E+00
Nd-147	9.39654E-03	2.99215E-04	1.24501E-01	8.00680E-07	1.34197E-01
Np-239	4.89204E-06	4.45548E+01	4.75614E+01	7.90225E-02	9.21953E+01
Na-24	1.02563E-28	1.79796E+01	6.66214E+00	1.28545E-02	2.46546E+01
P-32	1.88577E+00	2.31703E+00	8.07594E+00	5.74655E-03	1.22845E+01
Cr-51	3.68994E+02	6.94206E-01	3.61455E+02	1.94491E-03	7.31145E+02
Mn-54	3.06319E+01	9.34598E-03	5.41727E+00	2.56280E-05	3.60585E+01
Fe-55	5.00015E+02	1.35535E-01	7.87846E+01	3.69124E-04	5.78936E+02
Mn-56	0.00000E+00	1.05957E-01	4.10384E+00	2.25117E-07	4.20980E+00
Co-58	4.48745E+01	2.51447E-02	1.41928E+01	7.02877E-05	5.90926E+01
Fe-59	4.09647E+00	3.64253E-03	1.99866E+00	1.02257E-06	6.09878E+00
Co-60	2.06817E+02	5.44352E-02	3.16425E+01	1.47877E-04	2.38514E+02
Ni-63	5.32216E-01	1.36400E-04	7.94843E-02	3.705470-07	6.12838E-01
Cu-64	2.53975E-32	4.21139E-01	3.14881E+01	2.70328E-04	3.19096E+01
Ni-65	0.00000E+00	6.09019E-04	2.34736E-02	1.09315E-09	2.40826E-02
Zn-65	8.32162E+01	2.74891E+00	1.40248E+01	7.30284E-03	9.99972E+01
Zn-69	0.00000E+00	2.61347E-02	4.09250E-03	1.45818E-13	3.02272E-02
Zn-69m	0.00000E+00	1.51306E-13	6.90983E-12	0.00000E+00	7.06113E-12
Ag-110m	4.17246E-01	1.32888E-04	7.68785E-02	3.64906E-07	4.94258E-01
W-187	2.65465E-18	7.40498E-03	7.49820E-01	9.18594E-06	7.57234E-01
Total	1.40723E+03	6.19777E+02	1.20444E+03	8.63634E-01	3.23231E+03

[a] This column also includes the floor-drain filter backwash, etched-disk filter backwash, waste-collector filter backwash, fuel pool filter backwash, and waste-surge-tank sludge letdown activities.

[b] 0.00000E-1 = 0.00000 x 10^{-1}

TABLE 11.5-4 ESTIMATED ANNUAL VOLUME OF SOLIDS TO BE SHIPPED FROM PROCESSING THROUGH THE EXTRUDER SYSTEM

System	Estimated Annual Shipped Solidified Volume[a] (gal)	Annual Number of Drums Shipped[a]
RWCU demineralizer resins Condensate filter-demineralizer resisns Waste collector and floor drain etched-disk backwash solids Fuel pool filter backwash	6,584	133
Radwaste demineralizer resins	11,286	228
Evaporator bottoms	5,148	104
Total	23,018	465

[a] These volumes are the solidified product volumes as shipped in 55-gal drums assumed to be 90 percent full and assumed to have a final waste-to-asphalt weight ratio of 50 percent/50 percent. They assume operation of the evaporators and the etched-disk filter/oil-coalescer trains and a dry (centrifuge) feed to the extruder.

11.6 RADIOLOGICAL ENVIRONMENTAL MONITORING PROGRAM

A program is provided to monitor the radiation and radionuclides in the environs of the plant. The program provides (1) representative measurements of radioactivity in the highest potential exposure pathways, and (2) verification of the accuracy of the effluent monitoring program and modeling of environmental exposure pathways. The program is (1) contained in the ODCM, (2) conforms to the guidance of Appendix I to 10 Part CFR 50, and (3) includes the following:

1. Monitoring, sampling, analysis, and reporting of radiation and radionuclides in the environment in accordance with the methodology and parameters in the ODCM,

2. A Land Use Census to ensure that changes in the use of areas at and beyond the SITE BOUNDARY are identified and that modifications to the monitoring program are made if required by the results of this census, and,

3. Participation in an Interlaboratory Comparison Program to ensure that independent checks on the precision and accuracy of the measurements of radioactive materials in environmental sample matrices are performed as part of the quality assurance program for environmental monitoring.

11.7 ONSITE STORAGE FACILITY

11.7.1 Introduction

The onsite storage facility is essentially an above-grade structure for holding low-level radioactive waste. It provides interim storage capacity for an amount of waste estimated to be generated in 5 years of plant operation. This surge capacity is primarily intended to be used to allow Fermi 2 to continue operating during a period when no offsite disposal facilities are available. Under normal conditions, when offsite disposal is available, a portion of the storage facility will be used as a staging area for waste. The onsite storage facility also includes space for a dry active waste compactor, offices, a control room, and rooms for housing the radwaste solidification system's asphalt storage tank and pumps. Provision is also made to allow processing of radwaste by transportable vendor-supplied equipment inside the facility.

11.7.1.1 Design Objectives

The onsite storage facility provides a protective barrier around the stored waste to

a. Protect the waste containers from the effects of the environment

b. Prevent an uncontrolled release of the waste to the environment

c. Provide shielding from the radiation emitted by the waste.

The waste will be retrievable from the facility. Waste will not be stored permanently in the facility. Handling of the waste within the facility can normally be done remotely with a crane or, when radiation levels allow, with a hand truck or a forklift vehicle.

The waste containers will be stored inside the structure, which protects them from the external environment. The storage facility has full-length trench drains in each storage cell to prevent collection of water on the facility floor.

All potential pathways for the release of radioactivity to the environment are controlled and monitored in accordance with 10 CFR 50, Appendix A, Criteria 60-64. In particular, all potentially contaminated drains within the facility are collected and routed to the liquid radwaste system. All ventilation exhaust from the onsite storage facility is filtered and monitored for radioactivity.

11.7.1.2 Description of Waste Stored

Normally, the radioactive wastes to be stored in this facility are of three general types: dry active wastes, processed wastes, and miscellaneous unprocessed wastes. Storage containers for processed waste could be either liners, high-integrity containers, or drums. High integrity containers will be used for processed waste which is potentially corrosive. Containers for dry active wastes could be drums, low specific activity boxes, or other appropriate containers. Waste with the potential for gas generation is stored in vented containers, or the container shall be vented at least every 5 years.

The dry wastes, which are generally of low radioactivity, can normally be handled by direct contact. These wastes normally are collected in containers or bags located in various zones around the plant. The filled containers are closed and then transferred to the onsite storage facility. These wastes are of two types: compressible and noncompressible. The compressible wastes are normally processed and packaged. The noncompressible wastes are manually packaged into containers meeting transportation criteria and stored until shipment.

This facility is also used for the storage of mixed, hazardous and radioactive waste materials in accordance with applicable regulations and permit requirements.

11.7.1.3 Design Safety Features

To reduce the possible exposure of personnel during maintenance, the following concepts have been incorporated into the design of the onsite storage facility:

a. Lighting will be provided via the bridge crane. No lights have to be replaced over the high level radwaste storage cells

b. The container processing room has been provided with adequate shielding to minimize exposure during these operations

c. Epoxy coating has been provided on all floors and walls where potential contamination could occur

d. Access to the bridge crane and its cables will normally be over the truck bay to reduce exposure to maintenance personnel

e. Normal operations involving the storage containers and bridge crane can be performed remotely.

11.7.2 Onsite Storage Facility

11.7.2.1 Location

The onsite storage facility is located at the northeast corner of the existing radwaste building (see Figure 11.7-1). The facility's control room, compactor area, offices, and asphalt tank rooms are located adjacent to the north wall of the radwaste building and are attached to the onsite storage facility (see Figures 11.7-1 and 11.7-2). The entire complex is located within the site-protected area.

11.7.2.2 Design Features

11.7.2.2.1 Structural and Architectural

All surfaces in the onsite storage facility are sloped to drainage ditches or drains that are connected with the liquid radwaste collection systems. Rainwater is prevented from entering the facility by a rise in the grade at the entrance of the facility and a drainage ditch that connects to the onsite sewer system. Drains from the heating, ventilating, and air conditioning (HVAC) system are connected to the radwaste collection system.

The onsite storage facility is a non-safety-related structure and is designed and constructed in accordance with the following codes and standards:

a. ACI-318-77: American Concrete Institute, Building Code Requirements for Reinforced Concrete

b. AISC-1978: American Institute of Steel Construction, Specification for the Design Fabrication and Erection of Structural Steel for Buildings

c. ANSI-58.1-72: American National Standards Institute, Building Code Requirements for Minimum Design Loads in Buildings and Other Structures. The wind loading will be based on the 50-year mean recurrence interval

d. UBC-79: Uniform Building Code. The main plant requirements for the operating-basis and safe-shutdown earthquakes will not be considered, in accordance with NRC Generic Letter 81-38. The onsite storage facility is designed to comply with UBC-79 requirements for Seismic Zone 1

e. OSHA: Occupational Safety and Health Administration requirements

f. ACI-531-79: American Concrete Institute, Building Code Requirements for Concrete Masonry Structures

g. NRC Regulatory Guide 1.143: Pipes, joints, and fittings of the piping from the main radwaste system to the piping connection for the portable solidification system.

The onsite storage facility is constructed of the following non-combustible materials:

a. Exterior - reinforced-concrete and reinforced-concrete block walls, reinforced-concrete roof, insulated metal siding, and hollow metal doors

b. Interior - reinforced-concrete walls.

The rooms housing the asphalt storage tank and pumps are constructed of concrete block walls and have approved fire-rated doors (see Figure 11.7-2). Both rooms are accessible only from an outside entrance. A high wall with a door sill that can contain the full contents of a tank rupture is located in the asphalt storage tank room. There are no drains in this room, nor are there any in the adjacent pump room.

To ease any potential problems with decontamination, all floors in the facility are finished with two layers of epoxy coating. The walls are coated to a level of 2 ft above the floor, with the exception of the truck-bay area and the container processing room, where the coating extends to the top of the interior wall.

11.7.2.2.2 Shielding

Shielding has been provided for the onsite storage facility to ensure that the radiation doses resulting from its use and operation will be as low as reasonably achievable (ALARA). In general, the criteria to which shielding is designed are as follows: less than 1.0 mrem/hr in working areas within the facility; less than 0.1 mrem/hr in areas outside the facility; and less than 1.0 mrem/yr in areas at or beyond the boundary of the restricted area. The shielding design assumed the entire storage space to be filled with drums of processed waste, each containing a conservative design-basis source. The shielding design takes into full account such considerations as

a. Direct and scattered radiation paths

b. Ducts and other voids or penetrations in shield walls

c. Multiple radiation sources and source transport paths that may contribute to the dose rate in any given area.

The major components of the shielding design include

a. The facility's outer shield walls, which protect the yard area from direct radiation

b. The facility's roof slab, which protects the yard area from air scatter and the HVAC equipment room from direct radiation

c. The north and south truck-bay shield walls, which protect truck-bay workers from direct radiation

d. The low roof of the truck bay which protects truck-bay workers from the scatter off the main roof slab

e. The shielding around the container processing room, which protects truck-bay workers during the associated operations

f. The storage cell walls, which protect workers during any necessary maintenance in adjoining storage cells

g. The shielding around the dry-active-waste compactor area, which protects surrounding areas from potential sources in this area.

11.7.2.2.3 Radiation Monitoring

Area radiation monitors are provided in the truck-bay area and near the dry-active-waste compactor (see Figure 11.7-2). If predetermined radiation setpoints are exceeded, alarms will be sounded both locally and in the control room of the onsite storage facility.

Effluent radiation monitoring is provided by an off-line noble gas, particulate, and iodine monitor. This system takes a representative sample from the exhaust duct of the HVAC system. The HVAC system is designed to hold the building at a minimum of 1/4-in. negative water gage, thus ensuring that no unmonitored releases can occur. Readings of the noble gas channel will be displayed in the main control room. If predetermined setpoints are exceeded, an alarm will sound.

11.7.2.2.4 Fire Protection

The onsite storage facility is structurally a separate building and is, therefore, a separate fire-protection area. Only a portion of the facility is attached to any other building. The walls, floor, and ceiling of the onsite storage facility are of reinforced concrete or concrete block.

Fire-detection equipment is designed to annunciate and alarm locally and in the control room of the onsite storage facility. Fire-suppression equipment consists of a hydraulically designed sprinkler system. Automatic sprinkler system protection is provided in all areas of the onsite storage facility except the control room, office area, corridor, and empty-drum storage area. Combustible loading in these areas does not justify a suppression system. A manual hose station with enough hose to reach all areas in the onsite storage facility, except the asphalt storage and pump rooms, is located in the truck-bay area. An additional hose reel will be used to access the asphalt storage and pump rooms from the truck bay.

Water is supplied from the existing fire protection system by a 6-in.-diameter header pipe. Fire-suppression water will be collected in the liquid drain trenches and routed to the radwaste treatment system. Inadvertent operation of the automatic fire- suppression system will have no adverse effect upon the ability to shut down the plant.

The HVAC system for the onsite storage facility will automatically shut down on sensing smoke in the outside air supply and exhaust air ducts. Ionization detection is provided in the control room, office area, empty-drum storage area, HVAC room, and asphalt storage and pump rooms. Combustible materials in the storage areas are normally kept in storage containers as described in Section 11.7.1.2, and are protected by an automatic sprinkler system. In addition, the sprinkler system alarms upon activation.

Fire-protection equipment is listed by Underwriters Laboratories. Fire-protection and fire-detection drawings were approved by Edison and its insurer.

Significant quantities of potential combustibles which are stored in the facility are normally kept in storage containers as described in Section 11.7.1.2, which are segregated into two distinct areas (see Figures 11.7-2 and 11.7-3, Sheets 1 through 3). This configuration reduces the probability of ignition to insignificant levels. A portion of the dry-active-waste storage area is used for trash sorting before further processing.

Fire protection for the truck bay is provided by the sprinkler system. The truck-bay area is separated from the storage areas by reinforced-concrete walls. The fire protection system for the onsite storage facility was designed using NFPA-13 for guidance.

The rooms housing the asphalt storage tank and pumps contain 3-hr fire-barrier walls and doors, even though no plant safety-related equipment is located therein. They also contain an automatic fire-detector and sprinkler system. The HVAC systems for these rooms are completely separate from the rest of the storage facility, with no interactions possible, and fusible links automatically close the fire dampers in the HVAC systems in the rooms in case of fire.

The onsite storage facility is separated from the radwaste building with a 3-hr fire barrier except for the door opening to the access aisle which is a nonrated metal door. However, the door leads to a corridor that is a low-combustible area.

11.7.2.2.5 Flood Protection

The onsite storage facility is located above the maximum flood elevation of 586.9 ft. The drum storage area is at Elevation 587.0 ft. This is 4 ft above the plant grade elevation of 583.0 ft. Therefore, flooding is not considered a design-basis event.

11.7.2.2.6 Tornado Protection

The minimum thickness of concrete walls below Elevation 624 ft is 54 in.; above Elevation 624 ft, it is 28 in. The minimum thickness of the concrete slab for the roof is 24 in. It is unlikely that a tornado would damage a building with this structural integrity to the extent that the building's contents would be scattered. Therefore, a tornado is not considered a design-basis event.

11.7.2.2.7 Facility HVAC Systems

The HVAC system in the onsite storage facility is composed of (1) the heating and ventilating system for the onsite storage facility; (2) the HVAC system for the onsite storage facility control room and offices; (3) the heating and ventilating system for the asphalt storage pump room; (4) the heating and ventilating system for the asphalt storage tank room; and (5) the heating and ventilating system for the HVAC equipment room. Each system is described below.

11.7.2.2.7.1 Onsite Storage Facility Heating and Ventilating System

The heating and ventilating system for the onsite storage facility is designed to maintain a suitable environment for equipment and for proper air flow from normally accessible areas to potentially contaminated areas. The system is also designed to maintain the facility at a 1/4-in. water gage negative pressure with respect to the ambient air to minimize the release of potentially contaminated air to the outside. The exhaust air is filtered to remove any radioactive particulates and is monitored before its release to the environs.

The system is designed to maintain a minimum temperature of 50°F in all areas and to limit the maximum temperatures to 104°F in the truck-loading area, the empty-drum area, the compactor area, and the aisle, and to 110°F in the remaining areas.

The system provides 100-percent outside air by two 50 percent- capacity supply systems, each consisting of an air-intake louver, a prefilter, a medium-efficiency filter, an electric blast coil, a fan, and associated controls. The air is exhausted through prefilters and high-efficiency particulate air (HEPA) filters and is monitored before its release to the outdoors. Electric unit heaters are provided to offset the heat loss due to the infiltration of air in the truck-loading area. All the major equipment of the system is located in the HVAC equipment room.

11.7.2.2.7.2 Control Room and Offices HVAC System

The HVAC system for the control room and offices is designed to maintain a suitable environment for the comfort of personnel and for proper functioning of the equipment. A minimum of 20 percent outside air is provided to maintain a positive pressure with respect to the outside and to remove odors.

The HVAC system is designed to maintain a temperature of 75°F ± 2°F year round. It consists of (1) a packaged cooling unit comprising an air-cooled condensing unit, a filter, a DX coil, and a supply fan; and (2) zone electric heating coils for winter heating.

The packaged cooling unit is located on the roof of the asphalt storage tank room, and the electric heating coils are located in the supply ductwork.

11.7.2.2.7.3 Asphalt Storage Tank Room, Asphalt Storage Pump Room, and HVAC Equipment Room Heating and Ventilating Systems

These three heating and ventilating systems are designed to maintain a suitable environment for the equipment housed in each room.

The heating and ventilating system for the asphalt storage tank room is designed to limit summer and winter temperatures to a maximum of 110°F and a minimum of 50°F, respectively. The system consists of an air-intake louver, an exhaust fan, control dampers, and unit heaters.

The heating and ventilating systems for the asphalt storage pump room and the HVAC equipment room are designed to limit summer and winter temperatures to a maximum of 104°F and a minimum of 50°F, respectively. Each system consists of an air-intake louver, a supply fan, control dampers, and unit heaters. The heating and ventilating system for the HVAC equipment room provides 1000-cfm outside air to maintain the room at a positive pressure with respect to the ambient air.

The equipment for each of these systems is located in its respective room.

11.7.2.2.8 Provisions for Liquid Drainage

The onsite storage facility is provided with an extensive system of drains and trenches. All surfaces in the facility are sloped so that any spillage is directed toward one or more of the drains. Because of this network, permanent curbs are not provided.

Drains in potentially contaminated areas of the onsite storage facility are routed directly to the floor drain collector subsystem of the liquid radwaste system. These include drains in the drum-storage areas, the truck-bay area, the HVAC equipment room, and the drum-compactor area. These drains are adequately sized for all normally expected influents and will also drain water from the fire-suppression system.

11.7.2.2.9 Container-Handling Systems

Within the storage structure proper, containers are handled by a 10-ton electric overhead traveling bridge crane, by forklift truck or, when radiation levels allow, by hand truck. The bridge crane is remotely operated from the control room located in the annex structure. The crane system is designed for precise placement of the containers. The bridge and trolley is accurately positioned by the use of a closed-circuit television (CCTV) monitoring system and a coordinate target system. Dedicated TV cameras mounted on the trolley are directed at the indices of each of two perpendicular coordinates: One coordinate hangs from a crane rail, and the other is attached to a wall. This system enables the operator to accurately position the bridge and trolley by viewing the TV monitor and lining up cross hairs on the camera system with the appropriate coordinate. Additional dedicated TV cameras are mounted in the drum accumulator-conveyor (see Subsection 11.7.3.1) and in the container processing room.

Downward-viewing TV cameras mounted on the bridge crane and incandescent lights provide a view of the area below the bridge on three control-console monitors. In addition, a solid-state digital grab elevation readout is located on the control console. The readout tells the operator the height of the grab above a fixed reference point.

The drum grab is designed to lift drums weighing up to 6000 lb and has the capability to handle closed-head drums. It is supplied with a motor-operated jaw actuator for positive load-release control. For the jaw to operate, the cable has to be slack (no load). This ensures positive control.

For personnel safety and to assist positioning accuracy, containers must be raised to the full up position before high-speed operation is possible with the bridge or trolley. In this position, the container is between the bridge beams. It will clear all obstacles cleared by the crane and is supported to eliminate swinging.

The bridge crane is capable of placing containers into any storage bay, the pallet room, the container processing room, onto the conveyor, and onto a truck.

Crane bearings inside gear cases and high-speed gearing bearings are splash lubricated. Other bearings are lifetime lubricated. A weight-type hoist limit switch is provided for the upper hoist limit, and a screw-type limit switch is provided for upper and lower limits. A tipped drum uprighting attachment will be used if necessary. Two bridge motors with separate bridge circuitry are provided so that if one motor fails, the other can be used as a backup. Eye-bolts are attached to the bridge to allow towing of the crane by a building-mounted winch if both motors become defective. Magnetic-particle testing has been used by the manufacturer to determine the presence of discontinuities at or near the surface of the crane hook, lifting eyes, and all weldments.

11.7.2.2.10 Compaction

To decrease the volume of solid waste, the onsite storage facility contains a high-efficiency, in-drum, ram-head compactor system with a filtration and ventilation system.

The ventilation system controls any contaminated particles that may be released while the packaging equipment is being operated. The compacting press has an air exhaust system, consisting of a hood, a prefilter and absolute filter, and an exhaust fan.

This system is so arranged that when the ram descends to compress waste material, the air exhaust system is in position to filter the air from the drum as the material is compressed.

When the compactor is used, the compressible trash, which is made up of low-activity material, including glass, paper, rags, mop heads, booties, gloves, and towels, is normally transported to the compactor room in plastic bags. The trash is then placed in the drums and compacted. When a drum is filled, the top is fastened onto the drum, and a forklift truck or, when radiation levels allow, a hand truck is used to transport the drum from the compactor room to drum-staging or drum-storage areas.

11.7.2.2.11 Temporary Processing

Permanent piping is routed from the radwaste system to the onsite storage facility to allow vendor processing and/or solidification of wet waste in the truck-bay area and adjoining rooms.

All pipes run in a shielded pipe tunnel beneath the storage facility and conform to ANSI B31.1. An access hatch to the pipe tunnel beneath the storage facility is located in the truck bay area. The radwaste pipelines terminate in the truck bay (see Figure 11.7-2). A blind flange is at the termination of each line. Each pipeline is capable of being flushed as necessary with condensate. Water decanted from processed waste in the truck bay will be returned through the pipelines to the liquid radwaste system in the radwaste building. When vendor processing is utilized, the wet waste will be pumped through the pipelines to commercial process equipment provided by the vendor. The permanent radwaste piping will be connected at the flange fittings to the equipment provided by the vendor. Details concerning the vendor-supplied mobile processing equipment are given in Subsections 11.2.10 and 11.5.6.

11.7.3 Operations

11.7.3.1 Storage

The asphalt solidification system in the radwaste building dewaters and solidifies the radwaste in 55-gal drums; these drums can be moved from the radwaste building to the onsite storage facility by the method described in Section 11.5.

Drums of compacted waste are normally brought into the facility by a forklift truck or, when radiation levels allow, by a hand truck. The crane can then lift each drum and perform essentially the same functions as with the drums of solidified waste. Alternatively, the forklift or hand truck can be used to place the drums of compacted waste into storage.

The facility is designed for one-on-one stacking of 55-gal drums, up to eight layers in height, with steel grating between each layer. Tests performed for Sargent & Lundy Engineers indicate that the maximum compressive load that an 18-gage 55-gal DOT-17H drum can carry before failure is approximately 6000 lb. During storage, a 17H drum on the bottom layer (with seven layers above) will be subjected to a maximum compressive load of 3395 lb, which is only 57 percent of the failure load. Drum manufacturers' data indicate that the maximum compressive load a 55-gal DOT-17E drum can withstand before failure is 10,000 lb. During storage, a 17E drum on the bottom layer will be subjected to a maximum compressive load of 4970 lb. Thus, the maximum load that a 17E drum on the bottom layer will be subjected to is only 50 percent of the failure load. This provides confidence that eight-high drum stacking is safe and justifiable for 55-gal drums. The dry active waste can be stored in 55-gal drums having the same dimensional, physical, and strength characteristics as Department of Transportation (DOT) type 17H drums. The solidified waste will be stored in drums having the same dimensional, physical, and strength characteristics as DOT type 17E drums. In such cases, eight-drum stacking is possible. When other storage containers (liners, HICs, non-standard drums, etc.) are utilized, eight-high stacking would not be used.

The storage facility is separated into cubicles by inner walls. This allows the potential segregation of waste containers by radioactivity level and/or waste type. Compacted dry active waste can be stored separately from processed waste. Also, sample drums from each batch of solidified radwaste resins can be stored in the test and sample area of the onsite storage facility (see Figure 11.7-2).

A record board is located in the control room of the onsite storage facility, which can be used to record the position of all containers stored in the facility. The board consists of a plan view of the storage areas, with container setdown positions identified by alphanumeric designations that correspond to the bridge crane coordinate grid system. The operator can place a tag on the board for each container. The tag can contain such information as container number, weight, radiation level, and date of storage, etc.

11.7.3.2 Loading

Retrieving containers of processed waste from storage for offsite disposal is also performed with the bridge crane. Retrieval of drums of compacted trash will be done by either a forklift truck, a hand truck, or the bridge crane. Containers of processed waste are picked up from storage and loaded into a truck (for drums, one method is by use of a circular shipping pallet) for ultimate offsite disposal. Drums of compacted trash are placed onto transport vehicles by the bridge crane, forklift truck, or hand truck.

If a drum of asphalted waste were accidentally dropped while being manipulated from the bridge crane, no airborne radioactive material would be released because the waste, being solidified in asphalt, is inherently bound within this matrix. The bridge crane is designed to have the capability of righting a fallen drum.

11.7.4 Radiological Assessment: ALARA Doses

Design features included to ensure that doses due to external radiation sources are ALARA are described in Subsection 11.7.2.2.1.

Control of potential airborne contamination is provided by an HVAC design that ensures that air will flow from areas of lesser potential contamination to areas of greater potential contamination. Specifically, air will tend to flow

a. From outside the facility to inside the facility

b. From the truck-bay to the drum-storage area

c. From the control room and offices to the compactor area for dry active waste.

Measures have been taken to provide airflow barriers in the two openings between the two buildings so as to minimize any differential flow.

The exhaust of the dry-active-waste compactor is filtered and routed directly to the facility's exhaust to minimize airborne contamination.

All drain lines that are potential pathways for airborne cross-contamination are trapped and provided with fill lines.

Control of surface contamination is provided by segregating clean areas (the control room and offices) from potentially contaminated areas (the drum-storage, truck-bay, and dry-active-waste compactor areas).

All lines and equipment in the facility that can carry radioactive sources are capable of being flushed after use.

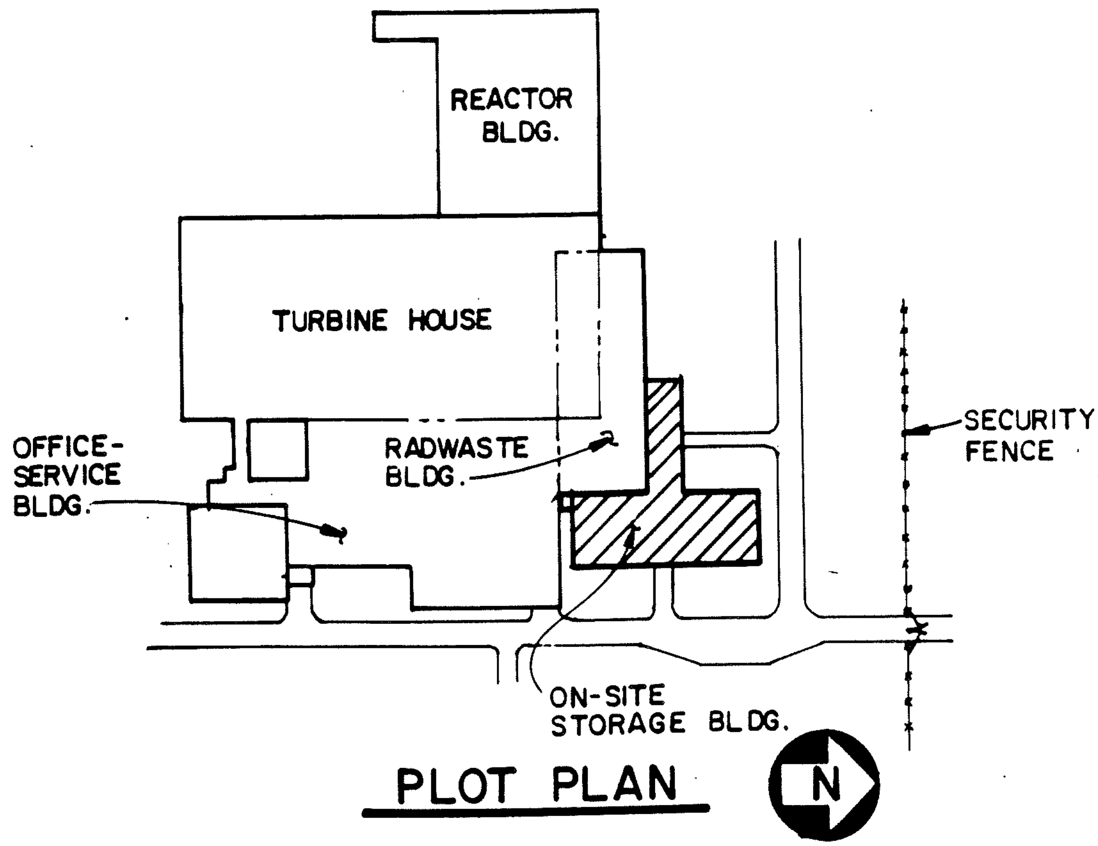
11.7.4.1 Onsite Doses

The building shielding is sufficient to reduce the dose rates from the drums to persons at the site to acceptably low levels (see Subsection 11.7.2.2.2). The potential for significant airborne or surface contamination is very remote, and the overall design of the facility is in accordance with the ALARA philosophy.

11.7.4.2 Offsite Doses

The design of the facility ensures that the annual dose to the unrestricted area will be below 1.0 mrem/yr (see Subsection 11.7.2.2.2), in compliance with 40 CFR 190.

Although no radioactivity is expected to be released from this facility under normal conditions, the single controlled atmospheric release path is monitored (see Subsection 11.7.2.2.3) in accordance with 10 CFR 50, Appendix A.



Fermi 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 11.7-1

ONSITE STORAGE FACILITY
PLOT PLAN

Figure Intentionally Removed
Refer to Plant Drawing A-2438

Fermi 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 11.7-2

ONSITE STORAGE FACILITY FLOOR PLAN

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Refer to Plant Drawing A-2438

Fermi 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 11.7-3, SHEET 1

ONSITE STORAGE FACILITY CROSS SECTION

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Refer to Plant Drawing A-2438

Fermi 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 11.7-3, SHEET 2

ONSITE STORAGE FACILITY CROSS SECTION

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Refer to Plant Drawing A-2438

Fermi 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 11.7-3, SHEET 3

ONSITE STORAGE FACILITY CROSS SECTION

11.8 ISFSI STORAGE PAD

The Independent Spent Fuel Storage Installation (ISFSI) storage pad provides a level resting surface for dry fuel storage casks. The pad is a 141' by 141' square reinforced concrete structure that is two feet thick designed to accommodate sixty four dry storage casks. The pad is compliant with ACI 349, "Code Requirements for Nuclear Safety-Related Concrete Structures," 2001, and designed in accordance with NUREG-1567, "Standard Review Plan for Spent Fuel Dry Storage Facilities." The pad is surrounded by a fence with signage identifying the location as a radiologically controlled area. The pad is also surrounded by a subsurface drainage system to minimize the effects of freeze and thaw cycles on the soil under the pad to preclude soil displacement. Additional information regarding the ISFSI storage pad is available in the Holtec Final Safety Analysis Report for their HI-STORM 100 Cask System to which Fermi 2 is a declared general licensee in accordance with 10CFR72.

I. INTRODUCTION

This Appendix was prepared to demonstrate compliance of the Enrico Fermi Atomic Power Plant Unit 2 with Section II of Appendix I of 10 CFR Part 50 (Reference 1). Applicable portions of Section II of Appendix I specifically set forth the following design objectives:

A. The calculated annual total quantity of all radioactive material above background to be released from each light-water-cooled nuclear power reactor to unrestricted areas will not result in an estimated annual dose or dose commitment from liquid effluents for any individual in an unrestricted area from all pathways of exposure in excess of 3 millirems to the total body or 10 millirems to any organ.

B.1. The calculated annual total quantity of all radioactive material above background to be released from each light-water-cooled nuclear power reactor to the atmosphere will not result in an estimated annual air dose from gaseous effluents at any location near ground level which could be occupied by individuals in unrestricted areas in excess of 10 millirads for gamma radiation or 20 millirads for beta radiation.

B.2. Notwithstanding the guidance of paragraph B.1:

(a) The Commission may specify, as guidance on design objectives, a lower quantity of radioactive material above background to be released to the atmosphere if it appears that the use of the design objectives in paragraph B.1 is likely to result in an estimated annual external dose from gaseous effluents to any individual in an unrestricted area in excess of 5 millirems to the total body; and

(b) Design objectives based upon a higher quantity of radioactive material above background to be released to the atmosphere than the quantity specified in paragraph B.1 will be deemed to meet the requirements for keeping levels of radioactive material in gaseous effluents as low as practicable if the applicant provides reasonable assurance that the proposed higher quantity will not result in an estimated annual external dose from gaseous effluents to any individual in unrestricted areas in excess of 5 millirems to the total body or 15 millirems to the skin.

C. The calculated annual total quantity of all radioactive iodine and radioactive material in particulate form above background to be released from each light-water-cooled nuclear power reactor in effluents to the atmosphere will not result in an estimated annual dose or dose commitment from such radioactive iodine and radioactive material in particulate form for any individual in an unrestricted area from all pathways of exposure in excess of 15 millirems to any organ.

This Appendix also supplies the responses requested of Detroit Edison Company by NRC letter, R. C. DeYoung to H. Tauber, dated February 23, 1976. The information requested was in the form of two enclosures. Enclosure 1 provided guidance for use in the evaluation of Appendix I. Enclosure 2 requested additional information which would be used by NRC in their evaluation of Section II of Appendix I. Tables I-1 and I-2 provide cross references to the location of the information requested by Enclosures 1 and 2, respectively. References to the FSAR in Tables I-1 and I-2 refer to the original FSAR.

Detroit Edison chose to comply with 10 CFR 50, Appendix I, Section II.D, for Fermi 2 by choosing the option of showing compliance with the design objectives of RM-50-2 as an optional method of demonstrating compliance with the cost-benefit analysis of Section II.D.

Tables 4.7 and 4.8 of NUREG-0769, "Draft Environmental Statement Related to the Operation of Enrico Fermi Atomic Power Plant, Unit No. 2" demonstrate compliance with the design objectives of Appendix I and RM-50-2, respectively.

TABLE I-1 LOCATION OF ENCLOSURE 1 GUIDANCE[a.]

Item	Guidance	Location
1.	Licensees should provide an evaluation showing their facility capabilities to meet the requirements set forth in Section II of Appendix I to 10 CFR Part 50.	This Appendix is the evaluation.
2.	Radioactive source terms used in the evaluation should be consistent with the parameters and methodology set forth in Draft Regulatory Guide 1.BB and 1.CC (as appropriate). Note: For BWR's, gaseous releases from the containment building and auxiliary building should be combined with the reactor building release for pre-BWR/6 Mark III Containment designs.	Annex A provides the source term information.
3.	Meteorology/hydrology information used in the calculation of doses should be consistent with Draft Regulatory Guides 1.DD and 1.EE.	Annex B provides the meteorology dispersion information. The hydrology dispersion information is provided in Section III of this Appendix.
4.	Dose calculations should be consistent with Draft Regulatory Guide 1.AA.	Sections III and IV provide the description of the models used.

TABLE I-1 LOCATION OF ENCLOSURE 1 GUIDANCE[a.]

Item	Guidance	Location
5.	Effluent release data from previous reactor operation should be provided, if available, for use in evaluating the source term calculations. Such data should include at least one full year of effluent release data tabulated by effluent release point, month, mode of operation (e.g., full power operation, refueling shutdown), excluding the first year of reactor operation.	Effluent release data are not available since Fermi 2 is not yet operational.
6.	The above evaluations should be accomplished by the information requested in Enclosure 2.. Exceptions from the information requested will be considered on a case-by-case basis.	Table I-2 provides a cross reference to the Enclosure 2 information.
7.	The staff is preparing standard Technical Specifications and will issue further guidance to licensees regarding changes to Technical Specifications to implement Appendix I objectives. Proposed revisions to Technical Specifications by licensees based on the limiting conditions for operation set forth in Section IV of Appendix I should be withheld pending further guidance from the staff.	Fermi 2 Technical Specifications are based on the BWR 4 STS effective in 1982.

[a.] Draft Regulatory Guide 1.AA is now Regulatory Guide 1.109.
Draft Regulatory Guides 1.BB and 1.CC are now Regulatory Guide 1.112.
Draft Regulatory Guide 1.DD is now Regulatory Guide 1.111.
Draft Regulatory Guide 1.EE is now Regulatory Guide 1.113.

TABLE I-2 LOCATION OF ENCLOSURE 2 REQUESTED INFORMATION[a.]

Item	Request	Location
1.	Provide the information requested in Appendix D of Draft Regulatory Guide 1.BB or 1.CC, as appropriate.	Annex A.
2.	Provide, in tabular form, the distances from the centerline of the first nuclear unit to the following for each of the 22-1/2 degree radial sectors centered on the 16 cardinal compass directions: a) nearest milk cow (to a distance of 5 miles) b) nearest meat animal (to a distance of 5 miles) c) nearest milk goat (to a distance of 5 miles) d) nearest residence (to a distance of 5 miles) e) nearest vegetable garden greater than 500 ft^2 (to a distance of 5 miles) f) nearest site boundary. For radioactivity releases from stacks which qualify as elevated releases as defined in Draft Regulatory Guide 1.DD, identify the locations of all milk cows, milk goats, meat animals, residences, and vegetable gardens, in a similar manner, out to a distance of 3 miles for each radial sector.	Table 3.1 of Annex B.
3.	Based on considerations in Draft Regulatory Guide 1.DD, provide estimates of relative concentration (χ/Q) and deposition (D/Q) at locations specified in response to Item 2 above for each release point specified in response to Item 1 above.	Tables 3.3 through 3.8 of Annex B.
4.	Provide a detailed description of the meteorological data, models and parameters used to determine the χ/Q and D/Q values. Include information concerning the validity and accuracy of the models and assumptions for your site and the representativeness of the meteorological data used.	Sections 1 through 3 of Annex B.

TABLE I-2 LOCATION OF ENCLOSURE 2 REQUESTED INFORMATION[a.]

Item	Request	Location
5.	If an onsite program commensurate with the recommendations and intent of Regulatory Guide 1.23 exists. a) Provide representative annual and monthly, if available, joint frequency distributions of wind speed and direction by atmospheric stability class covering at least the most recent one-year period of record, preferably two or more years of record. Wind speed and direction should be measured at levels applicable to release point elevations, and stability should be determined from vertical temperature gradient between measurement levels that represent conditions into which the effluent is released. b) Describe the representativeness of the available data with respect to expected long-term conditions at the site.	a) Annex B and Reference 3 of Annex B b) Reference 2 of Annex B
6.	If recent onsite meteorological data are not available, or if the meteorological measurements program does not meet the recommendations and intent of Regulatory Guide 1.23: a) Provide …	Onsite meteorological data are available that meet Regulatory Guide 1.23 (Reference 2)
7.	Describe airflow trajectory regimes of importance in transporting effluents to the locations for which dose calculations are made.	References 2 and 3 of Annex B, ER Section 2.6.2.4.2, and FSAR. Sections 2.3.2.3 and 2.3.2.4.2 (References 3 and 4).

TABLE I-2 LOCATION OF ENCLOSURE 2 REQUESTED INFORMATION[a.]

Item	Request	Location
8.	Provide a map showing the detailed topographical features (as modified by the plant), on a large scale, within a 10-mile radius of the plant, and a plat of the maximum topographic elevation versus diatance from the center of the plant in each of the sixteen 22-1/2 degree cardinal compass point sectors (centered on the true north), radiating from the center of the plant, to a distance of 10 miles.	According to NRC Procedure RPOP-514 Revisions 2 and 3, copies of topographical maps submitted to NRC under separate cover. Figure 2.6-37 through Figure 2.6-38 (sheet 3) of ER. Figure 2.3-37 through Figure 2.3-38 (sheet 3) of FSAR.
9.	Provide the dates and times of radioactivity releases from intermittent sources by source location bases on actual plant operation and, if available, appropriate hourly meteorological data (i.e., wind direction and speed, and atmospheric stability) during each period of release.	Fermi is not yet operational.

[1.] Draft Regulatory Guide 1.AA is now Regulatory Guide 1.109.
Draft Regulatory Guides 1.BB and 1.CC are now Regulatory Guide 1.112.
Draft Regulatory Guide 1.DD is now Regulatory Guide 1.111.
Draft Regulatory Guide 1.EE is now Regulatory Guide 1.113.

II. SUMMARY AND CONCLUSIONS

This evaluation shows that the doses associated with the proposed operation of Fermi 2 at uprated power conditions (3486 MWt) meet the Appendix I objectives. Maximum individual doses have been estimated under normal operating conditions using site dispersion characteristics, 3499 MWt (102 percent of 3430 MWt), and a power uprate scale-up factor of 1.04 (Table 11.1-1).

For liquid effluents, the doses are:

A. 0.0048 mrem to the total body

B. 0.077 mrem to the bone (maximum dose to an organ).

For airborne releases, the doses are:

A. 4.93 mrad/year gamma air dose at the site boundary

B. 2.79 mrad/year beta air dose at the site boundary

C. 0.75 mrem/year total body dose to the maximum individual

D. 3.80 mrem/year skin dose to the maximum individual

E. 11.64 mrem/year thyroid dose to the maximum individual from radioactive iodine and radioactive material in particulate form.

The detailed breakdowns of doses are given in Tables III-2 and IV-3 for the liquid and gaseous effluents, respectively.

III. RADIATION EXPOSURE FROM LIQUID EFFLUENTS

Small amounts of liquid radwaste from Fermi 2 will be released to Lake Erie via discharge into the circulating water reservoir blowdown line which provides a minimum dilution flow of 10,000 gpm. The discharge point is shown in Figure III-1.

Dilution of the blowdown is provided by the material mixing characteristics of Lake Erie in the vicinity of the discharge. The estimated annual activity liquid releases (Table 5 of Annex A) were calculated in accordance with Regulatory Guide 1.112 (Reference 5).

A. Estimated Liquid Dilution Factors

For the evaluation of the maximum individual exposures from liquid effluents, two locations for dilution factor calculations were selected. These two locations were the nearest shoreline resident northeast and south of the site boundary. In addition, the dilution factor for the Monroe water intake approximately 2 miles south of the Fermi 2 discharge was also calculated, since it was assumed that the nearest shoreline resident to the south would drink water from this source.

The dilution calculations were based on the analysis presented previously in Section 5.1 of the ER and on Equation 17 of Regulatory Guide 1.113 (Reference 6). Although 3 decant pumps are available for use (Section 10.4.5.2), only 2 pumps are operated during liquid radwaste releases. The relative frequency of discharge flow (either 10,000 or 20,000 gpm) was taken from Table 3.4-1 of the ER, yielding a flow rate of 20,000 gpm 9 percent of the time on an annual basis. Lake Erie current direction frequencies were taken as 40 percent toward the south and 60 percent toward the north. For the dilution factor to the north, no additional dilution by Swan Creek was assumed.

In addition it was assumed that locations south of the discharge would be affected by all southerly flowing currents, and those to the north by all northerly flowing currents. The recirculation factor was calculated to be 0.020 with a travel time for the recirculated water (discharge to intake) of 0.672 hour. The dilution factors were calculated to be:

1. 45 at 1770 meters northeast of Fermi 2
2. 67 at 1530 meters south of Fermi 2
3. 77 at 3200 meters south of Fermi 2
4. 100 at distances greater than 3200 meters.

B. Estimated Radiation Exposure

The maximum individual for liquid exposure was assumed to be located, as discussed in Section III.A above, at 1770 meters northeast of Fermi 2 and 1530 meters south of Fermi 2. The resident south was assumed to drink potable water obtained from the Monroe water intake located 3200 meters south of Fermi 2. The resident north was assumed to obtain his potable water from the Detroit municipal water system, which will be unaffected by Fermi 2 operation. Table III-1 presents conservative usage factors for liquid exposures. The activities usage factors represent 2 hours per day for boating, swimming, and shoreline use, each for a period of 90 days per year for the teenager and child, while the adult will participate one hour per day in each activity. The ingestion rates are those recommended by Regulatory Guide 1.109 (Reference 7).

The liquid effluents given in Table 5 of Annex A were used as input into the NRC computer code LADTAP II (Reference 9), which uses Regulatory Guide 1.109 models. The usage factors of Table III-1, the minimum dilution flow of 10,000 gpm, and the appropriate dilution factors in Lake Erie were used. The doses to the individual are presented in Table III-2.

TABLE III-1 MAXIMUM INDIVIDUAL USAGE FACTORS FOR LIQUID EXPOSURES

	Activities							
	Adult		Teenager		Child		Infant	
Pathway	hr/day	hr/yr	hr/day	hr/yr	hr/day	hr/yr	hr/day	hr/yr
Boating	1	90	2	180	2	180	0	0
Swimming	1	90	2	180	2	180	0	0
Shoreline	1	90	2	180	2	180	1	90

	Ingestion (kg/yr)			
	Adult	Teenager	Child	Infant
Fish	21	16	6.9	0
Invertebrate[(a)]	5	3.8	1.7	0
Water	730	510	510	330

(a) Includes crustacean and molluses.

TABLE III-2 MAXIMUM DOSES TO AN INDIVIDUAL RESULTING FROM FERMI 2 LIQUID EFFLUENTS (3499 MWt)

Pathway	Dose to a Child (mrem/year) Total Body	Bone (Maximum Organ)
	Residents 1770 meter NE	
Fish ingestion	0.00343	0.07304
Invertebrate ingestion	0.00029	0.000385
Shoreline	0.00006	0.00006
Swimming	0.00004	0.00004
Boating	0.00003	0.00002
Total	0.0039	0.077
	Residents 1530 meters S	
Fish ingestion	0.00229	0.04911
Invertebrate ingestion	0.00021	0.00260
Drinking water	0.00223	0.00019
Shoreline	0.00004	0.00004
Swimming	0.00002	0.00002
Boating	0.00001	0.00001
Total	0.0048	0.052

IV. RADIATION EXPOSURES FROM GASEOUS EFFLUENTS

Gaseous source terms are based on the NRC GALE computer code and input data as presented in Annex A. The radioisotopic source terms are given in Table IV-1. The dose calculations are based on the NRC GASPAR computer code, using the models of Regulatory Guide 1.109.

For power uprate (3486 MWt), a scale-up factor of 1.04 was used to update the data in Table IV-1.

Dose contributions from the following pathways, where appropriate, were calculated:

1. Immersion in the plume
2. Ground contamination
3. Inhalation
4. Consumption of vegetables, meat, and milk.

The following data presented in Appendix A.IV was originally generated prior to plant operation and was scaled for power uprate. It is considered historical, and a more accurate presentation of the radioactive elements annually released from Fermi 2 can be found in the Annual Radioactive Effluent Release Report.

A. Gaseous Dispersion Factors

Annex B details the meteorological methodology and calculations. In summary, the data was based on a full year of site measurements (June 1, 1974, to May 31, 1975) taken and reduced in accordance with Regulatory Guide 1.23. Straightline air flow χ/Q's were calculated, with appropriate depletion and terrain correction factors in accordance with Regulatory Guide 1.111 (Reference 8). Table 3.2 of Annex B lists and describes the release points. Due to the characteristics of the release points, all three vent release points were considered as mixed-mode sources.

The containment building vent emits radioactivity from the containment, the auxiliary buildings, the gland seal, the condenser offgas system, and the mechanical vacuum pumps. The turbine building and radwaste building each releases radioactivity through its own vent. In addition, the following are assumed to be released from the containment building vent: 26.0 Ci/yr of argon-41, 9.9 Ci/yr of carbon-14, and 75 Ci/yr of tritium.

Figure III-1 shows the location of the three release points for gaseous effluents. Tables 3.3 through 3.8 of Annex B present the χ/Q and D/Q values for all of the locations listed in Table 3.1 of Annex B.

B. Gaseous Radiation Exposures

From examination of the χ/Q values, the landward site boundary direction that would result in the maximum beta and gamma air doses was determined to be the northwest direction at 915 meters. From the land use and meteorological information presented in Table 3.1 and Tables 3.3 through 3.8 of Annex B, the location of the worst plume dose was determined to be the residence at 1130 meters west-northwest of Fermi 2. The location of the worst consumptive pathway was determined by analyzing doses at two locations in detail, the garden at 1120 meters west-northwest, and the milk goat at 3180 meters northwest.

Table IV-2 summarizes the χ/Q and D/Q data used in GASPAR. Standard usage factors as specified in Regulatory Guide 1.109 were assumed. For the goat milk pathway, the χ/Q and D/Q values obtained for the grazing season were used. It has been determined that the goat is fed almost entirely on supplemental feed and is not grazing on open pasture. For conservatism, it was assumed that only 50 percent of the goat's diet was supplemental feed.

Additionally the goat milk-infant pathway need not be evaluated, since the youngest family member of the goat's owner is approximately 2 years old.

GASPAR does not calculate the effects of radiation exposure from a finite cloud emanating from an elevated release. The gamma air dose and total body and skin doses must incorporate the combined effects of both elevated and ground-level releases occurring during mixed-mode release. GASPAR accounts for the gamma ground level and total beta exposures (both elevated and ground). The elevated gamma doses are accounted for by the use of the NUS computer code FIDOS (FInite DOSe).

FIDOS calculates the gamma air dose from a finite cloud. The basis for the calculation is Equation B-1 of Regulatory Guide 1.109. As can be noted in Equation B-1, the gamma air dose is a direct function of both the energies emitted by each nuclide and the air absorption factor. In order to avoid handling each specific gamma energy emitted by each nuclide, the gamma energies were combined into groups. Decay was calculated during travel from the release point to the receptor location for each nuclide as a function of the wind speed within each stability class. The cloud inventory, the release height, and the receptor location are used as input combined with the joint frequency distributions described in Section 2.3 of Annex B.

The gamma air dose as calculated by FIDOS was corrected by the ratio of the energy absorption coefficient for tissue to that of air and by the application of a shielding factor of 0.7 to derive the total body dose. The skin dose was computed by combining the ground level-gamma and total beta contributions obtained from GASPAR with the elevated gamma contribution from FIDOS as corrected for tissue absorption and shielding.

Table IV-3 presents the results of the dose evaluation. As can be seen in the table, the doses are within the limits specified by Section II of Appendix I.

TABLE IV-1 ANNUAL GASEOUS EFFLUENTS FROM EACH RELEASE POINT (3499 MWt)

		Release Point	
Isotope	Containment Building (Ci)	Turbine Building (Ci)	Radwaste Building (Ci)
H-3	7.49×10^1	(a)	(a)
C-14	9.88	(a)	(a)
Ar-41	2.6×10^1	(a)	(a)
Kr-83m	5.31×10^1	0	0
Kr-85m	9.88×10^1	7.08×10^1	0
Kr-85	2.91×10^2	0	0
Kr-87	3.29×10^2	1.35×10^2	0
Kr-88	3.29×10^2	2.39×10^2	0
Kr-89	1.35×10^3	0	0
Xe-131m	7.28	0	0

TABLE IV-1 ANNUAL GASEOUS EFFLUENTS FROM EACH RELEASE POINT (3499 MWt)

Isotope	Release Point Containment Building (Ci)	Turbine Building (Ci)	Radwaste Building (Ci)
Xe-133m	4.16	0	0
Xe-133	2.72×10^{3}	2.60×10^{2}	1.04×10^{1}
Xe-135m	1.33×10^{2}	6.76×10^{2}	0
Xe-135	7.89×10^{2}	6.56×10^{2}	4.68×10^{1}
Xe-137	1.56×10^{3}	0	0
Xe-138	1.26×10^{3}	1.46×10^{3}	0
I-131	4.20×10^{-1}	1.98×10^{-1}	5.20×10^{-2}
I-133	1.57	7.91×10^{-1}	1.87×10^{-1}
Cr-51	6.24×10^{-4}	1.35×10^{-2}	9.36×10^{-5}
Mn-54	6.24×10^{-3}	6.24×10^{-4}	3.12×10^{-4}
Fe-59	8.32×10^{-4}	5.20×10^{-4}	1.56×10^{-4}
Co-58	1.25×10^{-3}	6.24×10^{-4}	4.68×10^{-5}
Co-60	2.08×10^{-2}	2.08×10^{-3}	9.36×10^{-4}
Zn-65	4.16×10^{-3}	2.08×10^{-4}	1.56×10^{-5}
Sr-89	1.87×10^{-4}	6.24×10^{-3}	4.68×10^{-6}
Sr-90	1.04×10^{-5}	2.08×10^{-5}	3.12×10^{-6}
Zr-95	8.32×10^{-4}	1.04×10^{-4}	5.20×10^{-7}
Sb-124	4.16×10^{-4}	3.12×10^{-4}	5.20×10^{-7}
Cs-134	8.32×10^{-3}	3.12×10^{-4}	4.68×10^{-5}
Cs-136	6.24×10^{-4}	5.20×10^{-5}	4.68×10^{-6}
Cs-137	1.14×10^{-3}	6.24×10^{-4}	9.36×10^{-5}
Ba-140	8.43×10^{-4}	1.14×10^{-2}	1.04×10^{-6}
Ce-141	2.08×10^{-4}	6.24×10^{-4}	2.71×10^{-5}

[a] Isotope was assumed to be released only from the containment building.

TABLE IV-2 SELECTED χ/Q AND D/Q VALUES BASED ON ANNUAL DATA

Uses	Direction, Distance	Containment Building χ/Q	Containment Building D/Q	Turbine Building χ/Q	Turbine Building D/Q	Radwaste Building χ/Q	Radwaste Building D/Q
Site Boundary	NW 915 meters	7.630×10^{-7}	2.010×10^{-8}	4.186×10^{-6}	5.395×10^{-8}	1.772×10^{-6}	3.238×10^{-8}
Residence and Garden	WNW 1130 meters	5.922×10^{-7}	1.376×10^{-8}	2.394×10^{-6}	3.215×10^{-8}	1.368×10^{-6}	2.222×10^{-8}
Milk Goat[(a)]	NW 3180 meters	6.581×10^{-8}	1.075×10^{-9}	1.759×10^{-9}	1.853×10^{-9}	1.146×10^{-7}	1.343×10^{-9}
Residence	NW 3180 meters	1.138×10^{-7}	1.534×10^{-9}	3.257×10^{-7}	2.829×10^{-9}	1.988×10^{-7}	1.985×10^{-9}

(a) χ/Q and D/Q data are based on the grazing season.

TABLE IV-3 MAXIMUM DOSES TO AN INDIVIDUAL RESULTING FROM FERMI 2 GASEOUS EFFLUENTS (3499 MWt)

Sources	Location			
	1130 meters NW Child (mrem/yr)		3180 meters WNW Child (mrem/yr)	
	Total Body Dose	Organ Dose[a]	Total Body Dose	Organ Dose[a]
A. Radioiodines and Particulates				
Ground	0.355	0.354	0.037	0.037
Ingestion of Vegetables	0.220	10.634	NOT APPLICABLE	
Inhalation	0.002	0.656	0.0003	0.099
Ingestion of Goat Milk	NOT APPLICABLE		0.022	3.319
Total	0.576	11.64	0.059	3.456
B. Noble Gas Plume	0.75	3.80	NC[b]	NC[b]

C. Air Doses

	Site Boundary (915 meters NW)
Annual (mrad/yr)	2.79 β beta
Annual (mrad/yr)	4.93 γ gamma

[a] For radioiodine and particulates the maximum organ dose occurs to the thyroid while the maximum organ dose from noble gas plume exposure occurs to the skin.

[b] NC = not necessary to calculate by inspection of χ/Q values in Tables 3.3 through 3.8 of Annex B.

11A EVALUATION OF FERMI 2 TO DEMONSTRATE COMPLIANCE WITH SECTION II OF APPENDIX I TO 10 CFR PART 50

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix I, U.S. Nuclear Regulatory Commission, April 1975.
2. "Onsite Meteorological Programs (Safety Guide 23)," Regulatory Guide 1.23, U.S. Atomic Energy Commission, February 1972.
3. Enrico Fermi Atomic Power Plant Unit 2, Applicant's Environmental Report, Operating License Stage, Docket 50-341, Supplement 1, dated June 1975.
4. Enrico Fermi Atomic Power Plant Unit 2, Final Safety Analysis Report, Docket 50-341, updated through Amendment 5, dated September 1976.
5. "Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Light Water Reactors," Regulatory Guide 1.112, U.S. Nuclear Regulatory Commission, April 1976.
6. "Estimating Aquatic Dispersion of Effluents from Accidental and Routine Reactor Releases for the Purpose of Implementing Appendix I," Regulatory Guide 1.113, U.S. Nuclear Regulatory Commission, May 1976.
7. "Calculation of Annual Doses to Man from Routine Release of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR Part 50, Appendix I," Regulatory Guide 1.109, U.S. Nuclear Regulatory Commission, March 1976.
8. "Methods for Estimating Atmospheric Transport and Dispersion of Gaseous Effluents in Routine Releases from Light-Water-Cooled Reactors," Regulatory Guide 1.111, U.S. Nuclear Regulatory Commission, March 1976.
9. Oak Ridge National Laboratory, Users Manual for LADTAP II - A Computer Program for Calculating Radiation Exposures of Nuclear Reactor Liquid Effluents, NUREG/CR-1976, May 1980.

Figure Intentionally Removed
Refer to Plant Drawing A-2100

FIGURE III-1

RELEASE POINT LOCATIONS

CHAPTER 11 APPENDIX A

ANNEX A

DATA NEEDED FOR RADIOACTIVE

SOURCE TERM CALCULATIONS

FOR FERMI 2

TABLE OF CONTENTS

ANNEX A DATA NEEDED FOR RADIOACTIVE SOURCE TERM CALCULATIONS FOR FERMI 2

Following are the data requested in Appendix A to Regulatory Guide (RG) 1.112. This RG states that the information presented should be taken from the contents of the Safety Analysis Report (SAR) and the Environmental Report (ER). However, RG 1.112 (Reference 1) was issued subsequent to the submittal of the Enrico Fermi Atomic Power Plant Unit 2 (Fermi 2) FSAR (Reference 2) and ER (Reference 3). Regulatory Guide 1.112 provided new guideline values (through reference to NUREG-0016) (Reference 4) to be used when projecting the effectiveness of a given BWR radwaste system to reduce the quantity of radionuclides in plant effluents. These new guidelines are based on surveys of operating plants and represent average or expected conditions. Although the RG 1.112 values may vary from the expected values reported in the Fermi 2 FSAR, that does not mean that the Fermi 2 radwaste system will not perform as projected. This is based on the fact that the RG 1.112 value for each parameter is a single value which should best be represented by a range of values and therefore the possibility of a radwaste system parameter actually being greater or less than that predicted by RG 1.112 is to be expected.

On September 9, 1992, the NRC issued Amendment 87 to the Fermi 2 Operating License authorizing a change in the thermal power limit for 3293 MWt to 3430 MWt. Subsequently, on February 10, 2014, the NRC issued Amendment 196 to the Fermi 2 operating license authorizing a change in the thermal power limit from 3430 MWt to 3486 MWt. This Annex has been revised to reflect the changes that resulted from the power uprates.

The item in parentheses following the requested information is the section, page, table, or figure number of the original FSAR and/or ER or UFSAR wherein the information is presented. Also, when parameters reported in the FSAR, ER, and/or UFSAR differ from guideline values given in RG 1.112, the RG values will also be listed and followed by "(RG)". Values given in RG 1.112 were used in the generation of source terms.

1. GENERAL

   a. The maximum core thermal power evaluated for safety consideration in the UFSAR

      Response

      3430 MWt x 1.02 = 3499 MWt (UFSAR Section 1.1)

   b. The quantity of tritium released in liquid and gaseous effluents

      Response

Tritium Released (Ci/yr)

	FSAR		RG
Liquid	52.5	(UFSAR Subsection 11.2.6)	11
Gaseous	52.5	(UFSAR Table 11.3-1)	75

2. NUCLEAR STEAM SUPPLY SYSTEM

a. Total steam flow rate

Response

1.52×10^7 lb/hr at 3499 MWt (UFSAR Subsection 11.3.2.2)

b. Mass of reactor coolant in the reactor vessel at full power (3486 MWt)

Response

5.52×10^5 lb (ER page 3A-3)

3. REACTOR COOLANT CLEANUP SYSTEM

a. Average flow rate

Response

1.33×10^5 lb/hr (ER page 3A-4)

b. Demineralizer type and size

Response

Type - powdered resin and filter aid material (ER page 3A-4)

Size - approximately 135 ft^2 of flow area, 20 lb of dry resin and filter aid material

There are two 50 percent units (UFSAR Table 5.5-2).

c. Replacement frequency

Response

The resin in each demineralizer is replaced about once per week (ER page 3A-4).

d. Backwash volume and activity

Response

Approximately 1100 gallons per backwash (based on data in UFSAR Figure 11.2-15)

Specific activity is 20 percent of reactor coolant (UFSAR Figure 11.2-15).

4. CONDENSATE DEMINERALIZERS

a. Average flow rate

Response

10.8×10^6 lb/hr at 3499 MWt (UFSAR Subsection 10.4.6.1.1)

b. Demineralizer type

Response

Powdered resin (UFSAR Subsection 10.4.6)

c. Number and size of demineralizers

Response

Number - 8 parallel operating demineralizers (UFSAR Subsection 10.4.6.2)

Size - approximately 890 ft^2 of filter surface flow area for non-pleated filters; approximately 17000 ft^2 of filter surface flow area for pleated filters

d. Replacement frequency

Response

10 days per vessel (ER page 3A-4)

e. Indicate whether ultrasonic resin cleaning is used and the waste liquid volume associated with its use

Response

Ultrasonic resin cleaning will not be used.

f. Backwash volume and activity

Response

5300 gallons per backwash (based on data in UFSAR Figure 11.2-15)

Specific activity is 5 x 10^{-6} μCi/ml (UFSAR Figure 11.2-15)

5. LIQUID WASTE PROCESSING SYSTEMS

a. For each liquid waste processing system, provide, in tabular form, the following information:

(1) Sources, flow rates, and expected activities [fraction of primary coolant activity (PCA) for all inputs to each system]

Response

This information as given in the UFSAR is presented in Table 1 of this Annex. Presented in Table 2 of this Annex are the RG 1.112 guideline values for sources to the liquid radwaste system. A power uprate scale-up factor of 1.02 was applied to obtain the sources at uprated conditions.

(2) Holdup times associated with the collection, processing, and discharge of all liquid streams

Response

In calculating the releases of radionuclides reported in the Fermi 2 UFSAR, no credit was taken for decay resulting from holdup within the process system. Holdup times based on the data presented in Table 1 have been calculated per RG 1.112 and are shown in Table 3 of this Annex. Holdup times based on RG 1.112 expected source volumes (Table 2) have also been calculated and are also presented in Table 3.

(3) Capacities of all tanks and processing equipment considered in calculating holdup times

Response

This information is presented in Table 4 of this Annex.

(4) Decontamination factors for each processing step

Response

Decontamination factors (DF) as projected in the FSAR are given in Table 4. Also given in Table 4 are the RG 1.112 guideline values for process equipment DF's.

(5) The fraction of each processing stream expected to be discharged over the life of the plant

Response

This data is presented in Table 4.

(6) For waste demineralizer regeneration, show the time between regenerations, regenerant volumes and activities, treatment of regenerants, and fractions of regenerant discharged. Include parameters used in making these determinations.

Response

There will be no demineralizer regeneration waste. All demineralizers will utilize either disposal deep beds or Powdex beds.

(7) Liquid source term by radionuclide (in Ci/yr) for normal operation, including anticipated operational occurrences

Response

Liquid source terms based on RG 1.112 guideline values are presented in Table 5 of this Annex.

b. Provide piping and instrumentation diagrams and process flow diagrams for the liquid radwaste systems along with all other systems influencing the source term calculations

Response

The requested figures are presented in both the FSAR and the ER. The source term calculations for the floor drain and chemical systems included only the use of filters and demineralizers.

Diagram	FSAR Figure 11.2-1	ER Figure 3.5-1
Waste Collector System	Sheet 1	Sheet 3
Floor Drain Collector System	Sheet 2	Sheet 4
Evaporator Feed	Sheets 4 and 5	Sheet 5

Diagram	FSAR Figure 11.2-1	ER Figure 3.5-1
Chemical Waste System	Sheet 6	Sheet 6
Waste Sludge System	Sheet 7	Sheet 7
Sump Pump	Figure 11.2-2 Sheets 4 and 5	Sheets 1 and 2

6. MAIN CONDENSER AND TURBINE GLAND SEAL AIR REMOVAL SYSTEMS

a. The holdup time for offgases from the main condenser air ejector prior to processing by the offgas treatment system

Response

From the air ejector to the discharge from the chiller unit just upstream of the first charcoal bed, the holdup time is 0.066 hour (UFSAR Subsection 11.3.2.7.3.1).

b. A description and the expected performance of the gaseous waste treatment systems for the offgases from the condenser air ejector and mechanical vacuum pump.

Include the expected air inleakage per condenser shell, the number of condenser shells, and the iodine source term from the condenser.

Response

Radiogases in the condenser offgas are reduced in concentration by the natural decay process. Most of the decay occurs in the six charcoal adsorbers; however, the short-lived radionuclides, such as N-16, decay off almost entirely prior to the offgas stream entering the charcoal units.

Noncondensable gases, including air inleakage and fission gases, are removed from the main condenser by air ejector (not part of the condenser offgas system). These gases then enter the offgas system where additional steam is injected into the air ejector discharge stream to dilute the hydrogen below 4 percent by volume. The mixture passes through a moisture separator before it is superheated in a preheater to remove water droplets and to decrease humidity. It enters the catalytic recombiner where free hydrogen and oxygen are converted into water vapor. The offgas effluent from the recombiner is passed through a condenser cooled by reactor condensate to remove the bulk moisture, and then through an aftercooler and a precooler for drying.

The gas then enters a 2.2-minute delay pipe which is followed by a sand filter. The gas is then cooled to +14°F and enters the ambient temperature charcoal adsorbers. Chilling and drying the air improve charcoal adsorber performance. Adsorber system discharge is filtered, mainly to remove any charcoal fines that may have been carried out of the last charcoal bed. The gas is then pumped into the offgas discharge piping. The system vacuum pump is used to maintain a slightly negative pressure throughout the system, ensuring that any leakage would be into the system. The effluent from the offgas system is discharged from the plant after dilution in the reactor building ventilation system exhaust. A more detailed discussion of the condenser offgas system is presented in Section 11.3 of the UFSAR.

For the one-shell condenser, the expected inleakage is approximately 6 SCFM; however, the system was designed assuming a 40-SCFM inleakage. The RG 1.112 guideline value for condenser inleakage is 10 ft^3/min per shell; therefore, for Fermi 2 an inleakage of 10 ft^3/ min is used when evaluating this system for Appendix I compliance.

Based on the design value of 40 SCFM inleakage; however, the condenser offgas system is expected to perform as follows:

(1) Holdup time for kryptons, 24 hours

(2) Holdup time for xenons, 16 days

(3) A DF of about 1160 for radiogases of kryptons and xenons (inlet concentration/outlet concentration)

(4) A DF of about 90 over that provided by 30-minute delay.

The above values are not used in the Appendix I calculations, but are utilized as the design basis (see Section 11.3).

The iodine source term from the condenser was not supplied in the FSAR or ER. The RG 1.112 guideline value for the iodine source term from the main condenser to the offgas system for expected conditions is 5 Ci/yr of I-131.

The mechanical vacuum pumps discharge via a 2-minute delay pipe. These pumps are expected to be used only during operation below 5 percent reactor power, and the source term from the condenser to the vacuum pumps is expected to be negligible. However, presented below are the expected quantities of radionuclides released from the condenser via the mechanical vacuum pumps as projected by the Fermi 2 FSAR and RG 1.112.

	Fermi 2 FSAR Estimate (FSAR Table 11.3-1)	RG 1.112 Guideline Values
Xe-133	24 Ci/yr	2393 Ci/yr
XE-135	negligible	364 Ci/yr
I-131	negligible	0.03 Ci/yr

c. The mass of charcoal in the charcoal delay system used to treat the offgases from the main condenser air ejector, the operating and dew point temperatures of the delay system, and the dynamic adsorption coefficients for Xe and Kr

<u>Response</u>

(1) 60 tons of charcoal

(2) 70°F operating temperature

(3) -4°F dew point

(4) The dynamic adsorption coefficients for krypton and xenon are as follows:

Dynamic Adsorption Coefficients

	Fermi 2 FSAR	RG 1.112
Kr	36	25
Xe	610	440

This data is presented in Section 11.3 of the FSAR.

d. A description of the cryogenic distillation system, the fraction of gases partitioned during distillation, the holdup in the system, storage following distillation, and the expected system leakage rate

Response

Not applicable

e. The steam flow to the turbine gland seal and the source of the steam (primary or auxiliary)

Response

1.51×10^4 lb/hr of primary steam; the steam flow rate is consistent with RG 1.112 assumptions

f. The design holdup time for gas vented from the gland seal condenser, the iodine partition factor for the condenser, and the fraction of radioiodine released through the system vent. A description of the treatment system used to reduce radioiodine and particulate releases from the gland seal system.

Response

(1) 0.032 hour holdup

(2) 100 is the iodine partition factor expressed as DF; this is consistent with RG 1.112.

(3) 100 percent of the iodine exiting the 2-minute delay pipe is discharged via the reactor building vent.

(4) No treatment system is necessary downstream of the gland seal condenser and 2-minute delay pipe to further reduce the quantity of radioiodine or particulates released from this system.

g. Piping and instrumentation diagrams and process flow diagrams for the gaseous waste treatment system along with all other systems influencing the source term calculations

Response

The requested figures are presented in both the FSAR and the ER:

Diagram	FSAR Figure	ER Figure
Offgas System P&ID (2 sheets)	11.3-1	3.5-3
Flow Diagram of the Condenser Offgas System	11.3-2	3.5-4

7. VENTILATION AND EXHAUST SYSTEM

For each plant building that houses a main condenser evacuation system, a mechanical vacuum pump, a turbine gland seal system exhaust, or a system that contains radioactive materials, provide the following:

a. Provisions incorporated to reduce radioactivity releases through the ventilation or exhaust systems

Response

(1) Reactor/Auxiliary Building Ventilation System (UFSAR Subsection 9.4.2)

Fermi 2 utilizes a Mark 1 containment design. One ventilation system is provided for both the reactor and auxiliary building portion of the complex. Under normal operating conditions the radionuclide concentration in the ventilation exhaust from these areas is expected to be negligible.

(2) Radwaste Building Ventilation System (UFSAR Subsection 9.4.3)

Under normal operating conditions the radwaste building exhaust is discharged through HEPA filters to remove particulate radioactive material.

(3) Turbine Building Ventilation System (UFSAR Subsection 9.4.4)

Filtration of the turbine building ventilation effluent is not necessary.

b. Decontamination factors assumed and the bases (include charcoal adsorbers, HEPA filters, and mechanical devices)

Response

Although HEPA filters are being installed in the exhaust stream of the radwaste building ventilation system to remove particulate radioactive material, no credit was assumed for this equipment in the Fermi 2 UFSAR. Regulatory Guide 1.112 does allow a DF of 100 on particulates for this equipment. Charcoal filters in the ventilation exhaust are not necessary.

c. Release rates for radioiodines, noble gases, and radioactive particulates and their bases

Response

This information is presented in Table 6 of this Annex for both the expected conditions as given in Table 11.3-1 of the FSAR and the guideline values given in RG 1.112.

d. Release point descriptions, including height above grade, height above and location relative to adjacent structures, expected average temperature difference between gaseous effluents and ambient air, flow rate, exit velocity, and size and shape of flow orifice.

Response

There are three ventilation release points: reactor building vent, turbine building vent, and the radwaste building vent. The reactor building vent is the release point for the following:

(1) Offgas system

(2) Turbine gland seal exhaust

(3) Mechanical vacuum pump

(4) Reactor/auxiliary building ventilation system.

The turbine building ventilation system exhaust is discharged via the turbine building vent, and radwaste building ventilation system exhaust is discharged via the radwaste building vent.

The reactor building vent is cylindrical in shape, extends 22.5 feet above the top of the reactor building and is 7 feet 2 inches in diameter. The vent centerline is approximately 8 feet 3 inches from the south wall of the reactor building. The top of the vent is at elevation 751 feet (mean tide, N. Y., 1935) and the grade is 583 feet. The exhaust from this vent is 112,000 ft^3/min at a velocity of 2750 ft/min (FSAR Subsection 11.3.7, Table 3.2, Annex B).

The turbine building vent is rectangular in shape, extends 8 feet above the upper roof of the turbine building and has a cross-sectional area of approximately 420 ft^2. The vent centerline is approximately 67 feet from the south wall and 73 feet from the east wall of the turbine building. The top of the vent is at elevation 719.5 feet (mean tide, N.Y., 1935). The exhaust from the vent is approximately 390,000 ft^3/min at a velocity of 830 ft/min (FSAR Subsection 11.3.7, Table 3.2, Annex B).

The radwaste building vent is rectangular in shape, extends 54 feet above the lower roof of the turbine building, and has a cross-sectional area of approximately 20 ft^2. The vent centerline is approximately 383 feet from the south wall and 78 feet from the east wall of the turbine building. The top of the vent is at elevation 729 feet (mean tide, N.Y., 1935). The exhaust from the vent is approximately 35,100 ft^3/min at a velocity of 1755 feet/min (UFSAR Figure 9.4-5, Table 3.2, Annex B).

e. For the containment building, the expected purge and venting frequencies and duration and the continuous purge rate (if used)

Response

Fermi 2 is of the Mark I containment design. Following reactor startup, excess air from the reactor drywell will be exhausted along the wall above the refueling floor and discharged by the reactor/auxiliary building ventilation exhaust system (UFSAR Subsection 9.4.2).

Also the drywell atmosphere is controlled by the drywell cooling system (UFSAR Subsection 9.4.5) and will not normally require purging. No significant releases of radionuclides are expected from the Fermi 2 drywell.

11A.ANNEX A DATA NEEDED FOR RADIOACTIVE SOURCE TERM CALCULATIONS FOR FERMI 2

REFERENCES

1. "Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Light Water Reactors," Regulatory Guide 1.112, U.S. Nuclear Regulatory Commission (April 1976).
2. Enrico Fermi Atomic Power Plant Unit 2, Final Safety Analysis Report, Docket 50-341 updated through Amendment 5, dated September 1976.
3. Enrico Fermi Atomic Power Plant Unit 2, Applicant's Environmental Report, Operating License Stage, Docket 50-341, updated through Supplement 1, dated June 1976.
4. "Calculation of Release of Radioactive Materials in Gaseous and Liquid Effluents from Boiling Water Reactors," NUREG-0016, U.S. Nuclear Regulatory Commission, April 1976.

TABLE 1 EXPECTED DAILY AVERAGE INPUTS TO THE FERMI 2 LIQUID RADWASTE SYSTEM AS GIVEN IN THE UFSAR

Subsystem	Source	Flow Rates[a] of Sources (gpm)	Fraction of Primary Coolant Activity
Waste collector	Drywell equipment drain sump	8,914	1.00
	Reactor building equipment drain sump	9,700	0.10
	Radwaste building equipment drain sump	2,884	0.10
	Turbine building equipment drain sump	7,865	0.001
	Effluent from waste surge tank	6,121	1.1×10^{-3}
Subtotal		35,484	
Floor drain collector	Turbine building oil separator effluent	3,122	0.001
	Drywell floor drain sump	1,821	0.001
	Reactor building floor drain sumps	5,203	0.001
	Personnel decontamination	102	0.001
	Cask-cleaning drains	14	0.001
	Radwaste building floor drain sumps	2,601	0.001
	Drains from loadout building	204	0.001
	Turbine building floor drain sumps	2,081	0.001
	Chemical waste tank effluent	377	0.02
Subtotal		15,525	
Total		51,009	

[a] Based on the UFSAR Figure 11.2-15.

TABLE 2 EXPECTED DAILY AVERAGE INPUTS TO THE FERMI 2 RADWASTE SYSTEM USING REGULATORY GUIDE 1.112 VALUES

Source	Flow Rates of Sources (gpm)	Fraction of Primary Coolant Activity
Equipment Drains		
Drywell	3,400	1
Containment, auxiliary building, and fuel pool	3,700	0.1
Radwaste building	1,100	0.1
Turbine building	3,000	0.001
Subtotal	11,200	
Floor drains		
Drywell	700	0.001
Containment, auxiliary building and fuel pool	2,000	0.001
Radwaste building	1,000	0.001
Turbine building	2,000	0.001
Subtotal	5,700	
Other		
Cleanup phase separator decant	640	0.002
Laundry drains	1,000	(a)
Lab drains	500	0.02
Condensate backwash[b]	8,100	10^{-6}
Chemical lab waste	100	0.02
Subtotal	14,840	
Total	31,740	

[a.] Listed in GALE code.
[b] Filter/demineralizer (Powdex) condensate demineralizer.

TABLE 3 HOLDUP TIMES ASSOCIATED WITH THE COLLECTION, PROCESSING, AND DISCHARGE OF LIQUID RADWASTE

	Holdup Times (days)[a]	
Subsystem	Collection	Processing and discharging
Waste collector	0.319	0
Floor drain collector	0.520	0

[a] In calculating the releases of radionuclides reported in the Fermi 2 UFSAR and ER, no credit was taken for decay resulting from holdup within the processing system.

TABLE 4 LIQUID RADWASTE SYSTEM PROCESS PARAMETERS

Subsystem	Number and Volume of Tanks	Process Equipment and Throughput Capability	Decontamination Factor		Fraction of Each process Stream Discharged
			Soluble	Insoluble	
Waste collector	1 waste collector tank, 23,400 gallons	Etched-disk filter, 216,000 gpd	1	10	0.01
		3 oil coalescers, 216,000 gpd (total)	1	10	--
Floor drain collector	1 floor drain collector tank, 20,000 gallons	Etched-disk filter, 72,000 gpd	1	10	0.01
	1 evaporator feed/surge tank, 25,000 gallons	3 oil coalescers, 72,000 gpd (total)	1	10	--
	2 distillate tanks, 5100 gallons	2 radwaste evaporators, 43,200 gpd (each)	1,000	10,000	--
	1 chemical waste tank, 5,200 gallons	--	--	--	--
Shared equipment[a]	2 waste sample tanks, 24,300 gallons	2 radwaste demineralizers, 201,600 gpd	100(10)[b]	100(10)	--
	1 waste sample tank, 21,000 gallons	--	--	--	--

[a] The liquid radwaste system shares interchangeably the radwaste demineralizer and waste sample tanks between the floor drain and waste collector subsystems.
[b] Number in parentheses is for a second demineralizer in series.

TABLE 5 LIQUID EFFLUENTS FROM FERMI 2 (3499 MWt)

NUCLIDE	HALF-LIFE (Days)	CONC. IN REACTOR COOLANT (uCi/cc)	HIGH PURITY (Ci)	LOW PURITY (Ci)	CHEMICAL (Ci)	TOTAL LWS (Ci)	ADJUSTED TOTAL (Ci/Yr)	DETERGENT WASTES (Ci/Yr)	TOTAL (Ci/Yr)
CORROSION AND ACTIVATION PRODUCTS:									
NA24	6.25E-01	9.62E-03	0.00111	0.00000	0.00000	0.00111	0.00460	0.00000	0.00460
P32	1.43E+01	2.03E-04	0.00003	0.00000	0.00000	0.00003	0.00011	0.00000	0.00011
CR51	2.78E+01	6.09E-03	0.00083	0.00000	0.00000	0.00083	0.00345	0.00000	0.00345
MN54	3.03E+02	7.11E-05	0.00001	0.00000	0.00000	0.00001	0.00004	0.00000	0.00004
MN56	1.08E-01	4.23E-02	0.00243	0.00000	0.00000	0.00243	0.01007	0.00000	0.01007
FE55	9.50E+02	1.02E-03	0.00014	0.00000	0.00000	0.00014	0.00058	0.00000	0.00058
FE59	4.50E+01	3.05E-05	0.00000	0.00000	0.00000	0.00000	0.00002	0.00000	0.00002
CO58	7.13E+01	2.03E-04	0.00003	0.00000	0.00000	0.00003	0.00011	0.00000	0.00011
CO60	1.92E+3	4.06E-04	0.00005	0.00000	0.00000	0.00005	0.00023	0.00000	0.00023
NI65	1.07E-01	2.54E-04	0.00001	0.00000	0.00000	0.00001	0.00006	0.00000	0.00006
CU64	5.33E-01	2.87E-02	0.00320	0.00000	0.00000	0.00320	0.01329	0.00000	0.01329
ZN65	2.45E+02	2.03E-04	0.00003	0.00000	0.00000	0.00003	0.00011	0.00000	0.00011
ZN69M	5.75E-01	1.92E-03	0.00022	0.00000	0.00000	0.00022	0.00091	0.00000	0.00091
ZN69	3.96E-02	0.00E+00	0.00019	0.00000	0.00000	0.00019	0.00076	0.00000	0.00076
W187	9.96E-01	2.94E-04	0.00003	0.00000	0.00000	0.00003	0.00015	0.00000	0.00015
NP239	2.35E+00	7.00E-03	0.00092	0.00000	0.00000	0.00092	0.00380	0.00000	0.00380
FISSION PRODUCTS:									
BR83	1.00E-01	5.28E-03	0.00029	0.00000	0.00000	0.00029	0.00120	0.00000	0.00120
BR84	2.21E-02	5.37E-03	0.00007	0.00000	0.00000	0.00007	0.00030	0.00000	0.00030
BR85	2.08E-03	2.14E-03	0.00000	0.00000	0.00000	0.00000	0.00001	0.00000	0.00001
RB89	1.07E-02	3.61E-03	0.00024	0.00000	0.00000	0.00024	0.00098	0.00000	0.00098
SR89	5.20E+01	1.02E-04	0.00001	0.00000	0.00000	0.00001	0.00006	0.00000	0.00006
SR91	4.03E-01	3.76E-03	0.00040	0.00000	0.00000	0.00040	0.00163	0.00000	0.00163
Y91M	3.47E-02	0.00E+00	0.00021	0.00000	0.00000	0.00021	0.00084	0.00000	0.00084
Y91	5.88E+01	4.06E-05	0.00001	0.00000	0.00000	0.00001	0.00002	0.00000	0.00002
SR92	1.13E-01	8.50E-03	0.00051	0.00000	0.00000	0.00051	0.00209	0.00000	0.00209
Y92	1.47E-01	5.22E-03	0.00067	0.00000	0.00000	0.00067	0.00278	0.00000	0.00278
Y93	4.25E-01	3.77E-03	0.00041	0.00000	0.00000	0.00041	0.00166	0.00000	0.00166
NB98	3.54E-02	3.09E-03	0.00006	0.00000	0.00000	0.00006	0.00028	0.00000	0.00028
MO99	2.79E+00	2.00E-03	0.00026	0.00000	0.00000	0.00026	0.00109	0.00000	0.00109
TC99M	2.50E-01	1.82E-02	0.00173	0.00000	0.00000	0.00173	0.00715	0.00000	0.00715
TC101	9.72E-03	6.56E-02	0.00038	0.00000	0.00000	0.00038	0.00161	0.00000	0.00161

TABLE 5 LIQUID EFFLUENTS FROM FERMI 2 (3499 MWt)

NUCLIDE	HALF-LIFE (Days)	CONC. IN REACTOR COOLANT (uCi/cc)	HIGH PURITY (Ci)	LOW PURITY (Ci)	CHEMICAL (Ci)	TOTAL LWS (Ci)	ADJUSTED TOTAL (Ci/Yr)	DETERGENT WASTES (Ci/Yr)	TOTAL (Ci/Yr)
RU103	3.96E+01	2.03E-05	0.00000	0.00000	0.00000	0.00000	0.00001	0.00000	0.00001
TC104	1.25E-02	5.88E-02	0.00045	0.00000	0.00000	0.00045	0.00185	0.00000	0.00185
RU105	1.85E-01	1.78E-03	0.00015	0.00000	0.00000	0.00015	0.00058	0.00000	0.00058
RH105M	5.21E-04	0.00E+00	0.00015	0.00000	0.00000	0.00015	0.00058	0.00000	0.00058
RH105	1.50E+00	0.00E+00	0.00001	0.00000	0.00000	0.00001	0.00005	0.00000	0.00005
TE129M	3.40E+01	4.06E-05	0.00001	0.00000	0.00000	0.00001	0.00002	0.00000	0.00002
TE129	4.79E-02	0.00E+00	0.00000	0.00000	0.00000	0.00000	0.00001	0.00000	0.00001
TE131M	1.25E+00	9.86E-05	0.00001	0.00000	0.00000	0.00001	0.00005	0.00000	0.00005
I131	8.05E+00	4.02E-03	0.00054	0.00000	0.00000	0.00054	0.00226	0.00000	0.00226
I132	9.58E-02	5.25E-02	0.00278	0.00000	0.00000	0.00278	0.01152	0.00000	0.01152
I133	8.75E-01	5.22E-02	0.00633	0.00000	0.00000	0.00633	0.02621	0.00000	0.02621
I134	3.67E-02	7.97E-02	0.00178	0.00000	0.00000	0.00178	0.00736	0.00000	0.00736
CS134	7.49E+02	3.05E-05	0.00004	0.00000	0.00000	0.00004	0.00018	0.00000	0.00018
I135	2.79E-01	4.88E-02	0.00460	0.00000	0.00000	0.00460	0.01903	0.00000	0.01903
CS136	1.30E+01	8.09E-05	0.00011	0.00000	0.00000	0.00011	0.00046	0.00000	0.00046
CS137	1.10E+04	2.03E-05	0.00003	0.00000	0.00000	0.00003	0.00011	0.00000	0.00011
CS138	2.24E-02	7.34E-03	0.00100	0.00000	0.00000	0.00100	0.00415	0.00000	0.00415
BA139	5.76E-02	8.02E-03	0.00027	0.00000	0.00000	0.00027	0.00114	0.00000	0.00114
BA140	1.28E+01	4.05E-04	0.00005	0.00000	0.00000	0.00005	0.00023	0.00000	0.00023
LA140	1.67E+00	0.00E+00	0.00000	0.00000	0.00000	0.00000	0.00001	0.00000	0.00001
BA141	1.25E-02	7.34E-03	0.00005	0.00000	0.00000	0.00005	0.00023	0.00000	0.00023
LA141	1.62E-01	0.00E+00	0.00004	0.00000	0.00000	0.00004	0.00018	0.00000	0.00018
CE141	3.24E+01	3.04E-05	0.00000	0.00000	0.00000	0.00000	0.00002	0.00000	0.00002
BA142	7.64E-03	4.35E-03	0.00002	0.00000	0.00000	0.00002	0.00008	0.00000	0.00008
LA142	6.39E-02	4.04E-03	0.00018	0.00000	0.00000	0.00018	0.00072	0.00000	0.00072
CE143	1.38E+00	2.97E-05	0.00000	0.00000	0.00000	0.00000	0.00001	0.00000	0.00001
PR143	1.37E+01	4.05E-05	0.00001	0.00000	0.00000	0.00001	0.00002	0.00000	0.00002
All Others		5.01E-05	0.00002	0.00000	0.00000	0.00002	0.00006	0.00000	0.00006
Total except H3		5.55E-01	0.03311	0.00000	0.00000	0.03311	0.13716	0.00000	0.13716
H3									27.053

TABLE 6 RADIONUCLIDE RELEASES IN CURIES PER YEAR FROM THE VARIOUS PLANT VENTILATION SYSTEMS (3499 MWt)

	Ventilation System					
	Reactor/Auxiliary Building[a]		Turbine Building		Radwaste Building	
Nuclide	FSAR Value	RG 1.112 Value	FSAR VALUE	RG 1.112 Value	FSAR Value	RG 1.112 Value
Kr-83	(b)	(b)	9.7	(b)	(b)	(b)
Kr-85m	(b)	6.2	18	71	(b)	(b)
Kr-87	(b)	6.2	55	200	(b)	(b)
Kr-88	(b)	6.2	58	240	(b)	(b)
Kr-89	(b)	(b)	45	(b)	(b)	(b)
Xe-133	(b)	140	25	290	(b)	10
Xe-135m	(b)	96	50	680	(b)	(b)
Ce-135m	(b)	96	50	680	(b)	(b)
Xe-135	(b)	71	66	660	(b)	47
Xe-137	(b)	(b)	74	(b)	(b)	(b)
Xe-138	(b)	15	170	1500	(b)	(b)
I-131	0.01	0.35	0.28	0.20	(b)	0.048
I-133	0.068	1.4	1.9	0.79	(b)	0.18
Co-60	(b)	0.021	(b)	2.10(-3)	(b)	0.094
Co-58	(b)	1.2(-3)[c]	(b)	6.20(-4)	(b)	4.7(-3)
Cr-51	(b)	6.2(-4)	(b)	0.014	(b)	9.4(-3)
Mn-54	(b)	6.2(-3)	(b)	6.2(-4)	(b)	0.047
Fe-59	(b)	8.3(-4)	(b)	5.2(-4)	(b)	0.016
Zn-65	(b)	4.2(-3)	(b)	2.1(-4)	(b)	1.0(-3)
Zr-95	(b)	8.3(-4)	2.3(-4)	1.0(-4)	(b)	5.2(-5)
Sr-89	(b)	1.9(-4)	1.8(-2)	6.2(-3)	(b)	5.2(-4)
Sr-90	(b)	1.0(-5)	1.2(-3)	2.1(-5)	(b)	3.1(-4)
Sb-124	(b)	4.2(-4)	(b)	3.1(-4)	(b)	5.2(-5)
Cs-134	(b)	8.3(-3)	8.9(-4)	3.1(-4)	(b)	4.7(-3)
Cs-137	(b)	0.01	1.4(-3)	6.2(-4)	(b)	9.4(-3)
Ba-140	(b)	8.3(-4)	5.1(-2)	0.011	(b)	1.0(-4)
Ce-141	(b)	2.1(-4)	2.2(-4)	6.2(-4)	(b)	6.2(-3)

[a] RG 1.112 sources are identified assuming the plant in question utilizes a Mark III containment. RG 1.112 data are based on data from facilities of Fermi 2 design. In order to be representative of Mark III containment, RG 1.112 divided the expected releases equally between the containment and the auxiliary building. For Fermi 2, whose reactor building and auxiliary building share the same exhaust line, the RG 1.112 values for each building were added back together.

[b] Negligible quantities of the radionuclide are expected to be released.

[c.] $1.2(-3) = 1.2 \times 10^{-3}$

CHAPTER 11 APPENDIX A

ANNEX B

ATMOSPHERIC TRANSPORT AND DISPERISON

MODELING FOR THE 10 CFR PART 5O APPENDIX I

CALCULATIONS

TABLE OF CONTENTS

1.0 INTRODUCTION

This annex presents the atmospheric transport and dispersion modeling methodology; the meteorological joint frequency distributions; and the normalized effluent concentrations, χ/Q, and relative deposition rates, D/Q, required for the 10 CFR Part 50 Appendix I evaluations. All calculations and methods used are in complete compliance with Regulatory Guide 1.111 (Reference 1). The results presented are used for dose calculations from airborne effluents.

The modeling technique chosen was the Straight-line Airflow Model which is presented and specifically approved in Reference 1. Because of flat terrain and the use of only one data station, it was felt that long term modeling using the mixed mode adaptation of the straight-line airflow technique and the open terrain correction factor developed by the NRC would provide as conservative and valid an estimate of the dispersion as the other more sophisticated techniques.

The mixed mode analyses were performed for three sources at the Fermi 2 site: the containment building vent, the turbine building vent, and the radwaste building vent. In addition, a fourth set of calculations were performed for strictly ground level releases.

The data used were taken at the 60-meter tower at the Fermi 2 site for the period June 1, 1974 through May 31, 1975. As part of the 10 CFR Part 50 Appendix I evaluations, the long term temporal representativeness of this on-site data, based upon 10 years of NWS data, is presented in Reference 2. The degree to which this single year of data base at the 60-meter tower is representative of actual site conditions is further discussed in Reference 3. The discussion of the primary air flow regimes which govern dispersion at the Fermi 2 site can be found in References 2 and 3 and in Section 2.3.2.3 and Section 2.3.2.4.2 of the FSAR (Reference 4).

Section 2 presents a description of the methodology used to calculate χ/Q, D/Q and mixed mode joint frequency distributions. Section 3 presents the results of the calculations for the specific source specifications of the Fermi 2 plant. Joint frequency distributions of a strictly ground level source for the annual average and grazing period average are tabulated in Appendix A. The mixed mode joint frequency distributions used for calculation of the elevated plume dose for the containment building emitting in the mixed mode for these same periods are tabulated in Appendix B. This same information for the turbine building emitting in the mixed mode is tabulated in Appendix C and for the radwaste building vent emitting in the mixed mode in Appendix D.

2.0 DESCRIPTION OF MODELING TECHNIQIES

This section describes the assumptions and calculational methodology used to compute the annual average and grazing period average values of the source-normalized effluent concentration χ/Q and the source-normalized relative deposition rate per unit area D/Q, as well as the joint frequency distributions of wind speeds, directions, and stabilities for these two intervals.

The calculational techniques for χ/Q and D/Q using the Straight-line Airflow Model described in Regulatory Guide 1.111 (Reference 1) require specification of the frequency of time, over a specified period, that each particular meteorological condition existed. In addition, estimates of the wind speeds at the height of release are needed. The models used and justification for the wind speed values used in these analyses are discussed in the following sections.

2.1 Description of χ/Q Calculational Methodology

This section describes the modeling methodology used to calculate the source-normalized concentrations used in the radiological dose calculations for sources considered appropriate to a mixed mode analysis and a ground level analysis following recommendations in Regulatory Guide 1.111 (Reference 1). The applicability of a mixed mode analysis for a particular source depends upon the source's relationship to nearby structures. For effluents released from points above adjacent solid structures, but lower than twice the height of these structures, the effluent plume is treated in a manner consistent with a mixed mode analysis. For effluents released from points below the height of adjacent solid structures, a strictly ground level release is assumed.

The mixed mode analysis is essentially a Straight-line Airflow Model with modifications to permit weighting calculated downwind concentrations by the amount of time the plume is considered to be entrained (or not entrained) in the volumetric wake of the building.

The equation for this model, as presented by Sagendorf (Reference 5), is:

$$\left(\overline{\chi/Q'}\right)_D = 2.032 \sum_{ij} n_{ij} \left[N X \bar{u}_i \Sigma_{zj}(X)\right]^{-1} \exp\left[-h_e^2/2\sigma_{zj}^2(X)\right] \quad (1)$$

where

h_e	is the effective release height;
n_{ij}	is the length of time (hours of valid data) weather conditions are observed to be at a given wind direction, windspeed class, i, and atmospheric stability class, j;
N	is the total hours of valid data;
$\bar{u}_i$	is the midpoint of windspeed class, i, at a height, h_e (effective release height)
$\sigma_{zj}(X)$	is the vertical plume spread without volumetric correction at distance, X, for stability class, j;
$\Sigma_{zj}(X)$	is the vertical plume spread with a volumetric correction for a release within the building wake cavity, at a distance, X, for stability class, j; otherwise $\Sigma_{zj}(X) = \sigma_{zj}(X)$;
$\left(\overline{\chi/Q'}\right)_D$	is the average effluent concentration, χ, normalized by source strength, Q', at distance, X, in a given downwind direction, D; and
2.032	is $(2/\pi)^{1/2}$ divided by the width in radians of a 22.5° sector.

For effluents released from points less than or equal to the height of adjacent solid structures, a ground-level release is assumed ($h_e = 0$).

For effluents released from vents or other points above adjacent solid structures, but lower than elevated release points, the effluent plume is considered as an elevated release whenever the vertical exit velocity of the plume, W°, is at least five times the mean horizontal windspeed, u_r, at the height of release; i.e., as modified from Johnson et al. (Reference 6):

$$W_o/\bar{u}_r \geq 5.0$$

In this case, the effective release height is determined from (Reference 5):

$$h_e = h_s + h_{pr} - h_t - c \tag{2}$$

where

- c is the correction for low relative exit velocity (see equation 9)
- h_e is the effective release height
- h_{pr} is the rise of the plume above the release point, according to Sagendorf (Reference 5), whose treatment is based on Briggs (Reference 7); (see below)
- h_s is the physical height of the release point (the elevation of the stack base should be assumed to be zero); and
- h_t is the maximum terrain height (above the stack base) between the release point and the point for which the calculation is made (for this calculation h_t identically equals zero).

Because of flat terrain around the Fermi 2 site, the terrain height h_t was set equal to zero in all calculations reported herein. Plume rise was calculated using formulae from Briggs (Reference 7). For neutral or unstable conditions,

$$h_{pr} = 1.44 \left(\frac{W_o}{\bar{u}_r}\right)^{2/3} \left(\frac{X}{d}\right)^{1/3} d \tag{3}$$

where

- h_{pr} plume rise
- W_o exit velocity
- X distance
- $\bar{u}_r$ wind speed
- d internal stack diameter

The result from this calculation is compared with that from

$$h_{pr} = 3\left(\frac{W_o}{\bar{u}_r}\right) d \tag{4}$$

and the lesser value is used.

For stable conditions the results from equation (3) or (4) are compared with the results from the following two equations:

$$h_{pr} = 4\left(\frac{F_m}{S}\right)^{1/4} \tag{5}$$

$$h_{pr} = 1.5\left(\frac{F_m}{\bar{u}_r}\right)^{1/3} S^{-1/6} \quad (6)$$

where

F_m = momentum flux parameter

S = stability parameter.

and the smallest value of h_{pr} is used. F_m and S are defined as follows:

$$F_m = W_o^2\left(\frac{d}{2}\right)^2 \quad (7)$$

$$S = \frac{g}{T}\frac{\delta\theta}{\delta z} \quad (8)$$

where

g = acceleration of gravity

T = ambient air temperature

$\frac{\delta\theta}{\delta z}$ = vertical potential temperature gradient.

For the purposes of the calculations for the Fermi 2 site, S was defined as 8.75×10^{-4} for E stability; 1.75×10^{-3} for F stability; and 2.45×10^{-3} for G stability.

When the vertical exit velocity is less than 1.5 times the horizontal windspeed, a correction for downwash is subtracted from Equation (2) according to Gifford (Reference 8):

$$c = 3\left(1.5 - {W_o}/{\bar{u}_r}\right)d \quad \text{for} \quad 1 \leq {W_o}/{\bar{u}_r} \leq 1.5 \quad (9)$$

and $\quad c = 0$ otherwise

where

c is the downwash correction;

$\bar{u}_r$ is the mean windspeed at the height of release; and

W_o is the vertical exit velocity of the plume.

If ${W_o}/{\bar{u}_r}$ is less than 1.0 or unknown, a ground-level release is assumed ($h_e = 0$).

For cases where the ratio of plume exit velocity to horizontal windspeed is between one and five, a mixed release mode is assumed, in which the plume is considered as an elevated release during a part of the time and as a ground-level release ($h_e = 0$) during the remainder of the time. An entrainment coefficient, E_t, modified from Reference 7, is determined for those cases in which W_o/u_r is between one and five:

$$E_t = 2.58 - 1.58(W_o/\bar{u}_r) \text{ for } 1 \leq W_o/\bar{u}_r \leq 1.5 \quad (10)$$

and

$$E_t = 0.3 - 0.06(W_o/\bar{u}_r) \text{ for } 1.5 \leq W_o/\bar{u}_r \leq 5.0 \quad (11)$$

The release is considered to occur as an elevated release $100(1\text{-}E_t)$ percent of the time and as a ground release $100E_t$ percent of the time. Each of these cases is then evaluated separately and the concentration calculated according to the fraction of time each type of release occurs. Windspeeds representative of conditions at the plume heights are used for the times when the release is considered to be elevated. Wind speeds measured at the 10-meter level are used for those times when the effluent plume is considered to be a ground level release.

For the ground-level portion of the releases only ($h_e = 0$), an adjustment is made in Equation (2) that takes into consideration initial mixing of the effluent plume within the building wake. This adjustment, according to Yanskey et al. (Reference 9), is in the form of:

$$\Sigma_{zj}(X) = \left(\sigma_{zj}^2(X) + 0.5\, D_z^2/\pi\right)^{1/2} \leq \sqrt{3}\sigma_{zj}(X) \tag{12}$$

where

D_z is the maximum adjacent building height either up- or downwind from the release point;

$\sigma_{zj}(X)$ is the vertical standard deviation of the materials in the plume at distance, X, for atmospheric stability class, j; and

$\Sigma_{zj}(X)$ is the vertical standard deviation of plume material as above, with the correction for additional dispersion within the building wake cavity, restricted by the condition that

$$\Sigma_{zj}(X) = \sqrt{3}\sigma_{zj}(X)$$

when

$$\left(\sigma_{zj}^2(X) + 0.5D_z^2/\pi\right)^{1/2} > \sqrt{3}\sigma_{zj}(X)$$

For the elevated portion of the releases, no credit is taken for any additional dispersion within the building wake cavity and $\Sigma_{zj}(X)$ is set equal to $\sigma_{zj}(X)$.

Adjustments were made to the normalized effluent concentrations because the Straight-line Airflow Model does not consider the effects of spatial and temporal variations in airflow in the region of the site. The terrain near the site is flat and open so adjustment factors for "sites in open terrain" were applied. The final calculations of χ/Q and D/Q for both strictly ground level release and mixed mode release were multipled by the open terrain correction factor as a function of distance as shown in Figure 2, in Reference 1.

A conceptual flow diagram summarizing the calculational methodology used to calculate χ/Q from the joint frequency distribution is presented in Figure 2.1.

2.2 Deposition Methodology for Calculating D/Q

This section describes the modeling methodology used to calculate the source-normalized relative deposition rate per unit area (D/Q) used in the radiological dose calculations for sources considered as strictly ground level and those considered acceptable to a mixed mode analysis.

The deposition rate per unit downwind distance divided by the source strength was determined from Figures 7 through 10 of Reference 1.

The criteria by which a meteorological condition caused the source to emit in the elevated mode were taken as the same as in the χ/Q calculational methodology. If an elevated release was appropriate, the plume rise was calculated in the same manner as for the χ/Q estimates. Generally this effective plume height was greater than 60 meters but less than 100 meters.

To interpolate relative deposition rate for release heights other than those presented in Figures 7 through 10 of Reference 1, a logarithmic relationship was used,

$$\log D_r(h) = a \log h + b \tag{13}$$

where

$D_r(h)$ relative deposition rate for release height h

$$a = \frac{\log D_{r_1}(h_1) - \log D_{r_2}(h_2)}{\log h_1 - \log h_2} \tag{14}$$

$$b = \frac{\log D_{r_2}(h_2) \log h_1 - \log D_{r_1}(h_1) \log h_2}{\log h_1 - \log h_2} \tag{15}$$

For example, to find the relative deposition rate for a release height of 80 meters under unstable conditions at a downwind distance of one kilometer, first $D_r(100) = 5 \times 10^{-5}$ is found from Figure 10, Reference 1, and $D_r(60) = 6 \times 10^{-5}$ is found from Figure 9, Reference 1. Then, a and b are calculated as follows:

$$a = \frac{\log(5\times10^{-5}) - \log(6\times10^{-5})}{\log 100 - \log 60} = -0.35691$$

$$b = \frac{\log(6\times10^{-5}) \log 100 - \log(5\times10^{-5}) \log 60}{\log 100 - \log 60} = -3.58721$$

Finally, $D_r(80)$ is calculated:

$$\begin{aligned} \log D_r(80) &= -0.35691 \log 80 - 3.58721 \\ &= 0.73356 - 5 \\ D_r(80) &= 5.41452 \times 10^{-5} \end{aligned}$$

In order to calculate values for D_r for distances which are not shown on Figures 7 through 10 of Reference 1, (e.g., values for distances close to the release site under stable conditions for elevated releases) the portions of the curve which are presented were logarithmically extrapolated to a minimum value of 10^{-10}. Any values less than this were set equal to 10^{-10} and used in the calculations.

For the ground level portion of the mixed mode release, no interpolation for height was performed and the values from the curve in Figure 7 of Reference 1 were used. In accordance with recommendations in Reference 1, the final calculations of χ/Q and D/Q for strictly ground level release and mixed mode release were multiplied by the open terrain correction factor as a function of distance as shown in Figure 2, Reference 1.

A conceptual flow diagram summarizing the calculational methodology used to calculate D/Q from the joint frequency distribution is presented in Figure 2.2. Note the similarity between techniques for χ/Q and D/Q.

2.3 Description of Mixed Mode Joint Frequency Distribution for Gamma Doses

This section describes the methodology used to calculate the sets of joint frequency distributions used as input for the calculation of the gamma doses. Each set of joint frequency distributions consists of two combinations: a ground level release and an elevated release. For a ground level release, the frequency of occurrence of each wind speed-wind direction-stability class combination was calculated and was weighted by the percent of time that meteorological combination was considered to be entrained in the building wake cavity. For the elevated release a separate similar distribution was calculated but weighted by the percent of time that each meteorological condition caused the vent to emit in the elevated mode. The entrainment coefficient was calculated in the same manner as for the □/Q estimates. These two joint frequency distributions, taken separately, do not sum to unity. The first sums to the total frequency that the release was considered to be a ground level source, and the second to the total frequency that the release was considered elevated. Together, however, these distributions sum to unity.

Because the criteria for the determination of the entrainment coefficient are dependent upon wind speed only, the relative frequencies of occurrence for stability and wind direction are identical for the mixed mode ground level and mixed mode elevated distributions. However, the relative wind speed frequencies of occurrence are different. Because lower wind speeds tend to be categorized as elevated releases, the average speeds for the mixed mode ground level distribution tend to be higher than those for a strictly ground level release. Similarly, since higher winds tend to be categorized as ground level releases, the average speeds for the mixed mode elevated distribution tend to be lower than those expected from the power law extrapolation of the strictly ground level release.

Presentation of the final plume height attained for each meteorological combination for the elevated portion of the mixed mode source is difficult to include with the joint frequency distribution. For this reason, the most conservative approach possible was taken. That is, since the wind speeds categorized in the elevated joint frequency distribution were calculated at the height of release (e.g., 51.2 meters for the containment building), the radiological dose calculations were performed under the assumption that when an elevated release was considered to exist, the plume rise was zero.

The mixed mode joint frequency distribution tables for the annual average and grazing period average are presented in Appendices B, C, and D for each of the three different sources considered. Note that the grazing period frequencies of occurrence are normalized to the number of hours during that period, i.e., the sum of all frequencies adds to unity.

2.4 Meteorological Data

Meteorological data were taken on-site at 10 meters and at 60 meters from 1 June 1974 through 31 May 1975. A complete description of the on-site meteorological monitoring program, along with instrument accuracy and adequacy, can be found in Reference 4.

The degree to which this year of data base at the 60-meter tower is representative of actual site conditions is discussed in Reference 3. The discussion of the primary airflow regimes which govern dispersion at the Fermi 2 site can be found in References 2 and 4.

The mixed mode release analysis specified in Reference 1 requires that the wind speed be determined at the point of release. Because the measured wind velocities are at heights other than the point of release, a power law wind profile was used for interpolation (section 2.4.2).

2.4.1 Joint Frequency Distributions

The calculational methodology used to develop the joint frequency distributions (other than those used in gamma dose calculations) of meteorological variables used in the analyses is described below.

Joint frequency distributions give the frequency of time, over a specified period, that specified classes of wind speed, wind direction, and atmospheric stability co-existed.

Wind direction, as measured at the 10-meter level, was classified into sixteen 22.5-degree sectors centered on the cardinal compass points. Wind speed, as measured at the 10-meter level, was categorized into 12 classes as shown below:

Class Number	Wind Speed Range (mph)	Interval Medial Used in Calculations (mph)
1 (Calms)	$0.0 \leq u \leq 0.5$	0.5*
2	$0.5 \leq u \leq 2.5$	1.5
3	$2.5 \leq u \leq 4.5$	3.5
4	$4.5 \leq u \leq 6.5$	5.5
5	$6.5 \leq u \leq 8.5$	7.5
6	$8.5 \leq u \leq 11.5$	10.0
7	$11.5 \leq u \leq 14.5$	13.0
8	$14.5 \leq u \leq 18.5$	16.5
9	$18.5 \leq u \leq 23.5$	21.0
10	$23.5 \leq u \leq 30.5$	27.0
11	$30.5 \leq u \leq 39.5$	35.0
12	$39.5 < u$	42.0

* 0.5 was used for calms because the median is less than 1/2 the starting threshold of the instruments.

The joint frequency data used in the radiological dose calculations were derived from the data collected on the 60-meter tower. The meteorological data used in the joint frequency distribution derivation were collected over the period from 1 June 1974 through 31 May 1975. Tables of frequency of occurrence of wind speed by direction for each stability category are presented in Appendix A. For radiological dose evaluations during the grazing period, the data collected over the period 15 April 1975 through 31 May 1975 were sequenced around to the beginning of the 1 June 1974 through 15 October 1974 period and the resultant 6 month period categorized. The grazing period frequencies of occurrence are normalized to the number of hours during that period, i.e., the sum of all frequencies adds to unity.

2.4.2 Power Law Wind Profile

Mixing-Length Theory (Reference 10) predicts that the wind speed profile should follow a simple logarithmic pattern in the presence of purely mechanically generated turbulence over homogeneous terrain and in the absence of thermal stratification. This logarithmic profile fits observations well only when the temperature lapse rate is neutrally stable. Under these conditions, mechanical turbulence dominates and is neither augmented by thermally induced turbulence (unstable case) nor suppressed by thermal stratification (stable case). When the lapse rate is not neutral, the logarithmic law is not a good description of the wind profile. In order to describe the wind speed profile when the lapse rate is not neutral, various empirical methods have been suggested which incorporate corrections for stability. The most successful of these is the power law profile. This is stated as:

$$\frac{u_1}{u_2} = \left(\frac{z_1}{z_2}\right)^m \text{ where } 0 \leq m \leq 1 \qquad (16)$$

where

z_1 = height at elevation 1

z_2 = height at elevation 2

u_1 = wind speed at height z_1

u_2 = wind speed at height z_2

m = a non-dimensional variable which depends on thermal stability

This technique was used to interpolate wind velocities at the point of release at the Fermi 2 site from the on-site data.

To determine the behavior of m with lapse rate at the Fermi 2 site, equation (16) was solved for m in terms of the hourly-averaged wind speeds at the 10- and 60-meter levels:

$$m = \frac{\log u_{60} - \log u_{10}}{\log(60) - \log(10)} \qquad (17)$$

The calculated hourly values of m were then plotted on a scatter diagram as a function of the corresponding hourly average temperature difference between the 10- and 60-meter levels. The diagram shown in Figure 2.3 presents these data for the period 1 June 1974 through 31 May 1975. The number of occurrences of any particular set of values is given by the alphabetic rank of the letter plotted at the location of those values. The average value of m decreases with increasing temperature difference. The Pasquill stability categories are also shown in Figure 2.3 to allow easy comparison with the average value of m in each class. For the annual period considered, the average value of the power law exponent by stability class is given in Table 2.1.

To determine whether there was a seasonal dependence on the power law wind profile exponent for the Fermi 2 site data, the same type of analysis as that done in Figure 2.3 was done for the data for each of the four seasons. The seasonal behavior of the power law exponent is shown in Figure 2.4. From this analysis it can be seen that there is little variation in the average curve for the different seasons.

Because of the possibility of a parametric dependence of the power law exponent upon other meteorological variables, the scatter diagram technique was applied to the 10-meter level wind speed averages as well. These data are shown in Figure 2.5. The dependence of m upon wind speed for values greater than about seven mph is negligible. For wind speeds less than this, the average value of m increases relatively slowly down to a speed of about five mph and then rapidly for lower values. This is probably due to the parametric relationship between low wind speeds and high atmospheric thermal stability where the surface winds essentially decouple from the faster moving upper level flows. This does not invalidate the power law profile extrapolation technique.

In all elevated wind speed calculations, the 10-meter level wind speed was extrapolated to the elevated height using the power law profile with the exponent values shown in Table 2.1 by stability class.

TABLE 2.1. AVERAGE VALUES OF POWER LAW WIND PROFILE EXPONENT BY STABILITY CLASS.

Pasquill Stability Class	Average Value of Exponent	Standard Deviation of Average	Average Wind Speed (mph)	Percentage of Occurrence
A	0.141	0.157	8.95	9.17
B	0.176	0.154	9.94	2.08
C	0.174	0.117	10.08	2.40
D	0.209	0.131	10.04	30.29
E	0.277	0.172	8.79	40.46
F	0.414	0.186	6.82	10.31
G	0.435	0.274	5.41	5.30

3.0 FERMI 2 SITE SPECIFIC χ/Q AND D/Q VALUES

The methodology described in section 2 of this annex was applied to the 60-meter tower data base from June 1, 1974 through May 31, 1975 for the receptor locations shown in Table 3.1. This table describes the distance to the nearest receptor type in each 22 1/2 degree sector out to a distance of 5 miles (8.047 Km). The analyses were performed for the three separate sources whose release specifications are shown in Table 3.2.

The annual average values for the ground level and mixed mode χ/Q and D/Q for the containment building vent, the turbine building vent, and the radwaste building vent are presented in Tables 3.3, 3.5, and 3.7, respectively. The grazing period (April 15 through October 15) values for the ground level and mixed mode χ/Q and D/Q for the three sources are presented in Tables 3.4, 3.6, and 3.8.

TABLE 3.1 RECEPTOR LOCATIONS USED IN χ/Q AND D/Q EVALUATION FOR APENDIX I (SURVEYED MAY-JUNE 1976)

	Distance in Meters to First						
Direction	Site Boundary	Residence	Garden	Milk Goat	Meat Animal	Milk Cow	Nature of Site Boundary
N	1249**	1720	1800	*	2600 (Pig)	*	Farmland**
NNE	1646	1740	1740	*	4440 (Beef)	*	Swan Creek
NE	579	1770	1770	*	*	*	Lake Erie Shore-Woodlot
S	1417	1530	1530	*	*	*	Marsh
SSW	1542	1840	1840	*	*	*	Point Aux Peaux Road-Sparse Trees
SW	1920	2150	2150	*	*	*	Point Aux Peaux Road-Sparse Trees
WSW	1798	2300	2300	*	3490 (Beef)	*	Meadow
W	1390	1950	1950	*	*	6440	Toll Road and Edison Plant Entrance Road - Wood Lot
WNW	1082	1130	1130	7820	4100 (Pig)	*	Toll Road - Marsh
NW	915	1720	1720	3180	4750 (Beef)	4750	Toll Road - Meadow/Sparse Trees

TABLE 3.1 RECEPTOR LOCATIONS USED IN χ/Q AND D/Q EVALUATION FOR APENDIX I (SURVEYED MAY-JUNE 1976)

	Distance in Meters to First						
Direction	Site Boundary	Residence	Garden	Milk Goat	Meat Animal	Milk Cow	Nature of Site Boundary
NNW	990	1690	1690	*	4700 (Beef)	*	Toll Road - Meadow/Sparse Trees

* None found within 5-mile radius of site
** Presently under water 6/1/76

TABLE 3.2 RELEASE POINT SPECIFICATIONS FOR CONTAINMENT BUILDING AND TURBINE BUILDING SOURCES

	Containment Building Source	Turbine Building Source	Radwaste Building Source
Release Height Above Grade (meters)	51.20	40.08	44.50
Structure Height Used to Evaluate Volumetric Wake Size (meters)	47.50	40.08	40.08
Height of Vent Above Adjacent Structures (meters)	3.70	0	4.42
Vent Diameter (meters)	2.19	7.46[a]	1.54[a]
Vent Configuration[b]	Circular	Rectangular	Rectangular
ΔT Between Gaseous Effluent and Ambient Air (°C)	17	17	17
Exit Velocity from Vent (m/sec)	13.97	4.22	8.92

[a] Release vent is rectangular in cross section with area equivalent to a cylinder vent with this diameter.
[b] There are no deflectors or diffusers on vents.

TABLE 3.3 ANNUAL: 6/1/74 - 5/31/75; AVERAGE χ/Q (sec/m^3) AND D/Q (m^{-2}) FOR VARIOUS RECEPTOR LOCATIONS AND CONTAINMENT BUILDING SOURCE

Receptor Label	Downwind Distance (km)	Radial	χ/Q Ground Source	χ/Q Mixed Mode Source	D/Q Ground Source	D/Q Mixed Mode Source
Site Boundary (Under H_2O)	1.249	N	3.679×10^{-6}	6.401×10^{-7}	3.794×10^{-8}	1.401×10^{-8}
Site Boundary (Swan Creek)	1.646	NNE	2.654×10^{-6}	6.078×10^{-7}	2.610×10^{-8}	9.808×10^{-9}
Site Boundary (Lake Shore)	0.579	NE	1.687×10^{-5}	2.279×10^{-6}	1.962×10^{-7}	5.461×10^{-8}
Site Boundary (Marsh)	1.417	S	2.707×10^{-6}	3.251×10^{-7}	1.758×10^{-8}	4.915×10^{-9}
Site Boundary Pnt Aux Peaux	1.542	SSW	1.619×10^{-6}	2.331×10^{-7}	1.126×10^{-8}	3.687×10^{-9}
Site Boundary Pnt Aux Peaux	1.920	SW	8.095×10^{-7}	1.850×10^{-7}	7.696×10^{-9}	3.726×10^{-9}
Site Boundary (Meadow)	1.798	WSW	1.036×10^{-6}	2.645×10^{-7}	1.131×10^{-8}	5.793×10^{-9}
Site Boundary Toll Rd.-Entrc	1.390	W	1.586×10^{-6}	3.570×10^{-7}	1.814×10^{-8}	8.318×10^{-9}
Site Boundary Toll Rd.-Marsh	1.082	WNW	3.221×10^{-6}	6.193×10^{-7}	3.773×10^{-8}	1.467×10^{-8}
Site Boundary Toll Rd.-Meadow	0.915	NW	5.372×10^{-6}	7.630×10^{-7}	6.133×10^{-8}	2.010×10^{-8}
Site Boundary Toll Rd.-Meadow	0.990	NNW	5.091×10^{-6}	7.159×10^{-7}	4.979×10^{-8}	1.499×10^{-8}
Residence	1.720	N	1.747×10^{-6}	3.505×10^{-7}	1.594×10^{-8}	6.470×10^{-9}
Residence	1.740	NNE	2.316×10^{-6}	5.418×10^{-7}	2.228×10^{-8}	8.508×10^{-9}
Residence	1.770	NE	2.248×10^{-6}	4.536×10^{-7}	1.927×10^{-8}	7.207×10^{-9}
Residence	1.530	S	2.209×10^{-6}	2.745×10^{-7}	1.392×10^{-8}	4.014×10^{-9}

TABLE 3.3 ANNUAL: 6/1/74 - 5/31/75; AVERAGE χ/Q (sec/m^3) AND D/Q (m^{-2}) FOR VARIOUS RECEPTOR LOCATIONS AND CONTAINMENT BUILDING SOURCE

			χ/Q		D/Q	
Receptor Label	Downwind Distance (km)	Radial	Ground Source	Mixed Mode Source	Ground Source	Mixed Mode Source
Residence	1.840	SSW	1.046×10^{-6}	1.645×10^{-7}	6.797×10^{-9}	2.422×10^{-9}
Residence	2.150	SW	6.257×10^{-7}	1.518×10^{-7}	5.703×10^{-9}	2.858×10^{-9}
Residence	2.300	WSW	5.904×10^{-7}	1.702×10^{-7}	5.894×10^{-9}	3.261×10^{-9}
Residence	1.950	W	6.725×10^{-7}	1.744×10^{-7}	6.840×10^{-9}	3.602×10^{-9}
Residence	1.130	WNW	3.035×10^{-6}	5.922×10^{-7}	3.499×10^{-8}	1.376×10^{-8}
Residence	1.720	NW	1.512×10^{-6}	3.205×10^{-7}	1.492×10^{-8}	6.363×10^{-9}
Residence	1.690	NNW	1.737×10^{-6}	3.298×10^{-7}	1.468×10^{-8}	5.150×10^{-9}
Garden	1.800	N	1.566×10^{-6}	3.209×10^{-7}	1.405×10^{-8}	5.790×10^{-9}
Garden	1.740	NNE	2.316×10^{-6}	5.418×10^{-7}	2.228×10^{-8}	8.508×10^{-9}
Garden	1.770	NE	2.248×10^{-6}	4.536×10^{-7}	1.927×10^{-8}	7.207×10^{-9}
Garden	1.530	S	2.209×10^{-6}	2.745×10^{-7}	1.392×10^{-8}	4.014×10^{-9}
Garden	1.840	SSW	1.046×10^{-6}	1.645×10^{-7}	6.797×10^{-9}	2.422×10^{-9}
Garden	2.150	SW	6.257×10^{-7}	1.518×10^{-7}	5.703×10^{-9}	2.858×10^{-9}
Garden	2.300	WSW	5.904×10^{-7}	1.702×10^{-7}	5.894×10^{-9}	3.261×10^{-9}
Garden	1.950	W	6.725×10^{-7}	1.744×10^{-7}	6.840×10^{-9}	3.602×10^{-9}
Garden	1.130	WNW	3.035×10^{-6}	5.922×10^{-7}	3.499×10^{-8}	1.376×10^{-8}
Garden	1.720	NW	1.512×10^{-6}	3.205×10^{-7}	1.492×10^{-8}	6.363×10^{-9}
Garden	1.690	NNW	1.737×10^{-6}	3.298×10^{-7}	1.468×10^{-8}	5.150×10^{-9}
Milk Goat	7.820	WNW	6.333×10^{-8}	2.315×10^{-8}	3.271×10^{-10}	1.861×10^{-10}
Milk Goat	3.180	NW	3.996×10^{-7}	1.138×10^{-7}	3.098×10^{-9}	1.534×10^{-9}
Meat Animal-Pig	2.600	N	6.997×10^{-7}	1.701×10^{-7}	5.393×10^{-9}	2.383×10^{-9}
Meat Animal-Beef	4.440	NNE	3.456×10^{-7}	1.138×10^{-7}	2.201×10^{-9}	9.521×10^{-10}

TABLE 3.3 ANNUAL: 6/1/74 - 5/31/75; AVERAGE χ/Q (sec/m^3) AND D/Q (m^{-2}) FOR VARIOUS RECEPTOR LOCATIONS AND CONTAINMENT BUILDING SOURCE

			χ/Q		D/Q	
Receptor Label	Downwind Distance (km)	Radial	Ground Source	Mixed Mode Source	Ground Source	Mixed Mode Source
Meat Animal-Beef	3.490	WSW	2.514×10^{-7}	8.675×10^{-8}	2.134×10^{-9}	1.266×10^{-9}
Meat Animal-Pig	4.100	WNW	2.064×10^{-7}	6.392×10^{-8}	1.418×10^{-9}	7.512×10^{-10}
Meat Animal-Beef	4.750	NW	1.868×10^{-7}	6.165×10^{-8}	1.223×10^{-9}	6.532×10^{-10}
Meat Animal-Beef	4.700	NNW	2.179×10^{-7}	6.248×10^{-8}	1.173×10^{-9}	4.941×10^{-10}
Milk Cow	6.440	W	6.332×10^{-8}	2.450×10^{-8}	3.958×10^{-10}	2.485×10^{-10}
Milk Cow	4.750	NW	1.868×10^{-7}	6.165×10^{-8}	1.223×10^{-9}	6.532×10^{-10}

TABLE 3.4 GRAZING PERIOD: APRIL 15 TO OCTOBER 15;* AVERAGE χ/Q (sec/m^3) AND D/Q (m^{-2}) FOR VARIOUS RECEPTOR LOCATIONS AND CONTAINMENT BUILDING SOURCE

			χ/Q		D/Q	
Receptor Label	Downwind Distance (km)	Radial	Ground Source	Mixed Mode Source	Downwind Distance (km)	Radial
Site Boundary (Under H_2O)	1.249	N	2.125×10^{-6}	4.102×10^{-7}	2.566×10^{-8}	1.061×10^{-8}
Site Boundary Swan Creek	1.646	NNE	1.436×10^{-6}	3.321×10^{-7}	1.462×10^{-8}	5.761×10^{-9}
Site Boundary (Lake Shore)	0.579	NE	8.530×10^{-6}	1.057×10^{-6}	8.990×10^{-8}	2.370×10^{-8}
Site Boundary (Marsh)	1.417	S	1.765×10^{-6}	1.902×10^{-7}	9.751×10^{-9}	2.381×10^{-9}
Site Bndry-Pnt Aux Peaux	1.542	SSW	1.087×10^{-6}	1.574×10^{-7}	7.351×10^{-9}	2.196×10^{-9}
Site Bndry-Pnt Aux Peaux	1.920	SW	3.763×10^{-7}	9.339×10^{-8}	4.226×10^{-9}	1.973×10^{-9}

TABLE 3.4 GRAZING PERIOD: APRIL 15 TO OCTOBER 15;* AVERAGE χ/Q (sec/m^3) AND D/Q (m^{-2}) FOR VARIOUS RECEPTOR LOCATIONS AND CONTAINMENT BUILDING SOURCE

			χ/Q		D/Q	
Receptor Label	Downwind Distance (km)	Radial	Ground Source	Mixed Mode Source	Downwind Distance (km)	Radial
Site Bndry (Meadow)	1.793	WSW	4.763×10^{-7}	9.490×10^{-8}	4.749×10^{-9}	2.150×10^{-9}
Site Bndry-Toll Rd.-Entrc	1.390	W	8.010×10^{-7}	1.821×10^{-7}	9.070×10^{-9}	3.793×10^{-9}
Site Bndry-Toll Rd.-Marsh	1.082	WNW	1.936×10^{-6}	3.587×10^{-7}	2.375×10^{-8}	9.480×10^{-9}
Site Bndry-Toll Rd.-Meadow	0.915	NW	2.990×10^{-6}	4.476×10^{-7}	3.965×10^{-8}	1.435×10^{-8}
Site Bndry-Toll Rd.-Meadow	0.990	NNW	2.814×10^{-6}	4.472×10^{-7}	3.271×10^{-8}	1.034×10^{-8}
Residence	1.720	N	1.002×10^{-6}	2.217×10^{-7}	1.078×10^{-8}	4.846×10^{-9}
Residence	1.740	NNE	1.252×10^{-6}	2.957×10^{-7}	1.248×10^{-8}	4.991×10^{-9}
Residence	1.770	NE	1.117×10^{-6}	2.049×10^{-7}	8.831×10^{-9}	3.093×10^{-9}
Residence	1.530	S	1.441×10^{-6}	1.591×10^{-7}	7.730×10^{-9}	1.934×10^{-9}
Residence	1.840	SSW	7.041×10^{-7}	1.095×10^{-7}	4.439×10^{-9}	1.419×10^{-9}
Residence	2.150	SW	2.912×10^{-7}	7.639×10^{-8}	3.133×10^{-9}	1.504×10^{-9}
Residence	2.300	WSW	2.728×10^{-7}	6.230×10^{-8}	2.474×10^{-9}	1.208×10^{-9}
Residence	1.950	W	3.391×10^{-7}	8.861×10^{-8}	3.423×10^{-9}	1.635×10^{-9}
Residence	1.130	WNW	1.824×10^{-6}	3.428×10^{-7}	2.202×10^{-8}	8.891×10^{-9}
Residence	1.720	NW	8.300×10^{-7}	1.867×10^{-7}	9.640×10^{-9}	4.493×10^{-9}
Residence	1.690	NNW	9.461×10^{-7}	2.087×10^{-7}	9.640×10^{-9}	3.612×10^{-9}
Garden	1.800	N	8.971×10^{-7}	2.026×10^{-7}	9.501×10^{-9}	4.328×10^{-9}
Garden	1.740	NNE	1.252×10^{-6}	2.956×10^{-7}	1.248×10^{-8}	4.991×10^{-9}
Garden	1.770	NE	1.117×10^{-6}	2.049×10^{-7}	8.831×10^{-9}	3.093×10^{-9}
Garden	1.530	S	1.441×10^{-6}	1.591×10^{-7}	7.730×10^{-9}	1.934×10^{-9}

TABLE 3.4 GRAZING PERIOD: APRIL 15 TO OCTOBER 15;* AVERAGE χ/Q (sec/m^3) AND D/Q (m^{-2}) FOR VARIOUS RECEPTOR LOCATIONS AND CONTAINMENT BUILDING SOURCE

			χ/Q		D/Q	
Receptor Label	Downwind Distance (km)	Radial	Ground Source	Mixed Mode Source	Downwind Distance (km)	Radial
Garden	1.840	SSW	7.041×10^{-7}	1.095×10^{-7}	4.439×10^{-9}	1.419×10^{-9}
Garden	2.150	SW	2.912×10^{-7}	7.639×10^{-8}	3.133×10^{-9}	1.504×10^{-9}
Garden	2.300	WSW	2.728×10^{-7}	6.230×10^{-8}	2.474×10^{-9}	1.208×10^{-9}
Garden	1.950	W	3.391×10^{-7}	8.861×10^{-8}	3.423×10^{-9}	1.635×10^{-9}
Garden	1.130	WNW	1.824×10^{-6}	3.428×10^{-7}	2.202×10^{-8}	8.891×10^{-9}
Garden	1.720	NW	8.300×10^{-7}	1.867×10^{-7}	9.640×10^{-9}	4.493×10^{-9}
Garden	1.690	NNW	9.461×10^{-7}	2.087×10^{-7}	9.640×10^{-9}	3.612×10^{-9}
Milk Goat	7.820	WNW	3.746×10^{-8}	1.392×10^{-8}	2.059×10^{-10}	1.192×10^{-10}
Milk Goat	3.180	NW	2.174×10^{-7}	6.581×10^{-8}	2.003×10^{-9}	1.075×10^{-9}
Meat Animal-Pig	2.600	N	3.980×10^{-7}	$1.061 \times 10_{-7}$	3.647×10^{-9}	$1.7\ 7 \times 10^{-9}$
Meat Animal-Beef	4.440	NNE	1.867×10^{-7}	6.111×10^{-8}	1.233×10^{-9}	5.580×10^{-10}
Meat Animal-Beef	3.490	WSW	1.171×10^{-7}	3.288×10^{-8}	8.960×10^{-10}	4.705×10^{-10}
Meat Animal-Pig	4.100	WNW	1.231×10^{-7}	3.779×10^{-8}	8.931×10^{-10}	4.778×10^{-10}
Meat Animal-Beef	4.750	NW	1.008×10^{-7}	3.543×10^{-8}	7.911×10^{-10}	4.565×10^{-10}
Meat Animal-Beef	4.700	NNW	1.161×10^{-7}	3.895×10^{-8}	7.711×10^{-10}	3.528×10^{-10}
Milk Cow	6.440	W	3.245×10^{-8}	1.264×10^{-8}	1.971×10^{-10}	1.134×10^{-10}
Milk Cow	4.750	NW	1.008×10^{-7}	3.543×10^{-8}	7.911×10^{-10}	4.565×10^{-10}

* see section 2 of text

TABLE 3.5 ANNUAL: 6/1/74 - 5/31/75; AVERAGE χ/Q (sec/m^3) AND D/Q (m^{-2}) FOR VARIOUS RECEPTOR LOCATIONS AND TURBINE BUILDING SOURCE

			χ/Q		D/Q	
Receptor Label	Downwind Distance (km)	Radial	Ground Source	Mixed Mode S	Downwind Distance (km)	Radial
Site Boundary (Under H_2O)	1.249	N	3.891×10^{-6}	2.625×10^{-6}	3.794×10^{-8}	3.348×10^{-8}
Site Boundary-Swan Creek	1.646	NNE	2.795×10^{-6}	2.164×10^{-6}	2.610×10^{-8}	2.422×10^{-8}
Site Boundary (Lake Shore)	0.579	NE	1.829×10^{-5}	1.196×10^{-5}	1.962×10^{-7}	1.702×10^{-7}
Site Boundary (Marsh)	1.417	S	2.839×10^{-6}	1.678×10^{-6}	1.758×10^{-8}	1.410×10^{-8}
Site Bndry-Pnt Aux Peaux	1.542	SSW	1.698×10^{-6}	9.864×10^{-7}	1.126×10^{-8}	9.312×10^{-9}
Site Bndry-Pnt Aux Peaux	1.920	SW	8.426×10^{-7}	5.591×10^{-7}	7.696×10^{-9}	6.920×10^{-9}
Site Bndry (Meadow)	1.798	WSW	1.077×10^{-6}	7.966×10^{-7}	1.131×10^{-8}	1.023×10^{-8}
Site Bndry-Toll Rd.-Entrc	1.390	W	1.666×10^{-6}	1.196×10^{-6}	1.814×10^{-8}	1.615×10^{-8}
Site Bndry-Toll Rd.-Marsh	1.082	WNW	3.398×10^{-6}	2.540×10^{-6}	3.773×10^{-8}	3.464×10^{-8}
Site Bndry-Toll Rd.-Meadow	0.915	NW	5.745×10^{-6}	4.186×10^{-6}	6.133×10^{-8}	5.395×10^{-8}
Site Bndry-Toll Rd.-Meadow	0.990	NNW	5.462×10^{-6}	3.950×10^{-6}	4.979×10^{-8}	4.403×10^{-8}
Residence	1.720	N	1.835×10^{-6}	1.254×10^{-6}	1.594×10^{-8}	1.418×10^{-8}
Residence	1.740	NNE	2.439×10^{-6}	1.890×10^{-6}	2.228×10^{-8}	2.069×10^{-8}
Residence	1.770	NE	2.362×10^{-6}	1.591×10^{-6}	1.927×10^{-8}	1.689×10^{-8}
Residence	1.530	S	2.313×10^{-6}	1.371×10^{-6}	1.392×10^{-8}	1.119×10^{-8}

TABLE 3.5 ANNUAL: 6/1/74 - 5/31/75; AVERAGE χ/Q (sec/m^3) AND D/Q (m^{-2}) FOR VARIOUS RECEPTOR LOCATIONS AND TURBINE BUILDING SOURCE

			χ/Q		D/Q	
Receptor Label	Downwind Distance (km)	Radial	Ground Source	Mixed Mode S	Downwind Distance (km)	Radial
Residence	1.840	SSW	1.100×10^{-6}	6.432×10^{-7}	6.797×10^{-9}	5.652×10^{-9}
Residence	2.150	SW	6.518×10^{-7}	4.337×10^{-7}	5.703×10^{-9}	5.140×10^{-9}
Residence	2.300	WSW	6.121×10^{-7}	4.582×10^{-7}	5.894×10^{-9}	5.355×10^{-9}
Residence	1.950	W	7.037×10^{-7}	5.128×10^{-7}	6.840×10^{-9}	6.167×10^{-9}
Residence	1.130	WNW	3.199×10^{-6}	2.394×10^{-6}	3.499×10^{-8}	3.215×10^{-8}
Residence	1.720	NW	1.575×10^{-6}	1.189×10^{-6}	1.492×10^{-8}	1.340×10^{-8}
Residence	1.690	NNW	1.824×10^{-6}	1.338×10^{-6}	1.468×10^{-8}	1.309×10^{-8}
Garden	1.800	N	1.645×10^{-6}	1.125×10^{-6}	1.405×10^{-8}	1.251×10^{-8}
Garden	1.740	NNE	2.439×10^{-6}	1.890×10^{-6}	2.228×10^{-8}	2.069×10^{-8}
Garden	1.770	NE	2.362×10^{-6}	1.591×10^{-6}	1.927×10^{-8}	1.689×10^{-8}
Garden	1.530	S	2.313×10^{-6}	1.371×10^{-6}	1.392×10^{-8}	1.119×10^{-8}
Garden	1.840	SSW	1.100×10^{-6}	6.432×10^{-7}	6.797×10^{-9}	5.652×10^{-9}
Garden	2.150	SW	6.518×10^{-7}	4.337×10^{-7}	5.703×10^{-9}	5.140×10^{-9}
Garden	2.300	WSW	6.121×10^{-7}	4.582×10^{-7}	5.894×10^{-9}	5.355×10^{-9}
Garden	1.950	W	7.037×10^{-7}	5.128×10^{-7}	6.840×10^{-9}	6.167×10^{-9}
Garden	1.130	WNW	3.199×10^{-6}	2.394×10^{-6}	3.499×10^{-8}	3.215×10^{-8}
Garden	1.720	NW	1.575×10^{-6}	1.189×10^{-6}	1.492×10^{-8}	1.340×10^{-8}
Garden	1.690	NNW	1.824×10^{-6}	1.338×10^{-6}	1.468×10^{-8}	1.309×10^{-8}
Milk Goat	7.820	WNW	6.547×10^{-8}	5.203×10^{-8}	3.271×10^{-10}	3.099×10^{-10}
Milk Goat	3.180	NW	4.180×10^{-7}	3.257×10^{-7}	3.098×10^{-9}	2.829×10^{-9}
Meat Animal-Pig	2.600	N	7.362×10^{-7}	5.108×10^{-7}	5.393×10^{-9}	4.834×10^{-9}
Meat Animal-Beef	4.440	NNE	3.596×10^{-7}	2.851×10^{-7}	2.201×10^{-9}	2.058×10^{-9}
Meat Animal-Beef	3.490	WSW	2.587×10^{-7}	1.984×10^{-7}	2.134×10^{-9}	1.948×10^{-9}

TABLE 3.5 ANNUAL: 6/1/74 - 5/31/75; AVERAGE χ/Q (sec/m^3) AND D/Q (m^{-2}) FOR VARIOUS RECEPTOR LOCATIONS AND TURBINE BUILDING SOURCE

			χ/Q		D/Q	
Receptor Label	Downwind Distance (km)	Radial	Ground Source	Mixed Mode S	Downwind Distance (km)	Radial
Meat Animal-Pig	4.100	WNW	2.161×10^{-7}	1.683×10^{-7}	1.418×10^{-9}	1.334×10^{-9}
Meat Animal-Beef	4.750	NW	1.939×10^{-7}	1.541×10^{-7}	1.223×10^{-9}	1.128×10^{-9}
Meat Animal-Beef	4.700	NNW	2.277×10^{-7}	1.729×10^{-7}	1.173×10^{-9}	1.060×10^{-9}
Milk Cow	6.440	W	6.514×10^{-8}	5.073×10^{-8}	3.958×10^{-10}	3.653×10^{-10}
Milk Cow	4.750	NW	1.939×10^{-7}	1.541×10^{-7}	1.223×10^{-9}	1.128×10^{-9}

TABLE 3.6 GRAZING PERIOD: APRIL 15 TO OCTOBER 15*; AVERAGE χ/Q (sec/m^3) AND D/Q (m^{-2}) FOR VARIOUS RECEPTOR LOCATIONS AND TURBINE BUILDING SOURCE

			χ/Q		D/Q	
Receptor Label	Downwind Distance (km)	Radial	Ground Source	Mixed Mode Source	Downwind Distance (km)	Radial
Site Boundary (Under H_2O)	1.249	N	2.238×10^{-6}	1.578×10^{-6}	2.566×10^{-8}	2.297×10^{-8}
Site Boundary-Swan Creek	1.646	NNE	1.511×10^{-6}	1.157×10^{-6}	1.462×10^{-8}	1.355×10^{-8}
Site Boundary (Lake Shore)	0.579	NE	9.150×10^{-5}	5.696×10^{-6}	8.980×10^{-8}	7.602×10^{-8}
Site Boundary (Marsh)	1.417	S	1.849×10^{-6}	1.095×10^{-6}	9.751×10^{-9}	7.636×10^{-9}
Site Bndry-Pnt Aux Peaux	1.542	SSW	1.145×10^{-6}	7.093×10^{-7}	7.351×10^{-9}	6.160×10^{-9}
Site Bndry-Pnt Aux Peaux	1.920	SW	3.926×10^{-7}	3.079×10^{-7}	4.226×10^{-9}	3.940×10^{-9}
Site Bndry (Meadow)	1.798	WSW	4.986×10^{-7}	3.463×10^{-7}	4.749×10^{-9}	4.157×10^{-9}
Site Bndry-Toll Rd.-Entrc	1.390	W	8.383×10^{-7}	6.569×10^{-7}	9.070×10^{-9}	8.041×10^{-9}

TABLE 3.6 GRAZING PERIOD: APRIL 15 TO OCTOBER 15*; AVERAGE χ/Q (sec/m^3) AND D/Q (m^{-2}) FOR VARIOUS RECEPTOR LOCATIONS AND TURBINE BUILDING SOURCE

			χ/Q		D/Q	
Receptor Label	Downwind Distance (km)	Radial	Ground Source	Mixed Mode Source	Downwind Distance (km)	Radial
Site Bndry-Toll Rd.-Marsh	1.082	WNW	2.049 x 10^{-6}	1.498 x 10^{-6}	2.375 x 10^{-8}	2.186 x 10^{-8}
Site Bndry-Toll Rd.-Meadow	0.915	NW	3.202 x 10^{-6}	2.381 x 10^{-6}	3.965 x 10^{-8}	3.544 x 10^{-8}
Site Bndry-Toll Rd.-Meadow	0.990	NNW	3.025 x 10^{-6}	2.472 x 10^{-6}	3.271 x 10^{-8}	3.002 x 10^{-8}
Residence	1.720	N	1.048 x 10^{-6}	7.481 x 10^{-7}	1.078 x 10^{-8}	9.729 x 10^{-9}
Residence	1.740	NNE	1.319 x 10^{-6}	1.010 x 10^{-6}	1.248 x 10^{-8}	1.157 x 10^{-8}
Residence	1.770	NE	1.173 x 10^{-6}	7.536 x 10^{-7}	8.831 x 10^{-9}	7.557 x 10^{-9}
Residence	1.530	S	1.507 x 10^{-6}	8.948 x 10^{-7}	7.730 x 10^{-9}	6.054 x 10^{-9}
Residence	1.840	SSW	7.446 x 10^{-7}	4.623 x 10^{-7}	4.439 x 10^{-9}	3.734 x 10^{-9}
Residence	2.150	SW	3.036 x 10^{-7}	2.383 x 10^{-7}	3.133 x 10^{-9}	2.924 x 10^{-9}
Residence	2.300	WSW	2.845 x 10^{-7}	2.000 x 10^{-7}	2.474 x 10^{-9}	2.179 x 10^{-9}
Residence	1.950	W	3.549 x 10^{-7}	2.828 x 10^{-7}	3.423 x 10^{-9}	3.608 x 10^{-9}
Residence	1.130	WNW	1.929 x 10^{-6}	1.412 x 10^{-6}	2.202 x 10^{-8}	2.029 x 10^{-8}
Residence	1.720	NW	8.645 x 10^{-7}	6.589 x 10^{-7}	9.640 x 10^{-9}	8.792 x 10^{-9}
Residence	1.690	NNW	9.921 x 10^{-7}	8.202 x 10_{-7}	9.640 x 10^{-9}	8.938 x 10^{-9}
Garden	1.800	N	9.387 x 10^{-7}	6.710 x 10^{-7}	9.501 x 10^{-9}	8.585 x 10^{-9}
Garden	1.740	NNE	1.319 x 10^{-6}	1.010 x 10^{-6}	1.248 x 10^{-8}	1.157 x 10^{-8}
Garden	1.770	NE	1.173 x 10^{-6}	7.536 x 10^{-7}	8.831 x 10^{-9}	7.557 x 10^{-9}
Garden	1.530	S	1.507 x 10^{-6}	8.948 x 10^{-7}	7.730 x 10^{-9}	6.054 x 10^{-9}
Garden	1.840	SSW	7.446 x 10^{-7}	4.623 x 10^{-7}	4.439 x 10^{-9}	3.734 x 10^{-9}
Garden	2.150	SW	3.036 x 10^{-7}	2.383 x 10^{-7}	3.133 x 10^{-9}	2.924 x 10^{-9}
Garden	2.300	WSW	2.845 x 10^{-7}	2.000 x 10^{-7}	2.474 x 10^{-9}	2.179 x 10^{-9}
Garden	1.950	W	3.549 x 10^{-7}	2.828 x 10^{-7}	3.423 x 10^{-9}	3.608 x 10^{-9}
Garden	1.130	WNW	1.929 x 10^{-6}	1.412 x 10^{-6}	2.202 x 10^{-8}	2.029 x 10^{-8}

TABLE 3.6 GRAZING PERIOD: APRIL 15 TO OCTOBER 15*; AVERAGE χ/Q (sec/m^3) AND D/Q (m^{-2}) FOR VARIOUS RECEPTOR LOCATIONS AND TURBINE BUILDING SOURCE

			χ/Q		D/Q	
Receptor Label	Downwind Distance (km)	Radial	Ground Source	Mixed Mode Source	Downwind Distance (km)	Radial
Garden	1.720	NW	8.645×10^{-7}	6.589×10^{-7}	9.640×10^{-9}	8.792×10^{-9}
Garden	1.690	NNW	9.921×10^{-7}	8.202×10^{-7}	9.640×10^{-9}	8.938×10^{-9}
Milk Goat	7.820	WNW	3.858×10^{-8}	3.056×10^{-8}	2.059×10^{-10}	1.959×10^{-10}
Milk Goat	3.180	NW	2.260×10^{-7}	1.759×10^{-7}	2.003×10^{-9}	1.853×10^{-9}
Meat Animal-Pig	2.600	N	4.177×10^{-7}	3.020×10^{-7}	3.647×10^{-9}	3.320×10^{-9}
Meat Animal-Beef	4.440	NNE	1.945×10^{-7}	1.514×10^{-7}	1.233×10^{-9}	1.152×10^{-9}
Meat Animal-Beef	3.490	WSW	1.211×10^{-7}	8.726×10^{-8}	8.960×10^{-10}	7.945×10^{-10}
Meat Animal-Pig	4.100	WNW	1.283×10^{-7}	9.891×10^{-8}	8.931×10^{-10}	8.424×10^{-10}
Meat Animal-Beef	4.750	NW	1.040×10^{-7}	8.207×10^{-8}	7.911×10^{-10}	7.385×10^{-10}
Meat Animal-Beef	4.700	NNW	1.204×10^{-7}	1.020×10^{-7}	7.711×10^{-10}	7.244×10^{-10}
Milk Cow	6.440	W	3.354×10^{-8}	2.822×10^{-8}	1.971×10^{-10}	1.818×10^{-10}
Milk Cow	4.750	NW	1.040×10^{-7}	8.207×10^{-8}	7.911×10^{-10}	7.385×10^{-10}

* see section 2 of text

TABLE 3.7 ANNUAL: 6/1/74 - 5/31/75; AVERAGE χ/Q (sec/m^3) AND D/Q (m^{-2}) FOR VARIOUS RECEPTOR LOCATIONS AND RADWASTE BUILDING VENT SOURCE

			χ/Q		D/Q	
Receptor Label	Downwind Distance (km)	Radial	Ground Source	Mixed Mode Source	Downwind Distance (km)	Radial
Site Boundary (Under H_2O)	1.249	N	3.891×10^{-6}	1.370×10^{-6}	3.794×10^{-8}	2.139×10^{-8}
Site Boundary-Swan Creek	1.646	NNE	2.795×10^{-6}	1.311×10^{-6}	2.610×10^{-8}	1.656×10^{-8}

TABLE 3.7 ANNUAL: 6/1/74 - 5/31/75; AVERAGE χ/Q (sec/m^3) AND D/Q (m^{-2}) FOR VARIOUS RECEPTOR LOCATIONS AND RADWASTE BUILDING VENT SOURCE

			χ/Q		D/Q	
Receptor Label	Downwind Distance (km)	Radial	Ground Source	Mixed Mode Source	Downwind Distance (km)	Radial
Site Boundary (Lake Shore)	0.579	NE	1.829×10^{-5}	5.611×10^{-6}	1.962×10^{-7}	1.042×10^{-7}
Site Boundary (Marsh)	1.417	S	2.839×10^{-6}	7.195×10^{-7}	1.758×10^{-8}	7.970×10^{-9}
Site Boundary - Pnt Aux Peaux	1.542	SSW	1.698×10^{-6}	4.919×10^{-7}	1.126×10^{-8}	5.936×10^{-9}
Site Boundary - Pnt Aux Peaux	1.920	SW	8.426×10^{-7}	3.419×10^{-7}	7.696×10^{-9}	5.150×10^{-9}
Site Boundary (Meadow)	1.798	WSW	1.077×10^{-6}	4.714×10^{-7}	1.131×10^{-8}	7.611×10^{-9}
Site Boundary - Toll Rd.-Entrc	1.390	W	1.666×10^{-6}	7.213×10^{-7}	1.814×10^{-8}	1.210×10^{-8}
Site Boundary - Toll Rd.-Marsh	1.082	WNW	3.398×10^{-6}	1.440×10^{-6}	3.773×10^{-8}	2.383×10^{-8}
Site Boundary - Toll Rd.- Meadow	0.915	NW	5.745×10^{-6}	1.772×10^{-6}	6.133×10^{-8}	3.238×10^{-8}
Site Boundary - Toll Rd.- Meadow	0.990	NNW	5.462×10^{-6}	1.742×10^{-6}	4.979×10^{-8}	2.579×10^{-8}
Residence	1.720	N	1.835×10^{-6}	7.029×10^{-7}	1.594×10^{-8}	9.399×10^{-9}
Residence	1.740	NNE	2.439×10^{-6}	1.155×10^{-6}	2.228×10^{-8}	1.421×10^{-8}
Residence	1.770	NE	2.362×10^{-6}	9.557×10^{-7}	1.927×10^{-8}	1.148×10^{-8}
Residence	1.530	S	2.313×10^{-6}	5.978×10^{-7}	1.392×10^{-8}	6.397×10^{-9}
Residence	1.840	SSW	1.100×10^{-6}	3.331×10^{-7}	6.797×10^{-9}	3.696×10^{-9}
Residence	2.150	SW	6.518×10^{-7}	2.720×10^{-7}	5.703×10^{-9}	3.868×10^{-9}
Residence	2.300	WSW	6.121×10^{-7}	2.862×10^{-7}	5.894×10^{-9}	4.087×10^{-9}
Residence	1.950	W	7.037×10^{-7}	3.278×10^{-7}	6.840×10^{-9}	4.828×10^{-9}

TABLE 3.7 ANNUAL: 6/1/74 - 5/31/75; AVERAGE χ/Q (sec/m^3) AND D/Q (m^{-2}) FOR VARIOUS RECEPTOR LOCATIONS AND RADWASTE BUILDING VENT SOURCE

			χ/Q		D/Q	
Receptor Label	Downwind Distance (km)	Radial	Ground Source	Mixed Mode Source	Downwind Distance (km)	Radial
Residence	1.130	WNW	3.199×10^{-6}	1.368×10^{-6}	3.499×10^{-8}	2.222×10^{-8}
Residence	1.720	NW	1.575×10^{-6}	6.478×10^{-7}	1.492×10^{-8}	9.046×10^{-9}
Residence	1.690	NNW	1.824×10^{-6}	7.069 x 10+	1.468×10^{-8}	8.188×10^{-9}
Garden	1.800	N	1.645×10^{-6}	6.371×10^{-7}	1.405×10^{-8}	8.339×10^{-9}
Garden	1.740	NNE	2.439×10^{-6}	1.155×10^{-6}	2.228×10^{-8}	1.421×10^{-8}
Garden	1.770	NE	2.362×10^{-6}	9.557×10^{-7}	1.927×10^{-8}	1.148×10^{-8}
Garden	1.530	S	2.313×10^{-6}	5.978×10^{-7}	1.392×10^{-8}	6.397×10^{-9}
Garden	1.840	SSW	1.100×10^{-6}	3.331×10^{-7}	6.797×10^{-9}	3.696×10^{-9}
Garden	2.150	SW	6.518×10^{-7}	2.720×10^{-7}	5.703×10^{-9}	3.868×10^{-9}
Garden	2.300	WSW	6.121×10^{-7}	2.862×10^{-7}	5.894×10^{-9}	4.087×10^{-9}
Garden	1.950	W	7.037×10^{-7}	3.278×10^{-7}	6.840×10^{-9}	4.828×10^{-9}
Garden	1.130	WNW	3.199×10^{-6}	1.368×10^{-6}	3.499×10^{-8}	2.222×10^{-8}
Garden	1.720	NW	1.575×10^{-6}	6.478×10^{-7}	1.492×10^{-8}	9.046×10^{-9}
Garden	1.690	NNW	1.824×10^{-6}	7.069×10^{-7}	1.468×10^{-8}	8.188×10^{-9}
Milk Goat	7.820	WNW	6.547×10^{-8}	3.783×10^{-8}	3.271×10^{-10}	2.387×10^{-10}
Milk Goat	3.180	NW	4.180×10^{-7}	1.988×10^{-7}	3.098×10^{-9}	1.985×10^{-9}
Meat Animal-Pig	2.600	N	7.362×10^{-7}	3.108×10^{-7}	5.393×10^{-9}	3.281×10^{-9}
Meat Animal-Beef	4.440	NNE	3.596×10^{-7}	1.976×10^{-7}	2.201×10^{-9}	1.445×10^{-9}
Meat Animal-Beef	3.490	WSW	2.587×10^{-7}	1.332×10^{-7}	2.134×10^{-9}	1.506×10^{-9}
Meat Animal-Pig	4.100	WNW	2.161×10^{-7}	1.161×10^{-7}	1.418×10^{-9}	1.004×10^{-9}
Meat Animal-Beef	4.750	NW	1.939×10^{-7}	9.904×10^{-8}	1.223×10^{-9}	7.988×10^{-10}

TABLE 3.7 ANNUAL: 6/1/74 - 5/31/75; AVERAGE χ/Q (sec/m^3) AND D/Q (m^{-2}) FOR VARIOUS RECEPTOR LOCATIONS AND RADWASTE BUILDING VENT SOURCE

			χ/Q		D/Q	
Receptor Label	Downwind Distance (km)	Radial	Ground Source	Mixed Mode Source	Downwind Distance (km)	Radial
Meat Animal-Beef	4.700	NNW	2.277×10^{-7}	1.081×10^{-7}	1.173×10^{-9}	6.907×10^{-10}
Milk Cow	6.440	W	6.514×10^{-8}	3.691×10^{-8}	3.958×10^{-10}	2.937×10^{-10}
Milk Cow	4.750	NW	1.939×10^{-7}	9.904×10^{-8}	1.223×10^{-9}	7.988×10^{-10}

TABLE 3.8 GRAZING PERIOD: APRIL 15 TO OCTOBER 15*; AVERAGE χ/Q (sec/m^3) AND D/Q (m^{-2}) FOR VARIOUS RECEPTOR LOCATIONS AND RADWASTE BUILDING VENT SOURCE

			χ/Q		D/Q	
Receptor Label	Downwind Distance (km)	Radial	Ground Source	Mixed Mode Source	Downwind Distance (km)	Radial
Site Boundary (Under H_2O)	1.249	N	2.238×10^{-6}	8.485×10^{-7}	2.566×10^{-8}	1.527×10^{-8}
Site Boundary-Swan Creek	1.646	NNE	1.511×10^{-6}	6.896×10^{-7}	1.462×10^{-8}	9.440×10^{-9}
Site Boundary (Lake Shore)	0.579	NE	9.150×10^{-6}	2.607×10^{-6}	8.989×10^{-8}	4.582×10^{-8}
Site Boundary (Marsh)	1.417	S	1.849×10^{-6}	4.166×10^{-7}	9.756×10^{-9}	3.859×10^{-9}
Site Bndry-Pnt Aux Peaux	1.542	SSW	1.145×10^{-6}	3.274×10^{-7}	7.353×10^{-9}	3.631×10^{-9}
Site Bndry-Pnt Aux Peaux	1.920	SW	3.926×10^{-7}	1.756×10^{-7}	4.227×10^{-9}	2.754×10^{-9}
Site Bndry (Meadow)	1.798	WSW	4.986×10^{-7}	1.768×10^{-7}	4.749×10^{-9}	2.746×10^{-9}
Site Bndry-Toll Rd.-Entrc	1.390	W	8.382×10^{-7}	3.815×10^{-7}	9.076×10^{-9}	5.659×10^{-9}
Site Bndry-Toll Rd.-Marsh	1.082	WNW	2.049×10^{-6}	8.548×10^{-7}	2.375×10^{-8}	1.491×10^{-8}

TABLE 3.8 GRAZING PERIOD: APRIL 15 TO OCTOBER 15*; AVERAGE χ/Q (sec/m^3) AND D/Q (m^{-2}) FOR VARIOUS RECEPTOR LOCATIONS AND RADWASTE BUILDING VENT SOURCE

			χ/Q		D/Q	
Receptor Label	Downwind Distance (km)	Radial	Ground Source	Mixed Mode Source	Downwind Distance (km)	Radial
Site Bndry-Toll Rd.-Meadow	0.915	NW	3.202×10^{-6}	1.031×10^{-6}	3.965×10^{-8}	2.181×10^{-8}
Site Bndry-Toll Rd.-Meadow	0.990	NNW	3.025×10^{-6}	1.084×10^{-6}	3.271×10^{-8}	1.745×10^{-8}
Residence	1.720	N	1.048×10^{-6}	4.313×10^{-7}	1.078×10^{-8}	6.692×10^{-9}
Residence	1.740	NNE	1.319×10^{-6}	6.072×10^{-7}	1.248×10^{-8}	8.105×10^{-9}
Residence	1.770	NE	1.173×10^{-6}	4.347×10^{-7}	8.826×10^{-9}	5.081×10^{-9}
Residence	1.530	S	1.507×10^{-6}	3.446×10^{-7}	7.726×10^{-9}	3.089×10^{-9}
Residence	1.840	SSW	7.446×10^{-7}	2.204×10^{-7}	4.439×10^{-9}	2.248×10^{-9}
Residence	2.150	SW	3.036×10^{-7}	1.393×10^{-7}	3.132×10^{-9}	2.063×10^{-9}
Residence	2.300	WSW	2.845×10^{-7}	1.094×10^{-7}	2.474×10^{-9}	1.482×10^{-9}
Residence	1.950	W	3.549×10^{-7}	1.742×10^{-7}	3.423×10^{-9}	2.269×10^{-9}
Residence	1.130	WNW	1.929×10^{-6}	8.127×10^{-7}	2.203×10^{-8}	1.390×10^{-8}
Residence	1.720	NW	8.644×10^{-7}	3.767×10^{-7}	9.645×10^{-9}	6.118×10^{-9}
Residence	1.690	NNW	9.920×10^{-7}	4.388×10^{-7}	9.645×10^{-9}	5.613×10^{-9}
Garden	1.800	N	9.386×10^{-7}	3.905×10^{-7}	9.500×10^{-9}	5.935×10^{-9}
Garden	1.740	NNE	1.319×10^{-6}	6.072×10^{-7}	1.248×10^{-8}	8.105×10^{-9}
Garden	1.770	NE	1.173×10^{-6}	4.347×10^{-7}	8.826×10^{-9}	5.081×10^{-9}
Garden	1.530	S	1.507×10^{-6}	3.446×10^{-7}	7.726×10^{-9}	3.089×10^{-9}
Garden	1.840	SSW	7.446×10^{-7}	2.204×10^{-7}	4.439×10^{-9}	2.248×10^{-9}
Garden	2.150	SW	3.036×10^{-7}	1.393×10^{-7}	3.132×10^{-9}	2.063×10^{-9}
Garden	2.300	WSW	2.845×10^{-7}	1.094×10^{-7}	2.474×10^{-9}	1.482×10^{-9}
Garden	1.950	W	3.549×10^{-7}	1.742×10^{-7}	3.423×10^{-9}	2.269×10^{-9}
Garden	1.130	WNW	1.929×10^{-6}	8.127×10^{-7}	2.203×10^{-8}	1.390×10^{-8}

TABLE 3.8 GRAZING PERIOD: APRIL 15 TO OCTOBER 15*; AVERAGE χ/Q (sec/m^3) AND D/Q (m^{-2}) FOR VARIOUS RECEPTOR LOCATIONS AND RADWASTE BUILDING VENT SOURCE

			χ/Q		D/Q	
Receptor Label	Downwind Distance (km)	Radial	Ground Source	Mixed Mode Source	Downwind Distance (km)	Radial
Garden	1.720	NW	8.644×10^{-7}	3.767×10^{-7}	9.645×10^{-9}	6.118×10^{-9}
Garden	1.690	NNW	9.920×10^{-7}	4.388×10^{-7}	9.645×10^{-9}	5.613×10^{-9}
Milk Goat	7.820	WNW	3.858×10^{-8}	2.299×10^{-8}	2.059×10^{-10}	1.505×10^{-8}
Milk Goat	3.180	NW	2.260×10^{-7}	1.146×10^{-7}	2.003×10^{-9}	1.343×10^{-9}
Meat Animal-Pig	2.600	N	4.177×10^{-7}	1.886×10^{-7}	3.647×10^{-9}	2.331×10^{-9}
Meat Animal-Beef	4.440	NNE	1.945×10^{-7}	1.032×10^{-7}	1.233×10^{-9}	8.259×10^{-10}
Meat Animal-Beef	3.490	WSW	1.211×10^{-7}	5.260×10^{-8}	8.960×10^{-10}	5.477×10^{-10}
Meat Animal-Pig	4.100	WNW	1.283×10^{-7}	7.041×10^{-8}	8.926×10^{-10}	6.295×10^{-10}
Meat Animal-Beef	4.750	NW	1.040×10^{-7}	5.665×10^{-8}	7.908×10^{-10}	5.403×10^{-10}
Meat Animal-Beef	4.700	NNW	1.204×10^{-7}	6.515×10^{-8}	7.706×10^{-10}	4.777×10^{-10}
Milk Cow	6.440	W	3.354×10^{-8}	1.988×10^{-8}	1.981×10^{-10}	1.388×10^{-10}
Milk Cow	4.750	NW	1.040×10^{-7}	5.665×10^{-8}	7.908×10^{-10}	5.403×10^{-10}

* see section 2 of text

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APPENDIX A

Strict Ground Level Joint Frequency Distributions Between Wind Speed, Wind Direction, and Stability for Fermi 2

a) Wind speed at 10 meters

b) Wind direction at 10 meters

c) Delta temperature between 10 and 60 meters

APPENDIX A

Part A-1: Joint Frequency Distribution of Annual Data Base
6/1/74 - 5/31/75

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY A

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0001	.0000	.0004	.0005	.0013	.0000	.0006	.0000	.0000	.0000	.0000	.0029	9.60
NNE	.0000	.0000	.0003	.0004	.0003	.0003	.0000	.0001	.0000	.0000	.0000	.0000	.0013	7.56
NE	.0000	.0000	.0001	.0006	.0015	.0015	.0004	.0003	.0001	.0000	.0000	.0000	.0045	9.19
ENE	.0000	.0000	.0003	.0021	.0020	.0020	.0003	.0000	.0000	.0000	.0000	.0000	.0066	7.91
E	.0000	.0001	.0013	.0009	.0008	.0006	.0006	.0000	.0001	.0000	.0000	.0000	.0044	7.14
ESE	.0000	.0001	.0006	.0005	.0016	.0029	.0011	.0000	.0000	.0000	.0000	.0000	.0069	8.79
SE	.0000	.0001	.0003	.0026	.0060	.0025	.0004	.0000	.0000	.0000	.0000	.0000	.0119	7.60
SSE	.0000	.0000	.0003	.0016	.0035	.0020	.0003	.0001	.0000	.0000	.0000	.0000	.0078	7.92
S	.0000	.0001	.0005	.0014	.0020	.0044	.0019	.0005	.0000	.0000	.0000	.0000	.0108	9.41
SSW	.0000	.0000	.0004	.0016	.0014	.0025	.0016	.0006	.0000	.0000	.0000	.0000	.0081	9.42
SW	.0000	.0000	.0001	.0004	.0015	.0014	.0021	.0011	.0000	.0000	.0000	.0000	.0066	10.86
WSW	.0000	.0000	.0003	.0008	.0008	.0014	.0021	.0008	.0000	.0000	.0000	.0000	.0060	10.75
W	.0000	.0000	.0001	.0010	.0013	.0013	.0006	.0003	.0000	.0000	.0000	.0000	.0045	8.97
WNW	.0000	.0000	.0003	.0000	.0008	.0008	.0006	.0003	.0000	.0000	.0000	.0000	.0026	9.99
NW	.0000	.0004	.0006	.0003	.0014	.0008	.0008	.0006	.0001	.0000	.0000	.0000	.0049	9.23
NNW	.0000	.0000	.0001	.0004	.0004	.0004	.0003	.0004	.0000	.0000	.0000	.0000	.0019	10.11
TOTAL	.0000	.0010	.0054	.0149	.0256	.0258	.0130	.0056	.0004	.0000	.0000	.0000	.0917	8.95

PERIOD OF RECORD: 6/1/74 – 5/31/75

NUMBER OF CALM HOURS - 0

NUMBER OF MISSING HOURS - 777

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY B

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0000	.0001	.0003	.0001	.0003	.0000	.0000	.0000	.0000	.0008	12.08
NNE	.0000	.0000	.0001	.0000	.0003	.0006	.0000	.0000	.0001	.0000	.0000	.0000	.0011	9.59
NE	.0000	.0000	.0000	.0003	.0003	.0006	.0003	.0000	.0000	.0000	.0000	.0000	.0014	9.15
ENE	.0000	.0000	.0003	.0004	.0003	.0003	.0000	.0001	.0001	.0000	.0000	.0000	.0014	8.73
E	.0000	.0000	.0001	.0000	.0005	.0010	.0003	.0005	.0000	.0000	.0000	.0000	.0024	11.33
ESE	.0000	.0000	.0000	.0001	.0008	.0004	.0001	.0001	.0000	.0000	.0000	.0000	.0015	9.38
SE	.0000	.0000	.0001	.0003	.0003	.0006	.0000	.0000	.0000	.0000	.0000	.0000	.0113	7.73
SSE	.0000	.0000	.0001	.0001	.0004	.0003	.0001	.0000	.0000	.0000	.0000	.0000	.0010	7.53
S	.0000	.0000	.0000	.0008	.0006	.0003	.0004	.0000	.0000	.0000	.0000	.0000	.0020	8.15
SSW	.0000	.0000	.0001	.0003	.0004	.0005	.0003	.0001	.0000	.0000	.0000	.0000	.0016	9.11
SW	.0000	.0000	.0001	.0000	.0001	.0001	.0003	.0000	.0000	.0000	.0000	.0000	.0006	9.26
WSW	.0000	.0000	.0000	.0001	.0001	.0005	.0003	.0004	.0000	.0000	.0000	.0000	.0014	11.71
W	.0000	.0000	.0001	.0000	.0001	.0001	.0001	.0001	.0000	.0000	.0000	.0000	.0006	11.10
WNW	.0000	.0000	.0003	.0000	.0000	.0003	.0003	.0001	.0001	.0000	.0000	.0000	.0010	10.60
NW	.0000	.0000	.0001	.0000	.0003	.0005	.0000	.0000	.0000	.0000	.0000	.0000	.0009	8.69
NNW	.0000	.0000	.0000	.0000	.0003	.0003	.0005	.0008	.0001	.0000	.0000	.0000	.0019	13.56
TOTAL	.0000	.0000	.0015	.0023	.0046	.0065	.0029	.0025	.0005	.0000	.0000	.0000	.0208	9.94

PERIOD OF RECORD: 6/1/74 – 5/31/75

NUMBER OF CALM HOURS - 0

NUMBER OF MISSING HOURS - 777

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY C

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0001	.0001	.0001	.0003	.0003	.0003	.0001	.0000	.0000	.0000	.0010	10.52
NNE	.0000	.0000	.0000	.0001	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0004	7.09
NE	.0000	.0000	.0000	.0003	.0001	.0008	.0004	.0000	.0000	.0000	.0000	.0000	.0015	9.50
ENE	.0000	.0000	.0000	.0000	.0003	.0008	.0000	.0000	.0000	.0000	.0000	.0000	.0010	9.21
E	.0000	.0000	.0003	.0001	.0008	.0000	.0000	.0005	.0000	.0000	.0000	.0000	.0016	9.01
ESE	.0000	.0000	.0001	.0003	.0000	.0001	.0001	.0001	.0000	.0000	.0000	.0000	.0014	6.75
SE	.0000	.0001	.0000	.0005	.0005	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0013	7.12
SSE	.0000	.0000	.0000	.0004	.0010	.0005	.0000	.0000	.0000	.0000	.0000	.0000	.0014	7.59
S	.0000	.0000	.0003	.0005	.0003	.0006	.0001	.0000	.0000	.0000	.0000	.0000	.0016	10.99
SSW	.0000	.0000	.0000	.0000	.0005	.0008	.0009	.0001	.0000	.0000	.0000	.0000	.0021	10.39
SW	.0000	.0000	.0000	.0005	.0003	.0006	.0008	.0005	.0003	.0000	.0000	.0000	.0030	11.39
WSW	.0000	.0000	.0000	.0001	.0000	.0005	.0009	.0001	.0000	.0000	.0000	.0000	.0018	11.92
W	.0000	.0000	.0003	.0001	.0005	.0004	.0001	.0000	.0000	.0000	.0000	.0000	.0015	7.54
WNW	.0000	.0000	.0000	.0001	.0004	.0009	.0003	.0005	.0003	.0000	.0000	.0000	.0019	12.70
NW	.0000	.0000	.0000	.0000	.0003	.0004	.0000	.0001	.0003	.0001	.0000	.0000	.0016	13.04
NNW	.0000	.0000	.0000	.0000	.0001	.0074	.0001	.0004	.0000	.0000	.0000	.0000	.0010	12.03
TOTAL	.0000	.0010	.0010	.0031	.0051	.0065	.0039	.0024	.0009	.0001	.0000	.0000	.0240	10.08

PERIOD OF RECORD: 6/1/74 – 5/31/75

NUMBER OF CALM HOURS - 0

NUMBER OF MISSING HOURS - 777

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY D

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0003	.0009	.0013	.0029	.0029	.0018	.0005	.0000	.0000	.0000	.0000	.0104	8.70
NNE	.0000	.0001	.0004	.0023	.0015	.0028	.0028	.0013	.0003	.0000	.0000	.0000	.0113	10.05
NE	.0000	.0003	.0006	.0026	.0055	.0063	.0025	.0011	.0001	.0000	.0000	.0000	.0190	9.17
ENE	.0000	.0001	.0006	.0025	.0074	.0076	.0034	.0040	.0009	.0001	.0000	.0000	.0267	10.41
E	.0000	.0000	.0015	.0015	.0034	.0035	.0034	.0029	.0009	.0000	.0000	.0000	.0170	10.77
ESE	.0000	.0005	.0010	.0015	.0038	.0056	.0028	.0013	.0006	.0000	.0000	.0000	.0170	9.66
SE	.0000	.0004	.0018	.0038	.0076	.0043	.0020	.0008	.0000	.0000	.0000	.0000	.0205	8.05
SSE	.0000	.0001	.0006	.0024	.0056	.0029	.0004	.0004	.0001	.0000	.0000	.0000	.0125	8.10
S	.0000	.0001	.0015	.0025	.0025	.0065	.0024	.0000	.0000	.0000	.0000	.0000	.0155	8.68
SSW	.0000	.0003	.0005	.0020	.0028	.0074	.0050	.0024	.0010	.0000	.0000	.0000	.0213	10.87
SW	.0000	.0004	.0009	.0016	.0036	.0049	.0040	.0024	.0015	.0000	.0000	.0000	.0193	10.95
WSW	.0000	.0001	.0010	.0020	.0048	.0063	.0050	.0045	.0018	.0001	.0000	.0000	.0256	11.33
W	.0000	.0001	.0009	.0028	.0065	.0069	.0040	.0033	.0006	.0003	.0000	.0000	.0253	10.32
WNW	.0000	.0006	.0013	.0026	.0031	.0063	.0055	.0028	.0009	.0001	.0000	.0000	.0232	10.65
NW	.0000	.0005	.0013	.0024	.0024	.0083	.0051	.0023	.0009	.0000	.0000	.0000	.0230	10.37
NNW	.0000	.0004	.0009	.0013	.0021	.0046	.0040	.0019	.0000	.0000	.0000	.0000	.0152	10.20
TOTAL	.0000	.0043	.0155	.0349	.0655	.0869	.0540	.0316	.0095	.0006	.0000	.0000	.3029	10.04

PERIOD OF RECORD: 6/1/74 – 5/31/75

NUMBER OF CALM HOURS - 0

NUMBER OF MISSING HOURS - 777

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY E

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0001	.0025	.0026	.0041	.0031	.0021	.0005	.0000	.0000	.0000	.0000	.0152	7.97
NNE	.0000	.0008	.0014	.0030	.0031	.0028	.0029	.0010	.0000	.0000	.0000	.0000	.0145	8.27
NE	.0000	.0003	.0020	.0021	.0034	.0041	.0029	.0009	.0006	.0001	.0000	.0000	.0164	9.32
ENE	.0000	.0008	.0020	.0039	.0036	.0029	.0014	.0015	.0008	.0000	.0000	.0000	.0168	8.62
E	.0000	.0003	.0014	.0021	.0020	.0029	.0010	.0009	.0001	.0000	.0000	.0000	.0106	8.51
ESE	.0000	.0004	.0005	.0024	.0039	.0045	.0020	.0016	.0008	.0000	.0000	.0000	.0160	9.88
SE	.0000	.0003	.0020	.0034	.0069	.0056	.0019	.0010	.0001	.0000	.0000	.0000	.0212	8.39
SSE	.0000	.0003	.0024	.0041	.0073	.0066	.0043	.0005	.0000	.0000	.0000	.0000	.0254	8.41
S	.0000	.0008	.0021	.0048	.0083	.0078	.0034	.0011	.0005	.0000	.0000	.0000	.0287	8.62
SSW	.0000	.0008	.0021	.0048	.0111	.0155	.0108	.0025	.0006	.0000	.0000	.0000	.0482	9.70
SW	.0000	.0013	.0038	.0064	.0090	.0138	.0081	.0031	.0008	.0014	.0000	.0000	.0476	9.74
WSW	.0000	.0006	.0043	.0080	.0101	.0132	.0075	.0039	.0004	.0000	.0000	.0000	.0480	9.12
W	.0000	.0011	.0033	.0069	.0064	.0101	.0021	.0004	.0003	.0000	.0000	.0000	.0306	7.79
WNW	.0000	.0013	.0043	.0050	.0045	.0064	.0024	.0026	.0008	.0000	.0000	.0000	.0272	8.57
NW	.0000	.0005	.0033	.0051	.0050	.0044	.0024	.0011	.0000	.0000	.0000	.0000	.0218	7.75
NNW	.0000	.0010	.0028	.0040	.0033	.0028	.0015	.0010	.0000	.0000	.0000	.0000	.0163	7.45
TOTAL	.0001	.0103	.0400	.0686	.0921	.1065	.0562	.0237	.0056	.0015	.0000	.0000	.4046	8.79

PERIOD OF RECORD: 6/1/74 – 5/31/75

NUMBER OF CALM HOURS - 1

NUMBER OF MISSING HOURS - 777

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY F

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0004	.0019	.0038	.0006	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0069	5.00
NNE	.0000	.0004	.0013	.0016	.0005	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0039	5.07
NE	.0000	.0003	.0001	.0005	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0010	4.52
ENE	.0000	.0001	.0004	.0004	.0006	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0015	5.59
E	.0000	.0003	.0003	.0004	.0006	.0013	.0005	.0003	.0000	.0000	.0000	.0000	.0035	9.01
ESE	.0000	.0000	.0005	.0008	.0014	.0034	.0011	.0000	.0001	.0000	.0000	.0000	.0073	9.16
SE	.0000	.0000	.0004	.0015	.0005	.0015	.0006	.0001	.0000	.0000	.0000	.0000	.0046	8.32
SSE	.0000	.0005	.0008	.0016	.0019	.0018	.0001	.0006	.0001	.0001	.0000	.0000	.0075	8.22
S	.0000	.0005	.0008	.0015	.0013	.0014	.0014	.0005	.0003	.0000	.0000	.0000	.0075	8.69
SSW	.0000	.0003	.0014	.0023	.0024	.0040	.0023	.0010	.0005	.0000	.0000	.0000	.0140	9.34
SW	.0000	.0001	.0029	.0021	.0009	.0018	.0004	.0008	.0003	.0000	.0000	.0000	.0089	7.09
WSW	.0000	.0006	.0036	.0028	.0003	.0003	.0001	.0001	.0000	.0000	.0000	.0000	.0078	4.83
W	.0000	.0003	.0034	.0028	.0005	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0071	4.85
WNW	.0000	.0003	.0046	.0021	.0003	.0001	.0001	.0000	.0003	.0000	.0000	.0000	.0075	4.45
NW	.0000	.0009	.0026	.0030	.0008	.0004	.0001	.0000	.0003	.0000	.0000	.0000	.0078	4.98
NNW	.0000	.0005	.0029	.0011	.0008	.0003	.0005	.0001	.0000	.0000	.0000	.0000	.0061	5.32
TOTAL	.0001	.0053	.0277	.0282	.0133	.0167	.0073	.0035	.0010	.0001	.0000	.0000	.1031	6.82

PERIOD OF RECORD: 6/1/74 – 5/31/75

NUMBER OF CALM HOURS - 1

NUMBER OF MISSING HOURS - 777

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY G

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0001	.0031	.0015	.0005	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0053	4.54
NNE	.0000	.0003	.0009	.0010	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0024	4.90
NE	.0000	.0003	.0003	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0006	3.47
ENE	.0000	.0000	.0000	.0003	.0003	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0006	7.11
E	.0000	.0000	.0001	.0004	.0005	.0001	.0003	.0000	.0000	.0000	.0000	.0000	.0014	7.80
ESE	.0000	.0003	.0003	.0003	.0009	.0011	.0000	.0000	.0000	.0000	.0000	.0000	.0028	7.47
SE	.0000	.0001	.0006	.0009	.0010	.0005	.0000	.0000	.0001	.0000	.0000	.0000	.0033	6.88
SSE	.0000	.0001	.0008	.0010	.0009	.0011	.0004	.0000	.0000	.0000	.0000	.0000	.0043	7.22
S	.0000	.0003	.0006	.0003	.0003	.0001	.0003	.0000	.0000	.0000	.0000	.0000	.0018	6.04
SSW	.0000	.0004	.0003	.0004	.0004	.0010	.0006	.0001	.0000	.0000	.0000	.0000	.0031	8.67
SW	.0000	.0000	.0018	.0004	.0003	.0004	.0004	.0000	.0000	.0000	.0000	.0000	.0031	6.19
WSW	.0000	.0001	.0019	.0011	.0003	.0004	.0000	.0000	.0000	.0000	.0000	.0000	.0038	5.06
W	.0000	.0000	.0025	.0014	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0039	4.14
WNW	.0000	.0011	.0035	.0013	.0001	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0063	3.87
NW	.0000	.0005	.0029	.0018	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0051	4.01
NNW	.0000	.0005	.0034	.0013	.0001	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0054	4.21
TOTAL	.0000	.0040	.0228	.0130	.0056	.0051	.0020	.0003	.0001	.0000	.0000	.0000	.0530	5.41

PERIOD OF RECORD: 6/1/74 – 5/31/75

NUMBER OF CALM HOURS - 0

NUMBER OF MISSING HOURS - 777

APPENDIX A

Part A-2: Joint Frequency Distribution of Grazing Period Data Base

6/1/74 - 10/15/74

sequenced on to

4/15/74 - 5/31/75

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY A

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0005	.0008	.0013	.0000	.0000	.0000	.0000	.0000	.0000	.0025	8.17
NNE	.0000	.0000	.0003	.0008	.0005	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0018	6.75
NE	.0000	.0000	.0000	.0008	.0028	.0031	.0008	.0003	.0003	.0000	.0000	.0000	.0079	9.39
ENE	.0000	.0000	.0003	.0031	.0036	.0036	.0005	.0000	.0000	.0000	.0000	.0000	.0109	8.14
E	.0000	.0003	.0020	.0010	.0013	.0013	.0003	.0000	.0000	.0000	.0000	.0000	.0061	6.29
ESE	.0000	.0000	.0010	.0008	.0033	.0053	.0020	.0000	.0000	.0000	.0000	.0000	.0125	8.99
SE	.0000	.0003	.0003	.0046	.0114	.0048	.0005	.0000	.0000	.0000	.0000	.0000	.0219	7.64
SSE	.0000	.0000	.0003	.0023	.0066	.0031	.0003	.0000	.0000	.0000	.0000	.0000	.0125	7.78
S	.0000	.0003	.0010	.0028	.0033	.0086	.0036	.0010	.0000	.0000	.0000	.0000	.0206	9.43
SSW	.0000	.0000	.0008	.0033	.0025	.0036	.0015	.0013	.0000	.0000	.0000	.0000	.0130	9.04
SW	.0000	.0000	.0003	.0005	.0013	.0015	.0025	.0013	.0000	.0000	.0000	.0000	.0074	10.99
WSW	.0000	.0000	.0005	.0003	.0013	.0020	.0041	.0010	.0000	.0000	.0000	.0000	.0092	11.33
W	.0000	.0000	.0003	.0008	.0018	.0015	.0008	.0000	.0000	.0000	.0000	.0000	.0051	8.72
WNW	.0000	.0000	.0005	.0000	.0010	.0015	.0010	.0000	.0000	.0000	.0000	.0000	.0041	9.42
NW	.0000	.0005	.0008	.0005	.0025	.0005	.0008	.0000	.0000	.0000	.0000	.0000	.0056	7.28
NNW	.0000	.0000	.0000	.0003	.0005	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0010	8.50
TOTAL	.0000	.0013	.0081	.0221	.0445	.0422	.0186	.0048	.0003	.0000	.0000	.0000	.1419	8.73

PERIOD OF RECORD: 4/15/74 – 10/15/74

NUMBER OF CALM HOURS - 0

NUMBER OF MISSING HOURS - 485

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY B

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0000	.0003	.0000	.0000	.0005	.0000	.0000	.0000	.0000	.0008	13.12
NNE	.0000	.0000	.0003	.0000	.0005	.0005	.0000	.0000	.0000	.0000	.0000	.0000	.0013	7.66
NE	.0000	.0000	.0000	.0005	.0000	.0010	.0005	.0000	.0000	.0000	.0000	.0000	.0020	9.74
ENE	.0000	.0000	.0005	.0008	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0013	4.99
E	.0000	.0000	.0003	.0000	.0005	.0018	.0000	.0000	.0000	.0000	.0000	.0000	.0025	9.26
ESE	.0000	.0000	.0000	.0003	.0010	.0008	.0003	.0003	.0000	.0000	.0000	.0000	.0025	9.62
SE	.0000	.0000	.0000	.0000	.0003	.0008	.0000	.0000	.0000	.0000	.0000	.0000	.0010	8.67
SSE	.0000	.0000	.0003	.0000	.0005	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0010	6.67
S	.0000	.0000	.0000	.0013	.0010	.0003	.0008	.0000	.0000	.0000	.0000	.0000	.0033	8.26
SSW	.0000	.0000	.0000	.0005	.0003	.0008	.0005	.0003	.0000	.0000	.0000	.0000	.0023	10.07
SW	.0000	.0000	.0003	.0000	.0003	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0008	7.33
WSW	.0000	.0000	.0000	.0000	.0000	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0003	10.00
W	.0000	.0000	.0003	.0000	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0005	6.07
WNW	.0000	.0000	.0003	.0000	.0000	.0005	.0003	.0000	.0000	.0000	.0000	.0000	.0010	8.76
NW	.0000	.0000	.0003	.0000	.0005	.0010	.0000	.0000	.0000	.0000	.0000	.0000	.0018	8.69
NNW	.0000	.0000	.0000	.0000	.0005	.0003	.0003	.0000	.0000	.0000	.0000	.0000	.0010	9.61
TOTAL	.0000	.0000	.0023	.0033	.0058	.0084	.0025	.0010	.0000	.0000	.0000	.0000	.0234	8.77

PERIOD OF RECORD: 4/15/74 – 10/15/74

NUMBER OF CALM HOURS - 0

NUMBER OF MISSING HOURS - 485

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY C

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0003	.0003	.0000	.0000	.0005	.0000	.0003	.0000	.0000	.0000	.0013	13.89
NNE	.0000	.0000	.0000	.0003	.0003	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0008	7.09
NE	.0000	.0000	.0000	.0000	.0003	.0010	.0005	.0000	.0000	.0000	.0000	.0000	.0018	9.97
ENE	.0000	.0000	.0000	.0000	.0000	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0003	10.60
E	.0000	.0000	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0003	4.10
ESE	.0000	.0000	.0003	.0003	.0000	.0010	.0003	.0003	.0000	.0000	.0000	.0000	.0020	9.48
SE	.0000	.0000	.0000	.0010	.0008	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0018	6.73
SSE	.0000	.0000	.0000	.0005	.0013	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0018	6.98
S	.0000	.0000	.0005	.0010	.0005	.0010	.0000	.0000	.0000	.0000	.0000	.0000	.0031	7.03
SSW	.0000	.0000	.0000	.0000	.0008	.0008	.0013	.0000	.0000	.0000	.0000	.0000	.0028	10.57
SW	.0000	.0000	.0000	.0008	.0000	.0010	.0008	.0000	.0000	.0000	.0000	.0000	.0025	9.39
WSW	.0000	.0000	.0000	.0000	.0000	.0008	.0003	.0000	.0000	.0000	.0000	.0000	.0010	11.30
W	.0000	.0000	.0003	.0003	.0010	.0008	.0000	.0000	.0000	.0000	.0000	.0000	.0023	7.50
WNW	.0000	.0000	.0000	.0000	.0005	.0003	.0003	.0005	.0000	.0000	.0000	.0000	.0015	11.72
NW	.0000	.0000	.0000	.0000	.0005	.0008	.0000	.0000	.0000	.0000	.0000	.0000	.0013	9.53
NNW	.0000	.0000	.0000	.0000	.0000	.0005	.0000	.0000	.0000	.0000	.0000	.0000	.0005	9.54
TOTAL	.0000	.0000	.0015	.0043	.0058	.0084	.0038	.0008	.0003	.0000	.0000	.0000	.0249	8.94

PERIOD OF RECORD0: 4/15/74 – 10/15/74

NUMBER OF CALM HOURS - 0

NUMBER OF MISSING HOURS - 485

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY D

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0008	.0008	.0013	.0038	.0010	.0003	.0000	.0000	.0000	.0000	.0079	8.98
NNE	.0000	.0000	.0005	.0020	.0020	.0025	.0018	.0015	.0000	.0000	.0000	.0000	.0104	9.60
NE	.0000	.0000	.0003	.0028	.0041	.0066	.0013	.0005	.0000	.0000	.0000	.0000	.0155	8.93
ENE	.0000	.0003	.0005	.0025	.0064	.0051	.0008	.0000	.0000	.0000	.0000	.0000	.0155	7.98
E	.0000	.0000	.0010	.0018	.0033	.0043	.0018	.0008	.0000	.0000	.0000	.0000	.0130	8.90
ESE	.0000	.0010	.0008	.0020	.0043	.0076	.0023	.0008	.0000	.0000	.0000	.0000	.0188	8.71
SE	.0000	.0008	.0013	.0051	.0122	.0051	.0013	.0005	.0000	.0000	.0000	.0000	.0262	7.71
SSE	.0000	.0000	.0013	.0031	.0099	.0043	.0000	.0000	.0003	.0000	.0000	.0000	.0188	7.80
S	.0000	.0000	.0025	.0028	.0033	.0084	.0020	.0000	.0000	.0000	.0000	.0000	.0191	8.33
SSW	.0000	.0005	.0005	.0025	.0036	.0086	.0051	.0008	.0000	.0000	.0000	.0000	.0216	9.54
SW	.0000	.0000	.0008	.0015	.0041	.0041	.0013	.0013	.0010	.0000	.0000	.0000	.0140	10.06
WSW	.0000	.0000	.0008	.0015	.0020	.0015	.0018	.0028	.0000	.0000	.0000	.0000	.0104	10.56
W	.0000	.0000	.0013	.0008	.0015	.0018	.0013	.0005	.0000	.0000	.0000	.0000	.0071	8.49
WNW	.0000	.0000	.0008	.0020	.0025	.0031	.0036	.0005	.0000	.0000	.0000	.0000	.0125	9.37
NW	.0000	.0000	.0005	.0013	.0018	.0041	.0038	.0000	.0000	.0000	.0000	.0000	.0114	9.67
NNW	.0000	.0003	.0005	.0015	.0018	.0043	.0015	.0003	.0000	.0000	.0000	.0000	.0102	8.81
TOTAL	.0000	.0028	.0140	.0341	.0641	.0753	.0305	.0104	.0013	.0000	.0000	.0000	.2325	8.84

PERIOD OF RECORD: 4/15/74 – 10/15/74

NUMBER OF CALM HOURS - 0

NUMBER OF MISSING HOURS - 485

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY E

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0023	.0020	.0038	.0031	.0018	.0003	.0000	.0000	.0000	.0000	.0132	7.97
NNE	.0000	.0003	.0015	.0038	.0046	.0051	.0031	.0018	.0000	.0000	.0000	.0000	.0201	8.88
NE	.0000	.0000	.0010	.0028	.0053	.0058	.0038	.0003	.0000	.0000	.0000	.0000	.0191	8.91
ENE	.0000	.0003	.0020	.0041	.0043	.0036	.0000	.0000	.0000	.0000	.0000	.0000	.0142	6.87
E	.0000	.0000	.0018	.0028	.0028	.0025	.0013	.0005	.0003	.0000	.0000	.0000	.0120	8.18
ESE	.0000	.0008	.0005	.0023	.0056	.0064	.0010	.0010	.0000	.0000	.0000	.0000	.0175	8.50
SE	.0000	.0000	.0020	.0031	.0092	.0074	.0015	.0005	.0000	.0000	.0000	.0000	.0237	8.20
SSE	.0000	.0000	.0015	.0046	.0112	.0099	.0053	.0005	.0000	.0000	.0000	.0000	.0331	8.76
S	.0000	.0005	.0023	.0053	.0125	.0086	.0048	.0018	.0008	.0000	.0000	.0000	.0366	8.87
SSW	.0000	.0003	.0020	.0053	.0104	.0163	.0140	.0031	.0005	.0000	.0000	.0000	.0519	10.03
SW	.0000	.0008	.0041	.0061	.0079	.0099	.0092	.0046	.0005	.0003	.0000	.0000	.0432	9.59
WSW	.0000	.0005	.0038	.0056	.0084	.0114	.0043	.0018	.0000	.0000	.0000	.0000	.0359	8.57
W	.0000	.0008	.0036	.0051	.0061	.0084	.0020	.0008	.0003	.0000	.0000	.0000	.0270	7.93
WNW	.0000	.0000	.0028	.0043	.0043	.0031	.0015	.0003	.0000	.0000	.0000	.0000	.0163	7.34
NW	.0000	.0003	.0023	.0053	.0033	.0010	.0008	.0000	.0000	.0000	.0000	.0000	.0130	6.39
NNW	.0000	.0010	.0025	.0043	.0043	.0015	.0000	.0000	.0000	.0000	.0000	.0000	.0137	5.99
TOTAL	.0000	.0053	.0361	.0669	.1040	.1040	.0544	.0170	.0023	.0003	.0000	.0000	.3904	8.58

PERIOD OF RECORD: 4/15/74 – 10/15/74
NUMBER OF CALM HOURS - 0
NUMBER OF MISSING HOURS - 485

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY F

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0005	.0028	.0061	.0013	.0005	.0000	.0000	.0000	.0000	.0000	.0000	.0112	5.12
NNE	.0000	.0008	.0023	.0028	.0008	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0069	4.98
NE	.0000	.0003	.0003	.0005	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0013	4.84
ENE	.0000	.0003	.0008	.0005	.0010	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0025	5.40
E	.0000	.0000	.0003	.0005	.0005	.0020	.0008	.0005	.0000	.0000	.0000	.0000	.0046	10.25
ESE	.0000	.0000	.0003	.0010	.0013	.0058	.0020	.0000	.0000	.0000	.0000	.0000	.0104	9.55
SE	.0000	.0000	.0003	.0010	.0008	.0025	.0010	.0000	.0000	.0000	.0000	.0000	.0056	9.06
SSE	.0000	.0003	.0008	.0013	.0025	.0023	.0003	.0000	.0000	.0000	.0000	.0000	.0074	7.47
S	.0000	.0003	.0010	.0010	.0013	.0010	.0013	.0010	.0000	.0000	.0000	.0000	.0069	9.08
SSW	.0000	.0005	.0020	.0025	.0028	.0020	.0020	.0020	.0005	.0000	.0000	.0000	.0145	9.30
SW	.0000	.0003	.0028	.0025	.0013	.0005	.0003	.0000	.0000	.0000	.0000	.0000	.0076	5.36
WSW	.0000	.0010	.0043	.0031	.0005	.0005	.0003	.0000	.0000	.0000	.0000	.0000	.0097	4.82
W	.0000	.0003	.0036	.0038	.0005	.0005	.0000	.0000	.0000	.0000	.0000	.0000	.0086	5.06
WNW	.0000	.0005	.0048	.0031	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0086	4.27
NW	.0000	.0018	.0031	.0020	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0071	3.88
NNW	.0000	.0008	.0031	.0020	.0010	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0069	4.42
TOTAL	.0000	.0074	.0323	.0338	.0163	.0181	.0079	.0036	.0005	.0000	.0000	.0000	.1198	6.57

PERIOD OF RECORD: 4/15/74 – 10/15/74
NUMBER OF CALM HOURS - 0
NUMBER OF MISSING HOURS - 485

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY G

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0056	.0031	.0008	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0094	4.61
NNE	.0000	.0003	.0013	.0018	.0003	.0000	.0003	.0000	.0000	.0000	.0000	.0000	.0038	5.11
NE	.0000	.0000	.0005	.0000	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0008	4.39
ENE	.0000	.0000	.0000	.0003	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0005	7.28
E	.0000	.0000	.0003	.0003	.0010	.0003	.0005	.0000	.0000	.0000	.0000	.0000	.0023	8.41
ESE	.0000	.0003	.0003	.0003	.0003	.0010	.0000	.0000	.0000	.0000	.0000	.0000	.0020	7.39
SE	.0000	.0000	.0003	.0000	.0000	.0005	.0000	.0000	.0000	.0000	.0000	.0000	.0018	5.20
SSE	.0000	.0000	.0005	.0005	.0008	.0010	.0005	.0000	.0000	.0000	.0000	.0000	.0033	7.73
S	.0000	.0003	.0010	.0000	.0003	.0003	.0005	.0000	.0000	.0000	.0000	.0000	.0023	6.66
SSW	.0000	.0005	.0003	.0008	.0003	.0008	.0008	.0003	.0000	.0000	.0000	.0000	.0036	8.17
SW	.0000	.0000	.0033	.0003	.0005	.0005	.0008	.0000	.0000	.0000	.0000	.0000	.0053	6.22
WSW	.0000	.0003	.0020	.0018	.0005	.0008	.0000	.0000	.0000	.0000	.0000	.0000	.0053	5.43
W	.0000	.0000	.0033	.0023	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0056	4.29
WNW	.0000	.0008	.0048	.0013	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0069	3.62
NW	.0000	.0008	.0043	.0025	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0076	3.95
NNW	.0000	.0000	.0048	.0018	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0066	4.13
TOTAL	.0000	.0031	.0336	.0168	.0051	.0051	.0033	.0003	.0000	.0000	.0000	.0000	.0671	5.24

PERIOD OF RECORD: 4/15/74 – 10/15/74

NUMBER OF CALM HOURS - 0

NUMBER OF MISSING HOURS - 485

APPENDIX B

Mixed Mode Joint Frequency Distribution Between Wind Speed, Wind Direction, and Stability for the Fermi 2 Containment Building Source.

APPENDIX B

Part B-1: Analysis for Ground Level Portion of Mixed Mode Source

a) Wind speed at 10 meters

b) Wind direction at 10 meters

c) Delta temperature between 10 and 60 meters

d) Containment building source

Note: In the tables of computer printout the term, "Split-H", should be replaced by the term, "mixed mode".

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY A

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0000	.0001	.0002	.0000	.0001	.0000	.0000	.0000	.0000	.0004	11.66
NNE	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0001	10.07
NE	.0000	.0000	.0000	.0000	.0002	.0002	.0001	.0001	.0001	.0000	.0000	.0000	.0006	11.58
ENE	.0000	.0000	.0000	.0001	.0002	.0003	.0001	.0000	.0000	.0000	.0000	.0000	.0006	9.01
E	.0000	.0000	.0000	.0000	.0001	.0001	.0001	.0000	.0001	.0000	.0000	.0000	.0004	12.09
ESE	.0000	.0000	.0000	.0000	.0002	.0004	.0002	.0000	.0000	.0000	.0000	.0000	.0008	10.17
SE	.0000	.0000	.0000	.0001	.0006	.0004	.0001	.0000	.0000	.0000	.0000	.0000	.0011	8.56
SSE	.0000	.0000	.0000	.0000	.0004	.0003	.0001	.0000	.0000	.0000	.0000	.0000	.0008	8.98
S	.0000	.0000	.0000	.0000	.0002	.0007	.0004	.0001	.0000	.0000	.0000	.0000	.0014	10.77
SSW	.0000	.0000	.0000	.0000	.0001	.0004	.0003	.0001	.0000	.0000	.0000	.0000	.0010	11.16
SW	.0000	.0000	.0000	.0000	.0002	.0002	.0004	.0002	.0000	.0000	.0000	.0000	.0010	12.25
WSW	.0000	.0000	.0000	.0000	.0001	.0002	.0004	.0002	.0000	.0000	.0000	.0000	.0009	12.23
W	.0000	.0000	.0000	.0000	.0001	.0002	.0001	.0001	.0000	.0000	.0000	.0000	.0005	10.53
WNW	.0000	.0000	.0000	.0000	.0001	.0001	.0001	.0001	.0000	.0000	.0000	.0000	.0004	11.44
NW	.0000	.0000	.0000	.0000	.0001	.0001	.0001	.0001	.0001	.0000	.0000	.0000	.0006	12.68
NNW	.0000	.0000	.0000	.0000	.0000	.0001	.0001	.0001	.0000	.0000	.0000	.0000	.0003	12.21
TOTAL	.0000	.0000	.0000	.0004	.0026	.0039	.0024	.0012	.0002	.0000	.0000	.0000	.0108	10.82

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSES FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY B

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0002	13.32
NNE	.0000	.0000	.0000	.0000	.0000	.0001	.0000	.0000	.0001	.0000	.0000	.0000	.0002	13.86
NE	.0000	.0000	.0000	.0000	.0000	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0002	10.14
ENE	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0001	.0000	.0000	.0000	.0002	14.44
E	.0000	.0000	.0000	.0000	.0001	.0002	.0001	.0002	.0000	.0000	.0000	.0000	.0004	12.54
ESE	.0000	.0000	.0000	.0000	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0002	10.14
SE	.0000	.0000	.0000	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0001	8.99
SSE	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0001	9.36
S	.0000	.0000	.0000	.0000	.0001	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0002	9.57
SSW	.0000	.0000	.0000	.0000	.0000	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0002	10.95
SW	.0000	.0000	.0000	.0000	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0001	11.71
WSW	.0000	.0000	.0000	.0000	.0000	.0001	.0001	.0001	.0000	.0000	.0000	.0000	.0003	13.47
W	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0001	13.10
WNW	.0000	.0000	.0000	.0000	.0000	.0000	.0001	.0000	.0001	.0000	.0000	.0000	.0002	15.84
NW	.0000	.0000	.0000	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0001	9.26
NNW	.0000	.0000	.0000	.0000	.0000	.0000	.0001	.0003	.0001	.0000	.0000	.0000	.0005	15.39
TOTAL	.0000	.0000	.0000	.0001	.0006	.0011	.0006	.0008	.0003	.0000	.0000	.0000	.0035	12.57

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSES FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY C

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0000	.0000	.0000	.0001	.0000	.0001	.0000	.0000	.0000	.0002	15.04
NNE	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	8.49
NE	.0000	.0000	.0000	.0000	.0000	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0002	10.63
ENE	.0000	.0000	.0000	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0002	9.48
E	.0000	.0000	.0000	.0000	.0001	.0000	.0000	.0002	.0000	.0000	.0000	.0000	.0003	13.19
ESE	.0000	.0000	.0000	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0002	11.10
SE	.0000	.0000	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0001	7.46
SSE	.0000	.0000	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0001	7.23
S	.0000	.0000	.0000	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0002	9.19
SSW	.0000	.0000	.0000	.0000	.0001	.0001	.0002	.0000	.0000	.0000	.0000	.0000	.0004	11.66
SW	.0000	.0000	.0000	.0000	.0000	.0001	.0002	.0002	.0002	.0000	.0000	.0000	.0007	15.41
WSW	.0000	.0000	.0000	.0000	.0000	.0001	.0002	.0000	.0000	.0000	.0000	.0000	.0003	12.33
W	.0000	.0000	.0000	.0000	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0002	9.36
WNW	.0000	.0000	.0000	.0000	.0000	.0001	.0001	.0002	.0002	.0000	.0000	.0000	.0006	16.55
NW	.0000	.0000	.0000	.0000	.0000	.0001	.0000	.0000	.0002	.0001	.0000	.0000	.0006	18.15
NNW	.0000	.0000	.0000	.0000	.0000	.0001	.0000	.0001	.0000	.0000	.0000	.0000	.0002	13.92
TOTAL	.0000	.0000	.0000	.0001	.0006	.0012	.0008	.0008	.0008	.0001	.0000	.0000	.0044	13.60

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSES FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY D

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0001	.0004	.0005	.0004	.0002	.0000	.0000	.0000	.0000	.0015	10.88
NNE	.0000	.0000	.0000	.0001	.0002	.0005	.0006	.0006	.0003	.0000	.0000	.0000	.0022	13.38
NE	.0000	.0000	.0000	.0001	.0007	.0011	.0005	.0005	.0001	.0000	.0000	.0000	.0030	11.14
ENE	.0000	.0000	.0000	.0001	.0009	.0013	.0007	.0018	.0008	.0001	.0000	.0000	.0057	13.77
E	.0000	.0000	.0000	.0001	.0004	.0006	.0007	.0013	.0008	.0000	.0000	.0000	.0039	14.56
ESE	.0000	.0000	.0000	.0001	.0004	.0009	.0006	.0006	.0005	.0000	.0000	.0000	.0032	13.13
SE	.0000	.0000	.0000	.0002	.0009	.0007	.0004	.0004	.0000	.0000	.0000	.0000	.0026	10.09
SSE	.0000	.0000	.0000	.0001	.0007	.0005	.0001	.0002	.0001	.0000	.0000	.0000	.0017	10.05
S	.0000	.0000	.0000	.0001	.0003	.0011	.0005	.0000	.0000	.0000	.0000	.0000	.0020	10.00
SSW	.0000	.0000	.0000	.0001	.0003	.0012	.0010	.0011	.0009	.0000	.0000	.0000	.0047	13.99
SW	.0000	.0000	.0000	.0001	.0004	.0008	.0008	.0011	.0014	.0000	.0000	.0000	.0046	14.99
WSW	.0000	.0000	.0000	.0001	.0006	.0011	.0010	.0020	.0016	.0001	.0000	.0000	.0065	15.21
W	.0000	.0000	.0000	.0002	.0008	.0012	.0008	.0015	.0005	.0003	.0000	.0000	.0052	13.91
WNW	.0000	.0000	.0000	.0001	.0004	.0011	.0011	.0013	.0008	.0001	.0000	.0000	.0049	14.24
NW	.0000	.0000	.0000	.0001	.0003	.0014	.0010	.0010	.0008	.0000	.0000	.0000	.0047	13.72
NNW	.0000	.0000	.0000	.0001	.0003	.0008	.0008	.0009	.0000	.0000	.0000	.0000	.0027	12.56
TOTAL	.0000	.0000	.0000	.0020	.0080	.0145	.0107	.0144	.0087	.0006	.0000	.0000	.0590	13.44

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSES FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY E

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0002	.0006	.0006	.0004	.0003	.0000	.0000	.0000	.0000	.0021	10.51
NNE	.0000	.0000	.0000	.0002	.0004	.0005	.0005	.0007	.0000	.0000	.0000	.0000	.0024	11.57
NE	.0000	.0000	.0000	.0002	.0005	.0007	.0006	.0006	.0006	.0001	.0000	.0000	.0033	13.65
ENE	.0000	.0000	.0000	.0003	.0005	.0005	.0003	.0010	.0008	.0000	.0000	.0000	.0035	13.91
E	.0000	.0000	.0000	.0002	.0003	.0005	.0002	.0006	.0001	.0000	.0000	.0000	.0019	12.21
ESE	.0000	.0000	.0000	.0002	.0005	.0008	.0004	.0011	.0008	.0000	.0000	.0000	.0039	13.84
SE	.0000	.0000	.0000	.0003	.0010	.0010	.0004	.0007	.0001	.0000	.0000	.0000	.0034	10.87
SSE	.0000	.0000	.0000	.0003	.0010	.0012	.0009	.0003	.0000	.0000	.0000	.0000	.0038	10.21
S	.0000	.0000	.0000	.0004	.0012	.0014	.0007	.0007	.00005	.0000	.0000	.0000	.0049	11.57
SSW	.0000	.0000	.0000	.0004	.0016	.0028	.0022	.0017	.0006	.0000	.0000	.0000	.0093	12.00
SW	.0000	.0000	.0000	.0005	.0013	.0025	.0017	.0021	.0008	.0014	.0000	.0000	.0103	14.45
WSW	.0000	.0000	.0000	.0007	.0014	.0024	.0016	.0026	.0004	.0000	.0000	.0000	.0091	12.17
W	.0000	.0000	.0000	.0006	.0009	.0018	.0004	.0003	.0003	.0000	.0000	.0000	.0043	10.36
WNW	.0000	.0000	.0000	.0004	.0006	.0012	.0005	.0018	.0008	.0000	.0000	.0000	.0053	13.47
NW	.0000	.0000	.0000	.0004	.0007	.0008	.0005	.0007	.0000	.0000	.0000	.0000	.0032	10.54
NNW	.0000	.0000	.0000	.0003	.0005	.0005	.0003	.0007	.0000	.0000	.0000	.0000	.0023	11.17
TOTAL	.0000	.0000	.0000	.0057	.0130	.0192	.0117	.0160	.0058	.0015	.0000	.0000	.0729	12.33

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSES FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY F

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0001	.0005	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0007	6.04
NNE	.0000	.0000	.0000	.0002	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0003	6.06
NE	.0000	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0001	5.85
ENE	.0000	.0000	.0000	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0002	6.62
E	.0000	.0000	.0000	.0001	.0001	.0003	.0003	.0003	.0000	.0000	.0000	.0000	.0011	12.26
ESE	.0000	.0000	.0000	.0001	.0002	.0007	.0007	.0000	.0001	.0000	.0000	.0000	.0019	11.12
SE	.0000	.0000	.0000	.0002	.0001	.0003	.0004	.0001	.0000	.0000	.0000	.0000	.0011	10.62
SSE	.0000	.0000	.0000	.0002	.0003	.0004	.0001	.0006	.0001	.0001	.0000	.0000	.0018	12.81
S	.0000	.0000	.0000	.0002	.0002	.0003	.0009	.0005	.0003	.0000	.0000	.0000	.0024	13.17
SSW	.0000	.0000	.0000	.0003	.0004	.0008	.0015	.0010	.0005	.0000	.0000	.0000	.0046	13.05
SW	.0000	.0000	.0001	.0003	.0002	.0004	.0003	.0008	.0000	.0000	.0000	.0000	.0019	12.01
WSW	.0000	.0000	.0001	.0004	.0001	.0001	.0001	.0001	.0000	.0000	.0000	.0000	.0007	7.92
W	.0000	.0000	.0001	.0004	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0006	5.94
WNW	.0000	.0000	.0001	.0003	.0001	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0005	6.31
NW	.0000	.0000	.0001	.0004	.0001	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0007	6.84
NNW	.0000	.0000	.0001	.0001	.0001	.0001	.0003	.0001	.0000	.0000	.0000	.0000	.0008	10.16
TOTAL	.0000	.0000	.0008	.0036	.0023	.0035	.0047	.0035	.0010	.0001	.0000	.0000	.0194	11.16

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSES FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY G

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0001	.0002	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0004	5.37
NNE	.0000	.0000	.0000	.0001	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0003	7.48
NE	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	5.97
ENE	.0000	.0000	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0001	7.26
E	.0000	.0000	.0000	.0001	.0001	.0000	.0002	.0000	.0000	.0000	.0000	.0000	.0004	10.42
ESE	.0000	.0000	.0000	.0000	.0002	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0004	8.52
SE	.0000	.0000	.0000	.0001	.0002	.0001	.0000	.0000	.0001	.0000	.0000	.0000	.0005	9.96
SSE	.0000	.0000	.0000	.0001	.0002	.0002	.0003	.0000	.0000	.0000	.0000	.0000	.0008	9.61
S	.0000	.0000	.0000	.0000	.0001	.0000	.0002	.0000	.0000	.0000	.0000	.0000	.0003	10.54
SSW	.0000	.0000	.0000	.0001	.0001	.0002	.0004	.0001	.0000	.0000	.0000	.0000	.0009	11.66
SW	.0000	.0000	.0001	.0001	.0001	.0001	.0003	.0000	.0000	.0000	.0000	.0000	.0005	10.10
WSW	.0000	.0000	.0001	.0001	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0004	6.47
W	.0000	.0000	.0001	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0003	4.84
WNW	.0000	.0000	.0001	.0002	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0004	5.65
NW	.0000	.0000	.0001	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0003	4.88
NNW	.0000	.0000	.0001	.0002	.0000	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0004	7.64
TOTAL	.0000	.0000	.0008	.0018	.0010	.0011	.0015	.0002	.0001	.0000	.0000	.0000	.0065	8.59

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSES FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

APPENDIX B

Part B-2: Analysis for Elevated Portion of Mixed Mode Source

a) Wind speed at 51.2 meters

b) Wind direction at 10 meters

c) Delta temperature between 10 and 60 meters

d) Containment building source

Note: In the tables of computer printout the term, "Split-H", should be replaced by the term, "mixed mode".

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY A

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0001	.0000	.0000	.0004	.0004	.0011	.0000	.0005	.0000	.0000	.0000	.0025	12.27
NNE	.0000	.0000	.0003	.0000	.0004	.0003	.0003	.0000	.0001	.0000	.0000	.0000	.0013	8.83
NE	.0000	.0000	.0001	.0000	.0006	.0013	.0013	.0003	.0002	.0000	.0000	.0000	.0039	11.36
ENE	.0000	.0000	.0003	.0000	.0020	.0018	.0017	.0002	.0000	.0000	.0000	.0000	.0061	9.51
E	.0000	.0001	.0013	.0000	.0009	.0007	.0005	.0005	.0000	.0000	.0000	.0000	.0040	8.44
ESE	.0000	.0001	.0006	.0000	.0005	.0014	.0025	.0009	.0000	.0000	.0000	.0000	.0060	10.94
SE	.0000	.0001	.0003	.0000	.0025	.0054	.0021	.0003	.0000	.0000	.0000	.0000	.0108	9.47
SSE	.0000	.0000	.0003	.0000	.0016	.0031	.0017	.0002	.0001	.0000	.0000	.0000	.0070	9.80
S	.0000	.0001	.0005	.0000	.0014	.0018	.0037	.0015	.0004	.0000	.0000	.0000	.0094	11.59
SSW	.0000	.0000	.0004	.0000	.0016	.0013	.0021	.0013	.0005	.0000	.0000	.0000	.0071	11.57
SW	.0000	.0000	.0001	.0000	.0004	.0013	.0012	.0017	.0009	.0000	.0000	.0000	.0056	13.72
WSW	.0000	.0000	.0003	.0000	.0008	.0007	.0012	.0017	.0006	.0000	.0000	.0000	.0053	13.06
W	.0000	.0000	.0001	.0000	.0010	.0012	.0011	.0005	.0002	.0000	.0000	.0000	.0041	11.06
WNW	.0000	.0000	.0003	.0000	.0000	.0007	.0007	.0005	.0002	.0000	.0000	.0000	.0024	12.21
NW	.0000	.0004	.0006	.0000	.0003	.0013	.0007	.0007	.0005	.0000	.0000	.0000	.0044	10.75
NNW	.0000	.0000	.0001	.0000	.0004	.0004	.0003	.0002	.0003	.0000	.0000	.0000	.0017	12.22
TOTAL	.0000	.0009	.0056	.0000	.0146	.0232	.0222	.0107	.0045	.0001	.0000	.0000	.0817	10.97

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSES FOR ELEVATED PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY B

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0000	.0000	.0001	.0003	.0001	.0002	.0000	.0000	.0000	.0006	16.16
NNE	.0000	.0000	.0000	.0001	.0000	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0009	11.66
NE	.0000	.0000	.0000	.0000	.0003	.0003	.0005	.0002	.0000	.0000	.0000	.0000	.0013	12.07
ENE	.0000	.0000	.0000	.0003	.0004	.0003	.0003	.0000	.0001	.0000	.0000	.0000	.0013	9.49
E	.0000	.0000	.0000	.0001	.0000	.0004	.0008	.0002	.0003	.0000	.0000	.0000	.0020	14.10
ESE	.0000	.0000	.0000	.0000	.0001	.0007	.0003	.0001	.0001	.0000	.0000	.0000	.0013	11.75
SE	.0000	.0000	.0000	.0001	.0003	.0003	.0005	.0000	.0000	.0000	.0000	.0000	.0012	10.33
SSE	.0000	.0000	.0000	.0001	.0001	.0004	.0003	.0001	.0000	.0000	.0000	.0000	.0009	10.73
S	.0000	.0000	.0000	.0000	.0008	.0005	.0003	.0003	.0000	.0000	.0000	.0000	.0019	10.62
SSW	.0000	.0000	.0000	.0001	.0003	.0004	.0004	.0002	.0001	.0000	.0000	.0000	.0015	11.82
SW	.0000	.0000	.0000	.0001	.0000	.0001	.0001	.0002	.0000	.0000	.0000	.0000	.0005	12.96
WSW	.0000	.0000	.0000	.0000	.0001	.0001	.0004	.0002	.0003	.0000	.0000	.0000	.0011	15.49
W	.0000	.0000	.0000	.0001	.0000	.0001	.0001	.0001	.0001	.0000	.0000	.0000	.0004	12.70
WNW	.0000	.0000	.0000	.0003	.0000	.0000	.0003	.0002	.0001	.0000	.0000	.0000	.0009	12.44
NW	.0000	.0000	.0000	.0001	.0000	.0003	.0004	.0000	.0000	.0000	.0000	.0000	.0008	11.10
NNW	.0000	.0000	.0000	.0000	.0000	.0003	.0003	.0004	.0005	.0000	.0000	.0000	.0015	17.14
TOTAL	.0000	.0000	.0000	.0014	.0023	.0043	.0056	.0025	.0017	.0001	.0000	.0000	.0179	12.50

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSES FOR ELEVATED PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY C

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0001	.0001	.0001	.0003	.0002	.0000	.0000	.0000	.0000	.0008	12.68
NNE	.0000	.0000	.0000	.0000	.0001	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0003	10.06
NE	.0000	.0000	.0000	.0000	.0003	.0001	.0007	.0003	.0000	.0000	.0000	.0000	.0014	12.76
ENE	.0000	.0000	.0000	.0000	.0000	.0003	.0007	.0000	.0000	.0000	.0000	.0000	.0009	12.34
E	.0000	.0000	.0000	.0003	.0001	.0007	.0000	.0000	.0003	.0000	.0000	.0000	.0014	11.47
ESE	.0000	.0000	.0000	.0001	.0003	.0000	.0007	.0001	.0001	.0000	.0000	.0000	.0012	11.90
SE	.0000	.0001	.0000	.0000	.0005	.0004	.0001	.0000	.0000	.0000	.0000	.0000	.0011	8.35
SSE	.0000	.0000	.0000	.0000	.0004	.0009	.0000	.0000	.0000	.0000	.0000	.0000	.0013	9.16
S	.0000	.0000	.0000	.0003	.0005	.0003	.0004	.0001	.0000	.0000	.0000	.0000	.0015	9.40
SSW	.0000	.0000	.0000	.0000	.0000	.0004	.0005	.0007	.0001	.0000	.0000	.0000	.0017	14.44
SW	.0000	.0000	.0000	.0000	.0005	.0003	.0007	.0006	.0003	.0001	.0000	.0000	.0025	14.33
WSW	.0000	.0000	.0000	.0000	.0001	.0000	.0005	.0007	.0001	.0000	.0000	.0000	.0014	15.37
W	.0000	.0000	.0000	.0003	.0001	.0004	.0004	.0001	.0000	.0000	.0000	.0000	.0013	10.07
WNW	.0000	.0000	.0000	.0000	.0001	.0004	.0003	.0002	.0003	.0001	.0000	.0000	.0014	15.36
NW	.0000	.0000	.0000	.0000	.0000	.0003	.0008	.0000	.0001	.0001	.0000	.0000	.0011	13.75
NNW	.0000	.0000	.0000	.0000	.0000	.0001	.0003	.0001	.0003	.0000	.0000	.0000	.0008	16.32
TOTAL	.0000	.0001	.0000	.0011	.0030	.0047	.0064	.0032	.0015	.0002	.0000	.0000	.0202	12.55

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSES FOR ELEVATED PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY D

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0003	.0000	.0009	.0012	.0025	.0024	.0014	.0003	.0000	.0000	.0000	.0091	11.88
NNE	.0000	.0001	.0000	.0004	.0022	.0013	.0027	.0022	.0007	.0000	.0000	.0000	.0093	13.34
NE	.0000	.0003	.0000	.0006	.0025	.0048	.0052	.0020	.0006	.0000	.0000	.0000	.0160	12.36
ENE	.0000	.0001	.0000	.0006	.0024	.0065	.0063	.0027	.0022	.0001	.0000	.0000	.0209	13.51
E	.0000	.0000	.0000	.0015	.0014	.0030	.0029	.0027	.0016	.0001	.0000	.0000	.0132	13.62
ESE	.0000	.0005	.0000	.0010	.0014	.0033	.0047	.0022	.0007	.0001	.0000	.0000	.0139	12.71
SE	.0000	.0004	.0000	.0018	.0036	.0067	.0036	.0016	.0004	.0000	.0000	.0000	.0181	10.94
SSE	.0000	.0001	.0000	.0006	.0023	.0049	.0024	.0003	.0002	.0000	.0000	.0000	.0108	10.86
S	.0000	.0001	.0000	.0015	.0024	.0022	.0054	.0019	.0000	.0000	.0000	.0000	.0135	11.89
SSW	.0000	.0003	.0000	.0005	.0019	.0025	.0062	.0040	.0013	.0001	.0000	.0000	.0167	14.17
SW	.0000	.0004	.0000	.0009	.0015	.0032	.0041	.0032	.0013	.0001	.0000	.0000	.0147	13.66
WSW	.0000	.0001	.0000	.0010	.0019	.0042	.0052	.0040	.0025	.0002	.0000	.0000	.0191	14.32
W	.0000	.0001	.0000	.0009	.0026	.0057	.0057	.0032	.0018	.0001	.0000	.0000	.0202	13.31
WNW	.0000	.0006	.0000	.0013	.0025	.0027	.0052	.0044	.0015	.0001	.0000	.0000	.0183	13.51
NW	.0000	.0005	.0000	.0013	.0023	.0021	.0069	.0041	.0013	.0001	.0000	.0000	.0185	13.55
NNW	.0000	.0004	.0000	.0009	.0012	.0018	.0038	.0032	.0010	.0000	.0000	.0000	.0125	13.73
TOTAL	.0000	.0043	.0000	.0157	.0331	.0575	.0726	.0434	.0175	.0009	.0000	.0000	.2449	13.05

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSES FOR ELEVATED PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY E

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0001	.0000	.0025	.0000	.0024	.0035	.0025	.0017	.0002	.0000	.0000	.0129	11.98
NNE	.0000	.0008	.0000	.0014	.0000	.0028	.0027	.0023	.0020	.0003	.0000	.0000	.0122	12.26
NE	.0000	.0003	.0000	.0020	.0000	.0019	.0029	.0034	.0023	.0003	.0000	.0000	.0131	12.99
ENE	.0000	.0008	.0000	.0020	.0000	.0036	.0031	.0024	.0011	.0005	.0000	.0000	.0134	11.38
E	.0000	.0003	.0000	.0014	.0000	.0019	.0017	.0024	.0008	.0003	.0000	.0000	.0088	12.09
ESE	.0000	.0004	.0000	.0005	.0000	.0022	.0034	.0037	.0016	.0005	.0000	.0000	.0122	13.56
SE	.0000	.0003	.0000	.0020	.0000	.0031	.0059	.0046	.0015	.0003	.0000	.0000	.0178	12.38
SSE	.0000	.0003	.0000	.0024	.0000	.0038	.0063	.0054	.0034	.0002	.0000	.0000	.0217	12.86
S	.0000	.0008	.0000	.0021	.0000	.0044	.0071	.0064	.0027	.0004	.0000	.0000	.0239	12.58
SSW	.0000	.0008	.0000	.0021	.0000	.0044	.0095	.0127	.0086	.0008	.0000	.0000	.0389	14.38
SW	.0000	.0013	.0000	.0038	.0000	.0059	.0077	.0113	.0064	.0010	.0000	.0000	.0374	13.38
WSW	.0000	.0006	.0000	.0043	.0000	.0073	.0087	.0108	.0059	.0013	.0000	.0000	.0389	13.23
W	.0000	.0011	.0000	.0033	.0000	.0063	.0055	.0083	.0017	.0001	.0000	.0000	.0263	11.70
WNW	.0000	.0013	.0000	.0043	.0000	.0046	.0039	.0052	.0019	.0008	.0000	.0000	.0220	11.57
NW	.0000	.0005	.0000	.0033	.0000	.0047	.0043	.0036	.0019	.0004	.0000	.0000	.0186	11.55
NNW	.0000	.0010	.0000	.0028	.0000	.0037	.0028	.0023	.0012	.0003	.0000	.0000	.0141	10.75
TOTAL	.0000	.0107	.0000	.0402	.0000	.0629	.0790	.0873	.0446	.0076	.0000	.0000	.3323	12.65

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSES FOR ELEVATED PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY F

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0004	.0000	.0018	.0033	.0000	.0005	.0002	.0000	.0000	.0000	.0063	9.51
NNE	.0000	.0000	.0004	.0000	.0013	.0014	.0000	.0004	.0001	.0000	.0000	.0000	.0036	9.19
NE	.0000	.0000	.0003	.0000	.0001	.0004	.0000	.0001	.0000	.0000	.0000	.0000	.0009	8.18
ENE	.0000	.0000	.0001	.0000	.0004	.0003	.0000	.0005	.0000	.0000	.0000	.0000	.0013	10.54
E	.0000	.0000	.0003	.0000	.0003	.0003	.0000	.0005	.0010	.0002	.0000	.0000	.0026	14.66
ESE	.0000	.0000	.0000	.0000	.0005	.0007	.0000	.0012	.0027	.0004	.0000	.0000	.0054	16.75
SE	.0000	.0000	.0000	.0000	.0004	.0013	.0000	.0004	.0012	.0002	.0000	.0000	.0035	14.73
SSE	.0000	.0000	.0005	.0000	.0008	.0014	.0000	.0016	.0014	.0000	.0000	.0000	.0057	12.98
S	.0000	.0000	.0005	.0000	.0008	.0013	.0000	.0011	.0011	.0005	.0000	.0000	.0053	13.54
SSW	.0000	.0000	.0003	.0000	.0014	.0020	.0000	.0020	.0032	.0008	.0000	.0000	.0096	14.98
SW	.0000	.0000	.0001	.0000	.0028	.0018	.0000	.0007	.0014	.0001	.0000	.0000	.0071	11.63
WSW	.0000	.0000	.0006	.0000	.0035	.0024	.0000	.0002	.0002	.0000	.0000	.0000	.0071	8.71
W	.0000	.0000	.0003	.0000	.0033	.0024	.0000	.0004	.0002	.0000	.0000	.0000	.0067	9.08
WNW	.0000	.0000	.0003	.0000	.0045	.0018	.0000	.0002	.0001	.0000	.0000	.0000	.0070	8.27
NW	.0000	.0000	.0009	.0000	.0025	.0026	.0000	.0007	.0003	.0000	.0000	.0000	.0071	9.24
NNW	.0000	.0000	.0005	.0000	.0028	.0010	.0000	.0007	.0002	.0002	.0000	.0000	.0054	9.37
TOTAL	.0000	.0000	.0055	.0000	.0271	.0247	.0000	.0112	.0135	.0025	.0000	.0000	.0846	11.42

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSES FOR ELEVATED PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY G

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0001	.0000	.0030	.0013	.0000	.0004	.0000	.0000	.0000	.0000	.0048	8.84
NNE	.0000	.0000	.0003	.0000	.0009	.0009	.0000	.0001	.0000	.0000	.0000	.0000	.0021	8.77
NE	.0000	.0000	.0003	.0000	.0003	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0007	6.30
ENE	.0000	.0000	.0000	.0000	.0000	.0003	.0000	.0002	.0001	.0000	.0000	.0000	.0006	14.14
E	.0000	.0000	.0000	.0000	.0001	.0003	.0000	.0004	.0001	.0001	.0000	.0000	.0010	14.45
ESE	.0000	.0000	.0003	.0000	.0003	.0003	.0000	.0007	.0009	.0000	.0000	.0000	.0025	14.19
SE	.0000	.0000	.0001	.0000	.0006	.0008	.0000	.0008	.0004	.0000	.0000	.0000	.0027	12.61
SSE	.0000	.0000	.0001	.0000	.0008	.0009	.0000	.0007	.0009	.0001	.0000	.0000	.0035	13.73
S	.0000	.0000	.0003	.0000	.0006	.0003	.0000	.0002	.0001	.0001	.0000	.0000	.0016	10.06
SSW	.0000	.0000	.0004	.0000	.0003	.0003	.0000	.0003	.0008	.0002	.0000	.0000	.0023	14.10
SW	.0000	.0000	.0000	.0000	.0017	.0003	.0000	.0002	.0003	.0001	.0000	.0000	.0028	10.68
WSW	.0000	.0000	.0001	.0000	.0018	.0010	.0000	.0002	.0003	.0000	.0000	.0000	.0034	9.93
W	.0000	.0000	.0000	.0000	.0024	.0012	.0000	.0000	.0000	.0000	.0000	.0000	.0036	8.49
WNW	.0000	.0000	.0011	.0000	.0034	.0011	.0000	.0001	.0002	.0000	.0000	.0000	.0059	7.79
NW	.0000	.0000	.0005	.0000	.0028	.0016	.0000	.0000	.0000	.0000	.0000	.0000	.0049	8.01
NNW	.0000	.0000	.0005	.0000	.0033	.0011	.0000	.0001	.0000	.0000	.0000	.0000	.0050	7.77
TOTAL	.0000	.0000	.0041	.0000	.0222	.0116	.0000	.0048	.0040	.0006	.0000	.0000	.0473	9.97

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSES FOR ELEVATED PORTION OF SPLIT-H SOURCE

APPENDIX B

Part 2: Mixed Mode Joint Frequency Distribution of Grazing Period Data Base for the Containment Building Source

6/01/74 - 10/15/74

and

4/15/75 - 05/31/75

APPENDIX B

Part B-3: Analysis for Ground Level portion of Mixed Mode Source

a) Wind speed at 10 meters

b) Wind direction at 10 meters

c) Delta temperature between 10 and 60 meters

d) Containment building source

Note: In the tables of computer printout the term, "Split-H", should be replaced by the term, "mixed mode".

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY A

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0000	.0001	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0003	9.08
NNE	.0000	.0000	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0001	8.06
NE	.0000	.0000	.0000	.0000	.0003	.0005	.0001	.0001	.0002	.0000	.0000	.0000	.0012	11.99
ENE	.0000	.0000	.0000	.0001	.0004	.0005	.0001	.0000	.0000	.0000	.0000	.0000	.0011	9.05
E	.0000	.0000	.0000	.0000	.0001	.0002	.0001	.0000	.0000	.0000	.0000	.0000	.0004	9.29
ESE	.0000	.0000	.0000	.0000	.0003	.0008	.0004	.0000	.0000	.0000	.0000	.0000	.0015	10.11
SE	.0000	.0000	.0000	.0001	.0012	.0007	.0001	.0000	.0000	.0000	.0000	.0000	.0021	8.47
SSE	.0000	.0000	.0000	.0001	.0007	.0005	.0001	.0000	.0000	.0000	.0000	.0000	.0013	8.56
S	.0000	.0000	.0000	.0001	.0003	.0013	.0007	.0002	.0000	.0000	.0000	.0000	.0026	10.83
SSW	.0000	.0000	.0000	.0001	.0003	.0005	.0003	.0003	.0000	.0000	.0000	.0000	.0014	11.07
SW	.0000	.0000	.0000	.0000	.0001	.0002	.0005	.0003	.0000	.0000	.0000	.0000	.0011	12.50
WSW	.0000	.0000	.0000	.0000	.0001	.0003	.0008	.0002	.0000	.0000	.0000	.0000	.0014	12.32
W	.0000	.0000	.0000	.0000	.0002	.0002	.0001	.0000	.0000	.0000	.0000	.0000	.0006	9.80
WNW	.0000	.0000	.0000	.0000	.0001	.0002	.0002	.0000	.0000	.0000	.0000	.0000	.0005	10.59
NW	.0000	.0000	.0000	.0000	.0003	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0005	9.48
NNW	.0000	.0000	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0001	8.41
TOTAL	.0000	.0000	.0000	.0007	.0045	.0064	.0035	.0010	.0002	.0000	.0000	.0000	.0163	10.32

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSES FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY B

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0002	.0000	.0000	.0000	.0000	.0002	14.99
NNE	.0000	.0000	.0000	.0000	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0001	8.97
NE	.0000	.0000	.0000	.0000	.0000	.0002	.0001	.0000	.0000	.0000	.0000	.0000	.0003	10.68
ENE	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	5.50
E	.0000	.0000	.0000	.0000	.0001	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0003	9.59
ESE	.0000	.0000	.0000	.0000	.0001	.0001	.0001	.0001	.0000	.0000	.0000	.0000	.0004	11.18
SE	.0000	.0000	.0000	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0002	9.48
SSE	.0000	.0000	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0001	8.65
S	.0000	.0000	.0000	.0001	.0001	.0000	.0002	.0000	.0000	.0000	.0000	.0000	.0004	9.79
SSW	.0000	.0000	.0000	.0000	.0000	.0001	.0001	.0001	.0000	.0000	.0000	.0000	.0004	11.99
SW	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0001	8.97
WSW	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	10.00
W	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	7.50
WNW	.0000	.0000	.0000	.0000	.0000	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0001	11.26
NW	.0000	.0000	.0000	.0000	.0001	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0002	9.35
NNW	.0000	.0000	.0000	.0000	.0001	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0002	10.20
TOTAL	.0000	.0000	.0000	.0002	.0007	.0014	.0005	.0004	.0000	.0000	.0000	.0000	.0031	10.51

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSES FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY C

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0000	.0000	.0000	.0001	.0000	.0002	.0000	.0000	.0000	.0004	18.25
NNE	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0001	8.49
NE	.0000	.0000	.0000	.0000	.0000	.0002	.0001	.0000	.0000	.0000	.0000	.0000	.0003	10.71
ENE	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	10.00
E	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	0.00
ESE	.0000	.0000	.0000	.0000	.0000	.0002	.0001	.0001	.0000	.0000	.0000	.0000	.0003	12.30
SE	.0000	.0000	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0001	6.85
SSE	.0000	.0000	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0002	7.24
S	.0000	.0000	.0000	.0000	.0001	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0003	8.70
SSW	.0000	.0000	.0000	.0000	.0001	.0001	.0002	.0000	.0000	.0000	.0000	.0000	.0005	11.12
SW	.0000	.0000	.0000	.0000	.0000	.0002	.0002	.0000	.0000	.0000	.0000	.0000	.0003	10.87
WSW	.0000	.0000	.0000	.0000	.0000	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0002	10.93
W	.0000	.0000	.0000	.0000	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0003	8.66
WNW	.0000	.0000	.0000	.0000	.0001	.0000	.0001	.0002	.0000	.0000	.0000	.0000	.0003	13.38
NW	.0000	.0000	.0000	.0000	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0002	9.24
NNW	.0000	.0000	.0000	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0001	10.00
TOTAL	.0000	.0000	.0000	.0002	.0007	.0014	.0008	.0003	.0002	.0000	.0000	.0000	.0035	11.18

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSES FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY D

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0000	.0002	.0006	.0002	.0001	.0000	.0000	.0000	.0000	.0012	10.74
NNE	.0000	.0000	.0000	.0001	.0002	.0004	.0004	.0007	.0000	.0000	.0000	.0000	.0018	12.40
NE	.0000	.0000	.0000	.0002	.0005	.0011	.0003	.0002	.0000	.0000	.0000	.0000	.0022	10.12
ENE	.0000	.0000	.0000	.0001	.0008	.0009	.0002	.0000	.0000	.0000	.0000	.0000	.0019	8.90
E	.0000	.0000	.0000	.0001	.0004	.0007	.0004	.0004	.0000	.0000	.0000	.0000	.0019	11.00
ESE	.0000	.0000	.0000	.0001	.0005	.0013	.0005	.0004	.0000	.0000	.0000	.0000	.0027	10.69
SE	.0000	.0000	.0000	.0003	.0015	.0009	.0003	.0002	.0000	.0000	.0000	.0000	.0031	9.10
SSE	.0000	.0000	.0000	.0002	.0012	.0007	.0000	.0000	.0003	.0000	.0000	.0000	.0024	9.65
S	.0000	.0000	.0000	.0002	.0004	.0014	.0004	.0000	.0000	.0000	.0000	.0000	.0024	9.77
SSW	.0000	.0000	.0000	.0001	.0004	.0014	.0010	.0004	.0000	.0000	.0000	.0000	.0034	11.07
SW	.0000	.0000	.0000	.0001	.0005	.0007	.0003	.0006	.0009	.0000	.0000	.0000	.0030	14.28
WSW	.0000	.0000	.0000	.0001	.0002	.0003	.0004	.0013	.0000	.0000	.0000	.0000	.0022	13.77
W	.0000	.0000	.0000	.0000	.0002	.0003	.0003	.0002	.0000	.0000	.0000	.0000	.0010	11.56
WNW	.0000	.0000	.0000	.0001	.0003	.0005	.0007	.0002	.0000	.0000	.0000	.0000	.0019	11.24
NW	.0000	.0000	.0000	.0001	.0002	.0007	.0008	.0000	.0000	.0000	.0000	.0000	.0017	10.79
NNW	.0000	.0000	.0000	.0001	.0002	.0007	.0003	.0001	.0000	.0000	.0000	.0000	.0015	10.57
TOTAL	.0000	.0000	.0000	.0020	.0078	.0125	.0061	.0048	.0012	.0000	.0000	.0000	.0344	10.99

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSES FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY E

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0002	.0005	.0006	.0004	.0002	.0000	.0000	.0000	.0000	.0015	10.19
NNE	.0000	.0000	.0000	.0003	.0006	.0009	.0006	.0012	.0000	.0000	.0000	.0000	.0037	11.82
NE	.0000	.0000	.0000	.0002	.0007	.0010	.0005	.0002	.0000	.0000	.0000	.0000	.0030	10.26
ENE	.0000	.0000	.0000	.0003	.0006	.0007	.0000	.0000	.0000	.0000	.0000	.0000	.0016	8.09
E	.0000	.0000	.0000	.0002	.0004	.0005	.0003	.0003	.0003	.0000	.0000	.0000	.0020	12.15
ESE	.0000	.0000	.0000	.0002	.0008	.0012	.0002	.0007	.0000	.0000	.0000	.0000	.0030	10.72
SE	.0000	.0000	.0000	.0003	.0013	.0013	.0003	.0003	.0000	.0000	.0000	.0000	.0035	9.64
SSE	.0000	.0000	.0000	.0004	.0016	.0018	.0011	.0003	.0000	.0000	.0000	.0000	.0052	9.97
S	.0000	.0000	.0000	.0004	.0018	.0016	.0010	.0012	.0008	.0000	.0000	.0000	.0068	11.97
SSW	.0000	.0000	.0000	.0004	.0015	.0029	.0029	.0021	.0005	.0000	.0000	.0000	.0104	12.14
SW	.0000	.0000	.0000	.0005	.0011	.0018	.0019	.0031	.0005	.0003	.0000	.0000	.0092	13.41
WSW	.0000	.0000	.0000	.0005	.0012	.0021	.0009	.0012	.0000	.0000	.0000	.0000	.0058	10.95
W	.0000	.0000	.0000	.0004	.0009	.0015	.0004	.0005	.0003	.0000	.0000	.0000	.0041	10.99
WNW	.0000	.0000	.0000	.0004	.0006	.0006	.0003	.0002	.0000	.0000	.0000	.0000	.0020	9.57
NW	.0000	.0000	.0000	.0004	.0005	.0002	.0002	.0000	.0000	.0000	.0000	.0000	.0013	7.89
NNW	.0000	.0000	.0000	.0004	.0006	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0012	7.47
TOTAL	.0000	.0000	.0000	.0056	.0147	.0188	.0113	.0117	.0024	.0003	.0000	.0000	.0647	11.23

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSES FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY F

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0001	.0008	.0002	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0012	6.14
NNE	.0000	.0000	.0001	.0004	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0006	6.19
NE	.0000	.0000	.0000	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0001	6.21
ENE	.0000	.0000	.0000	.0001	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0003	6.67
E	.0000	.0000	.0000	.0001	.0001	.0004	.0005	.0005	.0000	.0000	.0000	.0000	.0016	12.68
ESE	.0000	.0000	.0000	.0001	.0002	.0012	.0013	.0000	.0000	.0000	.0000	.0000	.0028	10.95
SE	.0000	.0000	.0000	.0001	.0001	.0005	.0006	.0000	.0000	.0000	.0000	.0000	.0014	10.68
SSE	.0000	.0000	.0000	.0002	.0004	.0005	.0002	.0000	.0000	.0000	.0000	.0000	.0013	8.92
S	.0000	.0000	.0000	.0001	.0002	.0002	.0008	.0010	.0000	.0000	.0000	.0000	.0024	13.18
SSW	.0000	.0000	.0000	.0003	.0005	.0004	.0013	.0020	.0005	.0000	.0000	.0000	.0051	13.83
SW	.0000	.0000	.0001	.0003	.0002	.0001	.0002	.0000	.0000	.0000	.0000	.0000	.0009	7.92
WSW	.0000	.0000	.0001	.0004	.0001	.0001	.0002	.0000	.0000	.0000	.0000	.0000	.0009	7.57
W	.0000	.0000	.0001	.0005	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0008	6.07
WNW	.0000	.0000	.0001	.0004	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0006	5.22
NW	.0000	.0000	.0001	.0003	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0004	5.33
NNW	.0000	.0000	.0001	.0003	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0005	5.84
TOTAL	.0000	.0000	.0009	.0043	.0029	.0037	.0052	.0035	.0005	.0000	.0000	.0000	.0209	10.56

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSES FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY G

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0002	.0004	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0008	5.33
NNE	.0000	.0000	.0000	.0002	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0006	8.42
NE	.0000	.0000	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0001	6.47
ENE	.0000	.0000	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0001	6.64
E	.0000	.0000	.0000	.0000	.0002	.0001	.0004	.0000	.0000	.0000	.0000	.0000	.0006	10.58
ESE	.0000	.0000	.0000	.0000	.0001	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0003	8.77
SE	.0000	.0000	.0000	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0002	7.95
SSE	.0000	.0000	.0000	.0001	.0001	.0002	.0004	.0000	.0000	.0000	.0000	.0000	.0008	10.38
S	.0000	.0000	.0000	.0000	.0001	.0001	.0004	.0000	.0000	.0000	.0000	.0000	.0005	11.37
SSW	.0000	.0000	.0000	.0001	.0001	.0002	.0006	.0003	.0000	.0000	.0000	.0000	.0012	12.47
SW	.0000	.0000	.0001	.0000	.0001	.0001	.0006	.0000	.0000	.0000	.0000	.0000	.0003	10.57
WSW	.0000	.0000	.0001	.0002	.0001	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0006	6.87
W	.0000	.0000	.0001	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0004	4.93
WNW	.0000	.0000	.0002	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0003	4.49
NW	.0000	.0000	.0002	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0005	4.85
NNW	.0000	.0000	.0002	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0004	4.65
TOTAL	.0000	.0000	.0012	.0023	.0010	.0011	.0024	.0003	.0000	.0000	.0000	.0000	.0083	8.62

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSES FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

APPENDIX B

Part B-4: Analysis for Elevated Portion of Mixed Mode Source

a) Wind speed at 51.2 meters

b) Wind direction at 10 meters

c) Delta temperature between 10 and 60 meters

d) Containment building source

Note: In the tables of computer printout, the term, "Split-H", should be replaced by the term, "mixed mode".

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY A

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0000	.0005	.0007	.0011	.0000	.0000	.0000	.0000	.0000	.0023	10.42
NNE	.0000	.0000	.0003	.0000	.0008	.0004	.0003	.0000	.0000	.0000	.0000	.0000	.0018	7.95
NE	.0000	.0000	.0000	.0000	.0008	.0025	.0026	.0007	.0002	.0001	.0000	.0000	.0069	11.62
ENE	.0000	.0000	.0003	.0000	.0030	.0032	.0031	.0004	.0000	.0000	.0000	.0000	.0100	9.78
E	.0000	.0003	.0020	.0000	.0010	.0012	.0011	.0002	.0000	.0000	.0000	.0000	.0058	7.78
ESE	.0000	.0000	.0010	.0000	.0008	.0030	.0045	.0016	.0000	.0000	.0000	.0000	.0109	11.14
SE	.0000	.0003	.0003	.0000	.0045	.0102	.0041	.0004	.0000	.0000	.0000	.0000	.0198	9.47
SSE	.0000	.0000	.0003	.0000	.0022	.0059	.0026	.0002	.0000	.0000	.0000	.0000	.0113	9.69
S	.0000	.0003	.0010	.0000	.0027	.0030	.0073	.0029	.0008	.0000	.0000	.0000	.0180	11.56
SSW	.0000	.0000	.0008	.0000	.00032	.0022	.0031	.0012	.0010	.0000	.0000	.0000	.0116	10.97
SW	.0000	.0000	.0003	.0000	.0005	.0012	.0013	.0020	.0010	.0000	.0000	.0000	.0063	13.74
WSW	.0000	.0000	.0005	.0000	.0003	.0012	.0017	.0033	.0008	.0000	.0000	.0000	.0078	13.83
W	.0000	.0000	.0003	.0000	.0008	.0016	.0013	.0007	.0000	.0000	.0000	.0000	.0046	10.54
WNW	.0000	.0000	.0005	.0000	.0000	.0009	.0013	.0008	.0000	.0000	.0000	.0000	.0035	11.49
NW	.0000	.0005	.0008	.0000	.0005	.0022	.0004	.0007	.0000	.0000	.0000	.0000	.0051	8.82
NNW	.0000	.0000	.0000	.0000	.0003	.0004	.0003	.0000	.0000	.0000	.0000	.0000	.0010	9.51
TOTAL	.0000	.0014	.0084	.0000	.0217	.0400	.0359	.0152	.0039	.0001	.0000	.0000	.1266	10.68

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSES FOR ELEVATED PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY B

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0000	.0000	.0003	.0000	.0000	.0003	.0000	.0000	.0000	.0006	16.66
NNE	.0000	.0000	.0000	.0003	.0000	.0004	.0004	.0000	.0000	.0000	.0000	.0000	.0012	9.83
NE	.0000	.0000	.0000	.0000	.0005	.0000	.0008	.0004	.0000	.0000	.0000	.0000	.0017	12.60
ENE	.0000	.0000	.0000	.0005	.0008	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0013	6.28
E	.0000	.0000	.0000	.0003	.0000	.0004	.0015	.0000	.0000	.0000	.0000	.0000	.0023	11.52
ESE	.0000	.0000	.0000	.0000	.0003	.0009	.0007	.0002	.0002	.0000	.0000	.0000	.0023	12.47
SE	.0000	.0000	.0000	.0000	.0000	.0003	.0007	.0000	.0000	.0000	.0000	.0000	.0009	12.38
SSE	.0000	.0000	.0000	.0003	.0000	.0004	.0003	.0000	.0000	.0000	.0000	.0000	.0010	9.24
S	.0000	.0000	.0000	.0000	.0012	.0009	.0003	.0006	.0000	.0000	.0000	.0000	.0030	10.75
SSW	.0000	.0000	.0000	.0000	.0005	.0003	.0007	.0004	.0002	.0000	.0000	.0000	.0020	13.13
SW	.0000	.0000	.0000	.0003	.0000	.0003	.0003	.0000	.0000	.0000	.0000	.0000	.0008	9.07
WSW	.0000	.0000	.0000	.0000	.0000	.0000	.0003	.0000	.0000	.0000	.0000	.0000	.0003	13.33
W	.0000	.0000	.0000	.0003	.0000	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0006	7.17
WNW	.0000	.0000	.0000	.0003	.0000	.0000	.0004	.0002	.0000	.0000	.0000	.0000	.0010	11.64
NW	.0000	.0000	.0000	.0003	.0000	.0004	.0008	.0000	.0000	.0000	.0000	.0000	.0016	10.76
NNW	.0000	.0000	.0000	.0000	.0000	.0004	.0003	.0002	.0000	.0000	.0000	.0000	.0009	12.79
TOTAL	.0000	.0000	.0000	.0026	.0032	.0053	.0073	.0022	.0007	.0000	.0000	.0000	.0214	11.24

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSES FOR ELEVATED PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY C

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0003	.0003	.0000	.0000	.0004	.0000	.0001	.0000	.0000	.0010	11.51
NNE	.0000	.0000	.0000	.0000	.0003	.0003	.0007	.0000	.0000	.0000	.0000	.0000	.0008	10.06
NE	.0000	.0000	.0000	.0000	.0000	.0003	.0008	.0004	.0000	.0000	.0000	.0000	.0015	13.77
ENE	.0000	.0000	.0000	.0000	.0000	.0000	.0003	.0000	.0000	.0000	.0000	.0000	.0003	13.29
E	.0000	.0000	.0000	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0003	4.65
ESE	.0000	.0000	.0000	.0003	.0003	.0000	.0008	.0002	.0002	.0000	.0000	.0000	.0019	12.43
SE	.0000	.0000	.0000	.0000	.0010	.0007	.0000	.0000	.0000	.0000	.0000	.0000	.0017	8.44
SSE	.0000	.0000	.0000	.0000	.0005	.0012	.0000	.0000	.0000	.0000	.0000	.0000	.0016	9.19
S	.0000	.0000	.0000	.0005	.0010	.0004	.0008	.0000	.0000	.0000	.0000	.0000	.0027	9.09
SSW	.0000	.0000	.0000	.0000	.0000	.0007	.0007	.0011	.0000	.0000	.0000	.0000	.0024	14.04
SW	.0000	.0000	.0000	.0000	.0008	.0000	.0008	.0006	.0000	.0000	.0000	.0000	.0023	12.40
WSW	.0000	.0000	.0000	.0000	.0000	.0000	.0007	.0002	.0000	.0000	.0000	.0000	.0009	14.34
W	.0000	.0000	.0000	.0003	.0003	.0009	.0007	.0000	.0000	.0000	.0000	.0000	.0021	9.91
WNW	.0000	.0000	.0000	.0000	.0000	.0004	.0003	.0002	.0003	.0000	.0000	.0000	.0013	15.16
NW	.0000	.0000	.0000	.0000	.0000	.0004	.0007	.0000	.0000	.0000	.0000	.0000	.0011	11.97
NNW	.0000	.0000	.0000	.0000	.0000	.0000	.0004	.0000	.0000	.0000	.0000	.0000	.0004	13.29
TOTAL	.0000	.0000	.0000	.0017	.0043	.0053	.0072	.0032	.0005	.0001	.0000	.0000	.0224	11.51

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSES FOR ELEVATED PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY D

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0008	.0008	.0011	.0032	.0008	.0002	.0000	.0000	.0000	.0068	12.43
NNE	.0000	.0000	.0000	.0005	.0019	.0018	.0021	.0014	.0008	.0000	.0000	.0000	.0085	13.00
NE	.0000	.0000	.0000	.0003	.0026	.0036	.0055	.0010	.0003	.0000	.0000	.0000	.0134	12.18
ENE	.0000	.0003	.0000	.0005	.0024	.0056	.0042	.0006	.0000	.0000	.0000	.0000	.0137	11.13
E	.0000	.0000	.0000	.0010	.0017	.0029	.0036	.0014	.0004	.0000	.0000	.0000	.0111	12.26
ESE	.0000	.0010	.0000	.0008	.0019	.0038	.0063	.0018	.0004	.0000	.0000	.0000	.0161	12.03
SE	.0000	.0008	.0000	.0013	.0048	.0107	.0042	.0010	.0003	.0000	.0000	.0000	.0232	10.50
SSE	.0000	.0000	.0000	.0013	.0029	.0087	.0036	.0000	.0000	.0000	.0000	.0000	.0165	10.41
S	.0000	.0000	.0000	.0025	.0026	.0029	.0070	.0016	.0000	.0000	.0000	.0000	.0166	11.49
SSW	.0000	.0005	.0000	.0005	.0024	.0032	.0072	.0041	.0004	.0000	.0000	.0000	.0182	13.23
SW	.0000	.0000	.0000	.0008	.0014	.0036	.0034	.0010	.0007	.0001	.0000	.0000	.0111	12.57
WSW	.0000	.0000	.0000	.0008	.0014	.0018	.0012	.0014	.0015	.0000	.0000	.0000	.0082	13.78
W	.0000	.0000	.0000	.0013	.0008	.0013	.0015	.0010	.0003	.0000	.0000	.0000	.0062	11.74
WNW	.0000	.0000	.0000	.0008	.0019	.0022	.0026	.0029	.0003	.0000	.0000	.0000	.0106	12.91
NW	.0000	.0000	.0000	.0005	.0012	.0016	.0034	.0030	.0000	.0000	.0000	.0000	.0098	13.56
NNW	.0000	.0003	.0000	.0005	.0014	.0016	.0036	.0012	.0002	.0000	.0000	.0000	.0087	12.23
TOTAL	.0000	.0029	.0000	.0142	.0320	.0563	.0627	.0246	.0058	.0001	.0000	.0000	.1986	12.02

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSES FOR ELEVATED PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY E

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0023	.0000	.0018	.0033	.0025	.0014	.0001	.0000	.0000	.0115	12.09
NNE	.0000	.0003	.0000	.0015	.0000	.0035	.0040	.0042	.0025	.0006	.0000	.0000	.0165	13.17
NE	.0000	.0000	.0000	.0010	.0000	.0026	.0046	.0048	.0030	.0001	.0000	.0000	.0160	13.77
ENE	.0000	.0003	.0000	.0020	.0000	.0038	.0037	.0029	.0000	.0000	.0000	.0000	.0127	10.56
E	.0000	.0000	.0000	.0018	.0000	.0026	.0024	.0020	.0010	.0002	.0000	.0000	.0100	11.78
ESE	.0000	.0008	.0000	.0005	.0000	.0021	.0048	.0052	.0008	.0003	.0000	.0000	.0146	12.80
SE	.0000	.0000	.0000	.0020	.0000	.0028	.0079	.0061	.0012	.0002	.0000	.0000	.0202	12.53
SSE	.0000	.0000	.0000	.0015	.0000	.0042	.0096	.0081	.0042	.0002	.0000	.0000	.0278	13.51
S	.0000	.0005	.0000	.0023	.0000	.0049	.0107	.0070	.0038	.0006	.0000	.0000	.0298	12.94
SSW	.0000	.0003	.0000	.0020	.0000	.0049	.0089	.0134	.0111	.0010	.0000	.0000	.0415	14.96
SW	.0000	.0008	.0000	.0041	.0000	.0056	.0068	.0081	.0073	.0015	.0000	.0000	.0342	13.69
WSW	.0000	.0005	.0000	.0038	.0000	.0051	.0072	.0093	.0034	.0006	.0000	.0000	.0300	12.78
W	.0000	.0008	.0000	.0036	.0000	.0047	.0052	.0069	.0016	.0003	.0000	.0000	.0230	11.77
WNW	.0000	.0000	.0000	.0028	.0000	.0039	.0037	.0025	.0012	.0001	.0000	.0000	.0143	11.20
NW	.0000	.0003	.0000	.0023	.0000	.0049	.0028	.0008	.0006	.0000	.0000	.0000	.0117	9.76
NNW	.0000	.0010	.0000	.0025	.0000	.0039	.0037	.0012	.0000	.0000	.0000	.0000	.0124	9.14
TOTAL	.0000	.0056	.0000	.0360	.0000	.0612	.0893	.0852	.0431	.0056	.0000	.0000	.3261	12.76

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSES FOR ELEVATED PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY F

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0005	.0000	.0027	.0053	.0000	.0011	.0004	.0000	.0000	.0000	.0100	10.13
NNE	.0000	.0000	.0008	.0000	.0022	.0024	.0000	.0007	.0002	.0000	.0000	.0000	.0064	9.19
NE	.0000	.0000	.0003	.0000	.0003	.0004	.0000	.0002	.0000	.0000	.0000	.0000	.0013	8.83
ENE	.0000	.0000	.0003	.0000	.0008	.0004	.0000	.0008	.0000	.0000	.0000	.0000	.0023	9.89
E	.0000	.0000	.0000	.0000	.0003	.0004	.0000	.0004	.0016	.0003	.0000	.0000	.0030	17.02
ESE	.0000	.0000	.0000	.0000	.0003	.0009	.0000	.0011	.0046	.0007	.0000	.0000	.0076	18.00
SE	.0000	.0000	.0000	.0000	.0003	.0009	.0000	.0007	.0020	.0004	.0000	.0000	.0042	16.63
SSE	.0000	.0000	.0003	.0000	.0008	.0011	.0000	.0021	.0018	.0001	.0000	.0000	.0062	14.10
S	.0000	.0000	.0003	.0000	.0010	.0009	.0000	.0011	.0008	.0005	.0000	.0000	.0045	13.46
SSW	.0000	.0000	.0005	.0000	.0019	.0022	.0000	.0023	.0016	.0007	.0000	.0000	.0092	13.19
SW	.0000	.0000	.0003	.0000	.0027	.0022	.0000	.0011	.0004	.0001	.0000	.0000	.0068	10.26
WSW	.0000	.0000	.0010	.0000	.0042	.0027	.0000	.0004	.0004	.0001	.0000	.0000	.0088	8.81
W	.0000	.0000	.0003	.0000	.0035	.0033	.0000	.0004	.0004	.0000	.0000	.0000	.0079	9.43
WNW	.0000	.0000	.0005	.0000	.0047	.0027	.0000	.0002	.0000	.0000	.0000	.0000	.0081	8.19
NW	.0000	.0000	.0018	.0000	.0030	.0017	.0000	.0002	.0000	.0000	.0000	.0000	.0068	7.14
NNW	.0000	.0000	.0008	.0000	.0030	.0017	.0000	.0008	.0000	.0000	.0000	.0000	.0064	8.48
TOTAL	.0000	.0000	.0077	.0000	.0317	.0294	.0000	.0136	.0142	.0028	.0000	.0000	.0995	11.17

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSES FOR ELEVATED PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY G

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0000	.0054	.0027	.0000	.0007	.0000	.0000	.0000	.0000	.0087	8.99
NNE	.0000	.0000	.0003	.0000	.0013	.0016	.0000	.0002	.0000	.0001	.0000	.0000	.0034	9.68
NE	.0000	.0000	.0000	.0000	.0005	.0000	.0000	.0002	.0000	.0000	.0000	.0000	.0007	19.88
ENE	.0000	.0000	.0000	.0000	.0000	.0003	.0000	.0002	.0000	.0000	.0000	.0000	.0005	13.17
E	.0000	.0000	.0000	.0000	.0003	.0003	.0000	.0008	.0002	.0001	.0000	.0000	.0018	14.92
ESE	.0000	.0000	.0003	.0000	.0003	.0003	.0000	.0002	.0008	.0000	.0000	.0000	.0019	13.65
SE	.0000	.0000	.0000	.0000	.0013	.0000	.0000	.0000	.0004	.0000	.0000	.0000	.0016	10.30
SSE	.0000	.0000	.0000	.0000	.0005	.0004	.0000	.0007	.0008	.0001	.0000	.0000	.0025	15.24
S	.0000	.0000	.0003	.0000	.0010	.0000	.0000	.0002	.0002	.0001	.0000	.0000	.0019	10.67
SSW	.0000	.0000	.0005	.0000	.0003	.0007	.0000	.0002	.0006	.0002	.0000	.0000	.0026	13.14
SW	.0000	.0000	.0000	.0000	.0032	.0003	.0000	.0004	.0004	.0002	.0000	.0000	.0045	10.27
WSW	.0000	.0000	.0003	.0000	.0019	.0016	.0000	.0004	.0006	.0000	.0000	.0000	.0048	10.61
W	.0000	.0000	.0000	.0000	.0032	.0020	.0000	.0000	.0000	.0000	.0000	.0000	.0052	8.69
WNW	.0000	.0000	.0008	.0000	.0046	.0011	.0000	.0000	.0000	.0000	.0000	.0000	.0066	7.33
NW	.0000	.0000	.0008	.0000	.0041	.0022	.0000	.0000	.0000	.0000	.0000	.0000	.0071	7.91
NNW	.0000	.0000	.0000	.0000	.0046	.0016	.0000	.0000	.0000	.0000	.0000	.0000	.0062	8.15
TOTAL	.0000	.0000	.0033	.0000	.0324	.0148	.0000	.0044	.0041	.0010	.0000	.0000	.0600	9.73

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSES FOR ELEVATED PORTION OF SPLIT-H SOURCE

APPENDIX C

Mixed Mode Joint Frequency Distribution Between Wind Speed. Wind Direction, and Stability for the Fermi 2 Turbine Building Source.

APPENDIX C

Part 1: Mixed Mode Joint Frequency Distribution of Annual Data Base for the Turbine Building Source

6/1/74 - 5/31/75

APPENDIX C

Part C-1: Analysis for Ground Level Portion of Mixed Mode Source

a) Wind speed at 10 meters

b) Wind direction at 10 meters

c) Delta temperature between 10 and 60 meters

d) Turbine building source

Note: In the tables of computer printout the term,"Split-H", should be replaced by the term, "mixed mode".

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY A

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0001	.0005	.0013	.0000	.0006	.0000	.0000	.0000	.0000	.0025	10.83
NNE	.0000	.0000	.0001	.0001	.0003	.0003	.0000	.0001	.0000	.0000	.0000	.0000	.0009	8.83
NE	.0000	.0000	.0000	.0002	.0014	.0015	.0004	.0003	.0001	.0000	.0000	.0000	.0039	9.91
ENE	.0000	.0000	.0001	.0007	.0019	.0020	.0003	.0000	.0000	.0000	.0000	.0000	.0050	8.50
E	.0000	.0000	.0002	.0003	.0008	.0006	.0006	.0000	.0001	.0000	.0000	.0000	.0026	9.29
ESE	.0000	.0000	.0001	.0002	.0015	.0029	.0011	.0000	.0000	.0000	.0000	.0000	.0058	9.67
SE	.0000	.0000	.0001	.0009	.0057	.0025	.0004	.0000	.0000	.0000	.0000	.0000	.0095	8.17
SSE	.0000	.0000	.0001	.0006	.0033	.0020	.0003	.0001	.0000	.0000	.0000	.0000	.0063	8.48
S	.0000	.0000	.0001	.0005	.0019	.0044	.0019	.0005	.0000	.0000	.0000	.0000	.0093	10.16
SSW	.0000	.0000	.0001	.0006	.0013	.0025	.0016	.0006	.0000	.0000	.0000	.0000	.0067	10.36
SW	.0000	.0000	.0000	.0001	.0014	.0014	.0021	.0011	.0000	.0000	.0000	.0000	.0062	11.48
WSW	.0000	.0000	.0001	.0003	.0008	.0014	.0021	.0008	.0000	.0000	.0000	.0000	.0054	11.49
W	.0000	.0000	.0000	.0004	.0012	.0013	.0006	.0003	.0000	.0000	.0000	.0000	.0038	9.73
WNW	.0000	.0000	.0001	.0000	.0008	.0008	.0006	.0003	.0000	.0000	.0000	.0000	.0025	10.61
NW	.0000	.0000	.0001	.0001	.0013	.0008	.0008	.0006	.0001	.0000	.0000	.0000	.0038	10.77
NNW	.0000	.0000	.0000	.0001	.0004	.0004	.0003	.0004	.0000	.0000	.0000	.0000	.0016	11.11
TOTAL	.0000	.0000	.0009	.0053	.0244	.0261	.0131	.0057	.0003	.0000	.0000	.0000	.0758	9.85

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSES FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY B

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0000	.0001	.0003	.0001	.0003	.0000	.0000	.0000	.0000	.0008	12.50
NNE	.0000	.0000	.0000	.0000	.0003	.0006	.0000	.0000	.0001	.0000	.0000	.0000	.0010	10.23
NE	.0000	.0000	.0000	.0001	.0003	.0006	.0003	.0000	.0000	.0000	.0000	.0000	.0013	9.65
ENE	.0000	.0000	.0001	.0002	.0003	.0003	.0000	.0001	.0001	.0000	.0000	.0000	.0010	9.84
E	.0000	.0000	.0000	.0000	.0005	.0010	.0003	.0005	.0000	.0000	.0000	.0000	.0023	11.20
ESE	.0000	.0000	.0000	.0000	.0008	.0004	.0001	.0001	.0000	.0000	.0000	.0000	.0014	9.13
SE	.0000	.0000	.0000	.0001	.0003	.0006	.0000	.0000	.0000	.0000	.0000	.0000	.0011	8.60
SSE	.0000	.0000	.0000	.0000	.0004	.0003	.0001	.0000	.0000	.0000	.0000	.0000	.0009	8.82
S	.0000	.0000	.0000	.0004	.0006	.0003	.0004	.0000	.0000	.0000	.0000	.0000	.0014	8.83
SSW	.0000	.0000	.0000	.0001	.0004	.0005	.0003	.0001	.0000	.0000	.0000	.0000	.0015	9.88
SW	.0000	.0000	.0000	.0000	.0001	.0001	.0003	.0000	.0000	.0000	.0000	.0000	.0005	11.04
WSW	.0000	.0000	.0000	.0000	.0001	.0005	.0003	.0004	.0000	.0000	.0000	.0000	.0013	12.26
W	.0000	.0000	.0000	.0000	.0001	.0001	.0001	.0001	.0000	.0000	.0000	.0000	.0004	11.41
WNW	.0000	.0000	.0001	.0000	.0000	.0003	.0003	.0001	.0001	.0000	.0000	.0000	.0008	12.71
NW	.0000	.0000	.0000	.0000	.0003	.0005	.0000	.0000	.0000	.0000	.0000	.0000	.0008	8.94
NNW	.0000	.0000	.0000	.0000	.0003	.0003	.0005	.0008	.0001	.0000	.0000	.0000	.0020	13.52
TOTAL	.0000	.0000	.0002	.0011	.0049	.0067	.0031	.0025	.0004	.0000	.0000	.0000	.0189	10.59

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSES FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY C

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0000	.0001	.0003	.0003	.0000	.0001	.0000	.0000	.0000	.0009	11.66
NNE	.0000	.0000	.0000	.0000	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0002	8.15
NE	.0000	.0000	.0000	.0001	.0001	.0008	.0004	.0000	.0000	.0000	.0000	.0000	.0014	10.24
ENE	.0000	.0000	.0000	.0000	.0003	.0008	.0000	.0000	.0000	.0000	.0000	.0000	.0011	9.32
E	.0000	.0000	.0001	.0000	.0008	.0000	.0000	.0005	.0000	.0000	.0000	.0000	.0014	10.51
ESE	.0000	.0000	.0000	.0001	.0000	.0008	.0001	.0001	.0000	.0000	.0000	.0000	.0012	10.20
SE	.0000	.0000	.0000	.0002	.0005	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0008	7.25
SSE	.0000	.0000	.0000	.0002	.0010	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0012	7.19
S	.0000	.0000	.0001	.0002	.0003	.0005	.0001	.0000	.0000	.0000	.0000	.0000	.0012	8.47
SSW	.0000	.0000	.0000	.0000	.0005	.0006	.0009	.0001	.0000	.0000	.0000	.0000	.0021	11.00
SW	.0000	.0000	.0000	.0002	.0003	.0008	.0008	.0005	.0003	.0000	.0000	.0000	.0029	12.45
WSW	.0000	.0000	.0000	.0000	.0000	.0006	.0009	.0001	.0000	.0000	.0000	.0000	.0016	11.91
W	.0000	.0000	.0001	.0000	.0005	.0005	.0001	.0000	.0000	.0000	.0000	.0000	.0012	8.75
WNW	.0000	.0000	.0000	.0000	.0004	.0004	.0003	.0005	.0003	.0000	.0000	.0000	.0019	13.21
NW	.0000	.0000	.0000	.0000	.0003	.0009	.0000	.0001	.0003	.0001	.0000	.0000	.0017	12.88
NNW	.0000	.0000	.0000	.0000	.0001	.0004	.0001	.0004	.0000	.0000	.0000	.0000	.0010	12.65
TOTAL	.0000	.0000	.0002	.0014	.0053	.0076	.0040	.0023	.0010	.0001	.0000	.0000	.0219	10.86

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSES FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY D

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0002	.0007	.0029	.0029	.0018	.0005	.0000	.0000	.0000	.0000	.0090	9.67
NNE	.0000	.0000	.0001	.0013	.0015	.0028	.0028	.0013	.0003	.0000	.0000	.0000	.0100	11.01
NE	.0000	.0000	.0001	.0014	.0055	.0063	.0025	.0011	.0001	.0000	.0000	.0000	.0171	9.69
ENE	.0000	.0000	.0001	.0014	.0074	.0076	.0034	.0040	.0009	.0001	.0000	.0000	.0249	10.90
E	.0000	.0000	.0003	.0008	.0034	.0035	.0034	.0029	.0009	.0000	.0000	.0000	.0152	11.64
ESE	.0000	.0000	.0002	.0008	.0038	.0056	.0028	.0013	.0006	.0000	.0000	.0000	.0151	10.59
SE	.0000	.0000	.0003	.0021	.0076	.0043	.0020	.0008	.0000	.0000	.0000	.0000	.0171	8.87
SSE	.0000	.0000	.0002	.0013	.0056	.0029	.0004	.0004	.0001	.0000	.0000	.0000	.0108	8.54
S	.0000	.0000	.0003	.0014	.0025	.0065	.0024	.0000	.0000	.0000	.0000	.0000	.0131	9.46
SSW	.0000	.0000	.0001	.0011	.0028	.0074	.0050	.0024	.0010	.0000	.0000	.0000	.0198	11.46
SW	.0000	.0000	.0002	.0009	.0036	.0049	.0040	.0024	.0015	.0000	.0000	.0000	.0175	11.72
WSW	.0000	.0000	.0002	.0011	.0048	.0063	.0050	.0045	.0018	.0001	.0000	.0000	.0238	12.00
W	.0000	.0000	.0002	.0015	.0065	.0069	.0040	.0033	.0006	.0003	.0000	.0000	.0233	10.90
WNW	.0000	.0000	.0002	.0014	.0071	.0063	.0055	.0028	.0009	.0001	.0000	.0000	.0204	11.50
NW	.0000	.0000	.0002	.0013	.0024	.0083	.0051	.0023	.0009	.0000	.0000	.0000	.0206	11.29
NNW	.0000	.0000	.0002	.0007	.0021	.0046	.0040	.0019	.0000	.0000	.0000	.0000	.0135	11.09
TOTAL	.0000	.0001	.0028	.0194	.0655	.0871	.0541	.0319	.0096	.0006	.0000	.0000	.2711	10.79

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSES FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY E

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0005	.0019	.0041	.0031	.0021	.0005	.0000	.0000	.0000	.0000	.0122	8.98
NNE	.0000	.0000	.0003	.0022	.0031	.0028	.0025	.0010	.0000	.0000	.0000	.0000	.0119	9.52
NE	.0000	.0000	.0004	.0015	.0034	.0041	.0029	.0009	.0006	.0001	.0000	.0000	.0139	10.35
ENE	.0000	.0000	.0004	.0029	.0036	.0029	.0014	.0015	.0008	.0000	.0000	.0000	.0135	9.86
E	.0000	.0000	.0003	.0015	.0020	.0029	.0010	.0009	.0001	.0000	.0000	.0000	.0087	9.56
ESE	.0000	.0000	.0001	.0018	.0039	.0045	.0020	.0016	.0008	.0000	.0000	.0000	.0147	10.46
SE	.0000	.0000	.0004	.0025	.0069	.0056	.0019	.0010	.0001	.0000	.0000	.0000	.0184	9.03
SSE	.0000	.0000	.0005	.0030	.0073	.0066	.0043	.0005	.0000	.0000	.0000	.0000	.0222	9.15
S	.0000	.0000	.0004	.0035	.0083	.0078	.0034	.0011	.0005	.0000	.0000	.0000	.0251	9.33
SSW	.0000	.0000	.0004	.0035	.0111	.0155	.0108	.0025	.0006	.0000	.0000	.0000	.0445	10.20
SW	.0000	.0001	.0007	.0047	.0090	.0138	.0081	.0031	.0008	.0014	.0000	.0000	.0417	10.68
WSW	.0000	.0000	.0008	.0059	.0101	.0132	.0075	.0039	.0004	.0000	.0000	.0000	.0418	9.88
W	.0000	.0000	.0006	.0051	.0064	.0101	.0021	.0004	.0003	.0000	.0000	.0000	.0251	8.76
WNW	.0000	.0001	.0008	.0037	.0045	.0064	.0024	.0026	.0008	.0000	.0000	.0000	.0213	9.97
NW	.0000	.0000	.0006	.0038	.0050	.0044	.0024	.0011	.0000	.0000	.0000	.0000	.0173	8.88
NNW	.0000	.0000	.0005	.0029	.0033	.0028	.0015	.0010	.0000	.0000	.0000	.0000	.0121	8.82
TOTAL	.0000	.0005	.0076	.0505	.0920	.1065	.0563	.0236	.0058	.0015	.0000	.0000	.3443	9.71

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSES FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY F

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0004	.0038	.0006	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0051	5.81
NNE	.0000	.0000	.0003	.0016	.0005	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0025	5.81
NE	.0000	.0000	.0000	.0005	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0006	5.58
ENE	.0000	.0000	.0001	.0004	.0006	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0011	6.41
E	.0000	.0000	.0001	.0004	.0006	.0013	.0005	.0003	.0000	.0000	.0000	.0000	.0032	9.85
ESE	.0000	.0000	.0001	.0008	.0014	.0034	.0011	.0000	.0001	.0000	.0000	.0000	.0069	9.51
SE	.0000	.0000	.0001	.0015	.0005	.0015	.0006	.0001	.0000	.0000	.0000	.0000	.0043	8.58
SSE	.0000	.0000	.0002	.0016	.0019	.0018	.0001	.0006	.0001	.0001	.0000	.0000	.0064	9.00
S	.0000	.0000	.0002	.0015	.0013	.0014	.0014	.0005	.0003	.0000	.0000	.0000	.0066	9.89
SSW	.0000	.0000	.0003	.0023	.0024	.0040	.0023	.0000	.0005	.0000	.0000	.0000	.0128	10.03
SW	.0000	.0000	.0006	.0021	.0009	.0018	.0004	.0008	.0000	.0000	.0000	.0000	.0066	8.59
WSW	.0000	.0001	.0008	.0028	.0003	.0003	.0001	.0001	.0000	.0000	.0000	.0000	.0044	5.97
W	.0000	.0000	.0007	.0028	.0005	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0043	5.69
WNW	.0000	.0000	.0010	.0021	.0003	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0036	5.44
NW	.0000	.0001	.0005	.0030	.0008	.0004	.0001	.0000	.0000	.0000	.0000	.0000	.0049	6.06
NNW	.0000	.0000	.0006	.0011	.0008	.0003	.0005	.0001	.0000	.0000	.0000	.0000	.0034	7.36
TOTAL	.0000	.0005	.0058	.0283	.0135	.0170	.0072	.0035	.0010	.0001	.0000	.0000	.0769	8.10

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSES FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY G

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0008	.0015	.0005	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0028	5.28
NNE	.0000	.0000	.0002	.0010	.0001	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0015	5.76
NE	.0000	.0000	.0001	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0002	5.19
ENE	.0000	.0000	.0000	.0003	.0003	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0007	7.00
E	.0000	.0000	.0000	.0004	.0005	.0001	.0003	.0000	.0000	.0000	.0000	.0000	.0013	8.25
ESE	.0000	.0000	.0001	.0003	.0009	.0011	.0000	.0000	.0000	.0000	.0000	.0000	.0024	8.20
SE	.0000	.0000	.0002	.0009	.0010	.0005	.0000	.0000	.0001	.0000	.0000	.0000	.0027	7.55
SSE	.0000	.0000	.0002	.0010	.0009	.0011	.0004	.0000	.0000	.0000	.0000	.0000	.0036	8.08
S	.0000	.0000	.0002	.0003	.0003	.0001	.0003	.0000	.0000	.0000	.0000	.0000	.0012	7.94
SSW	.0000	.0000	.0001	.0004	.0004	.0010	.0006	.0001	.0000	.0000	.0000	.0000	.0026	9.56
SW	.0000	.0000	.0005	.0004	.0003	.0004	.0004	.0000	.0000	.0000	.0000	.0000	.0020	7.80
WSW	.0000	.0000	.0005	.0011	.0003	.0004	.0000	.0000	.0000	.0000	.0000	.0000	.0023	6.11
W	.0000	.0000	.0006	.0014	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0020	4.88
WNW	.0000	.0001	.0009	.0013	.0001	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0027	5.26
NW	.0000	.0000	.0007	.0018	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0026	4.86
NNW	.0000	.0000	.0009	.0013	.0001	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0024	5.25
TOTAL	.0000	.0004	.0058	.0134	.0058	.0051	.0021	.0002	.0001	.0000	.0000	.0000	.0329	6.74

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSES FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

APPENDIX C

Part C-2: Analysis for Elevated Portion of Mixed Mode Source

a) Wind speed at 51.2 meters

b) Wind direction at 10 meters

c) Delta temperature between 10 and 60 meters

d) Turbine building source

Note: In the tables of computer printout the term, "Split-H", should be replaced by the term, "Mixed mode".

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY A

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0001	.0000	.0000	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0004	5.60
NNE	.0000	.0000	.0002	.0000	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0005	5.61
NE	.0000	.0000	.0001	.0000	.0004	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0006	6.68
ENE	.0000	.0000	.0002	.0000	.0014	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0017	6.49
E	.0000	.0001	.0011	.0000	.0006	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0018	5.02
ESE	.0000	.0001	.0005	.0000	.0003	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0010	5.21
SE	.0000	.0001	.0002	.0000	.0017	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0024	6.56
SSE	.0000	.0000	.0002	.0000	.0010	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0015	6.59
S	.0000	.0001	.0004	.0000	.0009	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0015	5.88
SSW	.0000	.0000	.0003	.0000	.0010	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0014	6.25
SW	.0000	.0000	.0001	.0000	.0003	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0004	6.67
WSW	.0000	.0000	.0002	.0000	.0005	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0008	6.07
W	.0000	.0000	.0001	.0000	.0006	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0008	6.65
WNW	.0000	.0000	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0003	4.97
NW	.0000	.0004	.0005	.0000	.0002	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0012	4.14
NNW	.0000	.0000	.0001	.0000	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0004	6.27
TOTAL	.0000	.0009	.0047	.0000	.0097	.0014	.0000	.0000	.0000	.0000	.0000	.0000	.0167	5.95

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSES FOR ELEVATED PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY B

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	0.00
NNE	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0001	4.47
NE	.0000	.0000	.0000	.0000	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0002	7.02
ENE	.0000	.0000	.0002	.0000	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0005	5.66
E	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0001	4.47
ESE	.0000	.0000	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0001	7.02
SE	.0000	.0000	.0001	.0000	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0002	6.16
SSE	.0000	.0000	.0001	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0001	5.48
S	.0000	.0000	.0000	.0000	.0004	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0004	7.02
SSW	.0000	.0000	.0001	.0000	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0002	6.16
SW	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0001	4.47
WSW	.0000	.0000	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0001	7.02
W	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0001	4.47
WNW	.0000	.0000	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0002	4.47
NW	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0001	4.47
NNW	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	0.00
TOTAL	.0000	.0000	.0012	.0000	.0013	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0025	5.82

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSES FOR ELEVATED PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY C

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0001	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0001	5.47
NNE	.0000	.0000	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0001	7.00
NE	.0000	.0000	.0000	.0000	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0002	7.00
ENE	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	0.00
E	.0000	.0000	.0002	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0003	4.92
ESE	.0000	.0000	.0001	.0000	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0002	6.15
SE	.0000	.0001	.0000	.0000	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0004	5.64
SSE	.0000	.0000	.0000	.0000	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0002	7.00
S	.0000	.0000	.0002	.0000	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0005	5.79
SSW	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	0.00
SW	.0000	.0000	.0000	.0000	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0003	7.00
WSW	.0000	.0000	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0001	7.00
W	.0000	.0000	.0002	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0003	4.92
WNW	.0000	.0000	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0001	7.00
NW	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	0.00
NNW	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	0.00
TOTAL	.0000	.0001	.0009	.0000	.0017	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0027	5.96

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSES FOR ELEVATED PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY D

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0003	.0000	.0007	.0006	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0016	5.15
NNE	.0000	.0001	.0000	.0003	.0010	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0015	6.39
NE	.0000	.0003	.0000	.0005	.0012	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0019	5.87
ENE	.0000	.0001	.0000	.0005	.0011	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0017	6.27
E	.0000	.0000	.0000	.0012	.0007	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0019	5.62
ESE	.0000	.0005	.0000	.0008	.0007	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0020	4.92
SE	.0000	.0004	.0000	.0015	.0017	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0036	5.66
SSE	.0000	.0001	.0000	.0005	.0011	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0017	6.24
S	.0000	.0001	.0000	.0012	.0011	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0024	5.79
SSW	.0000	.0003	.0000	.0004	.0009	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0016	5.68
SW	.0000	.0004	.0000	.0007	.0007	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0018	5.14
WSW	.0000	.0001	.0000	.0008	.0009	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0018	5.85
W	.0000	.0001	.0000	.0007	.0013	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0021	6.15
WNW	.0000	.0006	.0000	.0011	.0012	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0028	5.22
NW	.0000	.0005	.0000	.0011	.0011	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0026	5.27
NNW	.0000	.0004	.0000	.0007	.0006	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0017	4.97
TOTAL	.0000	.0042	.0000	.0129	.0157	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0328	5.61

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSES FOR ELEVATED PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY E

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0001	.0000	.0020	.0007	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0028	5.76
NNE	.0000	.0008	.0000	.0011	.0008	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0027	5.17
NE	.0000	.0003	.0000	.0016	.0006	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0025	5.46
ENE	.0000	.0008	.0000	.0016	.0010	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0034	5.37
E	.0000	.0003	.0000	.0011	.0006	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0020	5.54
ESE	.0000	.0004	.0000	.0004	.0006	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0014	5.66
SE	.0000	.0003	.0000	.0016	.0009	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0028	5.78
SSE	.0000	.0003	.0000	.0019	.0011	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0033	5.85
S	.0000	.0008	.0000	.0017	.0013	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0037	5.54
SSW	.0000	.0008	.0000	.0017	.0013	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0037	5.54
SW	.0000	.0012	.0000	.0031	.0017	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0060	5.36
WSW	.0000	.0006	.0000	.0035	.0021	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0062	5.87
W	.0000	.0011	.0000	.0027	.0018	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0055	5.55
WNW	.0000	.0012	.0000	.0035	.0013	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0060	5.18
NW	.0000	.0005	.0000	.0027	.0013	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0045	5.71
NNW	.0000	.0010	.0000	.0023	.0011	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0043	5.21
TOTAL	.0000	.0102	.0000	.0326	.0181	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0609	5.52

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSES FOR ELEVATED PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY F

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0004	.0015	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0019	5.52
NNE	.0000	.0000	.0004	.0010	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0014	5.29
NE	.0000	.0000	.0003	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0004	3.46
ENE	.0000	.0000	.0001	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0004	5.42
E	.0000	.0000	.0003	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0005	4.32
ESE	.0000	.0000	.0000	.0004	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0004	6.22
SE	.0000	.0000	.0000	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0003	6.22
SSE	.0000	.0000	.0005	.0006	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0011	4.73
S	.0000	.0000	.0005	.0006	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0011	4.73
SSW	.0000	.0000	.0003	.0011	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0014	5.51
SW	.0000	.0000	.0001	.0023	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0024	6.08
WSW	.0000	.0000	.0005	.0028	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0034	5.65
W	.0000	.0000	.0003	.0027	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0030	5.89
WNW	.0000	.0000	.0003	.0036	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0039	5.97
NW	.0000	.0000	.0008	.0021	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0029	5.20
NNW	.0000	.0000	.0005	.0023	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0028	5.63
TOTAL	.0000	.0000	.0050	.0221	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0271	5.56

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSES FOR ELEVATED PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY G

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0001	.0023	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0024	6.26
NNE	.0000	.0000	.0003	.0007	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0009	5.35
NE	.0000	.0000	.0003	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0005	4.40
ENE	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	0.00
E	.0000	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0001	6.40
ESE	.0000	.0000	.0003	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0005	4.40
SE	.0000	.0000	.0001	.0004	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0005	5.79
SSE	.0000	.0000	.0001	.0006	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0007	5.92
S	.0000	.0000	.0003	.0004	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0007	5.02
SSW	.0000	.0000	.0004	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0006	4.14
SW	.0000	.0000	.0000	.0013	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0013	6.40
WSW	.0000	.0000	.0001	.0014	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0015	6.18
W	.0000	.0000	.0000	.0019	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0019	6.40
WNW	.0000	.0000	.0010	.0026	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0036	5.39
NW	.0000	.0000	.0005	.0022	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0026	5.77
NNW	.0000	.0000	.0005	.0025	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0030	5.85
TOTAL	.0000	.0000	.0037	.0172	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0209	5.75

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSES FOR ELEVATED PORTION OF SPLIT-H SOURCE

APPENDIX C

Part 2: Mixed Mode Joint Frequency Distribution of Grazing Period Data Base for the Turbine Building Source

6/01/74 - 10/15/74

sequenced on to

4/15/75 - 05/31/75

APPENDIX C

Part C-3: Analysis for Ground Level Portion of Mixed Mode Source

a) Wind speed at 10 meters

b) Wind direction at 10 meters

c) Delta temperature between 10 and 60 meters

d) Turbine building source

Note: In the tables of computer printout the term, "Split-H", should be replaced by the term, "mixed mode".

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY A

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0002	.0008	.0013	.0000	.0000	.0000	.0000	.0000	.0000	.0022	8.80
NNE	.0000	.0000	.0001	.0003	.0005	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0011	7.49
NE	.0000	.0000	.0000	.0003	.0027	.0031	.0008	.0003	.0003	.0000	.0000	.0000	.0074	9.97
ENE	.0000	.0000	.0001	.0011	.0034	.0036	.0005	.0000	.0000	.0000	.0000	.0000	.0087	8.58
E	.0000	.0000	.0003	.0004	.0012	.0013	.0003	.0000	.0000	.0000	.0000	.0000	.0035	8.31
ESE	.0000	.0000	.0002	.0003	.0031	.0053	.0020	.0000	.0000	.0000	.0000	.0000	.0109	9.62
SE	.0000	.0000	.0001	.0016	.0108	.0048	.0005	.0000	.0000	.0000	.0000	.0000	.0178	8.14
SSE	.0000	.0000	.0001	.0008	.0062	.0031	.0003	.0000	.0000	.0000	.0000	.0000	.0105	8.22
S	.0000	.0000	.0002	.0010	.0031	.0036	.0036	.0010	.0000	.0000	.0000	.0000	.0175	10.23
SSW	.0000	.0000	.0001	.0012	.0024	.0036	.0015	.0013	.0000	.0000	.0000	.0000	.0101	10.09
SW	.0000	.0000	.0001	.0002	.0012	.0015	.0025	.0013	.0000	.0000	.0000	.0000	.0068	11.74
WSW	.0000	.0000	.0001	.0001	.0012	.0020	.0041	.0010	.0000	.0000	.0000	.0000	.0085	11.73
W	.0000	.0000	.0001	.0003	.0017	.0015	.0008	.0000	.0000	.0000	.0000	.0000	.0043	9.20
WNW	.0000	.0000	.0001	.0000	.0009	.0015	.0010	.0000	.0000	.0000	.0000	.0000	.0035	10.03
NW	.0000	.0000	.0001	.0002	.0024	.0005	.0008	.0000	.0000	.0000	.0000	.0000	.0040	8.70
NNW	.0000	.0000	.0000	.0001	.0005	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0009	8.11
TOTAL	.0000	.0000	.0014	.0079	.0421	.0423	.0187	.0049	.0003	.0000	.0000	.0000	.1176	9.50

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSES FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY B

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0000	.0003	.0000	.0000	.0005	.0000	.0000	.0000	.0000	.0008	13.13
NNE	.0000	.0000	.0001	.0000	.0005	.0005	.0000	.0000	.0000	.0000	.0000	.0000	.0011	8.49
NE	.0000	.0000	.0000	.0002	.0000	.0010	.0005	.0000	.0000	.0000	.0000	.0000	.0017	10.27
ENE	.0000	.0000	.0001	.0004	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0005	5.12
E	.0000	.0000	.0001	.0000	.0005	.0018	.0000	.0000	.0000	.0000	.0000	.0000	.0024	9.32
ESE	.0000	.0000	.0000	.0001	.0010	.0008	.0003	.0003	.0000	.0000	.0000	.0000	.0025	9.89
SE	.0000	.0000	.0000	.0000	.0003	.0008	.0000	.0000	.0000	.0000	.0000	.0000	.0011	9.32
SSE	.0000	.0000	.0001	.0000	.0005	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0009	8.14
S	.0000	.0000	.0000	.0006	.0010	.0003	.0008	.0000	.0000	.0000	.0000	.0000	.0027	8.97
SSW	.0000	.0000	.0000	.0002	.0003	.0008	.0005	.0003	.0000	.0000	.0000	.0000	.0021	10.78
SW	.0000	.0000	.0001	.0000	.0003	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0007	8.33
WSW	.0000	.0000	.0000	.0000	.0000	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0003	10.00
W	.0000	.0000	.0001	.0000	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0004	6.91
WNW	.0000	.0000	.0001	.0000	.0000	.0005	.0003	.0000	.0000	.0000	.0000	.0000	.0009	10.66
NW	.0000	.0000	.0001	.0000	.0005	.0010	.0000	.0000	.0000	.0000	.0000	.0000	.0016	8.98
NNW	.0000	.0000	.0000	.0000	.0005	.0003	.0003	.0000	.0000	.0000	.0000	.0000	.0011	9.68
TOTAL	.0000	.0000	.0005	.0016	.0060	.0087	.0027	.0011	.0000	.0000	.0000	.0000	.0205	9.53

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSES FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY C

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0001	.0001	.0000	.0000	.0005	.0000	.0003	.0000	.0000	.0000	.0010	13.90
NNE	.0000	.0000	.0000	.0001	.0003	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0007	8.15
NE	.0000	.0000	.0000	.0000	.0003	.0010	.0005	.0000	.0000	.0000	.0000	.0000	.0018	10.42
ENE	.0000	.0000	.0000	.0000	.0000	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0003	10.00
E	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0001	3.50
ESE	.0000	.0000	.0001	.0001	.0000	.0010	.0003	.0003	.0000	.0000	.0000	.0000	.0018	11.06
SE	.0000	.0000	.0000	.0005	.0008	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0013	6.78
SSE	.0000	.0000	.0000	.0002	.0013	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0015	7.20
S	.0000	.0000	.0001	.0005	.0005	.0010	.0000	.0000	.0000	.0000	.0000	.0000	.0020	8.11
SSW	.0000	.0000	.0000	.0000	.0008	.0008	.0013	.0000	.0000	.0000	.0000	.0000	.0029	10.66
SW	.0000	.0000	.0000	.0004	.0000	.0010	.0008	.0000	.0000	.0000	.0000	.0000	.0022	10.36
WSW	.0000	.0000	.0000	.0000	.0000	.0008	.0003	.0000	.0000	.0000	.0000	.0000	.0011	10.82
W	.0000	.0000	.0001	.0001	.0010	.0008	.0000	.0000	.0000	.0000	.0000	.0000	.0020	8.27
WNW	.0000	.0000	.0000	.0000	.0005	.0003	.0003	.0005	.0000	.0000	.0000	.0000	.0016	11.81
NW	.0000	.0000	.0000	.0000	.0005	.0008	.0000	.0000	.0000	.0000	.0000	.0000	.0013	9.04
NNW	.0000	.0000	.0000	.0000	.0000	.0005	.0000	.0000	.0000	.0000	.0000	.0000	.0005	10.00
TOTAL	.0000	.0000	.0003	.0020	.0060	.0086	.0040	.0008	.0003	.0000	.0000	.0000	.0220	9.75

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSES FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY D

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0001	.0004	.0013	.0038	.0010	.0003	.0000	.0000	.0000	.0000	.0070	9.82
NNE	.0000	.0000	.0001	.0011	.0020	.0025	.0018	.0015	.0000	.0000	.0000	.0000	.0090	10.51
NE	.0000	.0000	.0001	.0015	.0041	.0066	.0013	.0005	.0000	.0000	.0000	.0000	.0141	9.26
ENE	.0000	.0000	.0001	.0014	.0064	.0051	.0008	.0000	.0000	.0000	.0000	.0000	.0138	8.52
E	.0000	.0000	.0002	.0010	.0033	.0043	.0018	.0008	.0000	.0000	.0000	.0000	.0114	9.71
ESE	.0000	.0000	.0001	.0011	.0043	.0076	.0023	.0008	.0000	.0000	.0000	.0000	.0163	9.71
SE	.0000	.0000	.0002	.0028	.0122	.0051	.0013	.0005	.0000	.0000	.0000	.0000	.0222	8.30
SSE	.0000	.0000	.0002	.0017	.0099	.0043	.0000	.0000	.0003	.0000	.0000	.0000	.0164	8.13
S	.0000	.0000	.0004	.0015	.0033	.0084	.0020	.0000	.0000	.0000	.0000	.0000	.0157	9.23
SSW	.0000	.0000	.0001	.0014	.0036	.0086	.0051	.0008	.0000	.0000	.0000	.0000	.0196	10.24
SW	.0000	.0000	.0001	.0008	.0041	.0041	.0013	.0013	.0010	.0000	.0000	.0000	.0128	10.66
WSW	.0000	.0000	.0001	.0008	.0020	.0015	.0018	.0028	.0000	.0000	.0000	.0000	.0091	11.54
W	.0000	.0000	.0002	.0004	.0015	.0018	.0013	.0005	.0000	.0000	.0000	.0000	.0058	9.98
WNW	.0000	.0000	.0001	.0011	.0025	.0031	.0036	.0005	.0000	.0000	.0000	.0000	.0109	10.17
NW	.0000	.0000	.0001	.0007	.0018	.0041	.0038	.0000	.0000	.0000	.0000	.0000	.0105	10.29
NNW	.0000	.0000	.0001	.0008	.0018	.0043	.0015	.0003	.0000	.0000	.0000	.0000	.0088	9.73
TOTAL	.0000	.0001	.0025	.0188	.0641	.0752	.0307	.0106	.0013	.0000	.0000	.0000	.2033	9.57

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSES FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY E

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0004	.0015	.0038	.0031	.0018	.0003	.0000	.0000	.0000	.0000	.0109	8.94
NNE	.0000	.0000	.0003	.0028	.0046	.0051	.0031	.0018	.0000	.0000	.0000	.0000	.0177	9.71
NE	.0000	.0000	.0002	.0021	.0053	.0058	.0038	.0003	.0000	.0000	.0000	.0000	.0175	9.40
ENE	.0000	.0000	.0004	.0030	.0043	.0036	.0000	.0000	.0000	.0000	.0000	.0000	.0113	7.62
E	.0000	.0000	.0003	.0021	.0028	.0025	.0013	.0005	.0003	.0000	.0000	.0000	.0098	9.18
ESE	.0000	.0000	.0001	.0017	.0056	.0064	.0010	.0010	.0000	.0000	.0000	.0000	.0158	9.18
SE	.0000	.0000	.0004	.0023	.0092	.0074	.0015	.0005	.0000	.0000	.0000	.0000	.0213	8.68
SSE	.0000	.0000	.0003	.0034	.0112	.0099	.0053	.0005	.0000	.0000	.0000	.0000	.0306	9.15
S	.0000	.0000	.0004	.0039	.0125	.0086	.0048	.0018	.0008	.0000	.0000	.0000	.0329	9.48
SSW	.0000	.0000	.0004	.0039	.0104	.0163	.0140	.0031	.0005	.0000	.0000	.0000	.0486	10.44
SW	.0000	.0000	.0008	.0045	.0079	.0099	.0092	.0046	.0005	.0003	.0000	.0000	.0377	10.60
WSW	.0000	.0000	.0007	.0041	.0084	.0114	.0043	.0018	.0000	.0000	.0000	.0000	.0308	9.36
W	.0000	.0000	.0007	.0038	.0061	.0084	.0020	.0008	.0003	.0000	.0000	.0000	.0221	8.99
WNW	.0000	.0000	.0005	.0032	.0043	.0031	.0015	.0003	.0000	.0000	.0000	.0000	.0129	8.29
NW	.0000	.0000	.0004	.0039	.0033	.0010	.0008	.0000	.0000	.0000	.0000	.0000	.0094	7.21
NNW	.0000	.0000	.0005	.0032	.0043	.0015	.0000	.0000	.0000	.0000	.0000	.0000	.0095	7.00
TOTAL	.0000	.0002	.0068	.0492	.1040	.1040	.0544	.0173	.0024	.0003	.0000	.0000	.3386	9.35

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSES FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY F

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0006	.0061	.0013	.0005	.0000	.0000	.0000	.0000	.0000	.0000	.0085	5.91
NNE	.0000	.0001	.0005	.0028	.0008	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0045	5.88
NE	.0000	.0000	.0001	.0005	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0009	5.92
ENE	.0000	.0000	.0002	.0005	.0010	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0017	6.42
E	.0000	.0000	.0001	.0005	.0005	.0020	.0008	.0005	.0000	.0000	.0000	.0000	.0044	10.40
ESE	.0000	.0000	.0001	.0010	.0013	.0058	.0020	.0000	.0000	.0000	.0000	.0000	.0102	9.79
SE	.0000	.0000	.0001	.0010	.0008	.0025	.0010	.0000	.0000	.0000	.0000	.0000	.0054	9.27
SSE	.0000	.0000	.0002	.0013	.0025	.0023	.0003	.0000	.0000	.0000	.0000	.0000	.0066	8.10
S	.0000	.0000	.0002	.0010	.0013	.0010	.0013	.0010	.0000	.0000	.0000	.0000	.0058	10.18
SSW	.0000	.0000	.0004	.0025	.0028	.0020	.0020	.0020	.0005	.0000	.0000	.0000	.0123	10.26
SW	.0000	.0000	.0006	.0025	.0013	.0005	.0003	.0000	.0000	.0000	.0000	.0000	.0052	6.62
WSW	.0000	.0001	.0009	.0031	.0005	.0005	.0003	.0000	.0000	.0000	.0000	.0000	.0054	6.12
W	.0000	.0000	.0008	.0038	.0005	.0005	.0000	.0000	.0000	.0000	.0000	.0000	.0056	5.79
WNW	.0000	.0000	.0010	.0031	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0044	5.14
NW	.0000	.0002	.0006	.0020	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0031	5.07
NNW	.0000	.0001	.0006	.0020	.0010	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0037	5.61
TOTAL	.0000	.0007	.0068	.0337	.0165	.0179	.0080	.0035	.0005	.0000	.0000	.0000	.0876	7.82

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSES FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY G

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0014	.0031	.0008	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0053	5.27
NNE	.0000	.0000	.0003	.0018	.0003	.0000	.0003	.0000	.0000	.0000	.0000	.0000	.0028	6.25
NE	.0000	.0000	.0001	.0000	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0004	6.31
ENE	.0000	.0000	.0000	.0003	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0006	6.50
E	.0000	.0000	.0001	.0003	.0010	.0003	.0005	.0000	.0000	.0000	.0000	.0000	.0022	8.69
ESE	.0000	.0000	.0001	.0003	.0003	.0010	.0000	.0000	.0000	.0000	.0000	.0000	.0017	8.34
SE	.0000	.0000	.0003	.0000	.0000	.0005	.0000	.0000	.0000	.0000	.0000	.0000	.0008	7.42
SSE	.0000	.0000	.0001	.0005	.0008	.0010	.0005	.0000	.0000	.0000	.0000	.0000	.0029	8.78
S	.0000	.0000	.0003	.0000	.0003	.0003	.0005	.0000	.0000	.0000	.0000	.0000	.0014	9.18
SSW	.0000	.0000	.0001	.0008	.0003	.0008	.0008	.0003	.0000	.0000	.0000	.0000	.0031	9.71
SW	.0000	.0000	.0008	.0003	.0005	.0005	.0008	.0000	.0000	.0000	.0000	.0000	.0029	8.08
WSW	.0000	.0000	.0005	.0018	.0005	.0008	.0000	.0000	.0000	.0000	.0000	.0000	.0036	6.46
W	.0000	.0000	.0008	.0023	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0031	4.97
WNW	.0000	.0001	.0012	.0013	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0026	4.45
NW	.0000	.0001	.0011	.0025	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0037	4.82
NNW	.0000	.0000	.0012	.0018	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0030	4.69
TOTAL	.0000	.0003	.0085	.0171	.0054	.0052	.0034	.0003	.0000	.0000	.0000	.0000	.0402	6.61

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSES FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

APPENDIX C

Part C-4: Analysis for Elevated Portion of Mixed Mode Source

a) Wind speed at 51.2 meters

b) Wind direction at 10 meters

c) Delta temperature between 10 and 60 meters

d) Turbine building source

Note: In the tables of computer printout the term, "Split-H", should be replaced by the term, "mixed mode".

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY A

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0000	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0004	6.97
NNE	.0000	.0000	.0002	.0000	.0005	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0008	6.01
NE	.0000	.0000	.0000	.0000	.0005	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0007	7.23
ENE	.0000	.0000	.0002	.0000	.0020	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0024	6.63
E	.0000	.0003	.0017	.0000	.0006	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0027	4.70
ESE	.0000	.0000	.0008	.0000	.0005	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0015	5.64
SE	.0000	.0003	.0002	.0000	.0030	.0006	.0000	.0000	.0000	.0000	.0000	.0000	.0041	6.55
SSE	.0000	.0000	.0002	.0000	.0015	.0004	.0000	.0000	.0000	.0000	.0000	.0000	.0021	6.81
S	.0000	.0003	.0008	.0000	.0018	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0031	5.71
SSW	.0000	.0000	.0007	.0000	.0021	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0029	6.25
SW	.0000	.0000	.0002	.0000	.0003	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0006	6.01
WSW	.0000	.0000	.0004	.0000	.0002	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0007	5.45
W	.0000	.0000	.0002	.0000	.0005	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0009	6.26
WNW	.0000	.0000	.0004	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0005	4.81
NW	.0000	.0005	.0007	.0000	.0003	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0016	4.39
NNW	.0000	.0000	.0000	.0000	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0002	6.98
TOTAL	.0000	.0014	.0070	.0000	.0145	.0024	.0000	.0000	.0000	.0000	.0000	.0000	.0253	5.98

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSES FOR ELEVATED PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY B

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	0.00
NNE	.0000	.0000	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0002	4.47
NE	.0000	.0000	.0000	.0000	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0003	7.02
ENE	.0000	.0000	.0004	.0000	.0004	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0008	5.78
E	.0000	.0000	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0002	4.47
ESE	.0000	.0000	.0000	.0000	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0002	7.02
SE	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	0.00
SSE	.0000	.0000	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0002	4.47
S	.0000	.0000	.0000	.0000	.0007	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0007	7.02
SSW	.0000	.0000	.0000	.0000	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0003	7.02
SW	.0000	.0000	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0002	4.47
WSW	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	0.00
W	.0000	.0000	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0002	4.47
WNW	.0000	.0000	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0002	4.47
NW	.0000	.0000	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0002	4.47
NNW	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	0.00
TOTAL	.0000	.0000	.0021	.0000	.0018	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0040	5.65

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSES FOR ELEVATED PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY C

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0002	.0000	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0004	5.47
NNE	.0000	.0000	.0000	.0000	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0002	7.00
NE	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	0.00
ENE	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	0.00
E	.0000	.0000	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0002	4.46
ESE	.0000	.0000	.0002	.0000	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0004	5.47
SE	.0000	.0000	.0000	.0000	.0005	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0005	7.00
SSE	.0000	.0000	.0000	.0000	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0003	7.00
S	.0000	.0000	.0004	.0000	.0005	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0010	5.91
SSW	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	0.00
SW	.0000	.0000	.0000	.0000	.0004	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0004	7.00
WSW	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	0.00
W	.0000	.0000	.0002	.0000	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0004	5.47
WNW	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	0.00
NW	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	0.00
NNW	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	0.00
TOTAL	.0000	.0000	.0014	.0000	.0025	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0039	6.08

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSES FOR ELEVATED PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY D

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0007	.0004	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0010	5.62
NNE	.0000	.0000	.0000	.0004	.0009	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0013	6.51
NE	.0000	.0000	.0000	.0002	.0013	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0015	6.91
ENE	.0000	.0003	.0000	.0004	.0011	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0018	5.88
E	.0000	.0000	.0000	.0008	.0008	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0016	6.00
ESE	.0000	.0010	.0000	.0007	.0009	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0025	4.58
SE	.0000	.0008	.0000	.0011	.0023	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0041	5.64
SSE	.0000	.0000	.0000	.0011	.0014	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0025	6.19
S	.0000	.0000	.0000	.0021	.0013	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0033	5.69
SSW	.0000	.0005	.0000	.0004	.0011	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0020	5.51
SW	.0000	.0000	.0000	.0007	.0007	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0013	6.03
WSW	.0000	.0000	.0000	.0007	.0007	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0013	6.03
W	.0000	.0000	.0000	.0011	.0004	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0014	5.35
WNW	.0000	.0000	.0000	.0007	.0009	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0016	6.22
NW	.0000	.0000	.0000	.0004	.0006	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0010	6.24
NNW	.0000	.0003	.0000	.0004	.0007	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0014	5.41
TOTAL	.0000	.0028	.0000	.0117	.0152	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0297	5.79

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSES FOR ELEVATED PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY E

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0019	.0005	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0024	5.79
NNE	.0000	.0003	.0000	.0012	.0010	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0025	5.98
NE	.0000	.0000	.0000	.0008	.0007	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0015	6.54
ENE	.0000	.0003	.0000	.0016	.0011	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0030	5.92
E	.0000	.0000	.0000	.0015	.0007	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0022	6.13
ESE	.0000	.0008	.0000	.0004	.0006	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0018	4.88
SE	.0000	.0000	.0000	.0016	.0008	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0024	6.13
SSE	.0000	.0000	.0000	.0012	.0012	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0024	6.61
S	.0000	.0005	.0000	.0019	.0014	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0037	5.87
SSW	.0000	.0003	.0000	.0016	.0014	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0033	6.13
SW	.0000	.0008	.0000	.0033	.0016	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0057	5.68
WSW	.0000	.0005	.0000	.0031	.0015	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0050	5.73
W	.0000	.0008	.0000	.0029	.0013	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0050	5.48
WNW	.0000	.0000	.0000	.0023	.0011	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0034	6.12
NW	.0000	.0003	.0000	.0019	.0014	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0036	6.06
NNW	.0000	.0010	.0000	.0020	.0011	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0041	5.27
TOTAL	.0000	.0054	.0000	.0292	.0176	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0522	5.83

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSES FOR ELEVATED PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY F

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0005	.0022	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0027	5.61
NNE	.0000	.0000	.0007	.0018	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0025	5.20
NE	.0000	.0000	.0003	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0005	4.32
ENE	.0000	.0000	.0003	.0006	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0009	5.15
E	.0000	.0000	.0000	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0002	6.22
ESE	.0000	.0000	.0000	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0002	6.22
SE	.0000	.0000	.0000	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0002	6.22
SSE	.0000	.0000	.0003	.0006	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0009	5.15
S	.0000	.0000	.0003	.0008	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0011	6.30
SSW	.0000	.0000	.0005	.0016	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0020	5.42
SW	.0000	.0000	.0003	.0022	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0025	5.83
WSW	.0000	.0000	.0009	.0034	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0043	5.47
W	.0000	.0000	.0003	.0028	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0031	5.91
WNW	.0000	.0000	.0005	.0038	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0043	5.84
NW	.0000	.0000	.0016	.0025	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0041	4.79
NNW	.0000	.0000	.0007	.0025	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0032	5.40
TOTAL	.0000	.0000	.0070	.0258	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0328	5.46

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSES FOR ELEVATED PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY G

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0042	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0042	6.40
NNE	.0000	.0000	.0003	.0010	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0012	5.60
NE	.0000	.0000	.0000	.0004	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0004	6.40
ENE	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	0.00
E	.0000	.0000	.0000	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0002	6.40
ESE	.0000	.0000	.0003	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0005	4.40
SE	.0000	.0000	.0000	.0010	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0010	6.40
SSE	.0000	.0000	.0000	.0004	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0004	6.40
S	.0000	.0000	.0003	.0007	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0010	5.43
SSW	.0000	.0000	.0005	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0007	3.95
SW	.0000	.0000	.0000	.0025	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0025	6.40
WSW	.0000	.0000	.0003	.0015	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0018	5.84
W	.0000	.0000	.0000	.0025	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0025	6.40
WNW	.0000	.0000	.0007	.0036	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0043	5.79
NW	.0000	.0000	.0007	.0032	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0039	5.73
NNW	.0000	.0000	.0000	.0036	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0036	6.40
TOTAL	.0000	.0000	.0030	.0251	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0281	6.01

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSES FOR ELEVATED PORTION OF SPLIT-H SOURCE

APPENDIX D

Mixed Mode Joint Frequency Distribution Between Wind Speed, Wind Direction and Stability for the Fermi 2 Radwaste Building Source

APPENDIX D

Part 1: Mixed Mode Joint Frequency Distribution of Annual Data Base for the Radwaste Building Source.

6/1/74 - 5/31/75

APPENDIX D

Part D-1: Analysis for Ground Level Portion of Mixed Mode Source

a) Wind speed at 10 meters

b) Wind direction at 10 meters

c) Delta temperature between 10 and 60 meters

d) Radwaste building source

Note: In the tables of computer printout the term, "Split-H", should be replaced by the term, "mixed mode".

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY A

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0000	.0001	.0003	.0000	.0006	.0000	.0000	.0000	.0000	.0010	13.47
NNE	.0000	.0000	.0000	.0000	.0001	.0001	.0000	.0001	.0000	.0000	.0000	.0000	.0003	10.95
NE	.0000	.0000	.0000	.0001	.0003	.0003	.0002	.0003	.0001	.0000	.0000	.0000	.0013	12.18
ENE	.0000	.0000	.0000	.0003	.0003	.0004	.0002	.0000	.0000	.0000	.0000	.0000	.0012	8.74
E	.0000	.0000	.0000	.0001	.0001	.0001	.0004	.0000	.0001	.0000	.0000	.0000	.0009	11.35
ESE	.0000	.0000	.0000	.0001	.0003	.0006	.0007	.0000	.0000	.0000	.0000	.0000	.0018	10.61
SE	.0000	.0000	.0000	.0003	.0010	.0005	.0002	.0000	.0000	.0000	.0000	.0000	.0021	8.43
SSE	.0000	.0000	.0000	.0002	.0006	.0004	.0002	.0001	.0000	.0000	.0000	.0000	.0015	9.18
S	.0000	.0000	.0000	.0002	.0003	.0009	.0012	.0005	.0000	.0000	.0000	.0000	.0031	11.64
SSW	.0000	.0000	.0000	.0002	.0002	.0005	.0010	.0006	.0000	.0000	.0000	.0000	.0025	12.09
SW	.0000	.0000	.0000	.0000	.0003	.0003	.0013	.0011	.0000	.0000	.0000	.0000	.0030	13.40
WSW	.0000	.0000	.0000	.0001	.0001	.0003	.0013	.0008	.0000	.0000	.0000	.0000	.0026	13.15
W	.0000	.0000	.0000	.0001	.0002	.0003	.0004	.0003	.0000	.0000	.0000	.0000	.0013	11.51
WNW	.0000	.0000	.0000	.0000	.0001	.0002	.0004	.0003	.0000	.0000	.0000	.0000	.0010	12.74
NW	.0000	.0000	.0000	.0000	.0002	.0002	.0005	.0006	.0001	.0000	.0000	.0000	.0016	13.42
NNW	.0000	.0000	.0000	.0000	.0001	.0001	.0002	.0004	.0000	.0000	.0000	.0000	.0008	13.49
TOTAL	.0000	.0000	.0001	.0019	.0044	.0053	.0081	.0057	.0003	.0000	.0000	.0000	.0258	11.72

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSES FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY B

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0000	.0000	.0001	.0001	.0003	.0000	.0000	.0000	.0000	.0005	14.69
NNE	.0000	.0000	.0000	.0000	.0001	.0001	.0000	.0000	.0001	.0000	.0000	.0000	.0003	13.35
NE	.0000	.0000	.0000	.0000	.0001	.0001	.0002	.0000	.0000	.0000	.0000	.0000	.0004	10.77
ENE	.0000	.0000	.0000	.0001	.0001	.0001	.0000	.0001	.0001	.0000	.0000	.0000	.0004	13.44
E	.0000	.0000	.0000	.0000	.0001	.0002	.0002	.0005	.0000	.0000	.0000	.0000	.0010	13.59
ESE	.0000	.0000	.0000	.0000	.0001	.0001	.0001	.0001	.0000	.0000	.0000	.0000	.0004	11.10
SE	.0000	.0000	.0000	.0000	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0002	8.48
SSE	.0000	.0000	.0000	.0000	.0001	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0002	9.79
S	.0000	.0000	.0000	.0001	.0001	.0001	.0003	.0000	.0000	.0000	.0000	.0000	.0006	10.21
SSW	.0000	.0000	.0000	.0000	.0001	.0001	.0002	.0001	.0000	.0000	.0000	.0000	.0005	11.71
SW	.0000	.0000	.0000	.0000	.0000	.0000	.0002	.0000	.0000	.0000	.0000	.0000	.0003	12.24
WSW	.0000	.0000	.0000	.0000	.0000	.0001	.0002	.0004	.0000	.0000	.0000	.0000	.0007	14.19
W	.0000	.0000	.0000	.0000	.0000	.0000	.0001	.0001	.0000	.0000	.0000	.0000	.0002	13.72
WNW	.0000	.0000	.0000	.0000	.0000	.0001	.0002	.0001	.0001	.0000	.0000	.0000	.0005	14.75
NW	.0000	.0000	.0000	.0000	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0002	9.02
NNW	.0000	.0000	.0000	.0000	.0001	.0001	.0004	.0008	.0001	.0000	.0000	.0000	.0014	15.27
TOTAL	.0000	.0000	.0001	.0003	.0009	.0014	.0022	.0025	.0004	.0000	.0000	.0000	.0078	13.01

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSES FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY C

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0000	.0000	.0001	.0002	.0000	.0001	.0000	.0000	.0000	.0004	13.93
NNE	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0001	7.99
NE	.0000	.0000	.0000	.0000	.0000	.0002	.0003	.0000	.0000	.0000	.0000	.0000	.0005	11.24
ENE	.0000	.0000	.0000	.0000	.0001	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0002	9.39
E	.0000	.0000	.0000	.0000	.0001	.0000	.0000	.0005	.0000	.0000	.0000	.0000	.0007	14.15
ESE	.0000	.0000	.0000	.0000	.0000	.0002	.0001	.0001	.0000	.0000	.0000	.0000	.0004	11.74
SE	.0000	.0000	.0000	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0002	7.04
SSE	.0000	.0000	.0000	.0001	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0002	7.04
S	.0000	.0000	.0000	.0001	.0001	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0003	9.06
SSW	.0000	.0000	.0000	.0000	.0001	.0001	.0006	.0001	.0000	.0000	.0000	.0000	.0010	12.46
SW	.0000	.0000	.0000	.0001	.0001	.0002	.0006	.0005	.0003	.0000	.0000	.0000	.0017	14.73
WSW	.0000	.0000	.0000	.0000	.0000	.0001	.0006	.0001	.0000	.0000	.0000	.0000	.0009	12.86
W	.0000	.0000	.0000	.0000	.0001	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0003	9.52
WNW	.0000	.0000	.0000	.0000	.0001	.0001	.0002	.0005	.0003	.0000	.0000	.0000	.0012	15.89
NW	.0000	.0000	.0000	.0000	.0001	.0002	.0000	.0001	.0003	.0001	.0000	.0000	.0007	17.46
NNW	.0000	.0000	.0000	.0000	.0000	.0001	.0001	.0004	.0000	.0000	.0000	.0000	.0006	14.84
TOTAL	.0000	.0000	.0000	.0004	.0009	.0016	.0028	.0023	.0010	.0001	.0000	.0000	.0092	13.45

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSES FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY D

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0002	.0005	.0008	.0015	.0005	.0000	.0000	.0000	.0000	.0035	11.47
NNE	.0000	.0000	.0000	.0003	.0003	.0008	.0023	.0013	.0003	.0000	.0000	.0000	.0052	13.10
NE	.0000	.0000	.0000	.0004	.0010	.0017	.0020	.0011	.0001	.0000	.0000	.0000	.0063	11.57
ENE	.0000	.0000	.0000	.0004	.0014	.0021	.0027	.0040	.0009	.0001	.0000	.0000	.0116	13.52
E	.0000	.0000	.0001	.0002	.0006	.0010	.0027	.0029	.0009	.0000	.0000	.0000	.0084	14.04
ESE	.0000	.0000	.0000	.0002	.0007	.0015	.0023	.0013	.0006	.0000	.0000	.0000	.0066	12.83
SE	.0000	.0000	.0001	.0005	.0014	.0012	.0016	.0006	.0000	.0000	.0000	.0000	.0056	10.64
SSE	.0000	.0000	.0000	.0003	.0010	.0008	.0003	.0004	.0001	.0000	.0000	.0000	.0030	10.13
S	.0000	.0000	.0001	.0004	.0005	.0016	.0019	.0000	.0000	.0000	.0000	.0000	.0046	10.56
SSW	.0000	.0000	.0000	.0003	.0005	.0020	.0040	.0024	.0010	.0000	.0000	.0000	.0103	13.50
SW	.0000	.0000	.0000	.0002	.0007	.0013	.0032	.0024	.0015	.0000	.0000	.0000	.0094	14.13
WSW	.0000	.0000	.0000	.0003	.0009	.0017	.0040	.0045	.0018	.0001	.0000	.0000	.0134	14.42
W	.0000	.0000	.0000	.0004	.0012	.0019	.0032	.0033	.0006	.0003	.0000	.0000	.0109	13.45
WNW	.0000	.0000	.0001	.0004	.0006	.0017	.0044	.0028	.0009	.0001	.0000	.0000	.0110	13.61
NW	.0000	.0000	.0001	.0003	.0004	.0023	.0041	.0023	.0009	.0000	.0000	.0000	.0104	13.27
NNW	.0000	.0000	.0000	.0002	.0004	.0013	.0032	.0019	.0000	.0000	.0000	.0000	.0070	12.85
TOTAL	.0000	.0000	.0008	.0049	.0120	.0239	.0436	.0319	.0096	.0006	.0000	.0000	.1273	13.12

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSES FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY E

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0002	.0004	.0008	.0015	.0021	.0005	.0000	.0000	.0000	.0000	.0055	10.80
NNE	.0000	.0000	.0001	.0005	.0006	.0014	.0024	.0010	.0000	.0000	.0000	.0000	.0000	11.59
NE	.0000	.0000	.0001	.0003	.0007	.0020	.0028	.0009	.0006	.0001	.0000	.0000	.0070	12.44
ENE	.0000	.0000	.0001	.0006	.0007	.0014	.0014	.0015	.0008	.0000	.0000	.0000	.0066	12.62
E	.0000	.0000	.0001	.0003	.0004	.0014	.0010	.0009	.0001	.0000	.0000	.0000	.0042	11.60
ESE	.0000	.0000	.0000	.0004	.0008	.0022	.0020	.0016	.0008	.0000	.0000	.0000	.0078	12.74
SE	.0000	.0000	.0001	.0005	.0013	.0028	.0019	.0010	.0001	.0000	.0000	.0000	.0078	10.83
SSE	.0000	.0000	.0002	.0006	.0014	.0033	.0042	.0005	.0000	.0000	.0000	.0000	.0102	10.81
S	.0000	.0000	.0002	.0007	.0016	.0039	.0033	.0011	.0005	.0000	.0000	.0000	.0113	11.26
SSW	.0000	.0000	.0002	.0007	.0022	.0077	.0106	.0025	.0006	.0000	.0000	.0000	.0244	11.83
SW	.0000	.0000	.0003	.0010	.0018	.0069	.0079	.0031	.0008	.0014	.0000	.0000	.0231	12.85
WSW	.0000	.0000	.0003	.0012	.0020	.0066	.0073	.0039	.0004	.0000	.0000	.0000	.0217	11.80
W	.0000	.0000	.0002	.0011	.0012	.0050	.0021	.0004	.0003	.0000	.0000	.0000	.0103	10.24
WNW	.0000	.0000	.0003	.0008	.0009	.0032	.0023	.0026	.0008	.0000	.0000	.0000	.0109	12.29
NW	.0000	.0000	.0002	.0008	.0010	.0022	.0023	.0011	.0000	.0000	.0000	.0000	.0076	10.86
NNW	.0000	.0000	.0002	.0006	.0006	.0014	.0015	.0010	.0000	.0000	.0000	.0000	.0053	10.90
TOTAL	.0000	.0000	.0030	.0107	.0179	.0529	.0550	.0236	.0058	.0015	.0000	.0000	.1704	11.73

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSES FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY F

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0002	.0007	.0002	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0014	6.33
NNE	.0000	.0000	.0002	.0003	.0002	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0007	6.10
NE	.0000	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0001	5.80
ENE	.0000	.0000	.0000	.0001	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0003	6.43
E	.0000	.0000	.0000	.0001	.0002	.0011	.0005	.0003	.0000	.0000	.0000	.0000	.0022	11.08
ESE	.0000	.0000	.0001	.0001	.0004	.0030	.0011	.0000	.0001	.0000	.0000	.0000	.0048	10.47
SE	.0000	.0000	.0000	.0003	.0002	.0013	.0006	.0001	.0000	.0000	.0000	.0000	.0025	10.21
SSE	.0000	.0000	.0001	.0003	.0006	.0016	.0001	.0006	.0001	.0001	.0000	.0000	.0035	11.03
S	.0000	.0000	.0001	.0003	.0004	.0012	.0014	.0005	.0003	.0000	.0000	.0000	.0042	11.87
SSW	.0000	.0000	.0002	.0004	.0008	.0035	.0023	.0010	.0005	.0000	.0000	.0000	.0007	11.62
SW	.0000	.0000	.0003	.0004	.0003	.0016	.0004	.0008	.0000	.0000	.0000	.0000	.0038	10.47
WSW	.0000	.0000	.0004	.0005	.0001	.0003	.0001	.0001	.0000	.0000	.0000	.0000	.0015	7.11
W	.0000	.0000	.0004	.0005	.0002	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0013	6.04
WNW	.0000	.0000	.0005	.0004	.0001	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0012	5.73
NW	.0000	.0000	.0003	.0005	.0003	.0004	.0001	.0000	.0000	.0000	.0000	.0000	.0016	6.94
NNW	.0000	.0000	.0003	.0002	.0003	.0003	.0005	.0001	.0000	.0000	.0000	.0000	.0017	9.05
TOTAL	.0000	.0000	.0032	.0052	.0043	.0150	.0072	.0035	.0010	.0001	.0000	.0000	.0395	10.05

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSES FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY G

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0004	.0003	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0008	5.07
NNE	.0000	.0000	.0001	.0002	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0004	6.90
NE	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0001	5.56
ENE	.0000	.0000	.0000	.0001	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0003	7.96
E	.0000	.0000	.0000	.0001	.0002	.0001	.0003	.0000	.0000	.0000	.0000	.0000	.0007	10.01
ESE	.0000	.0000	.0000	.0001	.0003	.0010	.0000	.0000	.0000	.0000	.0000	.0000	.0015	9.08
SE	.0000	.0000	.0001	.0002	.0004	.0005	.0000	.0000	.0001	.0000	.0000	.0000	.0012	9.08
SSE	.0000	.0000	.0001	.0002	.0003	.0010	.0004	.0000	.0000	.0000	.0000	.0000	.0021	9.45
S	.0000	.0000	.0001	.0001	.0001	.0001	.0003	.0000	.0000	.0000	.0000	.0000	.0006	9.62
SSW	.0000	.0000	.0000	.0001	.0002	.0009	.0006	.0001	.0000	.0000	.0000	.0000	.0019	10.79
SW	.0000	.0000	.0002	.0001	.0001	.0004	.0004	.0000	.0000	.0000	.0000	.0000	.0012	9.28
WSW	.0000	.0000	.0002	.0002	.0001	.0004	.0000	.0000	.0000	.0000	.0000	.0000	.0009	7.07
W	.0000	.0000	.0003	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0006	4.42
WNW	.0000	.0000	.0004	.0002	.0000	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0010	6.00
NW	.0000	.0000	.0004	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0007	4.48
NNW	.0000	.0000	.0004	.0002	.0000	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0008	5.94
TOTAL	.0000	.0000	.0028	.0025	.0022	.0048	.0021	.0002	.0001	.0000	.0000	.0000	.0147	8.21

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSES FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

APPENDIX D

Part D-2: Analysis for Elevated Portion of Mixed Mode Source

a) Wind speed at 44.50 meters

b) Wind direction at 10 meters

c) Delta temperature between 10 and 60 meters

d) Radwaste building source

Note: In the tables of computer printout the term, "Split-H", should be replaced by the term, "mixed mode".

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY A

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0001	.0000	.0000	.0004	.0004	.0010	.0000	.0000	.0000	.0000	.0000	.0019	10.09
NNE	.0000	.0000	.0003	.0000	.0004	.0002	.0002	.0000	.0000	.0000	.0000	.0000	.0011	7.87
NE	.0000	.0000	.0001	.0000	.0005	.0012	.0012	.0002	.0000	.0000	.0000	.0000	.0032	10.17
ENE	.0000	.0000	.0003	.0000	.0018	.0017	.0016	.0001	.0000	.0000	.0000	.0000	.0055	9.20
E	.0000	.0001	.0013	.0000	.0008	.0007	.0005	.0002	.0000	.0000	.0000	.0000	.0035	7.58
ESE	.0000	.0001	.0006	.0000	.0004	.0013	.0023	.0004	.0000	.0000	.0000	.0000	.0052	10.28
SE	.0000	.0001	.0003	.0000	.0023	.0050	.0020	.0002	.0000	.0000	.0000	.0000	.0098	9.19
SSE	.0000	.0000	.0003	.0000	.0014	.0029	.0016	.0001	.0000	.0000	.0000	.0000	.0003	9.36
S	.0000	.0001	.0005	.0000	.0012	.0017	.0035	.0007	.0000	.0000	.0000	.0000	.0077	10.50
SSW	.0000	.0000	.0004	.0000	.0014	.0012	.0020	.0006	.0000	.0000	.0000	.0000	.0056	10.14
SW	.0000	.0000	.0001	.0000	.0004	.0012	.0011	.0008	.0000	.0000	.0000	.0000	.0036	11.35
WSW	.0000	.0000	.0003	.0000	.0007	.0007	.0011	.0008	.0000	.0000	.0000	.0000	.0036	10.86
W	.0000	.0000	.0001	.0000	.0009	.0011	.0010	.0002	.0000	.0000	.0000	.0000	.0033	9.89
WNW	.0000	.0000	.0003	.0000	.0000	.0007	.0006	.0002	.0000	.0000	.0000	.0000	.0018	10.40
NW	.0000	.0004	.0006	.0000	.0003	.0012	.0006	.0003	.0000	.0000	.0000	.0000	.0034	8.53
NNW	.0000	.0000	.0001	.0000	.0004	.0003	.0003	.0001	.0000	.0000	.0000	.0000	.0012	9.60
TOTAL	.0000	.0009	.0055	.0000	.0131	.0214	.0206	.0050	.0000	.0000	.0000	.0000	.0667	9.74

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSIS FOR ELEVATED PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY B

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0000	.0000	.0001	.0002	.0000	.0000	.0000	.0000	.0000	.0003	12.55
NNE	.0000	.0000	.0000	.0001	.0000	.0002	.0005	.0000	.0000	.0000	.0000	.0000	.0008	11.03
NE	.0000	.0000	.0000	.0000	.0003	.0002	.0005	.0001	.0000	.0000	.0000	.0000	.0011	11.14
ENE	.0000	.0000	.0000	.0003	.0003	.0002	.0002	.0000	.0000	.0000	.0000	.0000	.0011	8.30
E	.0000	.0000	.0000	.0001	.0000	.0004	.0008	.0001	.0000	.0000	.0000	.0000	.0014	11.69
ESE	.0000	.0000	.0000	.0000	.0001	.0007	.0003	.0000	.0000	.0000	.0000	.0000	.0011	10.68
SE	.0000	.0000	.0000	.0001	.0003	.0002	.0005	.0000	.0000	.0000	.0000	.0000	.0011	10.09
SSE	.0000	.0000	.0000	.0001	.0001	.0003	.0002	.0000	.0000	.0000	.0000	.0000	.0008	10.07
S	.0000	.0000	.0000	.0000	.0007	.0005	.0002	.0001	.0000	.0000	.0000	.0000	.0015	9.61
SSW	.0000	.0000	.0000	.0001	.0003	.0003	.0004	.0001	.0000	.0000	.0000	.0000	.0012	10.37
SW	.0000	.0000	.0000	.0001	.0000	.0001	.0001	.0001	.0000	.0000	.0000	.0000	.0003	10.82
WSW	.0000	.0000	.0000	.0000	.0001	.0001	.0004	.0001	.0000	.0000	.0000	.0000	.0007	12.32
W	.0000	.0000	.0000	.0001	.0000	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0003	9.61
WNW	.0000	.0000	.0000	.0003	.0000	.0000	.0002	.0001	.0000	.0000	.0000	.0000	.0006	9.55
NW	.0000	.0000	.0000	.0001	.0000	.0002	.0004	.0000	.0000	.0000	.0000	.0000	.0007	10.82
NNW	.0000	.0000	.0000	.0000	.0000	.0002	.0002	.0001	.0000	.0000	.0000	.0000	.0006	12.61
TOTAL	.0000	.0000	.0000	.0013	.0021	.0040	.0053	.0009	.0000	.0000	.0000	.0000	.0136	10.57

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSIS FOR ELEVATED PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY C

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0001	.0001	.0001	.0002	.0001	.0000	.0000	.0000	.0000	.0006	10.85
NNE	.0000	.0000	.0000	.0000	.0001	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0002	9.85
NE	.0000	.0000	.0000	.0000	.0003	.0001	.0006	.0001	.0000	.0000	.0000	.0000	.0011	11.74
ENE	.0000	.0000	.0000	.0000	.0000	.0002	.0006	.0000	.0000	.0000	.0000	.0000	.0009	12.06
E	.0000	.0000	.0000	.0003	.0001	.0007	.0000	.0000	.0000	.0000	.0000	.0000	.0010	8.06
ESE	.0000	.0000	.0000	.0001	.0003	.0000	.0006	.0000	.0000	.0000	.0000	.0000	.0010	10.79
SE	.0000	.0001	.0000	.0000	.0004	.0004	.0001	.0000	.0000	.0000	.0000	.0000	.0010	8.12
SSE	.0000	.0000	.0000	.0000	.0003	.0008	.0000	.0000	.0000	.0000	.0000	.0000	.0012	8.90
S	.0000	.0000	.0000	.0003	.0004	.0002	.0004	.0000	.0000	.0000	.0000	.0000	.0014	8.91
SSW	.0000	.0000	.0000	.0000	.0000	.0004	.0005	.0003	.0000	.0000	.0000	.0000	.0011	12.69
SW	.0000	.0000	.0000	.0000	.0004	.0002	.0006	.0002	.0000	.0000	.0000	.0000	.0015	11.39
WSW	.0000	.0000	.0000	.0000	.0001	.0000	.0005	.0003	.0000	.0000	.0000	.0000	.0008	13.58
W	.0000	.0000	.0000	.0003	.0001	.0004	.0004	.0000	.0000	.0000	.0000	.0000	.0012	9.53
WNW	.0000	.0000	.0000	.0000	.0001	.0003	.0003	.0001	.0000	.0000	.0000	.0000	.0008	11.48
NW	.0000	.0000	.0000	.0000	.0000	.0002	.0007	.0000	.0000	.0000	.0000	.0000	.0010	12.13
NNW	.0000	.0000	.0000	.0000	.0000	.0001	.0003	.0000	.0000	.0000	.0000	.0000	.0004	12.61
TOTAL	.0000	.0001	.0000	.0011	.0027	.0044	.0060	.0012	.0000	.0000	.0000	.0000	.0154	10.67

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSIS FOR ELEVATED PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY D

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0003	.0000	.0009	.0011	.0024	.0021	.0003	.0000	.0000	.0000	.0000	.0071	10.19
NNE	.0000	.0001	.0000	.0004	.0020	.0012	.0020	.0005	.0000	.0000	.0000	.0000	.0063	10.68
NE	.0000	.0003	.0000	.0006	.0022	.0045	.0046	.0005	.0000	.0000	.0000	.0000	.0127	10.85
ENE	.0000	.0001	.0000	.0006	.0021	.0060	.0055	.0007	.0000	.0000	.0000	.0000	.0150	11.18
E	.0000	.0000	.0000	.0014	.0013	.0028	.0025	.0007	.0000	.0000	.0000	.0000	.0087	10.51
ESE	.0000	.0005	.0000	.0010	.0013	.0031	.0041	.0005	.0000	.0000	.0000	.0000	.0105	10.74
SE	.0000	.0004	.0000	.0017	.0033	.0062	.0031	.0004	.0000	.0000	.0000	.0000	.0151	9.72
SSE	.0000	.0001	.0000	.0006	.0021	.0046	.0021	.0001	.0000	.0000	.0000	.0000	.0095	10.06
S	.0000	.0001	.0000	.0014	.0021	.0020	.0047	.0005	.0000	.0000	.0000	.0000	.0109	10.72
SSW	.0000	.0003	.0000	.0005	.0017	.0023	.0054	.0010	.0000	.0000	.0000	.0000	.0111	11.67
SW	.0000	.0004	.0000	.0009	.0014	.0029	.0036	.0008	.0000	.0000	.0000	.0000	.0099	10.88
WSW	.0000	.0001	.0000	.0010	.0017	.0039	.0046	.0010	.0000	.0000	.0000	.0000	.0122	11.24
W	.0000	.0001	.0000	.0009	.0024	.0053	.0050	.0008	.0000	.0000	.0000	.0000	.0145	11.00
WNW	.0000	.0006	.0000	.0012	.0022	.0025	.0046	.0011	.0000	.0000	.0000	.0000	.0122	10.73
NW	.0000	.0005	.0000	.0012	.0021	.0020	.0060	.0010	.0000	.0000	.0000	.0000	.0128	11.15
NNW	.0000	.0004	.0000	.0009	.0011	.0017	.0033	.0008	.0000	.0000	.0000	.0000	.0082	11.01
TOTAL	.0000	.0043	.0000	.0149	.0302	.0535	.0632	.0105	.0000	.0000	.0000	.0000	.1766	10.79

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSIS FOR ELEVATED PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY E

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0001	.0000	.0023	.0022	.0033	.0000	.0016	.0000	.0000	.0000	.0000	.0095	9.74
NNE	.0000	.0008	.0000	.0013	.0025	.0025	.0000	.0014	.0001	.0000	.0000	.0000	.0086	9.37
NE	.0000	.0003	.0000	.0019	.0018	.0027	.0000	.0021	.0001	.0000	.0000	.0000	.0088	10.10
ENE	.0000	.0008	.0000	.0019	.0033	.0029	.0000	.0015	.0000	.0000	.0000	.0000	.0103	9.15
E	.0000	.0003	.0000	.0013	.0018	.0016	.0000	.0015	.0000	.0000	.0000	.0000	.0065	9.76
ESE	.0000	.0004	.0000	.0005	.0020	.0031	.0000	.0023	.0000	.0000	.0000	.0000	.0063	10.91
SE	.0000	.0003	.0000	.0019	.0029	.0056	.0000	.0028	.0000	.0000	.0000	.0000	.0134	10.46
SSE	.0000	.0003	.0000	.0022	.0035	.0059	.0000	.0033	.0001	.0000	.0000	.0000	.0153	10.47
S	.0000	.0008	.0000	.0019	.0041	.0067	.0000	.0039	.0001	.0000	.0000	.0000	.0175	10.44
SSW	.0000	.0008	.0000	.0019	.0041	.0089	.0000	.0078	.0002	.0000	.0000	.0000	.0238	11.35
SW	.0000	.0013	.0000	.0035	.0054	.0072	.0000	.0069	.0002	.0000	.0000	.0000	.0246	10.46
WSW	.0000	.0006	.0000	.0040	.0068	.0081	.0000	.0066	.0002	.0000	.0000	.0000	.0263	10.45
W	.0000	.0011	.0000	.0031	.0058	.0052	.0000	.0051	.0000	.0000	.0000	.0000	.0203	10.04
WNW	.0000	.0013	.0000	.0040	.0042	.0036	.0000	.0032	.0001	.0000	.0000	.0000	.0164	9.15
NW	.0000	.0005	.0000	.0031	.0043	.0040	.0000	.0022	.0001	.0000	.0000	.0000	.0142	9.42
NNW	.0000	.0010	.0000	.0026	.0034	.0027	.0000	.0014	.0000	.0000	.0000	.0000	.0111	8.69
TOTAL	.0000	.0107	.0000	.0372	.0579	.0741	.0000	.0536	.0013	.0000	.0000	.0000	.2348	10.13

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSIS FOR ELEVATED PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY F

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0004	.0017	.0000	.0031	.0004	.0000	.0000	.0000	.0000	.0000	.0056	8.89
NNE	.0000	.0000	.0004	.0011	.0000	.0013	.0003	.0000	.0000	.0000	.0000	.0000	.0032	8.38
NE	.0000	.0000	.0003	.0001	.0000	.0004	.0001	.0000	.0000	.0000	.0000	.0000	.0009	7.55
ENE	.0000	.0000	.0001	.0004	.0000	.0003	.0004	.0000	.0000	.0000	.0000	.0000	.0012	9.76
E	.0000	.0000	.0003	.0003	.0000	.0003	.0004	.0000	.0002	.0000	.0000	.0000	.0015	9.93
ESE	.0000	.0000	.0000	.0004	.0000	.0007	.0010	.0000	.0004	.0000	.0000	.0000	.0025	12.35
SE	.0000	.0000	.0000	.0004	.0000	.0012	.0003	.0000	.0002	.0000	.0000	.0000	.0021	10.89
SSE	.0000	.0000	.0005	.0007	.0000	.0013	.0013	.0000	.0002	.0000	.0000	.0000	.0040	10.27
S	.0000	.0000	.0005	.0007	.0000	.0012	.0009	.0000	.0002	.0000	.0000	.0000	.0035	9.73
SSW	.0000	.0000	.0003	.0012	.0000	.0019	.0016	.0000	.0005	.0000	.0000	.0000	.0055	10.79
SW	.0000	.0000	.0001	.0026	.0000	.0017	.0006	.0000	.0002	.0000	.0000	.0000	.0052	9.01
WSW	.0000	.0000	.0006	.0032	.0000	.0023	.0002	.0000	.0000	.0000	.0000	.0000	.0063	7.80
W	.0000	.0000	.0003	.0030	.0000	.0023	.0003	.0000	.0000	.0000	.0000	.0000	.0060	8.23
WNW	.0000	.0000	.0003	.0041	.0000	.0017	.0002	.0000	.0000	.0000	.0000	.0000	.0063	7.59
NW	.0000	.0000	.0009	.0023	.0000	.0025	.0005	.0000	.0000	.0000	.0000	.0000	.0062	8.16
NNW	.0000	.0000	.0005	.0026	.0000	.0009	.0005	.0000	.0000	.0000	.0000	.0000	.0045	7.81
TOTAL	.0000	.0000	.0055	.0247	.0000	.0231	.0092	.0000	.0020	.0000	.0000	.0000	.0645	8.94

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSIS FOR ELEVATED PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY G

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0001	.0000	.0027	.0012	.0003	.0000	.0000	.0000	.0000	.0000	.0044	8.23
NNE	.0000	.0000	.0003	.0000	.0008	.0008	.0001	.0000	.0000	.0000	.0000	.0000	.0020	7.94
NE	.0000	.0000	.0003	.0000	.0003	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0006	5.62
ENE	.0000	.0000	.0000	.0000	.0000	.0002	.0002	.0000	.0000	.0000	.0000	.0000	.0004	12.28
E	.0000	.0000	.0000	.0000	.0001	.0003	.0003	.0000	.0000	.0000	.0000	.0000	.0007	11.76
ESE	.0000	.0000	.0003	.0000	.0003	.0002	.0006	.0000	.0001	.0000	.0000	.0000	.0014	10.13
SE	.0000	.0000	.0001	.0000	.0005	.0007	.0006	.0000	.0000	.0000	.0000	.0000	.0020	10.45
SSE	.0000	.0000	.0001	.0000	.0007	.0008	.0006	.0000	.0001	.0000	.0000	.0000	.0022	10.21
S	.0000	.0000	.0003	.0000	.0005	.0002	.0002	.0000	.0000	.0000	.0000	.0000	.0013	7.71
SSW	.0000	.0000	.0004	.0000	.0003	.0003	.0002	.0000	.0001	.0000	.0000	.0000	.0013	8.56
SW	.0000	.0000	.0000	.0000	.0016	.0003	.0002	.0000	.0000	.0000	.0000	.0000	.0021	8.11
WSW	.0000	.0000	.0001	.0000	.0017	.0009	.0002	.0000	.0000	.0000	.0000	.0000	.0029	8.36
W	.0000	.0000	.0000	.0000	.0022	.0011	.0000	.0000	.0000	.0000	.0000	.0000	.0033	8.01
WNW	.0000	.0000	.0011	.0000	.0031	.0011	.0001	.0000	.0000	.0000	.0000	.0000	.0053	6.80
NW	.0000	.0000	.0005	.0000	.0025	.0015	.0000	.0000	.0000	.0000	.0000	.0000	.0045	7.52
NNW	.0000	.0000	.0005	.0000	.0030	.0011	.0001	.0000	.0000	.0000	.0000	.0000	.0046	7.27
TOTAL	.0000	.0000	.0041	.0000	.0202	.0109	.0036	.0000	.0003	.0000	.0000	.0000	.0391	8.17

PERIOD OF RECORD: 6/1/74 – 5/31/75

ANALYSIS FOR ELEVATED PORTION OF SPLIT-H SOURCE

APPENDIX D

Part 2: Mixed Mode Joint Frequency Distribution of Grazing Period Data Base for the Radwaste Building Source

6/01/74 - 10/15/74

and

4/15/75 - 05/31/75

APPENDIX D

Part D-3: Analysis for Ground Level Portion of Mixed Mode Source

a) Wind speed at 10 meters

b) Wind direction at 10 meters

c) Delta temperature between 10 and 60 meters

d) Radwaste building source

Note: In the tables of computer printout the term, "Split-H", should be replaced by the term, "mixed mode".

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY A

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0001	.0001	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0005	8.66
NNE	.0000	.0000	.0000	.0001	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0003	7.21
NE	.0000	.0000	.0000	.0001	.0005	.0006	.0005	.0003	.0003	.0000	.0000	.0000	.0023	12.21
ENE	.0000	.0000	.0000	.0004	.0006	.0007	.0003	.0000	.0000	.0000	.0000	.0000	.0020	8.83
E	.0000	.0000	.0000	.0001	.0002	.0003	.0002	.0000	.0000	.0000	.0000	.0000	.0008	8.98
ESE	.0000	.0000	.0000	.0001	.0006	.0011	.0012	.0000	.0000	.0000	.0000	.0000	.0030	10.57
SE	.0000	.0000	.0000	.0006	.0019	.0010	.0003	.0000	.0000	.0000	.0000	.0000	.0038	8.28
SSE	.0000	.0000	.0000	.0003	.0011	.0006	.0002	.0000	.0000	.0000	.0000	.0000	.0022	8.39
S	.0000	.0000	.0000	.0003	.0006	.0017	.0022	.0010	.0000	.0000	.0000	.0000	.0059	11.70
SSW	.0000	.0000	.0000	.0004	.0004	.0007	.0009	.0013	.0000	.0000	.0000	.0000	.0038	12.15
SW	.0000	.0000	.0000	.0001	.0002	.0003	.0015	.0013	.0000	.0000	.0000	.0000	.0034	13.55
WSW	.0000	.0000	.0000	.0000	.0002	.0004	.0025	.0010	.0000	.0000	.0000	.0000	.0042	13.16
W	.0000	.0000	.0000	.0001	.0003	.0003	.0005	.0000	.0000	.0000	.0000	.0000	.0012	10.18
WNW	.0000	.0000	.0000	.0000	.0002	.0003	.0006	.0000	.0000	.0000	.0000	.0000	.0011	11.22
NW	.0000	.0000	.0000	.0001	.0004	.0001	.0005	.0000	.0000	.0000	.0000	.0000	.0011	10.01
NNW	.0000	.0000	.0000	.0000	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0002	7.93
TOTAL	.0000	.0000	.0002	.0028	.0076	.0086	.0115	.0049	.0003	.0000	.0000	.0000	.0359	11.03

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSIS FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY B

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0000	.0001	.0000	.0000	.0005	.0000	.0000	.0000	.0000	.0006	15.63
NNE	.0000	.0000	.0000	.0000	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0002	8.56
NE	.0000	.0000	.0000	.0001	.0000	.0002	.0004	.0000	.0000	.0000	.0000	.0000	.0006	11.23
ENE	.0000	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0001	5.20
E	.0000	.0000	.0000	.0000	.0001	.0004	.0000	.0000	.0000	.0000	.0000	.0000	.0005	9.38
ESE	.0000	.0000	.0000	.0000	.0002	.0002	.0002	.0003	.0000	.0000	.0000	.0000	.0009	12.20
SE	.0000	.0000	.0000	.0000	.0001	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0002	9.39
SSE	.0000	.0000	.0000	.0000	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0002	8.19
S	.0000	.0000	.0000	.0002	.0002	.0001	.0006	.0000	.0000	.0000	.0000	.0000	.0010	10.51
SSW	.0000	.0000	.0000	.0001	.0001	.0002	.0004	.0003	.0000	.0000	.0000	.0000	.0009	12.75
SW	.0000	.0000	.0000	.0000	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0001	8.38
WSW	.0000	.0000	.0000	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0001	10.00
W	.0000	.0000	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0001	6.81
WNW	.0000	.0000	.0000	.0000	.0000	.0001	.0002	.0000	.0000	.0000	.0000	.0000	.0003	11.73
NW	.0000	.0000	.0000	.0000	.0001	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0003	9.04
NNW	.0000	.0000	.0000	.0000	.0001	.0001	.0002	.0000	.0000	.0000	.0000	.0000	.0004	11.16
TOTAL	.0000	.0000	.0001	.0005	.0011	.0018	.0019	.0011	.0000	.0000	.0000	.0000	.0065	11.18

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSIS FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY C

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0000	.0000	.0000	.0004	.0000	.0003	.0000	.0000	.0000	.0007	15.83
NNE	.0000	.0000	.0000	.0000	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0002	7.99
NE	.0000	.0000	.0000	.0000	.0001	.0002	.0004	.0000	.0000	.0000	.0000	.0000	.0006	11.51
ENE	.0000	.0000	.0000	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0001	10.00
E	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	3.50
ESE	.0000	.0000	.0000	.0000	.0000	.0002	.0002	.0003	.0000	.0000	.0000	.0000	.0008	13.03
SE	.0000	.0001	.0000	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0003	6.53
SSE	.0000	.0000	.0000	.0001	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0003	7.05
S	.0000	.0000	.0000	.0001	.0001	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0004	7.91
SSW	.0000	.0000	.0000	.0000	.0001	.0002	.0009	.0000	.0000	.0000	.0000	.0000	.0012	11.96
SW	.0000	.0000	.0000	.0001	.0000	.0002	.0006	.0000	.0000	.0000	.0000	.0000	.0009	11.39
WSW	.0000	.0000	.0000	.0000	.0000	.0002	.0002	.0000	.0000	.0000	.0000	.0000	.0004	11.69
W	.0000	.0000	.0000	.0000	.0002	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0004	8.24
WNW	.0000	.0000	.0000	.0000	.0001	.0001	.0002	.0005	.0000	.0000	.0000	.0000	.0009	14.25
NW	.0000	.0000	.0000	.0000	.0001	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0003	9.13
NNW	.0000	.0000	.0000	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0001	10.00
TOTAL	.0000	.0000	.0001	.0006	.0011	.0018	.0028	.0008	.0003	.0000	.0000	.0000	.0074	11.52

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSIS FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY D

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0001	.0002	.0010	.0008	.0003	.0000	.0000	.0000	.0000	.0025	11.18
NNE	.0000	.0000	.0000	.0003	.0004	.0007	.0015	.0015	.0000	.0000	.0000	.0000	.0043	12.73
NE	.0000	.0000	.0000	.0004	.0003	.0018	.0010	.0005	.0000	.0000	.0000	.0000	.0045	10.59
ENE	.0000	.0000	.0000	.0004	.0012	.0014	.0006	.0000	.0000	.0000	.0000	.0000	.0036	9.24
E	.0000	.0000	.0000	.0003	.0006	.0012	.0015	.0008	.0000	.0000	.0000	.0000	.0043	11.52
ESE	.0000	.0000	.0000	.0003	.0008	.0021	.0019	.0008	.0000	.0000	.0000	.0000	.0058	11.24
SE	.0000	.0000	.0001	.0007	.0022	.0014	.0010	.0005	.0000	.0000	.0000	.0000	.0060	9.52
SSE	.0000	.0000	.0001	.0004	.0018	.0012	.0000	.0000	.0003	.0000	.0000	.0000	.0038	9.05
S	.0000	.0000	.0001	.0004	.0006	.0023	.0016	.0000	.0000	.0000	.0000	.0000	.0050	10.15
SSW	.0000	.0000	.0000	.0004	.0007	.0024	.0041	.0008	.0000	.0000	.0000	.0000	.0083	11.70
SW	.0000	.0000	.0000	.0002	.0008	.0011	.0010	.0013	.0010	.0000	.0000	.0000	.0055	13.56
WSW	.0000	.0000	.0000	.0002	.0004	.0004	.0015	.0028	.0000	.0000	.0000	.0000	.0053	13.87
W	.0000	.0000	.0001	.0001	.0003	.0005	.0010	.0005	.0000	.0000	.0000	.0000	.0025	11.92
WNW	.0000	.0000	.0000	.0003	.0005	.0008	.0029	.0005	.0000	.0000	.0000	.0000	.0050	11.85
NW	.0000	.0000	.0000	.0002	.0003	.0011	.0031	.0000	.0000	.0000	.0000	.0000	.0047	11.56
NNW	.0000	.0000	.0000	.0002	.0003	.0012	.0012	.0003	.0000	.0000	.0000	.0000	.0033	11.12
TOTAL	.0000	.0000	.0007	.0048	.0117	.0206	.0247	.0106	.0013	.0000	.0000	.0000	.0745	11.37

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSIS FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY E

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0002	.0003	.0007	.0015	.0018	.0003	.0000	.0000	.0000	.0000	.0048	10.60
NNE	.0000	.0000	.0001	.0006	.0009	.0025	.0030	.0018	.0000	.0000	.0000	.0000	.0090	11.69
NE	.0000	.0000	.0001	.0004	.0010	.0029	.0037	.0003	.0000	.0000	.0000	.0000	.0084	10.96
ENE	.0000	.0000	.0001	.0006	.0008	.0018	.0000	.0000	.0000	.0000	.0000	.0000	.0034	8.26
E	.0000	.0000	.0001	.0004	.0005	.0012	.0013	.0005	.0003	.0000	.0000	.0000	.0044	11.39
ESE	.0000	.0000	.0000	.0004	.0011	.0032	.0010	.0010	.0000	.0000	.0000	.0000	.0066	10.73
SE	.0000	.0000	.0001	.0005	.0018	.0037	.0015	.0005	.0000	.0000	.0000	.0000	.0081	10.00
SSE	.0000	.0000	.0001	.0007	.0022	.0049	.0052	.0005	.0000	.0000	.0000	.0000	.0136	10.69
S	.0000	.0000	.0002	.0008	.0024	.0043	.0047	.0018	.0008	.0000	.0000	.0000	.0150	11.58
SSW	.0000	.0000	.0001	.0008	.0020	.0081	.0137	.0031	.0005	.0000	.0000	.0000	.0284	12.01
SW	.0000	.0000	.0003	.0010	.0015	.0049	.0090	.0046	.0005	.0003	.0000	.0000	.0221	12.60
WSW	.0000	.0000	.0003	.0009	.0016	.0057	.0042	.0018	.0000	.0000	.0000	.0000	.0145	11.00
W	.0000	.0000	.0003	.0008	.0012	.0042	.0020	.0008	.0003	.0000	.0000	.0000	.0095	10.64
WNW	.0000	.0000	.0002	.0007	.0008	.0015	.0015	.0003	.0000	.0000	.0000	.0000	.0050	9.98
NW	.0000	.0000	.0002	.0008	.0006	.0005	.0008	.0000	.0000	.0000	.0000	.0000	.0029	8.60
NNW	.0000	.0000	.0002	.0007	.0008	.0007	.0000	.0000	.0000	.0000	.0000	.0000	.0024	7.41
TOTAL	.0000	.0000	.0027	.0104	.0202	.0516	.0532	.0173	.0024	.0003	.0000	.0000	.1581	11.19

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSIS FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY F

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0003	.0011	.0004	.0004	.0000	.0000	.0000	.0000	.0000	.0000	.0023	6.44
NNE	.0000	.0000	.0003	.0005	.0003	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0013	6.40
NE	.0000	.0000	.0000	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0002	6.04
ENE	.0000	.0000	.0001	.0001	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0005	6.39
E	.0000	.0000	.0000	.0001	.0002	.0018	.0008	.0005	.0000	.0000	.0000	.0000	.0033	11.38
ESE	.0000	.0000	.0000	.0002	.0004	.0051	.0020	.0000	.0000	.0000	.0000	.0000	.0077	10.51
SE	.0000	.0000	.0000	.0002	.0003	.0022	.0010	.0000	.0000	.0000	.0000	.0000	.0037	10.36
SSE	.0000	.0000	.0001	.0002	.0008	.0020	.0003	.0000	.0000	.0000	.0000	.0000	.0034	9.20
S	.0000	.0000	.0001	.0002	.0004	.0009	.0013	.0010	.0000	.0000	.0000	.0000	.0039	12.00
SSW	.0000	.0000	.0002	.0005	.0009	.0008	.0020	.0020	.0005	.0000	.0000	.0000	.0078	12.39
SW	.0000	.0000	.0003	.0005	.0004	.0004	.0003	.0000	.0000	.0000	.0000	.0000	.0019	7.78
WSW	.0000	.0000	.0005	.0006	.0002	.0004	.0003	.0000	.0000	.0000	.0000	.0000	.0020	7.31
W	.0000	.0000	.0004	.0007	.0002	.0004	.0000	.0000	.0000	.0000	.0000	.0000	.0017	6.36
WNW	.0000	.0000	.0006	.0006	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0012	4.74
NW	.0000	.0000	.0004	.0004	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0008	4.86
NNW	.0000	.0000	.0004	.0004	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0010	5.42
TOTAL	.0000	.0000	.0038	.0062	.0052	.0158	.0080	.0035	.0005	.0000	.0000	.0000	.0429	9.70

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSIS FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY G

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0007	.0006	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0016	5.03
NNE	.0000	.0000	.0002	.0003	.0001	.0000	.0003	.0000	.0000	.0000	.0000	.0000	.0009	7.88
NE	.0000	.0000	.0001	.0000	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0002	6.12
ENE	.0000	.0000	.0000	.0001	.0001	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0002	6.85
E	.0000	.0000	.0000	.0001	.0004	.0003	.0005	.0000	.0000	.0000	.0000	.0000	.0013	10.04
ESE	.0000	.0000	.0000	.0001	.0001	.0009	.0000	.0000	.0000	.0000	.0000	.0000	.0011	9.32
SE	.0000	.0000	.0002	.0000	.0000	.0005	.0000	.0000	.0000	.0000	.0000	.0000	.0006	8.36
SSE	.0000	.0000	.0001	.0001	.0003	.0009	.0005	.0000	.0000	.0000	.0000	.0000	.0019	9.95
S	.0000	.0000	.0001	.0000	.0001	.0003	.0005	.0000	.0000	.0000	.0000	.0000	.0010	10.41
SSW	.0000	.0000	.0000	.0001	.0001	.0007	.0008	.0003	.0000	.0000	.0000	.0000	.0021	11.47
SW	.0000	.0000	.0004	.0001	.0002	.0005	.0008	.0000	.0000	.0000	.0000	.0000	.0019	9.51
WSW	.0000	.0000	.0002	.0003	.0002	.0007	.0000	.0000	.0000	.0000	.0000	.0000	.0015	7.65
W	.0000	.0000	.0004	.0004	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0008	4.53
WNW	.0000	.0000	.0006	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0008	4.09
NW	.0000	.0000	.0005	.0005	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0010	4.44
NNW	.0000	.0000	.0006	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0009	4.23
TOTAL	.0000	.0000	.0041	.0032	.0021	.0049	.0034	.0003	.0000	.0000	.0000	.0000	.0179	8.11

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSIS FOR GROUND LEVEL PORTION OF SPLIT-H SOURCE

APPENDIX D

Part D-4: Analysis for Elevated Portion of Mixed Mode Source

a) Wind speed at 44.50 meters

b) Wind direction at 10 meters

c) Delta temperature between 10 and 60 meters

d) Radwaste building source

Note: In the tables of computer printout the term, "Split-H", should be replaced by the term, "mixed mode."

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY A

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0000	.0004	.0007	.0010	.0000	.0000	.0000	.0000	.0000	.0021	10.25
NNE	.0000	.0000	.0003	.0000	.0007	.0004	.0002	.0000	.0000	.0000	.0000	.0000	.0016	7.78
NE	.0000	.0000	.0000	.0000	.0007	.0023	.0025	.0003	.0000	.0000	.0000	.0000	.0058	10.63
ENE	.0000	.0000	.0003	.0000	.0027	.0030	.0029	.0002	.0000	.0000	.0000	.0000	.0091	9.48
E	.0000	.0003	.0020	.0000	.0009	.0011	.0010	.0001	.0000	.0000	.0000	.0000	.0054	7.38
ESE	.0000	.0000	.0010	.0000	.0007	.0027	.0042	.0008	.0000	.0000	.0000	.0000	.0094	10.50
SE	.0000	.0003	.0003	.0000	.0040	.0095	.0038	.0002	.0000	.0000	.0000	.0000	.0181	9.23
SSE	.0000	.0000	.0003	.0000	.0020	.0055	.0025	.0001	.0000	.0000	.0000	.0000	.0104	9.45
S	.0000	.0003	.0010	.0000	.0025	.0027	.0069	.0014	.0000	.0000	.0000	.0000	.0147	10.44
SSW	.0000	.0000	.0008	.0000	.0029	.0021	.0029	.0006	.0000	.0000	.0000	.0000	.0092	9.45
SW	.0000	.0000	.0003	.0000	.0004	.0011	.0012	.0010	.0000	.0000	.0000	.0000	.0040	11.19
WSW	.0000	.0000	.0005	.0000	.0003	.0011	.0016	.0016	.0000	.0000	.0000	.0000	.0050	11.77
W	.0000	.0000	.0003	.0000	.0007	.0015	.0012	.0003	.0000	.0000	.0000	.0000	.0040	9.91
WNW	.0000	.0000	.0005	.0000	.0000	.0008	.0012	.0004	.0000	.0000	.0000	.0000	.0029	10.60
NW	.0000	.0005	.0008	.0000	.0004	.0021	.0004	.0003	.0000	.0000	.0000	.0000	.0045	8.07
NNW	.0000	.0000	.0000	.0000	.0003	.0004	.0002	.0000	.0000	.0000	.0000	.0000	.0009	9.35
TOTAL	.0000	.0014	.0082	.0000	.0196	.0369	.0337	.0072	.0000	.0000	.0000	.0000	.1070	9.76

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSES FOR ELEVATED PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY B

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0000	.0000	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0002	9.75
NNE	.0000	.0000	.0000	.0003	.0000	.0004	.0004	.0000	.0000	.0000	.0000	.0000	.0011	9.56
NE	.0000	.0000	.0000	.0000	.0004	.0000	.0008	.0001	.0000	.0000	.0000	.0000	.0014	11.55
ENE	.0000	.0000	.0000	.0005	.0007	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0012	6.09
E	.0000	.0000	.0000	.0003	.0000	.0004	.0014	.0000	.0000	.0000	.0000	.0000	.0021	11.23
ESE	.0000	.0000	.0000	.0000	.0003	.0008	.0006	.0001	.0000	.0000	.0000	.0000	.0018	10.86
SE	.0000	.0000	.0000	.0000	.0000	.0002	.0006	.0000	.0000	.0000	.0000	.0000	.0008	12.09
SSE	.0000	.0000	.0000	.0003	.0000	.0004	.0002	.0000	.0000	.0000	.0000	.0000	.0009	8.98
S	.0000	.0000	.0000	.0000	.0011	.0008	.0002	.0002	.0000	.0000	.0000	.0000	.0024	9.53
SSW	.0000	.0000	.0000	.0000	.0004	.0002	.0006	.0001	.0000	.0000	.0000	.0000	.0015	11.09
SW	.0000	.0000	.0000	.0003	.0000	.0002	.0002	.0000	.0000	.0000	.0000	.0000	.0008	8.81
WSW	.0000	.0000	.0000	.0000	.0000	.0000	.0002	.0000	.0000	.0000	.0000	.0000	.0002	13.01
W	.0000	.0000	.0000	.0003	.0000	.0002	.0000	.0000	.0000	.0000	.0000	.0000	.0005	6.95
WNW	.0000	.0000	.0000	.0003	.0000	.0000	.0004	.0001	.0000	.0000	.0000	.0000	.0008	10.26
NW	.0000	.0000	.0000	.0003	.0000	.0004	.0008	.0000	.0000	.0000	.0000	.0000	.0015	10.47
NNW	.0000	.0000	.0000	.0000	.0000	.0004	.0002	.0001	.0000	.0000	.0000	.0000	.0007	11.64
TOTAL	.0000	.0000	.0000	.0025	.0029	.0049	.0069	.0008	.0000	.0000	.0000	.0000	.0180	10.15

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSES FOR ELEVATED PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY C

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0003	.0003	.0000	.0000	.0001	.0000	.0000	.0000	.0000	.0007	8.08
NNE	.0000	.0000	.0000	.0000	.0003	.0002	.0002	.0000	.0000	.0000	.0000	.0000	.0007	9.85
NE	.0000	.0000	.0000	.0000	.0000	.0002	.0008	.0001	.0000	.0000	.0000	.0000	.0012	12.77
ENE	.0000	.0000	.0000	.0000	.0000	.0000	.0002	.0000	.0000	.0000	.0000	.0000	.0002	12.97
E	.0000	.0000	.0000	.0003	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0003	4.54
ESE	.0000	.0000	.0000	.0003	.0003	.0000	.0008	.0001	.0000	.0000	.0000	.0000	.0014	10.43
SE	.0000	.0001	.0000	.0000	.0009	.0007	.0000	.0000	.0000	.0000	.0000	.0000	.0015	8.25
SSE	.0000	.0000	.0000	.0000	.0004	.0011	.0000	.0000	.0000	.0000	.0000	.0000	.0015	8.98
S	.0000	.0000	.0000	.0005	.0009	.0004	.0008	.0000	.0000	.0000	.0000	.0000	.0026	8.87
SSW	.0000	.0000	.0000	.0000	.0000	.0007	.0006	.0004	.0000	.0000	.0000	.0000	.0017	12.56
SW	.0000	.0000	.0000	.0000	.0007	.0000	.0008	.0002	.0000	.0000	.0000	.0000	.0017	11.13
WSW	.0000	.0000	.0000	.0000	.0000	.0000	.0006	.0001	.0000	.0000	.0000	.0000	.0007	13.43
W	.0000	.0000	.0000	.0003	.0003	.0008	.0006	.0000	.0000	.0000	.0000	.0000	.0020	9.66
WNW	.0000	.0000	.0000	.0000	.0000	.0004	.0002	.0001	.0000	.0000	.0000	.0000	.0007	11.61
NW	.0000	.0000	.0000	.0000	.0000	.0004	.0006	.0000	.0000	.0000	.0000	.0000	.0010	11.69
NNW	.0000	.0000	.0000	.0000	.0000	.0000	.0004	.0000	.0000	.0000	.0000	.0000	.0004	12.97
TOTAL	.0000	.0000	.0000	.0016	.0039	.0049	.0068	.0012	.0000	.0000	.0000	.0000	.0185	10.36

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSES FOR ELEVATED PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY D

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0008	.0007	.0011	.0028	.0002	.0000	.0000	.0000	.0000	.0055	11.13
NNE	.0000	.0000	.0000	.0005	.0017	.0016	.0018	.0003	.0000	.0000	.0000	.0000	.0060	10.50
NE	.0000	.0000	.0000	.0003	.0024	.0033	.0048	.0003	.0000	.0000	.0000	.0000	.0111	11.16
ENE	.0000	.0003	.0000	.0005	.0021	.0052	.0037	.0002	.0000	.0000	.0000	.0000	.0120	10.49
E	.0000	.0000	.0000	.0010	.0015	.0027	.0031	.0003	.0000	.0000	.0000	.0000	.0087	10.69
ESE	.0000	.0010	.0000	.0008	.0017	.0035	.0055	.0004	.0000	.0000	.0000	.0000	.0130	10.64
SE	.0000	.0008	.0000	.0012	.0044	.0100	.0037	.0003	.0000	.0000	.0000	.0000	.0203	9.72
SSE	.0000	.0000	.0000	.0012	.0027	.0081	.0031	.0000	.0000	.0000	.0000	.0000	.0151	10.02
S	.0000	.0000	.0000	.0024	.0024	.0027	.0061	.0004	.0000	.0000	.0000	.0000	.0140	10.55
SSW	.0000	.0005	.0000	.0005	.0021	.0029	.0062	.0010	.0000	.0000	.0000	.0000	.0133	11.46
SW	.0000	.0000	.0000	.0008	.0013	.0033	.0030	.0003	.0000	.0000	.0000	.0000	.0086	10.75
WSW	.0000	.0000	.0000	.0008	.0013	.0016	.0011	.0003	.0000	.0000	.0000	.0000	.0051	9.99
W	.0000	.0000	.0000	.0012	.0007	.0012	.0013	.0003	.0000	.0000	.0000	.0000	.0047	9.76
WNW	.0000	.0000	.0000	.0008	.0017	.0020	.0023	.0007	.0000	.0000	.0000	.0000	.0075	10.79
NW	.0000	.0000	.0000	.0005	.0011	.0015	.0030	.0007	.0000	.0000	.0000	.0000	.0068	11.73
NNW	.0000	.0003	.0000	.0005	.0013	.0015	.0031	.0003	.0000	.0000	.0000	.0000	.0069	10.86
TOTAL	.0000	.0029	.0000	.0135	.0292	.0524	.0546	.0060	.0000	.0000	.0000	.0000	.1585	10.59

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSES FOR ELEVATED PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY E

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0021	.0017	.0031	.0000	.0016	.0000	.0000	.0000	.0000	.0085	9.96
NNE	.0000	.0003	.0000	.0014	.0032	.0037	.0000	.0026	.0001	.0000	.0000	.0000	.0112	10.40
NE	.0000	.0000	.0000	.0009	.0024	.0043	.0000	.0029	.0001	.0000	.0000	.0000	.0106	11.25
ENE	.0000	.0003	.0000	.0019	.0035	.0035	.0000	.0018	.0000	.0000	.0000	.0000	.0109	9.73
E	.0000	.0000	.0000	.0017	.0024	.0023	.0000	.0013	.0000	.0000	.0000	.0000	.0076	9.73
ESE	.0000	.0008	.0000	.0005	.0019	.0045	.0000	.0032	.0000	.0000	.0000	.0000	.0110	11.02
SE	.0000	.0000	.0000	.0019	.0026	.0074	.0000	.0037	.0000	.0000	.0000	.0000	.0156	11.04
SSE	.0000	.0000	.0000	.0014	.0039	.0090	.0000	.0050	.0001	.0000	.0000	.0000	.0194	11.33
S	.0000	.0005	.0000	.0021	.0045	.0101	.0000	.0043	.0001	.0000	.0000	.0000	.0216	10.71
SSW	.0000	.0003	.0000	.0019	.0045	.0084	.0000	.0082	.0003	.0000	.0000	.0000	.0235	11.61
SW	.0000	.0008	.0000	.0038	.0051	.0064	.0000	.0050	.0002	.0000	.0000	.0000	.0213	10.16
WSW	.0000	.0005	.0000	.0035	.0047	.0068	.0000	.0057	.0001	.0000	.0000	.0000	.0213	10.52
W	.0000	.0008	.0000	.0033	.0043	.0049	.0000	.0042	.0000	.0000	.0000	.0000	.0176	9.98
WNW	.0000	.0000	.0000	.0026	.0036	.0035	.0000	.0016	.0000	.0000	.0000	.0000	.0113	9.53
NW	.0000	.0003	.0000	.0021	.0045	.0027	.0000	.0005	.0000	.0000	.0000	.0000	.0101	8.66
NNW	.0000	.0010	.0000	.0023	.0036	.0035	.0000	.0008	.0000	.0000	.0000	.0000	.0112	8.55
TOTAL	.0000	.0056	.0000	.0333	.0564	.0839	.0000	.0524	.0012	.0000	.0000	.0000	.2327	10.42

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSES FOR ELEVATED PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY F

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0005	.0025	.0000	.0050	.0008	.0000	.0001	.0000	.0000	.0000	.0089	9.18
NNE	.0000	.0000	.0008	.0020	.0000	.0023	.0005	.0000	.0000	.0000	.0000	.0000	.0057	8.25
NE	.0000	.0000	.0003	.0003	.0000	.0004	.0002	.0000	.0000	.0000	.0000	.0000	.0012	8.13
ENE	.0000	.0000	.0003	.0007	.0000	.0004	.0007	.0000	.0000	.0000	.0000	.0000	.0021	9.10
E	.0000	.0000	.0000	.0003	.0000	.0004	.0003	.0000	.0002	.0000	.0000	.0000	.0013	12.01
ESE	.0000	.0000	.0000	.0003	.0000	.0008	.0009	.0000	.0007	.0000	.0000	.0000	.0027	13.23
SE	.0000	.0000	.0000	.0003	.0000	.0008	.0005	.0000	.0003	.0000	.0000	.0000	.0019	12.03
SSE	.0000	.0000	.0003	.0007	.0000	.0011	.0017	.0000	.0003	.0000	.0000	.0000	.0041	11.13
S	.0000	.0000	.0003	.0009	.0000	.0008	.0009	.0000	.0001	.0000	.0000	.0000	.0030	9.80
SSW	.0000	.0000	.0005	.0018	.0000	.0020	.0019	.0000	.0002	.0000	.0000	.0000	.0065	10.02
SW	.0000	.0000	.0003	.0025	.0000	.0020	.0009	.0000	.0001	.0000	.0000	.0000	.0058	8.88
WSW	.0000	.0000	.0010	.0038	.0000	.0025	.0003	.0000	.0001	.0000	.0000	.0000	.0077	7.65
W	.0000	.0000	.0003	.0032	.0000	.0031	.0003	.0000	.0001	.0000	.0000	.0000	.0070	8.45
WNW	.0000	.0000	.0005	.0042	.0000	.0025	.0002	.0000	.0000	.0000	.0000	.0000	.0075	7.71
NW	.0000	.0000	.0018	.0027	.0000	.0016	.0002	.0000	.0000	.0000	.0000	.0000	.0064	6.64
NNW	.0000	.0000	.0008	.0027	.0000	.0016	.0007	.0000	.0000	.0000	.0000	.0000	.0059	7.89
TOTAL	.0000	.0000	.0077	.0288	.0000	.0275	.0113	.0000	.00021	.0000	.0000	.0000	.0775	8.85

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSES FOR ELEVATED PORTION OF SPLIT-H SOURCE

DETROIT EDISON 60-METER TOWER
FREQUENCY OF OCCURRENCE OF WIND SPEED BY WIND DIRECTION
STABILITY G

WIND SPEED CLASS (MPH)

	CALMS	0.5 - 2.5	2.5 - 4.5	4.5 - 6.5	6.5 - 8.5	8.5 - 11.5	11.5 - 14.5	14.5 - 18.5	18.5 - 23.5	23.5 - 30.5	30.5 - 39.5	MORE THAN 39.5	TOTAL	AVERAGE SPEED (MPH)
N	.0000	.0000	.0000	.0000	.0049	.0025	.0005	.0000	.0000	.0000	.0000	.0000	.0079	8.39
NNE	.0000	.0000	.0003	.0000	.0011	.0015	.0002	.0000	.0000	.0000	.0000	.0000	.0031	8.60
NE	.0000	.0000	.0000	.0000	.0004	.0000	.0002	.0000	.0000	.0000	.0000	.0000	.0006	5.96
ENE	.0000	.0000	.0000	.0000	.0000	.0002	.0002	.0000	.0000	.0000	.0000	.0000	.0004	12.18
E	.0000	.0000	.0000	.0000	.0003	.0002	.0006	.0000	.0000	.0000	.0000	.0000	.0011	11.85
ESE	.0000	.0000	.0003	.0000	.0003	.0002	.0002	.0000	.0001	.0000	.0000	.0000	.0011	8.61
SE	.0000	.0000	.0000	.0000	.00011	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0012	7.05
SSE	.0000	.0000	.0000	.0000	.0004	.0004	.0005	.0000	.0001	.0000	.0000	.0000	.0014	11.07
S	.0000	.0000	.0003	.0000	.0009	.0000	.0002	.0000	.0000	.0000	.0000	.0000	.0014	7.07
SSW	.0000	.0000	.0005	.0000	.0003	.0007	.0002	.0000	.0001	.0000	.0000	.0000	.0017	8.30
SW	.0000	.0000	.0000	.0000	.0029	.0002	.0003	.0000	.0000	.0000	.0000	.0000	.0035	7.76
WSW	.0000	.0000	.0003	.0000	.0018	.0015	.0003	.0000	.0001	.0000	.0000	.0000	.0039	8.62
W	.0000	.0000	.0000	.0000	.0029	.0019	.0000	.0000	.0000	.0000	.0000	.0000	.0048	8.20
WNW	.0000	.0000	.0008	.0000	.0042	.0011	.0000	.0000	.0000	.0000	.0000	.0000	.0061	6.86
NW	.0000	.0000	.0008	.0000	.0038	.0020	.0000	.0000	.0000	.0000	.0000	.0000	.0066	7.42
NNW	.0000	.0000	.0000	.0000	.0042	.0015	.0000	.0000	.0000	.0000	.0000	.0000	.0057	7.69
TOTAL	.0000	.0000	.0033	.0000	.0295	.0139	.0033	.0000	.0003	.0000	.0000	.0000	.0504	8.10

PERIOD OF RECORD: 4/15/74 – 10/15/74

ANALYSES FOR ELEVATED PORTION OF SPLIT-H SOURCE

CHAPTER 12: RADIATION PROTECTION

This chapter describes the radiation protection measures incorporated in plant design and in operating procedures to ensure that internal and external occupational radiation exposures and exposure of the population due to plant conditions, including anticipated operational occurrences, will be as low as reasonably achievable (ALARA) and within all applicable limits. Radiation protection measures include shielding designed to adequately attenuate radiation emanating from sources of significant ionizing radiation, ventilation systems designed to minimize inhalation exposures, operational and administrative controls and procedures including controlled access to hazardous and potentially hazardous areas, and permanently installed radiation-monitoring systems.

In September 1992, the NRC issued Amendment 87 to the Fermi 2 Operating License authorizing a change in the thermal power limit from 3293 MWt to 3430 MWt. The data provided in Chapter 11 for the original power level (3293 MWt) was calculated at 3430 MWt for source terms, activity releases, and doses to the public. As a result of the power uprate, source terms, activity releases, concentrations, and doses have been adjusted linearly to correspond to 102 percent of uprated power, or 3499 MWt. Flow rates, masses, and volumes are also scaled linearly for the uprated conditions. Table 11.1-1 provides the scale-up factors used in Sections 12.1 and 12.2. The source terms shown in Chapter 11 (Table 11.1-2) have not been adjusted for power level because they are derived from the standard annual average design basis release rate of 0.1 Ci/sec at t = 30 minutes.

On February 10, 2014, the NRC issued Amendment 196 to the Fermi 2 operating license authorizing a change in the thermal power limit from 3430 MWt to 3486 MWt, a 1.64 percent increase in thermal power. This Measurement Uncertainty Recapture (MUR) power uprate was performed in accordance with 10 CFR 50, Appendix K and the analyses performed at 102% of the pre-MUR licensed thermal power (3430 MWt) remain applicable at the MUR uprated thermal power (3486 MWt) because the 2% uncertainty is effectively reduced by the improvement in feedwater flow measurement. As such, the source terms, activity releases, concentrations, and doses were not adjusted as a result of the MUR power uprate.

The radiological/ALARA consequences of the addition of a Hydrogen Water Chemistry (HWC) system at Fermi 2 were thoroughly evaluated by Detroit Edison, with the assistance of General Electric personnel. The potential impacts will result from the increased N-16 concentrations in the steam. Detailed high-power radiation levels were measured by survey instruments around the Fermi site prior to the introduction of HWC. These measurements (both inside of major buildings and also outside, in yard areas) were then repeated under the full range of potential HWC conditions, up through high power and maximum hydrogn-injection rates. It was found that the N-16 concentration in the main steam lines increased by a maximum factor of six over the original design basis. Consequentially, radiation levels in many areas throughout the plant also increased. The measurements inside of the major buildings in the RCA showed that (with only two minor exceptions) the HWC radiation levels in normally-accessible areas remained below the original design-basis criteria described in this chapter. This information, along with data from area dosimeter of legal record (DLR) measurements, was then evaluated to assess the impact of HWC injection on:

a. Dose to members of the public, (40 CFR 190)

b. Dose to plant personnel outside of the Radiologically Controlled Area (RCA), (10 CFR 20)

c. Maintenance of ALARA levels during plant operation and maintenance.

The evaluation concluded that due to the large size of the Fermi 2 site, radiological concerns are limited to onsite personnel. Increases in steam-line radiation dose rates will impact activities within the RCA, and it was determined that an additional annual dose of about 5 person-rem would most likely result from the introduction of full-time HWC. Personnel exposures will be maintained ALARA, however, through appropriate compensatory measures. These measures include:

a. Re-posting and locking areas, as needed, in accordance with 10 CFR 20 requirements and Fermi 2 policy

b. Using additional permanent and/or temporary shielding where needed and feasible

c. Temporarily reducing the HWC injection flow during certain maintenance activities

d. Using remote sensing equipment such as closed circuit television, to reduce the need for entry into high radiation areas for inspections and surveillances, when practical

e. Monitoring of personnel as radiation workers, in accordance with 10 CFR 20.

12.1 SHIELDING

12.1.1 Design Objectives

12.1.1.1 Compliance With Federal Regulations

The primary design objective of the plant radiation shielding is to minimize the exposure of plant operating personnel and the general public to radiation due to the reactor, power conversion, auxiliary, and waste processing systems during normal operation, anticipated operational occurrences, postulated accident conditions, and maintenance.

This objective has been accomplished by designing the shielding to

a. Limit exposure to radiation of plant personnel, contractors, and authorized site visitors to as far below the limits set forth in 10 CFR 20 as reasonably achievable for plant operation, including anticipated operational occurrences and maintenance, as recommended in Regulatory Guide 8.8

b. Limit radiation exposure of main control room personnel to as far below the limits in 10 CFR 20 as reasonably achievable, and, in the unlikely event of an accident, to allow habitability of the main control room, as specified in General Design Criterion (GDC) 19 of 10 CFR 50, Appendix A

c. Limit exposures to the offsite general public from direct and air-scattered radiation to within a small fraction of the limits set forth in 10 CFR 20 during normal operation and anticipated operational occurrences, and to within the limits specified in 10 CFR 50.67 for postulated accident conditions

d. Provide barriers for restricting personnel access to high radiation areas and to assist in controlling the spread of radioactive contamination

e. Protect certain plant components from excessive radiation damage or activation. For example, radiation heating of bulk structural concrete is limited and neutron activation of equipment, piping, and other materials is reduced by the reactor sacrificial shield.

Examples of specific steps in design for representative activities that have been taken or are being taken to incorporate the guidance given in Regulatory Guides 8.8, 8.10, and 1.8, where applicable, are given below or are referenced in other chapters of the UFSAR.

The handling, processing, storage, and disposal of various wastes is described in Sections 11.5 and 11.7. In addition to pool storage for irradiated reactor components, the containers of processed waste that may contribute to a radiation level above normal background can be placed in the onsite storage building. Mobile air-handling and -filtering units are available for area airborne contamination control (tenting, bag/gloves, room isolation, etc.).

In the activities of routine operational surveillance and instrument calibration, which will be performed by properly trained personnel, a number of design features have been included to ensure ALARA radiation levels. Remote area alarms and process monitor alarms have been installed to provide advance warning of trouble spots, so that protective clothing and expendable equipment are available to perform surveys. As far as is reasonably achievable, offline monitors are used to allow low background use, maintenance, and calibration of the equipment. Consoles have been located in nonradiation zones wherever possible. Area radiation monitors are mounted to allow safe performance of inplace calibration checks with shielded units, and a calibration facility will be provided for the use of shielded calibration sources.

As an example of response to and cleanup following postulated accidents, the potential for accidents was factored into the design of the basement section of the radwaste building. Each basement room containing radioactive liquid tanks is isolated by a curb and watertight doors, designed to completely contain the liquid contents from a simultaneous rupture of all tanks in the room. Each such room also contains an emergency pump that automatically pumps the liquid released in an accident into an appropriate holdup tank. All of the floors and walls (to an appropriate height) are painted or coated to facilitate cleanup and decontamination. In most cases, provisions exist to flush and drain tanks and associated piping, and both floor and equipment drains are built into each room where applicable. Each room can be isolated from the main corridor and from other rooms, from both physical and ventilation standpoints.

Each demineralizer located in the radwaste building is contained within an individual cubicle; the pumps, piping, and valves are contained in an adjacent shielded area, and any manual valve actuators are located in a third adjacent shielded corridor. This permits remote nonroutine operation and cleanup of a demineralizer. Each cubicle is shielded from adjacent cubicles. The filter-demineralizer retaining screens can be removed from a point above the cubicle with concrete plugs that open to the mezzanine (Figure 12.1-1).

The primary methods used for maintaining ALARA exposures in the maintenance of the radwaste system are the placement of process equipment such as filters, demineralizers, and evaporators in individual cubicles and the separation of components by shield walls. Instruments, controls, and valves, to the extent practicable, are located outside tank and process equipment cubicles. In this way, maintenance can be performed on a component without personnel receiving significant exposure from nearby sources of radiation. In most instances, equipment can be removed from cells either through stepped plugs in ceilings or through (normally blocked) knockouts in walls. Clearance provisions are normally adequate for both in-place maintenance activities and the removal or replacement of components. Most valves, pumps, piping, tanks, and other equipment can be flushed and drained prior to maintenance. Permanent piping is available to drain the contents of any large tank into another appropriate tank located in a different room.

The handling of processed radwaste is covered in Section 11.5. Movement of the radwaste drums from the empty-drum loading point to the discharge point in the OSSF was originally designed to be performed remotely. Viewing was originally designed to be done by television, by means of periscopes, and through special shielded viewing windows. Remote drum-transfer facilities are available after discharge from the onsite storage facility either to temporary storage or to transport trucks.

The gaseous radwaste system (offgas system) was specifically designed to maintain ALARA radiation levels, during both maintenance and operation. Each of the four air ejectors is located in a separate shielded cell, isolated from all other components and other radiation sources. The recombiner system is composed of two completely redundant trains, each housed in a shielded cubicle and separated from each other and all other sources. The chillers, final filters, and sand filters have complete redundance, each unit being contained in a separate, shielded cell. All cells contain knockout walls or overhead plugs for the removal of equipment, and adequate laydown space is provided for the equipment immediately outside most cells.

Instrumentation, controls, and nonradioactive auxiliary systems (e.g., offgas precooler refrigeration units and chiller compressor units) are located exterior to the radioactive cells whenever possible. Separate shielded pipe chases feed the radioactive lines to the separate cells. Hence, when the equipment in a particular cell is shut down for maintenance, little radiation will enter that cell from adjacent radioactive piping. Radioactive lines to the offgas cells have normally been routed so they do not run through any radioactive cells other than the cell they are servicing. The sand filters have provisions for remote drainage into a room below, and their shielded cells can be entered by removing large concrete plugs in the ceiling.

Since the charcoal adsorber beds are passive equipment at ambient temperature and are at a slightly negative pressure, failure and/or maintenance of a charcoal unit has been considered very unlikely. Nonetheless, system availability is protected, since any of the individual units can be bypassed by remote valving operations. Sufficient room has been left between individual charcoal units for portable shielding to be used. A large knockout block, with roll-up door, is located in the shield wall of the adsorber room for equipment removal. This knockout (and the adjoining portion of the adsorber room) is an area of quite low radiation level. Also, space has been provided for an additional six to eight adsorber tanks for future need.

A special portable reactor vessel head unit is available for purging the head of gaseous fission products prior to its removal (see Subsection 9.1.4.2.5). During refueling and its associated outage, all air on the refueling floor is exhausted (and monitored) through special exhaust ports at the top of the fuel pool, equipment storage pool, and vessel cavity. A special watertight gate can be installed between the equipment storage pool and the reactor cavity, thus enabling the storage pool to remain flooded when the cavity is drained. The water in the equipment pool, combined with the concrete shielding blocks between the two regions, protects the personnel working in the cavity and at the refueling floor from radiation originating in equipment (e.g., steam separator and dryer) stored in the equipment pool. Reactor vessel laydown space is available on the refueling floor, and the floor has been painted for ease of cleanup and decontamination.

During refueling, special ventilation provisions are available, and air is exhausted through ports at the top of the pools and reactor cavity. Hence, gaseous activity emanating from refueling should be swept out of these ports and will not contaminate the overall refueling floor. Sufficient water thickness has been designed into the pools to reduce to low levels the radiation from the storage of spent fuel in the storage pool. A description of the special fuel-handling equipment is given in Subsection 9.1.4.2. A special lead "chute" is also available to protect personnel in the drywell during maintenance.

A nominal 13 in. has been allowed for the installation of remote operating inservice inspection devices between the reactor vessel and the vessel insulation. Removable metallic reflective insulation is installed on the piping, valves, reactor nozzles, etc. This insulation is designed for quick removal and reinstallation. Concrete surfaces in the drywell are coated or painted for ease of cleanup and decontamination. During refueling, a special lead shielding bridge or chute will be installed in the reactor cavity between the vessel flange and the fuel pool gate. Its purpose is to protect the personnel who may be simultaneously working in the drywell from high radiation levels during fuel transfer (see Subsection 9.1.4.2.7). The sacrificial shield was especially designed to (1) reduce the neutron activation of drywell components and (2) reduce the gamma ray levels from reactor pressure vessel (RPV) shutdown, so that overall radiation levels in the drywell would be ALARA during maintenance and during inservice inspections (Subsection 12.1.2.2.1).

Special shield doors are installed around the important RPV nozzles (Subsection 12.1.2.2.1). These also (1) reduce neutron activation of drywell components for maintenance purposes, (2) provide nozzle access for inservice inspections on an ALARA basis (quick opening and closing of doors), and (3) provide shutdown gamma ray shielding from the RPV sources during shutdown conditions. An area is available near the personnel air lock to the drywell for clothes changing, personal monitoring, etc., both prior and subsequent to drywell entry and maintenance work. A very detailed 16:1 scale model of the drywell and all internals was constructed and was used to design the layout and assembly of the drywell internals for the most advantageous use of space.

In-place work on the control rod drive (CRD) equipment is discussed in Section 4.5. The hot drives are first lowered into a lead-shielded ultrasonic preflush tank, where the majority of the radioactive contaminants are flushed off. This tank has a closed-loop system and filters. The filters are to be periodically removed and stored in special containers filled with lead shot. The cleaned CRDs will be stored in racks in a special shielded storage room. Concrete shield walls have been located in various areas of the CRD repair facility to minimize direct radiation streaming. The use of these processes and devices will reduce radiation exposures and help to control contamination during overhaul and replacement of parts.

An example of the deliberate and detailed attention to principles of ALARA exposure levels incorporated into the Fermi 2 design is the condensate polishing demineralizers, which are located on the first floor of the turbine building. Each of the eight units is located in a separate, completely shielded cell. Auxiliary equipment, instrumentation, and controls are, when practical, located outside the cells in accessible areas. Each cell has its own air supply and exhaust to prevent cross-contamination between cells.

Radioactive valves (and associated piping) are also located outside the cells in special shielded "valve galleries" adjacent to the demineralizers.

A permanent piping system has been installed for chemically cleaning and flushing the original A-G demineralizer filter elements. No chemical cleaning piping was installed on the newer H-demineralizer because this practice is not utilized. Access to the units is through a stepped shielded manhole in the ceiling, with the shield plugs being removed by an overhead monorail system. When filter elements need cleaning or replacement, provisions have been made for their removal from the demineralizer vessels.

12.1.1.2 Direct Dose Rate at the Site Boundary

The average annual external dose at the nearest point on the site boundary due to normal operation (at the design limit) of the plant, including anticipated operational occurrences and excluding normal vent releases, has been calculated to be less than 8.0 mrem. The largest contributor to this dose is the turbine-generator reheaters located in the turbine building.

For the Independent Spent Fuel Storage Installation (ISFSI), the annual external dose at the nearest point on the site boundary resulting from a fully loaded storage pad has been calculated to be 18.1 mRem.

The dose rate at the site boundary from ^{16}N radiation is less than 8.0 mrem/year (see Section 12.1.3.9). The dose rate from the two condensate storage tanks is 3.6 x 10^{-3} mrem/year, or approximately 7.8 x 10^{-4} mrem/year/Ci. Since the radwaste drums are stored inside the onsite storage building, the dose at the site boundary from these drums of stored waste will be negligible (see Subsection 11.7.2.2.2).

12.1.1.3 Dose Rates Within the Site Boundary

Ten main radiation zones have been defined as a means of classifying the occupancy restrictions on various areas within the plant site boundary. These zones are defined in Table 12.1-1. The basis for the values defined in Table 12.1-1 for Zones I through X is that any one individual is limited to a maximum whole-body dose of 100 mrem/week (1.25 rem/quarter) averaged over his occupational work period. This is equivalent to an average of 2.5 mrem/hr for a 40-hr work week. This criterion does not necessarily exclude entry into areas of higher radiation dose rates, since access is determined by an integrated dose to personnel acquired by a combination of exposure time and dose rate. However, the zone criteria establish the need for and extent of the shielding. A description of each radiation zone defined in Table 12.1-1 is given in Subsections 12.1.1.3.1 through 12.1.1.3.10.

A detailed plot plan defining total plant layout is shown in Figure 12.1-2. The radiation area access zones used in the Fermi 2 shielding design are shown in Figures 12.1-1 and 12.1-3 through 12.1-8 for all areas in the facility for normal operation, and for certain conditions of shutdown and anticipated exposures during a LOCA.

NOTE: The radiation zoning was defined and utilized primarily for the analyses of the overall plant shielding (and HVAC) design and for the locating of all components which could potentially contain radioactivity, and therefore the zoning represents maximum design-basis radiation exposure levels (as noted in the aforementioned figures). As such, these design-basis radiation levels do not necessarily always correspond to the actual operational dose rates in any particular area. The radiation zones and their corresponding dose rates, occupancy times, posting requirements, and 10CFR20 references were set-up or delineated based upon an early/preceding design-basis purpose. Since this zoning was used only for the described original plant design-basis, there is no need or purpose to continuously upgrade this original design-basis section of the UFSAR. Therefore, this Section is kept in its original format.

12.1.1.3.1 Zone I

Zone I is the radiation zone classification for the main control room. This zone is designated as an area in which there are no radiological restrictions. The design dose rate for Zone I during normal plant operation, including anticipated operational occurrences, is 0.3 mrem/hr. Following an accident, the dose rate is such that the integrated whole-body dose does not exceed 5 rem over the duration of the accident.

12.1.1.3.2 Zone II

This zone, with a maximum design dose rate of 0.5 mrem/hr, is a restricted area that can be occupied by plant personnel and authorized visitors on a 40-hr per week, 50 week per year basis, without exceeding a fraction of the 1.25 rem per calendar quarter limit specified in 10 CFR 20.101. Most corridors and other areas requiring frequent access in the turbine, radwaste, reactor, and auxiliary buildings are designed to Zone II classification.

12.1.1.3.3 Zone III

This zone, with a maximum design dose rate of 1.0 mrem/hr, is a restricted area that can be occupied by plant personnel and authorized visitors on a 40-hr per week, 50 week per year basis, without exceeding the 1.25 rem per calendar quarter limit specified in 10 CFR 20.101. An example of this zone is the reactor building corridor area below the new-fuel storage vault.

12.1.1.3.4 Zone IV

This zone, with a maximum design dose rate of 2.0 mrem/hr, is a restricted area that can be occupied by plant personnel and authorized visitors on a 40-hr per week, 50 week per year basis, without exceeding the 1.25 rem per calendar quarter limit specified in 10 CFR 20.101. For example, an area classified as Zone IV is the reactor building core spray pump cubicles during normal operation of the plant.

12.1.1.3.5 Zone V

This zone, with a maximum design dose rate of 4.0 mrem/hr, is a restricted area, as defined in 10 CFR 20.202, that plant personnel can occupy on a periodic basis. Posting will normally not be required. However, temporary posting will be required if anticipated occupancy in these areas would result in exposures in excess of 100 mrem for any 5 consecutive days. Any areas within this zone remain accessible to plant personnel.

12.1.1.3.6 Zone VI

This zone, with a maximum design dose rate of 8.0 mrem/hr, is a restricted radiation area as defined in 10 CFR 20.202, and is posted with "Caution - Radiation Area" signs. Occupancy is limited, and Health Physics will evaluate on a case-by-case basis whether entry to such areas will require a radiation work permit. Length of stay in these areas is determined by the actual radiation level in the area, the past radiation history of the person entering, and the nature of the radiation.

12.1.1.3.7 Zone VII

This zone, with a maximum design dose rate of 15 mrem/hr, is also a radiation area as defined in 10 CFR 20.202. Posting and access control requirements are identical to those defined for Zone VI.

12.1.1.3.8 Zone VIII

This zone, with a maximum design dose rate of 30 mrem/hr, is also a radiation area as defined in 10 CFR 20.202. Posting and access control requirements are identical to those defined for Zone VI.

12.1.1.3.9 Zone IX

This zone, with a maximum design dose rate of 60 mrem/hr, is also a radiation area as defined in 10 CFR 20.202. Posting and access control requirements are identical to those defined for Zone VI.

12.1.1.3.10 Zone X

This is a radiation area zone with a design dose rate that exceeds 60 mrem/hr. All areas that exceed 100 mrem/hr are posted with "Caution - High Radiation Area" signs, as prescribed in 10 CFR 20.203. Areas that exceed 1000 mrem/hr are either kept locked or are guarded. Occupancy of such areas is limited in both frequency and duration and must be authorized in advance with a radiation work permit. Length of stay in these areas is determined by the actual radiation level in the area, the past radiation history of the person entering, and the nature of the radiation.

12.1.2 Design Description

12.1.2.1 General Shielding Design Criteria

The following design criteria were used to maintain ALARA personnel exposures:

a. Design of shielding and radiation zones was based on either the operating or shutdown condition of a system, whichever is the most restrictive

b. To the extent reasonably achievable, major sources of radioactivity are located in individually shielded cubicles to facilitate safe inspection and maintenance. Labyrinths are normally used to eliminate radiation streaming through access doorways into the cubicles. Thus, maintenance and repair may be accomplished in one cubicle without shutdown and decontamination of equipment in adjacent cubicles. Shielding of cubicles is designed so that work can be performed with ease, minimizing maintenance time and hence radiation exposure

c. To the extent reasonably achievable, instrumentation is located outside shielding walls (where access is unlimited) within limits dictated by the specifications for each particular instrument and associated equipment, component, or process line

d. Shielded valve stations are used when feasible to allow valve maintenance without drainage of associated equipment. To further minimize personnel exposure, remotely operated valves are used wherever practical, and, if manual valves are required, extension stems through a shield wall to a "clean" area are provided for many locations

e. Attempts have been made to run radioactive piping in such a way as to minimize radiation exposure to plant personnel. This involves

    1. Minimization of radioactive pipe routing through areas that must be kept accessible at all times

    2. Avoidance of high-activity pipe routing through low-radiation zones

    3. Use of shielded pipe chases when Items 1. and 2. cannot be avoided

    4. When feasible, the use of sharp elbows, T's and Y's, pockets, and dead legs is kept to a minimum. Lines can be drained, and drain connections are attached to selected pockets and dead legs.

f. When feasible, pipeline and duct penetrations in shielding walls are located in such a way that they are not in a direct line with a major radioactive source, particularly between zones of significantly different radiation levels. Whenever necessary, shielding of the penetration is provided where this cannot be accomplished to reduce radiation streaming into areas occupied by personnel

g. The plant ventilation and drainage systems are designed so that contamination can be either controlled or confined to its place of origin. Health Physics procedures implementing good contamination-control practices further ensure that contamination is not spread to other areas of the plant. Most areas where contamination may occur are provided with protective coatings to ensure ease of decontamination

h. Health Physics procedures provide for the use of protective clothing to minimize contamination of personnel. Material or equipment being removed from a contaminated area is handled in such a manner as to prevent the spread of contamination. Contamination monitoring of exiting personnel is performed at the access control point or the nearest frisker station

i. Shielding has been provided to permit access to and occupancy of the main control room for normal operation and to ensure that occupancy of the main control room for the duration of the postulated design-basis accident (DBA) will not result in exposures to personnel exceeding 5 rem to the whole body or its equivalent to any part of the body. This design criterion complies with GDC 19 of 10 CFR 50, Appendix A

j. Shielding discontinuities caused by shield plugs, concrete hatch covers, and shield doors to high radiation areas are provided with offsets when necessary to reduce radiation streaming

k. When feasible, equipment deterioration due to cumulative radiation exposure is limited by the selection and use of proper materials as well as by judicious use of permanently installed shielding. Wherever possible, special attention is given to reducing the use of organic and other radiosensitive materials such as electric cable insulation and connectors; solid-state electronics; gaskets and sealants; seats, packings, and diaphragms for valves; and lubricants

l. A number of design features were built into the standby gas treatment system (SGTS) related to minimizing occupational exposures during the removal and replacement of filters. There are three sets of filters in addition to the high-efficiency carbon adsorber section. In the event that any or all filters are contaminated, exposure of maintenance personnel to radioactive material would be limited because of the following design features:

1. The charcoal in the adsorber section can be drained and disposed of remotely by placing it into containers (55-gal capacity) by means of a pneumatic conveying system. This design feature will minimize radiation exposure during charcoal removal. In addition, with the contaminated charcoal removed, exposure to personnel during the removal of filter sections would be minimized

2. The prefilter section and final high-efficiency particulate air (HEPA) filter section are at opposite ends of the SGTS filter housing, thereby minimizing exposures by providing the maximum distance between these filters. All filter sections are separated by at least one piece of intervening equipment or the structural framing of the filter housing

3. Each filter compartment is provided with its own access door. This allows maintenance personnel to go directly to a specific filter section without the need to pass near other filter sections

4. Each filter section is provided with a permanent light fixture to provide adequate internal light to expedite maintenance work. In addition, an

individual electrical plug-in receptacle is provided outside each access door.

m. Steps have been taken to minimize and control the buildup, transport, and deposition of activated corrosion products in the reactor coolant and auxiliary systems and in particular to minimize the production of ^{58}Co and ^{60}Co. These include

   1. Using material in the primary coolant system with very low nickel and cobalt content except for the use of austenitic stainless steel in the recirculation loops. A discussion and listing of the primary coolant system materials are included in Subsection 5.2.3 and Table 5.2-6

   2. Using low-to-moderate flow rates and low temperatures in the filter-demineralizer for the reactor water cleanup (RWCU) system. Both increase the efficiency of capturing radioactive fission products and corrosion products

   3. Selecting valves and packing materials that minimize crud buildup and maintenance

   4. Using butt-welded connections in lieu of flanged connections on lines 2.5 in. and larger in order to eliminate crud traps

   5. Providing drain/flush connections on the valve body of valves 12 in. and larger and on most of the primary system pumps

   6. Making it possible that, if necessary, any or all of the primary system can be drained and flushed by making the proper connections. Chemical cleaning and decontamination connections are provided to enable separate decontamination of the emergency core cooling system and reactor coolant system hardware. The recirculation system is equipped with special blank decontamination flanges, as shown in Figure 5.5-2, for decontamination of the recirculation pump and associated hardware. A blank flange on the RWCU return line also enables the feedwater line to be drained and flushed back to the reactor vessel. The piping has been routed to minimize crud traps and dead legs.

n. Steps and design features taken to achieve and maintain ALARA exposures during normal operation will ensure that radiation exposures during decommissioning will also be ALARA. Examples are as follows:

   1. The steps taken to minimize the collection and buildup of radioactive crud in piping, valves, tanks, and other equipment include special flush and drain connections and lines and minimal crud pockets. These steps are also used to clean, flush, and drain contaminated systems. In addition, they can be used for decontamination immediately before decommissioning as well as during normal plant operation. A majority of these operations can be performed remotely.

   2. Major sources of radioactivity are located in individual shielded rooms or cubicles. Labyrinths prevent radiation from streaming out into the

aisleways. Therefore, personnel performing decommissioning work on any major equipment would not be exposed to radiation from other sources. Items like pumps, valves, nonradioactive lines, and instrumentation are normally located outside such cubicles so they can be dismantled without exposure.

Separate shielded pipe chases are provided for the radioactive lines to the various isolated equipment cubicles. Hence, the residual radioactive sources in pipe galleries would not contribute to the exposure of decommissioning personnel working on adjacent equipment.

3. With a few exceptions, all cells or rooms containing major radioactive sources have built-in provisions for removing such equipment with minimal problems. The cells either have large stepped concrete plugs in their ceilings or else have large stepped block-outs in their walls (normally filled with concrete planks), opening out into major aisleways where sufficient laydown space has been provided

4. Provisions for the remote removal of radioactive contents of equipment internals (such as offgas sand filters, SGTS charcoal, and filter-demineralizers) will reduce decommissioning exposures

5. All concrete surfaces in the drywell are painted for ease of cleanup and decontamination. Special platforms and walkways will be installed in the drywell for speed and ease of movement and consequently to reduce exposures. The sacrificial shield was specially designed to limit neutron levels in the drywell so that long-term neutron activation of drywell equipment and piping would not result in significant radiation exposures when the reactor is shut down

6. Provisions exist to bring power equipment into the main buildings to lift or move major (radioactive) components. These pieces of mobile equipment, combined with the building cranes and monorails, would enable nearly all radioactive items to be removed from the buildings with a minimum of radiation exposure.

Additional descriptive material and diagrams of the design aspects to minimize the exposure to radioactive material are provided in the literature (Reference 1).

To ensure that occupational exposures are kept ALARA, the shielding design was reviewed, updated, and modified as necessary during plant design and construction. Sargent and Lundy and Edison reviewed the shielding design to ensure compatibility with mechanical, ventilation, and monitoring system design.

Building and equipment shielding and layout designs and drawings initiated by the Edison Engineering Design Groups were reviewed by one or both of two shielding evaluation specialists to ensure that occupational exposures will be ALARA.

12.1.2.2 Description of Plant Shielding

12.1.2.2.1 General

Nuclear radiation shielding in the plant is designed and constructed of materials having suitable composition, thickness, and density to satisfy the design dose rate criteria established for the plant and its offsite environs. Radiation shielding is provided so that, in conjunction with appropriate access control patterns, a properly trained operating staff can maintain radiation doses to personnel within the limits specified by applicable regulations during the following modes of plant operation:

a. Normal operation of the reactor, including anticipated operational occurrences

b. Normal shutdown of the reactor

c. Accident conditions.

Provisions have been made for the protection of personnel during access to equipment for the purpose of inspection, preventive maintenance, or repair.

Shielding is provided when necessary to limit nuclear heating of bulk structural concrete, to reduce neutron activation of equipment and materials, and to limit the irradiation of equipment and materials to acceptable levels.

Concrete, steel, and water are the primary shielding materials used in meeting the plant's shielding design criteria. For certain applications, it was necessary to use borated materials (for neutron absorption), special composition concretes, or other special shielding materials. Removable shields, such as floor plugs and block walls, are used where access must be provided for periodic inspection and maintenance.

Whenever feasible, equipment that is used in radioactive service is selected, designed, located, and oriented in such a manner as to minimize the amount of shielding required. A detailed plot plan defining total plant layout is shown in Figure 12.1-2. Radiation zones are defined in Figure 12.1-1 and Figures 12.1-3 through 12.1-8. A general description of the plant shielding in the various buildings containing radioactive process equipment and fluids is outlined below.

12.1.2.2.2 Reactor and Auxiliary Buildings

The reactor building contains four major shielding structures: the reactor sacrificial shield, the drywell biological shield, the main steam line chase, and the spent fuel pool. Portions of the outer (secondary containment) walls also serve as shield walls. The drywell and its contents are shielded so that most areas outside it are accessible during full-power operation.

Within the drywell, sacrificial shielding is provided between the RPV and drywell walls. It serves to protect important portions of the outer drywell space from excessive radiation exposures and heating during operation. After shutdown, it provides protection from the RPV radiation for plant personnel performing inservice inspection, maintenance, and repair of drywell equipment and components. The sacrificial shield minimizes activation of drywell materials near the reactor core and, together with the drywell biological shield, it protects the general reactor building work areas during normal operation.

The following three criteria have been used in designing the sacrificial shield:

a. The energy flux (neutron plus gamma) incident upon the inner face of the sacrificial shield wall is less than 5 x 10^{10} MeV/cm^2/sec

b. The thermal neutron flux emerging from the sacrificial shield is less than 2 x 10^5 neutrons/cm^2/sec so that excessive activation of steel components in the drywell is prevented

c. The total full-power dose rate in the drywell (outside of wall) should not exceed 100 rad/hr in order to reduce the integrated dose to certain sensitive-material components in the drywell.

Table 12.1-2 provides a summary of the sacrificial shield design bases.

During reactor shutdown, the radiation criterion is that the drywell dose rate from radiation through the sacrificial shield 1 day after shutdown should be less than about 30 mrem/hr. Two sources contribute to the drywell radiation field during shutdown: those sources internal to the sacrificial shield, and piping and equipment in the drywell. The internal sources arise from the delayed gamma rays emitted by the fuel and from the activation of structural components such as the RPV or sacrificial shield. The boration of the concrete reduces the activation of the sacrificial shield significantly, enabling the 30-mrem/hr level to be met. Contact radiation levels on much of the piping and equipment are likely to be in the 20 to 1000 mrem/hr range, most of which comes from radioactive depositions in the drywell piping. The thermal neutron flux limit imposed during operation is low enough to minimize the activation of steel in the drywell.

Recirculation piping penetrations of the sacrificial shield wall are shielded from the reactor core so that access to the drywell is provided during shutdown. All major penetrations in the region bounded by 9 ft above the core centerline to 16 ft below the core centerline contain special shielding doors. In the region of the drywell adjacent to those doors, the dose rate during operation is from components of the recirculation system as well as from the core. For local hot spots such as these openings, an increase of a factor of 10 in the neutron flux (that is, a flux of 2 x 10^6 neutrons/cm^2/sec) is assumed to occur in that vicinity in the drywell. The adopted shield door design consists of a combination of steel and a neutron-attenuating material to reduce the streaming of gamma radiation, as well as to limit the streaming of thermal neutrons to within the hot-spot limits.

The drywell biological shield is designed to limit the radiation level from the reactor core and from equipment in the drywell to the predetermined zone levels established for accessible areas during full-power operation. Table 12.1-2 summarizes the biological shield design criteria. In addition to serving as the basic biological shielding for the reactor system, this concrete structure also provides a major mechanical barrier for the protection of the RPV against potential missiles generated external to the primary containment. Whenever feasible, the penetrations through the biological shield are positioned so that they are not in a direct line with the core or major sources of radioactive equipment in the drywell. The penetrations are either terminated in shielded cubicles, located at very high elevations, or furnished with shielding collars or disks where necessary to further reduce radiation levels in the accessible areas.

The shield design criteria for the rest of the reactor and auxiliary buildings are defined in Table 12.1-3. This table lists the design conditions for each pertinent source area; that is, full- power operation (maximum activity for normal operation), shutdown, testing, and LOCA.

It should be noted that the Maximum Design Level in Protected Area column given in Table 12.1-3 represents the maximum- radiation-level shield design in the shielded area, and is a composite of dose rates resulting from radiation levels generated by several shielded sources. Therefore, the actual design criteria on a specific wall from a particular source cell will usually be less than the maximum values given in Table 12.1-3. This also applies to all other tables with a similar column. The Identification Number column given in Tables 12.1-3 through 12.1-5 is defined in Table 12.1-6.

The shielding has been designed and arranged to ensure that, for the area above the RPV flange, sufficient water shielding is provided above the core and the fuel pool to permit access for refueling operations. The shielding requirements have been based on maintaining a sufficient depth of water above the fuel at all times to limit the dose rate to the operators. A special lead-lined fuel-transfer bridge or chute is used to protect personnel working in the drywell when spent-fuel assemblies are being transferred between the core and the spent-fuel storage pool.

A special drywell radiation monitor is provided as a part of the area radiation monitor system to provide radiation protection for personnel working in the drywell during fuel-transfer operations. The monitor and alarm are hand carried into the drywell and plugged into the fixed connector whenever the drywell is opened for maintenance.

Since some areas adjacent to the refueling and fuel storage pool structures are accessible, the pool-wall concrete has been designed to provide the required attenuation. The concrete pool shielding has been adequately designed for both fuel storage and fuel transfer operations.

During normal fuel transfer, the fuel element is covered at all times by a pool of water that serves as a radiation shield. When fuel is transferred from the reactor cavity to the fuel pool, it crosses the narrow transfer canal. It takes about 24 sec to reach the fuel pool, where it is lowered further down into water. During the short time it is in the transfer canal, there is still sufficient water (approximately 7ft) above the actual fuel portion of the fuel assembly to furnish adequate shielding and to maintain low radiation levels at the operating bridge. Although these dose rates will be somewhat higher than when the fuel is lowered further into the storage pool, they will not be of significance. Likewise, there is sufficient water (approximately 5 ft 3 inches) above the actual fuel portion of the fuel assembly to furnish adequate shielding and to maintain low radiation level at the Reactor Cavity Work Platform used for In-service Inspection of the vessel and other outage related activities. Radiation levels from fuel handling to other personnel located elsewhere on the operating floor will be much lower than levels on the bridge.

Since the RWCU system filter-demineralizers are a radiation source during operation and shutdown, they have been located in separately shielded rooms so that each can be maintained while the others are in operation. Valves and instruments have been located outside the demineralizer cubicle. During operation, access to the remaining cleanup equipment (except for the pumps) is normally not required, but shielding requirements were based on location and the need for access to adjacent areas.

The main steam line pipe tunnel shielding has been designed to adequately reduce ^{16}N gamma radiation, emanating from the steam lines during normal full-power reactor operation, to the proper design levels.

A contaminated-equipment storage room, located in the turbine building, is used for the storage of low-activity miscellaneous pieces of small equipment. The walls serve more as a physical barrier than as a radiation shield.

12.1.2.2.3 Turbine Building

The radiation levels existing during plant operation, as well as those experienced during shutdown, were considered in determining shielding requirements for the turbine building. With the main exception of the offgas charcoal units and filters, the major radiation source considered has been the ^{16}N isotope. Figures 12.1-1 and 12.1-3 through 12.1-8 define the access zones used in the turbine building shielding design. The areas are zoned according to their expected occupancy by plant personnel and their design-basis radiation exposure levels under normal plant conditions. Shielding is provided around the following areas, and access to these areas is generally not permitted during full power operation:

a. Main condenser-hotwell area
b. Reactor feedwater system heaters, drain coolers, and associated piping
c. All main steam, extraction steam, and drain piping
d. Condensate demineralizer system equipment and piping
e. Steam-jet air ejectors and piping
f. Gland seal condenser and vacuum pump systems and piping
g. Heater drain pumps
h. Regions around the turbine, reheater separators, and associated steam and condensate piping
i. Reactor feed pump turbine systems and piping
j. Offgas delay lines
k. The offgas combiners, charcoal delay beds, filters, and associated piping and equipment.

As can be seen in Figures 12.1-1 and 12.1-3 through 12.1-8, limited access is allowed to a few areas during full-power operation. Access to the crane and to the turbine floor inside the turbine reheater shielding walls is administratively controlled during reactor operation, by use of locked access doors.

Since the air ejectors are a high radiation source, each is provided with separate shielding to permit maintenance access to the cubicles not in operation. Offgas holdup piping is also shielded. The two recombiner cells are separately shielded to permit limited access to the cell that is shut down while the other is operating. Since access for filter replacement is possible, shielding is provided for the offgas filters, with consideration given to draining the radioactive sand from these filters and separately shielding each filter for maintenance or removal.

The condensate filter-demineralizers are also shielded to accommodate access to adjacent areas. Access to the filter- demineralizers is restricted unless adequate decontamination procedures are taken. Access to valves, pumps, and instrumentation is generally made available by locating this equipment in outer shield cubicles.

The condensate is held up in the hotwell long enough to reduce the dose rate from ^{16}N and ^{19}O to below 1 mrem/hr (normal water chemistry) at points adjacent to the piping. Even though a 2-minute holdup time is sufficient for this purpose, the hotwell is designed for a nominal holdup time of 4 minutes (see Subsection 10.4.1.1.5). However, even though these lines are not normally shielded, the condensate storage tanks are provided with a barrier to prevent close access.

The design criteria for the turbine building shielding design are provided in Table 12.1-4. Though this table does not indicate the design limits for turbine shield design as applicable to skyshine (^{16}N), Subsection 12.1.3.9 describes the pertinent results of skyshine analysis. These data show that the turbine building shielding adequately reduces all direct and skyshine radiation to ensure that both onsite and offsite doses are maintained ALARA.

12.1.2.2.4 Radwaste Building

The radwaste building contains a complex arrangement of settling tanks, filters, demineralizers, evaporators, solidification equipment, and holding and storage tanks of various types and kinds. These serve to remove the impurities (soluble, nonsoluble, radioactive, and nonradioactive) from water collected in floor and equipment drains throughout the plant and from the backwash of reactor water and condensate filter-demineralizer purification systems, prior to reactor recycle usage or ultimate disposal through the liquid- or solid-waste disposal systems. Almost all of the entire radwaste system uses batch processing of liquid volumes. Because of the system complexity, a wide variance in radioactivity levels is encountered throughout the radwaste system. In fact, the activity level at a particular location can vary considerably, depending on the conditions and mode of systems operation. For conservative shielding design calculations, therefore, the condition giving maximum activity levels of each component was first identified. The activity concentrations used in each major shield design effort for the radwaste building are covered in more detail in Subsection 12.1.3.

Table 12.1-5 defines the specific shield design criteria for the radwaste building. Figures 12.1-3 through 12.1-5 define the access zones and the major components. The shielding is designed to maintain the radiation level below 0.5 mrem/hr in the radwaste control room and in the operating aisles of the solid-waste preparation areas. The areas surrounding the radwaste equipment are protected according to the necessary access requirements. The liquid radwaste system is operated remotely from a control panel in the radwaste control room.

As previously indicated, the shield design is based on radiation resulting from the processing of corrosion products and/or fission products resulting from substantial fuel leakage (Subsection 12.1.3). The design is such that when certain low-frequency types of fluid transfer operations are to be performed, slightly higher radiation levels and limited-access restrictions will apply to certain areas that are normally Zone II access areas.

The primary function of the waste surge tank is to receive overflow from the waste clarifier. The waste clarifier is full during normal operation and displaces a volume equivalent to the influent directly to the waste surge tank. The principal inputs to the waste clarifier are the decants from the RWCU and condensate phase separators as well as the centrifuge decant. As these streams enter the waste clarifier, undissolved solids settle out and liquid within the clarifier is displaced to the waste surge tank. The waste surge tank can also be used for storing the waste collected in the radwaste emergency sump in the unlikely event of rupture of either the floor drain collector or waste collector tanks. The principal activity within the waste surge tank is therefore from the phase separator and centrifuge decant water.

Components such as waste collector and floor drain collector tanks are grouped in one common area. These areas contain only tanks and piping and require infrequent access. Resin storage and concentrated-waste storage tanks are located in another area. Access to these areas is not normally required.

Demineralizers and filters have been separately shielded so access to one will not require draining of the others. There is little need for access to the demineralizers, but the filters may require periodic maintenance.

12.1.2.2.5 Main Control Room

The main control room is located in the auxiliary building so that accessibility is normally unrestricted. The shielding provides for normal radiation levels below 0.3 mrem/hr. Advantage has been taken of the shadow shielding from other structures.

Further, the main control room shielding has been designed for the maximum design accident condition so as to allow continuous main control room occupancy during the course of an accident. The regulation followed for the shield design was GDC 19 of 10 CFR 50, Appendix A. As a result, wall, floor, and ceiling concrete thicknesses are provided (as shown in Figures 12.1-9 and 12.1-10) to adequately attenuate sources of direct radiation. The design of the main control room shielding was such that the predominant sources originate during an accident condition rather than during normal plant operation. The shielding design features were reevaluated using Alternative Source Terms and with some additional detail. As a result, calculated doses are substantially lower than originally determined. See Appendix 15A for details.

12.1.2.2.6 Other Plant Areas

Those portions of the service building and all other yard buildings which are fully accessible will be maintained so that no person can receive a radiation dose rate of greater than 0.5 mrem/hr. Access to other portions of these buildings will be controlled, in order to assure all personnel radiation exposures will be ALARA.

12.1.2.2.7 Component Cubicles

Component and equipment cubicles containing radioactive material are designed not only to limit radiation levels in corridors and other adjacent areas requiring frequent access (Figures 12.1-1 and 12.1-3 through 12.1-8), but also to ensure that the maximum radiation level in the cubicles from adjacent cubicles containing radioactive material does not exceed 8 mrem/hr (normal water chemistry). There are some areas or cells in which the maintenance dose criteria were set significantly lower than 8 mrem/hr. The actual design dose rates are shown in Tables 12.1-3 through 12.1-5. This concept means that when the lines and equipment in a particular normally radioactive cubicle are shut down and drained for maintenance purposes, the maximum radiation level from outside sources will produce radiation levels that will not exceed 8 mrem/hr in the cubicle containing the drained equipment. For this particular phase of the shield design, it was assumed that the rest of the plant remained at full-power operation.

12.1.2.2.8 Penetrations, Ducts, and Voids

Normally, a large number of various sizes and types of penetrations exist through the bulk shielding walls surrounding radioactive components. There are mechanical, doorway, instrument and lighting, electrical, ventilation and heating, process piping, and drain line penetrations. As is true in the shield design of all plants, these penetrations represent violations of the bulk shield and consequently represent potential sources of high-level localized radiation streaming.

When necessary, these penetrations, ducts, and other voids in shields are designed so that the radiation streaming through such discontinuities is minimized. The design also ensures that the general dose rate in each plant area, including contributions from radiation streaming, satisfies the design dose rate for that area's radiation zone designation. The shield designers worked closely with other design groups to meet the above criteria. All important proposed penetrations of a shield wall were approved by the shield designer before they were finalized, and appropriate calculations were performed by the shield designers when necessary.

When feasible, penetrations of shield walls, such as pipe and duct penetrations, are located in such a manner that a direct shine from major sources of radiation is minimized. Large empty pipes or ducts penetrating the shield into accessible areas are provided with additional concrete, steel, or other shielding where required. When necessary, penetrations are located sufficiently high above the floor (generally greater than 10 ft) to minimize shielding requirements and personnel exposure in adjacent accessible areas.

Shield discontinuities include such items as concrete hatch covers, plank walls, block walls, shielding doors, and access labyrinths into areas of high radiation. Access labyrinths into rooms containing highly radioactive equipment are designed in such a manner that direct shine through the offset passage to outside accessible areas is eliminated. Where necessary, the equipment is shielded in all directions, including the access passage, with the same equivalent thickness of shield as in the solid shield walls. During normal operations, the access labyrinths are provided with barriers for personnel access control. The labyrinth designs are such that the dose rate at the outer surface of the barrier locations would not be greater than that outside the adjacent bulk shield walls.

Shielding discontinuities are normally designed with offsets in the gap between the movable section and the fixed shield so that radiation streaming is reduced. Wherever possible, gaps are positioned to eliminate a direct line with the radiation source. The tolerance or clearance between the movable section and the fixed shield wall is designed to be as small as practicable.

A general description of the method used for handling such penetrations in the shield design of the Fermi 2 plant is given in the following paragraphs. The design intent was to limit the total radiation passage through shields (that is, the sum of the bulk shield dose rate and penetration dose rate) to the levels given previously in Subsection 12.1.1.

It is desired that personnel working in an operating area for a 40-hr week receive an average dose rate no larger than that specified (usually 0.5 mrem/hr). The Fermi 2 shield design (normal water chemistry) used is as follows:

a. The general area dose rate through the bulk shield was kept somewhat less than 0.5 mrem/hr (approximately 0.2 - 0.4 mrem/hr)

b. Where possible, the combined dose rate (bulk radiation plus streaming) at all floor locations below an elevation of approximately 7 ft (assumed man's head height), taking into consideration the penetrations important to that location, was kept less than 0.5 mrem/hr.

12.1.2.2.9 Valve Operating Stations

Manual valve operating stations for pipelines containing highly radioactive material are designed with the valve body and all piping enclosed in a shielded cell, with only the valve's operating rod extended through the shield wall. When possible, these penetrations are located overhead so that radiation streaming does not shine directly on personnel in the operating aisle. The operating rod, which is a solid steel shaft in most cases, helps attenuate radiation streaming through the penetration. In cases where the quantity of valves requires a large number of penetrations, the valve operating station is isolated from the personnel access corridor by a shield wall, and is declared a limited-access area.

12.1.2.2.10 Shield Materials

Advantage was taken of the shielding properties of structural walls and of distance, whenever possible. The material used for biological shielding throughout the plant is reinforced concrete with a density of approximately 150 lb/ft^3. Other materials, such as steel and lead for gamma shielding and boron or hydrogenous materials for neutron shielding, are used in special instances. Wherever possible, walls that were installed primarily for structural purposes are also used to provide shielding. Whenever cast-in-place concrete was replaced by concrete blocks or special offset shield planks, the design ensured protection on an equivalent shielding basis.

No federal regulations similar to those established for the protection of individuals exist for materials and components. Whenever possible, materials are selected on the premise that their predicted radiation exposure during the design life of the plant would not cause significant changes in their physical properties that might adversely affect their operation.

12.1.2.3 Shield Design Calculations

12.1.2.3.1 General

Presented below is a summary discussion of the analyses performed to define the required shield thickness for the various components containing radioactive material. Included is a general description of the analytical tools used in the analyses, the sources and models used in the analyses, and the required shielding thicknesses. All shielding is designed to ensure that the specific design criteria defined in Tables 12.1-2 through 12.1-6 are met.

For a given process system, consideration of each of its various modes of operation is used to determine the highest expected dose rate to personnel and/or equipment. The shield or series of shields were then designed to attenuate radiation resulting from this design-basis operational mode. The source of radiation (Subsection 12.1.3), the technical description of the nuclear steam supply system, and the descriptions of the operation of the components of each radioactive process system are all used in determining the final shield design.

Shielding that protects areas during normal operation, anticipated operational occurrences, and following DBAs is designed such that adequate protection is provided for the most severe case. Each radioactive source and its shield is modeled mathematically to represent the actual configuration as nearly as possible or as closely as necessary.

To design the sacrificial shield, the one-dimensional transport code ANISN (Reference 2) was used to account for the migration and production of neutrons and gamma rays from the reactor core.

The DLC-9 coupled neutron and gamma ray cross-sectional data (Reference 3) were originally used with the ANISN code to enable all production and loss mechanisms for both neutrons and gamma rays to be handled in a single calculation, and subsequently the DLC-23/CASK coupled cross-sectional set (Reference 4) was used to verify the original calculations.

All other shields are designed for gamma ray attenuation by the standard point attenuation kernel (buildup factor, exponential attenuation, and geometry factor) numerically integrated over the volume of the source. The buildup factors and gamma ray attenuation coefficients were obtained from published nuclear data (for example, References 5 through 10). These data were used in the ISOSHLD-III computer code (Reference 11) and also in various hand calculations that were made. Direct transmission of gamma radiation through bulk shielding was also calculated by CAI-KAP, a modification of the QAD (Reference 12) point kernel attenuation program, written for the IBM 1130 computer. Some of the modifications were made in order to fit the large program into the small machine. For instance, CAI-KAP has no capability to calculate neutron attenuation. The program will accommodate geometries of 50 zones defined by 50 boundaries, up to 15 materials, and 30 gamma energy groups. The program also has the capability of automatically preparing the detailed source description on the basis of an input gross source description.

Scattered radiation from labyrinths and penetrations was analyzed by the albedo or Monte Carlo method (References 13 and 14). As mentioned in Subsection 12.1.2.2.8, penetrations are normally located so that no direct path of escape exists for direct radiation. Thus, the only method of radiation escape from the labyrinth without shield attenuation is through scatter. Wall penetrations are located as much as possible above head height, and the use of wall or floor penetrations that run between radioactive regions and unlimited-access areas is minimized.

The radwaste system modification resulted in the building of new shield walls for new equipment, supplementing existing walls with additional shielding for new equipment, and reanalyzing existing walls where new equipment was installed or where the operating function of existing equipment had changed. In addition to the walls, the floors, ceilings, shield doors, and labyrinths were evaluated. These analyses were done using four shielding codes: KAP VI, CYLDOSE, SCAP, and NUSALB.

KAP VI (Reference 15) is a point kernel code used for complex geometries describable by quadratic surfaces. This was used for all of the larger pieces of equipment. CYLDOSE (Reference 16) is a code for calculating linear attenuation, scatter buildup, and resulting tissue dose rate from cylindrical gamma ray sources. CYLDOSE was used primarily for piping shielding analyses with some usage for smaller components. SCAP (Reference 15) is a point kernel code using energy-dependent single or albedo scatter methods to calculate radiation levels at detector points located within complex geometries describable by a combination of quadratic surfaces. SCAP was used where complex gamma ray scatter-radiation geometries were encountered. The NUSALB code (Reference 17) determines ground backscatter according to the albedo technique through the summation of differential back-scatter doses by means of the appropriate differential albedos. This code was used for the simpler scatter analyses.

Some of the basic assumptions used in the shielding design are as follows:

a. The shielding in the turbine building is based on ^{16}N gamma radiation

MeV/Photon	Photons/Disintegration
2.75	0.01
6.143	0.69
7.112	0.05

b. The original shielding design of the radwaste building walls was based on an average gamma ray energy of 1.5 MeV/photon. The walls that have been added or supplemented as a result of the newer system installation are based on the calculated gamma ray energy spectrum estimated to exist in the components being shielded. Previously designed walls that are being used to shield new equipment or equipment for which the function has been changed or modified were reevaluated on a case-by- case basis using the calculated gamma ray energy spectrum within the component being shielded

c. The magnitudes of all sources of radiation are based on failed fuel operation with the following source terms calculated at 102 percent of 3430 MWt (3499 MWt) (see Chapter 11):

    1. A noble gas release equivalent to 100,000 μCi/sec after a 30-minute holdup

    2. Corrosion and fission product concentration in the reactor water consistent with the values presented in Tables 11.1-2 through 11.1-6.

d. Credit is normally taken for self-absorption within a given source geometry

e. Credit is normally taken for holdup of ^{16}N in various system components

f. Design-basis dose rates in aisles or outside cubicles containing multiple sources are based on the sum of the direct radiation emanating through all adjacent cubicle shield walls (including both floors and ceilings). The shielding for cells is designed so that the maximum radiation dose rate in operating areas outside the cells would be no more than 0.5 mrem/hr (Zone II) from all sources under normal operating modes (normal water chemistry). This is the total combined dose rate from all nearby cells, any piping running through the operating area, and from any miscellaneous sources.

Additional information concerning the shield designs in each building containing equipment for processing radioactive material is given in Subsections 12.1.2.3.2 through 12.1.2.3.5.

12.1.2.3.2 Reactor and Auxiliary Building Shield Design

To ensure that the specific design criteria are met in the reactor building, the RPV is surrounded by a 7-ft-thick biological shield and a 21.25-in.-thick sacrificial shield. Computerized discrete ordinates techniques (that is, the ANISN code) were used to calculate the dose rates outside the biological shield. Table 12.1-7 defines the multigroup coupled neutron and gamma flux as calculated outside the RPV. These data served as the basis spectrum for the sacrificial and biological shield design.

During the course of the shield design, it was found necessary to use borated concrete for the central portion of the sacrificial shield. This borated section extends from 17 ft below the core centerline up to 12 ft above the core centerline. The boration is accomplished by the addition of 6 weight-percent boron frits to the concrete mixture. The frits contain approximately 16 weight-percent natural boron. As previously mentioned, the boration of the concrete reduces the activation of the sacrificial shield significantly, enabling the 30 mrem/hr requirement to be met 1 day after shutdown.

Table 12.1-8 summarizes the shielding design for the important areas in the reactor and auxiliary buildings. This table summarizes

a. The area being shielded

b. The equipment in the shielded cell

c. The operating condition for the source determination that was subsequently used for the shield design

d. The source strength, expressed in curies, in the component/room being shielded

e. The basis calculational source geometry used for the shield design analysis

f. The particular wall or shield location on the cell

g. The shield wall thickness as constructed

h. The radiation level, expressed in mrem/hr, used as a shield design basis for the wall both at the outer wall surface and in the general area around the wall.

12.1.2.3.3 Turbine Building Shield Design

Table 12.1-9 summarizes the turbine building shield design. This table summarizes the data in the same manner as does Table 12.1-8. However, dose-rate estimates due to skyshine have not been included in either of these tables. Further discussions concerning skyshine dose-rate calculations are presented in Subsection 12.1.3.9.

12.1.2.3.4 Radwaste Building Shield Design

Table 12.1-10 summarizes the shield design for the radwaste building. The pertinent items of design as described for Tables 12.1-8 and 12.1-9 are included in this table.

Concrete shielding is used exclusively throughout the radwaste building for bulk shielding, except for several instances where steel wall inserts are used and several instances where tanks are shielded with steel and/or lead shot because of space considerations. There are also several steel shield doors. The general procedure for determining the bulk (wall thickness) shielding requirements for component cells was to use the maximum total activity buildup together with data on component process fluid volume and geometry, and then to reduce the actual component to an appropriate idealized point, line, cylindrical, or disk radiation source for the shielding calculations. Also taken into consideration was the self-shielding effect of the process fluid, where applicable, and radiation buildup due to scattering in the shield walls. In addition, the following nuclear data, ground rules, and assumptions were used:

a. The actual radionuclide inventories in each of the radwaste system components have been calculated. Based on the radionuclides present and the specific activities of those nuclides, a specific energy spectrum has been determined and used for the shielding calculations. This spectrum could be different for each component in the radwaste system

b. The piping inside the cells that contain large sources (such as tanks) or sources where radionuclide inventories can become concentrated (such as filters and demineralizers) has not been considered for the bulk- shielding calculations. This differs from the practice followed in many of the turbine and reactor building cell calculations. However, it is a valid assumption for the radwaste building because of the following:

    1. The volume (size) of the process lines to and from radwaste components is extremely small compared to the component fluid volumes

    2. The radwaste system uses batch processing (compared to continuous processing in the turbine building), and the lines are therefore normally either empty or filled with clean flush water

    3. As opposed to the situation often encountered in the turbine and reactor buildings, there are no significant density differences (due to temperature changes) or specific activity ($\mu Ci/cm^3$) differences (due to either dilution or radioactive decay) between the process fluid in the lines and that in the tanks where cells contain only pumps; however, the piping in those cells is used for bulk-shielding calculations. It is a conservative assumption to consider a pump to be a section of the piping through which it pumps fluid. Compared to the piping within a cell, the volume of the source within a pump is usually very small. The piping must, therefore, be considered.

c. In certain instances of offnormal operation, the Zone II dose rate could be exceeded in some areas. Examples of offnormal operations are the following:

   1. Use of operating modes following tank ruptures
   2. Abnormal operating modes used when components are shut down for maintenance and must be bypassed
   3. Operating modes used during filter or demineralizer malfunction
   4. Abnormal tank-drainage operations.

   It should be emphasized, however, that there are only a limited number of anticipated offnormal operating modes that will result in Zone II radiation dose rates being exceeded in operating areas

d. The shielding for common walls between adjacent shielded cells is designed so that the radiation dose rate inside a cell shut down for maintenance is less than 8 mrem/hr (Zone VI) due to radiation from sources in adjacent cells under normal operating modes. As implied by Item c., the offnormal maintenance dose rate inside such a cell could exceed the Zone VI criteria in certain rare instances.

12.1.2.3.5 Main Control Room Shield Design

As previously described in Subsection 12.1.2.2.5, the main control room is designed so that accessibility is normally unrestricted and, following a postulated accident occurrence, personnel exposure will not exceed 5 rem TEDE as specified in 10 CFR 50.67.

In particular, the shielding in the main control room is designed to protect its inhabitants following a LOCA, as described in Regulatory Guide 1.183. For the LOCA, the fission products that are released from the fuel are assumed to be transported through the primary and secondary containments and entrained on the SGTS filter. LOCA sources are determined using RADTRAD (Reference 24) models with design basis core source terms, credited removal mechanisms, and transport parameters. Uniform mixing in secondary containment is assumed when evaluating secondary containment gamma shine, and 100 percent filter efficiency is assumed when evaluating SGTS filter source terms. RADTRAD calculated time dependent compartment activities are time integrated and then evaluated using MicroShield 5.05 (Reference 25). Sources considered are the primary containment, the reactor building, a standby gas treatment system filter, and an environmental plume outside of the control room shielding. Shielding is provided that is equivalent to the following:

a. The total floor thickness between the main control room and torus area is effectively 8 ft 4 in., as shown in Figure 12.1-9

b. The roof of the main control room is 1 ft thick below the air conditioning equipment room (effectively 6 ft 6 in. thick, including the auxiliary building roof), and 5 ft thick below the SGTS (effectively 10 ft 6 in. thick including the auxiliary building roof)

c. The outside (north) wall of the main control room is 2 ft thick in order to provide shielding of personnel from the overhead plume

d. The wall between the main control room and secondary containment is 4 ft 4 in. thick. Therefore, the dose to personnel from radioactivity in the secondary containment is reduced.

Shielding walls are used to accommodate other design criteria; for example, to provide missile protection. In some instances, therefore, the slab thickness may be governed by criteria other than shielding requirements. Further details on the estimated personnel exposure during a LOCA are provided in Appendix 15A.

12.1.2.4 Inspection and Testing

Inspection and testing of the plant shielding is conducted using ANSI Standard N18.9-1972 as a guide to verify that the shielding performs its function of reducing radiation to design levels. During the initial power operation, radiation surveys are made to identify and correct any defects or inadequacies in the shielding that might affect personnel exposures during normal operation and maintenance of the plant. Surveys consisting of gamma and neutron monitoring, as appropriate, will be performed at various power levels (typically 0, 25, 50, and 100 percent power) as the reactor is initially increased in power.

12.1.3 Source Terms

12.1.3.1 General

The shielding design source terms are based on the three general plant conditions of normal full-power operation, shutdown, or design-basis events. The shield design for normal operation and anticipated operational occurrences is based on design radiation sources. These sources provide a rational basis for design. The source data assume plant operation is at maximum design power, with a noble gas release rate from the core equivalent to 0.1 Ci/sec after 30 minutes decay. Concentrations in the reactor water are based on a fission product equilibrium halogen concentration as defined in Section 11.1. Concentration of other fission and activation products is based on information defined in Section 11.1. The activities of these sources are considered to be maximum values, although it is not anticipated that the plant will normally operate at these high levels. Later, Hydrogen Water Chemistry conditions were also examined and factored in.

Three types of radiation sources occur in the plant: primary radiation from the reactor core, secondary radiation resulting from nuclear reactions between the primary radiation and the reactor environment, and release of radioactive materials from the reactor core to the coolant. During normal plant operation, secondary sources and released radioactive materials are transported in either the reactor coolant or main steam to process equipment in the plant.

The source intensity in equipment and pipelines handling radioactive fluids is determined from that in the reactor water or reactor steam by considering the processes that the reactor water or steam has undergone (dilution, filtering, demineralization, delay, or change of phase) prior to entering the equipment or pipe.

Tables 12.1-8 through 12.1-10 summarize the estimated source terms in the reactor and auxiliary building, turbine building, and radwaste building used for the Fermi 2 shield design for cubicles and components containing radioactive material. These sources are based on the originating source terms provided in Chapter 11, and cover the worst-expected design condition: that is, full-power operation (normal), shutdown, refueling, anticipated operational occurrences (including tests), and the design-basis accident (DBA). For plant operation with Hydrogen Water Chemistry, in-plant tests have shown that the calculated N-16 activity estimates will increase a maximum factor of six from the estimates shown in these tables. LOCA sources are determined using RADTRAD (Reference 24) models with design basis core source terms, credited removal mechanisms, and transport parameters. Uniform mixing in secondary containment is assumed when evaluating secondary containment gamma shine, and 100 percent filter efficiency is assumed when evaluating SGTS filter source terms. RADTRAD calculated time dependent compartment activities are time integrated and then evaluated using MicroShield 5.05 (Reference 25). Sources considered are the primary containment, the reactor building, a standby gas treatment system filter, and an environmental plume outside of the control room shielding.

12.1.3.2 Radiation From Reactor Core

During full-power operation, radiation from the reactor core proper consists of neutrons and gamma radiation resulting from the fission process itself, gamma radiation resulting from capture or inelastic scattering of neutrons within the core, and gamma radiation resulting from fission product decay. In addition, neutron interactions with the core shroud and RPV result in capture or inelastic scattering of gamma rays.

Table 12.1-7 presents multigroup neutron and gamma ray fluxes outside the RPV. The gamma ray fluxes include core fission gamma sources as well as secondary gamma sources that result from neutron capture in the core, water shroud, and vessel.

12.1.3.3 Activity in Steam and Condensate

Piping and equipment that contain reactor water, steam, or condensate are principal sources of radiation. The predominant activity requiring shielding in these systems is the ^{16}N carried in the steam and water from the reactor. Usually, all other activity sources in the steam other than ^{16}N can be neglected, since their magnitude is so much smaller. The radiation source strength at any of the various pieces of equipment containing steam or reactor water is then the RPV appropriate outlet nozzle activity of ^{16}N decayed by the transit time from the reactor outlet to the equipment. Tables 12.1-8 and 12.1-9 define the ^{16}N sources used in the Fermi 2 shield design. With Hydrogen Water Chemistry in operation, these N-16 estimates will increase up to a factor of six.

12.1.3.4 Offgas System Activity

The major radiation source of the offgas system is the ^{16}N in the noncondensables traveling from the condenser to the recombiners. The total transit time of the offgas between the RPV and the steam-jet air ejector is conservatively calculated as about 7 sec. Decay and delay through the offgas system are taken into account. The ^{16}N is the major source of radiation up to the 2-minute delay line. After the delay line, the fission products predominate as the shielding source. The sources used in this system design are defined in Table 12.1-9.

12.1.3.5 Activity for Radwaste, Reactor Water Cleanup, and Condensate Demineralizer Systems

The radiation source in these systems is due to the radioisotopes originating in the reactor water and steam. In the RWCU system, radioisotopes (including corrosion products) present in the water are the source of activity. In the condensate demineralizer system, the sources are the activities carried over in the primary steam and daughters resulting from radioactive gas decay in the condensate demineralizer system itself. In the RWCU system, ^{16}N and similar short-lived activity isotopes were taken into account, with ^{16}N included only for that portion of the RWCU system in the reactor building.

In the reactor water, the corrosion product activity is present in both soluble and insoluble forms. The latter is primarily removed by filtration and the former by ion exchange. When considering fission product accumulation, the predominant fission products were assumed to be essentially soluble. Activity accumulates in equipment such as filters and demineralizers. Activity levels in such equipment build up during plant operation until equilibrium is achieved or until the activity is removed (or diminished) by backwashing, or by discarding resins.

The solid and liquid radwaste systems contain varying degrees of activity, depending on the system and the point of processing.

Table 12.1-10 defines the sources used in the radwaste building shield design.

12.1.3.6 Shutdown Sources

The largest radiation source after reactor shutdown is decaying fission products in the fuel. For shield design purposes, the strength of the fission product source has been based either on data from other operating plants (Section 11.1) or on a reactor operating sufficiently long to establish equilibrium conditions for the buildup of all major fission products (see Table 12.1-15).

A secondary source is the structural material activation of the RPV, its internals, and the piping and equipment located between the RPV and the biological shield.

The third type of source is the activated corrosion products accumulated or deposited on the internals of the RPV, the primary loop piping, the secondary loop piping, and components associated with primary coolant processing. Table 12.1-8 contains further information on the shutdown sources used in the Fermi 2 shield design.

12.1.3.7 Design-Basis Accident Sources

To determine the original shielding requirements for the main control room, the radiation sources used for the DBA assumed that 100 percent of the noble gases, 50 percent of the halogens, and 1 percent of the remaining fission product inventory is released from the fuel at the time of the accident. These accident sources were also considered in conjunction with normal operation sources in determining the required thicknesses.

A complete reevaluation of the shielding design for post-LOCA source conditions was performed in conjunction with the response to NUREG-0737 Item II.B.2. A discussion of the reevaluation is contained in Subsection 12.1.6.

The present shielding design has been reevaluated using Alternative Source Terms per 10 CFR 50.67 and Regulatory Guide 1.183 guidance. This analysis was performed to confirm the 10 CFR 50.67 limits to operator doses will be met, and to credit certain of the available margins provided by the original design.

12.1.3.8 Stored Waste

With the exception of the Independent Spent Fuel Storage Installation there are no plans to store high-level radioactive wastes outside the building structures at the Fermi 2 site. Radioactive waste products are normally stored at designated areas within the plant buildings. These areas are shielded as necessary. Table 12.1-16 defines the site boundary dose rate for a curie of stored waste along with the assumptions used in the calculations.

The condensate storage tanks contain trace amounts of radio-isotopes, the concentrations of which do not normally exceed 1.0×10^{-3} $\mu Ci/cm^3$. The maximum dose rate at the site boundary caused by this activity in two tanks is 3.6×10^{-3} mrem/year, as shown in Table 12.1-17.

12.1.3.9 Turbine Building Skyshine Exposures

The SKYSHINE code (Reference 19), designed to evaluate the effect of the turbine building geometry on site boundary radiation levels, was used to calculate gamma ray dose rates at eight specific locations distributed on and within the site boundary. The SKYSHINE code uses a Monte Carlo method and air transport data, along with concrete and steel transmission and reflection data, to evaluate the structure design. The program designates which portion of the calculated dose rates results from gamma rays penetrating the roof and each wall of the building, as well as that which results from gamma rays emitted through openings in the building roof and walls. The results of these calculations (Reference 19) are shown in Table 12.1-18, and the locations of the receiver points are shown in Figure 12.1-2.

The turbine building is a source of radiation due to the inherent activity of the steam. In the dose-rate calculations, only the ^{16}N activity from the steam was considered since it is the only isotope of any significance. For example, the ^{16}N activity leaving the reactor is at least a factor of 100 greater than any other isotopic activity. Also, the high energy (6 MeV) gamma rays from the ^{16}N will be attenuated in air much less than the lower energy gamma rays from the other isotopes, thereby giving higher dose rates. The turbine, reheaters, and steam lines are enclosed on all sides by shield walls. Hence, all radiation must first travel upward (through the roof and upper walls) and scatter in the air before reaching the ground. The site boundary dose rate, therefore, will be less than that from a corresponding unit with an exposed or unshielded turbine area. The internal or self-attenuation of each source component (that is, reheaters, turbines, high-pressure piping, and low-pressure crossover piping) was included in the calculations.

Receiver points C and D (Figure 12.1-2) are located north of the plant in line with the turbine. Receiver point H is located in the area of the Fermi 2 interpretive building in the environmental center. Point B is located at the main office building complex, whereas point A is located at the far eastern aisleway on the third floor of the turbine building (60 ft above grade). All other points were taken to be 3 ft above ground elevation. All receiver points were positioned in air with no shielding effect of structures, except for points A and B. For point A, the attenuating effect of an 8-in. concrete ceiling was included. This is conservative, since the major portion of the roof of the turbine building is significantly thicker than 8 in. Point B took into account the shadowing effect of the other (eastern) wall of the turbine building. Points E, F, and G were located to the west of the turbine building, in a lateral direction from the major radiation sources.

The computed dose rate at the site boundary in this due west direction (point G) is 3.8×10^{-4} mrem/hr or 3.32 mrem/year. The nearest actual site boundary is in the northwest direction (3200 ft from the turbine). Extrapolation of the SKYSHINE code data to this point results in a dose rate of 7.8 mrem/year at the nearest site boundary. This is a conservative estimate, since the value does not take into account the geometrical "shadowing" effect of the tall reactor building on the sources in this particular direction. For plant operation with Hydrogen Water Chemistry, in-plant tests have shown that these conservative calculated N-16 estimates could increase by a maximum factor of six from the estimates calculated in Reference 19 and shown in Table 12.1-18.

The computed dose rates shown in Table 12.1-18 indicate that the gamma ray emission from the reheaters is the major contributor to the dose rate at all points except for the point at point H near the Quarry Lakes. The next largest contribution to the dose rate results from the gamma rays emitted from the low-pressure crossover pipes. The maximum contribution by the gamma rays emitted from the high-pressure inlet pipes is about 6 percent at points C and D. The dose rate due to gamma rays produced in the high- and low-pressure turbines is insignificant when compared to that from the other sources.

A second source of turbine building radiation comes through the outer walls of the building itself from radiation in hot equipment cells adjacent to the outer building walls. These levels are then further attenuated through air to the site boundary. The maximum radiation level so calculated occurs at the southern boundary of the site, opposite the southern end of the turbine building, and is less than 0.5 mrem/year. Corresponding levels from other walls of the turbine building are at least a factor of 10 lower.

The third source of turbine building radiation is also insignificant. It is due to skyshine, which occurs from radiation leaving the concrete ceilings of the various radioactive cells on the third floor. The total air scattered dose rate of the site boundary from all of these sources was calculated to be less than 0.03 mrem/year.

The reactor building is not a significant source of radiation dosage at the site boundary. This building is shielded such that the radiation levels at its outer walls are below 0.5 mrem/hr.

The maximum dose rate at the site boundary, which is due to the attenuation of core gamma radiation through the concrete walls and then through the air, was calculated to be less than 0.003 mrem/year. Skyshine doses from the fifth (operating) floor of the reactor building are insignificant.

12.1.3.10 Field Run Piping

Steps were taken to ensure that the routing of field run process piping, which carries radioactive fluid, would result in minimal radiation exposure to plant personnel. Only that piping which is 2 in. or smaller (nominal diameter) is field run, fabricated, and erected.

All process piping including field run piping is shown on the appropriate system piping diagrams. These drawings provide enough information for an adequate shielding review. When necessary, field drawings prepared before the installation of the piping were also reviewed for shielding requirements. Similarly, the completed as-built drawings are reviewed and approved.

Onsite inspections were conducted as necessary to review the shielding design. If any of these review steps indicated a necessity for modifying the field routing of a given piping run, such modifications were evaluated and made as necessary.

System piping diagrams that include field run piping are also reviewed for considerations of ALARA exposures. Any piping that may adversely affect occupational exposures is given an additional review.

12.1.4 Area Radiation Monitoring

12.1.4.1 Criteria for Necessity

The objective of the area radiation monitoring system (ARMS) is to provide plant personnel with a continuous record and indication in the main control room of gamma radiation levels at selected locations. These locations are within various plant buildings where radioactive materials may be present or inadvertently introduced. The system is designed to obtain accurate and reliable information concerning radiation levels in selected plant areas to ensure personnel safety.

The design objectives of the ARMS are to provide

a. Supervisory information to plant operators so that decisions on deployment of personnel in the event of an accident resulting in a release of radioactive material can be properly made

b. Supervisory information to plant operators to warn of unauthorized or inadvertent movement of radioactive material in the plant. This system also supplements other systems, including the process and effluent radiation monitor system and reactor coolant leak detection system, in detecting abnormal migrations of any radioactive material from plant process streams

c. Indication and recording in the main control room of the gamma radiation level in selected areas as a function of time, and the alarming of abnormal radiation conditions

d. Local alarms and/or indicators at all points where a substantial increase in radiation levels might be of immediate importance to personnel frequenting or working in the area

e. Indication to operating personnel that a channel is inoperable.

12.1.4.2 Criteria for Location

A total of 47 monitors are provided at various locations inside the reactor, auxiliary, radwaste, service, onsite storage, and turbine buildings. The detectors are located in areas where:

a. Personnel perform regular duties in areas where radiation is present. These duties are performed once per day or more frequently

b. Personnel perform infrequent duties, but where there is a high probability that significant changes in radiation levels could occur

c. Personnel perform infrequent duties, or where there is a low probability that significant changes in radiation levels could occur, but where surveillance is desired.

The functional description, general locations, ranges, and alarm setpoints of the area monitors are given in Figures 12.1-11 through 12.1-13. The locations, which may be changed based on operating experience, were chosen so that a clear indication of radiation levels and radiation trends in occupied areas is given. Figures 12.1-1 and 12.1-3 through 12.1-8 show these general locations.

12.1.4.3 Design Criteria

The following design criteria are used in the design of the ARMS:

a. To facilitate compliance with applicable regulations and guides, monitors and detectors have sensitivities and ranges in accordance with radiation levels anticipated at specific detector locations

b. All monitors register full-scale if exposed to radiation levels that exceed full-scale indication

c. Radiation dose rates are continuously recorded in the main control room and are indicated on meters in the relay room

d. Main control room alarms annunciate high radiation dose rates and signal failures

e. A "mimic panel" in the main control room indicates which monitor has alarmed

f. Local alarms and indications are provided near selected detector locations

g. Access to the alarm setpoints is under the administrative control of Health Physics

h. Monitor equipment is readily accessible for maintenance and calibration, with the exception of a few sensor- converter units and auxiliary units located in high- radiation areas during power operation

i. Environmental design conditions for the components are consistent with the conditions stated for the reactor building and control center

j. Each power supply unit, which has sufficient capacity to power 10 monitor channels, is provided with a power feed that is manually restorable to diesels

k. The detector is responsive to gamma radiation over an energy range of 80 keV to 7 MeV, with an average energy dependence of ±20 percent from 100 keV to 3 MeV (per GEK-32374).

12.1.4.4 Equipment Description

The ARMS functional diagram is shown in Figure 12.1-11. The system has no control functions. All locally mounted instruments are located where accidental damage from movement of material or equipment is highly improbable.

The monitors are well scattered throughout the plant. One monitor does not serve as a backup for another monitor. Requirements for a small number of monitors to be in service during plant operation are contained in the Technical Specifications. Any malfunctioning monitors are repaired as soon as possible. During work in the fuel storage pool when irradiated fuel is handled, the low-range monitor on the refueling platform provides an alarm if an assembly is accidentally raised too high in the water.

Each channel has plug-in modules that make the system easy to test, maintain, or troubleshoot. Each channel contains items described in Subsections 12.1.4.4.1 through 12.1.4.4.8.

12.1.4.4.1 Sensor-Converter

The sensor-converter unit is encased in a small cylindrical aluminum container that is sealed against its environment. It is not affected by water spray and is designed to be fully operational over a wide range of temperatures. The unit is normally mounted on a wall or other vertical surface.

The sensor (detector) is one of a series (depending on the monitor range) of halogen-quenched Geiger-Mueller (GM) tubes that detect gamma radiation over the energy range of 80 keV to 7 MeV. The converter amplifies the detector signal and supplies an integrated logarithmic output. At low dose rates, radiation levels are measured by the usual pulse counting technique. At higher dose rates, a current generated by the detector is added to the pulse counting circuit output current, thus compensating for loss of counts resulting from resolving time losses.

The sensor-converter has good sensitivity at low levels and fast response at high levels because of the count rate circuit, which combines a long integrating time constant at low radiation levels with a fast overall response at high radiation levels. Another circuit is included that keeps the instrument reading full scale for a radiation level greater than full scale. The overall accuracy within the design conditions stated in Subsection 12.1.4.3, including energy dependence (100 keV to 3 MeV), is within 10 percent of equivalent linear full-scale recorder output for any decade.

The sensitivity and range of the detectors have been selected to have the meters and recorders read on scale during normal operation. For the range and setpoints for each detector, see CECO.

If any of the monitor locations chosen prove to be ineffective after a period of plant operation, the sensor-converter unit may be moved to more effective locations.

12.1.4.4.2 Indicator and Trip Unit

The indicator and trip units are mounted in racks in the relay room. Each unit provides channel indication and control. In each unit, there are two solid-state trip circuits that use an extremely reliable low drift differential input bistable amplifier. A four-decade logarithmic meter, which corresponds to the range of the detector, is supplied together with low (failure) and high (radiation) trip indicator lights. Controls include a TRIP RESET pushbutton and a mode switch (TRIP TEST/ZERO/OPERATE). The unit provides an output to the recorder and mimic panel. The power input is provided by the power supply unit.

12.1.4.4.3 Auxiliary Unit

The auxiliary unit is mounted locally near the sensor whenever a local audible alarm or light beacon is used. It is also used when only a local indication of radiation level is desired. The unit has a four-decade logarithmic meter that corresponds to the range of the detector. On a high (radiation) trip, an indicator on the unit lights, and a 120-V ac relay closes. A local lighting circuit is used to supply 120 V ac to this relay to operate any audible and visual signals used.

12.1.4.4.4 Power Supply Unit

Six power supply units are mounted in racks in the relay room. Each unit is capable of supplying power to 10 channels consisting of a sensor-converter unit, an indicator and trip unit, and an auxiliary unit. The voltages supplied to the channel components are +575 V dc, ±24 V dc regulated, +33 V dc unregulated and a trip test voltage. The unit has a high voltage meter (0-1000 V dc), a POWER ON light and a TRIP CHECK ADJUST potentiometer. When the mode switch on the indicator and trip unit is placed in TRIP TEST, this potentiometer can be used to adjust the output of the indicator and trip unit over its entire range to determine the trip setpoints.

12.1.4.4.5 Recorder

There are two multipoint chart recorders located on the combination operating panel H11-P816 in the main control room. These recorders make a continuous permanent record of the radiation levels detected by all the area radiation monitors. A list of the range and trip point of each detector by point number is posted on the recorder. This same information is listed in Figures 12.1-12 and 12.1-13. The signal to be recorded is supplied from the indicator and trip unit located in the relay room. Power to the recorder is supplied from an instrument circuit.

12.1.4.4.6 Mimic Panel

The mimic panel is located on the combination operating panel H11-P816 in the main control room. The panel consists of a layout of the plant buildings with labeled alarm lights for items such as high temperature, high pressure, smoke, and radiation. There are labeled lights that correspond to the location of the detectors (sensor-convertor units). When a high alarm is indicated in the relay room on the indicator and trip unit, a mimic light marked "Channel XX" also illuminates, showing which channel has alarmed and the general location of the detector.

12.1.4.4.7 Audible and Visual Alarms

The alarms of the ARMS consist of

a. A low (failure) alarm, which will be activated whenever the indicator and trip unit reaches a downscale setpoint due to detector failure or circuit failure. This setpoint is adjustable over the entire scale

b. A high (radiation) alarm, which will be activated whenever radiation levels exceed a predetermined alarm setpoint. This setpoint is adjustable over the entire scale.

When the radiation level exceeds the high alarm setpoint, a main control room annunciator sounds. In addition, the light for the specific channel detector lights on the mimic panel in the main control room, the high trip indicator lights on the specific indicator and trip unit in the relay room, an indicator lights on the local auxiliary unit, and a local audible or visual alarm activates, when provided.

If the low alarm setpoint is reached, an annunciator sounds and the low trip indicator lights on the specific indicator and trip unit in the relay room.

The annunciators may be silenced in the main control room, but the alarms have to be reset at the indicator and trip unit when the alarm conditions are corrected. The local audible alarm or light beacon, when provided, remains on until the alarm is reset in the relay room.

Low (failure) alarm setpoints are normally set below the background radiation level to indicate when the system has failed. High alarm setpoints are set at least double the background level to prevent spurious alarms. The alarm setpoints can be changed as required to compensate for changes in the background radiation levels. This is done under the direction of Health Physics.

12.1.4.4.8 Area Radiation Monitor Portable Calibrator

The area radiation monitor portable calibrator is a test and calibration unit designed to facilitate "in-the-field" operational testing of the sensor and convertor. It contains a radioactive test source. To use this unit, the sensor-convertor is removed from the wall and calibrated while still connected to the ARMS circuit. Different gamma radiation levels can be obtained by adjusting the source and shield controls.

Additional sources with higher radiation levels, which are not specifically designed for use with this system, can also be used to check the higher ranges. If the proper radiation level is not indicated by the channel, adjustments to the channel are made.

12.1.4.5 Testing Requirements

Each area monitor is capable of being tested as a channel. The system has testing and calibrating equipment that permits local channel testing without disassembling any components. An internal trip test circuit, located in the indicator and trip unit, is adjustable over the full range of the readout scale using the TRIP CHECK ADJUST potentiometer located on the power supply unit. The test signal is introduced internally into the indicator and trip unit input so that a meter reading is obtained in addition to a trip (alarm). Thus, the alarm point can be easily checked. All of the trip relays are of the latching type and must be manually reset at the front panel of the indicator and trip unit.

12.1.4.6 Calibration

An initial calibration of each monitor/detector is performed before installation. During normal operation, checks of system operability are made by observing channel behavior. Functional checks and/or full-channel detector calibrations are performed at specified intervals and are in accordance with the Technical Specifications, as required. (Only channels 6, 15, 16 and 17).

12.1.4.7 Maintenance

The channel detector, electronics, and recorder are serviced and maintained on a scheduled basis to ensure reliable operation. Such maintenance includes cleaning, lubrication, and assurance of free movement of the recorder in addition to the replacement or adjustment of any components required after performing a test or calibration. The local alarms and readouts associated with the detector, which may require periodic adjustment, are located in radiation fields less than 1 mrem/hr in most cases.

12.1.5 Estimates of Exposures

12.1.5.1 Anticipated Doses

The maximum design dose rates in any designated area of the plant are given in Subsection 12.1.1 and in Figures 12.1-1 and 12.1-3 through 12.1-8. The area zones were determined by either the anticipated radiation level of the equipment in the area or the maximum radiation levels at the walls, achieved through shielding. The maximum design shield dose rates are not expected to occur during normal operation, because of the conservative nature of the design-basis calculations. Inside equipment compartments or adjacent to equipment carrying radioactive material, the anticipated dose will result from the actual operation of the equipment itself. The highest dose rates in the plant will occur in Zone X areas, such as inside the drywell, in the turbine condenser area, and in rooms in which equipment and piping contain highly radioactive material. However, personnel access to these areas is nonroutine, infrequent, and rigidly controlled.

Because of the large number of variables involved, an estimate based on operating histories of similar plants, rather than theoretical calculations, was used to estimate the radionuclide concentration in the fuel pool and the possible resulting exposures or radiation levels that may exist in the area above and around the pool. Only those reactors with more than 2 years of operating experience and recent history of troublesome fuel elements were surveyed.

In the presentation of their paper at the Eighth Midyear Health Physics Society Symposium (Reference 20), Golden and Pavlick state that adequate fuel pool treatment should be provided to limit isotope concentration to 1 x 10^5 pCi/ml (equivalent to less than 1 mrem/hr above the pool) during refueling operations. These numbers show good agreement with the survey. The average isotope concentration in the fuel pool during normal operation was about 1 x 10^{-4} μCi/ml, with no measurable activity that could be attributed to the fuel pool.

A range of peak isotopic concentrations was obtained for refueling operations, from 0.015 to 0.75 μCi/ml. During refueling operations, those plants with filters and demineralizers reported radiation levels from 1 to 15 mrem/hr at the surface of the fuel pool. The maximum reported radiation level at the bridge attributable in part to the radioactive contamination in the fuel pool was about 2 mrem/hr. None reported any measurable radiation level on the main refueling floor attributable to the water.

The Fermi 2 fuel pool cleanup system design is influenced by the lessons learned from the reactors surveyed. Based on their history, less than 2 mrem/hr can be expected on the bridge, and less than 0.5 mrem/hr on the general refueling floor during normal work periods.

Experience in the design and operation of power plants shows that the actual (measured) radiation levels are usually less than those used as shielding design objectives for controlling the radiation doses. The annual doses received by the plant personnel can be kept well below the limits of 10 CFR 20 on the basis of the plant shielding and access control design. Shielding design takes into consideration radiation levels from maximum coolant activities, fission product leakage, and combinations of anticipated occurrences.

The main control room will be a Zone I area and hence will have a maximum allowable dose rate of 0.3 mrem/hr. Service areas will be Zone II areas, with a maximum dose rate of 0.5 mrem/hr. Therefore, annual doses in these areas, considering occupancy factors, will be well within the limits of 10 CFR 20. Boiling water reactor operating experience confirms the above contentions. For instance, dose rates in the main control room, visitor center (interpretive building), and office areas have been measured at operating BWR units and have been found to be between 0.01 and 0.06 mrem/hr during full-power operation. This is considerably below the 0.3 and 0.5 mrem/hr design limit for these areas in the Fermi 2 plant. Dose rates in controlled- access corridors shielded from process equipment containing radioactive material, such as the RWCU system and fuel pool cooling and cleanup system, vary typically between 0.5 and 3 mrem/hr, whereas dose rates outside the shielded steam tunnels are generally less than 0.1 mrem/hr. Dose rates inside the reactor building and in assigned Zone X areas are generally expected to be consistent with data available from operating BWR facilities. For example, typical contact readings on the high-pressure turbine have been found to exceed 400 mrem/hr at full power.

Since measured radiation levels from operating facilities indicate that actual dose rates to be expected in normally accessible areas should be significantly less than the peak external shield design dose rates used for the Fermi 2 design, an exposure analysis (described in Subsection 12.1.5.2) has been performed using average expected dose rates. These average dose rates for all access zones described in Figures 12.1-1 and 12.1-3 through 12.1-8 are defined in Table 12.1-1, Footnote a.

12.1.5.2 Estimate of Exposure of Plant Personnel

12.1.5.2.1 General

The annual exposure that could be received by plant personnel during patrolling, control operations, manual work, and expected maintenance has been estimated. This estimate was made during the intermediate stages of plant design as part of a process to review, examine, and/or evaluate various ALARA considerations and design features (see discussion in Regulatory Guide 8.19). As the Regulatory Guide indicates, these exposure estimates are by their very nature fairly imprecise. Their relationship to the actual man-rem doses received during subsequent plant operation will depend primarily on operating experience and the maintenance and repair problems encountered.

It is estimated that, with the plant operating continuously under expected radiological conditions, personnel exposures would not exceed the 1.25 rem per calendar quarter limit, and average personnel exposures will be less than 5 rem/year. Unexpected major repairing of equipment is excluded from the annual exposure since the 1.25 rem per calendar quarter can be exceeded under such exceptional conditions. For the purposes of the estimate, normal work, control operations, and expected maintenance include

a. Routine patrol

b. Periodic tests, operations, and maintenance jobs (including planned repairs taking place more than once a year)

c. Main control room operations

d. Refueling.

The assumptions for the estimate are as follows:

a. Fermi 2 is operated by three shifts and six crews, each crew consisting of a minimum of six operating personnel as described in Subsection 13.1.2. These personnel are trained in various areas of radiation protection. Shift personnel do not perform technical functions in chemistry, radiochemistry, or instrument and/or control adjustments. Technicians qualified to meet the requirements of ANSI N18.1 perform these functions and are called in during off hours, when needed, by the Shift Manager. Routine patrols, tests, and periodic jobs throughout the facility are alternated between operating personnel to ensure an even distribution of radiation exposure

b. All electrical and mechanical maintenance is performed by the maintenance section. A maintenance crew of 12 is assumed for all expected mechanical and electrical maintenance. Exposures for the maintenance crew are assumed to be uniformly distributed over the personnel available

c. Calibration, testing, and maintenance of most plant instruments and control systems are accomplished by the instrumentation and control group. An instrumentation and control crew of at least eight persons is assumed for all plant instrumentation and control work. Exposures for the instrumentation and control group are assumed to be equally distributed over the normal personnel available, and are included in the maintenance staff exposure data

d. Maximum design-level dose rates in various plant areas are shown in Figures 12.1-1 and 12.1-3 through 12.1-8, and anticipated average design dose rates for these areas are defined in Table 12.1-1.

The estimate of average exposure and total yearly man-rem for each of the Fermi 2 working groups has been based on the plant operating continuously with the expected design-basis radiological conditions, and with personnel performing all their operations and patrolling in areas where in the dose rates have been assumed to be constant and equal to the average expected dose rate in the area (Table 12.1-1).

NOTE: These whole-body dose estimates of Section 12.1.5 have been performed as part of the original overall design-basis determination that the plant was well-designed from an ALARA standpoint. These calculations are/were intended to only represent conservative pre-operational estimates. They were not intended to be updated or revised in order to correspond to operational data or to any revised criteria, assumptions, methodology, etc. Detailed whole-body dose information is continuously taken and analyzed as an integral part of plant operations, and summary dose information is periodically provided to pertinent regulatory agencies.

12.1.5.2.2 Results

The estimates for the various buildings and jobs are as follows:

a. Tables 12.1-19 through 12.1-21 define the exposures operating personnel receive on routine rounds while checking equipment. These tables make the conservative assumption that the rounds are performed once per shift (once every 8 hr) 52 weeks per year

b. Tables 12.1-22 through 12.1-24 define the exposures that operating personnel receive during maintenance, such as filter changing and lubrication

   It should be noted that the radwaste handling (i.e., drumming, capping) and maintenance, as defined in Tables 12.1-19 through 12.1-24 and in Tables 12.1-26 through 12.1-28, include the estimates of exposures that radwaste handlers would experience

c. For the remaining time in the shift, it is assumed that the operations personnel spend their time in the shop, main control room, or other buildings where the average dose rate of 0.10 mrem/hr is expected. Table 12.1-25 defines the bases for which the man-rem exposure estimate has been established

d. Tables 12.1-26 through 12.1-28 define the exposures maintenance personnel receive during normal expected maintenance functions. These tables include man-hours expected for the maintenance groups, including mechanical, electrical, and instrumentation and control maintenance, and are defined for a whole year of operation

e. For the remaining time in the year, it is assumed that the maintenance personnel spend their time in a Zone II area, i.e., a maximum design dose rate of 0.5 mrem/hr, and an expected average dose rate of 0.1 mrem/hr. (See Table 12.1-

25 for this estimate). Table 12.1-25 also gives an exposure estimate for the remaining personnel associated with operation of the Fermi 2 facility and also the basis by which the estimate has been established

f. It is difficult to accurately estimate the amount of personnel exposure associated with the actual refueling process. The same is true for inservice inspection. However, data from the Millstone facility obtained in an AIF study indicate that 61 men had received a total of 74.23 manrem over a period of a year (1972) during routine plant surveillance, inspection, and routine refueling operation, for an average of 1.22 rem/man- year. Refueling exposures as reported by operating facilities normally include maintenance exposures associated with the refueling operation, not those associated with the refueling alone. Thus, it can be concluded that Tables 12.1-19 through 12.1-25 include the estimate of man-rem exposure for the maintenance portion of the refueling operation

g. Radiation exposure received by the chemists or designated technicians is difficult to assess since they perform technical functions in chemistry, radiochemistry, instrument, and/or control adjustments. However, experience indicates that these personnel receive 2 rem/ year/man. The same is true for the health physicists and the Health Physics technicians

h. Table 12.1-29 summarizes the exposure data presented in Items a. through g.

Comparison of the estimated results with data available from the operation of Nine Mile Point, Quad Cities 1 and 2, and Oyster Creek is given in Table 12.1-30. Data from the operating plants were obtained by averaging information presented in WASH-1311 (Reference 21).

12.1.6 Postaccident Shielding Assessment

12.1.6.1 Introduction

A postaccident radiation shielding review has been performed to ensure adequate access to vital areas and protection of safety equipment. The assumptions, approach, and results of the review are outlined below. These analyses were prepared in response to post-TMI guidance with Regulatory Guide 1.3 based source terms, and are typically conservative relative to analyses that would be performed in accordance with 10 CFR 50.67 and Regulatory Guide 1.183 guidance. Evaluations are made of control room doses and impacts on vital area accessibility with AST based parameters.

12.1.6.2 Source Terms

The initial reactor core inventory of radioactive nuclides was determined using assumptions in accordance with Regulatory Guides 1.3 and 1.7 and NRC post-TMI guidance. At time-equals- zero after the reactor shutdown, an instantaneous release of radioactivity from the core was assumed to occur. Liquid- containing systems were assumed to receive 100 percent of the noble gas inventory, 50 percent of the core halogen inventory, and 1 percent of all other radionuclides. Gas-containing systems were assumed to receive 100 percent of the core noble gas inventory and 25 percent of the core halogen inventory. Radioactivity in liquid systems was assumed to be uniformly mixed in a volume of water equal to the total volume of the reactor vessel, the recirculation system volume, and the suppression pool water volume. Radioactivity in the primary containment air was assumed to be uniformly mixed in the total of the drywell and torus free air volumes. (Vapor-containing lines connected to the primary system have this activity confined to the primary system vapor space.) At time-equals-zero, the primary containment air volume was assumed to begin leaking into the reactor building atmosphere at the rate of 0.5 percent per day.

At the same time, the SGTS was assumed to begin drawing activity from the reactor building at a rate of one reactor building volume per day. The above considerations define the airborne radionuclide activity in the reactor building atmosphere. This airborne activity (plus the airborne activity released from an assumed 1500-gal primary liquid leak into the reactor building [with 100 percent noble gas and 10 percent halogen evolution assumed]) was used to determine the radionuclide inventory accumulated on the SGTS filters, the control room emergency makeup and recirculation filters, the process radiation monitor sample filters, and the technical support center emergency makeup recirculation filters.

The initial core inventory and the transport and decay of radionuclides were handled by the RACER computer code (Reference 22). The RACER code is made up of two major subroutines, RIBD and BAFFLE. RIBD is a standard industry code for calculating reactor core inventories. BAFFLE is a code that analyzes the transport of radionuclides between communicating compartments. Leak rates, filtration, and plate-out can all be modeled with this code, taking full account of radionuclide decay and daughter-product buildup.

Section 6.4 of NUREG-75/087 (Reference 23) provided the guideline for modeling the SGTS effluent plume.

For AST based analyses for the main control room, LOCA sources are determined using RADTRAD models with design basis core source terms, credited removal mechanisms, and transport parameters. Uniform mixing in secondary containment is assumed when evaluating secondary containment gamma shine, and 100 percent filter efficiency is assumed when evaluating SGTS filter source terms.

Chapter 15 analyses of accident radiological consequences are performed per Regulatory Guide 1.183 Alternative Source Term (AST) (Reference 27) using core source terms reflective of anticipated fuel cycle conditions obtained with appropriate isotope generation and depletion computer codes. Whereas the original AST analysis of onsite and offsite consequences used ORIGEN-S – based source terms (Reference 29), re-analysis and consideration of the Chapter 15 accidents to support implementation of a 24-month, GNF3 fuel cycle are performed using ORIGEN 2.1-based source terms (References 26 and 30) appropriate for anticipated fuel cycle conditions.

RADTRAD (Reference 24) calculated time dependent compartment activities are time integrated and then evaluated using Microshield (Reference 25). Sources considered are the primary containment, the reactor building, a standby gas treatment system filter and an environmental plume outside of the control room shielding.

12.1.6.3 Radioactive Systems

The systems assumed to contain radioactive liquids include the high-pressure injection system, the core spray system, the reactor core isolation coolant (RCIC) system, and the residual heat removal (RHR) system, as well as portions of the control rod hydraulic system, sample lines, and all piping and equipment in communication with the primary coolant system out to the second isolation valve. A design review was performed to ensure that no systems other than those mentioned above would become contaminated with postaccident primary coolant. In particular, design corrections have been made to ensure that the reactor building sumps (which could contain postaccident primary coolant) would not be pumped out of the reactor building. The radwaste system, therefore, would not be contaminated by postaccident sources.

Systems assumed to contain postaccident primary containment atmosphere are the drywell, the torus free air volume, all piping and equipment connected to the drywell, and torus free air volume out to the second isolation valve. The reactor building atmosphere is assumed to be contaminated as a result of primary containment leakage. Steam lines are assumed to contain the core release fractions for airborne sources outlined in Subsection 12.1.6.2. It is assumed that these sources are restricted to the vapor-containing areas of the primary coolant system. A design review showed that the gaseous radwaste system is not exposed to postaccident source terms.

12.1.6.4 Radiation Environment

The determination of the total radiation environment at any location includes the consideration of all of the many potentially contributing sources. The sources considered include the following:

a. Direct radiation shine from the airborne and liquid radiation sources in the drywell and torus

b. Direct radiation shine from enigneered safety features equipment and piping circulating postaccident contaminated liquids or gases in the reactor building (e.g., RHR, high-pressure coolant injection, RCIC, and core spray system)

c. Immersion in and inhalation of the airborne sources within the reactor building heating, ventilation, and air conditioning (HVAC) boundary, resulting in gamma whole-body doses, beta skin doses, and thyroid doses due to iodine inhalation

d. Direct radiation shine of the reactor building and refueling floor atmospheres to surrounding areas

e. Direct shine from (or immersion in and inhalation of) the SGTS exhaust plume

f. Direct radiation shine from airborne filters that accumulate radionuclides (e.g., SGTS filters, control room and technical support center emergency makeup filters, and continuous air monitor sample filters).

g. Direct shine from the dry cask storage system HI-STORM units emplaced on the ISFSI storage pad.

The total radiation dose at any particular location was determined by summing all of the above-mentioned contributors. The final dose rates were then assembled and presented in the form of radiation zone maps. Zone map sets were prepared for times of 1 hr, 1 day, 1 week, and 1 month after the onset of the accident. These zone maps were prepared from the following zone designations:

I	-	greater than 500 rem/hr
II	-	500 to 100 rem/hr
III	-	100 to 10 rem/hr
IV	-	10 to 1.0 rem/hr
V	-	1.0 to 0.10 rem/hr
VI	-	0.10 to 0.015 rem/hr
VII	-	less than 0.015 rem/hr

12.1.6.5 Method of Analysis

External dose rates due to direct radiation from the drywell, the torus, the various contained sources, and the effluent plume were determined by using Microshield on time integrated concentrations determined using RADTRAD.

Airborne immersion and inhalation doses were calculated using the RADTRAD computer code.

12.1.6.6 Radiological Equipment Qualification

Appropriate radiation calculations were generated, and the ability of safety-related equipment to withstand postaccident radiation levels was determined.

12.1.6.7 Vital Areas

A review was performed to determine the radiological accessibility and habitability of the station's vital areas. Areas considered in this review included the control room, the technical support center, the postaccident sample panel, the postaccident sample analysis areas, the radwaste panel, the motor control centers, instrumentation locations, emergency power supplies, the security center, the hydrogen recombiners, the hydrogen purge control areas, the containment isolation reset areas, and the manual emergency core cooling system (ECCS) alignment areas.

It was determined whether each of these potential vital areas is necessary for postaccident operation of the plant. Besides the control room, four vital areas were identified as listed in Section 11.4.3.12. For those areas necessary for postaccident operation of the plant, the extent of occupancy for these areas to fulfill their functions was established. This information, in conjunction with the postaccident radiation zone maps, made it possible to verify if the postaccident occupancy of vital areas would result in radiation doses to personnel that would exceed the limits set forth in GDC 19 and 10 CFR 50.67.

The postaccident accessibility review of the vital areas concluded that only one major modification was necessary; it was determined that excessive radiation skyshine from the refueling floor could enter the ground floor of the turbine building through a large equipment blockout in the north wall thus limiting the accessibility of this area. A removable concrete shield wall (14 ft 2 in. x 11 ft 8 in. x 18 in.) was constructed in front of the two former door openings in this area. This modification corrected the problem so that postaccident occupancy of vital areas will not be unduly limited by radiation.

The four vital areas identified in UFSAR Section 11.4.3.12 as being necessary for post-accident operations of the plant will continue to be habitable (within 10 CFR 50.67 limits)following a DBA-LOCA, after the application of AST to Fermi 2 as described below.

a. The calculated doses in the Technical Support Center (TSC) with existing TSC HVAC design parameters remains within allowable limits

b. The Operational Support Center (OSC) in the Turbine Building (TB) as well as the alternate OSC in the Service Building machine shop will continue to be habitable with some increase in dose in the primary OSC due to additional postulated activity in the TB due to MSIV leakage

c. The post-accident sampling facility will remain accessible, based on 1-hour occupancy and optional use of self-contained breathing apparatus (SCBA) when taking samples.

d. The post-accident sample analysis areas will continue to be accessible, and based on TSC results, most of these facilities would be expected to have lower exposures based on AST assumptions

An assessment was performed of access paths to the control room to confirm that increased airborne activity in the TB will not interfere with personnel change-over.

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TABLE 12.1-1 PLANT RADIATION SHIELDING ZONES FOR NORMAL OPERATION AND ANTICIPATED OPERATIONAL OCCURRENCES[h,i]

Zone Number	Maximum Dose Rate[a] (mrem/hr)	Posting Required[b]	Anticipated Access[c]
I	≤0.3[d]	No	Unrestricted
II	≤0.5	No	Restricted with unlimited access
III	≤1.0	No	Restricted with occupational access
IV	≤2.0	No	Restricted with occupational access
V	≤4.0	No	Restricted with periodic access
VI	≤8.0	Yes[e,f,g]	Restricted with limited access[f]
VII	≤15.0	Yes[f,g]	Restricted with limited access[f]
VIII	≤30.0	Yes[f,g]	Restricted with limited access[f]
IX	≤60.0	Yes[f,g]	Restricted with limited access[f]
X	≤60.0	Yes[f,g]	Restricted with limited access[f]

[a] Except for Zone X, the anticipated average dose rate is approximately 0.25-0.33 times that of the maximum design dose rate.

[b] Refers exclusively to whether posting with the signs "Caution - Radiation or High Radiation Area" is required; not the posting of actual radiation levels.

Actual radiation levels will be routinely posted at selected portions of Zones V through X.

[c] All access within the site boundary is controlled.

[d] This zone applies to the main control room only.

[e] Posting will be required in those areas in which there exists radiation such that a major portion of the body could receive a dose in excess of 100 mrem in any 5 consecutive days.

[f] Access only with Health Physics permission, with duration based on (1) radiation intensity level, (2) nature of the radiation, (3) past radiation exposure history of entering personnel.

[g] Posting with these signs will be required in those areas in which there exists radiation such that a major portion of the body could receive a dose in excess of 100 mrem in any 1 hr.

[h] These are design-basis radiation shielding zones; they do not necessarily represent the maximum actual operational dose in any particular area of the plant.

[i] These zones are original design-bases values, without the operation of Hydrogen Water Chemistry.

TABLE 12.1-2 SUMMARY OF DRYWELL SHIELD DESIGN

Item	Protected Region	Design Condition	Design Value
A	Inner face of sacrificial shield wall	Full power	≤5 x 10^{10} MeV/cm^2/sec
B	Outer face of sacrificial shield, and at mating flange for top head of RPV	Full power	≤2 x 10^5 neut/cm^2/sec (thermal)
C	Outer face of drywell biological shield	Full power	0.3 mrem/hr (laterally) 2 mrem/hr (above plug)
D	Outer face of sacrificial shield	1-day shutdown, with core in place	30 mrem/hr (from sources inside shield)

TABLE 12.1-3 SPECIFIC SHIELD DESIGN CRITERIA FOR REACTOR AND AUXILIARY BUILDINGS

Identification Number[a]	Location of Source	Design Conditions of Source Area	Protected Area	Protected Area Design Conditions	Maximum Design Level in Protected Area (mrem/hr)
A.B.C.					
1.1.1	Torus in subbasement	Radiation streaming from drywell	A) Adjacent northwest cubicle	Local equipment down	1.5
			B) Adjacent southwest cubicle	Local equipment down	1.5
			C) Adjacent northeast cubicle	Local equipment down	1.5
			D) Adjacent southeast cubicle	Local equipment down	1.5
2.1.1	HPCI room	Testing of HPCI system	A) Area above (562 ft)	Always	30.0
			B) First-floor level (583 ft 6 in.)	Always	2.0
1.1.2	RHR rooms (2)	Reactor shutdown	A) Cubicles directly above (562 ft)	Always	2.0
1.1.3	RCIC system cell (NE)	Testing of RCIC system	A) Cubicles directly above (562 ft)	Always	2.0
1.1.4	Spray pump cell (SE)	Equipment testing	A) Cubicles directly above (562 ft)	Always	2.0
1.2.1	Torus in basement	A) Radiation streaming from drywell	A) Adjacent northeast cubicle	Always	1.5
			B) Adjacent southeast cubicle	Always	1.5
			C) Adjacent northwest cubicle	Always	1.5
			D) Adjacent southwest cubicle	Always	1.5
			E) Operating floor above (583 ft 6 in.)	Always	0.5
		B) Testing mode for RCIC, RHR, or HPCI	A) Operating floor above (583 ft 6 in.)	Always	2.0

TABLE 12.1-3 SPECIFIC SHIELD DESIGN CRITERIA FOR REACTOR AND AUXILIARY BUILDINGS

Identification Number[a]	Location of Source	Design Conditions of Source Area	Protected Area	Protected Area Design Conditions	Maximum Design Level in Protected Area (mrem/hr)
A.B.C.					
2.2.1	Radioactive pipe tunnel	Maximum activities in all lines	A) Adjacent operating areas	Always	0.5
			B) Operating aisles above (583 ft 6 in.)	Always	0.5
1.3.1	RHR heat exchangers	Reactor shutdown	A) Adjacent aisles	Always	2.0 (Max.)
			B) Region outside building	Always	0.5 (Max.)
1.3.2	Steam tunnel	Normal	A) Adjacent operating areas	Always	0.5
			B) Areas above and below	Always	0.5
1.3.3	Neutron monitoring (TIP)	TIP (maximum activity) in TIP room	A) Adjacent operating areas	Always	2.0
			B) Roof of cell	Always	8.0
			C) Operating floor above (613 ft 6 in.)	Always	2.0
1.5.1	Waste sludge discharge pump	Intermittent sludge discharge	A) Adjacent operating areas	Always	1.0
			B) Operating areas above and below	Always	1.0
1.5.2	RWCU phase separators	Maximum activities in tanks	A) Adjacent sludge-pump room	Pumps down	4.0
			B) Adjacent heat-exchanger room	Units down	4.0
			C) Adjacent RHR room	RHR down	4.0
			D) Region outside building	Always	0.5
			E) Operating area below	Always	0.5
			F) Room directly above	Always	1.0
1.5.3	RWCU heat exchangers	Normal	A) Adjacent aisles	Always	0.5
			B) Operating floor below	Always	0.5

TABLE 12.1-3 SPECIFIC SHIELD DESIGN CRITERIA FOR REACTOR AND AUXILIARY BUILDINGS

Identification Number[a]	Location of Source	Design Conditions of Source Area	Protected Area	Protected Area Design Conditions	Maximum Design Level in Protected Area (mrem/hr)
A.B.C.					
			C) Adjacent phase-separators	Units down	4.0
1.5.4	RHR heat exchangers	Reactor shutdown	A) Adjacent aisles	Always	2.0 (Max.)
			B) Operating floor above	Always	2.0 (Max.)
			C) Region outside building	Always	0.5 (Max.)
			D) Adjacent phase-separator room	Units down	4.0 (Max.)
1.5.5	RWCU recirculating pumps	Normal	A) Adjacent aisles	Always	0.5
			B) Adjacent RWCU pump cell	Pumps down	4.0
			C) Room below	Always	0.5
			D) Operating aisle below	Always	0.5
			E) Roof above cell	Always	4.0
			F) Operating floor above (641 ft 6 in.)	Always	0.5
1.7.1	Fuel pool heat exchanger	Normal	A) Adjacent aisles	Always	0.5
			B) Roof above cell	Always	4.0
			C) Operating floor above (659 ft 6 in.)	Always	0.5
			D) Pump rooms below	Pumps down	0.5
1.7.2	Fuel storage pool	Pool contains 1/2 of core spent fuel	A) Rooms below	Equipment down	4.0
			B) Adjacent east aisle	Always	1.0
			C) Adjacent west aisle	Always	0.5
			D) Adjacent north room	Always	1.0
1.8.1	Fuel storage pool	Pool contains 1/2 of core spent fuel	A) Adjacent east aisle	Always	1.0
			B) Adjacent west aisle	Always	0.5

TABLE 12.1-3 SPECIFIC SHIELD DESIGN CRITERIA FOR REACTOR AND AUXILIARY BUILDINGS

Identification Number[a]	Location of Source	Design Conditions of Source Area	Protected Area	Protected Area Design Conditions	Maximum Design Level in Protected Area (mrem/hr)
A.B.C.					
			C) Adjacent north room	Always	8.0
1.8.2	Dryer-separator storage pool	Storage of equipment in pool, after 3 days' decay	A) Adjacent aisles	Always	0.5
			B) Operating area below	Always	0.5
1.8.3	RWCU filter-demineralizers	Normal	A) Adjacent aisle (south)	Always	0.5
			B) Region outside building (north)	Always	0.5
			C) Adjacent demineralizer cell	Unit down	8.0
			D) Adjacent RWCU holding pumps	Pumps down	8.0
			E) Operating floor below	Always	0.5
			F) Operating floor above	Always	0.5
1.9.1	Dryer-separator pool	Normal	A) Adjacent aisles	Always	0.5
1.9.2	North SGTS room	LOCA	A) Region outside building (north)	Always	50.0[b]
			B) Adjacent SGTS cell	Unit down	8.0
			C) Adjacent HVAC room	Always	50.0[b]
			D) Main control room below	Always	5.0 rem[c]
1.9.3	South SGTS room	LOCA	A) Adjacent SGTS cell	Unit down	8.0
			B) Adjacent HVAC room	Always	50.0[b]
			C) Adjacent vent equipment room	Always	50.0[b]
			D) Main control room below	Always	<5.0 rem[c]

TABLE 12.1-3 SPECIFIC SHIELD DESIGN CRITERIA FOR REACTOR AND AUXILIARY BUILDINGS

[a] See Table 12.1-6 for explanation of identification numbers.

[b] Maximum value after a LOCA, when SGTS source is also at maximum activity.

[c] Dose integrated over duration of the LOCA.

[d] These levels are original design-basis values, without the operation of Hydrogen Water Chemistry.

TABLE 12.1-4 SPECIFIC SHIELD DESIGN CRITERIA FOR TURBINE BUILDING

Identification Number[a]	Location of Source	Design Conditions of Source Area	Protected Area	Protected Area Design Conditions	Maximum Design Level in Protected Area (mrem/hr)
A.B.C.					
4.2.1	Condensate backwash tank	Tank full of maximum activity	A) Operating floor above (583 ft 6 in.)	Always	0.5
			B) Pump rooms at either side	Pumps shut down	0.5
4.2.2	Condensate pump cells	Pumps and equipment operating	A) End rooms outside pump cells	Always	0.5
			B) Operating floor above	Always	0.5
4.2.3	Main pipe tunnel	Full power	A) Operating floor above (583 ft 6 in.)	Always	0.5
			B) Stairs and access areas at 564 ft	Always	0.5
			C) Other radioactive cells in basement	Shut down	8.0
4.2.4	Offgas holdup line	Full power	A) Southeast corner of basement	Always	0.5
			B) Two pump rooms in basement	Pumps down	8.0
			C) Operating floor above (583 ft 6 in.)	Always	0.5
			D) Steam jet air-ejector cells above (583 ft 6 in.)	Steam-jet air ejector shut down	8.0
4.2.5	Heater drain pumps	Full power	A) Adjacent heater pump cells	Pump down	8.0
4.3.1	Vacuum pumps	Maximum source conditions	A) Basement directly below	Always	0.5
			B) Main aisle outside pump cell	Always	0.5
			C) Operating floor above (613 ft 6 in.)	Always	0.5
4.3.2	Steam-jet air ejector cells	Full power	A) Main aisles outside cells	Always	0.5
			B) Adjacent steam jet air-ejector cells	Steam-jet air ejector down	8.0

TABLE 12.1-4 SPECIFIC SHIELD DESIGN CRITERIA FOR TURBINE BUILDING

Identification Number[a]	Location of Source	Design Conditions of Source Area	Protected Area	Protected Area Design Conditions	Maximum Design Level in Protected Area (mrem/hr)
A.B.C.					
			C) Adjacent vacuum pump cell	Pump down	8.0
			D) Recombiner cells above (613 ft 6 in.)	Equipment down	8.0
4.3.3	Heater drain-pump cells	Full power	A) Main aisles outside cells	Always	0.5
			B) Adjacent pump cells	Pump down	8.0
4.3.4	North reactor feed pump turbine cell	Full power	A) Main aisle outside cell	Always	0.5
			B) Operating floor above (613 ft 6 in.)	Always	0.5
4.3.5	South reactor feed pump turbine cell	Full power	A) Main aisle outside cell	Always	0.5
			B) Oil reservoir room	Always	2.0
			C) Operating floor above (613 ft 6 in.)	Always	0.5
4.3.6	Gland condenser room	Full power	A) Main aisle outside cell	Always	0.5
			B) Oil reservoir room	Always	2.0
			C) North reactor feed pump turbine cell	Reactor feed pump turbine down	8.0
			D) Operating floor above (613 ft 6 in.)	Always	0.5
4.3.7	Drains cooler cells	Full power	A) Main aisle outside cells	Always	0.5
			B) Adjacent drains cooler cells	Cooler down	8.0
4.3.8	Polishing demineralizers	Maximum demineralizer activity	A) Main aisles outside cells	Always	0.5
			B) Adjacent demineralizer cells	Demineralizer down	8.0

TABLE 12.1-4 SPECIFIC SHIELD DESIGN CRITERIA FOR TURBINE BUILDING

Identification Number[a]	Location of Source	Design Conditions of Source Area	Protected Area	Protected Area Design Conditions	Maximum Design Level in Protected Area (mrem/hr)
A.B.C.					
			C) Operating floor above (613 ft 6 in.)	Always	0.5
			D) Pump cells in basement below	Always	0.5
			E) Backwash tank in basement	Tank empty	8.0
4.3.9	Main pipe chase	Full power	A) Main aisles at south end	Always	0.5
			B) Oil reservoir room	Always	2.0
			C) Adjacent radioactive cells	Equipment shut down	8.0
4.3.10	Main condenser and steam piping	Full power	A) Main aisles at both ends	Always	0.5
			B) Oil lube equipment (west side)	Always	0.5
			C) Operating floor above (south end)	Always	0.5
4.5.1	Recombiner cells	Full power	A) Main aisles outside cells	Always	0.5
			B) Steam jet air-ejector cells below(583 ft 6 in.)	Steam-jet air ejector down	8.0
			C) Operating floor above (643 ft 6 in.)	Always	0.5
			D) Chiller cells above	Chiller down	8.0
4.5.2	North feedwater heater cell	Full power	A) Main aisles surrounding cell	Always	0.5
			B) Operating floor above (643 ft 6 in.)	Always	0.5
			C) Feedwater heater cell above (643 ft 6 in.)	Heater down	8.0
			D) Operating aisle below (583 ft 6 in.)	Always	0.5
			E) Drains cooler cells below	Cooler down	8.0

TABLE 12.1-4 SPECIFIC SHIELD DESIGN CRITERIA FOR TURBINE BUILDING

Identification Number[a]	Location of Source	Design Conditions of Source Area	Protected Area	Protected Area Design Conditions	Maximum Design Level in Protected Area (mrem/hr)
A.B.C.					
4.5.3	South feedwater heater cell	Full power	A) Main aisles surrounding cell	Always	0.5
			B) Operating floor above (643 ft 6 in.)	Always	0.5
			C) Heater cell above (643 ft 6 in.)	Heater down	8.0
			D) Operating aisle below (583 ft 6 in.)	Always	0.5
			E) Heater-pump cell below (583 ft 6 in.)	Pump down	8.0
4.5.4	Main condenser and steam piping	Full power	A) Main aisles at both ends	Always	0.5
			B) Heater cells on east side	Heaters down	8.0
			C) Aisle on east side	Always	0.5
			D) Oil lube equipment room (west)	Always	2.0
			E) Operating floor above (643 ft 6 in.)	Always	0.5
4.7.1	Charcoal adsorbers	Maximum activity	A) Main aisle	Always	0.5
			B) Chiller cells	Chiller down	8.0
			C) Sand filters	Filter drained	8.0
			D) Main aisle below (613 ft 6 in.)	Always	0.5
			E) Recombiner cell below	Equipment down	8.0
4.7.2	Sand filters	Maximum activity	A) Main aisles	Always	0.5
			B) Charcoal adsorber cell	No source	8.0
			C) Chiller cell	Chiller down	8.0
			D) Offgas pump cell	Always	0.5

TABLE 12.1-4 SPECIFIC SHIELD DESIGN CRITERIA FOR TURBINE BUILDING

Identification Number[a]	Location of Source	Design Conditions of Source Area	Protected Area	Protected Area Design Conditions	Maximum Design Level in Protected Area (mrem/hr)
A.B.C.					
4.7.3	Chiller cells	Full power	A) Main aisles	Always	0.5
			B) Offgas pump cell	Always	0.5
			C) Charcoal adsorber cell	No source	8.0
4.7.4	North feedwater heater cell	Full power	A) Main aisles	Always	0.5
			B) Heater cell below (613 ft 6 in.)	Heater down	8.0
4.7.5	South feedwater heater cell	Full power	A) Main aisles	Always	0.5
			B) Operating aisle below (613 ft 6 in.)	Always	0.5
			C) Heater cell below	Heater down	8.0
4.7.6	Reheater cells	Full power	A) Main aisle (east side)	Always	0.5
			B) Aisles at both ends	Always	0.5
			C) Feedwater heater cells	Heater down	8.0

[a] See Table 12.1-6 for explanation of identification numbers.

[b] These levels are original design-bases values, without the operation of Hydrogen Water Chemistry.

TABLE 12.1-5 SPECIFIC SHIELD DESIGN CRITERIA FOR RADWASTE BUILDING

Identification Number[a]	Location of Source	Design Conditions of Source Area	Protected Area	Protected Area Design Conditions	Maximum Design Level in Protected Area (mrem/hr)
A.B.C.					
3.2.1	Condensate phase separators	Maximum activity	A) Main aisle outside cell	Always	0.5
			B) Adjacent condensate decant pumps cell	Pumps down	8.0
			C) Adjacent condensate sludge discharge mix pumps cell	Pumps down	8.0
			D) Adjacent waste oil tank and chemical waste tank cell	Tanks drained	8.0
			E) Adjacent piping tunnel	Pipes drained	8.0
			F) Drum conveyor room above (583 ft 6 in.)	Room empty	8.0
			G) Main aisle above	Always	0.5
3.2.2	Condensate decant pumps	Maximum activity	A) Main aisle outside cell	Always	0.5
			B) Adjacent condensate sludge discharge mix pumps cell	Pumps down	8.0
			C) Adjacent condensate phase separators cell	Tanks drained	8.0
			D) On ceiling above (567 ft 6 in.)	Pipes drained	0.5
3.2.3	Condensate sludge discharge mix pumps	Maximum activity	A) Adjacent aisle outside cell	Always	0.5
			B) Adjacent waste oil pump and chemical waste pumps cell	Pumps down	8.0
			C) Adjacent condensate phase separators cell	Tanks drained	8.0
			D) On ceiling above (567 ft 6 in.)	Pipes drained	0.5
3.2.4	Waste oil pump and chemical waste pumps	Maximum activity	A) Adjacent condensate sludge discharge mix pumps cell	Pumps down	8.0
			B) Adjacent aisle outside cell	Always	0.5
			C) Adjacent waste clarifier sludge pump and slurry dilution pump cell	Pumps down	8.0
			D) Adjacent waste oil tank and chemical waste tank cell	Tanks drained	8.0
			E) On ceiling above (567 ft 6 in.)	Pipes drained	0.5
3.2.5	Chemical waste tank and waste oil tank	Maximum activity	A) Adjacent condensate phase separators cell	Tanks drained	8.0
			B) Adjacent chemical waste pumps and waste oil pumps cell	Pumps down	8.0
			C) Adjacent waste clarifier tank and spent-resin tank cell	Tanks drained	8.0
			D) Adjacent pipe tunnel	Pipes drained	8.0
			E) Waste collector oil coalescer and floor drain oil coalescer above	Tanks drained	8.0
			F) Access aisle to coalescers above	Always	8.0
3.2.6	Waste clarifier sludge pump, slurry dilution pump, and spent-resin transfer pump	Maximum activity	A) Adjacent chemical waste pump and waste oil pump cell	Pumps down	8.0
			B) Aisle outside cell	Always	0.5
			C) Adjacent waste surge tank cell	Tank drained	8.0
			D) Adjacent pipe tunnel	Pipes drained	8.0
			E) On ceiling above (567 ft 6 in.)	Pipes drained	0.5

TABLE 12.1-5 SPECIFIC SHIELD DESIGN CRITERIA FOR RADWASTE BUILDING

Identification Number[a]	Location of Source	Design Conditions of Source Area	Protected Area	Protected Area Design Conditions	Maximum Design Level in Protected Area (mrem/hr)
A.B.C.					
3.2.7	Waste surge tank, waste sample tanks, and chloride waste tank	Maximum activity in all tanks	A) Adjacent waste clarifier tank and spent-resin tank cell	Tanks drained	8.0
			B) Adjacent waste collector tank and floor drain collector tank cell	Tanks drained	8.0
			C) Adjacent pipe tunnel	Pipes drained	8.0
			D) Adjacent waste sample pumps, waste collector pumps, waste surge pumps, equipment drain pumps, and evaporator feed pumps cell	Pumps down and pipes drained	0.5
			E) Health physics lab, control room, and office on operating floor above	Always	0.5
3.2.8	Waste clarifier tank and spent-resin tank	Maximum activity	A) Adjacent chemical waste tank and waste oil tank cell	Tanks drained	8.0
			B) Adjacent clarifier sludge pump, slurry dilution pump, and spent-resin transfer pump cell	Pumps down	8.0
			C) Adjacent waste surge tank cell	Tank drained	8.0
			D) Adjacent pipe tunnel	Pipes drained	8.0
			E) Demineralizer piping gallery above	Pipes drained	8.0
			F) Floor drain demineralizer and floor drain filter cells above	Tank and filter drained	8.0
3.2.9	Waste collector tank and floor drain collector tanks	Maximum activity in all tanks	A) Adjacent evaporator feed surge tank cell	Tank drained	8.0
			B) Adjacent waste sample, waste surge, waste collector, and floor drain collector pumps cell	Pumps down	0.5
			C) Adjacent waste sample tanks cell	Tanks drained	8.0
			D) Operating floor and office above (583 ft 6 in.)	Always	0.5
3.2.10	Evaporator feed surge tank	Maximum activity	A) Stairway outside cell	Always	0.5
			B) Evaporator feed pumps in aisle outside cell	Always	0.5
			C) Adjacent floor drain collector and waste collector tanks cell	Tanks drained	8.0
			D) Medical decontamination room and washdown area on operating floor above (583 ft 6 in.)	Always	0.5
3.2.11	Centrifuge feed tank	Maximum activity	A) Adjacent boiler	Always	0.5
			B) Centrifuge feed/recirculation pumps cell	Pumps down	8.0
			C) Aisle outside cell	Always	0.5
			D) Stairway outside cell	Always	0.5
			E) Adjacent floor sump	Always	2.0
			F) Drum-handling turntable on operating floor above (583 ft 6 in.)	Turntable not in use	8.0
3.2.12	Centrifuge feed/recirculation pumps	Maximum activity	A) Aisle and stairwell outside cell	Always	0.5
			B) Adjacent extruder/evaporator boiler area	Always	0.5
			C) Adjacent centrifuge feed tank cell	Tank drained	8.0

TABLE 12.1-5 SPECIFIC SHIELD DESIGN CRITERIA FOR RADWASTE BUILDING

Identification Number[a]	Location of Source	Design Conditions of Source Area	Protected Area	Protected Area Design Conditions	Maximum Design Level in Protected Area (mrem/hr)
A.B.C.					
3.2.13	Waste slurry metering pump, spent-resin slurry metering pump, and concentrates metering pump	Maximum activity	A) Adjacent aisle north of cell	Always	0.5
			B) Adjacent boiler cell	Always	0.5
			C) Extruder/evaporator on floor above	Extruder/evaporator not in use	8.0
3.2.14	Spent-resin slurry feed tank	Maximum activity	A) Adjacent spent-resin slurry recirculation pump cell	Pumps down	8.0
			B) Adjacent concentrates recirculation pump and emergency drain sump pumps cell	Pumps down	8.0
			C) Reciprocating drive units area on operating floor above	Always	0.5
			D) Concentrates feed tank cell	Tank drained	8.0
			E) Access aisle	Always	0.5
3.2.15	Concentrates recirculation pump	Maximum activity	A) Adjacent concentrates feed tank	Tank drained	8.0
			B) Adjacent spent-resin slurry feed tank	Tank drained	8.0
			C) Adjacent aisle outside cell	Always	0.5
			D) Reciprocating drive units on operating floor above	Always	0.5
3.2.16	Spent-resin slurry decant pump and spent-resin slurry recirculation pump	Maximum activity	A) Adjacent spent-resin slurry feed tank cell	Tank drained	8.0
			B) Adjacent emergency drains sump pumps and concentrates recirculation pump cell	Pumps down	8.0
			C) On ceiling above	Pipes drained	0.5
			D) Adjacent boiler and centrifuge feed and recirculation pump cell	Pumps down	8.0
3.2.17	Concentrates feed tank	Maximum activity	A) Adjacent spent-resin slurry feed tank cell	Tank drained	8.0
			B) Adjacent main aisle outside	Always	0.5
			C) Reciprocating drive units area on operating floor above	Always	0.5
			D) Concentrates recirculation pump cell	Pump and pipes drained	8.0
3.2.18	Pipe tunnel	Maximum activity in all pipes	A) Adjacent condensate phase separator cell	Tanks drained	8.0
			B) Adjacent chemical waste tank cell	Tank drained	8.0
			C) Adjacent waste clarifier tank and spent-resin tank cell	Tanks drained	8.0
			D) Adjacent waste surge tank and waste sample tanks cell	Tanks drained	8.0
			E) Above pipe tunnel outside	Always	0.1
3.3.1	Deleted				
3.3.2	Etched-disk filters	Maximum activity	A) Adjacent main aisle	Always	0.5
			B) Adjacent access aisle to coalescer	Pipes drained and coalescer filter removed	15.0

TABLE 12.1-5 SPECIFIC SHIELD DESIGN CRITERIA FOR RADWASTE BUILDING

Identification Number[a]	Location of Source	Design Conditions of Source Area	Protected Area	Protected Area Design Conditions	Maximum Design Level in Protected Area (mrem/hr)
A.B.C.					
			C) Adjacent etched-disk filter backwash skid	Always	0.5
			D) Adjacent etched-disk filter	Filter backwashed	8.0
			E) Outside building	Always	0.1
			F) Washdown area above (601 ft 6 in.)	Always	0.5
3.3.3	Waste collector oil coalescer	Maximum activity	A) Adjacent access aisles to oil coalescers	Pipes drained and etched-disk filter backwashed	30.0
			B) Adjacent floor drain demineralizer	Tank drained	8.0
			C) Chemical waste tank cell below	Tank drained	8.0
			D) Outside building	Always	0.1
			E) Aisle in washdown area above (601 ft 6 in.)	Always	0.5
3.3.4	Floor drain oil coalescer	Maximum activity	A) Adjacent access aisles to oil coalescers	Pipes drained and etched-disk filter backwashed	30.0
			B) Adjacent access aisle	Always	0.5
			C) Aisles, air supply area, and washdown area above	Always	0.5
			D) Adjacent demineralizer piping gallery	Pumps down, pipes drained	8.0
			E) Waste clarifier tank cell and waste oil tank cell below (557 ft 6 in.)	Tanks drained	8.0
3.3.5	Floor drain demineralizer	Maximum activity	A) Adjacent waste collector oil coalescer cell	Tank drained	8.0
			B) Adjacent floor drain filter cell	Filter removed	8.0
			C) Waste clarifier tank cell below	Tank drained	8.0
			D) Adjacent demineralizer piping gallery	Pumps down, pipes drained	8.0
			E) Outside building	Always	0.1
			F) Aisle in washdown area above (601 ft 6 in.)	Always	0.5
3.3.6	Floor drain filter	Maximum activity	A) Adjacent floor drain demineralizer cell	Tank drained	8.0
			B) Adjacent waste collector filter cell	Filter removed	8.0
			C) Adjacent demineralizer piping gallery	Pumps down, pipes drained	8.0
			D) Waste clarifier tank cell below	Tank drained	8.0
			E) Outside building	Always	0.1
			F) Aisle in washdown area above(601 ft 6 in.)	Always	0.5
3.3.7	Waste collector filter	Maximum activity	A) Adjacent floor drain filter cell	Filter removed	8.0
			B) Adjacent waste demineralizer cell	Tank drained	8.0
			C) Adjacent demineralizer piping gallery pump area	Pumps down, pipes drained	8.0
			D) Waste surge tank cell below	Tank drained	8.0

TABLE 12.1-5 SPECIFIC SHIELD DESIGN CRITERIA FOR RADWASTE BUILDING

Identification Number[a]	Location of Source	Design Conditions of Source Area	Protected Area	Protected Area Design Conditions	Maximum Design Level in Protected Area (mrem/hr)
A.B.C.					
			E) Aisle in washdown area above (601 ft 6 in.)	Always	0.5
			F) Outside building	Always	0.1
3.3.8	East fuel pool filter-demineralizer	Maximum activity	A) Adjacent waste demineralizer cell	Tank drained	8.0
			B) Adjacent fuel pool filter-demineralizer cell	Filter removed	8.0
			C) Adjacent demineralizer piping gallery	Pumps down, pipes drained	8.0
			D) Waste sample tank cell below	Tank drained	8.0
			E) Aisle in washdown area above	Always	0.5
			F) Outside building	Always	0.1
3.3.9	West fuel pool filter-demineralizer	Maximum activity	A) Adjacent fuel pool filter-demineralizer cell	Filter removed	8.0
			B) Adjacent radwaste building control room	Always	0.5
			C) Adjacent demineralizer piping gallery	Pumps down, pipes drained	8.0
			D) Waste sample tank below	Tank drained	8.0
			E) Aisle in washdown area above (601 ft 6 in.)	Always	0.5
			F) Outside building	Always	0.1
3.3.10	Health Physics laboratories	Source samples	A) Main aisle next to labs	Always	0.5
			B) Adjacent radwaste building control room	Always	0.5
3.3.11	Valve operating tunnel	Normal operation	A) Adjacent demineralizer piping gallery	Pumps down, pipes drained	8.0
			B) Adjacent radwaste building control room	Always	0.5
			C) Adjacent operating aisle	Always	0.5
			D) Operating aisle and waste surge tank cell below	Aisle always Waste surge tank drained	0.5 0.8
			E) Supply air area above (601 ft 6 in.)	Always	0.5
3.3.12	Deleted				
3.3.13	Extruder/evaporator	Mechanism in use with drums of maximum activity	A) Adjacent turntable cell	Turntable empty	8.0
			B) Adjacent hatch and operating aisle	Always	0.5
			C) Adjacent drum conveying aisle	Conveyor not in use	8.0
			D) Adjacent operating aisle below (557 ft 6 in.)	Always	0.5
			E) Motor control center area above (601 ft 6 in.)	Always	0.5
3.3.14	Deleted				

TABLE 12.1-5 SPECIFIC SHIELD DESIGN CRITERIA FOR RADWASTE BUILDING

Identification Number[a]	Location of Source	Design Conditions of Source Area	Protected Area	Protected Area Design Conditions	Maximum Design Level in Protected Area (mrem/hr)
A.B.C.					
3.4.1	South distillate surge tank and evaporator	Maximum activity	A) Adjacent north distillate surge tank and evaporator cell	Tank and evaporator	8.0
			B) Outside building	Always	0.1
			C) Reciprocating drive units below (583 ft 6 in.)	Always	0.5
			D) Adjacent caustic feed tank and chemical feed tanks area	Always	0.5
			E) Adjacent aisle to stairway	Always	0.5
			F) Drum storage below	Conveyors empty	8.0
3.4.2	North distillate surge tank and evaporator	Maximum activity	A) Adjacent south distillate surge tank and evaporator cell	Tank and evaporator drained	8.0
			B) Adjacent stairway	Always	0.5
			C) Adjacent steam station	Always	0.5
			D) Outside building	Always	0.1
			E) Drum conveyor area below (583 ft 6 in.)	Conveyor area empty	8.0
3.4.3	Evaporator drains holdup tank	Maximum activity	A) Adjacent north distillate surge tank and evaporator cell	Tank and evaporator drained	8.0
			B) Adjacent south distillate surge tank and evaporator cell	Tank and evaporator drained	8.0
			C) Adjacent aisleway	Always	0.5
3.4.4	Centrifuge	Maximum activity	A) Adjacent washdown area and access aisle	Always	0.5
			B) Adjacent vent hood filter train	Filter element removed	8.0
			C) Adjacent turbine building	Always	0.5
			D) Reciprocating drive units area below (583 ft 6 in.)	Always	0.5
			E) Drum conveyor aisle below (583 ft 6 in.)	Conveyor not in use	8.0
			F) Rooms above	Always	0.5
3.4.5	Vent hood filter train	Normal operation	A) Adjacent centrifuge cell	Centrifuge empty	8.0
			B) Adjacent access aisle and stairway from washdown area	Always	0.5
			C) Adjacent turbine building	Always	0.5
			D) Part of reciprocating drive units area below (583 ft 6 in.)	Always	0.5
			E) Part of drum conveyor aisle below (583 ft 6 in.)	Conveyor not in use	8.0
			F) Rooms above	Always	0.5

[a] See Table 12.1-6 for explanation of identification numbers.

TABLE 12.1-6 SPECIFIC SHIELD DESIGN CRITERIA

Explanatory Note for Identification

Number in First Column of Tables 12.1-3, 12.1-4, and 12.1-5

The number in the first column of Tables 12.1-3, 12.1-4 and 12.1-5 is a three-part identifier, A.B.C., which is coded in the following manner:

The first digit, A, represents the general area location of the equipment which is to be shielded.

A	Location
1	Reactor building
2	Auxiliary building
3	Radwaste building
4	Turbine building

The second digit, B, represents the floor elevation of the equipment.

Corresponding Building Elevations

B	Floor	Reactor	Auxiliary	Radwaste	Turbine
1	Subbasement	540 ft	540 ft	-	-
2	Basement	562 ft	551 ft	557 ft 6 in.	564 ft
3	Grade	583 ft 6 in.	583 ft 6 in.	583 ft 6 in.	583 ft 6 in.
4	Mezzanine	600 ft 6 in.	603 ft 6 in.	601 ft 6 in.	-
5	Second	613 ft 6 in.	613 ft 6 in.	613 ft 6 in.	613 ft 6 in.
6	Mezzanine	626 ft	630 ft 6 in.	628 ft 6 in.	-
7	Third	641 ft 6 in.	643 ft 6 in.	-	643 ft 6 in.
8	Fourth	659 ft 6 in.	-	-	-
9	Fifth	684 ft 6 in.	-	-	-

The third digit, C, is simply a sequence number.

Example:

4.3.4. represents the turbine building (A = 4) at Elevation 586 ft 6 in. (B = 3) and is the fourth item (C = 4) in the series of items listed.

TABLE 12.1-7 CALCULATED MULTIGROUP NEUTRON AND GAMMA RAY FLUX OUTSIDE REACTOR PRESSURE VESSEL (3499 MWt)

GROUP	Upper Energy (eV)	Flux neutrons/cm^2/sec	Upper Energy (eV)	Flux photons/cm^2/sec
1	1.50E+07	1.35E+05	1.00E+07	8.39E+06
2	1.22E+07	4.50E+05	8.00E+06	8.14E+07
3	1.00E+07	9.78E+05	6.50E+06	8.03E+07
4	8.18E+06	1.86E+06	5.00E+06	8.98E+07
5	6.36E+06	2.54E+06	4.00E+06	1.57E+08
6	4.96E+06	1.93E+06	3.00E+06	1.17E+08
7	4.06E+06	3.14E+06	2.50E+06	3.39E+08
8	3.01E+06	3.55E+06	2.00E+06	2.67E+08
9	2.46E+06	1.13E+06	1.66E+06	3.19E+08
10	2.35E+06	6.81E+06	1.33E+06	4.07E+08
11	1.83E+06	2.25E+07	1.00E+06	3.11E+08
12	1.11E+06	6.45E+07	8.00E+05	4.04E+08
13	5.50E+05	1.83E+08	6.00E+05	7.54E+08
14	1.11E+05	1.31E+08	4.00E+05	4.99E+08
15	3.35E+03	3.49E+07	3.00E+05	7.81E+08
16	5.83E+02	3.07E+07	2.00E+05	7.61E+07
17	1.01E+02	2.02E+07	1.00E+05	3.78E+07
18	2.90E+01	1.42E+07	5.00E+04	2.78E+04
19	1.07E+01	1.49E+07		
20	3.06E+00	9.73E+06		
21	1.12E+00	7.31E+06		
22	4.14E-01	2.15E+07		

TABLE 12.1-8 SUMMARY OF SHIELD DESIGN IN REACTOR AND AUXILIARY BUILDINGS (3499 MWt)

Floor	Name of Cell	Main Equipment in Cell	Operating Conditions	Source Strength (Ci)	Source Geometry	Source Type[a]	Location of Wall	As-Built Wall Thickness	Design Level in Overall Area (mrem/hr)	Design Level at Surface (mrem/hr)	Notes[b]
Subb	HPCI room	HPCI turbine	HPCI-turbine testing	1.45	Point	N-16	Ceiling	2 ft	30	30	-
Subb	RHR pump rooms	RHR pump	Shutdown, after 4-hr decay	46	Cyl	FP, CP	Ceiling	2 ft	2	2	-
Subb	Core spray rooms	RCIC pumps and turbine	RCIC-turbine testing	1.5	Cyl and line	N-16	Ceiling	2 ft 6 in.	2	2	-
Subb B	Torus region	Drywell streaming suppression pool	Normal RCIC operation	- 39.9	- Cyl	N-16 N-16	4 corners -	3 ft 3 in. -	1.5 -	1.5 -	A A
B	CRD pump room	Streaming from below	HPCI-turbine testing	-	-	N-16	N, S, E	2 ft	30	30	-
1	Neutron monitor room	Irradiated TIP probe and cable	Withdrawal of TIP	3672	Point and line	-	E, S, W	3 ft	2	2	B
1,2	Steam tunnel	4 steam lines	Normal	139	Line	N-16	Sides	4 ft 8 in.	0.5	0.5	C
1,2	RHR rooms	RHR heat exchangers	Reactor shutdown	14.8	Cyl	FP, CP	Main Outer	2 ft 3 in. 3 ft	2 0.5	2 0.5	D
2	RWCU pumps	RWCU recirc. pumps	Normal	0.12	Cyl	FP, CP	N, S, W	1 ft 6 in.	0.5	0.3	-
2	RWCU piping	RWCU lines to pumps	Normal	0.4	Line	FP, CP	N, S	1 ft 6 in.	0.5	0.5	-
2	RWCU holdup	Holdup line	Normal	27	Line	N-16	E W	4 ft 4 ft 6 in.	0.5 0.5	0.5 0.5	- -
2	RWCU heat exchangers	Heat exchangers	Normal	232	Cyl	FP, CP	E, W	2 ft	0.5	0.3	-
2	RWCU separators	Phase separators	Normal	9589	Cyl	FP, CP	N S	4 ft 3 ft	0.5 4	0.5 4	E E
2	RWCU sludge pump room	Sludge in pump and lines	Intermittent sludge discharge	1734	Cyl and line	FP, CP	N S	4 ft 2 ft	0.5 1	0.5 1	- -
3	Fuel pool heat exchangers	Fuel pool heat exchangers	Normal	2.2	Cyl	FP, CP	N, S, W	2 ft	0.5	0.3	F
3,4	Fuel storage pool	Spent fuel	Fuel decay	1×10^9	Slab	FP	N E W	6 ft 6 ft 4 in. 6 ft 4 in.	1 1 0.5	0.6 0.6 <0.5	G G G
4,5	Steam dryer pool	Steam dryer and separator	Refueling	2.2×10^5	Cyl	-	S,E,W	3 ft	0.5	0.5	B
4	RWCU demineralizer	Filter demineralizers	Normal	2346	Cyl	FP,CP	N S W	4 ft 4 ft 3 ft	0.5 0.5 8	0.5 0.3 8	E E E
5	SGTS cells	Charcoal and HEPA filters	During a LOCA	8.5×10^5	Point	FP	N, E walls floors	4 ft 6 in. 6 ft	50 (Max) <5 Rem	- -	H,I H,J

[a] FP = Fission Products.
CP = Corrosion Products.
[b] The following notes apply as indicated:

TABLE 12.1-8 SUMMARY OF SHIELD DESIGN IN REACTOR AND AUXILIARY BUILDINGS (3499 MWt)

A. Main source, which is radiation streaming from the main recirculating lines in drywell, determines shield thicknesses. Secondary RCIC source is present for about 0.5 hr per month

B. Source is maximum value of irradiated steel activation products, with no decay

C. Source values given for portion of tunnel in reactor and auxiliary buildings

D. Source strength is maximum value, when unit starts (4 hr decay). Hence, design doses are also maximum values

E. Source values for one tank or unit

F. Source strength (in "effective Ci") is based on measurements of crud deposition at Dresden operating units

G. Source is one-half of a core, with 7-day decay

H. Source value (per cell) is given at a 2-hr decay time post-LOCA

I. Criteria is maximum dose rate of 50 mrem/hr, which occurs when SGTS source is maximum

J. Criterion is less that 5 rem to personnel in main control room, over 30 days.

K. With Hydrogen Water Chemistry in operation, the calculated N-16 steam sources will increase by a maximum factor of six; the design levels are original design-bases values, without Hydrogen Water Chemistry

TABLE 12.1-9 SUMMARY OF SHIELD DESIGN IN TURBINE BUILDING (3499 MWt)

Floor	Name of Cell	Main Equipment in Cell	Source Strength (Ci)	Source Geometry	Source Type[a]	Location of Wall	As-Built Wall Thickness	Design Level in Overall Area (mrem/hr)	Design Level at Surface (mrem/hr)	Recommended Wall Thickness	Notes[b]
B	Condensate tank	Backwash tank	61	Cyl	FP, CP	North, South	2 ft 6 in.	0.5	0.17	2 ft 3 in.	A
B	Pump (2)	Offgas pumps	0.8	Line	N-16	East	2 ft 8 in.	0.5	0.3	2 ft 8 in.	-
1	West drains cooler	Drains cooler	0.5	Cyl	N-16	North	3 ft 6 in.	0.5	0.25	3 ft 6 in.	-
1	Central drains cooler	Drains cooler	0.16	Cyl	N-16	North	3 ft 6 in.	0.5	0.25	3 ft	-
1	East drains cooler	Drains cooler	0.05	Cyl	N-16	North	3 ft 6 in.	0.5	0.17	2 ft 3 in.	-
1	Cond. demineralizers	Demineralizers	41	Cyl	FP, CP	West	3 ft 3 in.	0.5	0.13	3 ft 3 in.	-
1	Heater drain pumps	Heater seal tank	3.6	Cyl	N-16	East	3 ft 6 in.	0.5	0.13	3 ft 6 in.	A
1	Offgas air ejectors	Steam-jet air ejector	8	Cyl	N-16	North	7 ft	0.5	0.13	5 ft 9 in.	B
1	Gland seal	A) Condenser	3	Cyl	N-16	East	4 ft 9 in.	0.5	0.13	4 ft 9 in.	-
		B) Drains tank	1	Cyl	N-16						
1	Vacuum pump	Vacuum pumps	0.11	Cyl	N-16						
			0.02	Cyl	0-19	North	4 ft	0.5	0.2	4 ft	C
			0.005	Cyl	FP						
1	Reactor feed pumps	Reactor feed pump turbine	7	Cyl	N-16	East	4 ft 6 in.	0.5	0.13	4 ft 3 in.	D
2	Offgas system	All equipment and lines	867	Cyls and Lines	N-16	North	8 ft	0.5	0.17	7 ft	E
2	Feedwater heaters	A) No. 3 heater	23	Cyl	N-16						-
		B) No. 4 heater	28	Cyl	N-16	East	6 ft	0.5	0.25	6 ft	-
		C) No. 5 heater	66	Cyl	N-16						-
2	Steam tunnel	Steam lines and header	163	Line	N-16	North	5 ft	0.5	0.5	5 ft	F
2	Main N-S pipe chase	(A) Misc. lines	--	Line	N-16						
		(B) Reheater seal tank	5	Cyl	N-16	South	5 ft	0.5	0.3	4 ft 8 in.	-
3	Reheaters	Reheater	383	Cyl	N-16	East	5 ft 6 in.	0.5	0.17	5 ft 6 in.	-
3	Feedwater heaters	No. 6 heater	31	Cyl	N-16	East	5 ft 9 in.	0.5	0.25	5 ft 9 in.	-
3	Sand filters	Filters	329	Cyl	FP	West	4 ft 3 in.	0.5	0.25	3 ft 9 in.	-

TABLE 12.1-9 SUMMARY OF SHIELD DESIGN IN TURBINE BUILDING (3499 MWt)

Floor	Name of Cell	Main Equipment in Cell	Source Strength (Ci)	Source Geometry	Source Type[a]	Location of Wall	As-Built Wall Thickness	Design Level in Overall Area (mrem/hr)	Design Level at Surface (mrem/hr)	Recommended Wall Thickness	Notes[b]
3	Offgas chillers	Chillers	24	Cyl	FP	North	3 ft 9 in.	0.5	0.25	3 ft 3 in.	-
3	Offgas adsorbers	Charcoal units	5508	Cyl	FP	North	2 ft 6 in.	0.5	0.5	2 ft	H
						East	2 ft 9 in.	0.5	0.5	2 ft 6 in.	-

[a] FP = Fission Products.
CP = Corrosion Products.

[b] Notes apply as indicated:

A. Values are given for "worst" (north) cell: other cells have less activity

B. Values are given for one cell, but all cells are typically the same

C. Values are given for startup condition, i.e., maximum sources

D. Values are given for "worst" (low-power) condition: sources are less at full power

E. Various pieces of equipment, such as recombiner, preheater, condenser, aftercooler, and other associated equipment

F. Values are given only for that portion of tunnel inside turbine building.

G. With Hydrogen Water Chemistry in operation, the calculated N-16 steam sources will increase by a maximum factor of six; the design levels are original design-bases values, without Hydrogen Water Chemistry.

H. Charcoal Adsorber Room Knockout (TB3 South End) has a roll-up door installed rather than a block wall.

TABLE 12.1-10 SUMMARY OF SHIELD DESIGN IN RADWASTE BUILDING (3499 MWt)

Floor	Name of Cell	Main Equipment in Cell	Source Strength (Ci)	Source Geometry	Location of Wall	As-Built Wall Thickness	Design Level in Overall Area (mrem/hr)	Design Level at Surface (mrem/hr)	Recommended Wall Thickness	Notes[a]
B	Condensate phase separator	Phase separators	223.6[b]	Cyl	E	3 ft 3 in.	0.5	0.3	2 ft 6 in.	-
B	Waste oil tank	Waste oil tank	0.018	Cyl	S	12 in.	8.0	4.0	1 in.	-
B	Chemical waste tank	Waste tank	0.004	Cyl	S	12 in.	8.0	4.0	6 in.	-
B	Waste clarifier	Waste clarifier tank	10.2	Cyl	S	2 ft 9 in.	8.0	4.0	11 in.	-
		Spent-resin tank	178.7	Cyl	S	2 ft 9 in.	8.0	4.0	2 ft 0 in.	-
B	Evaporator feed surge tank	Evaporator feed surge tank	0.77	Cyl	N	1 ft 4 in.	0.5	0.3	1 ft 4 in.	-
B	Sample tanks	Waste sample tanks	0.06[b]	Cyl	S and E	12 in.	0.5	0.3	3 in.	-
B	Centrifuge feed tank	Centrifuge feed tank	220.5	Cyl	W	3 ft 0 in.	0.5	0.3	3 ft 0 in.	K
B	Collector tanks	Waste collector tank	150.0	Cyl	N	2 ft 0 in.	8.0	4.0	1 ft 7 in.	-
		Floor drain collector tank	3.9	Cyl	N	2 ft 0 in.	0.5	0.3	1 ft 3 in.	-
B	Waste surge tank	Waste surge tank	10.2	Cyl	S	12 in.	0.5	0.3	10 in.	-
B	Concentrates feed tank	Concentrates feed tank	2.0	Cyl	N	1 ft 9 in.	0.5	0.3	1 ft 9 in.	-
B	Slurry feed tank	Slurry feed tank	178.7	Cyl	E	2 ft 6 in.	0.5	0.3	2 ft 6 in.	-
B	Waste pumps	Waste oil pump	0.005[c]	Line	S	12 in.	0.5	0.3	11 in.	-
		Chemical waste pump	0.099[c]	Line	S	12 in.	0.5	0.3	11 in.	-
B	Clarifier-cell pumps	Spent-resin transfer pump	41[c]	Line	S	1 ft 10 in.	0.5	0.3	1 ft 10 in.	-
		Waste clarifier sludge pump	2.4[c]	Line	S	1 ft 10 in.	0.5	0.3	1 ft 10 in.	M
		Slurry dilution pump	0.013[c]	Line	S	1 ft 10 in.	0.5	0.3	1 ft 10 in.	M
B	Centrifuge recirculation pumps	Centrifuge feed/recirculation pumps	15.4[b,c]	Line	N	2 ft 3 in.	0.5	0.3	2 ft 3 in.	G
B	Condensate sludge pumps	Condensate sludge discharge mix pumps	15.5[b,c]	Line	S	2 ft 10 in.	0.5	0.3	2 ft 0 in.	-
B	Spent-resin slurry pumps	Spent-resin slurry decant pump	0.017[b,c]	Line	N	10 in.	8.0	4.0	10 in.	-

TABLE 12.1-10 SUMMARY OF SHIELD DESIGN IN RADWASTE BUILDING (3499 MWt)

Floor	Name of Cell	Main Equipment in Cell	Source Strength (Ci)	Source Geometry	Location of Wall	As-Built Wall Thickness	Design Level in Overall Area (mrem/hr)	Design Level at Surface (mrem/hr)	Recommended Wall Thickness	Notes[a]
		Spent-resin slurry recirculation pump	82[c]	Line	N	10 in.	8.0	4.0	10 in.	-
B	Condensate decant pumps	Condensate decant pumps	0.005[b,c]	Line	S	1 ft 10 in.	0.5	0.3	1 ft 10 in.	-
B	Concentrates recirculation pump	Concentrates recirculation pump	0.69[c]	Line	N	12 in.	0.5	0.3	10 in.	-
1	Precoat filters	Floor drain collector Precoat filter	0.04	Cyl	N	2 ft 6 in.	0.1	0.1	1 ft 0 in.	-
		Waste collector Precoat filter	13.5	Cyl	N	2 ft 6 in.	0.1	0.1	2 ft 6 in.	-
1	Extruder/ evaporator	Extruder/ evaporator	2.27	Cyl	N	8 in.	0.5	0.3	8 in.	H,L
1	Etched-disk filter	Filters	2.1[b]	Cyl	N	2 ft 9 in.	0.3	0.1	2 ft 9 in.	-
1	Oil coalescer	Oil coalescers	9.7[b]	Cyl	N	2 ft 9 in.	0.3	0.1	2 ft 0 in.	J
1	Waste demineralizer	Demineralizer	146.0	Cyl	N	3 ft 6 in.	0.3	0.1	3 ft 6 in.	N
1	East fuel pool filter-demineralizer	Filter-demineralizer	19.8	Cyl	N	2 ft 9 in.	0.3	0.1	2 ft 9 in.	-
1	West fuel pool filter-demineralizer	Filter demineralizer	19.8	Cyl	N	2 ft 9 in.	0.3	0.1	2 ft 9 in.	-
1	Filter-demineralizer valve room	Pumps and lines	N/A	Point	E and W	2 ft 0 in.	0.5	0.25	2 ft 0 in.	-
				Cyl	S	2 ft 0 in.	8	0.25	2 ft 0 in.	C
1	Valve operating tunnel	Streaming radiation	N/A	N/A	S	2 ft 0 in.	0.5	0.25	1 ft 0 in.	-
1	Health Physics counting room	Misc. samples	0.001	Point	E	1 ft 0 in.	0.5	0.25	NA	D
1	Health Physics spectrometer room	Misc. samples	0.001	Point	E	1 ft 0 in.	0.5	0.25	NA	D
1	Health Physics high-level lab	Misc. samples	0.1	Point	All	1 ft 0 in.	0.5	0.25	1 ft 0 in.	E
Mezz.	South evaporator	Evaporator	2.0	Cyl	E	2 ft 0 in.	0.3	0.1	1 ft 6 in.	-
Mezz.	North evaporator	Evaporator	2.0	Cyl	E	2 ft 0 in.	0.3	0.1	1 ft 6 in.	-
		Evaporator drains tank	2.0	Cyl	N and E	4 in.	8.0	4.0	4 in.	L
Mezz.	Centrifuge	Centrifuge	109.7	Cyl	N	2 ft 2 in.	0.5	0.3	2 ft 2 in.	F, I

TABLE 12.1-10 SUMMARY OF SHIELD DESIGN IN RADWASTE BUILDING (3499 MWt)

Floor	Name of Cell	Main Equipment in Cell	Source Strength (Ci)	Source Geometry	Location of Wall	As-Built Wall Thickness	Design Level in Overall Area (mrem/hr)	Design Level at Surface (mrem/hr)	Recommended Wall Thickness	Notes[a]

[a] Notes apply as indicated:

A. Source strength based on condensate sludge. Value for RWCU sludge-filled drum is 772.6 Ci (only six times per year); value for waste demineralizer sludge-filled drum is 29.3 Ci; value for evaporator concentrates-filled drum is 0.7 Ci

B. Values given for westernmost storage aisle (30 drums per conveyor)

C. Design level at wall is well below overall design level to allow for streaming radiation through various wall penetrations

D. Sources are small enough that no shielding (other than distance effect) is required

E. In addition to walls of room, appropriate shadow shielding will be used around sources

F. Recommended thickness is for a composite wall of 21 in. of concrete with a density of 145 lb/ft^3 and 5 in. of steel

G. Source strength based on condensate phase separator dump to centrifuge feed tank. Value for dump from spent-resin tank is 7.89 μCi/cm^3; value for dump from RWCU phase separator is 148 μCi/cm^3 (only six times per year)

H. Source strength based on condensate phase separator processing. Value for waste demineralizer resin processing is 0.79 Ci; value for RWCU phase separator processing is 21.78 Ci (only six times per year); value for evaporator concentrates processing is 0.02 Ci

I. Source strength based on RWCU sludge. Value for processing of waste demineralizer sludge is 6.5 Ci; value for processing of condensate sludge is 11.8 Ci

J. Source strength based on lead waste collector coalescer. Value for second coalescer is 9.0 Ci; value for third coalescer is 2.7 Ci

K. Source strength based on condensate sludge processing. Value for RWCU sludge is 784 Ci (only six times per year)

L. Wall is lead-shot-filled steel-framed wall

M. Value based on spent-resin transfer pump

N. Additional shielding added to original wall to give equivalent of 3 ft 6 in. of concrete

O. Wall made of lead brick

P. Motor-operated shield doors made of 7 in. of steel.

[b] Values are per tank, per drum, per source, or per line.

[c] Values are in μCi/cm^3.

TABLE 12.1-11 THROUGH TABLE 12.1-13
HAVE BEEN INTENTIONALLY DELETED

TABLE 12.1-14 DIRECT MAIN CONTROL ROOM DOSES FOLLOWING A LOSS-OF-COOLANT ACCIDENT (3499 MWt)

		Integrated Dose From Following Sources				
Time After LOCA (days)	Occupancy Factor	SGTS (rem)	Primary Containment (rem)	Secondary Containment (rem)	Plume (rem)	Total[a] (rem)
		<<0.0001	<<0.0001	<0.0001	0.040	0.040

[a] Refers to Total Effective Dose Equivalent (TEDE) contribution, using R.G. 1.183 based analysis. Direct doses are doses as seen by main control room personnel, through various concrete walls and ceilings.

TABLE 12.1-15 PHOTON PRODUCTION RATE OF FISSION PRODUCTS IN THE REACTOR CORE, FOLLOWING FIVE YEARS OF OPERATIONS, AT VARIOUS TIMES AFTER SHUTDOWN (3430 MWt)

		Total Photon Production Rate (photons/sec) After Shutdown				
Group	Average Group Energy (MeV)	0 Time	1 Hr	1 Day	3 Days	7 Days
1	1.500(-2)[a]	2.134(20)	4.259(19)	1.504(19)	1.112(19)	9.200(18)
2	2.500(-2)	5.719(19)	1.571(19)	6.895(18)	4.940(18)	3.416(18)
3	3.500(-2)	4.666(19)	1.770(19)	1.113(19)	8.011(18)	5.562(18)
4	4.500(-2)	2.507(19)	6.599(18)	3.239(18)	2.497(18)	1.964(18)
5	5.500(-2)	1.952(19)	5.523(18)	2.615(18)	1.703(18)	1.134(18)
6	6.500(-2)	1.500(19)	3.173(18)	1.142(18)	8.297(17)	6.853(17)
7	7.500(-2)	1.451(19)	3.258(18)	9.210(17)	6.712(17)	5.545(17)
8	8.500(-2)	1.540(19)	4.961(18)	3.327(18)	2.694(18)	1.813(18)
9	9.500(-2)	3.084(19)	6.862(18)	2.674(18)	2.081(18)	1.732(18)
10	1.500(-1)	7.700(19)	2.402(19)	1.168(19)	8.807(18)	6.254(18)
11	2.500(-1)	6.371(19)	2.033(19)	9.048(18)	4.032(18)	1.838(18)
12	3.500(-1)	4.179(19)	1.039(19)	5.283(18)	4.300(18)	3.191(18)
13	4.750(-1)	6.795(19)	2.629(19)	1.336(19)	9.777(18)	7.611(18)
14	6.500(-1)	8.169(19)	4.622(19)	2.038(19)	1.027(19)	6.193(18)
15	8.250(-1)	5.807(19)	3.275(19)	1.616(19)	1.415(19)	1.295(19)
16	1.000	3.082(19)	1.077(19)	2.139(18)	1.251(18)	7.909(17)
17	1.225	3.379(19)	7.603(18)	1.355(18)	4.838(17)	1.992(17)
18	1.475	4.060(18)	1.655(19)	6.976(18)	6.200(18)	4.993(18)
19	1.700	9.139(18)	2.282(18)	1.577(17)	1.591(16)	5.000(15)
20	1.900	6.102(18)	2.551(18)	2.154(17)	7.678(16)	3.196(16)
21	2.100	6.830(18)	1.729(18)	7.771(16)	6.207(16)	5.320(16)
22	2.300	4.961(18)	1.893(18)	6.212(16)	5.299(16)	4.358(16)
23	2.500	5.404(18)	1.816(18)	2.248(17)	2.107(17)	1.751(17)
24	2.700	2.734(18)	5.266(17)	1.157(15)	5.766(14)	2.837(14)
25	3.000	5.986(18)	7.868(17)	7.190(15)	6.628(15)	5.517(15)
26	6.143	3.348(18)	1.021(16)	3.485(13)	2.417(08)	1.162(-2)
27	7.112	0.000	0.000	0.000	0.000	0.000
Total		9.776(20)	3.129(20)	1.341(20)	9.424(19)	6.959(19)

[a] 1.500(-2) = 1.500 x 10^{-2}.

TABLE 12.1-16 DOSE AT SITE BOUNDARY FROM STORED WASTE

$D = 2 \times 10^{-12}$ mrem/hr/Ci of waste, or

$D^1 = 1.8 \times 10^{-8}$ mrem/year/Ci of waste, with a 100 percent occupancy factor

Assumptions:

A. Minimum site boundary distance is 4000 ft

B. Minimum concrete thickness surrounding the drums is 4 ft (north wall of radwaste building)

C. Average gamma ray energy of 1.5 MeV used

D. Photon attenuation and appropriate buildup factors for both air and concrete walls were used

E. Waste drums stored inside building. No drums are to be stored outside

F. Gamma ray self-absorption in the drum is taken into account. Each drum consists of a mixture of water, cement aggregate, and radioactive sludge, resulting in a concrete mixture.

TABLE 12.1-17 DOSE AT SITE BOUNDARY FROM CONDENSATE STORAGE TANKS

Dose rate per tank = 2×10^{-7} mrem/hr, or

Dose rate per tank = 1.8×10^{-3} mrem/year

Assuming 100 percent occupancy factor

Assumptions:

A. Tanks contain their maximum concentrations of 0.001 $\mu Ci/cm^3$

B. Each tank contains its full volume of liquid (600,000 gal), thereby giving a maximum content of 2.3 Ci per tank

C. Distance between tanks and site boundary is 4400 ft. This is the minimum distance which is not interrupted by any of the concrete buildings. In other words, it is the nearest point at which the tanks could be "seen" by a person at the site boundary.

TABLE 12.1-18 DOSE RATES AT VARIOUS POSITIONS NEAR FERMI 2 (3499 MWt)

		Dose Rates, mrem/hr								
	Source	Point No[a].	A[b]	B[c]	C	D	E	F	G	H
Source Description	Strength (photon/sec)	Distance (ft)	120	300	500	900	1200	2600	3600	4560
Low-pressure turbines (3)	1.65E+12		9.9E-05	5.2E-04	1.7E-03	5.7E-04	1.0E-04	1.7E-06	1.4E-07	4.4E-08
High-pressure turbines	2.35E+12		1.0E-04	6.2E-04	1.6E-03	4.7E-04	1.2E-04	2.2E-06	1.6E-07	3.8E-07
Crossover pipes	1.84E+12		4.0E-03	4.2E-02	6.2E-02	2.8E-02	8.6E-03	4.8E-04	1.0E-04	6.3E-05
High-pressure turbine inlet lines	3.06E+12		8.2E-04	5.2E-03	1.6E-02	5.4E-03	1.3E-03	4.2E-05	3.3E-06	1.5E-06
Reheaters (2)	1.53E+14		1.9E-02	1.1E-01	1.5E-01	4.5E-02	3.4E-02	2.0E-03	2.8E-04	4.9E-05
Total	1.62E+14		2.4E-02	1.5E-01	2.3E-01	7.9E-02	4.4E-02	2.6E-03	3.8E-04	1.1E-04

[a] For point designations, see Figure 12.1-2. Distances are measured to the center of the turbine reheater complex.

[b] Point at third floor aisleway of turbine building: photon attenuation through 8-in. concrete roof included in calculation.

[c] Point at center of main office building. Calculations account for the shadowing effect of the outer (eastern) wall of the turbine building.

[d] With Hydrogen Water Chemistry in operation, these N-16 estimates will increase up to factor of six.

TABLE 12.1-19 CALCULATED OPERATOR EXPOSURE DURING ROUTINE ROUNDS IN REACTOR BUILDING

Equipment	Expected Dose Rate (mrem/hr)	Time[a] (minutes/year)	Exposure (man-rem/year)
HPCI turbine and pump	0.15	4368	0.011
CRD pumps	0.15	2184	0.005
RBCCW heat exchangers	0.15	1092	0.003
Emergency control air compressor	0.15	2184	0.005
RBCCW pumps	0.15	1092	0.003
RBCCW expansion tank	0.15	546	0.001
CRD hydraulic control units	0.15	1092	0.003
Railroad access	0.15	546	0.001
Personnel changing rooms	0.15	1092	0.003
Relay room	0.15	5460	0.014
Motor-generator sets	0.15	4368	0.011
Battery room	0.15	4368	0.011
Computer room	0.15	2184	0.005
Air conditioning equipment	0.15	2184	0.005
Recirc. motor-generator sets	0.15	4368	0.011
SGTS	0.15	4368	0.011
Refueling floor	0.15	5460	0.014
CRD filters	0.15	2184	0.005
Switchgear room	0.15	1092	0.003
RWCU demin. resin tank	0.30	2184	0.011
RHR pumps	0.50	3276	0.027
Core spray pumps	0.50	3276	0.027
RCIC pump and turbine	0.50	3276	0.027
RWCU hold pump	0.50	2184	0.018
Sump pumps	0.50	2184	0.018
Air coolers	0.50	1092	0.009
Instrument racks	0.50	546	0.004
RWCU sludge pumps	1.0	2184	0.036

TABLE 12.1-19 CALCULATED OPERATOR EXPOSURE DURING ROUTINE ROUNDS IN REACTOR BUILDING

Equipment	Expected Dose Rate (mrem/hr)	Time[a] (minutes/year)	Exposure (man-rem/year)
CRD storage and repair	2.0	2184	0.073
RWCU demin. tank	22[b]	546	0.200
RWCU heat exchangers	22[b]	546	0.200
RHR heat exchangers	22[b]	1092	0.400
Primary containment	22[b]	546	0.200
RWCU phase separator	22[b]	3276	1.201
		Total[c]	2.58

[a] Assumes the rounds are performed once per shift every day of the year.

[b] Values do not include major maintenance. They do consider access to an area or piece of equipment, averaged over a year, both during shutdown and during the time the equipment is still in operation but the reactor is at partial load. It is estimated that, over a year, 10 percent of personnel time (in a given cell) will be in a field of 125 mrem/hr, 10 percent in a field of 55 mrem/hr and 80 percent in a field of 5 mrem/hr.

[c] Total is based on 1346.8 man-hours available. Total man-hour availability for operators is 52,416 man-hours.

TABLE 12.1-20 CALCULATED OPERATOR EXPOSURE DURING ROUTINE ROUNDS IN RADWASTE BUILDING

Equipment	Expected Dose Rate (mrem/hr)	Time[a] (minutes/year)	Exposure (man-rem/year)
Waste collector pump	0.15	1092	0.003
Floor drain collector pump	0.15	1092	0.003
Waste sample pumps	0.15	1092	0.003
Floor drain sample pump	0.15	546	0.001
Waste surge pump	0.15	1092	0.003
Equipment drain sump pump	0.15	1092	0.003
Chemical waste pump	0.15	1092	0.003
Emergency floor drain sump pump	0.15	546	0.001
Waste sludge discharge mixing pump	0.15	1092	0.003
Spent-resin pump	0.15	546	0.001
Radwaste control room	0.15	10,920	0.027
Demineralizer precoat tank	0.15	546	0.001
Precoat pump	0.15	1092	0.003
Resin tank	0.15	546	0.001
Waste precoat pump	0.15	546	0.001
Waste filter aid pump	0.15	546	0.001
Filter aid tank	0.15	10,920	0.027
Health Physics lab.	0.15	2184	0.005
Solid waste baler	0.15	1092	0.003
Drum rolling machine	0.15	1092	0.003
Misc. tanks	0.15	1092	0.003
Switchgear room	0.15	2184	0.005
Air conditioning equipment	0.15	2184	0.005
Ventilation equipment	0.15	2184	0.005
Fuel pool filter demineralizer	47.0[b]	1092	0.855
Floor drain collector tank	47.0[b]	546	0.428
Waste collector tank	47.0[b]	546	0.428
North and south waste sample tank	3.0	546	0.027
Floor drain sample tank	3.0	546	0.027
Waste surge tank	0.6	546	0.006
Condensate phase separators	47.0[b]	1092	0.855

TABLE 12.1-20 CALCULATED OPERATOR EXPOSURE DURING ROUTINE ROUNDS IN RADWASTE BUILDING

Equipment	Expected Dose Rate (mrem/hr)	Time[a] (minutes/year)	Exposure (man-rem/year)
Chemical waste tank	6.0	546	0.055
Spent-resin tank	47.0[b]	546	0.428
Condensate phase decant pump	47.0[b]	546	0.428
Condensate phase sludge			
Discharge mixing pump	47.0[b]	546	0.428
Fuel pool filter demineralizer	47.0[b]	546	0.428
Waste demineralizer	47.0[b]	546	0.428
Waste collector filter	47.0[b]	546	0.428
Drum mixing	47.0[b]	546	0.428
Drum capping	47.0[b]	546	0.428
Drum storage	47.0[b]	546	0.428
Floor drain demineralizer	47.0[b]	546	0.428
Waste hopper	47.0[b]	546	0.428
Floor drain filter	6.0	546	0.055
Evaporators	3.0	546	0.027
Centrifuge	47.0[b]	1092	0.855
		Total[c]	8.443

[a] Assumes the rounds are performed once per shift every day of the year.

[b] It is estimated that, over a year's time, about 50 percent of personnel time is spent in a field of 80 mrem/hr, 30 percent in a field of 20 mrem/hr, and 20 percent in a field of 5 mrem/hr. For areas with design levels below 20 mrem/hr, the average level was estimated to be one-third of the maximum design level.

[c] Total is based on 1055.8 man-hours available (Column 2). Total man-hour availability for operators is 52,416 man-hours.

TABLE 12.1-21 CALCULATED OPERATOR EXPOSURE DURING ROUTINE ROUNDS IN TURBINE BUILDING

Equipment	Expected Dose Rate (mrem/hr)	Time[a] (minutes/year)	Exposure (man-rem/year)
Instruments and controls	0.15	5460	0.014
Generator CO_2 unit	0.15	546	0.001
Station air compressor	0.15	1092	0.003
Heater feed pumps	0.15	1092	0.003
Demineralizer control	0.15	4368	0.011
Demineralizer pumps and valves	0.15	1092	0.003
MTG lubrication system	0.15	2184	0.005
Hatch area above demin. tanks	0.15	1092	0.003
Stator cooling equipment	0.5	1092	0.01
H2 seal oil equipment	0.15	1092	0.003
Heater shell pull space	0.15	546	0.001
TBCCW heat exchanger and pumps	0.15	1092	0.003
TBCCW expansion tank	0.15	1092	0.003
Ventilation equipment	0.15	2184	0.005
Demineralizer precoat and resin tanks	0.15	2184	0.005
Demineralizer precoat pumps	0.15	1092	0.003
Offgas refrigeration units	0.15	1092	0.003
Sump pumps	0.5	2184	0.018
Reactor feed pump turbine lube system	0.5	1092	0.009
MTG lube oil cooler	0.5	546	0.004
Miscellaneous equipment	0.5	2184	0.018
Main generator and excitation equipment	0.50	3276	0.027
MTG unitized actuators - stop and throttle valves	5.0	3276	0.273
Heater drain pumps	38[b]	1092	0.692
Heater drains flash tanks	38[b]	546	0.346
Condenser water box	38[b]	546	0.346
Circ. water isolation valves	38[b]	546	0.346
Reactor feed pumps and turbines	38[b]	4368	2.766
Drain coolers	38[b]	546	0.346
Powdex demineralizer tanks	38[b]	109	0.069

TABLE 12.1-21 CALCULATED OPERATOR EXPOSURE DURING ROUTINE ROUNDS IN TURBINE BUILDING

Equipment	Expected Dose Rate (mrem/hr)	Time[a] (minutes/year)	Exposure (man-rem/year)
Mech. vacuum pumps	38[b]	2184	1.383
Steam-jet air ejectors	38[b]	546	0.346
Feedwater heaters (all)	38[b]	2184	1.383
Offgas system	38[b]	6552	4.150
Reheater seal tank	38[b]	1092	0.692
Gland steam condenser	38[b]	546	0.346
Main turbine	38[b]	2184	1.383
Reheater separators	38[b]	1092	0.692
		Total[c]	15.71

[a] Assumes rounds are performed once per shift every day of the year.

[b] It is estimated that, over a year, 10 percent of personnel time (in a given cell) will be in a field of 110 mrem/hr, 50 percent in a field of 50 mrem/hr, and 40 percent in a field of 5 mrem/hr.

[c] Total is based on 1084.7 man-hours available. Total man-hours available for operators is 52,416 man-hours.

TABLE 12.1-22 CALCULATED OPERATOR EXPOSURE DURING MINOR REPAIR OF ISOLATED COMPONENTS IN REACTOR BUILDING

Equipment	Expected Dose Rate (mrem/hr)	Time (minutes/year)	Exposure (man-rem/year)
HPCI turbine and pump	0.15		
CRD pumps	0.15		
RBCCW heat exchangers	0.15		
Emergency control air comp.	0.15		
RBCCW pumps	0.15		
RBCCW expansion tank	0.15		
CRD hydraulic control units	0.15		
Railroad access	0.15		
Personnel changing rooms	0.15		
Relay room	0.15	2184	0.005
Motor-generator sets	0.15		
Battery rooms	0.15		
Computer room	0.15		
Air conditioning equipment	0.15		
Recirculation M-G sets	0.15		
SGTS	0.15		
Refueling floor	0.15		
CRD filters	0.15		
Switchgear room	0.15		
RWCU demin. resin tank	0.3	208	0.001
RHR pumps	0.5		
Core spray pumps	0.5		
RCIC pump and turbine	0.5		
RWCU hold pump	0.5	780	0.006
Sump pumps	0.5		
Air coolers	0.5		
Instrument racks	0.5		
RWCU sludge pumps	1.0	1440	0.024
RHR heat exchangers	1.0		
CRD storage and repair	2.0	600	0.020
RWCU demineralizer tank	2.0		
RWCU heat exchangers	22.0[a]	2160	0.729
RWCU phase separator	22.0		
		Total[b]	0.84

TABLE 12.1-22 CALCULATED OPERATOR EXPOSURE DURING MINOR REPAIR OF ISOLATED COMPONENTS IN REACTOR BUILDING

[a] It is estimated, over a year, that 10 percent of personnel time (in a given cell) will be in a field of 125 mrem/hr, 10 percent in a field of 55 mrem/hr, and 80 percent in a field of 5 mrem/hr.

[b] Total is based on 122.9 man-hours available. Total of man-hours available for the operators is 52,416 man-hours.

TABLE 12.1-23 CALCULATED OPERATOR EXPOSURE DURING MINOR REPAIR OF ISOLATED COMPONENTS IN RADWASTE BUILDING

Equipment	Expected Dose Rate (mrem/hr)	Time (minutes/year)	Exposure (man-rem/year)
Waste collector dump	0.15	2392.0	0.009
Flood drain collector pump	0.15		
Waste sample pumps	0.15		
Floor drain sample pump	0.15		
Waste surge pump	0.15		
Equipment drain sump pump	0.15		
Chemical waste pump	0.15		
Emergency floor drain sump pump	0.15		
Waste sludge discharge mixing pump	0.15		
Spent-resin pump	0.15		
Radwaste control room	0.15		
Demineralizer precoat tank	0.15		
Precoat pump	0.15		
Resin tank	0.15		
Waste precoat	0.15		
Waste filter aid pump	0.15		
Filter aid tank	0.15		
Health Physics lab	0.15		
Solid waste baler	0.15		
Drum rolling machine	0.15		
Miscellaneous tanks	0.15		
Switchgear room	0.15		
Air conditioning equipment	0.15		
Ventilation equipment	0.15		
Floor drain collector tank	2.0	60	0.002
Waste collector tank	2.0	60	0.002
North and south water sample tank	2.0	120	0.004
Floor drain sample tank	2.0	60	0.002
Waste surge tank	2.0	60	0.002
Condensate phase separators	2.0	180	0.006
Chemical waste tank	2.0	60	0.002
Spent-resin tank	2.0	60	0.002
Condensate phase decanting pump	2.0	120	0.004
Condensate phase sludge discharge mixing pump	2.0	120	0.004

TABLE 12.1-23 CALCULATED OPERATOR EXPOSURE DURING MINOR REPAIR OF ISOLATED COMPONENTS IN RADWASTE BUILDING

Equipment	Expected Dose Rate (mrem/hr)	Time (minutes/year)	Exposure (man-rem/year)
Fuel pool filter-demineralizer	2.0	120	0.004
Waste demineralizer	2.0	120	0.004
Waste collector filter	2.0	60	0.002
Floor drain filter	2.0	60	0.002
Evaporators	2.0	180	0.006
Centrifuge	2.0	180	0.006
Drum mixing	10.0		
Drum capping	10.0	9360	1.560
Drum storage	10.0		
		Total[a]	1.62

[a] Total is based on 222.9 man-hours available. Total of man-hours available for operators is 52,416 man-hours.

TABLE 12.1-24 CALCULATED OPERATOR EXPOSURE DURING MINOR REPAIR OF ISOLATED COMPONENTS IN TURBINE BUILDING

Equipment	Expected Dose Rate (mrem/hr)	Time (minutes/year)	Exposure (man-rem/year)
Instruments and controls	0.15		
Generator CO_2 unit	0.15		
Station air compressor	0.15		
Heater feed pumps	0.15		
Demineralizer control	0.15		
Demineralizer pumps and valve	0.15		
MTG lubrication system	0.15		
Hatch area above demineralizer tanks	0.15		
H_2 seal oil equipment	0.15	1092	0.003
Heater shell pull space	0.15		
TBCCW heat exchanger and pump	0.15		
TBCCW expansion tank	0.15		
Ventilation equipment	0.15		
Demin. precoat and resin tank	0.15		
Demin. precoat pumps	0.15		
Offgas refrigeration units	0.15		
Sump pumps	0.5		
Reactor feed pump turbine lube system	0.5		
MTG lube oil cooler	0.5	312	0.003
Miscellaneous equipment	0.5		
Stator cooling equipment	0.5		
Main generator and excitation equipment	0.5		
Reactor feed pumps and turbine	2.0	4320	0.144
Drains coolers	2.0	720	0.024
Mechanical vacuum pumps	2.0	2880	0.096
Steam-jet air ejectors	2.0	1440	0.048
Feedwater heaters (3, 4, 5, 6)	2.0	4320	0.144
Gland steam condenser	38.0[a]	720	0.456
MTG unitized actuators -stop and throttle valves	5.0	156	0.013
Heater drain pumps	2	240	0.008

TABLE 12.1-24 CALCULATED OPERATOR EXPOSURE DURING MINOR REPAIR OF ISOLATED COMPONENTS IN TURBINE BUILDING

Equipment	Expected Dose Rate (mrem/hr)	Time (minutes/year)	Exposure (man-rem/year)
Heater drain flash tanks	2	120	0.004
Condenser water box	38[a]	360	0.228
Circulating water isolation valves	38[a]	60	0.038
Reheater seal tank	38[a]	120	0.076
Main turbine	38[a]	360	0.228
Reheater/separators	38[a]	240	0.152
		Total[b]	1.67

[a] It is estimated that, over a year, 10 percent of personnel time (in a given cell) will be in a field of 110 mrem/hr, 50 percent in a field of 50 mrem/hr, and 40 percent in a field of 5 mrem/hr.

[b] Total is based on 293.6 man-hours available. Total of man-hours available for operators is 52,416 man-hours.

TABLE 12.1-25 FERMI 2 PERSONNEL EXPOSURES CALCULATED FOR REMAINING MAN-HOURS

Personnel Category	Number of Personnel	Exposure (man-rem/year)
Administration	13	2.60[a]
Operations	32	5.23[b]
Radiation Protection supervision	3	3.00[c]
Equipment division	3	0.60[a]
	8	2.86[d]
	3 (QA personnel)	1.78[e]
Maintenance (electrical, mechanical, instrumentation and control)	20	1.83[f]
	Total[g]	18.37

[a] Assumes each person available 2000 man-hours per year while in a radiation field of 0.1 mrem/hr.

[b] Assumes 30 personnel receive 0.1 mrem/hr for remainder of man-hours not accounted for in Tables 12.1-19 through 12.1-24(48,289 man-hours), and that two supervisory personnel receive a total of 0.4 man-rem for 1 year (i.e., each person available 2000 hr per year while in a radiation field of 0.1 mrem/hr).

[c] Assumes each person accumulates 1 rem per year.

[d] Assumes these personnel receive 30 percent of total operations personnel exposure per man, i.e., sum of total exposures listed Tables 12.1-19 through 12.1-24, divided by 30 personnel, yielding an average of 1.19 rem/man per year. Thus, each of eight personnel in this category will receive an average of 0.357 rem/year.

[e] Assumes QA engineer, assistant QA engineer, and QA technician receive 25, 50, and 75 percent of total operational personnel exposure per man, respectively. That is, sum of 25 percent, 50 percent, and 75 percent of 1.19 rem/year per man (see d.) is 1.78 man-rem/year.

[f] Assumes maintenance personnel receive 0.1 mrem/hr for remaining man-hours available not accounted for in Tables 12.1-26 through 12.1-28 (i.e., 18,340 man-hours).

[g] Total based on available man-hours left over from required operational and maintenance functions. Radwaste personnel and Radiation Protection personnel (i.e., supervisor and technicians) included in other tables and Subsection 12.1.5.2.2.

TABLE 12.1-26 CALCULATED MAINTENANCE PERSONNEL EXPOSURE IN REACTOR BUILDING

Equipment	Expected Dose Rate (mrem/hr)	Time (hr/year)	Exposure (man-rem/year)
HPCI turbine and pump	0.15	80	0.012
CRD pumps	0.15	40	0.006
RBCCW heat exchangers	0.15	40	0.006
Non-Interruptible control air compressor	0.15	40	0.006
RBCCW pumps	0.15	40	0.006
RBCCW expansion tank	0.15	20	0.003
CRD hydraulic control units	0.15	80	0.012
Railroad access	0.15	40	0.006
Personnel changing rooms	0.15	60	0.009
Relay room	0.15	80	0.012
Main control room	0.15	80	0.012
DC motor-generator sets	0.15	40	0.006
Battery rooms	0.15	40	0.006
Computer room	0.15	--	--
Air conditioning equipment	0.15	120	0.018
Recirculation motor-generator sets	0.15	120	0.018
Standby gas treatment	0.15[a]	80	0.012
Refueling floor	0.15	240	0.036
CRD filters	0.15	40	0.006
Switchgear rooms	0.15	80	0.012
Miscellaneous	0.15	400	0.060
RWCU resin tank	0.3	80	0.024
Miscellaneous	0.3	40	0.012
RHR pumps	0.5[a]	80	0.040
Core spray pumps	0.5[a]	80	0.040
RCIC pump and turbine	0.5[a]	80	0.040
RWCU holding pump	0.5[a]	40	0.020
Sump pumps	0.5	160	0.080
Air coolers	0.5	40	0.020
Instrument racks	0.5	80	0.040

TABLE 12.1-26 CALCULATED MAINTENANCE PERSONNEL EXPOSURE IN REACTOR BUILDING

Equipment	Expected Dose Rate (mrem/hr)	Time (hr/year)	Exposure (man-rem/year)
Miscellaneous	0.5	80	0.040
Reactor water sludge pump	1.0[a]	20	0.020
RHR heat exchanger	1.0[a]	40	0.040
Miscellaneous	1.0	20	0.020
CRD repair and storage	2.0	600	1.200
Miscellaneous	2.0	40	0.080
Miscellaneous	5.0	20	0.100
RWCU demineralizer tanks	2[a]	40	0.080
RWCU heat exchanger	2[a]	80	0.160
Reactor cleanup separator	2[a]	40	0.080
Primary containment	22[b]	400	8.800
		Total[c]	11.20

[a] Assumes that reactor is operating, but that equipment is isolated.

[b] Assumes reactor is shut down.

[c] Total is based on 3820 man-hours available. Total of man-hours available for maintenance personnel is 40,000 man-hours.

TABLE 12.1-27 CALCULATED MAINTENANCE PERSONNEL EXPOSURE IN RADWASTE BUILDING

Equipment	Expected Dose Rate (mrem/hr)	Time (hr/year)	Exposure (man-rem/year)
Waste collector pump	0.15	140	0.021
Floor drain collector pump	0.15	200	0.030
Waste sample pumps	0.15	140	0.021
Floor drain sample pump	0.15	140	0.021
Waste surge pump	0.15	140	0.021
Equipment drain sump pump	0.15	160	0.024
Chemical waste pump	0.15	160	0.024
Emergency floor drain sump pump	0.15	160	0.024
Waste sludge discharge mixing pump	0.15	200	0.030
Spent resin pump	0.15	200	0.030
Radwaste control room	0.15	200	0.030
Demineralizer precoat tank	0.15	100	0.015
Precoat pump	0.15	140	0.021
Resin tank	0.15	100	0.015
Waste precoat pump	0.15	160	0.024
Waste filter aid pump	0.15	160	0.024
Filter aid tank	0.15	100	0.015
Health physics lab.	0.15	-	-
Solid waste baler	0.15	200	0.030
Drum rolling machine	0.15	200	0.030
Miscellaneous tanks	0.15	100	0.015
Switchgear room	0.15	300	0.045
Air conditioning equipment	0.15	300	0.045
Ventilation equipment	0.15	200	0.030
Miscellaneous	0.15	1500	0.225
Miscellaneous	0.3	100	0.030
Miscellaneous	0.5	100	0.050
Miscellaneous	1.0	100	0.100

TABLE 12.1-27 CALCULATED MAINTENANCE PERSONNEL EXPOSURE IN RADWASTE BUILDING

Equipment	Expected Dose Rate (mrem/hr)	Time (hr/year)	Exposure (man-rem/year)
Valve-operating tunnel	2.0	400	0.800
Floor drain collector tank	2.0[a]	40	0.080
Waste collector tank	2.0[a]	60	0.120
North and south waste sample tanks	2.0[a]	40	0.080
Floor drain sample tank	2.0[a]	60	0.120
Waste surge tank	2.0[a]	40	0.080
Cond. phase separators	2.0[a]	200	0.400
Chem. waste tank	2.0[a]	100	0.200
Waste sludge tank	2.0[a]	100	0.200
Cond. phase decanting pumps	2.0[a]	200	0.400
Cond. phase sludge disc.mix. pump	2.0[a]	200	0.400
Fuel pool filter-demineralizer	2.0[a]	100	0.200
Waste demineralizer	2.0[a]	100	0.200
Waste collector filter	2.0[a]	100	0.200
Floor drain filter	2.0[a]	100	0.200
Waste hoppers	2.0[a]	100	0.200
Evaporators	2.0[a]	200	0.400
Floor drain demineralizer	2.0[a]	100	0.200
Centrifuge	2.0[a]	200	0.400
Miscellaneous	2.0[a]	400	0.800
Drum mixing and filling	5.0[a]	300	1.500
Drum capping	5.0[a]	300	1.500
Miscellaneous	5.0	40	0.200
Miscellaneous	9.0	60	0.540
Drum storage	47.0	200	9.400
		Total[b]	19.840

[a] Assumes reactor is operating, but the equipment is isolated.

[b] Total is based on 9840 man-hours available. Total maintenance personnel availability is 40,000 man-hours.

TABLE 12.1-28 CALCULATED MAINTENANCE PERSONNEL EXPOSURE IN TURBINE BUILDING

Equipment	Expected Dose Rate (mrem/hr)	Time (hr/year)	Exposure (man-rem/year)
Instrument and controls	0.15	240	0.036
Generator CO_2 unit	0.15	80	0.012
Station air compressors	0.15	560	0.084
Heater feed pumps	0.15	240	0.036
Demineralizer controls	0.15	160	0.024
Demineralizer pumps and valves	0.15	400	0.060
MTG lubrication system	0.15	160	0.024
Hatch area above demineralizer tanks	0.15	160	0.024
Stator cooling equipment	0.50	80	0.040
H_2 seal oil equipment	0.15	160	0.024
Heater shell pull space	0.15	400	0.060
TBCCW heat exchangers and pumps	0.15	160	0.024
TBCCW expansion tanks	0.15	80	0.012
Ventilation equipment	0.15	400	0.060
Demineralizer precoat and resin tanks	0.15	80	0.012
Demineralizer precoat pumps	0.15	80	0.012
Offgas refrigeration units	0.15	80	0.012
Miscellaneous	0.15	800	0.120
Offgas holdup pipe	5.0[a]	20	0.100
Condensate pumps	5.0[a]	20	0.100
Circulating water isolation valves	1.0[a]	40	0.040
Reheater seal tank	2.0[a]	4	0.008
Main turbine generator	1.0[a]	360	0.360
Reheater separators	1.0[a]	20	0.020
Reheat-intercept and stop valves - unitized actuators	0.5[a]	16	0.008
RFP and turbine	0.5[a]	40	0.020
Drain coolers	0.5[a]	20	0.010
Feedwater heaters (3, 4, 5, 6)	0.5[a]	40	0.020
Gland steam condenser	0.5[a]	20	0.010
Miscellaneous	0.3[a]	160	0.048
Sump pumps	0.5	320	0.160
Reactor feed pump turbine lubrication system	0.5	80	0.040

TABLE 12.1-28 CALCULATED MAINTENANCE PERSONNEL EXPOSURE IN TURBINE BUILDING

Equipment	Expected Dose Rate (mrem/hr)	Time (hr/year)	Exposure (man-rem/year)
MTG Lube oil coolers	0.5	40	0.020
Miscellaneous	0.5	200	0.100
Main generator and excitation equipment	0.5	40	0.020
Miscellaneous	1.0	40	0.040
Condensate seal return tank	2.0[a]	40	0.080
Reactor feed pumps and turbine	2.0[b]	280	0.560
Drains coolers	2.0[b]	80	0.160
Filter demineralizer tanks	2.0[b]	160	0.320
Mechanical vacuum pumps	2.0[b]	80	0.160
Steam-jet air ejectors	2.0[b]	160	0.320
Feedwater heaters (3, 4, 5, 6)	2.0[b]	280	0.560
Offgas system (chillers, after-coolers, condensers, precoolers, collector tank and miscellaneous pumps)	2.0[b]	480	0.960
Miscellaneous	2.0	240	0.480
MTG unitized actuators -stop and throttle valves	5.0	40	0.200
Miscellaneous	5.0	40	0.200
Heater drain pumps	2.0[b]	160	0.320
Heater drains flash tanks	2.0[b]	40	0.080
Condenser water box	38.0[c]	20	0.760
Offgas charcoal and filter rooms	38.0[c]	80	3.040
Miscellaneous	38.0[c]	20	0.760
		Total[d]	10.76

[a] Assumes reactor is shut down.

[b] Assumes reactor is operating, but that equipment is isolated.

[c] It is estimated that over a year, 10 percent of personnel time (in a given cell) will be a field of 110 mrem/hr, 50 percent in a field of 50 mrem/hr, and 40 percent in a field of 5 mrem/hr.

[d] Total is based on 8000 man-hours available. Total of man-hours available for maintenance personnel is 40,000 man-hours.

TABLE 12.1-29 SUMMARY OF CALCULATED FERMI 2 EXPOSURE DATA

Personnel Category	Personnel (number)	Exposure (man-rem/year)
Operations	32	36.1
Maintenance (mechanical, electrical, and instrumentation and control)	20	43.7
Radiation Protection (including supervision)	11	19.0
Equipment division	14	5.2
Administration	13	2.6
	Total	106.6

TABLE 12.1-30 COMPARISON OF ESTIMATED FERMI 2 EXPOSURE AND OPERATING FACILITY EXPOSURES

Personnel Category	Fermi 2	Nine Mile Point (average 1970-73)	Quad Cities (1973)	Oyster Creek (average 1970-1973)
Operations[a]	43[b]	23[c]	14[c]	19.6[c]
Maintenance[a]	57[d,e]	77[c]	86[c]	80.4[c]
Total, man-rem/yr[f]	106.6	180.8	142	292

[a] Percent of total exposure.

[b] Includes Operations and Administrative personnel (See Table 12.1-29).

[c] Includes contractors.

[d] Includes Radiation Protection and Equipment Division personnel (See Table 12.1-29).

[e] Maintenance exposure estimates do not include exposures received during repair of unexpected trouble.

[f] Includes only utility personnel.

Figure Intentionally Removed
Refer to Plant Drawing A-2232

Fermi 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 12.1-1, SHEET 1

FERMI 2 RADIATION ZONES
MEZZANINE AND SECOND FLOOR

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Refer to Plant Drawing A-2232

FIGURE 12.1-1, SHEET 2

FERMI 2 RADIATION ZONES
MEZZANINE AND SECOND FLOOR PLAN

NORTH ARROW

MASTER GRID NUMBERS

N = NORTH FEET
E = EAST FEET

Fermi 2
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FIGURE 12.1-2

SITE PLOT PLAN
SKYSHINE REFERENCE POINTS

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Refer to Plant Drawing A-2230

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FIGURE 12.1-3, SHEET 1

FERMI 2 RADIATION ZONES – BASEMENT AND SUBBASEMENT FLOOR PLAN

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Refer to Plant Drawing A-2230

Fermi 2

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FIGURE 12.1-03, SHEET 2

FERMI 2 RADIATION ZONES-BASEMENT AND SUBBASEMENT FLOOR PLAN

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Refer to Plant Drawing A-2230

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FIGURE 12.1-3, SHEET 3

FERMI 2 RADIATION ZONES – BASEMENT AND SUBBASEMENT FLOOR PLAN

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Refer to Plant Drawing A-2231

Fermi 2

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FIGURE 12.1-4

FERMI 2 RADIATION ZONES
MEZZANINE AND FIRST FLOOR PLAN

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Refer to Plant Drawing A-2236

Fermi 2
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FIGURE 12.1-5

FERMI 2 RADIATION ZONES
ONSITE STORAGE FACILITY – FLOOR PLANS

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Refer to Plant Drawing A-2233

Fermi 2

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FIGURE 12.1-6

FERMI 2 RADIATION ZONES-THIRD FLOOR PLAN

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Refer to Plant Drawing A-2234

Fermi 2
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FIGURE 12.1-7, SHEET 1

FERMI 2 RADIATION ZONES
FOURTH FLOOR PLAN

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Refer to Plant Drawing A-2234

Fermi 2

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FIGURE 12.1-7, SHEET 2

FERMI 2 RADIATION ZONES
FOURTH FLOOR PLAN

Figure Intentionally Removed
Refer to Plant Drawing A-2235

Fermi 2

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FIGURE 12.1-8

FERMI 2 RADIATION ZONES – FIFTH BLOOR PLAN

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Refer to Plant Drawing A-2209

Fermi 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 12.1-9

AUXILIARY BUILDING – SECTIONAL MAIN CONTROL ROOM SHIELDING

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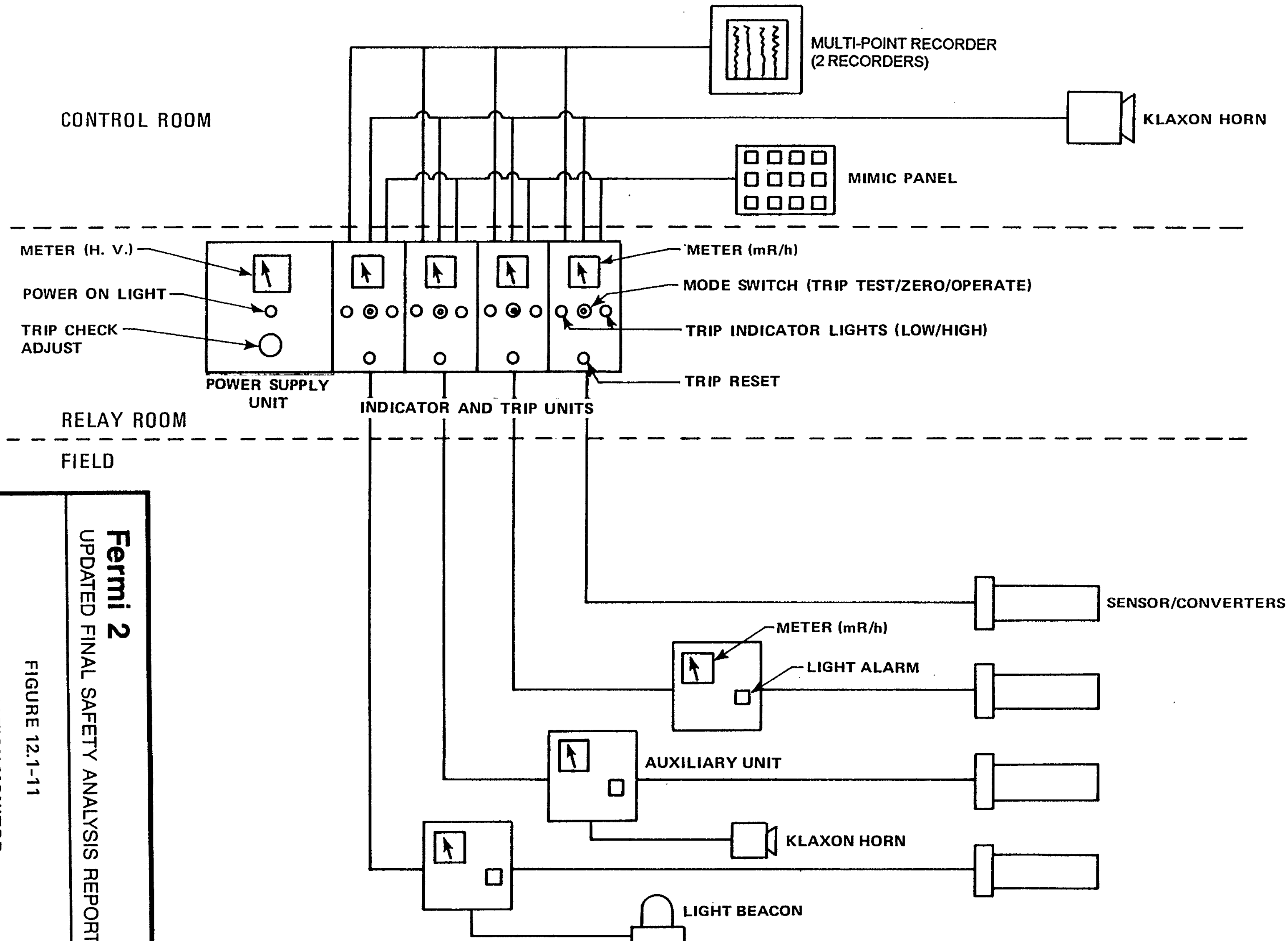
Refer to Plant Drawing A-2208

Fermi 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 12.1-10

AUXILIARY BUILDING – MAIN CONTROL ROOM SHIELDING ISOMETRIC



Fermi 2
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FIGURE 12.1-11
AREA RADIATION MONITOR
FUNCTIONAL DIAGRAM

REV 8

Figure Intentionally Removed
Refer to Plant Drawing I-2196-01

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FIGURE 12.1-12

AREA RADIATION MONITOR SYSTEM

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Refer to Plant Drawing I-2196-02

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FIGURE 12.1-13

AREA RADIATION MONITOR SYSTEM

12.2 VENTILATION

12.2.1 Design Objectives

The design of the plant ventilation system for radioactive airborne radiation control is based on the following objectives:

a. The system is designed to maintain the airborne radioactivity levels for normal operation, including anticipated operational occurrences, as far below 10 CFR 20 limits as reasonably achievable

b. The system is designed to maintain the airborne radioactivity levels for normal operations, including anticipated operational occurrences, as far below 10 CFR 20 limits as reasonably achievable for areas within the plant structure and on the plant site where construction workers and visitors are permitted

c. The system is designed to ensure that offsite releases during normal operation comply with limits specified in Appendix I of 10 CFR 50 for release to unrestricted areas beyond the site boundary

d. The system is designed to provide a suitable environment for equipment and personnel in the main control room under postaccident conditions, in accordance with General Design Criterion (GDC) 19 of 10 CFR 50, Appendix A.

The plant ventilation systems are designed to provide a suitable environment for personnel and equipment during normal plant operation, including anticipated operational occurrences. In addition to their primary function of preventing extreme thermal environmental conditions for operating personnel and equipment, the plant ventilation systems also provide effective protection against possible uncontrolled release or spread of radioactive airborne contamination. The systems are described in detail in Section 9.4.

The rooms in the plant buildings that are expected to be maintained below minimum contamination guidelines are separated from the potentially contaminated rooms and cubicles by gravity back- draft dampers at ventilation penetrations to ensure that there will be no backflow of the air from potentially contaminated areas to these generally accessible areas. The rooms are arranged so that, where possible, potentially contaminated rooms are not located at contiguous walls between buildings.

Pressure gradients are maintained in plant buildings by the ventilation systems to prevent the release of unmonitored radioactive gases or particulates to the environment and to prevent airborne radioactivity from entering areas normally occupied by plant personnel. In plant buildings where there is a potential for airborne radioactivity, the ventilation system will maintain the building at a slightly negative pressure with respect to the outside atmosphere. The reactor and radwaste buildings will be maintained at a negative pressure of approximately 0.25 in. of water with respect to the outside atmosphere. The turbine building pressure will be maintained at a pressure below outside atmospheric pressure. The control center, radwaste control room, and chemistry laboratory are located in buildings where the potential for airborne radioactivity exists, and these areas are normally maintained at a slightly positive pressure to prevent the flow of air into these areas resulting from pressure gradients.

Access doors and hatches, which have the capability to be sealed, are provided for most potentially contaminated rooms and cubicles. Most walls, ceilings, and floor penetrations in potentially contaminated rooms and cubicles also are sealed to prevent the uncontrolled flow of air from one area to another. Where the walls, ceilings, and floor penetrations were not sealed, they were evaluated and determined to pose no contamination problem. Flow of air between buildings at common walls is prevented because penetrations at the walls are sealed, and doors are provided at personnel access openings.

The calculated maximum airborne radioactivity levels presented in Subsection 12.2.5 correspond to those that could result from the design-basis reactor coolant inventory loss. The actual expected levels should be considerably smaller, since average coolant inventories and actual equipment leakages will be smaller than those used in the calculations. The estimated maximum airborne radioactivity levels are presented in Tables 12.2-1 through 12.2-13. The methods and assumptions used to calculate these airborne radioactivity levels are presented in Subsection 12.2.3, and a discussion of the resulting inhalation doses is presented in Subsection 12.2.5.

12.2.2 Design Description

The following general guidelines were used in the system design to accomplish the design objectives stated in Subsection 12.2.1:

a. Airflow patterns are maintained for airflow from clean areas to potentially contaminated areas, thus preventing the spread of airborne contamination

b. A negative pressure differential, with respect to surrounding areas, is maintained inside potentially contaminated cubicles by means of control dampers or airflow patterns

c. A slightly positive pressure (1/4 ± 1/8 in. of water in relation to the outside ambient air) is maintained in the main control room under all operating conditions to prevent infiltration of potential contaminants

d. Exhaust from potentially contaminated areas in the radwaste building is routed through high-efficiency particulate air (HEPA) filters to remove airborne radioactivity and reduce onsite and offsite inhalation doses

e. Exhaust from the drywell and suppression chamber or the reactor building in general can be routed through HEPA and charcoal filters in the standby gas treatment system (SGTS) to remove high airborne particulate and iodine radioactivity so that onsite and offsite doses from these sources will be prevented or reduced in the event of high airborne radioactivity that reaches the ventilation system

f. The fresh air supply to the main control room is designed to be operable during all modes of plant operation, including loss of offsite power. The normal air supply is filtered through roll filters, and the emergency air supply is filtered through HEPA and charcoal filters

g. Filters such as the chemistry laboratory fume hood exhaust filters are contained within individual filter housings maintained at a negative pressure by the fume hood exhaust fan. Filter replacement is accomplished by removing a plate on the side of the filter housing. The plate is held in place by wing nuts that are quickly and easily removed. The filter housing is positioned so that the removable panel is accessible. After the panel has been removed, the used filter can be easily removed by pulling the filter into a plastic bag so there will be a minimum spread of radioactivity

h. Portable filter units consisting of a fan and motor assembly, high-efficiency filter, charcoal filter, flexible ducting, and a control panel are provided for use in areas of maintenance and repair activities that may result in the release of airborne radioactivity. The portable filter serves the function of localizing the source and eliminating the spread of contamination by purging the gases from the enclosed maintenance and repair area and then venting them to the normal building ventilation exhaust system after filtering

i. Differential pressure control in the plant buildings is maintained by the building ventilation system to minimize the spread of potential airborne contamination within the plant. The direction of airflow including leakage is controlled by maintaining clean areas at a higher pressure than potentially contaminated areas. A positive pressure is maintained in those areas of the plant normally occupied by operating, maintenance, and administrative personnel under normal or abnormal operating conditions. All other radiologically controlled areas of the plant are maintained at a negative pressure with respect to the outside atmospheric pressure.

The guidelines above are incorporated into the design basis for each individual system. The detailed design of the heating, ventilation, and air conditioning (HVAC) systems is described in Section 9.4. A brief summary of those systems that are expected to handle airborne radioactive material is given in the following subsections.

Ventilation flow diagrams for the reactor/auxiliary building, radwaste building, and turbine house are presented in Figures 9.4-4, Sheets 1 and 2, 9.4-5, and 9.4-7, respectively. Points of air transfer, flow rates on a cubicle-by-cubicle basis, and the location of those process radiation monitors specific to the ventilation system are shown in these flow diagrams. In addition to the process radiation monitors, area radiation monitors that will detect airborne radiation are located in a network throughout the plant. Area radiation monitors are listed in UFSAR Figures 12.1-12 and 12.1-13, including grid location references. The location of the instruments can be determined using these grid references and referring to the radiation zone drawings in Figures 12.1-1 and 12.1-3 through 12.1-8. Details of the process radiation monitors are given in Table 11.4-2 and Figures 11.4-2 through 11.4-4. The gaseous cleanup systems are covered in Section 11.3.

12.2.2.1 Control Center Ventilation System

The control center ventilation system is described in detail in Subsections 9.4.1 and 6.4.2.3.

Basically, two 100 percent-capacity, redundant air conditioning systems having a common ductwork maintain habitability inside the main control room and other areas served by this system. The other areas include the relay room, cable spreading room, computer room, conference room, main control room office, air-conditioning equipment room, and SGTS rooms. The total volume for these areas is 275,960 ft^3.

Outside air is supplied through a missile-protected inlet located approximately halfway up the south wall of the auxiliary building. The incoming air passes through redundant dampers and joins the recirculated air prior to passing through one of the two redundant air conditioning systems. Each system contains an electronic air cleaner, a roll filter, a 37,000-cfm supply fan, an electrical heater-chiller section, and control dampers. The air is then supplied to the various rooms previously described, and is exhausted from these areas using one of the two 35,550-cfm redundant return fans. A damper on the exhaust is modulated to restrict the airflow to maintain a positive pressure ($1/4 \pm 1/8$ in. of water) in the control center relative to the outside ambient air pressure. The air from the return fans is either completely exhausted or a fraction is exhausted and the remainder returned and mixed with incoming outside air.

The emergency air makeup system can take air from either of two inlet sources, depending on the relative radiation at these inlets (see Subsection 11.4.3.8.2.14). One emergency inlet is located at approximately the same location on the south wall of the auxiliary building as the normal control room air inlet. The second inlet is also missile protected and is located about halfway down the north wall of the auxiliary building.

A maximum flow of 1800 cfm, which is used as makeup air for pressurization, passes through a mist eliminator, an electric heater, a HEPA filter, a charcoal filter, and a second HEPA filter. This flow joins with the 1200-cfm recirculation flow. The total flow of 3000 cfm passes through the recirculation filters consisting of a prefilter, a HEPA filter, a charcoal filter, and a second HEPA filter. The air is discharged by one of the two 3000-cfm redundant emergency recirculation fans into the recirculating airflow prior to entering one of the normal air conditioning systems.

The normal air conditioning system has a motor-driven roll filter with automatically renewable media, whereas the emergency recirculation filter has a fixed prefilter. The HEPA filters used in both emergency filters are fire-retardant fiberglass with a design efficiency of 99.97 percent for 0.3-μm particles at rated capacity using the dioctyl phthalate (DOP) test method. They are installed and tested for bypass leakage such that a decontamination efficiency of 95 percent can be assumed for removal of particulate iodine. The emergency makeup air charcoal adsorber uses 2-in. deep trays of impregnated charcoal assumed to adsorb 95 percent of the elemental and organic iodine from the outside air. The effluent from this filter, which is mixed with recirculated air, is passed through the recirculation charcoal adsorber. This filter is a 4-in.-deep gasketless charcoal adsorber that also is assumed to adsorb 95 percent of the elemental and organic iodine.

Four process radiation monitors (Section 11.4) are located before the makeup filters to determine the airborne activity entering the main control room.

In addition to the protection provided by the systems discussed above, respiratory protection devices, as discussed in Section 12.3, are also available when needed. The ventilation system is designed to limit the whole-body dose to less than 5 rem and the thyroid dose to less than 30 rem for the duration of an accident, in accordance with GDC 19. Evaluation of the system to meet GDC 19 with regard to inhalation dose is presented in Appendix 15A. All portions of the system required to operate during emergency conditions are designed to Category I requirements.

12.2.2.2 Reactor/Auxiliary Building Ventilation System

The reactor/auxiliary building ventilation system is described in Subsection 9.4.2. The volume of both buildings is 3,500,000 ft^3. Outside air is supplied to the buildings through an inlet located midway down the south side of the auxiliary building. The inlet flow rate is normally 96,060 cfm. The inlet air passes through a filter, a heater, and two of three 50 percent-capacity inlet fans before being supplied to accessible areas of the building. The air is exhausted from areas of higher potential contamination by two of the three 50 percent-capacity exhaust fans. A lower pressure is maintained in potentially contaminated areas than in general access areas, and the entire building is maintained at a lower pressure than the outside ambient air, thus preventing the spread of contamination and exfiltration of unmonitored contaminated air.

The refueling floor area ventilation is sized for a minimum of 7 air changes per hour in the lower 15 ft of the floor area. The airflow is directed across the refueling floor toward the pools and is exhausted through ducts in the dryer-separator pool, fuel storage pool, and the reactor well. This system limits the spread of activity to other parts of the building.

The ventilation system also serves to purge the primary containment to permit personnel access. Sufficient airflow is provided to purge the drywell and suppression chamber at the rate of three air changes per hour. The purge air can be discharged through the normal building exhaust system or, if there is activity, through the SGTS, which is discussed in Subsection 6.2.3.

Radiation monitors are supplied on both major fuel pool area exhaust ducts (Section 11.4) to warn if radioactive gases rise from the fuel pool by sounding an alarm in the main control room. The two pairs of radiation monitors, which are located on the east and west branches of the reactor building exhaust duct, will trip the ventilation fans, isolate the building, close the primary containment isolation valves, and start the SGTS on a high (radiation) alarm. In addition, a radiation monitor is provided in the reactor building exhaust plenum to provide a record of the amount of activity discharged to the environment.

The supply and exhaust isolation valves, which are required to operate during or after a design-basis accident (DBA), are designed to Category I requirements.

12.2.2.3 Radwaste Building Ventilation System

The radwaste building ventilation system is described in Subsection 9.4.3. The volume of the building is 861,000 ft^3. Outside air is supplied to the building through louvers located above the turbine building low roof. The flow rate is approximately 22,567 cfm. The inlet air passes through a prefilter, high efficiency filter, and one of the two 100 percent-capacity (32,800 cfm) supply fans before being supplied to accessible areas of the building. These fans also supply 1650 cfm to the pipe tunnel between the radwaste and turbine buildings. During periods of high ambient outdoor conditions, the supply air is maintained at a temperature of approximately 80°F to ensure safe operating temperatures for the equipment. The air is cooled with a water-cooled refrigerated chilled-water system. The air is supplied to general access areas and is exhausted from potentially contaminated areas. A lower pressure is maintained in the potentially contaminated areas than in the general access areas, and the entire building is maintained at a lower pressure than the outside ambient air, thus preventing the spread of contamination and the exfiltration of contaminated air.

The exhaust fans take suction from all principal areas and from the vents of radwaste tanks (as listed in Subsection 9.4.3). The air flows through a prefilter, a HEPA filter, and one of the two 100 percent-capacity (approximately 31,818 cfm) exhaust fans, which discharge the air through an exhaust vent above the turbine building high roof.

The HEPA filters, located on the fume hood exhausts and on the main exhaust, have an efficiency of 99.97 percent for 0.3 μm particles at rated capacity according to the DOP test method.

The hood exhaust from the drum-loading station on the turntable is filtered through a HEPA filter, charcoal adsorber, and a HEPA filter before discharge into the radwaste building ventilation exhaust duct. An area radiation monitor measures activity in the vicinity of the charcoal filter to ensure safe access for servicing the filter.

An airborne radioactivity monitor is located on the exhaust to provide a record of the amount of activity discharged to the environment (Section 11.4). On a high alarm, the monitor will trip the building ventilation fans and close the isolation dampers in the radwaste building.

The radwaste building ventilation system is required to operate only during normal plant operation and is therefore not designed to Category I requirements.

The HVAC design provides clean, fresh air in the corridors and normally accessible areas and exhausts the air from potentially contaminated areas such as the extruder/evaporator room, centrifuge room, filter room, evaporator room, and valve rooms. In all instances, airflow is directed to keep the corridors and maintenance areas clean of airborne radioactivity. All HVAC exhaust from potentially contaminated spaces is filtered through a high-efficiency (99.97 percent) filter before discharge to the radwaste building exhaust vent stack.

12.2.2.4 Turbine Building Ventilation System

The turbine building ventilation system is described in Subsection 9.4.4. Outside air enters the building through an intake located on top of the building. The design flow rate was approximately 315,900 cfm (actual flow rates have been measured and were found to be 15% to 20% lower). The inlet air passes through a prefilter, a high-efficiency filter, and two of the three 50 percent-capacity (195,000 cfm) supply fans before being distributed to general access areas.

Air is circulated into potentially contaminated areas by propeller fans. If the air is initially supplied to a potentially contaminated area, it is discharged from that area to the exhaust duct.

A lower pressure is maintained in potentially contaminated areas than in general access areas, and the entire building is maintained at a lower pressure than the outside ambient air, thus preventing the spread of contamination and exfiltration of unmonitored contaminated air.

The air is exhausted by two of the three 50 percent-capacity exhaust fans through an exhaust vent located on the roof.

An airborne radioactivity monitor is located on the exhaust to provide a record of the amount of activity discharged to the environment (Section 11.4). On a high (radiation) alarm, the monitor will trip the ventilation fans.

The turbine building ventilation system is required to operate only during normal plant operation, and is therefore not designed to Category I requirements.

12.2.2.5 Service Building Machine Shop Ventilation System

The volume of the machine shop in the service building is 257,400 ft^3. Outside air enters through two intakes, one for each supply fan, located on top of the warehouse roof. One supply fan has a capacity of 23,000 cfm and the other has a capacity of 6000 cfm. The inlet air passes through low efficiency filters and is discharged into the machine shop by one or both fans, depending upon whether or not the machines are operating. If the machines are in use, air is exhausted from the machines through a roughing filter and through a HEPA filter by a 15,000-cfm exhaust fan before being discharged to the stack located on the machine shop roof. The air from the ultrasonic cleaner fume hood is exhausted through a HEPA filter by a 10,000-cfm exhaust fan before being discharged to the stack.

The general shop area air is exhausted through a HEPA filter by a 7000-cfm exhaust fan before being discharged to the stack. The HEPA filters used on the exhaust have an efficiency of 99.97 percent for 0.3 μm particles at rated capacity.

12.2.3 Source Terms

Potential leakage from the reactor coolant and main steam systems can result in the release of radionuclides to the atmosphere of plant buildings.

The plant ventilation systems are designed such that areas that contain possible sources of leakage are kept at a slightly negative pressure. Clean and tempered air is supplied to general access areas from which it passes to potentially contaminated areas.

To estimate the doses to personnel in the plant structures from reactor coolant and main steam system leakage, the sources as defined in Sections 11.1 and 11.3 are used. These sources, in conjunction with estimates of personnel occupancy time and possible leakage rates, are used to calculate the inhalation doses presented in Subsection 12.2.5.

12.2.4 Airborne Radioactivity Monitoring

12.2.4.1 Design Objectives

The process radiation monitoring system (PRMS), which performs airborne radioactivity monitoring, is designed to measure and record airborne radioactivity levels, to alarm on high airborne radioactivity levels and, when required, to control the release of radioactive gases and particulates produced in the operation of the plant. It also ensures compliance with the requirements of 10 CFR 50; 10 CFR 20; Regulatory Guides 1.21, 8.8, and 8.10; and GDC 64. The system aids in the protection of the general public and plant personnel from exposure to airborne radioactivity in excess of that allowed by applicable regulations. This system controls or terminates releases exceeding discharge limits and warns plant personnel so that they can take appropriate measures to protect themselves and the general public.

The design objectives of the fixed system for normal operation are

a. To provide continuous surveillance of airborne radioactivity levels in effluent streams that discharge to the environment from minimum detectable levels to levels commensurate with Offsite Dose Calculation Manual radiological effluent control limits. The system indicates and records these levels in the main control room or the radwaste control room and alarms at abnormal levels

b. To provide data for estimating total released activity to comply with Regulatory Guide 1.21

c. To give early warning of increasing radioactivity levels indicative of equipment failure, malfunction, or deteriorating system performance

d. To initiate prompt corrective action, either automatically or through operator response, on high airborne radioactivity level

e. To provide continuous surveillance in the main control room of airborne radioactivity levels by indicating and recording exhaust duct radiation levels and by alarming at abnormal activity levels. This aids in preventing a person from inadvertently entering an area where he can inhale airborne activity in excess of limits defined in 10 CFR 20, Appendix B, Table I, Column 1.

For some anticipated operational occurrences resulting from accidents or operator error, the PRMS will activate necessary isolation or diversion valves to terminate or reduce releases, if the airborne radioactivity levels exceed alarm setpoints (as indicated in Table 11.4-1). Independence of redundant monitors is maintained by providing adequate separation of detectors, signal cabling, power supplies, and actuation circuits for isolation and diversion valves.

The fixed continuous monitors, which are described in Section 11.4, serve in conjunction with a comprehensive air sampling program using portable continuous airborne monitors (CAMs) and air samplers, both short and long term. It is necessary to use a local CAM or air sampler to determine the airborne activity of an enclosure because in many instances a fixed monitor sampling a ventilation duct indicates the activity coming from a group of areas.

12.2.4.2 Continuous Airborne Monitors

The following criteria were used in the design and selection of the equipment.

a. General

1. The filter media used in all monitors and air samplers to collect particulates have an efficiency of at least 98 percent for 0.3 μm particles

2. The iodine adsorbent cartridge, used in monitors and air samplers to sample radioactive iodine, has a collection efficiency of approximately 95 percent for elemental and organic iodine.

b. Fixed continuous airborne monitors - Details are given in Subsection 11.4.3.8

c. Portable continuous airborne monitors

1. The sample flow rate is automatically controlled to within ±1 liter/minute of the set value
2. A flow indicator is provided
3. Power requirements are 115 V ac ±15 percent, 60 Hz ±5 percent from a normal distribution panel
4. Environmental design conditions for the components are 40° to 120°F, 0 to 95 percent relative humidity, and atmospheric pressure
5. Adequate lead shielding approximately 3 in. thick is provided for detectors so that background radiation has a minimum effect on the ability of the monitors to sense low levels
6. The CAM is mounted on a cart on wheels so that it can be moved from one location to another
7. A meter with digital readout or an appropriate strip-chart recorder is provided
8. A low (failure) trip, a high (radiation) trip, and an audible alarm may be provided. The trips are adjustable over the full range of the meter. All alarms are local, but relays are provided if remote alarms or initiation are needed.

12.2.4.3 Air Samplers

The following criteria were used in the selection of portable air samplers.

a. Long-term air samplers

1. The sampler flow rate is controlled between 1 and 4 cfm
2. The filter holder holds a 47-mm or 2-in. filter media to collect particulates and iodine-adsorbent cartridge
3. An elapsed-time meter is installed to determine air sample time; however, this feature is not utilized, the time is recorded manually
4. The samplers are designed to operate at 40° to 140°F, 0 to 95 percent relative humidity, and atmospheric pressure
5. Power requirements are 115 V ac ±10 percent, 60 Hz ±5 percent.

b. Short-term air samplers

1. The sampler flow rate is between 1 and 28 cfm depending on the sampler
2. The air sampler uses a 47-mm or 2-in.-diameter filter media to collect particulates at 2 to 28 cfm. In conjunction with this, an iodine-adsorbent cartridge can be used to collect iodine. A 4-in. sample head and filter may be used to collect particulate samples above 8 cfm
3. Power requirements are 115 V ac ±10 percent, 60 Hz ±5 percent

4. The sampler is small enough to be carried by one man.

12.2.4.4 Air Sample Location Selection

a. Fixed continuous airborne monitors

   1. A separate effluent monitor samples the ventilation exhaust from each building that may contain radioactive material (reactor and auxiliary building, radwaste building, and turbine building) before it is discharged to the environment, to determine the level of airborne activity and to terminate the discharge if a preselected setpoint is exceeded

   2. Two monitors sample the control center ventilation system to determine the radioactivity level of intake air

   3. Four monitors (two pairs) monitor the air exhausted from the fuel pool area to determine the radioactivity level of the air in this area. The pool area is a potential source of high activity because of fuel handling. These monitors provide in-depth protection.

b. Portable continuous airborne monitors

   1. A portable CAM may be used to monitor work areas where it is likely there will be high levels of airborne radioactivity because of conditions in the area, equipment being worked on, or the type of work being performed

   2. A portable CAM can be used as a replacement for a fixed monitor in the event of a failure.

c. Portable air samplers

   1. Long-term air samplers are used to sample at low flow rates (1 to 4 cfm) over extended periods of time (often 24 hr or more). They are usually moved from one location to another in the plant to evaluate the long-term airborne exposures throughout the plant. They can also be used to obtain an average airborne activity level at a job of long duration if a portable CAM is not used

   2. Short-term air samplers are used to sample at high flow rates (2 to 40 cfm) over short periods of time to evaluate the air activity in local areas during maintenance jobs or other special operations. Short term air samplers can also be used to evaluate the air activity in enclosed spaces prior to entry for maintenance or other special operations as deemed necessary by Health Physics.

12.2.4.5 Expected Airborne Radioactivity Levels

The expected airborne radioactivity levels in the effluent streams are such that radiation levels at the site boundary are a small fraction of 10 CFR 20 limits and will be as low as reasonably achievable (ALARA).

The expected airborne radioactivity levels in the plant vary depending upon conditions in a given area and the maintenance work or special operations being performed. In clean areas, the expected airborne radioactivity after allowing for decay of radon-thoron daughters is on the order of 10^{-12} to 10^{-13} μCi/cm^3 for gross beta-gamma activity, and 10^{-14} to 10^{-15} μCi/cm^3 for gross alpha activity.

12.2.4.6 Quantity To Be Measured

a. Fixed continuous airborne monitors

The principal nuclides monitored by the fixed monitors are listed in Table 11.4-1. Each channel measures gross radioactivity

b. Portable continuous airborne monitors

Two CAMs measure gross particulate activity, iodine activity, and noble gas activity

c. Portable air samplers

The air samplers collect particulate samples that are normally counted for beta activity. When the gross beta activity is high, alpha activity may be counted to help evaluate radon-thoron activity and an attempt may be made to identify the gamma isotopes present on the filter by using a multichannel pulse height analyzer. During handling and inspection of new fuel, air samples taken in the work area are counted for alpha activity.

Impregnated charcoal or iodine-adsorbent cartridges are used to collect iodine when it is suspected that airborne iodine activity is likely to be present in a work area. These cartridges may be analyzed for radioiodine activity using a multichannel pulse height analyzer or iodine-specific analyzer.

12.2.4.7 Detector Types, Sensitivity, and Range

a. Fixed continuous airborne monitors

The detector types, sensitivity, and nominal range of each fixed monitor are listed in Table 11.4-1. The location of the sample probe and detector for offline monitors was chosen to minimize sample line length and number of direction changes to avoid sample plate-out. Unavoidable bends are made with radii not less than five times the tubing diameter. Probes are isokinetic

b. Portable continuous airborne monitors

The detectors in the portable CAMs are similar to those on the gaseous effluent monitor discussed in Table 11.4-1

c. Air sample counting

Long- and short-term particulate air sampler filter papers are counted using calibrated counting equipment, including Geiger-Mueller detector and rate meter combinations, proportional counters, and a high- resolution gamma spectrometry system. Gamma radionuclide identification can be performed on an air sample if there is sufficient activity on the sample so that a spectrum can be obtained in a reasonable amount of time. The efficiency of the gamma analyzer varies with the energy of the radionuclide measured. In addition to the efficiency and the background of the counter, the sensitivity of the measurement of air sample activities depends on the length of the sample collection and the counting time.

12.2.4.8 Inservice Inspection, Calibration, and Maintenance

a. Inspections and tests

The following inspections and tests are performed:

1. Fixed continuous airborne monitors - See Subsection 11.4.5.1
2. Portable continuous airborne monitors - During normal operation, daily checks of system operability are made by observing channel behavior. Each portable CAM is calibrated at least annually using an approved procedure
3. Air samplers - During normal operation, air samplers will be checked and calibrated at least annually using an approved procedure.

b. Calibration

1. Fixed continuous airborne monitors - See Subsection 11.4.5.2
2. Portable continuous airborne monitors - An initial certification of each CAM is performed at the factory. The certification of the sources is traceable to the National Institute of Standards and Tests or commercial standards

   After delivery to the plant, the calibration is rechecked by using calibration sources. Calibration is performed at least annually
3. Portable air samplers - The flow of each air sampler is checked initially with a flowmeter. The flow rate is checked at least annually and after maintenance work that could change the flow rate.

c. Maintenance

The detectors, electronics, recorders, and air samplers are serviced and maintained during the calibration process and as required to ensure reliable operation. Such maintenance includes cleaning, lubrication, and assurance of free movement of the recorder in addition to the replacement or adjustment of any components required during testing or calibration

d. Audits and verifications

Independent audits and verifications of test, calibration, and maintenance records and procedures shall be conducted at least annually.

12.2.5 Estimates of Inhalation Doses

12.2.5.1 Introduction

Low-level concentrations of airborne radionuclides are to be expected in the atmosphere of some plant structures. The inhalation dose received by individuals depends on many factors, a few of which are the following:

a. Period of time spent in the various compartments

b. Fluid leak rates to the compartments

c. Type of fluid leakage (water or steam)

d. Concentration of radionuclides in the leaking fluid

e. Volume of and airflow rate through each compartment

f. Use of respiratory equipment or supplemental air.

The plant ventilation systems, as described in Section 9.4, are designed to minimize operating personnel inhalation doses by supplying clean and tempered air to all areas normally accessible during plant operation. Equipment with radioactive leakage potential is located in compartments that are kept at a slightly negative pressure, so air flows into those compartments where leaking equipment might be a source of airborne activity. These compartments are not normally occupied during plant operation and are subject to Health Physics control, with respiratory protective devices or supplemental air used if necessary to allow entry. Also provided is a drywell purge system with sufficient capacity to reduce the airborne radioactivity levels in the drywell and suppression chamber so that short-term access is provided for minor inspection during reactor hot standby, and long-term access is provided for maintenance and inspection during the refueling shutdown.

The ventilation systems are designed such that clean and tempered air is supplied initially to normally occupied areas. The air flows through these areas into the individual equipment compartments, which are kept at a slightly negative pressure, and thence out of the building. This arrangement prevents any airborne activity present in the compartments from reaching normally occupied areas. Because of the ventilation system design and Health Physics controls, the inhalation dose to operations personnel in areas normally occupied during operation (such as the main control room, corridors, and areas not containing potential sources of airborne activity) will be ALARA as required by Regulatory Guide 8.8. The ventilation systems are designed, in conjunction with the shielding, to keep the whole-body dose ALARA.

Inhalation doses for areas with potential airborne activity have been estimated based on the radionuclide concentrations of Section 11.1, anticipated occupancy times, leakage rates, and appropriate ventilation flow rates. These estimates of the personnel inhalation doses received are presented in Tables 12.2-3 through 12.2-12. The inhalation doses as presented by these tables are well below the guidelines applicable to radiation workers as set forth in Table I of Appendix B to 10 CFR 20.

A survey of available information pertaining to operating BWR plants has shown that in cases where the permissible concentration was reached or exceeded, the condition usually existed for a very limited time and was confined to a limited area. When access for extended periods is necessary to an area where the airborne concentration is greater than MPC, the leaking equipment will be isolated and the area purged, occupancy time will be limited, or respiratory equipment will be used (Section 12.3) to ensure that personnel exposures to airborne radioactive material are both ALARA and within applicable regulatory limits.

Estimates of both maximum airborne concentrations and annual inhalation doses to plant personnel within the reactor building and turbine building are summarized in Tables 12.2-3 through 12.2-12. These are the buildings where the potential for significant inhalation doses would be expected to occur. The liquid in the radwaste building is essentially degassed liquid at atmospheric pressure. Equipment used in the radwaste building is designed to reduce the possibility of equipment leakage by the use of welded piping. The auxiliary building contains no normal sources for inhalation doses.

The most significant potential for inhalation doses in the reactor building is from liquid leakage from the reactor water cleanup (RWCU) system and from entry to the drywell. The drywell may be entered for short periods of time during reactor hot standby and will be opened for extensive maintenance and inspection activities during refueling outages. The reactor/auxiliary building ventilation system is sized to reduce the airborne activity levels in the normally occupied areas to a safe level that affords normal, continuous occupancy. The RWCU system components are enclosed in compartments that are kept at a slightly negative pressure to preclude the leakage of airborne radioactivity to the accessible areas of the building.

The most significant potential for inhalation doses in the turbine building is from liquid leakage from equipment containing condensate and reactor feedwater and from entry to the third floor turbine enclosure area. Leakage to the equipment compartments is primarily liquid, and leakage into the turbine enclosure is primarily steam. The heater feed pumps area is representative of low airborne concentrations where plant personnel may be expected to spend greater lengths of time than in the area of high airborne concentrations.

The turbine building ventilation system is sized to reduce the airborne levels in the normally occupied areas to a safe level that affords normal, continuous occupancy. Pieces of equipment that have the potential to become significant sources of airborne radionuclide concentrations are located in compartments, which are kept at a slightly negative pressure to preclude leakage to the accessible areas of the building. Periodic entrances to the turbine enclosure during normal operation could result in an inhalation dose to the person in the enclosure from steam leakage.

The calculated maximum airborne concentrations and annual inhalation doses presented by Tables 12.2-4 through 12.2-12 are based on the following assumptions:

a. An individual is exposed (without respiratory protection) for the maximum time estimated for each area, per year. In actual practice, several different people would make entries at different times during the year. Also, the use of respiratory protection would reduce the inhalation exposure to specific individuals to much less than those shown

b. The estimated airborne concentrations are based on the concentration of radionuclides in the reactor water and steam presented in Section 11.1 calculated at 102 percent of 3430 MWt (3499 MWt) and the proposed calculational leakage and partition factors as presented in Section 11.3.

Only the radionuclides that were considered to contribute significantly to personnel inhalation doses from the leakage have been included. Since hot and cold liquid leakage is essentially degassed, only halogens are considered.

Other radionuclides are present in such low concentrations that they should not significantly affect the estimated personnel dose. Steam leakage to the turbine enclosure includes noble gases, ^{16}N, and halogens. Radionuclide concentrations in the steam are those presented by Tables 11.1-2 through 11.1-5.

The estimated air concentrations and inhalation doses have been calculated utilizing conservative assumptions for leakage rates, partition factors, and radionuclide concentrations. These estimated annual inhalation doses are higher than would be anticipated during actual reactor operations because of the conservatism used in the calculations. The summary doses presented in Table 12.2-13 are the maximum doses that one person would receive if he remained in each of the areas for the estimated times. Since no individual would ever be exposed to all the areas, Table 12.2-13 does not represent the actual expected dose to a single specific individual, but would represent the "worst-case" total dose from each of the areas considered.

A plant load factor of 80 percent and appropriate building volumes and ventilation rates have been used in the calculations. For each case it has been assumed that the initial concentration is zero and that the leakage has occurred long enough to reach equilibrium condition in the area; that is, 90 hr. For assumptions of leakage rate, type of leakage, compartment volume ventilation flow rate, and the partition factors from the leakage to the atmosphere, see Tables 12.2-1 and 12.2-2. Operating plant data may be found in References 1 through 4.

NOTE: These inhalation-dose estimates of Section 12.2.5 have been performed as part of the original overall design-basis determination that the plant was well-designed from an ALARA standpoint. These calculations were/are intended to only represent conservative preoperational estimates. It was not intended to update or revise these values in order to correspond to operating plant data or to any revised criteria, assumptions, etc. Operational inhalation doses data is routinely measured in plant airborne areas, and summary dose information is periodically provided to pertinent regulatory agencies.

12.2.5.2 Air Concentration Calculation Methodology

Equation 12.2-1 was used to calculate the air concentration of the radionuclides given in Tables 12.2-3 through 12.2-12.

$$c = \frac{Lc_pPF}{V_{\lambda_s}} M\left(1 - e^{-2\lambda_s t}\right) \qquad (12.2\text{-}1)$$

$$\lambda_s = \lambda_d + \lambda_p \qquad (12.2\text{-}2)$$

$$\lambda_d = \frac{0.693}{T_{1/2}} \qquad (12.2\text{-}3)$$

$$\lambda_p = k\frac{F}{V} \qquad (12.2\text{-}4)$$

where

c	=	concentration of each radionuclide in compartment atmosphere, $\mu Ci/cm^3$
c_p	=	concentration of each radionuclide in system leakage, $\mu Ci/cm^3$
L	=	leak rate from system to compartment, g/sec
PF	=	partition factor for each radionuclide
k	=	building mixing factor (0.8)
λ_s	=	total removal constant for each radionuclide, hr^{-1}
λ_d	=	decay constant for each radionuclide, hr^{-1}
λ_p	=	purge constant for each radionuclide, hr^{-1}
$T_{1/2}$	=	half-life of radionuclide, hr
V	=	compartment volume, ft^3
F	=	volumetric airflow rate of compartment, ft^3/hr
t	=	time, hr
M	=	constant, sec $ft^3/hr\ cm^3$

The following relationships are used to estimate the doses:

$$c/MPC \times 5 = \text{Whole-body dose, rem/year} \qquad (12.2\text{-}5)$$

$$c/MPC \times 30 = \text{Thyroid dose, rem/year} \qquad (12.2\text{-}6)$$

where

c	=	airborne concentration of each radionuclide, $\mu Ci/cm^3$
MPC	=	maximum permissible concentration for each radionuclide as given in Table I, Appendix B of 10 CFR 20, $\mu Ci/cm^3$

12.2 VENTILATION

REFERENCES

1. Kahn et al., HEW Radiological Surveillance Studies at a Boiling Water Nuclear Power Reactor, BHF/DER 70-1 US, PHS, March 1970.
2. Gundremmingen, Nuclear Power Plant, Annual Report, AEC-tr-7179, 1969.
3. General Electric BWR/6 Standard Safety Analysis Report (GESSAR) Appendix 12A - Noble Gas and Iodine Activity in the Oyster Creek Ventilation and Off Gas Systems During Operation.
4. General Electric BWR/6 Standard Safety Analysis Report (GESSAR) Appendix 12B - Millstone Nuclear Power Station Ventilation Sampling Program.

TABLE 12.2-1 REACTOR BUILDING INHALATION DOSE PARAMETERS (3499 MWt)

Compartment and Location	Volume V (ft^3)	Ventilation Rate F (cfm)	Leak Rate L (g/sec)	Thermal Condition of Leakage	Partition Factor PF	Purge Constant λ_{p1} (hr)	Occupancy Time	Description of Leakage
Drywell	163,730	8500[a]	5.4	Hot	1.0	2.49	1 hr/year at hot standby excluding refueling and maintenance	Degassed reactor[b] coolant
			21.0	Hot	1.0			Degassed[c] feedwater
Reactor water cleanup pump (Elev. 613 ft 6 in., B-C,11-13)								
(North)	3200	1360	0.62	Hot	0.1	20.4	2 hr/week	Degassed reactor[b] coolant
(South)	4230	1360	0.62	Hot	0.1	15.5	2 hr/week	Degassed reactor[b] coolant
Regenerative and nonregenerative heat exchangers (Elev. 613 ft 6 in., C-E, 14-15)	21,500	1680	0.22	Hot	0.1	3.74	2 hr/week	Degassed reactor[b] coolant
Cleanup phase separator (Elev. 613 ft 6 in., C-E, 16-17)	17,100	395	0.22	Cold	0.001	1.10	2 hr/week	Degassed treated[c] reactor coolant

[a] During purging.

[b] Halogen concentration based on GE values from Table 11.1-2 adjusted to agree with Regulatory Guide 1.42. Regulatory Guide 1.42 gives ^{131}I as 0.5 x 10^{-2} µCi/g. Thus, Table 11.1-2 values are multiplied by 0.385 to obtain concentrations in the reactor coolant.

[c] Obtained from the degassed reactor coolant multiplied by an internal reactor PF of 0.01 and a polishing PF of 0.1.

TABLE 12.2-2 TURBINE BUILDING INHALATION DOSE PARAMETERS (3499 MWt)

Compartment and Location	Volume V (ft^3)	Ventilation Rate F (cfm)	Leak Rate L (g/sec)	Thermal Condition of Leakage	Partition Factor PF	Purge Constant $^{\lambda}p_1$ (hr)	Occupancy Time	Description of Leakage
Third floor turbine enclosure (Elev. 643 ft 6 in., K-N, 5-10)	703,550	81,870	128.5	N/A	1.0	5.59	0.5 hr/week	Steam at 7 sec[a]
Condenser pump (Elev. 564 ft 0 in., M-N, 4-9)	8062	350	19.4	Cold	0.001	2.08	1 hr/week	Degassed condensate[b]
Offgas system condensate return pump (Elev. 564 ft 0 in., P-R, 2-3)	6118	120	4.85	Cold	0.001	0.94	1 hr/week	Degassed condensate[b]
Gland steam condensate pump (Elev. 564 ft 0 in., N-P, 8-9)	33,120	10,490	4.85	Cold	0.001	15.2	1 hr/week	Degassed condensate[b]
Equipment drains (Elev. 564 ft 0 in., R-S, 8-10)	25,829	2,610	3.22	Cold	0.001	4.83	3 hr/week	Degassed condensate[b]
Heater feed pump (Elev. 583 ft 6 in., N-R, 12-14)	114,912	38,865	8.06	Hot	0.1	16.2	20 hr/week	Degassed condensate[b]

[a] Noble gas concentrations based on Table 11.1-2 (t = 7 sec) values adjusted to a 1000 lb/hr release rate. Halogens are based on Regulatory Guide 1.42 values for ^{131}I at 1700 lb/hr and ratioed for the 1000 lb/hr leak rate.

[b] Degassed reactor coolant concentrations based on GE values from Table 11.1-3 adjusted to agree with Regulatory Guide 1.42. Regulatory Guide 1.42 gives ^{131}I as 0.5×10^{-2} µCi/g. Thus, Table 11.1-3 values are multiplied by 0.385 to obtain concentration in the reactor coolant. The degassed reactor coolant concentrations are then reduced by a reactor internal PF of 0.01 and a condensate polishing PF of 0.1 to obtain the degassed condensate concentrations

TABLE 12.2-3 DRYWELL DOSES (3499 MWt)

Nuclide	Concentration in the Fluid[b] c_p (μCi/g)	Airborne Concentration[a] c (μCi/cm^3)	Expected Annual Thyroid and Whole Body Doses[a] Whole Body c/MPC[c]	Whole Body Dose rem/yr	Thyroid c/MPC[c]	Thyroid Dose rem/yr
I. Reactor coolant leakage						
Br-83	5.89E-03	8.73E-09	4.36E-06	2.18E-05		
Br-84	1.06E-02	1.15E-08	5.77E-06	2.89E-05		
Br-85	6.67E-03	1.06E-08	5.30E-06	2.65E-05		
I-131	5.10E-03	8.44E-09	1.41E-05	7.04E-05	4.69E-04	1.41E-02
I-132	5.75E-02	8.49E-08	4.71E-05	2.36E-04	2.12E-04	6.36E-03
I-133	4.27E-02	6.98E-08	1.74E-04	8.72E-04	1.16E-03	3.49E-02
I-134	1.15E-01	1.45E-07	2.41E-05	1.20E-04	1.45E-04	4.34E-03
I-135	6.24E-02	9.95E-08	1.24E-04	6.22E-04	4.98E-04	1.49E-02
TOTAL			4.00E-04	2.00E-03	2.49E-03	7.46E-02
II. Feedwater leakage						
Br-83	5.89E-06	3.52E-11	1.76E-08	8.79E-08	0.00E+00	0.00E+00
Br-84	1.06E-05	4.62E-11	2.31E-08	1.15E-07	0.00E+00	0.00E+00
Br-85	6.67E-06	4.26E-11	2.13E-08	1.07E-07	0.00E+00	0.00E+00
I-131	5.11E-06	3.40E-11	5.67E-08	2.83E-07	1.89E-06	5.67E-05
I-132	4.71E-05	2.79E-10	1.55E-07	7.74E-07	6.97E-07	2.09E-05
I-133	3.50E-05	2.29E-10	5.72E-07	2.86E-06	3.81E-06	1.14E-04
I-134	9.42E-05	4.72E-10	7.87E-08	3.93E-07	4.72E-07	1.42E-05
I-135	5.11E-05	3.28E-10	4.10E-07	2.05E-06	1.64E-06	4.91E-05
TOTAL			1.33E-06	6.67E-06	8.51E-06	2.55E-04

Summary of reactor coolant and feedwater drywell doses:

Σ c/MPC (whole body) = 4.01E-04
Σ c/MPC (thyroid) = 2.50E-03
Σ Whole-body dose = 4.01E-04 x 5 = 2.01E-03 rem/year
Σ Thyroid dose = 2.50E-03 x 30 = 7.50E-02 rem/year

[a] Scale-up factor 1.04

[b] Scale-up factor 1.02

[c] As defined in Appendix B of 10 CFR 20.

TABLE 12.2-4 REACTOR WATER CLEANUP PUMP AREA DOSES (3499 MWt)

Nuclide	Concentration in the Fluid[b] c_p (µCi/g)	Airborne Concentration[a] c (µCi/cm^3)	Expected Annual Thyroid and Whole Body Doses[a] Whole Body c/MPC[c]	Whole Body Dose rem/yr	Thyroid c/MPC[c]	Thyroid Dose rem/yr
I. Reactor coolant leakage						
Br-83	5.89E-03	6.99E-10	3.49E-05	1.75E-04		
Br-84	1.06E-02	1.20E-09	5.98E-05	2.99E-04		
Br-85	6.69E-03	7.99E-10	3.99E-05	2.00E-04		
I-131	5.12E-03	6.14E-10	1.02E-04	5.11E-04	3.41E-03	1.02E-01
I-132	4.71E-02	5.58E-09	3.10E-04	1.55E-03	1.40E-03	4.19E-02
I-133	3.50E-02	4.19E-09	1.05E-03	5.24E-03	6.99E-03	2.10E-01
I-134	9.44E-02	1.09E-08	1.82E-04	9.10E-04	1.09E-03	3.28E-02
I-135	5.11E-02	6.12E-09	7.64E-04	3.82E-03	3.06E-03	9.17E-02
TOTAL			2.54E-03	1.27E-02	1.59E-02	4.78E-01
II. Feedwater leakage						
Br-83	5.89E-03	6.91E-10	3.45E-05	1.73E-04		
Br-84	1.06E-02	1.16E-09	5.82E-05	2.91E-04		
Br-85	6.69E-03	7.95E-10	3.97E-05	1.99E-04		
I-131	5.12E-03	6.12E-10	1.02E-04	5.10E-04	3.40E-03	1.02E-01
I-132	4.71E-02	5.53E-09	3.07E-04	1.54E-03	1.38E-03	4.15E-02
I-133	3.50E-02	4.17E-09	1.04E-03	5.21E-03	6.95E-03	2.09E-01
I-134	9.44E-02	1.07E-08	1.79E-04	8.93E-04	1.07E-03	3.21E-02
I-135	5.11E-02	6.07E-09	7.59E-04	3.80E-03	3.04E-03	9.11E-02
TOTAL			2.52E-03	1.26E-02	1.58E-02	4.75E-01

Summary of north and south reactor cleanup pump doses:

Σ c/MPC$_i$ (whole body) = 5.06E-03
Σ c/MPC$_i$ (thyroid) = 3.17E-02
Σ Whole-body dose = 5.06E-03 x 5 = 2.53E-02 rem/year
Σ Thyroid dose = 3.17E-02 x 30 = 9.51E-01 rem/year

[a] Scale-up factor = 1.04

[b] Scale-up factor = 1.02

[c] As defined in Appendix B of 10 CFR 20.

TABLE 12.2-5 REGENERATIVE AND NONREGENERATIVE HEAT EXCHANGER AREA DOSES (3499 MWt)

Nuclide	Concentration in the Fluid[b] c_p (μCi/g)	Airborne Concentration[a] c (μCi/cm^3)	Expected Annual Thyroid and Whole Body Doses[a] Whole Body c/MPC[c]	Whole Body Dose rem/yr	Thyroid c/MPC[c]	Thyroid Dose rem/yr
Br-83	5.89E-03	1.92E-10	9.62E-06	4.81E-05		
Br-84	1.06E-02	2.77E-10	1.38E-05	6.92E-05		
Br-85	6.68E-03	2.29E-10	1.14E-05	5.72E-05		
I-131	5.10E-03	1.79E-10	2.98E-05	1.49E-04	9.94E-04	2.98E-02
I-132	4.73E-02	1.54E-09	8.55E-05	4.28E-04	3.85E-04	1.15E-02
I-133	3.50E-02	1.22E-09	3.04E-04	1.52E-03	2.03E-03	6.08E-02
I-134	9.42E-02	2.72E-09	4.54E-05	2.27E-04	2.72E-04	8.17E-03
I-135	5.10E-02	1.75E-09	2.18E-04	1.09E-03	8.74E-04	2.62E-02
TOTAL			7.18E-04	3.59E-03	4.55E-03	1.37E-01

[a] Scale-up factor = 1.04

[b] Scale-up factor = 1.02

[c] As defined in Appendix B of 10 CFR 20.

TABLE 12.2-6 CLEANUP PHASE SEPARATOR AREA DOSES (3499 MWt)

			Expected Annual Thyroid and Whole Body Doses[a]			
			Whole Body		Thyroid	
Nuclide	Concentration in the Fluid[b] c_p (μCi/g)	Airborne Concentration[a] c (μCi/cm^3)	c/MPC[c]	Dose rem/yr	c/MPC[c]	Dose rem/yr
Br-83	5.89E-03	7.00E-12	3.50E-07	1.75E-06		
Br-84	1.06E-02	7.28E-12	3.64E-07	1.82E-06		
Br-85	6.57E-03	9.20E-12	4.60E-07	2.30E-06		
I-131	5.10E-03	7.66E-12	1.28E-06	6.39E-06	4.26E-05	1.28E-03
I-132	4.73E-02	5.58E-11	3.10E-06	1.55E-05	1.40E-05	4.19E-04
I-133	3.50E-02	5.12E-11	1.28E-05	6.40E-05	8.53E-05	2.56E-03
I-134	9.42E-02	8.18E-11	1.36E-06	6.82E-06	8.18E-06	2.46E-04
I-135	5.10E-02	7.02E-11	8.77E-06	4.39E-05	3.51E-05	1.05E-03
TOTAL			2.85E-05	1.42E-04	1.85E-04	5.55E-03

[a] Scale-up factor = 1.04

[b] Scale-up factor = 1.02

[c] As defined in Appendix B of 10 CFR 20.

TABLE 12.2-7 TURBINE ENCLOSURE DOSES (3499 MWt)

			Expected Annual Thyroid and Whole Body Doses[a]			
			Whole Body		Thyroid	
Nuclide	Concentration in the Fluid[b] c_p (μCi/g)	Airborne Concentration[a] c (μCi/cm^3)	(c/MPC)[c]	Dose rem/yr	(c/MPC)[c]	Dose rem/yr
Kr-83m	1.87E-03	7.20E-09	9.00E-05	4.50E-04		
Kr-85m	3.34E-03	1.33E-08	2.77E-05	1.39E-04		
Kr-85	1.09E-05	4.50E-11	5.63E-08	2.81E-07		
Kr-87	1.09E-02	4.10E-08	5.12E-04	2.56E-03		
Kr-88	1.09E-02	4.31E-08	5.38E-04	2.69E-03		
Kr-89	6.96E-02	8.59E-08	1.07E-03	5.37E-03		
Kr-90	1.32E-01	3.56E-08	4.45E-04	2.22E-03		
Kr-91	1.03E-01	8.00E-09	1.00E-04	5.00E-04		
Kr-92	1.28E-02	1.75E-10	2.18E-06	1.09E-05		
Kr-93	1.25E-03	1.50E-11	1.87E-07	9.36E-07		
Kr-94	9.87E+05	9.13E-13	1.14E-08	5.71E-08		
Kr-95	7.01E-08	3.23E-16	4.04E-12	2.02E-11		
Kr-97	5.97E-08	5.52E-16	6.90E-12	3.45E-11		
Xe-131m	8.18E-06	3.37E-11	2.11E-08	1.05E-07		
Xe-133m	1.58E-04	6.52E-10	8.15E-07	4.08E-06		
Xe-133	4.49E-03	1.85E-08	2.31E-05	1.16E-04		
Xe-135m	1.42E-02	1.02E-08	1.27E-04	6.34E-04		
Xe-135	8.05E-02	1.12E-07	3.51E-04	1.76E-03		
Xe-137	1.20E-02	4.99E-08	6.24E-04	3.12E-03		
Xe-138	4.84E-01	1.31E-07	1.64E-03	8.19E-03		
Xe-139	1.36E-01	4.60E-08	5.75E-04	2.87E-03		
Xe-140	1.15E-01	1.39E-08	1.74E-04	8.71E-04		
Xe-141	7.50E-04	8.42E-12	1.05E-07	5.27E-07		
Xe-142	7.82E-03	1.24E-10	1.55E-06	7.74E-06		
Xe-143	4.19E-05	3.71E-13	4.64E-09	2.32E-08		
Xe-144	1.79E-04	1.46E-11	1.82E-07	9.10E-07		
N-13	6.57E-03	1.55E-08	1.94E-04	9.69E-04		
N-16	9.31E+01	3.35E-06	4.19E-02	2.09E-01		
N-17	2.10E+02	1.92E-10	2.41E-06	1.20E-05		
O-19	1.13E+04	1.79E-07	2.24E-03	1.12E-02		
Br-83	9.63E-05	2.20E-10	2.76E-06	1.38E-05		
Br-84	1.45E-04	2.83E-10	3.54E-06	1.77E-05		
Br-85	1.12E-05	2.67E-11	3.34E-07	1.67E-06		
I-131	8.66E-05	2.10E-10	8.75E-06	4.38E-05	2.92E-04	8.75E-03
I-132	7.61E-04	1.75E-09	2.43E-05	1.21E-04	1.09E-04	3.28E-03
I-133	5.92E-04	1.42E-09	8.91E-05	4.45E-04	5.94E-04	1.78E-02

TABLE 12.2-7 TURBINE ENCLOSURE DOSES (3499 MWt)

Nuclide	Concentration in the Fluid[b] c_p (µCi/g)	Airborne Concentration[a] c (µCi/cm^3)	Expected Annual Thyroid and Whole Body Doses[a] Whole Body (c/MPC)[c]	Whole Body Dose rem/yr	Thyroid (c/MPC)[c]	Thyroid Dose rem/yr
I-134	1.41E-03	2.97E-09	1.24E-05	6.20E-05	7.44E-05	2.23E-03
I-135	8.58E-04	2.04E-09	6.37E-05	3.18E-04	2.55E-04	7.64E-03
TOTAL			5.08E-02	2.54E-01	1.32E-03	3.97E-02

[a] Scale-up factor = 1.04
[b] Scale-up factor = 1.02
[c] As defined in Appendix B of 10 CFR 20.

TABLE 12.2-8 CONDENSER PUMP AREA DOSES (3499 MWt)

Nuclide	Concentration in the Fluid[b] c_p (µCi/g)	Airborne Concentration[a] c ($\mu Ci/cm^3$)	Expected Annual Thyroid and Whole Body Doses[a]: Whole Body c/MPC[c]	Whole Body Dose rem/yr	Thyroid c/MPC[c]	Thyroid Dose rem/yr
Br-83	5.89E-05	7.55E-12	1.89E-07	9.44E-07		
Br-84	1.06E-04	9.51E-12	2.38E-07	1.19E-06		
Br-85	6.68E-05	9.24E-12	2.31E-07	1.15E-06		
I-131	5.11E-05	7.43E-12	6.19E-07	3.09E-06	2.06E-05	6.19E-04
I-132	4.71E-04	5.99E-11	1.66E-06	8.32E-06	7.49E-06	2.25E-04
I-133	3.50E-04	5.02E-11	6.28E-06	3.14E-05	4.19E-05	1.26E-03
I-134	9.43E-04	9.94E-11	8.29E-07	4.14E-06	4.97E-06	1.49E-04
I-135	5.11E-04	7.09E-11	4.43E-06	2.22E-05	1.77E-05	5.32E-04
TOTAL			1.45E-05	7.24E-05	9.27E-05	2.78E-03

[a] Scale-up factor = 1.04

[b] Scale-up factor = 1.02

[c] As defined in Appendix B of 10 CFR 20.

TABLE 12.2-9 OFFGAS SYSTEM CONDENSATE RETURN PUMP AREA DOSES (3499 MWt)

Nuclide	Concentration in the Fluid[b] c_p (μCi/g)	Airborne Concentration[a] c (μCi/cm^3)	Expected Annual Thyroid and Whole Body Doses[a] Whole Body c/MPC[c]	Whole Body Dose rem/yr	Thyroid c/MPC[c]	Thyroid Dose rem/yr
Br-83	5.89E-05	5.04E-12	1.26E-07	6.31E-07		
Br-84	1.06E-04	4.69E-12	1.17E-07	5.86E-07		
Br-85	6.68E-05	6.38E-12	1.59E-07	7.97E-07		
I-131	5.11E-05	5.40E-12	4.50E-07	2.25E-06	1.50E-05	4.50E-04
I-132	4.71E-04	3.76E-11	1.05E-06	5.23E-06	4.71E-06	1.41E-04
I-133	3.50E-04	3.59E-11	4.49E-06	2.24E-05	2.99E-05	8.97E-04
I-134	9.43E-04	5.43E-11	4.52E-07	2.26E-06	2.71E-06	8.14E-05
I-135	5.11E-04	4.88E-11	3.05E-06	1.52E-05	1.22E-05	3.66E-04
TOTAL			9.88E-06	4.94E-05	6.45E-05	1.94E-03

[a] Scale-up factor = 1.04

[b] Scale-up factor = 1.02

[c] As defined in Appendix B of 10 CFR 20.

TABLE 12.2-10 GLAND STEAM CONDENSATE PUMP AREA DOSES (3499 MWt)

			Expected Annual Thyroid and Whole Body Doses[a]			
			Whole Body		Thyroid	
Nuclide	Concentration in the Fluid[b] c_p (μCi/g)	Airborne Concentration[a] c ($\mu Ci/cm^3$)	c/MPC[c]	Dose rem/yr	c/MPC[c]	Dose rem/yr
Br-83	5.89E-05	7.00E-14	1.75E-09	8.75E-09		
Br-84	1.06E-04	1.19E-14	2.96E-10	1.48E-09		
Br-85	6.68E-05	8.04E-14	2.01E-09	1.00E-08		
I-131	5.11E-05	6.20E-14	5.17E-09	2.58E-08	1.72E-07	5.17E-06
I-132	4.71E-04	5.60E-13	1.55E-08	7.77E-08	6.99E-08	2.10E-06
I-133	3.50E-04	4.19E-13	5.24E-08	2.62E-07	3.49E-07	1.05E-06
I-134	9.43E-04	1.08E-12	9.01E-09	4.51E-08	5.41E-08	1.62E-06
I-135	5.11E-04	6.15E-13	3.84E-08	1.92E-07	1.54E-07	4.61E-06
TOTAL			1.25E-07	6.23E-07	7.99E-07	2.40E-05

[a] Scale-up factor = 1.04

[b] Scale-up factor = 1.02

[c] As defined in Appendix B of 10 CFR 20.

TABLE 12.2-11 EQUIPMENT DRAINS AREA DOSES (3499 MWt)

			Expected Annual Thyroid and Whole Body Doses[a]			
			Whole Body		Thyroid	
Nuclide	Concentration in the Fluid[b] c_p (μCi/g)	Airborne Concentration[a] c (μCi/cm^3)	c/MPC[c]	Dose rem/yr	c/MPC[c]	Dose rem/yr
Br-83	5.89E-05	1.80E-13	1.35E-08	6.75E-08		
Br-84	1.06E-04	2.71E-13	2.04E-08	1.02E-07		
Br-85	6.68E-05	2.13E-13	1.60E-08	8.00E-08		
I-131	5.11E-05	1.65E-13	4.13E-08	2.07E-07	1.38E-06	4.13E-05
I-132	4.71E-04	1.45E-12	1.20E-07	6.02E-07	5.42E-07	1.63E-05
I-133	3.50E-04	1.12E-12	4.21E-07	2.11E-06	2.81E-06	8.42E-05
I-134	9.43E-04	2.64E-12	6.60E-08	3.30E-07	3.96E-07	1.19E-05
I-135	5.11E-04	1.63E-12	3.06E-07	1.53E-06	1.22E-06	3.67E-05
TOTAL			1.01E-06	5.03E-06	6.35E-06	1.90E-04

[a] Scale-up factor = 1.04
[b] Scale-up factor = 1.02
[c] As defined in Appendix B of 10 CFR 20.

TABLE 12.2-12 HEATER FEED PUMP AREA DOSES (3499 MWt)

Nuclide	Concentration in the Fluid[b] c_p (μCi/g)	Airborne Concentration[a] c (μCi/cm^3)	Expected Annual Thyroid and Whole Body Doses[a] Whole Body c/MPC[c]	Whole Body Dose rem/yr	Thyroid c/MPC[c]	Thyroid Dose rem/yr
Br-83	5.89E-06	1.58E-14	1.58E-08	7.90E-08		
Br-84	1.06E-05	2.68E-14	2.68E-08	1.34E-07		
Br-85	6.68E-06	1.82E-14	1.82E-08	9.10E-08		
I-131	5.11E-06	1.39E-14	4.65E-08	2.32E-07	1.55E-06	4.65E-05
I-132	4.71E-05	1.26E-13	1.40E-07	6.99E-07	6.29E-07	1.89E-05
I-133	3.50E-05	9.57E-14	4.78E-07	2.39E-06	3.19E-06	9.57E-05
I-134	9.43E-05	2.97E-13	9.91E-08	4.96E-07	5.96E-07	1.78E-05
I-135	5.11E-05	1.39E-13	3.48E-07	1.74E-06	1.39E-06	4.18E-05
TOTAL			1.17E-06	5.87E-06	7.36E-06	2.21E-04

[a] Scale-up factor = 1.04

[b] Scale-up factor = 1.02

[c] As defined in Appendix B of 10 CFR 20.

TABLE 12.2-13 SUMMARY PLANT INHALATION AND WHOLE-BODY DOSES (3499 MWt)

Area	Whole Body		Thyroid	
	c/MPC[a]	Dose rem/yr	c/MPC[a]	Dose rem/yr
Drywell	4.01E-04	2.01E-03	2.50E-03	7.50E-02
Reactor cleanup pumps	5.06E-03	2.53E-02	3.17E-02	9.51E-01
Regenerative and nonregenerative heat exchangers	7.18E-04	3.59E-03	4.55E-03	1.37E-01
Cleanup phase separator	2.85E-05	1.42E-04	1.85E-04	5.55E-03
Turbine enclosure	5.08E-02	2.54E-01	1.32E-03	3.97E-02
Condenser pumps	1.45E-05	7.24E-05	9.27E-05	2.78E-03
Offgas system condensate return pump	9.88E-06	4.94E-05	6.45E-05	1.94E-03
Gland steam condensate pump	1.25E-07	6.23E-07	7.99E-07	2.40E-05
Equipment drains	1.01E-06	5.03E-06	6.35E-06	1.90E-04
Heater feed pumps	1.17E-06	5.87E-06	7.36E-06	2.21E-04

[a] As defined in Appendix B of 10 CFR 20.

12.3 RADIATION PROTECTION PROGRAM

12.3.1 Program Organization and Objective

12.3.1.1 Program Organization

The Fermi 2 organization, including the Radiation Protection Section, is described in Section 13.1. The Manager - Radiation Protection has the responsibility for the Radiation Protection Program and for ensuring that plant operation meets the radiation protection requirements set forth in 10 CFR 19, 10 CFR 20, 10 CFR 50, applicable Regulatory Guides, and the Technical Specifications and licenses.

12.3.1.2 Program Objective

The objective of the Radiation Protection Program is to provide administrative control of persons on the site to ensure that personnel dose is within the requirements of 10 CFR 20 and that such exposure is kept as low as reasonably achievable (ALARA).

This program consists of rules, practices, and procedures that are used to accomplish the objectives previously stated in a practical and safe manner. The program meets the intent of Regulatory Guides 8.2, 8.8, and 8.10. The Radiation Protection Program is designed to ensure that

a. Operations, maintenance, technical, etc., personnel are provided radiation protection training appropriate for their assigned responsibilities. Contractors and other supporting personnel are provided orientation training to the extent required by the work that they are to perform. This training meets the requirements of 10 CFR 19, 10 CFR 20, and Regulatory Guide 1.8

b. Detailed procedures are prepared and approved to implement the Radiation Protection Program requirements. Major aspects and those that affect general plant personnel are documented in Administrative Procedures in the Plant Conduct Manual

c. Access-control procedures are followed so that access to Radiologically Controlled Areas (RCA) are controlled. Radiation and high radiation areas are segregated and identified in accordance with 10 CFR 20. Control is exercised over each individual entry into high radiation areas

d. All tools and equipment used in the RCAs are surveyed by Radiation Protection personnel before they are removed from the RCA. Normally, tools or equipment moved from one contaminated area to another are wrapped or packaged to prevent the spread of contamination to intermediate areas

e. Appropriate protective clothing is used as required to help prevent personnel contamination and the spreading of contamination from one area to another

f. Airborne radioactivity is measured in accordance with 10 CFR 20 and appropriate engineered controls, and respiratory protective equipment is used as required to keep inhalation of radioactive material ALARA

g. Radiation levels in the plant are measured and posted, so that when personnel enter an area, they can keep their dose ALARA by staying in areas with lower radiation levels

h. Personnel are provided with radiation monitoring equipment to measure their radiation dose (Subsection 12.3.4)

i. A Bioassay Program has been developed using guidance from Regulatory Guides 8.9 and 8.34. This program includes whole body counting and/or a urinalysis sampling program to measure uptakes of radioactive material

j. Records of occupational exposure to radiation are maintained using guidance from Regulatory Guide 8.7. Reports are made to the NRC as required by 10 CFR 20 and to the individual as required by 10 CFR 19

k. Entrance to high radiation areas and maintenance work in radiation or high radiation areas is controlled by using a radiation work permit. This permit typically states dose rates, protective clothing requirements, monitoring requirements, and any special notes or cautions pertinent to the specific job. These permits are prepared by and require approval of Radiation Protection. Jobs involving significant dose to personnel are preplanned and, where conditions require, practice runs on a mockup are made to reduce exposure time on the actual job. Use of special tools and temporary shielding to reduce dose is evaluated on a case basis. On complex or new jobs that involve significant dose, a debriefing session is held after the completion of the job in an attempt to improve methods and keep dose ALARA

    l. Periodic radiation, contamination, and airborne activity surveys are performed to determine and document radiological conditions throughout the plant. Radiological status in the plant is posted so that personnel can review the radiological conditions prior to entering an area.

m. Incoming and outgoing shipments that may be radioactive are surveyed to ensure compliance with applicable provisions of 10 CFR and 49 CFR

n. A record of radiological surveys is maintained in accordance with 10 CFR 20

o. Routine work involving radiation exposures is subject to a periodic review by Radiation Protection to identify situations in which dose can be reduced. Selection of items for review will be based upon area radiation and contamination surveys, personnel contamination surveys, personnel observations, and incidents

p. Process radiation, area radiation, portable radiation, and airborne radioactivity monitors are routinely calibrated and maintained in accordance with approved procedures

q. Radiological incidents are investigated and documented in an attempt to prevent their recurrence. Reports of radiological incidents are made to the NRC in accordance with 10 CFR 20.

r. Plant administrative procedures assure adequate control of radioactive material stored outside of the plant Radiologically Controlled Area (RCA). These controls include: (1) a total limit of 200 Curies for all radioactive material stored outside of the plant RCA, (2) an outdoor activity limit of 10 Curies per package or unpackaged component, (3) containment to prevent runoff of wet material stored longer than 30 days, (4) the use of skids or other means to raise outdoor packages and unpackaged components off of the ground, and (5) packaging in noncombustible containers suitable for shipment. Unpackaged radioactive material may be stored outdoors if it is nondispersable and noncombustible, and if any removable contamination is within transportation limits. In lieu of packaging in a noncombustible container suitable for shipment, packages stored indoors may be in a noncombustible cabinet or device appropriate for the type, form, and quantity of radioactive material stored. In lieu of a non-combustible package cabinet, or device, radioactive material may be stored in an area with approved fire detection and suppression systems. An inventory, survey and tracking system will be used to assure that quantity limits are not exceeded, radiological postings are appropriate, and packaging is in good condition. These controls do not apply to radioactive material in transit, radioactive material exempted from licensing requirements under 10 CFR parts 30, 40, and 70, and radioactive material maintained under the provisions of an outside license.

s. An In-Plant Radiation Monitoring program ensures the capability to accurately determine the airborne iodine concentrations in vital areas under accident conditions. This program includes the following:

   1. Training of personnel,
   2. Procedures for monitoring, and
   3. Provisions for maintenance of sampling and analysis equipment.

12.3.2 Facilities and Equipment

12.3.2.1 Facilities

The Radiation Protection facilities include an access-control checkpoint, low background counting facilities room, instrument calibration room, offices, personnel decontamination area, change areas, and areas for the storage of protective clothing, respiratory equipment, air-sampling equipment, portable radiation instruments, personnel dosimeters, and special shielding.

The main access-control point is located at the entrance to the RCA. The control point consists of personnel monitors and friskers located at the doorway to the service building.

Personnel change areas, disposal/laundry bags, and stepoff pads are available for major work in contaminated areas. Stepoff pads and other supplies are available for other jobs as needed.

A clothing supply is available, and protective equipment and clothing requirements are contained in radiation work permits as applicable.

If contamination is found on the body or work clothing of an individual, clean protective clothing is available for transit to the personnel decontamination area. Personnel-monitoring friskers are also located at the main access-control point and at various locations throughout the plant.

The personnel decontamination area is equipped with a sink and shower for decontamination. The personnel decontamination area is equipped with a cabinet supplied with common decontamination supplies and chemicals. Decontamination is done under the supervision of Radiation Protection. Areas are also provided for minor medical treatment and first aid of contaminated personnel.

Protective clothing is worn in contaminated areas. These areas are well marked, and stepoff pads are installed at the entrances to prevent inadvertent entry into the areas. The objective of this is to keep exposure to radioactive material as limited as possible. In the event of an incident that contaminates large portions of the plant, personnel can don clothing at an access-control point.

The low background counting facilities contain various radiation-detecting instruments including the following:

a. Low background proportional detector with an automatic sample changer and associated electronics for gross alpha and/or beta measurements

b. Liquid scintillation counter for counting tritium and other beta emitters

c. High resolution gamma spectrometry system to identify and quantify gamma-emitting radionuclides.

The low radiation level chemistry laboratory is divided into four working peninsulas. Each peninsula is equipped with a fume hood; sink; counter with storage drawers; and electrical, air, vacuum, gas, and water service. An exhaust is also supplied for an emission spectrophotometer. Sufficient space is provided so that the laboratory equipment that is used on a routine basis can be left set up. Sample evaporation, and other processes which will release activity, or noxious fumes, are performed inside one of the fume hoods.

Samples may be prepared by evaporation, filtration, ion-exchange chromatography, or chemical separation. A standard source geometry is obtained that can be counted in the counting room or the spectrometer room.

The counting room, which can be entered from the low-level laboratory, contains a sink, fume hood, storage cabinets, and counter space on which to set the various radiation detecting instruments.

A Radiation Protection instrument calibration room is provided. Portable radiation survey instruments and air sampling equipment are normally calibrated in this area. Solid and liquid sources, which may be stored here, are also used to calibrate counting room instruments and plant radiation monitoring systems.

The calibration sources include high- and low-level sources. The high-range calibrator contains a mechanism to expose or shield the source. The room is equipped with an area radiation monitor with the radiation detector located near the high-range calibrator.

Visible warning lights are activated when the high-range calibrator is in use. The sources include high- and low-level gamma sources. The box calibrator contains a mechanism to raise or lower, or move the detector closer or farther to obtain the desired source-to-detector distance and thus the desired radiation level. Various jigs, designed to hold the portable instruments and dosimeters used at Fermi 2, are used to properly position the detector chamber in the calibrator.

A copy of the instrument calibration and repair record for each portable radiation detecting instrument is kept on file in accordance with Radiation Protection procedures.

The main Radiation Protection offices are located in the office service building. In-use survey records are normally stored in this office area. Permanent record storage is provided by Information & Procedures.

12.3.2.2 Equipment

12.3.2.2.1 Anticontamination Protective Clothing

Anticontamination clothing is worn in contaminated areas to prevent the contamination of personnel. It is removed at the exit from contaminated areas and placed in containers at the local job site to prevent the spread of contamination to other plant areas.

At the end of the job, or when the container is full, the container is monitored and transported to a storage area for laundry service.

Personnel are trained in the proper donning and removal of anti-contamination clothing as part of their radiation worker training. The selection of clothing for a specific job or area is determined by Radiation Protection on the basis of survey results and type of work. Clothing requirements are specified on the radiation work permit for the area or job.

Appropriate protective clothing is stocked at the plant.

12.3.2.2.2 Respiratory Equipment

Airborne contamination is minimized by keeping floor contamination level low, reducing leaks as much as possible, using local ventilation, and by using enclosures such as glove boxes. However, where airborne contamination levels exceed, or there is a potential for exceeding, values listed in Appendix B of 10 CFR 20, respiratory equipment may be worn to minimize personnel exposure.

The airborne contamination levels will be determined by the use of air samplers. The concentrations measured or expected will be used to select proper respiratory equipment.

A respiratory protection program has been developed which meets the requirements of 10 CFR 20. Personnel who will wear respiratory equipment are trained in the use of the equipment. Typical respiratory equipment used at Fermi 2 includes the following.

a. Air-purifying respirators

b. Supplied-air respirators

c. Self-contained breathing apparatus.

Emergency respiratory equipment for the operators is stored in the main control room.

12.3.2.2.3 Air Sampling Equipment

Air sampling may be performed using continuous air monitors (CAMs) and air samplers, which are described in Sections 11.4 and 12.2.4. The CAMs can be used to measure particulate, iodine, and gaseous activity. The air samplers are used to collect particulate and/or iodine samples for analyses in the counting facilities

12.3.2.2.4 Portable Radiation Instruments

A complement of portable instruments is available for use by Radiation Protection. Certain instruments are also available to other personnel who have been trained in self-monitoring techniques and have passed a written and/or oral examination. A variety of instruments have been selected to cover the entire spectrum of radiation measurements expected to be made at Fermi 2. Sufficient quantities of each type have been obtained to permit use, calibration, maintenance, and repair. These instruments are calibrated at least annually when in use. The calibration is normally performed in the Radiation Protection instrument calibration room.

12.3.2.2.5 Other Radiation Instruments

Portal monitors are used to check personnel for contamination. A monitor is located in the security area at the main exits from the plant.

Frisker stations are located near contaminated areas in the plant so that personnel leaving the area can monitor themselves for radioactive contamination, thus minimizing the spread of the contamination.

The gamma radiation levels in certain key areas are monitored by area radiation monitors (ARMs) which are discussed in Section 12.1. The ARMs locations, ranges, and alarm setpoints are described in Section 12.1.

12.3.2.2.6 Shielding

Temporary shielding in the form of concrete blocks, lead bricks, lead sheets, lead wool, water, or other material is provided where necessary to reduce personnel dose during operational and maintenance activities in radiation and high radiation areas. Each activity in these areas requires a specific evaluation of dose rates, job complexity (number of people and overall time required), available space, and time required to place and remove temporary shielding. For these reasons, the use of temporary shielding is determined on a case basis rather than at a specific dose-rate action level.

12.3.3 Operating Procedures

Administrative and technical procedures, in conjunction with facility design, are used to ensure that the exposures to personnel are kept ALARA.

Edison personnel will be trained in radiation protection as necessary, as stated in Section 13.2. To ensure compliance with Edison's policy of keeping exposures ALARA, Radiation Protection personnel have the authority to prevent unsafe practices and to halt any activity deemed radiologically unsafe. The Radiation Protection Manager has a direct line of communication with the Assistant Plant Manager regarding any activity or condition that is causing, or threatens to cause, a radiological incident or occurrence.

New procedures and procedure revisions that impact the Radiation Protection program are reviewed by Radiation Protection as a normal part of the plant procedure review/approval cycle. The Radiation Protection Section also participates in ALARA planning and review to identify administrative and operational methods by which dose can be reduced. Approved changes are promptly implemented. In addition, procedures for receiving and evaluating suggestions from employees relating to radiation protection and ALARA dose control have been established.

The following practices, which are described in written procedures, or training are followed:

a. Permanent shielding is used, when feasible. Dose may be reduced by having workers stay behind walls or in areas of lower radiation level when not actively involved in work in radiation areas. On some jobs temporary shielding, such as lead sheets draped over a pipe on either side of a valve, or concrete blocks stacked around a piece of equipment, is used to reduce dose. The use of temporary shielding will be considered if the total dose, which includes the dose to install and remove the shielding, is reduced.

b. Systems and major pieces of equipment that are subject to crud buildup, such as the radwaste system, the cleanup pumps, and the reactor water recirculation pumps, have been equipped with connections that are used for flushing. Prior to performing maintenance work, consideration will be given to flushing and/or chemically decontaminating the system or piece of equipment to reduce the crud levels, and thus reduce the dose received to complete the work

c. Work in high radiation or airborne radioactivity areas is planned and controlled by the use of a radiation work permit. The purpose of the planning is to carefully prepare for the job so that it can be expeditiously performed in a proper and safe manner with minimum exposure to personnel

d. On complex jobs or jobs with exceptionally high radiation levels, "dry runs" are made, and in some cases mockups are used, to familiarize the workers with the exact operations they must perform at the job site. These techniques assist in making the work go more smoothly and thus minimize the amount of time spent in the radiation field

e. As many work activities as reasonably achievable are performed outside radiation areas. Reading instruction manuals or maintenance procedures, adjusting tools or jigs, repairing valve internals, and prefabricating components are examples of activities that are performed outside radiation areas whenever feasible

f. For long-term repair jobs involving radiation exposure, consideration is given to setting up communications systems, such as sound-powered telephones or closed-circuit television, so that key personnel can check on the progress of work from a lower radiation area. In addition, both local and radio communication devices suitable for use with respirators are available

g. On some jobs, special tools or jigs are used when their use would permit the job to be performed more efficiently or would prevent errors, thus reducing the time in the radiation field. Special tools may also be used if their use would increase the distance from the source to the worker, thus reducing the exposure rate. These tools or jigs are used only if the total exposure, which includes that received during installation and removal, is reduced

h. Local access control for prolonged work in high radiation areas is set up in low radiation areas so that personnel do not receive unnecessary dose when not actually performing radiation work and because personnel may spend significant amounts of time changing protective clothing and respiratory equipment in these entry and exit areas. These entry and exit locations are set up to control the spread of contamination from the job site and, when feasible, to confine local contamination to a small area

i. Protective clothing and respiratory equipment specification takes the worker's comfort into consideration. This can increase efficiency and reduce the time spent in radiation areas

j. Local containments such as glove bags may be taped around valves or other fixed components during maintenance so that personnel will be less likely to be exposed to the contamination produced during the work

k. Radiation levels are posted for personnel to review, and when a wide range of radiation and contamination levels exists, high-radiation areas are identified. Individuals are instructed to avoid high radiation areas as much as possible, consistent with performing their assigned jobs, and to minimize time spent in areas where significant radiation and contamination levels exist

l. Personnel wear direct-reading or electronic dosimeters so that they can monitor their accumulated dose during the job. In addition, on certain jobs where the radiation fields may vary or cannot be clearly delineated to personnel, personnel may be provided with a personal electronic doserate device or dose-rate instrument. Personal electronic devices provide display and/or an audible alarm function. Thus, personnel will receive warning if they enter areas of high radiation, which would aid in minimizing time spent in these areas

m. On jobs with exceptionally high radiation levels, stay-time limitations are used to ensure that personnel are removed from an area before exceeding their allowable dose for the job being performed

n. On maintenance jobs involving high radiation levels, the job preplanning includes estimates of the man-rem needed to complete the job. At the completion of the job, a debriefing session is held involving people who actually performed the work to investigate lessons learned as to how the work could have been completed more efficiently, thus resulting in lower exposure. This information, together with the procedures used and actual man-rem expended, is maintained for future reference. The information recorded includes the radiation, contamination, and airborne activity levels determined during the work. Records of any external body contamination or internal contamination resulting from the job are maintained to provide guidance at the planning stage of future similar operations

o. High levels of contamination that may become airborne normally occur in areas controlled by Radiation Protection. Access control procedures, as described in plant procedures, help prevent inadvertent entry into contaminated areas. In addition, any areas that are airborne radioactivity areas will be posted. The sign will have instructions for personnel who must enter the area. A radiation work permit is also required for entry to posted airborne radioactivity areas

p. The airborne radioactivity level is determined in enclosed spaces prior to entry for maintenance or other special operations if there is potential airborne contamination. If airborne radioactivity levels are above control limits, reasonable measures will be taken to remove or control the source of this airborne radioactivity prior to commencing the job. If personnel entry is required into areas of known airborne radionuclide concentration where the source of airborne radioactivity cannot be removed or controlled below a threshold value, either occupancy will be limited and monitored or respiratory protection equipment use will be evaluated to maintain total effective dose equivalent ALARA. If entry into an area of unknown but potentially significant airborne radionuclide concentration is required, respiratory protection equipment may be required.

12.3.4 Personnel Dosimetry

12.3.4.1 External Dosimetry

All personnel who enter a radiologically controlled area are monitored with both primary and secondary dosimeters, except those members of the public who are designated as visitors by Plant Management. These visitors are escorted and are normally monitored only by a secondary dosimeter.

12.3.4.1.1 Dosimeters of Legal Record

Dosimeters of Legal Record (DLRs) are used as primary dosimeters to determine beta-gamma and neutron dose.

Area-monitoring DLRs are placed in or around normally occupied areas, including office areas, warehouses, and the visitor center to determine total exposure in these areas. These badges are normally exchanged quarterly.

12.3.4.1.2 Direct-Reading Dosimeters

The pocket dosimeter provides an immediately available indication of radiation dose and may be used as a secondary dosimeter. Direct-reading dosimeters are tested and calibrated at least annually, whenever new dosimeters are put into use, whenever the dosimeter has been damaged, and whenever a significant discrepancy exists between primary and secondary dosimetry. The testing of direct-reading dosimeters is performed in accordance with the provisions of Regulatory Guide 8.4.

The choice of range of direct-reading dosimeters to be used is specified by Radiation Protection. Direct-reading dosimeters of appropriate ranges are provided.

Dosimeter chargers are available for rezeroing the dosimeters.

12.3.4.1.3 Electronic Dosimeters

Electronic dosimeters, which provide an immediate indication of gamma radiation dose, may be used as secondary dosimeters. These dosimeters will give indication of failure conditions, e.g., low battery or detector failure.

12.3.4.1.4 Neutron Dosimetry

Neutron dose exposure is determined by the use of the normal primary dosimeter or by an estimation of dose based on survey results and time spent in the area.

12.3.4.1.5 Extremity and Special Dosimetry

Personnel assigned to work involving dose to the extremities significantly higher than dose to the whole body are issued finger rings, wrist badges, or other special dosimeters to determine the extremity dose.

Special dosimetry devices or additional DLRs may be issued when unusual conditions or nonuniform radiation fields exist. Personnel involved in high radiation work may also be assigned alarming dosimeters or audible rate-dependent dosimeters (chirpers) to help them minimize their time in local high radiation fields and thus minimize their exposure.

12.3.4.1.6 Abnormal Exposures

Abnormal personnel-monitoring results are immediately reported to Radiation Protection supervision who initiates an investigation to determine if the abnormal dose is valid and the related circumstances. The investigation is documented. Abnormal monitoring results include those that result from lost or damaged dosimeters as well as anomalies.

12.3.4.2 Internal Dosimetry

Internal dosimetry bioassay analysis is provided using both body counting (direct bioassay) and biological sample analysis (indirect bioassay) techniques.

Bioassay analysis will be used to assess the amount of radioactive material (if any) that has been taken up by plant personnel. Bioassay analysis will be performed whenever significant internal contamination is suspected. Additional bioassay analysis may be performed during periods of extensive maintenance activity, such as refueling, and as directed by Radiation Protection.

Radiochemical analysis of urine and/or feces may also be used to evaluate possible intakes of non-gamma-emitting radionuclides. Both urine and fecal sample kits will be available and will be issued to an individual as deemed necessary. These samples will be processed by a contracted service agency.

12.3.4.3 Processing and Recording

The official and permanent record of accumulated external radiation dose received by individuals will be obtained from the interpretation of DLRs and associated information.

Readout of DLRs will be performed quarterly or as deemed necessary. Daily dosimetry updating will be based upon direct reading or electronic dosimeter readouts. A record of each person's official dose as determined by the DLR will be maintained.

The personnel dose records will document the following:

a. Period and amount of occupational dose to sources of radiation external to the body from Fermi 2 licensed material

b. Documentation of external dose received during a period when monitoring devices were damaged or lost

c. Evaluation of exposure due to internal radiation dose, including bioassay analysis from Fermi 2 licensed material.

Each monitored radiation worker will be advised at least annually of the worker’s dose if it exceeds 100 mrem TEDE or 100 mrem to any organ, or if requested by the worker.

Additionally, radiation monitoring records, environmental monitoring records, instrument repair records, and calibration records provide supportive information regarding occupational dose data. Radiation Protection records are transferred periodically for permanent retention and filming or imaging.

12.3.5 Sealed Source Leak Testing

Licensed sealed sources with the potential for significant radiological impact, except sources that have been installed in the reactor or are inaccessible, are leak tested at least semiannually.

CHAPTER 13: CONDUCT OF OPERATIONS

This chapter describes the framework within which Fermi 2 will be operated. It summarizes the organizational structure, the training program, review and audit procedures, plant procedures, plant records, and industrial security.

13.1 ORGANIZATIONAL STRUCTURE

The DTE Electric Company (DTE) is providing the operational organization for operating Fermi 2. This chapter describes the DTE organization as it pertains to testing and operation of the plant.

DTE Energy is an investor-owned public utility, incorporated and engaged in the generation, transmission, and sale of electrical energy in the State of Michigan.

DTE has had considerable experience in designing, constructing, and operating fossil-fueled facilities for generating electricity. Normally, the design engineering effort and the construction management for such facilities have been performed by DTE personnel with the assistance of design and construction contractors. Such contractors are guided and directed in their work by the responsible divisions that report through the DTE Corporate Organization. The corporate functions, responsibilities, and authorities related to Fermi 2 are described in this section. Figures 13.1-1 through 13.1-4 show the Corporate Organization; the Nuclear Generation Organization; and the Executive Director – Nuclear Production's Organization, including the Operations organization.

NOTE: The titles of Plant Manager and Executive Director – Nuclear Production have the same functional responsibility.

NOTE: When a position is not filled, reporting order will be to the next higher position.

13.1.1 Corporate Organization

See Figure 13.1-1 for reporting relationship.

13.1.1.1 Not Used

13.1.1.2 President and Chief Executive Officer – DTE Energy

The President and Chief Executive Officer, DTE Energy is subject to the control of the Board of Directors. This individual has responsibility for the company's DTE Electric subsidiary and other DTE Energy subsidiaries.

13.1.1.3 Senior Vice President and Chief Nuclear Officer (CNO)

The Senior Vice President and Chief Nuclear Officer reports to the President and Chief Executive Officer, DTE Energy. This individual has responsibility for the overall administration of DTE nuclear power. The CNO is the ultimate management authority for establishing QA policy and responsibility for the Quality Assurance function. Reporting to the CNO are the Director – Nuclear Oversight, the Site Vice President – Nuclear Generation, Vice President – Engineering and Technical Support, Director – Strategic Business Operations, and the Nuclear Safety Review Group (NSRG) Chairman. The Senior Vice President and Chief Nuclear Officer is also responsible for the Employee Concerns Program.

13.1.1.3.1 Director – Nuclear Oversight

The Director – Nuclear Oversight is responsible for establishing a sustainable oversight model for Fermi. This includes responsibility for Quality Assurance. Reporting to the Director – Nuclear Oversight is the Manager – Nuclear Quality Assurance.

13.1.1.3.1.1 Manager – Nuclear Quality Assurance

The responsibilities of the Manager – Nuclear Quality Assurance are discussed in Section 17.2.

13.1.1.3.2 Corporate Support

Corporate Support groups provide several functions to DTE nuclear organizations such as Information Technology Services, Supply Chain, Human Resources, Business Performance, Facilities, Communications and Controller Services.

When corporate support groups perform quality-related activities for Fermi 2, such activities are performed under the Fermi 2 Quality Assurance Program.

13.1.1.3.3 Director – Strategic Business Operations

The Director – Strategic Business Operations is responsible for strategic planning and business support, including information and procedure management. The Director – Strategic Business Operations is also responsible for managing budgets for site projects and contracts providing services. In the absence of a Director, the role and responsibilities may be filled by a Manager – Strategic Business Operations.

13.1.1.4 Site Vice President - Nuclear Generation

The Site Vice President – Nuclear Generation reports to the Senior Vice President and Chief Nuclear Officer and also has access to the President and Chief Executive Officer, DTE

Energy for the reporting of nuclear safety problems. This individual has responsibility for the administration of the Fermi 2 plant, overall plant safety including operation, maintenance, modification, training, security, outage management, and the fire protection program, with the exception of engineering aspects of the program (see Section 13.1.1.5). Refer to section 13.1.2 for the detailed description of the Nuclear Generation Organization including those organizations reporting to the Site Vice President – Nuclear Generation.

13.1.1.5 Vice President – Engineering and Technical Support

The Vice President – Engineering and Technical Support reports to the Senior Vice President and Chief Nuclear Officer and also has access to the President and Chief Executive Officer, DTE Energy for the reporting of nuclear safety problems. This individual has responsibility for the administration of engineering, including engineering aspects of the fire protection program, and technical support organizations. Supply Chain has a functional relationship to the Vice President – Engineering and Technical Support. Refer to section 13.1.2 for the detailed description of the Nuclear Generation Organization, including those organizations reporting to the Vice President – Engineering and Technical Support.

13.1.2 Nuclear Generation

Nuclear Generation refers collectively to all organizations reporting to the Site Vice President - Nuclear Generation and the Vice President – Engineering and Technical Support. See Figure 13.1-2.

Reporting to the Site Vice President - Nuclear Generation are the Executive Director – Nuclear Production, Manager – Nuclear Security, Manager – Nuclear Performance Improvement, and Director – Nuclear Training.

Reporting to the Vice President – Engineering and Technical Support are the Director – Nuclear Engineering, the Director – Nuclear Technical Support – Project Management, and the Manager – Nuclear Licensing.

13.1.2.1 Director - Nuclear Training

The Director - Nuclear Training is responsible for developing and implementing training programs in support of safe and efficient operation of the plant. The training program is described in Section 13.2. The Director - Nuclear Training also provides the support for licensed operator medical issues.

13.1.2.2 Executive Director - Nuclear Production

NOTE: The positions of Executive Director – Nuclear Production and Assistant Plant Manager may be combined.

The Executive Director - Nuclear Production is responsible for the operation, maintenance, plant administration, and implementation of the fire protection program of Fermi 2. The Executive Director - Nuclear Production shall delegate in writing the succession to this responsibility during any absence.

Reporting to the Executive Director - Nuclear Production are the Assistant Plant Manager, Director – Nuclear Operations, the Director – Nuclear Maintenance, and the Director – Outage and Work Management.

Figures 13.1-3 and 13.1-4 are the organization charts for the sections reporting to the Executive Director - Nuclear Production; each classification in the figures represents a job position for one or more individuals. The functions, responsibilities, and authorities of plant personnel are described below.

13.1.2.2.1 Director – Nuclear Operations

The Operations Section is responsible for the operation of plant equipment and systems, and implementation of the fire protection program. The Director – Nuclear Operations is responsible for the activities of this section.

The Director – Nuclear Operations exercises overall managerial and supervisory responsibility for the startup testing and safe, reliable, and efficient operation of the plant and all associated equipment. It is the Director's responsibility to have a staff of trained and properly licensed personnel to accomplish the various plant responsibilities and to ensure that qualified personnel are available to fill the plant complement positions. Prior to operation, the Director – Nuclear Operations was responsible for the Fermi 2 startup and testing activities. The Operations Section is shown in Figure 13.1-4.

All operations, testing, or maintenance work must be approved either by the Director or by an assigned delegate, as established in procedures.

In the absence of the Director, the succession to the Director's responsibilities is documented in the form of organizational charts, functional descriptions, job descriptions for key personnel or in equivalent forms of documentation.

Reporting to the Director are the Operations Engineer and other support personnel as necessary. The Director – Nuclear Operations may also assume the functions and responsibilities of the Operations Engineer. When assuming these responsibilities, the Director – Nuclear Operations shall hold a senior reactor operator’s license.
The Operations Engineer is responsible for the overall operation of the plant equipment and systems. The Operations Engineer shall have a senior reactor operator's (SRO) license. As designated in procedures, the Operations Engineer or a delegate approves written work requests for equipment operation, maintenance, or tests. During the Operations Engineer's absence, a licensed SRO may be appointed to assume the duties and responsibilities of that position. Reporting to the Operations Engineer are the Shift Manager(s) and shift organization.

The Shift Manager(s) is responsible for and exercises supervisory control over the operating personnel on shift. The Shift Manager (or a designated individual during the Shift Manager’s absence from the control room) has control room command function. The Shift Manager is responsible for the overall operation of the plant during the absence of the Director – Nuclear

Operations, and the Operations Engineer. Each Shift Manager shall have an SRO license. Reporting to the Shift Manager is the Control Room Supervisor and Shift Technical Advisors.

The Control Room Supervisor assists the Shift Manager in duties as directed. Each Control Room Supervisor shall have an SRO license. Reporting to the Control Room Supervisor are the Licensed Nuclear Operators.

The Licensed Nuclear Operators manipulate the reactor controls and other controls and direct the activities of the Nuclear Operators. Normally, three Licensed Nuclear Operators are assigned to each operating shift. Each Licensed Nuclear Operator shall have a reactor operator's (RO) license.

The Nuclear Operators are responsible, under the direction of the Shift Manager, the Control Room Supervisor, or the Licensed Nuclear Operators, for operating auxiliary systems and for assisting in the refueling of the plant as directed. Among their regular duties are the operation of such plant equipment as pumps, turbine generator auxiliaries, blowers, radwaste systems, compressors, and auxiliary service equipment. Additional duties include radiation monitoring, recordkeeping, and general housekeeping.

Operations is responsible for implementing and coordinating the Fire Protection Program, including coordinating fire protection surveillances.

13.1.2.2.2 Director – Nuclear Maintenance

The Director – Nuclear Maintenance is responsible for the maintenance of the plant and all associated systems and equipment. Reporting to the Director – Nuclear Maintenance are Manager – Nuclear Maintenance and Manager – Nuclear Projects.

The Director – Nuclear Maintenance is responsible for the oversight of the Nuclear Maintenance and Nuclear Projects organizations. Duties for the Director – Nuclear Maintenance include strategic planning, strategic budget decisions for Capital and Operations and Maintenance (O&M) projects, and management of the accredited training program.

13.1.2.2.2.1 Manager – Nuclear Maintenance

The Manager – Nuclear Maintenance is responsible for the maintenance of the plant and all associated systems and equipment. Reporting to the Manager – Nuclear Maintenance are the Maintenance Superintendent(s).

The Manager – Nuclear Maintenance is responsible for the maintenance of plant structures, systems, and equipment. In this capacity, compliance with the Technical Specifications related to maintenance, written procedures, and work practices is ensured; and duties include the instrument spare parts, routine calibration, instrument and control troubleshooting, and the standards calibration program.

13.1.2.2.2.2 Manager – Nuclear Projects

The Manager – Nuclear Projects is responsible for oversite of the functional, schedule and budget performance for nuclear projects including all nuclear construction, security, engineering, and facility projects. Reporting to the Manager – Nuclear Projects is the Superintendent(s) – Nuclear Projects.

The Manger – Nuclear Projects provides leadership and oversight of personnel on all nuclear Capital and Operations and Maintenance projects. Supports the Director – Nuclear Maintenance with ensuring all work performed is in accordance with the applicable regulatory and operating license requirements, and the Nuclear Quality Assurance Program.

13.1.2.2.3 Assistant Plant Manager

NOTE: The positions of Executive Director – Nuclear Production and Assistant Plant Manager may be combined.

The Assistant Plant Manager is responsible for managing a portion of the Nuclear Production organization. The specific areas of responsibility are based on departmental performance and development needs. The Assistant Plant Manager is responsible for leading the managers of the following organizations/responsibility areas – Radiation Protection, Chemistry, Industrial Health and Safety, Human Performance and Medical Programs. Reporting to the Assistant Plant Manager are the Manager – Radiation Protection, Manager – Chemistry, and the Manager – Industrial Health and Safety. The Radiation Protection Manager reports directly to the Assistant Plant Manager regarding radiological control.

13.1.2.2.3.1 Manager - Radiation Protection

The Manager - Radiation Protection is responsible for the administration and supervision of the Radiation Protection Department. This department is responsible for radiological engineering, health physics, radiation protection, radiological effluents, ALARA programs, and radwaste (radwaste shipping, decontamination, and Onsite Storage Facility). Reporting to the Manager - Radiation Protection are the Radiation Protection Manager, and the General Supervisor – RP Technical Services and Support. The Manager may also assume the functions and responsibilities of the Radiation Protection Manager as described in subsection 13.1.2.2.3.1.1. In addition, the Manager may also assume the functions and responsibilities of the Manager – Chemistry as described in subsection 13.1.2.2.3.2.

The Manager - Radiation Protection assists the Fermi 1 Custodian. On the average, this activity will not require more than 100 work hours of effort each year.

13.1.2.2.3.1.1 Radiation Protection Manager

The Radiation Protection Manager, as described in NRC Regulatory Guides 1.8, 8.8 and 8.10, has the responsibility and authority to formulate and administer plant programs and procedures which ensure radiation protection for plant personnel, members of the public, and the environment. This position receives delegated authority from the Assistant Plant Manager in the area of radiological control, which includes radiation protection, radioactive effluents, radioactive waste transportation and disposal, and radiological health. The Radiation Protection Manager has direct access to the Site Vice President - Nuclear Generation to resolve questions related to the conduct of the radiation protection program. In the event the Radiation Protection Manager function is assigned to the Manager - Radiation Protection, an Assistant Radiation Protection Manager may be assigned to supervise the Radiation Protection Staff.

13.1.2.2.3.1.2 General Supervisor – RP Technical Services and Support

The General Supervisor – RP Technical Services and Support is responsible for maintaining the site within local, state, and federal environmental regulations, radiological health, radiological instrumentation matters, and reporting Fermi 2 compliance with established site procedures, company policies, and governing regulations.

13.1.2.2.3.2 Manager – Chemistry

The Manager – Chemistry is responsible for maintaining the chemical parameters of the plant within the requirements of the Technical Specifications; UFSAR; fuel warranty and industry guidelines. The Manager – Chemistry may also assume the functions and responsibilities of the Manager – Radiation Protection as described in subsection 13.1.2.2.3.1. The Manager – Chemistry evaluates results, reports, and laboratory techniques and is responsible for the following:

a. Overseeing the operation, maintenance, and calibration of, and providing technical support for, the plant chemical processing and water treatment equipment,
b. Directing the sampling of plant fluid systems, for the chemical laboratory, and for prescribing the procedures to be followed for sample preparation and analysis, and results reports.
c. Nonradiological environmental monitoring.

The functions and responsibilities of the Manager – Chemistry may be assumed by the Manager – Radiation Protection.

13.1.2.2.4 Director – Outage and Work Management

The Director – Outage and Work Management is responsible for the on-line work control, outage management, and reactor services at Fermi 2.

Reporting to the Director – Outage and Work Management are the Manager – On Line Work Management, Manager – Outage, and Manager – Reactor Services.

The functions, responsibilities, and authorities of these job positions are described below.

13.1.2.2.4.1 Manager – Online Work Management

NOTE: The positions of Manager – Online Work Management and Manager – Outage may be combined.

The Manager – Online Work Management is responsible for plant work management and planning services. Reporting to the Manager – Online Work Management are individuals responsible for assigning priority and planning, coordinating, and tracking all evaluation, design, and testing activities in support of plant operations. Also reporting to the Manager – Online Work Management are individuals responsible for reviewing and prioritizing all work requests, ensuring that work requests are completed as scheduled, and reviewing completed work requests. Also included are managing the 30-day, 7-day, and 48-hr schedules and coordinating near-term outage support.

Individuals reporting to the Manager – Online Work Management are also responsible for plant cost engineering, engineering planning, maintenance planning, developing work request packages, preparing management tracking reports, and for the day-to-day operation of the surveillance and performance scheduling and tracking.

13.1.2.2.4.2 Manager – Outage

NOTE: The positions of Manager – Online Work Management and Manager – Outage may be combined.

The Manager – Outage is responsible for outage management including outage programs and schedules, cost engineering, engineering planning, estimating plant modifications and generating outage reports. Reporting to the Manager – Outage are individuals responsible for developing and maintaining outage programs and schedules and assuming the lead role during outages. Also included is work scheduling and database input. Other support staff is responsible for the remainder of the Manager's outage responsibilities.

13.1.2.2.4.3 Manager – Reactor Services

The Manager – Reactor Services is responsible for all activities related to reactor vessel refueling and maintenance, and dry storage loading campaigns.

13.1.2.3 Director – Nuclear Technical Support – Project Management

The Director – Nuclear Technical Support – Project Management is responsible for the project management and engineering support functions of large nuclear related projects. Reporting to the Director – Nuclear Technical Support – Project Management is the Manager – Engineering Projects and Modifications.

13.1.2.3.1 Manager – Engineering Projects and Modifications

The Manager – Engineering Projects and Modifications may be delegated the responsibility for the project management of large plant modifications and engineering support functions associated with modifications of plant structures, systems and equipment. This responsibility includes the planning and management of the engineering scope and specifications, detailed design, procurement, installation and testing phases of the project. In this capacity, the Manager – Engineering Projects and Modifications has the responsibility and authority to utilize DTE personnel or retain qualified contract architects/engineers or consultants to implement the design development and control procedures under the jurisdiction of the Manager – Nuclear Design Engineering.

13.1.2.4 Director – Nuclear Engineering

The Director – Nuclear Engineering is responsible for design engineering, nuclear fuel design and management, strategic engineering, performance engineering, inservice inspection, modifications and configuration management, and procurement engineering. The Director – Nuclear Engineering is responsible for the formulation and effectiveness of the fire protection program. Reporting to the Director – Nuclear Engineering are Manager – Nuclear Design Engineering, Manager – Nuclear Strategic Engineering, Manager – Nuclear Performance Engineering, and Manager – Nuclear Tactical Engineering.

13.1.2.4.1 Manager – Nuclear Design Engineering

The Manager – Nuclear Design Engineering has the overall responsibility for the Fermi 2 plant configuration management program. The Manager – Nuclear Design Engineering is responsible for Engineering Projects and Modifications, and engineering support functions associated with modifications to plant structures, systems and equipment. This responsibility includes the planning and management of the engineering scope and specification, detailed design, procurement, installation and testing phases of the modification.

Within the context of Section 4.6.1 of ANSI N18.1-1971 (Selection and Training of Nuclear Power Plant Personnel), the Manager – Nuclear Design Engineering is equivalent to the "Engineer in Charge." In this capacity, the Manager – Nuclear Design Engineering has the responsibility and authority to assign DTE personnel or to retain qualified consultants to perform necessary design work, design reviews, incident evaluations, or safety analyses.

13.1.2.4.2 Manager – Nuclear Strategic Engineering

The Manager – Nuclear Strategic Engineering is responsible for the engineering functions related to the operation of the plant, including strategic engineering, preventive maintenance program, and technical and administrative procedures.

13.1.2.4.3 Manager – Nuclear Performance Engineering

The Manager – Nuclear Performance Engineering is responsible for the Inservice Inspection Program, equipment performance evaluation, equipment qualification program, fire protection program, and performance and inservice testing.

The Manager – Nuclear Performance Engineering is also responsible for nuclear fuel, including fuel cycle analysis, nuclear fuel accountability, uranium and enrichment accounting, core analysis, reactor dynamics, fuel design, fuel fabrication contract administration, fuel storage and shipment, fuel performance, and fuel burn-up.

The Manager – Nuclear Performance Engineering is also responsible for safe operating procedures as related to reactor core operating limits, fuel management, including maintaining records and specifying plant operations for maximum economic performance within the limits of the operating license, and procedures and documentation for fuel handling.

The Manager – Nuclear Performance Engineering is also responsible for all aspects of the Probabilistic Safety Assessment program including ownership and maintenance of the PSA model and the plant operating and plant shutdown risk assessment activities.

13.1.2.4.4 <u>Manager – Nuclear Tactical Engineering</u>

The Manager – Nuclear Tactical Engineering is responsible for Procurement Engineering and the Engineering Response Team.

13.1.2.5 <u>Other Managers in Figure 13.1-2</u>

13.1.2.5.1 <u>Manager - Nuclear Security</u>

The Manager - Nuclear Security is responsible for the physical security of DTE nuclear power plants and the facilities, material, equipment, and construction associated with them. The physical security responsibility includes developing and implementing the Physical Security Plan, the Safeguards Contingency Plan, the Security Personnel Training and Qualifications Plan, the Safeguards Information Protection Program, and security policy; conducting personnel screening for all personnel requiring unescorted access into the protected area; and implementing the access authorization and fitness for duty programs. The Manager - Nuclear Security also conducts investigations or initiates investigations of attempts to breach nuclear security, whether committed by a person employed at Fermi or a member of the public.

13.1.2.5.2 <u>Manager - Nuclear Performance Improvement</u>

The Manager – Nuclear Performance Improvement is responsible for administration of the plant Corrective Action Program, including trending and tracking of corrective action documents, administration of root cause analysis program and administration of operating experience, self-assessment and benchmarking programs.

13.1.2.5.3 <u>Manager - Nuclear Licensing</u>

The Manager - Nuclear Licensing is responsible for licensing activities, including regulatory and compliance support. The Manager - Nuclear Licensing provides the interface and communications with the NRC and other outside agencies, as assigned. The Manager – Radiological Emergency Response Preparedness as described in subsection 13.1.2.5.4 reports to the Manager – Nuclear Licensing.

13.1.2.5.4 <u>Manager – Radiological Emergency Response Preparedness</u>

The Manager – Radiological Emergency Response Preparedness is responsible for coordinating the activities of Emergency Planning.

13.1.2.6 Shift Crew Composition

NOTE: The titles Nuclear Shift Supervisor (NSS), Nuclear Assistant Shift Supervisor (NASS), and Nuclear Power Plant Operator (NPPO) have the same functional responsibilities as the titles Shift Manager (SM), Control Room Supervisor (CRS) and Nuclear Operator (NO), respectively.

During routine operations, the shift complement consists of one Shift Manager, one Control Room Supervisor, one Shift Technical Advisor/Operations Shift Engineer (OSE), three Licensed Nuclear Operators, five Nuclear Operators, and one Radiation Protection Technician. The Shift Manager, Control Room Supervisor, and Operations Shift Engineer must hold SRO licenses, and the Licensed Nuclear Operators must hold RO or SRO licenses. The Nuclear Operators are not licensed because they do not perform activities for which an RO license is required.

All core alterations shall be observed and directly supervised by either a licensed Senior Reactor Operator or licensed Senior Reactor Operator limited to fuel handling who has no other concurrent responsibilities during the operation. This is in addition to the normal Shift Crew Compliment during Mode 5.

The minimum crew composition of operators for normal routine operations consists of the following:

Position	Number of Personnel per shift	NRC License Requirements
Shift Manager (SM)	1	SRO
Control Room Supervisor (CRS)	1	SRO
Licensed Nuclear Operators (LNO)	3	RO or SRO
Nuclear Operators (NO)	5	None

The minimum shift crew requirements for the various modes is as follows:

Positions	Number of individuals required to fill position	
	Mode 1, 2 or 3	Mode 4 or 5
SM	1	1*
CRS	1	None
LNO	3	1
NO	5	1
STA/OSE	1	1

* Does not include the supervision of core alterations by the licensed SRO or the SRO limited to fuel handling.

Except for the Shift Manager, the shift crew composition may be one less than the minimum requirements for a period of time not to exceed 2 hours in order to accommodate unexpected absence of on-duty shift crew members provided immediate action is taken to restore the shift crew composition to within the minimum requirements. This provision does not permit any shift crew position to be unmanned upon shift change due to an oncoming shift crewman being late or absent.

The operating modes are the following:

Mode	Title	Reactor Mode Switch Position	Average Reactor Coolant Temperature (°F)
1	Power operation	Run	N/A
2	Startup	Refuel[a] or Startup/Hot Standby	N/A
3	Hot shutdown[a]	Shutdown	> 200
4	Cold shutdown[a]	Shutdown	≤ 200
5	Refueling[b]	Shutdown or Refuel	N/A

---

[a] All reactor vessel head closure bolts fully tensioned.

[b] One or more reactor vessel head closure bolts less than fully tensioned

The Shift Technical Advisors are required to have a Bachelor's Degree or equivalent in a scientific or engineering discipline from an accredited institution and 2 years of related nuclear experience. They complete an INPO-accredited Shift Technical Advisor training program. This program contains all of the SRO training materials and practical skills training that has been identified on a job task listing that is Fermi 2 specific. The Shift Technical Advisors are normally assigned to a shift and participate in the training cycle for licensed operator requalification.

The Operations Shift Engineers are required to meet the same qualifications as a Shift Technical Advisor and hold an SRO license.

The Operations Shift Engineer may be designated as the Control Room Supervisor on some shifts. This is in accordance with the NRC Policy Statement on Engineering Expertise on Shift (Reference 1).

The Shift Managers, Control Room Supervisors, Licensed Nuclear Operators, and Nuclear Operators are trained in the following areas of radiation protection:

a. Use of portable radiation detectors
b. Limits of exposure rates and accumulated doses
c. Use of protective barriers and signs
d. Use of protective clothing and breathing apparatus
e. Limiting contamination
f. Pertinent plant and federal regulations.

Shift chemistry technicians perform technical quantitative functions in chemistry, radiochemistry, and other areas. These technicians are qualified to meet the requirements of ANSI N18.1.

13.1.2.7 Qualification Requirements for Nuclear Plant Personnel

Regulatory Guide 1.8, Revision 1, September 1975, and ANSI N18.1 (1971) provide the regulatory criteria for the selection and training of Fermi 2 plant personnel. Regulatory Guide 1.8 endorses the criteria of ANSI N18.1 (1971), with the exception of the Radiation Protection Manager whose requirements are defined in the Regulatory Guide. Training and retraining for NRC-licensed operators is in compliance with 10 CFR 55.

For the purposes of complying with these requirements, the Technical Specifications, and 10 CFR 55, the following definitions apply to Fermi 2 personnel:

Plant Staff	All personnel reporting to the Site Vice President – Nuclear Generation or the Vice President – Engineering and Technical Support

Unit Staff	All personnel reporting to the Executive Director – Nuclear Production, including the Executive Director – Nuclear Production
Operations Staff	All personnel reporting to the Operations Engineer
Technical Staff	All personnel reporting to the Director - Nuclear Engineering

A Regulatory Qualifications List (RQL) is maintained and revised as required for changes in the regulatory requirements and plant staff personnel and titles. Using this list, qualified personnel can be selected for positions and the correct training and retraining programs can be maintained.
The qualification summaries, as required for plant staff affected by the RQL are maintained onsite and are available for review.

The resumes of the initial appointees to the managerial and supervising technical positions for Fermi 2 were included in the original FSAR.

13.1 ORGANIZATIONAL STRUCTURE

REFERENCES

1. U.S. Nuclear Regulatory Commission, Policy Statement on Engineering Expertise on Shift, Generic Letter 86-04, February 13, 1986.

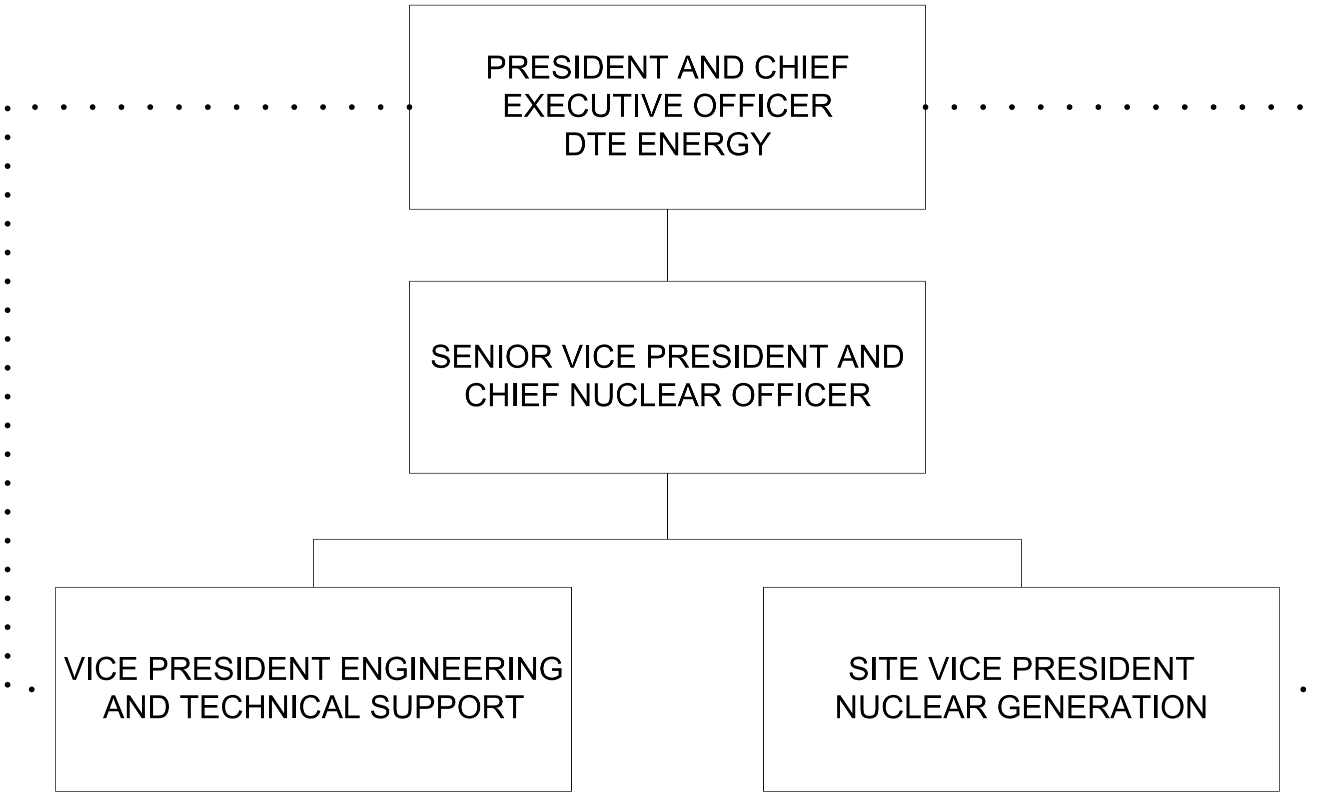

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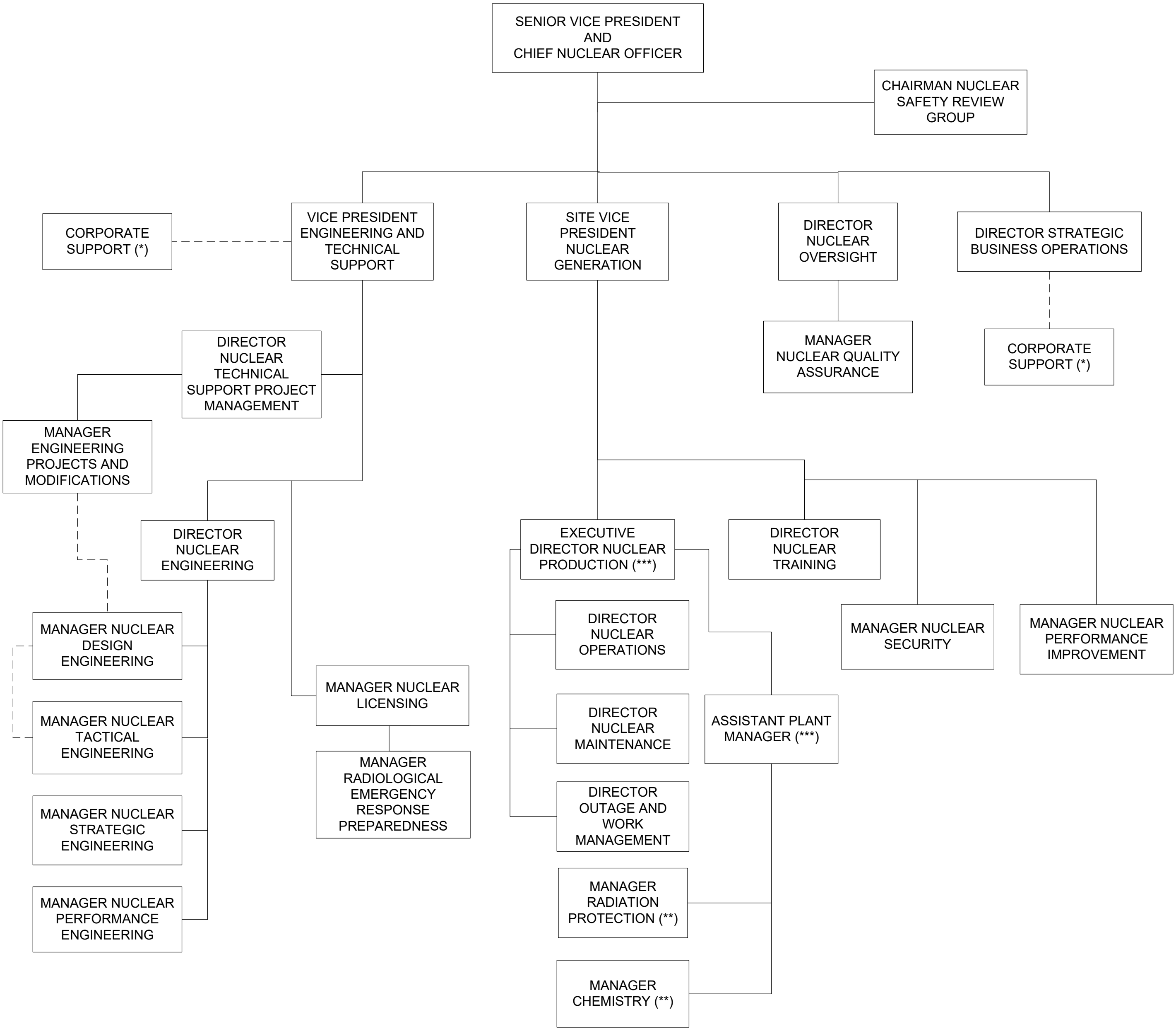
FIGURE 13.1-1

DTE ENERGY CORPORATE ORGANIZATION

FERMI 2 UFSAR



- - - - - - - Signifies Functional Relationship

(*) When corporate support organizations perform quality-related activities for Fermi 2, such activities are performed under the Fermi 2 Quality Assurance Program.

(**) Position of Manager – Chemistry may be combined with Manager – Radiation Protection.

(***) Executive Director Nuclear Production and Assistant Plant Manager positions may be combined.

NOTE: When a position is not filled, reporting order will be the next higher position.

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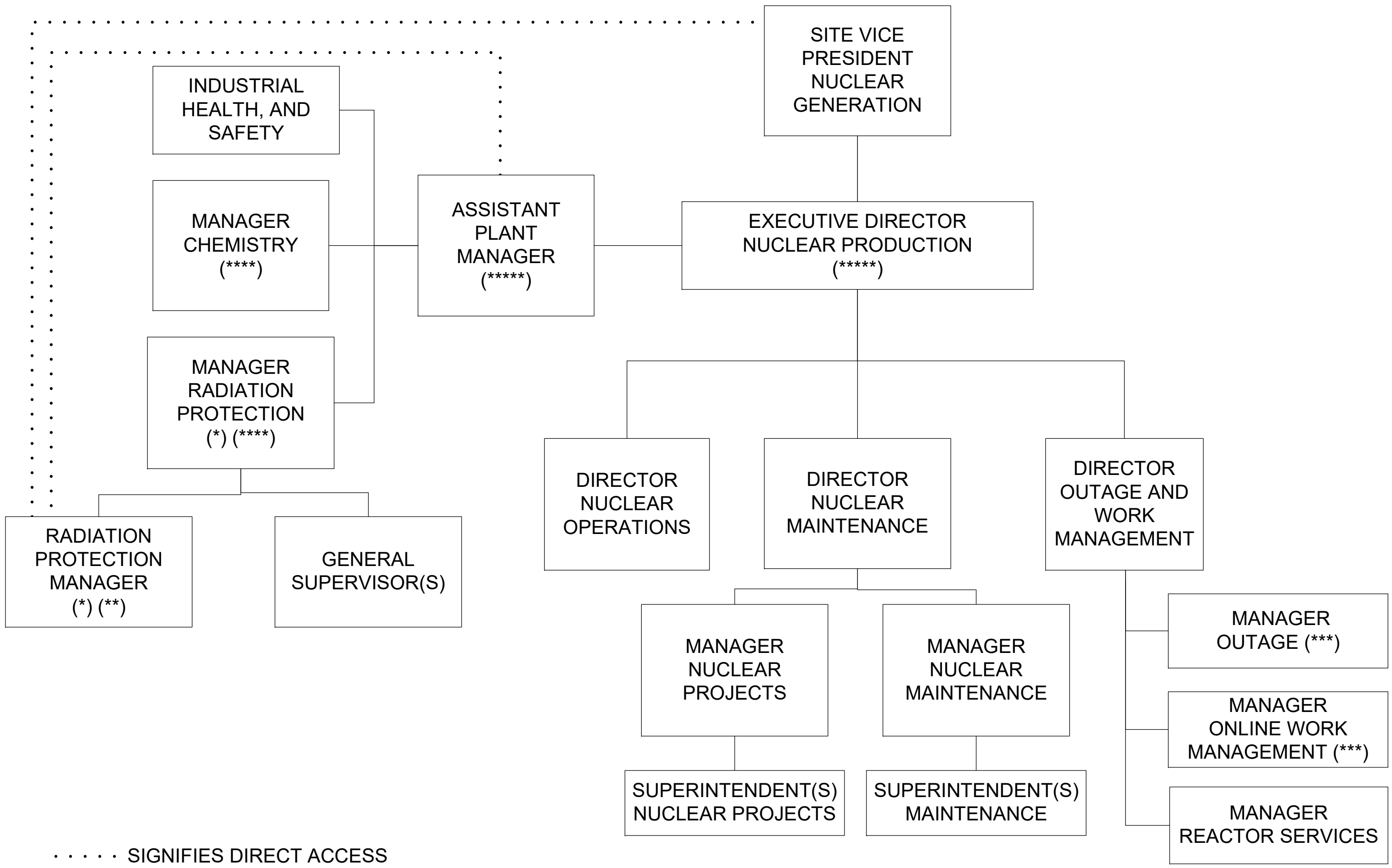
FIGURE 13.1-2
NUCLEAR GENERATION



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(*) MANAGER – RADIATION PROTECTION AND THE RADIATION PROTECTION MANAGER POSITIONS MAY BE COMBINED. SHOULD THIS OCCUR, AN ASSISTANT RADIATION PROTECTION MANAGER MAY BE ASSIGNED.

(**) THE RADIATION PROTECTION MANAGER HAS DIRECT ACCESS TO THE SITE VICE PRESIDENT – NUCLEAR GENERATION TO RESOLVE QUESTIONS RELATED TO THE CONDUCT OF THE RADIATION PROTECTION PROGRAM. THE RADIATION PROTECTION MANAGER REPORTS DIRECTLY TO THE ASSISTANT PLANT MANAGER REGARDING RADIOLOGICAL CONTROL.

(***) MANAGER – OUTAGE AND MANAGER – ONLINE WORK MANAGEMENT MAY BE COMBINED.

(****) MANAGER – RADIATION PROTECTION AND MANAGER – CHEMISTRY MAY BE COMBINED.

(*****) EXECUTIVE DIRECTOR NUCLEAR PRODUCTION AND ASSISTANT PLANT MANAGER MAY BE COMBINED.

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FIGURE 13.1-3
PLANT MANAGER'S ORGANIZATION

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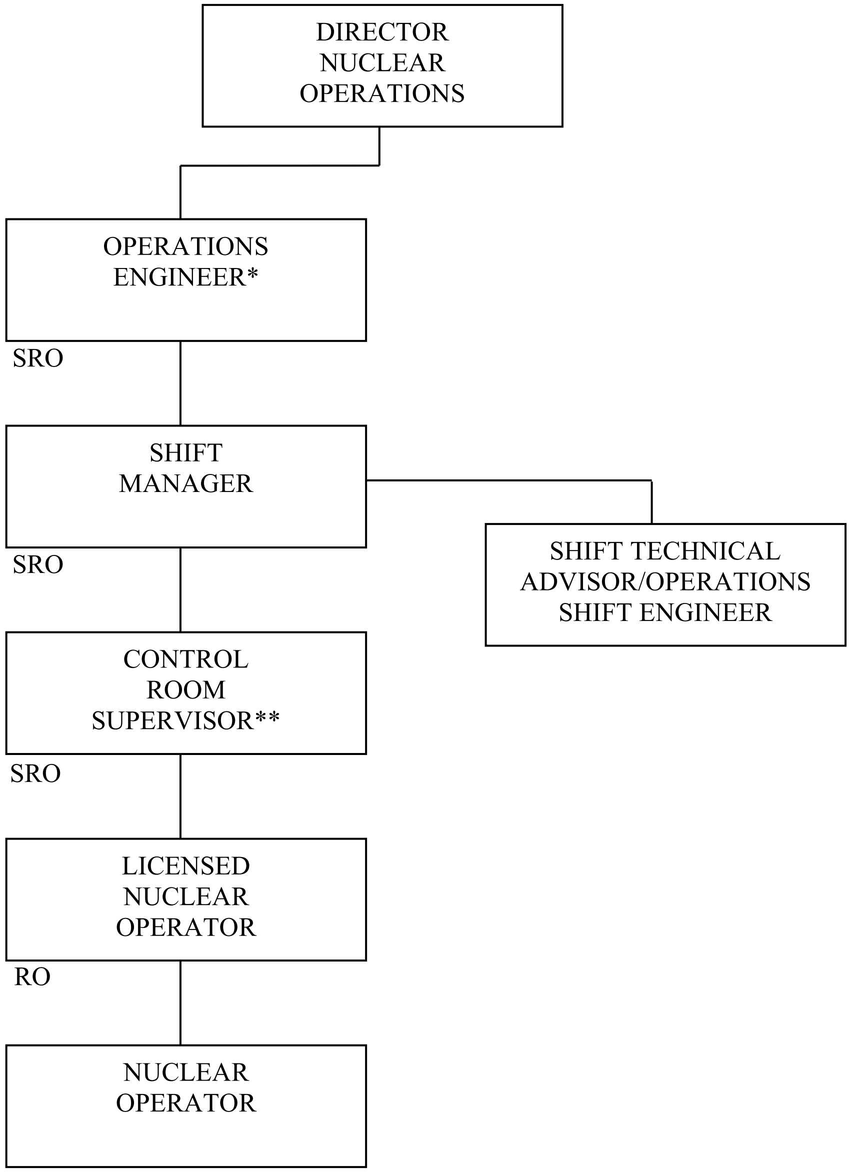


* DIRECTOR – NUCLEAR OPERATIONS AND OPERATIONS ENGINEER POSITION MAY BE COMBINED.

** CONTROL ROOM SUPERVISOR AND OPERATIONS SHIFT ENGINEER POSITION MAY BE COMBINED.

Fermi 2

UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 13.1-4

OPERATIONS ORGANIZATION

13.2 TRAINING PROGRAM

13.2.1 Program Description

13.2.1.1 General

The objective of the training program for Fermi 2 is to provide fully trained operating, maintenance, and technical personnel. To accomplish this objective, the nuclear training program for Fermi 2 has been designed, and is being implemented, to meet the needs of the individual staff members. Each person receives training on the basis of background, previous training, and staff assignment.

Training for the following positions is derived from a systems approach to training and satisfies 10 CFR 50.120 requirements:

a. Non-licensed Operator

b. Shift Manager

c. Shift Technical Advisor/Operations Shift Engineer

d. Instrument and Control Technician

e. Electrical Maintenance Personnel

f. Mechanical Maintenance Personnel

g. Radiological Protection Technician

h. Chemistry Technician

i. Engineering Support Personnel

The overall training program for the plant staff is divided into the following four areas:

a. Training programs for reactor operator and senior reactor operator license candidates, as described in Subsection 13.2.1.2

b. Training programs for nonlicensed personnel, as described in Subsection 13.2.1.3

c. General employee training (Fermi 2 orientation), as described in Subsection 13.2.1.4

d. Fire-protection training, as described in Subsection 13.2.4.

The Director - Nuclear Training has overall responsibility for the training program and is also in charge of simulator activities and simulator training.

13.2.1.2 Training Program for Operator License Candidates

The training program for operator license candidates has been implemented in accordance with 10 CFR 55. The licensed operator training program was initially accredited by the Institute of Nuclear Power Operations (INPO) on December 18, 1985. This training program was developed using a systems approach to training.

13.2.1.3 Training Programs for Nonlicensed Personnel

13.2.1.3.1 General

Training suited to individual needs and backgrounds is given to nonlicensed personnel, such as supervisors, engineers, operators, technicians, and repairmen. Each course is described in more detail in the sections that follow. In all cases, various sections of the training for nonlicensed personnel may be omitted for those who have applicable experience.

13.2.1.3.2 Training of Chemistry Personnel

Selected chemical or chemical engineering personnel obtain specialized training presented by qualified personnel. In classroom and laboratory sessions, students receive instruction and practical experience that enable them to complete both radiochemical and chemical analyses for process control, waste disposal, effluent monitoring, and process and laboratory instrument calibrations and evaluations. The course work also covers material on interpreting and complying with the chemical and radiochemical aspects of the Technical Specifications, procedures, licenses, and plant warranties.

13.2.1.3.3 Training of Instrumentation and Control Personnel

Training for instrumentation and control personnel is divided into two portions: (1) classroom and (2) practical exercises. Classroom courses include instrumentation theory, procedures, and plant specific systems training. During the practical exercises portion, the trainee receives specific hands-on training that is most beneficial to his/her position on the staff. In addition, personnel will demonstrate the ability to use plant and maintenance administrative procedures.

13.2.1.3.4 Training for Mechanical and Electrical Maintenance Personnel

Mechanical and electrical journeymen for the plant are selected from other DTE facilities or from outside the company and have a minimum of 3 years of experience in one or more crafts. Their dexterity and ability in the basic skills of mechanical and electrical maintenance repair are shown by their previous experience.

As needed, personnel receive training in those skills required for the performance of work in radiological areas, the use of respiratory protection equipment, the use and/or maintenance of specific equipment, plant systems, and general employee training. In addition, personnel will demonstrate the ability to use plant and maintenance administrative procedures.

13.2.1.3.5 Training for Shift Technical Advisors

Training for shift technical advisors is designed to provide the knowledge to effectively perform assigned duties. Included is theoretical training in the sciences related to nuclear power plant operations and practical training in the design and procedures used at Fermi 2. In addition, simulator training is used to develop experience in transient responses.

13.2.1.3.6 Training for Radiation Protection Personnel

The Radiation Protection Technician Program provides training and qualification in the duty areas of dosimetry, instrument calibration, effluent monitoring, and radiation protection operations. Trainees receive training as needed in general employee training, position-required training, and continuing training. Personnel will also demonstrate the use of plant and/or Radiation Protection administrative procedures, as applicable.

13.2.1.3.7 Training for Quality Assurance Personnel

Quality assurance personnel must be certified in accordance with the applicable codes, regulations, and standards for the positions they hold.

As needed, personnel receive training in those skills required for the performance of work in radiological areas, the use of respiratory protection equipment, the use and/or maintenance of specific equipment, plant systems, and general employee training. In addition, personnel will demonstrate the ability to use plant and quality assurance administrative procedures.

13.2.1.3.8 Training for Nonlicensed Operators

The training program for nonlicensed operators provides the necessary knowledge and skills for the operators to perform their jobs. Included in the program are systems training course(s) and area qualifications. This training facilitates ensuring the reliability of plant systems and equipment. The training program consists of two phases as described below.

System Training. System training increases the nonlicensed operator's knowledge of the function and operation of plant systems. It ensures the safety and reliability of plant operation as a result of the integrated activities performed by licensed and nonlicensed operators. The objective of system training, which is provided in addition to area qualifications, is to give the non-licensed operator a concept of the overall operation of the system, the purpose of systems, the interrelationships of systems, and the operator's responsibilities relative to each system. Emphasis is placed on systems that can affect the safe operation or the safe shutdown of the plant. System training uses examinations to verify qualifications in each system. Examinations are used for requalification purposes to ensure that an optimum level of proficiency is maintained by the nonlicensed operator.

Area Qualifications. Checklists are developed and established by plant area and by job classification to familiarize the operators with the specific job tasks expected to be performed as part of the normal shift functions. Area qualifications are based on the following plant areas:

a. Turbine building

b. Reactor building

c. Radwaste building

d. Outside areas, consisting of:

    1. Residual heat removal building

    2. General service water and circulating water pump houses

3. Auxiliary boiler house
4. 120 KV and 345 KV switchyards

Satisfactory completion of each checklist item by each operator is documented by a fully qualified nuclear operator, a licensed nuclear operator, a control room supervisor, or a shift manager. Final completion of each area qualification checklist is approved by the Operations Engineer or his/her designee.

13.2.1.3.9 Training for Engineer Support Personnel

Technical personnel receive training to improve their overall knowledge of Fermi 2. This includes fundamental science topics, plant systems, and plant operations. They also receive general employee training. As needed, engineer support personal receive training on job-specific tasks and demonstrate a knowledge of organization specific procedures.

13.2.1.4 General Employee Training

13.2.1.4.1 Permanent Plant Personnel Training

All DTE employees permanently assigned (those assigned on a day-to-day basis) to the plant are trained as necessary in the following areas.

a. Appropriate plans and procedures, including plant procedures for security, radiological emergency, and reporting fires
b. Radiological health and safety, including applicable portions of 10 CFR 19 and 10 CFR 20
c. Industrial safety
d. Use of protective clothing and equipment
e. Quality assurance
f. Evacuation signals and routes
g. Fitness for duty

13.2.1.4.2 Temporary Plant Personnel Training

Temporary maintenance and service personnel (those who are not assigned to the plant on a day-to-day basis) are trained in the areas listed in Subsection 13.2.1.4.1 to the extent necessary to ensure the safe execution of their duties, or they are escorted by properly trained personnel as required.

13.2.1.4.3 Consultant, Vendor, and Contract Personnel

Consultant, vendor, and contract personnel who are required to perform duties at the plant receive indoctrination training in the areas listed in Subsection 13.2.1.4.1 to the extent necessary for the safe execution of their normal duties, or they are escorted by properly trained personnel as required.

13.2.1.4.4 Deleted

13.2.1.5 Responsible Individual

The Site Vice President - Nuclear Generation is responsible for ensuring that all plant staff members are trained appropriately to do their jobs. Authority is delegated to the individual managers of Nuclear Generation, who are responsible for specifically defining training requirements and for ensuring that their personnel have been trained according to said requirements.

The Director - Nuclear Training is responsible for administering, designing, developing, and implementing all training that has been determined to be required by the Site Vice President - Nuclear Generation or his/her delegate.

13.2.2 Retraining Program

A continuing requalification program for licensed operators and senior operators has been implemented in accordance with 10 CFR 55. The licensed operator requalification program was initially accredited by the Institute of Nuclear Power Operations (INPO) on December 18, 1985. This requalification program was developed using a systems approach to training.

13.2.3 Replacement Training

The purpose of the plant replacement training program is to ensure that replacement personnel satisfy the training requirements stipulated in ANSI N18.1-1971 for the various plant positions.

13.2.3.1 Licensed Personnel Replacement

Personnel selected to be in training for a reactor operator's or senior reactor operator's license are given formal technical training and practical on-the-job training. Subsection 13.2.1.2 identifies replacement training requirements.

13.2.3.2 Nonlicensed Personnel Replacement

Personnel filling positions not requiring an NRC reactor operator's or senior reactor operator's license receive training as outlined in Subsection 13.2.1.3.8.

13.2.3.3 Program Administration

The program is administered as described in Subsection 13.2.1.5.

13.2.4 Fire-Protection Training

13.2.4.1 Fire Brigade Training

13.2.4.1.1 General

The fire brigade (five 5-member teams) is trained in accordance with the NRC staff supplemental guidance, "Nuclear Plant Fire Protection Functional Responsibilities, Administrative Controls and Quality Assurance," dated August 29, 1977. Fire brigade members will receive instruction in the following topics:

a. Identification of the fire hazards and associated types of fires that could occur in the plant and an identification of the location of the hazards, including areas where breathing apparatuses are required, regardless of the size of the fire

b. Identification of the location of installed and portable fire-fighting equipment in each area and familiarization with plant layout, including access and egress routes to each area

c. Proper use of available equipment and the correct method of fighting each type of fire (electrical fires, fires in cables and cable trays, hydrogen fires, flammable liquids, waste debris fires, and record file fires)

d. Indoctrination in the plant fire-fighting plan, with coverage of each employee's responsibilities, including changes thereto

e. Proper use of breathing equipment, and communication, lighting, and ventilation equipment

f. Detailed review of the procedures, with particular emphasis on what equipment must be used in particular areas

g. Review of the latest modifications, additions, or changes to the plant, procedures, fire-fighting equipment, and the fire-fighting plan

h. Proper method of fighting fires inside buildings and tunnels.

Special instruction in directing and coordinating fire-fighting activities will be provided for fire brigade leaders.

Qualified personnel, experienced in fighting the types of fires that could occur in the plant and in using the types of equipment available in the plant, provide the instruction. Classroom training is repeated at a frequency of at least every 2 years.

13.2.4.1.2 Practice Sessions

Practice sessions are held at regular intervals not to exceed 1 year (Subsection 13.2.4.1.4). These sessions are held at a location sufficiently remote from the plant so as not to endanger safety-related equipment. These sessions provide practice in extinguishing actual fires and are conducted by DTE or other qualified personnel.

Practice sessions are also conducted that require fire brigade members to use protective equipment, including emergency breathing apparatus. These sessions need not include fire fighting. They are provided at regular intervals not to exceed 1 year (Subsection 13.2.4.1.4).

13.2.4.1.3 Fire Drills

Fire brigade drills are performed at the plant so that the fire brigade can practice as a team. Drills include the following.

a. The simulated use of equipment for the various situations and types of fires that could reasonably occur in each safety-related area

b. Conformance, where possible, to the established plant fire-fighting plans

c. Operating fire-fighting equipment where practical; this also includes self-contained breathing apparatus, communication equipment, and portable or installed ventilation equipment, when applicable.

The drills are performed at regular intervals not to exceed 90 days, with a grace period of 25 percent, for each fire brigade. The minimum number of fire brigade drills conducted within a period shall be equal to the number of operating shifts at the station. At least one drill per year will be performed on a backshift for each brigade. At least one drill per year for each fire brigade will be unannounced.

The drills are preplanned, evaluated, and critiqued to assess the effectiveness, the response time, the selection, the placement, and the use of equipment. An assessment is also made of the leaders' direction of the effort and each member's response.

At 3-year intervals, a randomly selected unannounced drill must be critiqued by qualified individuals independent of the Fermi 2 staff.

13.2.4.1.4 Periodicity of Fire Brigade Training

All training shall be performed within the time interval specified with

a. A maximum allowable extension not to exceed 25 percent of the training interval, but

b. The combined time interval for three consecutive training intervals shall not exceed 3.25 times the specified training interval.

13.2.4.1.5 Periodicity of Fire Drills Including the Offsite Fire Department

Periodically (once per calendar year) these drills will include offsite fire department personnel and will conform with the Fermi 2 plan for coordination with offsite fire departments.

13.2.4.1.6 Offsite Fire Departments

Training for the offsite fire departments is made available and includes training in basic radiation principles and practices, typical radiation hazards that may be encountered when fighting fires, and related plant procedures.

13.3 EMERGENCY PLANNING

Information for this section is contained in the Fermi 2 Radiological Emergency Response Preparedness Plan, submitted separately to the NRC on the Fermi 2 docket. This plan is periodically updated and current revisions are submitted to the NRC.

13.4 REVIEW AND AUDIT

13.4.1 General

During the construction of Fermi 2, the Edison quality assurance (QA) review and audit program complied with and exceeded the requirements of 10 CFR 50, Appendix B, QA Criteria for Nuclear Power Plants. The review and audit functions that Edison performed during construction are briefly addressed in Subsection 13.4.2 and more completely described in Section 17.1.

DTE uses a formal committee method to review testing and operation at Fermi 2. The review functions are carried out at two levels: one at the plant operations level and the second at the corporate level. The organizations responsible for reviews at these two levels are the Onsite Review Organization (OSRO) and the Nuclear Safety Review Group (NSRG), respectively. The OSRO reviews plant operations, administrative procedures that could affect nuclear safety, and tests and plans for future activities to assist and advise the Executive Director - Nuclear Production on the safe operation of the plant. The NSRG functions to provide an independent review of plant activities and reports to and advises the Senior Vice President and Chief Nuclear Officer as described in Subsection 13.4.3.2. In developing the essential elements of DTE's review program for tests and operations, which is discussed more fully in Subsection 13.4.3, DTE was guided by ANSI N18.7-1976, Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants.

13.4.2 Review and Audit - Construction

Reviews and audits during the construction of Fermi 2 were part of the QA program described in Section 17.1. This program used a designated organizational unit to provide review and audit, the Project Management Organization, which met at least monthly for a review of construction work in progress. The Assistant Project Manager - Engineering was specifically assigned responsibility for design review. The Edison administrative and technical staffs reviewed design documentation (e.g., specifications, drawings, and design changes) for compliance with applicable codes, standards, good engineering practice, and overall design intent. Quality assurance for the project was the responsibility of the Director-Project Quality Assurance, who reported functionally to the Manager - Enrico Fermi 2 Project and administratively to the Manager - Quality Assurance. Quality Assurance performed vendor surveillance and review by witnessing significant check-points and overall vendor performance. Edison QA also systematically audited activities at the plant site to ensure that the required standards of quality were attained in all construction and installation work performed at the job site. These owner activities complied with the requirements of 10 CFR 50, Appendix B. The review and audit functions during the construction phase are more fully described in Section 17.1.

13.4.3 Review - Test and Operation

A review program has been established to ensure that the operation of the plant is in conformance with established requirements. Independent reviews by the Nuclear Safety

Review Group (NSRG) and reviews by the Onsite Review Organization (OSRO) are described in detail in Subsection 17.2.1.7.

13.4.3.1 Administration of the Onsite Review Organization

The OSRO is responsible for advising the Executive Director – Nuclear Production on all matters related to nuclear safety.

Onsite Review Organization membership, meeting frequency, meeting minutes, and subjects requiring OSRO review are described in Section 17.2 and covered in a written charter.

Procedure - The chairman of the OSRO has the authority to approve or disapprove proposals by the OSRO for nuclear-related matters that do not have safety implications. The OSRO Chairman, or designated alternate, may make a temporary change or authorize interim remedial action involving matters related to nuclear safety, as deemed necessary, provided the intent of the operating license or the Technical Specifications is not altered and the provisions of Subsection 13.5.2 are met.

In the review process, the item for review by the OSRO is placed on the agenda by the staff member initiating the item, who has seen that all necessary preliminary actions, such as the design review, and all necessary 10 CFR 50.59 reviews have been completed. The OSRO considers the item and votes approval or disapproval. The action taken by the OSRO is recorded in the minutes of the meeting. Should the proposed change require a license amendment prior to implementation, it is then forwarded to the NSRG for review, together with a report from the OSRO giving the basis for the findings.

Subjects that require the use of special technical skills may be handled by a subcommittee or task force composed of specialists in that field. When necessary, consultants are obtained to assist the subcommittee or task force in its deliberation. The members of the subcommittee or task force and the consultants are appointed by the OSRO Chairman.

13.4.3.2 Administration of the Nuclear Safety Review Group

The purpose of the NSRG is to provide independent review of facility operations as specified in Section 17.2. The NSRG reports to the Senior Vice President and Chief Nuclear Officer and acts for him in the review of the safety aspects of nuclear power plant operation.

Details concerning the membership requirements, areas of expertise, quorum requirements, review responsibilities and other administrative functions of the NSRG are given in Section 17.2.

13.4.3.3 Review of Operating Experience

Internal and external operating experience is reviewed and assessed to ensure that information pertinent to plant safety is supplied continually to operators and other appropriate personnel and is used for effecting design and procedural changes to correct generic or specific deficiencies and to enhance plant safety when warranted.

The review of externally generated operating experience shall be coordinated primarily by individuals in Nuclear Performance Improvement and Nuclear Design Engineering. These reviews include, but are not limited to, GE nuclear steam supply system (NSSS) reports;

INPO Significant Event Evaluation Information Network (SEEIN) reports such as SOERs and SERs, and NRC Bulletins, and Generic Letters.

The operating experience that is considered as warranting further evaluation is evaluated through the Corrective Action Program. The conclusions and recommendations are reviewed and documented. Recommendations, hardware and software modifications, procedures revisions, design changes, etc., resulting from the reviews are then implemented by the responsible groups within Nuclear Generation. Procedural changes are reviewed and approved by OSRO as applicable.

The Executive Director – Nuclear Production is responsible for ensuring that evaluations are performed for internally generated operating experience events. LERs are reviewed by OSRO and are distributed to appropriate groups for implementation or for information and to the NRC.

13.5 PROCEDURES

13.5.1 General

All safety-related operations at Fermi 2 are conducted in accordance with detailed written procedures. These procedures include the topics specified by Regulatory Guide 1.33 for compliance with the quality assurance (QA) requirements of 10 CFR 50, Appendix B and the applicable procedures required to implement the Fermi 2 commitments made in response to requirements of NUREG-0737. The procedures are implemented following the guidance provided in ANSI N18.7. The procedures related to nuclear safety are reviewed and approved prior to the initial use and periodically thereafter as described in Section 17.2.

The types of procedures used include the following:

a. Administrative Procedures

b. Technical Procedures, including:

    1. Operating Procedures
    2. Maintenance Procedures
    3. Reactor Engineering Procedures
    4. Radiation Protection
    5. Radiochemistry Procedures
    6. Fuel-Handling and Special Nuclear Materials Control and Accountability Procedures
    7. Fire Protection Implementing Procedures
    8. Radioactive-Materials-Handling Radwaste Procedures
    9. Environmental Procedures.
    10. Maintenance, Calibration, and Testing Procedures
    11. Surveillance Procedures

c. Radiological Emergency Response Preparedness Plan Procedures

d. Security Plan Procedures

Contract personnel were used to prepare the initial Fermi 2 procedures. Available plant personnel assisted with this work when training and preoperational testing workload permitted. The ultimate responsibility for the content and accuracy of the final operation procedures and any updating that becomes necessary is as shown below for the various documents. The Director – Strategic Business Operations is responsible for the distribution and upkeep of procedures.

The format varies with the different procedures, but each procedure generally contains the following.

a. Purpose

b. References

c. Description of the equipment involved

d. Prerequisites

e. Safety precautions

f. Valve status and checkoff

g. Step-by-step actions

h. Normal reactions

i. Monitoring requirements

j. Emergency actions or hold instructions.

A complete list of titles of all procedures is included in a procedure control system.

13.5.2 Temporary Changes

A temporary change to a procedure may be made provided that

a. The intent or format of the original procedure is not altered

b. The change is approved by two members of the plant management staff, at least one of whom holds a senior reactor operator's license

c. The change is documented, reviewed by the OSRO when required, and approved by the Executive Director – Nuclear Production or delegate within 14 days of implementation.

13.5.3 Conduct Manuals (Administrative Procedures)

The conduct manuals establish rules and instructions pertaining to the following:

a. Procedure adherence

b. Plant responsibilities and authorities

c. Review and audit programs

d. Reports and records

e. Equipment control and work permit procedures

f. Procurement and warehousing

g. Surveillance program

h. Plant security and visitor control

i. Standing or special orders (plant orders)

j. Radiation control standards procedures

k. Chemical-radiochemical procedures.

l. Shift and relief turnover procedure

Administrative Procedures are prepared under the direction of the appropriate director, or manager, who has the responsibility for their content and implementation. These procedures apply to all site activities and to all personnel at the site.

The procedure for shift and relief turnover consists in part of a checklist that is completed and signed by the oncoming and off-going Shift Managers and control room licensed nuclear operators.

The shift relief checklist is maintained in the control room by the control room operators.

13.5.4 Technical Procedures

Technical procedures shall be used to provide step-by-step sequences for performing technical work activities. The following subsections describe various types of technical procedures used at Fermi 2.

13.5.4.1 Operating Procedures

The preparation of the Operating Procedures is under the direction of the Director – Nuclear Operations. The implementation of these procedures mainly falls to the operating group and is performed under the direction of a licensed senior reactor operator or reactor operator. Procedures that are prepared include, but are not limited to, those in Regulatory Guide 1.33, Appendix A.

13.5.4.1.1 General Operating Procedures

The General Operating Procedures provide the necessary instructions for the integrated operation of all plant systems. Sign-offs are provided to ensure that necessary operating instructions, tests, and calibrations have been completed and are also used for confirming the completion of major steps in the proper sequence. General Operating Procedures are prepared under the direction of the Director – Nuclear Operations and implemented by Operations personnel.

13.5.4.1.2 System Operating Procedures

System Operating Procedures provide the necessary sequence of steps to properly operate a particular system, including the following, as necessary:

a. Normal operation

b. Startup operation

c. Shutdown operation

d. Standby operation

e. Automatic initiation

f. Manual initiation.

13.5.4.1.3 Alarm Response Procedures

Alarm Response Procedures provide guidance on actions to be taken by the control room operator when the alarm annunciators actuate. Each procedure contains the following:

a. The title of the annunciator

b. The actuating device

c. The setpoint(s) of the actuating device

d. The possible causes of the actuation

e. The immediate action to be taken by the operator and those actions which occur automatically

f. The subsequent action to be taken to return the system to its normal mode of operation, if necessary.

13.5.4.1.4 Abnormal Operating Procedures

Abnormal Operating Procedures provide operator guidance for stabilizing the plant or for restoring normal operating conditions following a perturbation.

13.5.4.1.5 Emergency Operating Procedures

Emergency Operating Procedures provide operator guidance to mitigate, reduce, or eliminate the consequence of an accident or potentially hazardous condition that has already occurred, to implement the emergency plan, or to prepare for possible hazardous natural occurrences.

13.5.4.2 Maintenance Procedures

Maintenance activities that affect the performance of safety- related equipment are preplanned and performed in accordance with written procedures, documented instructions, and drawings appropriate to the activity. Procedures for performing various categories of maintenance are prepared following the guidelines contained in Regulatory Guide 1.33, Appendix A. The Manager – Nuclear Maintenance is responsible for these procedures. Maintenance receives permission from the Shift Manager before performing maintenance on plant equipment. This ensures that the operability of redundant safety-related systems is maintained as required by the Technical Specifications.

13.5.4.3 Maintenance, Calibration, and Testing Procedures

Technical Procedures include the procedures necessary to provide periodic maintenance, calibration, and testing of plant instrumentation and components. These procedures have provisions for meeting surveillance schedules and for ensuring that measurement accuracies are adequate to keep parameters within operational and safety limits. Procedures for these tests and the control of measuring and test equipment used in conducting these tests are prepared in accordance with Regulatory Guide 1.33, Appendix A. The Manager – Nuclear Strategic Engineering, Manager – Nuclear Performance Engineering, and the Manager – Nuclear Maintenance are responsible for these procedures.

13.5.4.4 Reactor Engineering Procedures

Reactor Engineering Procedures provide guidance for activities associated with fuel and core management and nuclear performance evaluation. The Manager - Nuclear Performance Engineering is responsible for these procedures.

13.5.4.5 Radiation Protection Procedures

Procedures for personnel Radiation Protection are consistent with the requirements of 10 CFR Part 20 and are approved, maintained, and adhered to for all operations involving personnel radiation exposure. Radiation Protection Procedures describe the methods for personnel exposure control and monitoring; area radiation surveys; portable radiation surveys; portable radiation-monitoring equipment operation and calibration; emergency plan implementation; receipt, storage, and shipment of radioactive materials; and Radiation Protection training. The Manager - Radiation Protection is responsible for these procedures.

13.5.4.6 Radiochemistry Procedures

Radiochemistry Procedures describe the plant chemistry and radiochemistry program, the calibration and operation of plant chemistry and radiochemistry equipment, and the methods of analysis to implement this program. The Manager - Chemistry is responsible for these procedures.

13.5.4.7 Fuel-Handling and Special Nuclear Material Control and Accountability Procedures

Fuel-Handling Procedures specify all actions for core alterations and partial or complete refueling operations. Special Nuclear Material Control and Accountability Procedures define the methods for the control, accountability, and inventory of special nuclear material. The Manager - Nuclear Performance Engineering is responsible for ensuring that the requirements of the special nuclear material accountability program are implemented including the procedures governing special nuclear material greater than one gram. The Director – Nuclear Operations is also responsible fuel handling procedures.

13.5.4.8 Fire Protection Implementing Procedures

Fire Protection Implementing Procedures are developed to control the activities associated with the Fire Protection Program. These procedures include fire prevention, fire detection, confinement, suppression, extinguishment, and administrative controls. Procedures are available for fire brigade organization and training, fire inspection procedures, maintenance, and testing. The Director – Nuclear Operations is responsible for the implementation of the Fire Protection Program and ensures that the requirements for the Fire Protection Program are met.

13.5.4.9 Radioactive-Materials-Handling Radwaste Procedures

The Radioactive-Materials-Handling Radwaste Procedures describe the methods of operation and handling of liquid and solid radioactive waste. Radioactive waste from the floor, equipment, and chemical drains is included, plus the processing of sludges and liquids that result. The handling of dry compactible and noncompactible wastes is also included. Procedures for the implementation of the Process Control Program are also included in this group. The Director – Nuclear Operations and Manager – Radiation Protection are responsible for these procedures.

13.5.4.10 Environmental Procedures

The Environmental Procedures describe the environmental control programs, including whom to notify and what actions to take in the event of environmental incidents. Permits for the National Pollutant Discharge Elimination System are discussed, as are oil and chemical spills. The Manager – Chemistry is responsible for these procedures.

13.5.4.11 Surveillance Procedures

Surveillance Procedures provide the necessary steps to perform the required periodic testing of safety-related structures, systems, and components in accordance with Technical Specification requirements and/or the ASME Boiler and Pressure Vessel (B&PV) Code Section XI. Surveillance procedures require the Shift Manager's approval before performance of the surveillance. After completion of operability tests, the Shift Manager also reviews tests to verify that they have been successfully performed and meet the acceptance criteria cited in the surveillance procedure.

13.5.5 Radiological Emergency Response Preparedness Implementing Procedures

The Radiological Emergency Response Preparedness (RERP) Plan and Implementing Procedures are the responsibility of the Manager - RERP. The RERP Plan establishes and defines the criteria and concepts that are necessary to respond to and mitigate the consequences of radiological emergencies to safeguard plant personnel and protect the health and safety of the public. The RERP Implementing Procedures establish the organization, direction and control, overall response, and protective actions for an emergency at Fermi 2. RERP Implementing Procedures may be either administrative or technical procedures, depending upon content. The RERP Plan and Implementing Procedures are on file with the NRC.

13.5.6 Security Plan Procedures

Security Plan Procedures are the responsibility of the Manager -Nuclear Security working in conjunction with the Director – Nuclear Operations. Security procedures may be either administrative or technical, depending upon content. The implementation of the Security Plan Procedures is performed by Nuclear Security personnel under the direction of the Manager - Nuclear Security.

13.6 PLANT RECORDS

13.6.1 Plant History

The Director – Strategic Business Operations has overall responsibility for documents. Specific individuals within the Fermi Organization are assigned responsibility for the generation and control of documents within their purview. The preparation of written procedures and revisions thereto, and of other administrative records, is also included in the responsibilities of these individuals.

A recorded history of Fermi 2 documenting the design, engineering, construction, testing, operation, maintenance, and modification of the plant is maintained in accordance with 10 CFR 50, Appendix B, Section XVII, Quality Assurance Records.

13.6.2 Operating Records

Operating records and documents include appropriate log books, log sheets, data log output, and recorder charts covering the operation of the plant. These records are to include data sufficient to prepare operational information reports as required.

13.6.3 Events Records

In addition to the operating records that are maintained on a continuing basis, records of other occurrences that may be required to reconstruct significant events or satisfy statutory requirements are maintained for the life of the plant.

13.7 INDUSTRIAL SECURITY

13.7.1 Personnel and Plant Design

The Manager - Nuclear Security is directly responsible for the security at Fermi 2. This section describes, in general terms, the security measures that are in effect at Fermi 2 for protection against radiological sabotage. A detailed security plan, not for public disclosure, is made available to the NRC. The Fermi 2 Security Plan conforms to the requirements of 10 CFR 73.55, Requirements for Physical Protection of Licensed Activities in Nuclear Power Reactors Against Radiological Sabotage.

The security program is generally outlined in the Fermi 2 Physical Security Plan and is administered by the Manager - Nuclear Security. The security program at the plant is implemented by compliance with the criteria outlined in the Physical Security Plan.

The consequences of acts of radiological sabotage are minimized by the plant protective systems, including the nuclear safety features and engineered safety feature (ESF) systems incorporated in the plant design. The redundant protective systems and redundant ESF systems are described in detail in Chapters 6, 7, and 8. Also, fire protection equipment is located throughout the plant to minimize the effects of fire or explosion.

Plant operating, security, and staff personnel are screened to minimize potential security risks and to help ensure that reliable and emotionally stable personnel are selected for assignment in the plant. A background investigation, fitness for duty testing, and a psychological evaluation are performed for each employee who requires unescorted access to the Fermi 2 protected area. In addition, other DTE personnel and certain vendors or contractors, who have a need to be at the plant on a frequent basis, and whose personnel require unescorted access, are subject to the same pre-access screening. These people are issued photo-identification badges that permit unescorted access into the protected area. All other persons infrequently entering the protected area, such as certain subcontractors, vendor personnel, or visitors, are issued special badges that will provide limited and escorted access during their authorized visits.

Plant personnel in a management or supervisory capacity are advised of the necessity to recognize emotionally unstable personnel and to report abnormal behavior. A behavior observation program is established as required by 10 CFR 26.

A security training and qualification program is established for the purpose of developing and maintaining maximum proficiency of the Security Force personnel. In general, the guidelines in 10 CFR 73, Appendix B, are followed by the program. Security Force personnel are to be thoroughly familiar with all plant security procedures and are responsible for their implementation.

13.7.2 Security Plan

A detailed Physical Security Plan, Safeguards Contingency Plan, and Security Training and Qualification Plan are on file with the NRC.

Security procedures are issued to provide additional information for use by both the plant operating personnel and the plant security personnel in implementing the Physical Security Plan.

13.7.2.1 Access Control

The control of access into the protected area is accomplished with perimeter barriers and intrusion detection/assessment devices. An industrial-type security fence, properly lighted and cleared on both sides and contiguous with certain site buildings, forms the boundary of the protected area. The protected area barrier serves as a physical and psychological deterrent to entry. In addition, the protected area has intrusion detection alarms to detect entry into this area. Electronic equipment is used for the surveillance of the protected area perimeter fence. A vehicle barrier system is also in place to protect the plant from malevolent use of vehicles. A description of the vehicle barrier system is included in the Physical Security Plan.

Manned alarm stations are established to control and monitor alarms, personnel, vehicles, and materials entering and leaving the protected area. Specific responsibilities are assigned in the Physical Security Plan and by written procedures for the operation of these manned stations.

The control of materials into the protected area is covered by written procedures, which provide controls for articles carried by personnel as well as loads carried by vehicles.

Personnel access to vital buildings, rooms, and spaces, including the main control room, is controlled by a computer-based access control system. Access is granted by the need to enter specific areas. Portal protection of vital rooms, buildings, and structures is provided by locking devices and alarms. All alarms are self-checking and tamper-indicating.

The surveillance of vital areas is accomplished by periodic security patrols and by authorized operating personnel.

13.7.2.2 Control of Personnel by Categories

The control of authorized entry and movement is accomplished by a color-coded, conspicuously worn, photo-identification badge system. For permanent plant personnel and DTE employees who enter the plant frequently, a current access list is maintained and given to the Central Alarm Station and Secondary Alarm Station operators. Admission is granted to those persons who are positively identified and whose names appear on the approved access list. Access lists are reviewed and approved by a cognizant DTE manager or supervisor to ensure personnel on the list have a continued need for access.

For contractor, vendor, service personnel, or other authorized personnel not on the access authorization list, a visitor's badge is issued and an escort required. A visitor's log is maintained to show the name, date, time, purpose of visit, employment affiliation, citizenship, and name of individual to be visited.

13.7.2.3 Access Control During Emergencies

Requests for emergency aid are made either by site security personnel or by authorized plant operating personnel with such requests coordinated with security personnel to permit the required rapid access needed in emergency conditions. Procedures covering emergency access are referred to in the Physical Security or Safeguards Contingency Plans and are compatible with the Fermi 2 Radiological Plan.

13.7.2.4 Surveillance and Monitoring

Surveillance and monitoring of vital equipment, components, and areas are accomplished in accordance with administrative procedures and controls by the use of electronic equipment and remote-reading instruments to detect changes in ESF equipment. The inspection of nuclear fuel and radioactive materials upon receipt is in accordance with administrative controls and procedures.

13.7.2.5 Potential Security Threats

Nuclear security officers are armed and trained to respond as necessary as outlined in the site's Safeguards Contingency Plan in the event of situations affecting the security of the Fermi 2 plant. Fermi 2 security personnel have two independent means of communicating with local law enforcement agencies in order to summon aid. In addition, all on duty members of the security force are equipped with two-way portable radios if other means of communication are not available.

For any civil disorder, bomb threat, or other type of security threat, the Monroe County Sheriff's office and/or the Michigan State Police are notified and provide the necessary assistance. Any incidents involving attempted or actual breach of security controls or attempted acts of sabotage are reported to the NRC, in accordance with 10 CFR 73.71.

The Nuclear Security Organization evaluates all security incidents to determine if they are reportable to the NRC in accordance with 10 CFR 73.71. Those incidents found to be reportable are investigated and a report is developed. The report is reviewed by the Manager - Nuclear Security and the Site Vice President - Nuclear Generation before it is submitted to the NRC.

13.7.2.6 Administrative Procedures

The Physical Security Plan and implementing procedures are reviewed and approved and periodic reviews are performed according to the Physical Security Plan.

CHAPTER 14: INITIAL TESTS AND OPERATION

This chapter describes the initial testing and operating program conducted at Fermi 2. The program describes the manner in which the testing and initial operation was performed, controlled, and documented for the following four testing and initial operating phases:

a. Construction Test Phase - the period during which the Construction Manager had responsibility for activities. Construction tests were generally carried out before the energization of equipment. The transfer of jurisdiction over equipment and systems from the Construction Manager to the System Completion Organization (SCO) occurred at the end of this period

b. Checkout and Initial Operations Test Phase - the period during which the Edison Startup Group conducted checkout and initial operations (CAIO) tests, including initial equipment energizing, flushing and cleaning operations, initial calibration of instrumentation, electrical wiring and equipment tests, valve testing, and initial equipment and system operation. Hydrotesting (a construction test) was also conducted during this phase

c. Preoperational Test Phase - the period during which approved preoperational tests were performed. The preoperational testing was the responsibility of the Edison Startup Group

d. Startup Test Phase - the period beginning with preparation for fuel loading and extending through 100 percent power and warranty demonstrations, where the Edison Startup Test Phase Group has responsibility for startup testing. A detailed description of this test phase is provided in Subsection 14.1.3. The startup test phase is subdivided into four parts:

    1. Fuel-loading and open-vessel tests

    2. Initial heating to rated temperature and pressure

    3. Power testing from rated temperature and pressure to 100 percent of rated output

    4. Warranty demonstration.

The test program also encompassed cold functional testing, the Surveillance Testing Program, and hot functional testing.

The construction, CAIO, and preoperation test phases were not necessarily performed in series. Certain test activities were conducted in parallel, such as construction tests with CAIO tests and CAIO tests with preoperational tests. On ASME Code systems, the contractor maintained the responsibilities of the Installer through the ASME Code hydrotesting and N-stamping. Overall systems jurisdiction, however, was maintained by Edison's SCO in these situations. Figure 14.1-1 is an overall test program outline.

This test program closely adhered to Regulatory Guide 1.68 (11/73), "Preoperational and Initial Startup Test Programs for Water-Cooled Power Reactors," while recognizing the specific requirements of the construction codes (ASME Section III).

14.1 TEST PROGRAM

A comprehensive testing program was implemented at Fermi 2. This program was designed to ensure the following:

a. That the equipment and systems perform in accordance with General Design Criteria

b. That the plant is properly designed and constructed and is ready to operate in a manner that will not endanger the health or safety of the public

c. That the initial fuel loading is accomplished in a safe and efficient manner

d. That required verification of nuclear parameters is obtained

e. That the procedures for operating the plant are evaluated and demonstrated

f. That the operating staff is knowledgeable about the plant and procedures and fully prepared to operate the facility in a safe manner

g. That the plant achieves rated capacity while meeting all safety and environmental conditions.

Systems and components were tested and evaluated according to written and approved test procedures. An analysis of test results verified that each system or component performed satisfactorily. The written procedures for the initial tests and operation included objectives and prerequisites of the tests, initial conditions, precautions, the test method, acceptance criteria, return to normal status, and appropriate references.

During the preoperational and startup test phases, the permanent plant operating procedures, as described in Section 13.5, were used to support the preoperational and startup tests. The use of the plant system operating procedures in this manner enabled them to be verified and changed as necessary to become a safe, comprehensive set of system operating procedures.

14.1.1 Administrative Procedures (Testing)

The preoperational test program has been essentially completed for Fermi 2. All that presently (December 1988) remains is a small amount of testing to close out certain test items still open from previous testing on other systems.

The preoperational tests of the solid radwaste system were suspended in December 1987 because the system was unable to meet the design throughput values for ion-exchange resin waste streams. The objectives and test descriptions discussed in Subsection 14.1.3.2.17, as they apply to this system, will remain in effect should testing be resumed in the future.

The responsibilities and administrative controls necessary to complete this testing are defined in plant administrative procedures.

14.1.2 Administrative Procedures (Modifications)

(This section has been deleted.)

14.1.3 Preoperational Test Phase Objectives and Test Descriptions

14.1.3.1 General Objectives

(This section has been deleted.)

14.1.3.2 Discussion of Preoperational Tests

The preoperational test discussions that follow indicate the objectives, prerequisites, general test method, and acceptance criteria which formed the basis for the detailed preoperational test procedures. A listing of all preoperational tests, together with subsection and page references for use in locating a particular test discussion, follows under the heading "Preoperational Tests."

Systems that were not to be tested preoperationally were subjected to an acceptance test or a specific checkout and initial operations test. A list of acceptance tests that were performed follows the list of preoperational tests. After the list of acceptance tests is a list of specific checkout and initial operations tests that were used instead of acceptance tests.

PREOPERATIONAL TESTS

PREOPERATIONAL TESTS

Subsection Reference	Test Title
14.1.3.2.13	Core Spray System Preoperational Test
14.1.3.2.14	High Pressure Coolant Injection System Preoperational Test
14.1.3.2.15	Fuel Pool Cooling and Cleanup System Preoperational Test
14.1.3.2.16	Leak Detection System Preoperational Test
14.1.3.2.17	Liquid- and Solid-Radwaste System Preoperational Test
14.1.3.2.18	Reactor Protection System Preoperational Test
14.1.3.2.19	Neutron Monitoring System Preoperational Test
14.1.3.2.20	Traversing In-Core Probe System Preoperational Test
14.1.3.2.21	Rod Worth Minimizer System Preoperational Test
14.1.3.2.22	Process Radiation Monitoring System Preoperational Test
14.1.3.2.23	Area Radiation Monitoring System
14.1.3.2.24	Process Computer Interface System Preoperational Test
14.1.3.2.25	Rod Sequence Control System Preoperational Test
14.1.3.2.26	Condensate System Preoperational Test
14.1.3.2.27	Condensate Polishing Demineralizer System Preoperational Test
14.1.3.2.28	Condenser Vacuum System Preoperational Test
14.1.3.2.29	Condensate Storage System Preoperational Test
14.1.3.2.30	Plant Process Sampling System (Liquid Radwaste) Preoperational Test
14.1.3.2.31	Plant Process Sampling System (Reactor) Preoperational Test
14.1.3.2.32	Plant Process Sampling System (Turbine) Preoperational Test
14.1.3.2.33	Turbine Building Closed Cooling Water System Preoperational Test

PREOPERATIONAL TESTS

Subsection Reference	Test Title
14.1.3.2.34	Reactor Building Closed Cooling Water System Preoperational Test
14.1.3.2.35	Emergency Equipment Cooling and Service Water System Preoperational Test
14.1.3.2.36	Station and Control Air System Preoperational Test
14.1.3.2.37	Fire Protection System Preoperational Test
14.1.3.2.38	Auxiliary Electrical Power System Preoperational Test
14.1.3.2.39	Emergency Diesel Generator System Preoperational Test
14.1.3.2.40	l20-V ac Instrument and Control Power System Preoperational Test
14.1.3.2.41	130/260-V dc Power System Preoperational Test
14.1.3.2.42	24/48-V dc Power System Preoperational Test
14.1.3.2.43	Primary Containment Leak Rate Preoperational Test
14.1.3.2.44	Reactor Building Crane Preoperational Test
14.1.3.2.45	Reactor Building Heating and Ventilation System Preoperational Test
14.1.3.2.46	Main Control Room Heating, Ventilation, and Air Conditioning Systems Preoperational Test
14.1.3.2.47	Standby Gas Treatment System Preoperational Test
14.1.3.2.48	Drywell Cooling System Preoperational Test
14.1.3.2.49	Primary Containment Atmosphere Control System Preoperational Test
14.1.3.2.50	Primary Containment Monitoring System Preoperational Test
14.1.3.2.51	Secondary Containment Leak Rate Preoperational Test
14.1.3.2.52	Turbine Building Heating and Ventilation System Preoperational Test
14.1.3.2.53	Radwaste Building Heating and Ventilation System Preoperational Test

PREOPERATIONAL TESTS

Subsection Reference	Test Title
14.1.3.2.54	Communication and Evacuation Alarm System Preoperational Test
14.1.3.2.55	Seismic Monitoring System Preoperational Test
14.1.3.2.56	Residual Heat Removal Complex Heating and Ventilation System Preoperational Test
14.1.3.2.57	Residual Heat Removal Complex Service Water Systems Preoperational Test
14.1.3.2.58	Condensate Makeup Demineralizer System Preoperational Test
14.1.3.2.59	General Service Water System Preoperational Test
14.1.3.2.60	Circulating Water System Preoperational Test
14.1.3.2.61	Offgas System Preoperational Test
14.1.3.2.62	Main Turbine Electro-Hydraulic Control System Preoperational Test
14.1.3.2.63	Thermal Recombiner System Preoperational Test
14.1.3.2.64	System Vibration and Expansion Preoperational Test
14.1.3.2.65	Primary Containment, Secondary Containment, and Auxiliary Building Equipment Drains and Floor Drains Preoperational Test
14.1.3.2.66	Containment Vacuum Breakers Preoperational Test
14.1.3.2.67	Emergency Lighting System Preoperational Test
14.1.3.2.68	Personnel Monitoring, Survey Instruments, and Laboratory Equipment Preoperational Test
14.1.3.2.69	Reactor System Hydrostatic Preoperational Test
14.1.3.2.70	Main Steam Line Isolation Valve Leakage Control System Preoperational Test
14.1.3.2.71	Reactor Internals Flow-Induced Vibration Preoperational Test
14.1.3.2.72	Remote Shutdown Preoperational Test
14.1.3.2.73	Torus Water Management System Preoperational Test

PREOPERATIONAL TESTS

Subsection Reference	Test Title
14.1.3.2.74	Postaccident Sampling System Preoperational Test

ACCEPTANCE TESTS

Item	Test Title
1.	Security System
2.	Loose Parts Monitoring System
3.	Automated Records Management System/Plant Computer Network System
4.	Emergency Response Information System
5.	Plant Meteorological Monitoring System
6.	Onsite Storage Building Miscellaneous Systems
7.	Engineered Safety Feature Status Display
8.	Annunciator and Sequence Recorder System
9.	Heater Drain System
10.	Turbine Steam System
11.	Turbine Supervisory Equipment
12.	Main Turbine Protection System
13.	Turbine Sealing Steam System
14.	Turbine Lubricating Oil System
15.	Main Turbine Extraction Steam System
16.	Low Pressure Turbine Hood Cooling System

ACCEPTANCE TESTS

Item	Test Title
17.	High Pressure Turbine Flange Heating System
18.	Main Turbine Hydrogen Seal Oil System
19.	Stator Winding Cooling System
20.	Main Turbine Generator Cooling System/H_2 Supply System/CO_2 Purge System
21.	Potable Water System
22.	General Service Water Chlorination System
23.	Breathing Air System
24.	Auxiliary Boiler System
25.	Waste Oil System
26.	Plant Grounding System
27.	Steam Tunnel Cooling System
28.	Recirculation Motor Generator Ventilation System
29.	Turbine Building Crane
30.	Turbine Building Radioactive Drains System
31.	Radwaste Building Floor and Equipment Drains System
32.	Circulating Water Chlorination System
33.	Circulating Water Pumphouse Heating Ventilation System
34	Office and Service Building Heating, Ventilation, and Air Conditioning System
35.	General Service Water Pumphouse Heating and Ventilation System
36.	Onsite Storage Building Heating, Ventilation, and Air Conditioning System

ACCEPTANCE TESTS

Item	Test Title
37.	Residual Heat Removal Complex Equipment and Floor Drains System
38.	Technical Support Center/Office Building Annex (TSC/OBA) Heating, Ventilation, and Air Conditioning System

ACCEPTANCE TESTS THAT WERE REPLACED BY SPECIFIC CHECKOUT AND INITIAL OPERATIONS TESTS

Item	Test Title
1.	Main Unit Generator Relaying
2.	Main Unit Generator and Exciters
3.	Generator Field Breaker, Rectifier Assembly, and Suppression Resistor
4.	Generator Excitation System
5.	Engineers Test System
6.	Isophase Bus System
7.	Generator Synchronization System
8.	EF1-EF2 Telemetering
9.	Michigan Electric Power Pool Coordination Center Interface

14.1.3.2.1 Feedwater Control System Preoperational Test

a. Test Objective - To verify proper operation of the feedwater control system

b. Prerequisites - The checkout and initial operations tests have been completed and the technical review committee (TRC) has reviewed and approved the test procedure and the initiation of testing. The control air system must be available and all feedwater control components should have an initial calibration in accordance with vendor's instructions

c. General Test Method - Verification of the feedwater control system capability is demonstrated by the proper, integrated operation of the following.

   1. Feedwater control instrumentation and interlocks
   2. Startup (low-flow) valve regulator
   3. Annunciators.

d. Acceptance Criteria - All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14.1.3.2.2 Reactor Feedwater System Preoperational Test and Reactor Feedwater Pump Turbine Control System Preoperational Test

a. Test Objective - To verify the proper operation of the reactor feedwater pump turbine control system, including turbine support systems, controls, safety devices, and alarms and annunciators. Verify the proper operation of the reactor feedwater system valves and interlocks, and alarms and annunciators

b. Prerequisites - The checkout and initial operations tests have been completed, and the TRC has reviewed and approved the test procedure and the initiation of testing. The related support systems, the main turbine sealing steam, and the lube oil systems must have readiness verification. The Turbine Instruction Manual is reviewed in detail

c. General Test Methods - Verification of the reactor feedwater system and the turbine control system capability is demonstrated with actual and simulated signals by the proper, integrated operation of the following:

1. Automatic valves and interlocks
2. Alarms and annunciators
3. Lube-oil alarms and protective devices
4. Turbine hydraulic and lube oil system
5. Turbine turning gear and interlocks
6. Turbine trip and trip-reset system
7. Clean steam operation of north and south reactor feed pump turbine.

d. Acceptance Criteria - In addition to verification of operation of all system components, the turbine hydraulic and lube oil systems, turbine turning gear, and turbine trip and reset systems must be shown to be within their respective engineering design specifications.

14.1.3.2.3 Deleted (incorporated into Subsection 14.1.3.2.2)

14.1.3.2.4 Reactor Water Cleanup System Preoperational Test

a. Test Objective - To verify the operation of the reactor water cleanup (RWCU) system, including pumps, valves, and demineralizers

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing. Anion and cation resin mixture is available. Reactor building closed cooling water system (RBCCWS) and control air must have readiness verification

c. General Test Methods - Verification of the RWCU system capability is demonstrated by the proper, integrated operation of the following:

1. Drain flow regulator flow interlocks
2. System and filter isolation and logic
3. Valve-operating sequence
4. Pump and related control and logic
5. Annunciators.

d. Acceptance Criteria - All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications. Total system filterability must be demonstrated similarly.

14.1.3.2.5 Standby Liquid Control System Preoperational Test

a. Test Objective - To verify the operation of the standby liquid control system (SLCS) including pumps, tanks, control, logic, and instrumentation

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing. Relief valves are bench tested previously and other precautions relative to positive displacement pumps taken. The reactor pressure vessel (RPV) is available for injecting demineralized water

c. General Test Method - Verification of the SLCS capability is demonstrated by the proper, integrated operation of the following:

1. SLCS tank level instrumentation
2. Heaters and heat tracing
3. Alarms and logic
4. Relief valves
5. Pumps and related controls and logic
6. Flow testing with different flow paths
7. Injection of demineralized water by actual firing of squib valves
8. Volume and concentration limits according to the Technical Specifications.

d. Acceptance Criteria - All systems components must be either verified for proper operation, or demonstrated to be within their respective engineering design specifications.

14.1.3.2.6 Nuclear Boiler System Preoperational Test

a. Test Objective - To verify the proper operation of the nuclear boiler system, including the reactor vessel and containment isolation control logic, main steam isolation valves, automatic depressurization control logic, safety/relief valves (SRVs), and reactor vessel head leak detection system

b. Prerequisites - The checkout and initial operations tests have been completed as required and the TRC has reviewed and approved the test procedure and the initiation of testing

c. General Test Method - Verification of the system capability is demonstrated by integrated operation of the following portions of this system:

   1. Reactor vessel and containment isolation control including process sensors, logic channels, main steam isolation valves (MSIVs), drain valves, reactor water sample isolation valves, vacuum breakers, and pneumatic accumulators
   2. Automatic depressurization system (ADS) including sensors, logic channels, SRVs, manual controls, and pneumatic accumulators
   3. Non-ADS SRVs and associated manual controls
   4. Reactor head seal leak detection
   5. Annunciator and sequential operations recorder inputs
   6. Reactor head vent isolation valves
   7. Reactor vessel level instrument responses to actual water-level changes.

d. Acceptance Criteria - All system components must be verified for proper operation. The valves tested must meet required closing time maximum values. Logic response times where time delay devices are included must meet design values.

14.1.3.2.7 Residual Heat Removal System Preoperational Test

a. Test Objective - To verify the operation of the residual heat removal (RHR) system under its various modes of operation: standby, low pressure coolant injection (LPCI), shutdown cooling and vessel head spray, containment spray, suppression pool water cooling, and fuel pool cooling and cleanup (FPCC). Heat removal capabilities in certain modes are not verified

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing. The RPV and recirculation loops are intact and capable of receiving water

c. General Test Method - Verification of the RHR system capability is demonstrated by the proper, integrated operation of the following:

   1. System isolation valve control and logic tests
   2. RHR pumps, motors, controls, and related logic features
   3. Automatic LPCI initiation logic
   4. Break detection loop selection logic

5. Verification of all flow paths. The time from initiation signal to full flow is verified similarly to be within design specifications
6. Demonstrate adequate net positive suction head (NPSH) with simulated suppression chamber inlet strainer 50 percent plugged
7. Alarms and annunciators.

d. Acceptance Criteria - All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications; system flow paths under various modes of operation must be demonstrated similarly.

The time from initiation signal to full flow is verified similarly to be within design specifications.

14.1.3.2.8 Reactor Core Isolation Cooling System Preoperational Test

a. Test Objective - To verify the operation of the reactor core isolation cooling (RCIC) system, valves, instrumentation, and control

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing

c. General Test Method - Verification of system capability is demonstrated with simulated signals by the proper, integrated operation of the following:

1. All valves and related controls, interlocks, and indicators
2. Manual and automatic initiation logic
3. Automatic isolation, including leak detection system logic
4. Turbine speed control, trip logic, instrumentation, and test mode
5. Barometric condenser condensate pump, and vacuum pump controls
6. Annunciators.

d. Acceptance Criteria - All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14.1.3.2.9 Reactor Recirculation and Motor-Generator Sets Preoperational Test

a. Test Objective - To verify the operation of the reactor recirculation system, including pumps, and their associated motors and motor-generator (M-G) sets, valves, instrumentation, and controls. The rated conditions tests are conducted during the startup test program.

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing. The RBCCWS must receive readiness verification. All required testing of equipment up to the operation of the recirculation pump has been completed, including operation of the M-G sets and fluid coupling, recirculation pump motor (uncoupled), and all control loops. Reactor internals which are in place are those which can satisfactorily withstand the pressure drops encountered during these tests. Means must be provided to monitor audible noise and vibration of the pumps

c. General Test Method - After prerequisite testing, verification of system capability is demonstrated by the proper, integrated operation of the following:

1. System valves

   (a) Operability

   (b) Opening and closing speed

   (c) Manual operation

   (d) Limit switch and torque switch operation

   (e) Position indicating lights.

2. Logic and interlocks

   (a) Recirculation pump trip with reactor low level and/or with reactor high pressure (anticipated transient without scram [ATWS]) recirculation pump runback with reactor low level and loss of feed pump

   (b) Recirculation flow limit for NPSH protection with low feedwater flow

   (c) Scoop tube positioner lockup with signal failure

   (d) M-G set drive motor lockout

   (e) M-G set drive motor circuit breaker trip

   (f) Circulating lube oil system

   (g) Annunciators.

3. Operational Testing

   (a) Single pump operation at minimum speed

   (b) Single and dual-pump operation at higher loop flows within flow and cavitation

   (c) Pump trips, including one- and two-pump drive motor breaker trips and a two-pump trip consistent with the ATWS pump trip. (In addition, the time delay for the field breaker trip will be confirmed)

   (d) Recirculating pump and piping vibration measurements

   (e) M-G set motor, coupler, and generator

   (f) Jet pump consistency.

d. Acceptance Criteria - Performance cannot be evaluated properly in the preoperational phase, and, therefore, no conclusions on performance can be reached until the system is tested during the power test program. Expected values of measured parameters will be tabulated before the test. Significant variations from these values will be investigated. All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specification.

14.1.3.2.10 Control Rod Drive Manual Control System Preoperational Test

a. Test Objective - To verify the operation of the reactor manual control system (RMCS), including relays, control circuitry, switches and indicating lights, and control valves

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing. Associated primary coolant systems must be flushed

c. General Test Method - Verification of RMCS capability is demonstrated by the proper, integrated operation of the following:

    1. Control valve sensor and logic
    2. Rod blocks, interlocks, and alarms
    3. Control rod drive (CRD) position indication, alarms, and interlocks
    4. Alarms, annunciators, and system timer.

d. Acceptance Criteria - All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14.1.3.2.11 Control Rod Drive Hydraulic System Preoperational Test

a. Test Objective - To verify the operation of the CRD hydraulic system, including CRD mechanisms, hydraulic control units (HCUs), hydraulic power supply, instrumentation, and controls

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing. The CRD manual control system preoperational test (Subsection 14.1.3.2.10) must be completed on associated CRDs. The RBCCWS and control air system must receive readiness verification

c. General Test Method - Verification of CRD system capability is demonstrated by the proper, integrated operation of the following:

    1. Logic and interlocks
    2. CRD pumps and related controls and interlocks
    3. Flow controller, pressure control valves, and stabilizer valves
    4. Scram discharge level switches, and CRD position indication and alarms
    5. CRDs including latching and position indication

6. Scram testing of control rods at atmospheric pressure

7. Annunciators.

d. Acceptance Criteria - All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specification; full scram capability must be similarly demonstrated.

14.1.3.2.12 Fuel Handling and Vessel Servicing Equipment Preoperational Test

a. Test Objective - To verify the operation of the fuel handling and vessel servicing equipment, including tools used in the servicing of control rods and fuel assemblies, local power range monitors (LPRMs), and dry tubes. The test will also verify the operation of vacuum cleaning equipment, the refueling platform, the fuel preparation machine, and the service platform

b. Prerequisites - The checkout and initial operations tests have been completed as necessary, and the TRC has reviewed and approved the test procedure and the initiation of testing. Additionally, the refueling platform, fuel preparation machine, and fuel racks must be installed and operational; all slings and lifting devices must be certified at their design load, at least, by the vendor

c. General Test Method - Verification of the fuel handling and vessel servicing equipment is demonstrated by dry operation of the following equipment:

1. Cell disassembly tools

2. Channel replacement tools

3. Vacuum cleaning equipment

4. Interlocks and logic associated with the refueling and service platform

5. Refueling and service platforms.

d. Acceptance Criteria - The above tools must be verified for proper operation. In addition, logic and interlocks and grapple load cells must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14.1.3.2.13 Core Spray System Preoperational Test

a. Test Objective - To verify the operation of the core spray system, including spray pumps, sparger ring, spray nozzles, controls, valves, and instrumentation

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing. The RPV must be available and ready to receive water

c. General Test Method - Verification of core spray system capability is demonstrated by the proper, integrated operation of the following:

1. Logic and interlocks

2. Core spray system pumps, including auto initiation

3. Flow path verification
4. Annunciators
5. Adequate NPSH with simulated suppression chamber inlet strainer 50 percent plugged.

d. Acceptance Criteria - All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications; system flow rates and patterns and initiation time must be demonstrated similarly.

14.1.3.2.14 High Pressure Coolant Injection System Preoperational Test

a. Test Objective - To verify the operation of the high pressure coolant injection (HPCI) system, including turbine and related auxiliary equipment as available, vacuum pump, condensate pump, valves, instrumentation, and control

b. Prerequisites - The checkout and initial operations tests have been completed as necessary, and the TRC has reviewed and approved the test procedure and the initiation of testing

c. General Test Method - Verification of HPCI system capability is demonstrated with simulated signals by the proper, integrated operation of the following:

1. Automatic initiation
2. Automatic isolation, including leak detection and interlocks
3. Valve controls and interlocks
4. Turbine test mode and trip
5. Gland condenser condensate pump and vacuum pump, and interlocks
6. Alarms and annunciators.

d. Acceptance Criteria - All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications. All pump tests involving the HPCI main and booster pumps are deferred to the startup test phase.

14.1.3.2.15 Fuel Pool Cooling and Cleanup System Preoperational Test

a. Test Objective - To verify the operation of the fuel pool cooling and cleanup system (FPCCS), including valves, pumps, and demineralizer

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing. The related support systems, the RBCCW, control air, and portions of the radwaste system must have readiness verification

c. General Test Method - Verification of the FPCCS is demonstrated by the proper, integrated operation of the following:

1. Control air-operated valves and related sequence logic

2. Flow path verification
3. Pumps, and their motors and related automatic controls, interlocks, and vacuum breaker verification
4. Demineralizer operation
5. Annunciators.

d. Acceptance Criteria - All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications; a total system operational capability must be demonstrated similarly.

14.1.3.2.16 Leak Detection System Preoperational Test

a. Test Objective - To summarize the test requirements and verify the leak detection test data for each of the nuclear systems

b. Prerequisites - The prerequisites are included in the preoperational test specifications for each of the nuclear systems listed below

c. General Test Method - As an integral part of each of the following system preoperational tests, the nuclear systems leak detection is verified by the proper operation of the leak detection features of the following nuclear systems:

1. RWCU
2. Nuclear boiler system
3. RHR
4. RCIC
5. HPCI
6. Radwaste system

d. Acceptance Criteria - The leak detection features of the nuclear systems must be verified for proper operation and shown to be within their respective engineering design specifications.

14.1.3.2.17 Liquid and Solid Radwaste System Preoperational Test

a. Test Objective - To verify the operation of the radwaste system, including pumps, filters and demineralizers, centrifuge, and solid-handling equipment

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing. Additionally, laboratory facilities must be available to perform water quality tests

c. General Test Method - Verification of the radwaste system capability is demonstrated by the proper, integrated operation of the following:

1. System pumps under all normal possible flow paths and component operation
2. Isolation valve operation, including valve logic and leak detection sensors and related annunciators
3. Filters and demineralizers and related controls
4. Centrifuges and solid-handling equipment
5. Phase separator and waste sludge subsystems
6. Chemical waste and spent resin subsystems.

d. Acceptance Criteria - All system and subsystem components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14.1.3.2.18 Reactor Protection System Preoperational Test

a. Test Objective - To verify the proper operation of the reactor protection system (RPS), including sensors, logic channels, scram relays, reset logic, and motor-generator power supplies

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing. Checkout and initial operations tests of the MSIV limit switches must be complete. The CRD hydraulic system should have readiness verification

c. General Test Method - Verification of the RPS capability is demonstrated by the proper, integrated operation of the following.

1. M-G sets and associated voltage and underfrequency control logics
2. RPS input sensors including automatic bypass functions
3. Scram channel relay logic, including scram relays and manual scram switches
4. Mode switch functions and bypass time delays
5. Full scrams including CRDs if the CRD hydraulic system is available. Otherwise this verification is performed with the preoperational test of the CRD hydraulic system
6. Annunciator and sequential operations recorder inputs
7. RPS sensor initiation of reactor and containment isolation.

The method used for measuring the response times of initiating channels is described in Subsection 7.2.1.1.3.8.

d. Acceptance Criteria - All system components must be either verified for proper operation or demonstrated to perform within their respective engineering design specifications; the RPS must demonstrate the ability to scram the reactor within a specified, maximum time. Each portion of the scram chain including sensors must meet a specified, maximum-allowable operating time.

14.1.3.2.19 Neutron Monitoring System Preoperational Test

a. Test Objective - To verify the operation of the neutron monitoring system (NMS), including startup, intermediate, power range detectors, rod block monitor (RBM), and related equipment

b. Prerequisites - The checkout and initial operations tests have been completed as required, and the TRC has reviewed and approved the test procedure at the initiation of testing. Additionally, all source range monitors (SRMs) and pulse preamplifiers, intermediate range monitors (IRMs) and voltage preamplifiers, and average power range monitors (APRMs) will have been calibrated per vendor's instructions

c. General Test Method - Verification of the NMS capability is demonstrated by the proper, integrated operation of the following.

   1. All SRM detectors, and their respective insert and retract mechanisms, and cables

   2. SRM channel, including pulse preamp, remote meter and recorder, trip logic, logic bypass and related lamps and annunciators, control system interlocks, refueling instrument trips, and power supply

   3. All IRM detectors and their respective insert and retract mechanisms and cables

   4. IRM channels, including voltage preamps, remote recorders, RMCS interlocks, RPS trips, annunciators and lamps, and power supplies

   5. All LPRM detectors and their respective cables, and power supplies

   6. All APRM channels, including trips, trip bypasses, annunciators and lamps, remote recorders, RMCS interlocks, RPS interlocks, and power supplies

   7. Recirculation flow bias signal, including flow unit, flow transmitters, and related annunciators, interlocks, and power supplies.

d. Acceptance Criteria - All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications; the ability of the system to interface properly with the reactor protection system must be demonstrated similarly.

14.1.3.2.20 Traversing In-Core Probe System Preoperational Test

a. Test Objective - To verify the operation of the traversing in-core probe (TIP) system, including the TIP detector, controls and interlocks, containment secure lamp, and squib circuits

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing. Additionally, the TIP detector and dummy detector, ball valve time delay, core top and bottom limits, clutch, X-Y recorder, shear valves, and purge system are shown to be operational

c. General Test Method - With the exception of the shear valve which is not fired, verification of the TIP system is demonstrated by the proper, integrated operation of the following:

1. Indexer cross-calibration interlock
2. Shear valve monitor lamps
3. Drive motor manual control and override, automatic control and stop, and low speed control
4. TIP automatic detector withdrawal
5. Containment secure lamp and squib circuits
6. Ball valve control.

In addition, one explosive device is test fired to verify operability of the squib explosive channels. The squib valve firing circuit is checked by

(a) Jumpering pins to the valve actuators

(b) Operating the "fire" switch

(c) Measuring the current.

This test verifies wiring, operability of switch and interlocks, and capacity of the power supply. Continuity through the squib is monitored continuously by a "trickle" current

d. Acceptance Criteria - All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14.1.3.2.21 Rod Worth Minimizer System Preoperational Test

a. Test Objective - To verify the operation of the rod worth minimizer (RWM) system under its various modes of operation

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing. The CRD system, RMCS, and rod position indication system are shown to be operational. The rod sequence control system (RSCS) is bypassed, computer diagnostic and special tests are completed, and fuel is not loaded

c. General Test Method - Proper operation of RWM hardware and program is demonstrated by successful completion of the following items using a rod test sequence loaded into computer memory

1. Proper indication of errors and application of rod blocks while operating between 100 percent and 50 percent rod density and the low-power setpoint
2. Proper indication of errors while operating between the low-power setpoint and the low-power alarm point
3. System initialization below the low-power setpoint, initialization between the low-power setpoint and the low-power alarm point, and initialization above the low-power alarm point
4. Rod test mode
5. RWM acceptance of a substitute rod position valve
6. Rod drift scan.

d. Acceptance Criteria - All system operations must be either verified or demonstrated to be within their respective engineering design criteria.

14.1.3.2.22 Process Radiation Monitoring System Preoperational Test

a. Test Objective - To verify the operation of all subsystems of the process radiation monitoring system (PRMS), both liquid and gaseous. The primary containment radiation monitoring subsystem preoperational test is reviewed in Subsection 14.1.3.2.50

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has approved the test procedure and the initiation of testing. Additionally, all component units, including the pulse preamplifiers, power supplies, indicator and trip units, sensors, and converters, are calibrated according to the vendor's instruction manuals; circuit continuity, insulation resistance, and high potentiometer tests will have been completed

c. General Test Method - Verification of the process PRMS is demonstrated by the proper, integrated operation of the components of all subsystems, including the following:

1. Air or water flow rates and operation of controls and alarms for all off-line subsystems
2. Operation accessibility and viability of all filter collectors (iodine and particulate) included in specified subsystems
3. Accessibility and operability of all grab sample portions, such as the offgas vial sampler
4. Sensors, preamps, cabling, channels, lamps, annunciators, trip units, recorders, sample racks, check sources, and interlocks.

d. Acceptance Criteria - All subsystem components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14.1.3.2.23 Area Radiation Monitoring System Preoperational Test

a. Test Objective - To verify the operation of the area radiation monitoring system (ARMS), including sensors and channels, trip units, alarms, and recorder

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing. Additionally, indicator and trip units, power supplies, and sensor/converters are calibrated according to the vendor's instruction manual

c. General Test Method - Verification of the ARMS capability is demonstrated by the proper, integrated operation of the following:

1. Sensor/converter and associated channels
2. Channel trip units
3. Alarm annunciators, lights, and beacons
4. Recorders.

d. Acceptance Criteria - All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14.1.3.2.24 Process Computer Interface System Preoperational Test

a. Test Objective - To verify the operation of the process computer interface system, including computer inputs and printout

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing. Additionally, computer diagnostic checks and programming are completed

c. General Test Method - Verification of the process computer interface system is demonstrated by proper operation of the following:

1. Analog input signals
2. Computer printout
3. Digital input signals
4. Digital output signals.

d. Acceptance Criteria - All system operations must be either verified or demonstrated to be within their respective engineering design specifications.

14.1.3.2.25 Rod Sequence Control System Preoperational Test

a. Test Objective - To verify the operation of the RSCS under its various modes of operation

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing. Additionally, the self-test feature of the RSCS is verified

c. General Test Method - Verification of the RSCS is demonstrated by the proper operation of the following functions:

   1. Group fence blocks
   2. Full-in, full-out bypass blocks
   3. Group select blocks
   4. 50 percent rod density notch control logic
   5. 20 percent power notch control bypass (minimum)
   6. Illuminations and annunciation.

d. Acceptance Criteria - All system operations must be either verified, or demonstrated to be within their respective engineering design specifications; RSCS acceptance of an operator-initialized group reset must be demonstrated similarly.

14.1.3.2.26 Condensate System Preoperational Test

a. Test Objective - To verify the operation of the condensate system, including pumps, motors, controls and interlocks, feedwater heaters, control valves, condensers, and flow and pressure instrumentation. No attempt is made to verify design heat loads until nuclear steam is available

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing. Related support systems (condensate makeup demineralizer, condensate storage, and control air) must have readiness verification

c. General Test Method - With the exception of the condensate polishing demineralizer, condensate storage, condenser vacuum, and condensate makeup demineralizer systems, which are the subjects of their own preoperational tests, verification of the condensate system capability is demonstrated by the proper, integrated operation of the following:

   1. Condenser pumps, motors, controls, and interlocks
   2. Offgas, steam-jet air ejector, and gland steam condensers, and their related water control valves
   3. System normal and emergency relief protection valves
   4. System minimum recirculation flow and bypass control valves
   5. Condenser hotwell level controls
   6. System normal and emergency makeup valves and control
   7. Heater feed pumps and bypasses, motors, controls, and interlocks

8. System flow and pressure instrumentation
9. Feedwater heaters and control valves
10. Reactor feed pump seal water injection and return pumps, motors, controls and logic
11. Annunciators.

d. Acceptance Criteria - All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications. Verification of system design heat loads is deferred until nuclear steam is available.

14.1.3.2.27 Condensate Polishing Demineralizer System Preoperational Test

a. Test Objective - To verify the operation of the condensate polishing demineralizer system, including demineralizers, pumps, motors, and automatic controls

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedures and the initiation of testing. The related support systems (condensate storage, condensate portions of radwaste, station air, and control air) must have readiness verification

c. General Test Method - Verification of the condensate polishing demineralizer system is demonstrated by the proper, integrated operation of the following:

1. Holding pumps, precoat pumps, and related automatic controls and interlocks
2. System flow, flow balance control, interlocks and override, and automatic valve operation
3. Demineralizers' automatic controls and valves
4. Resin precoat batch preparation subsystem, automatic sequencing, and tank agitators
5. Annunciators.

d. Acceptance Criteria - All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications; effective system filterability must be demonstrated similarly.

14.1.3.2.28 Condenser Vacuum System Preoperational Test

a. Test Objective - To verify the operation of the condenser vacuum system, including air-ejectors, and seal water and vacuum pumps

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing. The related support systems (the condensate makeup demineralizer, condensate, condensate storage, general service water, control air, and radwaste systems) must have readiness verification

c. General Test Method - Total system performance cannot be verified until nuclear steam is available; functional verification of the condenser vacuum system capability is demonstrated by the proper operation of the following:

  1. Vacuum and seal water pumps automatic operation
  2. System automatic valve operation
  3. Water makeup system automatic operation
  4. Air-ejector system operation
  5. Annunciators.

d. Acceptance Criteria - All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14.1.3.2.29 Condensate Storage System Preoperational Test

a. Test Objective - To verify the operation of the condensate storage system, including tanks, storage tank recirculating heat exchanger, pumps, reducing station, valves, instrumentation and controls

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing. The related support systems (the condensate makeup demineralizer and demineralized water supply header) must have readiness verification

c. General Test Method - Verification of the condensate storage system capability is demonstrated by the proper, integrated operation of the following:

  1. System pumps, motors, and their related automatic controls, interlocks, and safety devices
  2. Condensate storage tank heat exchanger
  3. Automatic valve operation
  4. Annunciators.

d. Acceptance Criteria - All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications; the emergency capacity of the condensate storage tank must be demonstrated similarly.

14.1.3.2.30 Plant Process Sampling System (Liquid Radwaste) Preoperational Test

a. Test Objective - To verify the operation of the plant process sampling system (liquid radwaste), including valves and controls

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedures and the initiation of testing. The required support systems and demineralized water must have readiness verification. Additionally, portions of the radwaste system must have readiness verification

c. General Test Method - Verification of the plant process sampling system (liquid radwaste) is demonstrated by the ability of the system to draw samples from the following radwaste subsystems:

1. Chemical waste tank
2. Waste sample tanks
3. Liquid radwaste effluent
4. Waste collector system: waste-collector tank, etched-disk filter, oil coalescer, precoat filter, demineralizer
5. Floor drain collector system: collector tank, etched-disk filter, oil coalescer, precoat filter, demineralizer
6. Evaporator feed surge tank, evaporator drains, evaporator drains holdup tank, evaporator concentrates feed tank, evaporator distillate surge tank
7. Waste clarifier tank and condensate phase separators
8. Decant from centrifuge and distillate from extruder-evaporator
9. Centrifuge feed tank and spent resin slurry feed tank
10. Fuel pool filter-demineralizer.

d. Acceptance Criteria - All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14.1.3.2.31 Plant Process Sampling System (Reactor) Preoperational Test

a. Test Objective - To verify the operation of the plant process sampling system (reactor), including sampling valves, isolation valves, pumps, motors, heat exchangers, and related equipment

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedures and the initiation of testing. The required support systems (control air, demineralized water, emergency equipment service water [EESW], and RBCCWS) must have readiness verification

c. General Test Method - Verification of the plant process sampling system (reactor) is demonstrated by the proper, integrated operation of the following:

1. Sampling lines and valve, automatic isolation valves, and the related sensors and indicators
2. Annunciators.

d. Acceptance Criteria - All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications. The ability of the system to draw samples from the reactor building equipment must be demonstrated.

14.1.3.2.32 Plant Process Sampling System (Turbine) Preoperational Test

a. Test Objective - To verify the operation of the plant process sampling system (turbine) including sampling valves, pressure regulators and reliefs, flow meter, monitor and recorder, pumps valve controls, and lights

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedures and the initiation of testing. Required support systems (demineralized water, turbine building closed cooling water system [TBCCWS], RBCCWS, condensate, circulating water, and condensate polishing demineralizer) must have readiness verification

c. General Test Method - Verification of the plant process sampling system (turbine) is demonstrated by the proper, integrated operation of the following:

   1. Sample lines pressure regulators, relief valves, and temperature baths

   2. Related sensors and indicators

   3. Condenser sample pump and motor

   4. Solenoid valve controls and indicator lights.

d. Acceptance Criteria - All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications. The ability of the system to draw samples from the turbine building equipment must be demonstrated.

14.1.3.2.33 Turbine Building Closed Cooling Water System Preoperational Test

a. Test Objective - To verify the operation of the TBCCWS, including pumps and associated motors, heat exchangers, makeup tank, valves, and instrumentation and control

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing. The related support systems (condensate storage, and control air) must have readiness verification

c. General Test Method - Verification of the TBCCWS is demonstrated by the proper, integrated operation of the following:

   1. Pumps, motors, and associated controls, interlocks, and alarms

   2. Automatic makeup to head tank, and all control valve operation

   3. System flow through all heat exchangers and coolers

   4. Annunciators.

d. Acceptance Criteria - All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications. However, no attempt will be made to simulate design heat loads or design flow rates through the various coolers and heat exchangers.

14.1.3.2.34 Reactor Building Closed Cooling Water System Preoperational Test

a. Test Objective - To verify the operation of the RBCCWS, including pumps and associated motors, heat exchangers, makeup tank, valves, and instrumentation and control

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing. The related support systems (condensate storage and control air) must have readiness verification

c. General Test Method - Verification of the RBCCWS capability is demonstrated by the proper, integrated operation of the following:

   1. Pumps, motors, and associated controls, interlocks, and alarms
   2. System flow through all heat exchangers and coolers
   3. Annunciators.

d. Acceptance Criteria - All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications. However, no attempt will be made to simulate design heat loads or design flow rates through the various coolers and heat exchangers.

14.1.3.2.35 Emergency Equipment Cooling and Service Water System Preoperational Test

a. Test Objective - To verify the operation of the emergency equipment cooling water (EECW) system, including pumps and motors, heat exchangers, makeup tanks, valves, and instrumentation and control

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing. The related support systems (condensate storage, RBCCW, RHR service water system, RHR cooling towers, RHR reservoir, and control air) must have readiness verification

c. General Test Method - Verification of the EECW system is demonstrated by the proper, integrated operation of the following:

   1. Pumps, motors, and associated controls, interlocks, and alarms
   2. Automatic makeup to makeup tank, and control valve operation
   3. System flow through all heat exchangers and coolers
   4. Annunciators
   5. EECW pumps automatic start logic

6. Automatic isolation of nonessential RBCCW system cooling loads from the EECW system loads.

d. Acceptance Criteria - All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications. However, no attempt will be made to simulate design heat loads or design flow rates through the various coolers and heat exchangers.

14.1.3.2.36 Station and Control Air System Preoperational Test

a. Test Objective - To verify the operation of the station and control air systems, including station air compressors and their related motors and controls, aftercoolers and air receivers, control air compressors and their related motors and controls, and air drying equipment

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing. The related support systems (the TBCCW and RBCCW) must have readiness verification

c. General Test Method - Verification of the station and control air system capability is demonstrated by the proper, integrated operation of the following:

1. Station air compressors and their motors and related controls, including loading and unloading
2. Aftercoolers, moisture separators, air receivers, and related solenoid-operated valves
3. Control air compressors and their related motors and automatic start loading and unloading controls
4. Air dryers and desiccant purge system blower, heater, and heat exchanger
5. Annunciators
6. System pressure decay test on noninterruptible control air.

d. Acceptance Criteria

1. All system components must be either verified for proper operation, or demonstrated to be within their respective engineering design specifications
2. Preoperational testing of the control air system is in accordance with Regulatory Guide 1.80 (June 1974).

14.1.3.2.37 Fire Protection System Preoperational Test

a. Test Objective - To verify the operation of the fire protection system, including normal and emergency water supplies, heat and smoke detection equipment and alarms, carbon dioxide systems, and Halon systems

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing. The general service water (GSW) system must have readiness verification. Prior to test of the transformer deluge systems, upstream manual valves are closed

c. General Test Method - Verification of the fire protection system capability is demonstrated by the proper, integrated operation of the following:

1. Motor-driven fire pump and related automatic startup controls and alarms
2. Diesel-driven fire pump and related diesel automatic startup controls, alarms, automatic battery selector, and engine cooling water
3. Deluge and sprinkler systems solenoid valves and their related alarms and detectors
4. Main control room smoke detectors and alarms
5. Turbine building heat and smoke vents, outbuildings smoke and fire detectors, and diesel generator building smoke and fire detectors
6. Annunciators.

d. Acceptance Criteria - All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14.1.3.2.38 Auxiliary Electrical Power System Preoperational Test

Contained in the auxiliary electrical power system are two engineered safety feature (ESF) load divisions (load groups), which are totally independent of one another. Within each division are two ESF power trains that can be tested individually without affecting the other train's buses or emergency diesel generator (EDG). The two divisions can be tested independently without affecting the alternate division's buses, EDGs, or redundant equipment. The tests are designed to prove the operability of the redundant systems and the availability of onsite power sources beyond l0 sec and to ensure proper loading for each EDG. The independence of divisions and redundancy of load groups will be verified to meet the requirements of Regulatory Guide 1.41 in the ECCS integrated test.

a. Test Objective - To verify the operation of the 4.16-kV/480-V ac power systems, including bus ties, transformers, switchgear, and related controls for

1. Load group assignments
2. Full load capability
3. Loss of offsite power.

b. Prerequisites - The checkout and initial operations tests have been completed, and the TRC has reviewed and approved the test procedure and the initiation of testing. The offsite l3.8-kV (l20-kV) and 345-kV preferred power supply sources must have readiness verification

c. General Test Method - Verification of the 4.l6-kV/480-V ac power systems is demonstrated by the proper, integrated operation on a divisional basis of the following:

1. 13.8-kV (120-kV) and 345-kV system service transformers and related controls
2. 13.8-kV source breaker and related controls
3. 4.16-kV buses and related controls
4. 4.16-kV tie breakers and related controls
5. 4.16-kV/480-V unit substations, including transformers
6. 480-V buses and related controls
7. 480-V motor control centers (MCCs) and related controls
8. 480-V load breakers and related controls
9. Load shedding - loss of offsite power and LOCA
10. Load sequencer operation
11. Annunciators.

Actual loading of the EDGs will be performed in the EDG system preoperational test (refer to Subsection 14.1.3.2.39)

d. Acceptance Criteria - All system components must be verified for proper load group assignment. All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14.1.3.2.39 Emergency Diesel Generator System Preoperational Test

a. Test Objective - To verify the proper operation of the EDG system under all design test conditions. The testing will include diesel engines, related support equipment and controls; generators, related electrical switchgear and load-shedding devices; safety devices and alarms

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing. The related support systems (the RHRSW and emergency diesel generator service water [EDGSW] system, EDG room ventilation system, auxiliary electrical system, 130/260-V dc system) must have readiness verification

c. General Test Method

1. Loss of Offsite Power - Simulate loss of offsite power and verify that the EDG system starts automatically
2. Loss of Offsite Power and LOCA - Simulate loss of offsite power and a LOCA condition and verify the proper operation of the load sequencer
3. Full-Load Test - Parallel the EDG to the offsite system and demonstrate operation for 2 hr at the 2-hr rating for the EDGs and continue operation for an additional 22 hr at the continuous rated load of the EDG

4. Hot Condition Test - Following the full-load test, repeat the loss of offsite power and LOCA test

5. Load Shed Test - Verify that voltage limits and overspeed limits are not reached when testing the loss of RHR pumps load and loss of complete rated load

6. Simulate Recovery - Verify that the EDG can be synchronized with offsite power to restore it to standby status, following the loss of offsite power tests, while the unit is connected to the emergency load

7. Reliability Test - Demonstrate 23 consecutive successful tests consisting of a manual start and load to 50 percent of continuous rating.

d. Acceptance Criteria - All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications; automatic startup and total load-carrying capability under emergency conditions must be demonstrated similarly.

14.1.3.2.40 120-V AC Instrument and Control Power System Preoperational Test

There are six l20-V ac instrument and control power supply systems. Three are located in each redundant electrical division; one from each division is used for ESF equipment. The tests are designed to prove the independence of the load groups of each instrument and control supply, to the requirements of Regulatory Guide 1.41.

a. Test Objective - To verify the operation of the l20-V ac instrument and control power system, including regulators, transformers, automatic switchgear, and related controls

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing. The system supply transformers, transfer switches, and regulators must have readiness verification

c. General Test Method - Verification of the 120-V ac instrument and control power system capability is demonstrated by the proper, integrated operation of the following:

1. System supply transformers

2. Automatic transfer switchgear and respective controls

3. Regulators

4. Annunciators.

d. Acceptance Criteria - All system components must be verified for proper load group assignment. They must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14.1.3.2.41 130/260-V DC Power System Preoperational Test

The 130/260-V dc power system consists of two divisional redundant and one balance-of-plant (BOP) 130/260-V battery charger load group combinations. The divisional dc systems used for ESF loads are redundant and independent of each other and of the BOP dc system.

The tests are designed to prove the independence of the systems and their load groups and to verify the supply and operability of the required load throughout the entire designed battery load period during the design-basis event. This includes verification of the operability of Class 1E dc loads that are required to operate at reduced battery voltage conditions. The requirements of Regulatory Guide 1.41 for the two divisional 130/260-V dc power systems for redundancy and load group assignment will be verified in the integrated ECCS test.

a. Test Objective - To verify the operation of the 130/260-V dc power system, including batteries, battery chargers, distribution panels, ground detectors, and alarms

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing. The ac supply power, batteries, and system components must have readiness verification

c. General Test Method - Verification of the 130/260-V dc power system is demonstrated by the proper, integrated operation of the following:

   1. Battery chargers: 480-V ac-130-V dc, and related controls
   2. Batteries
   3. Ground detectors
   4. DC power distribution panels
   5. Annunciators.

d. Acceptance Criteria - Required system components must be verified for proper operation at the reduced dc system voltage encountered when they are required to operate or must have been qualification-tested previously to a lower voltage. Total battery capacities under specified discharge rates must be demonstrated similarly.

14.1.3.2.42 24/48-V DC Power System Preoperational Test

There are two, independent 24/48-V dc power systems. Each system can be tested independently without affecting the other. The tests are designed to prove their ability to perform as designed. The requirements of Regulatory Guide 1.41, for independence and proper load group assignment, are verified in the integrated ECCS preoperational test.

a. Test Objective - To verify the operation of the 24/48-V dc power system, including batteries, battery chargers, distribution panels, and alarms

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing. The ac supply power, batteries, and system components must have readiness verification

c. General Test Method - Verification of the 24/48-V dc power system is demonstrated by the proper, integrated operation of the following.

   1. Battery chargers: 120-V ac-24-V dc, and their 480/120-V ac supply transformers
   2. Batteries
   3. DC power distribution panels, including under-voltage relays
   4. Annunciators.

d. Acceptance Criteria - All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications; total battery capacities under specified discharge rates must be demonstrated similarly.

14.1.3.2.43 Primary Containment Leak Rate Preoperational Test

a. Test Objective - To determine the leak rates of the primary containment, containment penetrations, MSIVs, and the drywell to suppression pool vacuum breakers

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing. Permanent plant air supply or a portable air compressor with filters and valves, pressure and temperature sensors, flow meters, and soap bubble and ultrasonic leak detection equipment must be available. Functional tests of isolation valves described in the nuclear boiler preoperational test (14.1.3.2.6) and vacuum breakers described in the containment vacuum breakers preoperational test (14.1.3.2.66) must be completed

c. General Test Method - Leak rates are determined by leak rate testing of the following:

   1. Local leak rate test of primary containment penetrations
   2. Local leak rate test of primary containment isolation valves and each torus to reactor building vacuum breaker and isolation valve
   3. Local leak rate tests of the MSIV
   4. Overall containment integrated leakage
   5. Integrated leakage test - drywell to suppression pool.

d. Acceptance Criteria - All leak rates from penetrations, valves, and overall containment must be shown to be within the limits specified in 10 CFR 50, Appendix J. Leakage from the drywell to suppression pool vacuum breakers shall be within the limits specified in the Technical Specifications.

14.1.3.2.44 Reactor Building Crane Preoperational Test

a. Test Objective - To verify the operation of the reactor building crane to design load

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing

c. General Test Method - Verification of the reactor building crane is demonstrated by the proper, integrated operation of the following:

   1. Limit switches
   2. Interlocks
   3. Motors and their related controls
   4. No-load, full-load, and overload conditions tests.

d. Acceptance Criteria - All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications, at both no-load and overload conditions.

14.1.3.2.45 Reactor Building Heating and Ventilation System Preoperational Test

a. Test Objective - To verify the operation of the reactor building heating and ventilation system, including filters, heaters, supply and exhaust fans, essential cooling coil units, and controls

b. Prerequisites - The checkout and initial pperations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing

c. General Test Method - Verification of the reactor building heating and ventilation system is demonstrated by the proper, integrated operation of the following:

   1. Fresh air intake louvers and filters
   2. Air intake heater and controls
   3. Supply and exhaust air fans and their related motors and controls
   4. Secondary containment isolation logic
   5. System shutoff and modulating dampers
   6. Annunciators
   7. Essential cooling coil units
      (a) ECCS pump rooms
      (b) Control center air conditioning system (CCACS) equipment room
      (c) Thermal recombiner cubicles

(d) Control air compressor areas

(e) EECWS equipment areas

(f) SGTS rooms

(g) Essential switchgear rooms

(h) Essential battery rooms.

8. Reactor building booster exhaust fans

9. Reactor building unit heaters.

d. Acceptance Criteria - All system components including air flow balancing must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14.1.3.2.46 Main Control Room Heating, Ventilation, and Air Conditioning Systems Preoperational Test

a. Test Objective - To verify the operation of the main control room heating, ventilation, and air conditioning (HVAC) systems and their related heaters, chillers, fans, chlorine detection, and radiation monitoring response action and controls

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing. The related support systems (the RBCCW, and control air) must have readiness verification

c. General Test Method - Verification of the main control room HVAC systems is demonstrated by the proper, integrated operation of the following:

1. Refrigeration compressors, condensers, and evaporators

2. Chilled water pump and motor and associated controls

3. Chiller control panel and thermostatic controls

4. Cooling coils and fans

5. Multizone air conditioners, including electronic air cleaners, filters, heaters, and coolers, humidifiers, and all related thermostats, humidistats, and controls

6. Indicating lights and alarms

7. Emergency recirculation fans and motors, and filters

8. All air-operated valves and dampers

9. Return air fans and related controls

10. Deleted

11. Annunciators

12. Deleted

13. Radiation monitoring response action
14. CCACS equipment room.

d. Acceptance Criteria - All system components including air flow balancing must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14.1.3.2.47 Standby Gas Treatment System Preoperational Test

a. Test Objective - To verify the operation of the SGTS, including system exhaust fans, decay heat removal fans, filters, air heaters, charcoal adsorber unit, isolation valves, and their controls

b. Prerequisites - The checkout and initial operation tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing. The control air system must have readiness verification

c. General Test Method - Verification of the SGTS is demonstrated by the proper, integrated operation of the following:

1. Exhaust fans and their related motors and controls
2. Decay heat removal fans and their related motors and controls
3. Charcoal adsorber carbon dioxide fire protection system
4. Air heater and its controls
5. Charcoal adsorber heater and controls
6. Alarms and annunciators.

d. Acceptance Criteria

1. All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications
2. Preoperational testing is in accordance with Regulatory Guide l.52 (June l973), Regulatory Position, C5b, C5c, and C6.

14.1.3.2.48 Drywell Cooling System Preoperational Test

a. Test Objective - To verify the operation of the drywell cooling system, including coolers, blowers, motors, and related logic and controls. Heat load performance of the system is checked during the startup test program

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing

c. General Test Method - Verification of the drywell cooling system capability is demonstrated by the proper, integrated operation of the following:

1. Cooling coils and flow balance valves

2. Cooling fans and their motors and related controls
3. Motor logic circuitry and protective features
4. Annunciator alarms.

d. Acceptance Criteria - All system components including air flow balancing must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14.1.3.2.49 Primary Containment Atmosphere Control Preoperational Test

a. Test Objective - To verify the operation of the primary containment atmosphere control system, including nitrogen inerting, purging, primary containment pneumatic supply, and pressure control systems

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing. The auxiliary steam system must have readiness verification

c. General Test Method - Verification of the primary containment atmosphere control system capability is demonstrated by the proper, integrated operation of the following:

1. Nitrogen storage tank pressure valve and controller, pressure relief valves, and instrumentation
2. Electric vaporizer and pressure buildup coil
3. Automatic pneumatic supply line containment isolation valves, sensors, and controls
4. Primary containment pneumatic supply isolation valves, controls, and interlocks
5. Temperature control and valve controllers
6. Nitrogen receivers pressure monitors and alarms
7. Steam vaporizer and controls
8. Primary containment purging valves, controls, and interlocks
9. Primary containment pressure control valves, makeup valves, vent valves, and controls
10. Annunciators.

d. Acceptance Criteria - All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14.1.3.2.50 Primary Containment Monitoring System Preoperational Test

a. Test Objective - To verify the operation of the primary containment monitoring system, including valves, monitoring sensors and channels, and temperature, pressure, and level monitors

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing

c. General Test Method - Verification of the primary containment monitoring system capability is demonstrated by the proper, integrated operation of the following:

   1. Isolation valves and sample pumps

   2. Primary containment atmosphere monitoring system, including filters, detectors, recorders and meters, alarms, and channels

      (a) Hydrogen-oxygen subsystem, including analyzers, recorders, and alarms

      (b) RMS, including gaseous detector and related monitoring, recording, and annunciating equipment.

   3. Temperature, pressure, and level subsystems, including pressure transmitters and recorders, thermocouples and recorders, and level transmitters and recorders.

d. Acceptance Criteria - All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14.1.3.2.51 Secondary Containment Leak Rate Preoperational Test

a. Test Objective - To measure the secondary containment leak rate

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing. The SGTS and reactor building heating and ventilation system must have readiness verification

c. General Test Method - Verification of the secondary containment boundary integrity is demonstrated by the leak rate testing of the overall secondary containment

d. Acceptance Criteria

   1. The ability of the SGTS to maintain the design negative pressure under containment isolation conditions must be demonstrated

   2. The SGTS must be able to draw down the secondary containment pressure to -0.25 in. of water under accident conditions within 10 minutes.

14.1.3.2.52 Turbine Building Heating and Ventilation System Preoperational Test

a. Test Objective - To verify the operation of the turbine building heating and ventilation system, including filters, heaters, supply and exhaust fans, and related controls

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing

c. General Test Method - Verification of the turbine building heating and ventilation system capability is demonstrated by the proper, integrated operation of the following:

   1. Fresh air intake louvers, filter, heater, and controls
   2. Supply and exhaust air fans and their related motors and controls
   3. Booster fan and propeller fans and their motors and controls
   4. System shutoff and modulating dampers
   5. Condensate return tanks and condensate return pumps and their related controls and interlocks
   6. Offgas adsorber room air conditioning units and controls
   7. Turbine building unit heaters.

d. Acceptance Criteria - All system components including air flow balancing must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14.1.3.2.53 Radwaste Building Heating and Ventilation System Preoperational Test

a. Test Objective - To verify the operation of the heating and ventilation system for the radwaste building, Health Physics lab, and radwaste control room

b. Prerequisites - The checkout and initial operations tests have been completed, and the TRC has reviewed and approved the test procedure and the initiation of testing. The related support systems (the auxiliary steam, control air, and condensate makeup demineralizer) must have readiness verification

c. General Test Method - Verification of the heating system is demonstrated by the proper, integrated operation of the following:

   1. Radwaste building supply and exhaust fans, steam heater, chiller, and associated controls and interlocks
   2. Health Physics lab and radwaste control room supply and exhaust fans, heater and chiller, and associated controls and interlocks
   3. Health Physics lab fume hood exhaust fan and controls
   4. Radwaste building battery room air conditioning unit

5. Radwaste building booster exhaust fans
6. Radwaste building unit heaters.

d. Acceptance Criteria - All system components including air flow balancing must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14.1.3.2.54 Communication and Evacuation Alarm System Preoperational Test

a. Test Objective - To verify the operation of the communication and evacuation alarm system, including the two-way radio, hi-com, telephone, hard-wired headset, and emergency alarm

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing

c. General Test Method - Verification of the communication and evacuation system capability is demonstrated by the proper, integrated operation of the following:

1. Two-way radio system, including base station, monitor receivers, selected portable transmitter/receivers, and base station speaker
2. Hi-com, including amplifiers, speakers, microphones, tone generator, signal relays, and control switches
3. System Supervisor's system
4. Hard-wired headset system and selected headsets
5. Emergency alarm system and alarm devices.

d. Acceptance Criteria - All permanently installed system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications. Proper operation of portable components (headsets and transceivers) will be by random sample and documented in the preoperational test.

14.1.3.2.55 Seismic Monitoring System Preoperational Test

a. Test Objective - To verify the operation of the seismic monitoring system, including accelerometers and recorders

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing

c. General Test Method - Verification of the seismic monitoring system capability is demonstrated by the proper integrated operation of the following:

1. Triaxial accelerometers
2. Signal conditioners and magnetic tape recorders

3. Seismic trigger and logic
4. Strip-chart recorder
5. Alarm circuits and annunciators
6. Batteries.

d. Acceptance Criteria - All system components must either be verified for proper operation or demonstrated to be within their respective engineering design specifications. Accelerometer signal input is simulated with a signal generator.

14.1.3.2.56 Residual Heat Removal Complex Heating and Ventilation System Preoperational Test

a. Test Objective - To verify the operation of the RHR complex heating and ventilation system, including heaters, supply fans, and instrumentation and controls

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing

c. General Test Method - Verification of the RHR complex heating and ventilation system is demonstrated by the proper, integrated operation of the following:

1. Diesel generator room, switchgear room and pump room fans, motors, and related controls and logic
2. Pump room temperature monitor and fan logic
3. Unit heaters and controls.

d. Acceptance Criteria - All system components including air flow balancing must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14.1.3.2.57 Residual Heat Removal Complex Service Water Systems Preoperational Test

a. Test Objective - To verify the operation of the RHRSW, EESW, and EDGSW systems, including pumps, fans, motors, cooling towers, and valves

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing

c. General Test Method - Verification of the RHR complex service water systems capability is demonstrated by the proper, integrated operation of the following:

1. RHRSW, EDGSW, and EESW pumps, motors, controls, and logic
2. RHRSW, EDGSW, and EESW pumps at minimum submergence level without vortexing
3. RHRSW, DGSW, and EESW pumps for 100 hr at rated flow

4. Pump minimum flow valves to tower basin
5. Cooling tower fans, motors, and controls, and spray nozzles
6. Cooling tower control valves
7. Pressure sensors, indicators, and annunciators.

d. Acceptance Criteria - All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications; no attempt is made to simulate design heat loads.

14.1.3.2.58 Condensate Makeup Demineralizer System Preoperational Test

a. Test Objective - To verify operation of the condensate makeup demineralizer system including pumps, motors, demineralizers, storage tanks, controls, interlocks, and alarms

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing. The related support systems (the control air, potable water, and auxiliary steam systems) must have readiness verification

c. General Test Method - Verification of the condensate makeup demineralizer system capability is demonstrated by the proper, integrated operation of the following:

1. System pumps, motors, and the related automatic controls, interlocks, and safety devices
2. Demineralizer train alarms, stops, interlocks, and automatic controls
3. Acid and caustic storage tanks automatic controls, and heating; demineralized water tank controls
4. Annunciators.

d. Acceptance Criteria - All system components must be verified for proper operation and shown to be within their respective engineering design specifications.

14.1.3.2.59 General Service Water System Preoperational Test

a. Test Objective - To verify the operation of the GSW system, including GSW pumps and motors, traveling screens, circulating water reservoir makeup pumps and motors, and GSW pump strainers with motors, valves, and instrumentation and control

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing

c. General Test Method - Verification of the GSW system capability is demonstrated by the proper, integrated operation of the following:

1. GSW pumps, motors, and their controls, interlocks, and alarms
2. Traveling screens, motors, and their controls, interlocks, and alarms
3. Circulating water reservoir makeup pumps, motors, and controls
4. GSW pump strainer controls
5. Annunciators.

d. Acceptance Criteria - All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications; however, no attempt is made to simulate design heat loads or design flow rate through the various heat exchangers until nuclear steam is available.

14.1.3.2.60 Circulating Water System Preoperational Test

a. Test Objective - To verify the operation of the circulating water system, including pumps and motors, chemical subsystems, cooling towers, and screens

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing. The GSW and control air systems must have readiness verification

c. General Test Method - Total system performance cannot be verified until full-power operation. Functional verification of the circulating water system is demonstrated by the proper operation of the following:

1. Circulating water pumps and related motors, pump and motor cooling, discharge valve operation, automatic controls and trips
2. Cooling tower isolation and bypass valves
3. Reservoir decanting pumps and related controls and interlocks
4. Chemical injection equipment
5. Annunciators.

d. Acceptance Criteria - All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications. Heat load performance is deferred until the power test program.

14.1.3.2.61 Offgas System Preoperational Test

a. Test Objective - To verify the operation of the offgas system, including pumps, motors, fans, gas treatment equipment, and instrumentation and control

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing. Demineralized water and control air systems must have readiness verification

c. General Test Method - Verification of the offgas system capability is demonstrated by the proper, integrated operation of the following:

1. All motor-operated pumps, compressors, and fans and their related controls and logic
2. System instrumentation
3. System valves
4. Annunciators
5. Demonstrate offgas system gas-handling ability by introducing control air into the system at rated flow
6. Krypton gas test to verify design delay time.

d. Acceptance Criteria - All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications. The Krypton gas test will verify design delay time.

14.1.3.2.62 Main Turbine Electro-Hydraulic Control System Preoperational Test

a. Test Objective - To verify the operation of the electrohydraulic control (EHC) system, including speed governor equipment, reactor pressure control equipment valves, and instrumentation and control

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing. Turbine cannot be tested until nuclear steam is available, but functional verification is performed. The EHC system and hydraulic fluid cooling system must have readiness verification

c. General Test Method - Verification of the EHC system is demonstrated by the proper, integrated operation of the following:

1. Hydraulic fluid pumps, motors, and their controls; fluid test valve; and fluid heaters, coolers, fans, and their respective controls, alarms, and annunciators
2. Stop valves, control valves, intercept valves, and bypass valves opening, closing, and logic
3. Wide-range runup control
4. Onload testing of turbine valves
5. Narrow-range speed governor and reactor pressure control equipment (using signal generator).

d. Acceptance Criteria - All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14.1.3.2.63 Thermal Recombiner System Preoperational Test

a. Test Objective - To verify the operation of the thermal recombiner system, including reaction chamber, separator, blower, related valves, and instrumentation and control

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing. No attempt is made to simulate design heat loads

c. General Test Method - Verification of the thermal recombiner system capability is demonstrated by the proper, integrated operation of the following:

   1. Blower and controls
   2. Heater chamber and controls
   3. Reaction chamber and controls
   4. Water spray cooler and separator
   5. Instrumentation, valves, and annunciators.

d. Acceptance Criteria - All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14.1.3.2.64 System Vibration and Expansion Preoperational Test

a. Test Objective - To verify proper installation and load adjustment of the piping support system, and to verify that fluid systems and their supports are not subject to excessive deflections and vibrations caused by normal and abnormal hydrodynamic transients

b. Prerequisites - The checkout and initial operations tests for the affected systems have been completed and the TRC or Onsite Review Organization (OSRO) has reviewed and approved the test procedure and the initiation of testing. The specific system tested must have readiness verification

c. General Test Method - Verification of acceptable performance is demonstrated by the following tasks:

   1. Check all hangers and snubbers for proper position and load indication after the system is filled with fluid or drained as appropriate to the system service
   2. Check for abnormal deflection or sag of piping
   3. Conduct vibration surveys during system operation and record and evaluate deflection and vibration data. A detailed discussion of the vibration operational test program is presented in Subsection 3.9.1.1. Table 3.9-1 presents a list of the systems to be tested. Certain vibration surveys will be performed after fuel load as part of the startup test program.

d. Acceptance Criteria - The piping system and its support system must be verified to be within established engineering design limits. The detailed acceptance criteria are provided in Subsection 3.9.1.1.

14.1.3.2.65 Primary Containment, Secondary Containment, and Auxiliary Building Equipment Drains and Floor Drains Preoperational Test

a. Test Objective - To verify the operation of the isolation valves in the drain lines that interconnect the two corner rooms of each division located in the subbasement

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing. The sump pumps in the reactor building and primary containment must have readiness verification

c. General Test Method - The proper operation of the floor drains is demonstrated by closure of the valves in the floor drain and equipment drain lines that interconnect the corner rooms

d. Acceptance Criteria - All flood control isolation valves shall be verified to close on hi-hi sump water level.

14.1.3.2.66 Containment Vacuum Breakers Preoperational Test

a. Test Objective - To verify the proper adjustment and operation of the containment vacuum breakers, including the drywell-to-torus and torus-to-reactor building vacuum breakers and the torus-to-reactor building isolation valves. (Individual vacuum breaker leakage is measured as part of the primary containment leak-rate preoperational test)

b. Prerequisites - The Checkout and Initial Operations Tests have been completed as required, and the TRC has reviewed and approved the test procedure and the initiation of testing

c. General Test Method - Verification of the vacuum breaker functionability is demonstrated by the following:

   1. Opening force tests on each vacuum breaker

   2. Operability tests of the vacuum breakers using the air operators

   3. Measurement of the close switch setpoint gap on the vacuum breakers

   4. Operability tests on the torus-to-reactor building isolation valves.

d. Acceptance Criteria - During operability tests, valve closing times, position indicating instrumentation, and the torus-to-reactor building isolation valve opening differential pressure meet the respective engineering design specifications. The vacuum breaker opening force measurement is less than the equivalent force exerted by the design opening differential pressure. The opening gap at the close switch setpoint is adjusted to less than, or equal to, 0.03 in.

14.1.3.2.67 Emergency Lighting System Preoperational Test

The emergency lighting system is designed to provide minimum adequate lighting during loss of normal lighting. The tests are designed to prove the independence of load groups of the emergency lighting system. The tests are designed to meet the requirements of Regulatory Guide l.4l.

a. Test Objective - To verify the operation of the emergency lighting system, including transformers, automatic transfer switchgear, and the related controls

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing. The system supply transformers, automatic transfer switches, and dc systems must have readiness verification

c. General Test Method - Verification of the emergency lighting system capability is demonstrated by the proper, integrated operation of the following:

   1. System supply transformers
   2. Automatic transfer switchgear and respective controls
   3. The lighting fixtures
   4. Annunciators.

d. Acceptance Criteria - All system components must be verified for proper load group assignment. All system components must be either verified for proper operation, or demonstrated to be within their respective engineering design specifications.

14.1.3.2.68 Personnel Monitoring, Survey Instruments, and Laboratory Equipment Preoperational Test

a. Test Objective - To verify proper operation of personnel monitoring, survey instruments, and the laboratory equipment

b. Methodology - Site procedures of chemistry and health physics are used to preoperationally test and verify the proper operation of personnel monitoring, survey instruments, and the laboratory equipment described in Section 12.3. This testing is performed by chemistry and health physics personnel. Test results are reviewed by group supervisors and maintained as a plant record. This program is described in the Plant Operating Manual and is audited by Quality Assurance. Although this program is somewhat different from other preoperational tests, the intent of Regulatory Guide 1.68 is fulfilled.

14.1.3.2.69 Reactor System Hydrostatic Preoperational Test

a. Test Objective - The test objective is to demonstrate the pressure-retaining integrity of the RPV and all connecting piping welds out to, and including, the welds connecting the first isolation valve in each connecting pipe

b. Prerequisites - The checkout and initial operations tests have been completed as necessary, and the TRC has reviewed and approved the test procedure and the initiation of testing. The related support system must be operable

c. General Test Method - The RPV hydrostatic test includes heatup, pressurization, inspection, and depressurization requirements

d. Acceptance Criteria - The test demonstrates zero leakage at all welded connections at test pressure.

14.1.3.2.70 Main Steam Line Isolation Valve Leakage Control System Preoperational Test

a. Test Objective - To verify the operation of the MSIV leakage control system, including controls, instrumentation, and all active components

b. Prerequisites - The checkout and initial operations tests have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing

c. General Test Method - Verification of system capability is demonstrated by the proper, integrated operation of the following:

1. System logic, interlocks, and timers
2. All valves and related controls and instrumentation, including the pressure regulators
3. Pressure and flow monitoring devices
4. Local and remote indication
5. Proper system response to the loss of each of the leakage control system air supplies
6. Proper system response will be functionally tested by manual initiation of each division using the applicable Plant Operating Procedure under conditions that simulate actual service conditions.

d. Acceptance Criteria - All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications.

14.1.3.2.71 Reactor Internals Flow-Induced Vibration Preoperational Test

a. Test Objective - To detect damage or excessive wear, loose parts, or other unacceptable vibration that could result from assembly errors or undesirable deviation from the previously qualified prototype plant. The test is performed consistent with the requirements of Regulatory Guide 1.20

b. Prerequisites - The reactor recirculation system must have readiness verification. Core support structures and components, fuel support castings, surveillance specimen holders and specimens, jet pumps, spargers, shroud head, steam separator, and reactor vessel head are installed during the flow test.

Temporary hardware is removed, and control rod blades either removed or fully redrawn

The core matrix must be empty; fuel assemblies, incore instrumentation tubes, and neutron source rods are not installed

c. General Test Method - Prior to the recirculation system flow excitation testing, a preliminary, internal, visual inspection of the vessel and components takes place. All or part of this inspection is by normal, visual fabrication inspection. After the preliminary visual inspections, the reactor recirculation system is operated at rated volumetric core flow for a minimum of 35 hr. Each reactor recirculation loop is operated independently for a minimum of 14 hr. The flow testing sequence is not important as long as the above flow conditions, totaling a minimum of 63 hr, are accumulated at some time between the preflow and postflow vessel internal inspection

   Following completion of the flow testing, a reactor vessel water sample taken at bottom vessel drain line will be examined for wear products. The vessel will be drained, and the areas examined in the preflow inspection examined again

d. Acceptance Criteria - There must be no evidence of defects, loose parts, or wear resulting from the flow test. Flush cloths used for the bottom vessel drain sample must show no more than a slight particle speckling. Results of the vibration test are submitted to the NRC in accordance with Regulatory Guide 1.20.

14.1.3.2.72 Remote Shutdown Preoperational Test

a. Test Objective - To verify that systems to be used during a shutdown operation from outside the control room at the remote shutdown panel are operable in the manner in which they would be used during a shutdown

b. Prerequisites - The checkout and initial operations tests for the systems associated with the remote shutdown panel have been completed and the TRC has reviewed and approved the test procedure and the initiation of testing for each affected individual system

c. General Test Method - Verification of remote shutdown capability is demonstrated by the proper operation of the following:

   1. Individual system or component preoperational tests associated with the remote shutdown panel

   2. Each valve, pump, and logic that is controlled from the remote shutdown panel

   3. Instruments at the remote shutdown panel displaying plant parameters

   4. Annunciator alarms.

d. Acceptance Criteria - All system components must be either verified for proper operation or demonstrated to be within their engineering design specifications. Operation of all valves and pumps must be satisfactory. Analog instruments at the remote shutdown panel displaying plant parameters must mimic the corresponding main control room instruments.

14.1.3.2.73 Torus Water Management System Preoperational Test

a. Test Objective - To verify the operation of the torus water management system (TWMS), including pumps, valves, and controls and instrumentation

b. Prerequisites - The checkout and initial operations tests have been completed, and the TRC has reviewed and approved the test procedure and initiation of testing. The condenser must be available and ready to receive water. The torus must be available and contain water

c. General Test Method - Verification of TWMS capability is demonstrated by the proper, integrated operation of the following:

   1. Alarm and logic verification

   2. Pump performance and functional tests.

d. Acceptance Criteria - All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications; a total system operational capability must also be demonstrated.

14.1.3.2.74 Postaccident Sampling System Preoperational Test

a. Test Objective - The purpose of this test is to demonstrate proper operation of the postaccident sampling system. Specific objectives are to demonstrate the following:

   1. The ability to obtain a gas or liquid sample from the correct sample source

   2. The proper operation of the sample system control logic, including interlocks

   3. The proper operation of the sample panel graphic display lights.

b. Prerequisites - The checkout and initial operations tests have been completed, and the TRC has reviewed and approved the test procedure and the initiation of testing. The required support systems RHR system, reactor recirculation system, and RBCCWS must have readiness verification

c. General Test Method - Verification of the postaccident sampling system is demonstrated by the proper, integrated operation of the following.

   1. Sampling lines and sample isolation valves

   2. All sensing devices

   3. All motor-, solenoid-, and nitrogen-operated valves in the control panel, sample station, and piping station

   4. All control logic and interlocks

   5. Gas sample chiller

6. Gas sample heat tracing
7. All indicator lights and annunciators.

In addition, all cask and sample vial positioners shall be operated to verify ability to align with the sample station and to perform their functions in obtaining the desired liquid or gas sample.

d. Acceptance Criteria

1. All system components must be either verified for proper operation or demonstrated to be within their respective engineering design specifications
2. The postaccident sampling system shall be capable of obtaining both a gas and a liquid sample.

14.1.4 Fuel Load and Initial Operation - Startup Test Phase

At the time of fuel loading, the preoperational test results for all completed tests were approved by the TRC, and access control was established, and the startup test phase began. The startup test phase begins with preparation for fuel loading and extends to the completion of the warranty demonstration. This phase is subdivided into the following four parts:

a. Fuel loading and open vessel tests
b. Initial heatup
c. Power tests
d. Warranty demonstration.

This section describes each of the parts of the startup test phase, the tests to be conducted and their sequence, the administrative methods to be used for procedure and test control, and the functions of the Edison Startup Test Phase Group. Normal plant personnel responsibilities, authorities, and qualifications are given in Chapter 13. The startup test phase and all associated testing activities adhere closely to Regulatory Guide 1.68, "Preoperational and Initial Startup Test Programs for Water-Cooled Power Reactors."

The overall objectives of the startup test phase are as follows:

a. To achieve an orderly and safe initial core loading
b. To perform all testing and measurements necessary to determine that the approach to initial criticality and the subsequent power ascension are accomplished safely and orderly
c. To conduct low-power physics tests sufficient to ensure that physics design parameters have been met
d. To conduct initial heatup and hot functional testing so that hot integrated operation of all systems is shown to meet design specifications
e. To conduct an orderly and safe power ascension program, with requisite physics and systems testing, to ensure that the plant operating at power meets design intent

f. To conduct a successful warranty demonstration program.

Tests conducted during the startup test phase consist of major plant transients, stability tests, and a remainder of tests that are directed toward demonstrating correct performance of the nuclear boiler and numerous auxiliary plant systems while at power. Certain tests may be identified with more than one part of the startup test phase. Table 14.1-1 shows a general view of the startup test phase program and should be considered in conjunction with Figure 14.1-2, which shows, graphically, the various test areas as a function of core thermal power and flow.

14.1.4.1 Fuel Loading and Open Vessel Tests

Fuel loading began when the preoperational testing program described in Subsection l4.l.3 had been completed to the maximum extent practical and when the TRC and the augmented OSRO approved the initial fuel loading.

14.1.4.2 Initial Heatup

The heatup testing phase has been completed at Fermi 2. All required tests were completed successfully. A more detailed discussion of the testing performed during this period is given in the test abstracts (Subsection 14.1.4.8), which were applicable for this phase of testing.

14.1.4.3 Power Tests

Many of the tests of the power test phase are repeated several times at different test levels. Table 14.1-1 and Figure 14.1-2 show, in general, the planned order of execution for the full series of tests.

Coolant chemistry tests and radiation surveys are made at each principal test level to preserve a safe and efficient power increase. The effect of control rod movement on other parameters (e.g., electrical output, steam flow, and neutron flux level), is examined for different power conditions. Following the first reasonably accurate heat balance, the APRMs and IRMs are readjusted if necessary.

At major power levels, the LPRMs and APRMs are calibrated. Completion of the process computer checkout is made for all variables, and the various options are compared with independent calculations as soon as significant power levels are available. Further tests of the RCIC and the HPCI systems are made with and without injection into the RPV.

Collection of data from the system expansion tests is completed for those piping systems that had not previously reached full operating temperatures. The axial and radial power profiles are explored fully by means of the TIP system at representative power levels during power ascension.

Core performance evaluations are made at selected test points above the 10 percent power level; the work involves the determination of core thermal power, maximum linear heat generation rate, and minimum critical power ratio (MCPR).

Overall plant stability in relation to minor perturbations is shown by the following group of tests:

a. Pressure regulator setpoint change

b. Pressure regulator failure

c. Feedwater system setpoint change

d. Flow control setpoint change.

The category of major plant transients includes full closure of all the MSIVs, fast closure of turbine generator control/stop valves, loss of the main generator and offsite power, feedwater system heating loss, trip of a feedwater pump, and a recirculation pump trip. The plant transient behavior is recorded for each test, and the results are compared with the predicted design performance.

A test is made of the safety/relief valves (SRVs) in which leaktightness and general operability are demonstrated. At selected major power levels, the jet pump flow instrumentation is calibrated. The local control loop performance, based on the drive motor, fluid coupler, generator, drive pump, jet pumps, and control equipment, is checked. Vibration testing is conducted at several power conditions as the operating power level is raised.

Heat load performance of certain fluid and ventilation systems is demonstrated. These systems were tested previously during the preoperational test phase to demonstrate their operability and their ability to meet safety criteria, but could not be tested for heat load performance until normal plant operating conditions were available. The demonstration of heat load performance includes tuning of system controls and base line data acquisition for future performance evaluation. These continuations of preoperational tests will be treated, for administrative control purposes, as separate tests conducted in parallel with the startup tests.

14.1.4.4 Warranty Demonstration

The warranty test phase consists of a demonstration in which the steaming rate and steam quality are shown to comply with contractual obligations. This demonstration includes a 100-hr full-power run.

14.1.4.5 Startup Test Procedure Preparation, Approval, and Modification

Startup Test Procedures are prepared by Edison or their designated agents. These procedures are based on GE-supplied Startup Test Specifications and other source documents. Draft startup test procedures are reviewed by the Edison Startup Test Phase Group, then submitted to the augmented OSRO for review and approval.

Minor modifications to the approved procedures can be made if the modification does not change the intent of the test. The responsible Startup Test Phase Engineer and an Edison Senior Reactor Operator (SRO) can provide approval of the minor modifications. Minor changes are handled administratively in a manner similar to normal plant procedures as described in Section 13.5.

Major modifications to the approved procedures are those that change the intent of the startup test or that will change safety margins already approved. Such proposed modifications must undergo review and approval of the augmented OSRO prior to test performance. Major changes to procedures required after the start of testing necessitate a halt of the test until the augmented OSRO reviews and approves the proposed major modifications. If Startup Test Specification Level 1 Criteria are involved in the major change, the GE Site Operations Manager may be required to obtain approval of the intended change from GE Engineering.

14.1.4.6 Startup Test Execution

Startup test performance and supervision is the responsibility of the Startup Test Phase Engineer and plant personnel who obtain technical direction, where applicable, from the GE Operations Shift Engineers and Test Design and Analysis Shift Test Engineers. Startup Test Phase Engineers are assigned to follow startup tests on a shift basis.

All startup tests are performed according to approved startup test procedures.

14.1.4.7 Startup Test Results Approval and Approvals for Power Escalation

All startup tests are documented by the responsible Startup Test Phase Engineer. The test report is reviewed by the Startup Engineer - Test phase or his delegate before submittal to the augmented OSRO and Plant Manager for approval.

During startup testing, many of the tests are repeated several times at different test levels or test conditions. These test conditions are used for convenience to define the basic plant conditions of core power and core flow.

The sequence in which each test condition must be performed is shown below. An exception to this sequence is Test Condition 4, which may be conducted any time after the completion of Test Condition 3.

Individual tests within each test condition may be performed in any desired sequence. However, all testing within each test condition must be completed before proceeding to the next test condition except for justifiable exceptions approved by the augmented OSRO and Plant Manager.

Most of the test conditions are shown in terms of reactor power versus core flow on Figure 14.1-2. The test condition designations and sequence are further defined as follows:

<u>Test Conditions</u>

a. Pre fuel-load tests, fuel-load tests, and open vessel tests
b. Heatup testing
c. Test Condition 1
d. Test Condition 2
e. Test Condition 3
f. Test Condition 4 (may be performed at any time following Test Condition 3)
g. Test Condition 5
h. Test Condition 6 and warranty run tests.

Prior to initiating each test condition, the augmented OSRO reviews the test results of the previous test condition. It determines that the results are adequate and present no safety hazards to personnel, equipment, or the general public, and that any test exceptions have been properly dispositioned. The augmented OSRO presents its findings and recommendations to the Plant Manager. The Plant Manager, when satisfied that the test results are proper and that the conditions required for the next test condition of startup testing are available, will give approval to advance in the testing sequence.

14.1.4.8 General Discussion of Startup Tests

The startup test program is specified on the following pages. The general sequence planned can be obtained from Table 14.1-1. Start at the left side of the page and move to the right. The sequence of tests in a column is as follows:

a. Core performance analysis

b. Steady-state testing

c. Control system tuning

d. Major transients.

In describing the objectives of a test, an attempt is made to identify those operating and safety-oriented characteristics of the plant which are being explored.

Where applicable, a definition of the relevant acceptance criteria for the test is given and is designated either Level l or Level 2. A Level 1 criterion normally relates to the value of a process variable assigned in the design of the plant, component systems, or associated equipment. If a Level 1 criterion is not satisfied, the plant will be placed in a suitable hold-condition until resolution is obtained. Tests compatible with this hold- condition may be continued. Following resolution, applicable tests must be repeated to verify that the requirements of the Level 1 criterion are now satisfied.

A Level 2 criterion is associated with expectations relating to the performance of systems. If a Level 2 criterion is not satisfied, operating and testing plans would not necessarily be altered. The measurements and analytical techniques used for the predictions would be investigated.

Acceptance criteria values presented in the following test descriptions will be verified against the approved Technical Specifications prior to Startup Test Procedure performance. Where differences exist, the Technical Specifications shall take precedence.

A detailed and specific startup test procedure is written for each of the startup tests. The startup test procedure is the document which provides detailed instruction for each test when performed by the test personnel. A list of the startup tests presently planned, together with subsection sequence for use in locating a particular test discussion, follows.

STARTUP TESTS

Subsection	Test Title
14.1.4.8.1	Chemical and Radiochemical

STARTUP TESTS

Subsection	Test Title
14.1.4.8.2	Radiation Measurements
14.1.4.8.3	Fuel Loading
14.1.4.8.4	Full Core Shutdown Margin
14.1.4.8.5	Control Rod Drive System
14.1.4.8.6	Source Range Monitor Performance and Control Rod Sequence
14.1.4.8.7	Water Level Reference Leg Temperature Measurement
14.1.4.8.8	Intermediate Range Monitor Performance
14.1.4.8.9	Local Power Range Monitor Calibration
14.1.4.8.10	Average Power Range Monitor Calibration
14.1.4.8.11	Process Computer
14.1.4.8.12	Reactor Core Isolation Cooling System
14.1.4.8.13	High Pressure Coolant Injection System
14.1.4.8.14	Selected Process Temperatures
14.1.4.8.15	System Expansion
14.1.4.8.16	(Not Applicable)
14.1.4.8.17	Core Performance
14.1.4.8.18	Steam Production (Deleted)
14.1.4.8.19	(Not Applicable)
14.1.4.8.20	Pressure Regulator
14.1.4.8.21	Feedwater System
14.1.4.8.22	Turbine Valve Surveillance
14.1.4.8.23	Main Steam Isolation Valves
14.1.4.8.24	Relief Valves
14.1.4.8.25	Turbine Stop Valve and Control Valve Fast Closure Trips
14.1.4.8.26	Shutdown From Outside the Control Room
14.1.4.8.27	Flow Control
14.1.4.8.28	Recirculation System

STARTUP TESTS

Subsection	Test Title
14.1.4.8.29	Loss of Turbine-Generator and Offsite Power
14.1.4.8.30	Steady-State Vibration
14.1.4.8.31	Recirculation System Flow Calibration
14.1.4.8.32	Reactor Water Cleanup System
14.1.4.8.33	Residual Heat Removal System
14.1.4.8.34	Piping System Dynamic Response Testing

14.1.4.8.1 Chemical and Radiochemical

Purpose

The principal objectives of this test are to secure information on the chemistry and radiochemistry of the reactor coolant, and to determine that the sampling equipment, procedures, and analytic techniques are adequate to supply the data required to demonstrate that the chemistry of all parts of the entire reactor system meet specifications and process requirements.

Specific objectives of the test program include evaluation of fuel performance, evaluations of filter-demineralizer operations by direct and indirect methods, confirmation of condenser integrity, demonstration of proper steam separator-dryer operation, measurement and calibration of the offgas system, and calibration of certain process instrumentation. Data for these purposes are secured from a variety of sources: plant operating records, regular routine coolant analysis, radiochemical measurements of specific nuclides, and special chemical tests.

Description

Prior to fuel loading, a complete set of chemical and radiochemical samples is taken to ensure that all sample stations are functioning properly, and to determine initial concentrations. Subsequent to fuel loading, during reactor heatup and at each major power level change, samples are taken and analyzed to determine the chemical and radiochemical quality of primary coolant, the amount of radiolytic gas in the steam, gaseous activities leaving the air ejectors, decay times in the offgas lines, and performance of filter-demineralizers. Calibrations are made on monitors in the stack, liquid waste system, and liquid process lines.

Criteria

Level 1

Chemical factors defined in the Technical Specifications and Fuel Warranty must be maintained within the limits specified. The activity of gaseous and liquid effluents must conform to license limitations. Water quality must be known at all times and remain within the guidelines of the Water Quality Specifications.

Level 2

Not applicable.

14.1.4.8.2 Radiation Measurements

Purpose

The purposes of this test are to determine the background radiation levels in the plant environs prior to operation for base data on activity buildup, and to monitor radiation at selected power levels to ensure the protection of personnel during plant operation.

Description

A survey of natural background radiation throughout the plant site is made prior to fuel loading. Subsequent to fuel loading, during reactor heatup and at major levels during the initial power ascension program, gamma radiation level measurements, and, where appropriate, thermal and fast neutron dose-rate measurements, are made at significant locations throughout the plant. All potentially high radiation areas are surveyed.

Criteria

Level 1

The radiation doses of plant origin and the occupancy times of personnel in radiation zones shall be controlled consistent with the guidelines of the standards for protection against radiation outlined in 10 CFR 20, "Standards for Protection Against Radiation," and NRC General Design Criteria.

Level 2

Not applicable.

14.1.4.8.3 Fuel Loading

Purpose

The purpose of this test is to load fuel safely and efficiently to the full core size.

Description

Prior to fuel loading, control rods and neutron sources and detectors are installed and tested. Fuel loading begins at the center of the core and proceeds radially to the fully loaded configuration. Control rod functional tests, subcriticality checks, and shutdown margin demonstrations are performed periodically during the loading.

Criteria

Level 1

The partially loaded core must be subcritical by at least 0.38 percent $\Delta k/k$ with the analytically determined strongest rod fully withdrawn.

Level 2

Not applicable.

14.1.4.8.4 Full Core Shutdown Margin

Purpose

The purpose of this test is to demonstrate that the reactor is subcritical throughout the first fuel cycle with any single control rod fully withdrawn.

Description

This test is performed in the fully loaded core in the Xenon-free condition. The shutdown margin is measured by withdrawing the control rods until criticality is reached. If criticality is not reached with in-sequence control rods in the configuration corresponding to the required shutdown margin reactivity, the shutdown margin is satisfied. Additional in-sequence control rods are then withdrawn until the reactor is critical. The difference between the measured K_{eff} and the calculated K_{eff} for the in-sequence critical will be applied to the calculated shutdown margin to obtain the true shutdown margin.

Criteria

Level 1

The shutdown margin of the fully loaded core with the analytically determined strongest rod withdrawn must be at least 0.38 percent $\Delta k/k$ plus an additional margin for exposure.

Level 2

Criticality should occur within ±1.0 percent $\Delta k/k$ of the predicted critical.

14.1.4.8.5 Control Rod Drive System

Purpose

The purposes of the CRD system test are to demonstrate that the CRD system operates properly over the full range of primary coolant temperatures and pressures from ambient to operating, and to determine the initial operating characteristics of the entire CRD system.

Description

The CRD tests performed during the open vessel, heatup, and power test parts of the startup test program are designed as an extension of the tests performed during the preoperational CRD system tests. Thus, after it is verified that all CRDs operate properly when installed, they are tested periodically during heatup to ensure that there is no significant binding caused by thermal expansion of the core components. A list of all CRD tests to be performed during startup testing is given in Table 14.1-2.

Criteria

Level 1

Each CRD must have a normal withdrawal speed less than, or equal to, 3.6 in./sec, indicated by a full 12-ft stroke in greater than, or equal to, 40 sec. The mean scram time of all operable

CRDs with functioning accumulators must not exceed the following times (scram time is measured from the time the pilot scram valve solenoids are deenergized).

Position Inserted From Fully Withdrawn	Scram Time (sec)
46	0.358
36	1.096
26	1.860
06	3.419

The mean scram time of the three fastest CRDs in a two-by-two array must not exceed the following times (scram time is measured from the time the pilot scram valve solenoids are deenergized):

Position Inserted From Fully Withdrawn	Scram Time (sec)
46	0.379
36	1.161
26	1.971
06	3.624

Level 2

Each CRD must have a normal insertion or withdrawal speed of 3.0 ± 0.6 in./sec, indicated by a full 12-ft stroke in 40 to 60 sec. With respect to the CRD friction tests, if the differential pressure variation exceeds 15 psid for a continuous drive-in, a settling test must be performed. In this case, the differential settling pressure should not be less than 30 psid, nor should it vary by more than 10 psid over a full stroke.

14.1.4.8.6 Source Range Monitor Performance and Control Rod Sequence

Purpose

The purpose of this test is to demonstrate that the operational sources, source range monitor (SRM) instrumentation, and rod withdrawal sequences provide adequate information to achieve criticality and increase power in a safe and efficient manner. The effect of typical rod movements on reactor power will be determined.

Description

The operational neutron sources will be installed and SRM count rate data will be taken during rod withdrawals to critical and compared with stated criteria on signal and signal count-to-noise count ratio. A withdrawal sequence has been calculated that completely specifies control rod withdrawals from the all-rods-in condition to the rated power configuration.

Movement of rods in a prescribed sequence is monitored by the rod worth minimizer (RWM) and rod sequence control system (RSCS), which will prevent out-of-sequence withdrawal. Also, not more than two rods may be inserted out of sequence. As the withdrawal of each rod group is completed through Test Condition 1 (see Figure 14.1-2), the electrical power, steam flow, control valve position, and average power range monitor (APRM) response are recorded.

Criteria

Level 1

There must be a neutron signal count-to-noise count ratio of at least 2:1 on the required operable SRMs or fuel-loading chambers. The minimum count rate, as defined by the Technical Specifications, must be met on the required operable SRMs or fuel-loading chambers.

Level 2

Not applicable.

14.1.4.8.7 Water Level Reference Leg Temperature Measurement

Purpose

The purpose of this test is to measure the reference leg temperature and recalibrate the instruments if the measured temperature is different from the value assumed during the initial calibration.

Description

To monitor the reactor vessel water level, four level instrument systems are provided. These are the following:

a. Shutdown (floodup) range

b. Narrow range

c. Wide range

d. Fuel (core level) range.

These systems are used, respectively, as follows:

a. Water level measurement, cold shutdown conditions

b. Feedwater flow and water level control functions, hot operating conditions

c. Safety functions, hot operating conditions

d. Safety functions, postaccident conditions.

This test will be done at rated temperature and pressure and under steady-state conditions and will verify that the reference leg temperatures of the instruments are the values assumed during initial calibration. If not, the instruments will be recalibrated using the measured value.

Criteria

Level 1

Not applicable.

Level 2

The difference between the actual reference leg temperature(s) and the value(s) assumed during initial calibration shall be less than that amount that will result in a scale endpoint error of 1 percent of the instrument span for each range.

14.1.4.8.8 Intermediate Range Monitor Performance

Purpose

The purpose of this test is to adjust the intermediate range monitor system (IRMS) to obtain an optimum overlap with the SRM and APRM systems.

Description

Initially, the IRM system is set to maximum gain. After the APRM calibration, the IRM gains are adjusted to optimize the IRM overlap with the SRMs and APRMs.

Criteria

Level 1

Each IRM channel must be on scale before the SRMs exceed their rod block setpoint. Each APRM must be on scale before the IRMs exceed their rod block setpoint.

Level 2

Not applicable.

14.1.4.8.9 Local Power Range Monitor Calibration

Purpose

The purpose of this test is to calibrate the LPRM system.

Description

The LPRM channels are calibrated to make the LPRM readings proportional to the neutron flux in the LPRM water gap at the chamber elevation. Calibration factors are obtained through the use of either an off-line or a process computer calculation that relates the LPRM reading to average fuel assembly power at the chamber height.

Criteria

Level 1

Not applicable.

Level 2

Each LPRM reading will be within 10 percent of its calculated value.

14.1.4.8.10 Average Power Range Monitor Calibration

Purpose

The purpose of this test is to calibrate the APRM system.

Description

Generally a heat balance is made each shift and after each major power level change. Each APRM channel reading is adjusted to be consistent with the core thermal power as determined from the heat balance. During heatup, a preliminary calibration is made by adjusting the APRM amplifier gains so that the APRM readings agree with the results of a constant heatup rate heat balance. The APRMs will be recalibrated in the power range by a heat balance as soon as adequate feedwater indication is available.

Criteria

Level 1

The APRM channels must be calibrated to read equal to, or greater than, the actual core thermal power. Technical Specification and fuel warranty limits on APRM scram and rod block shall not be exceeded. In the startup mode, all APRM channels must produce a scram at less than, or equal to, 15 percent of rated thermal power. Recalibration of the APRM system is not necessary from a safety standpoint if at least two APRM channels per RPS trip circuit have readings greater than, or equal to, core power.

Level 2

If the above criteria are satisfied, then the APRM channels will be considered to be reading accurately if they agree with the heat balance to within (+7, -0) percent of rated power.

14.1.4.8.11 Process Computer

Purpose

The purpose of this test is to verify the performance of the process computer under plant operating conditions.

Description

Computer system program verifications and calculational program validations at static and at simulated dynamic input conditions are tested preoperationally at the computer supplier's site and following delivery to the plant site. Following fuel loading, during plant heatup, and the ascension to rated power, the nuclear steam supply system (NSSS) and the balance-of-plant (BOP) system process variables sensed by the computer as digital or analog signals will become available. Verify that the computer is receiving correct values of sensed process variables, and that the results of performance calculations of the NSSS programs are correct. At steady-state power conditions the Dynamic System Test Case will be performed.

Criteria

Level 1

Not applicable.

Level 2

Programs OD-1, P1, and OD-6 are considered operational when

a. The MCPR calculated by the BUCLE computer code and the process computer either

    1. Are in the same fuel assembly and do not differ in value by more than 2 percent, or

    2. For the case in which the MCPR calculated by the process computer is in a different assembly than that calculated by the BUCLE code, for those two assemblies, the MCPR and the critical power ratio (CPR) calculated by the two methods shall agree within 2 percent.

b. The maximum linear heat generation rate calculated by the BUCLE code and the process computer either

    1. Are in the same fuel nodes and do not differ in value by more than 2 percent, or

    2. For the case in which the maximum linear heat generation rate calculated by the process computer is in a different node than that calculated by the BUCLE code, for those two nodes, the maximum linear heat generation rate and the linear heat generation rate calculated by the two methods shall agree within 2 percent.

c. The maximum average planar linear heat generation rate calculated by the BUCLE code and the process computer either

    1. Are in the same fuel nodes and do not differ in value by more than 2 percent, or

    2. For the case in which the maximum average planar linear heat generation rate calculated by the process computer is in a different node than that calculated by the BUCLE code for those two nodes, the maximum average planar linear heat generation rate and the average planar linear heat generation rate calculated by the two methods shall agree within 2 percent.

d. The local power range monitor system gain adjustment factors calculated by BUCLE and the process computer agree to within 2 percent.

The remaining programs will be considered operational on the successful completion of the static and dynamic testing.

14.1.4.8.12 Reactor Core Isolation Cooling System

Purpose

The purpose of this test is to verify the proper operation of the reactor core isolation cooling (RCIC) system over its expected operating pressure range.

Description

The RCIC system test consists of two parts: injection to the CST and injection to the reactor vessel.

The CST injections consist of manual and automatic mode starts at 150 psig and near rated reactor pressure conditions. The pump discharge pressure during these tests is throttled to be 100 psi above reactor pressure. The initial testing is for demonstrating operability and making initial controller adjustments. This is followed by vessel injections beginning with cold RCIC hardware. Cold is defined as a minimum of 3 days without any kind of RCIC operation.

The vessel injections verify the adequacy of the startup transient and also include steady-state controller adjustments. Two consecutive vessel injections starting from cold conditions and with the same equipment settings are necessary to demonstrate system reliability.

After final controller settings are determined, CST injections are done with initially cold RCIC equipment. These runs provide a benchmark for future surveillance testing.

A demonstration of an extended operation of 30 minutes of continuous running or until the pump and turbine oil temperature is stabilized, is scheduled at a convenient time during the test program.

Criteria

Level 1

The average pump discharge flow must be equal to, or greater than, 100 percent-rated value after 50 sec have elapsed from initiation on all auto start at any reactor pressure between 150 psig and rated. With pump discharge at any pressure between 250 psig and 100 psi above rated pressure, the required flow is 600 gpm. (The 100 psi is a conservatively high value for line losses. The measured value may be used if available.)

The RCIC turbine shall not trip or isolate during auto or manual starts. If any Level 1 criteria are not met, the reactor will be allowed to operate only up to a restricted power level defined in the Startup Test Procedure.

Level 2

The turbine gland seal condenser system shall be capable of preventing steam leakage to the atmosphere. The DP switch for the RCIC steam supply line high-flow isolation trip shall be adjusted to actuate at 300 percent of the maximum required steady-state flow, with the reactor assumed to be near the pressure for main relief valve actuation. For small speed or flow changes in either manual or automatic mode, the decay ratio of each recorded RCIC system variable must be less than 0.25.

To provide a margin on the overspeed trip and isolation, the first and subsequent speed peaks on the transient start shall not exceed the rated speed of the RCIC turbine by more than 5 percent.

14.1.4.8.13 High Pressure Coolant Injection System

Purpose

The purpose of this test is to verify the proper operation of the high pressure coolant injection (HPCI) system over its expected operating pressure range.

Description

The HPCI system test consists of two parts: injection to the CST and injection to the reactor vessel.

The CST injections consist of manual and automatic starts at 150 psi and at rated reactor pressure. The pump discharge pressure during these tests is throttled to 100 psi above reactor pressure. The initial testing is for demonstrating operability and making initial controller adjustments. This is followed by vessel injections beginning with cold HPCI hardware. Cold is defined as a minimum of 3 days without any kind of HPCI operations.

The vessel injections verify the adequacy of the startup transient and also include steady-state controller adjustments. Two consecutive vessel injections starting from cold conditions with the same equipment settings are necessary to demonstrate system reliability.

After final controller settings are determined, CST injections are done with initially cold HPCI equipment. These runs provide a benchmark for future surveillance testing.

A demonstration of an extended operation of 30 minutes of continuous running or until pump and turbine oil temperature is stabilized, is scheduled at a convenient time during the test program.

Criteria

Level 1

The average pump discharge flow must be equal to, or greater than, the 100 percent-rated value with a system response time of less than or equal to 30 sec as defined in the Technical Specifications at any reactor pressure between 150 psig and rated. With pump discharge at any pressure between 250 psig and 100 psi above rated pressure, the flow should be at least 5000 gpm. (The 100 psi is a conservatively high value for line losses. The measured value may be used if available.) The HPCI turbine shall not trip or isolate during auto or manual starts.

Level 2

The turbine gland seal condenser system shall be capable of preventing steam leakage to the atmosphere. The delta P switch for the HPCI steam supply line high flow isolation trip shall be adjusted to actuate at 300 percent of the maximum required steady-state flow with reactor assumed to be near the pressure for main relief valve actuation. For small speed or flow changes in either manual or automatic mode, the decay ratio of each recorded HPCI system variable must be less than 0.25.

The margin to avoid the overspeed trip shall be at least 10 percent of the nominal overspeed trip setpoint of 5000 rpm during all auto starts of the HPCI system.

14.1.4.8.14 Selected Process Temperatures

Purpose

The purposes of this procedure are to establish the proper setting of the low speed limiter for the recirculation pumps to avoid coolant temperature stratification in the reactor pressure vessel (RPV) bottom head region, to provide assurance that the measured bottom head drain temperature corresponds to bottom head coolant temperature during normal operations, and to identify any reactor operating modes that cause temperature stratification.

Description

During initial heatup while at hot-standby conditions, the bottom drain line temperature, recirculation loop suction temperature, and applicable reactor parameters are monitored as the recirculation pump flow is slowly lowered to minimum stable flow. The parameters above are recorded during pump trips as well. The effects of cleanup flow, CRD flow, and power level are investigated as operational limits allow. Utilizing these data, it can be determined if coolant temperature stratification occurs when the recirculation pumps are on and if so, what minimum pump speed will prevent it. A comparison of recirculation loop coolant temperature with bottom drain line temperature when core flow is 100 percent will be performed.

Criteria

Level 1

The reactor recirculation pumps shall not be started nor flow increased unless the coolant temperatures between the steam dome and bottom head drain are within 145°F. The recirculation pump in an idle loop must not be started, active loop flow must not be raised, and power must not be increased unless the idle loop suction temperature is within 50°F of the active loop suction temperature. If two pumps are idle, the loop suction temperature must be within 50°F of the steam dome temperature before pump startup.

Level 2

During operation of two recirculation pumps at rated core flow, the bottom head temperature as measured by the bottom drain line thermocouple should be within 30°F of the recirculation loop temperatures.

14.1.4.8.15 System Expansion

Purpose

The purpose of this procedure is to verify that major piping of the NSSS and related auxiliary systems is free and unrestrained with regard to thermal expansion, and to verify that the thermal movement of the piping and associated support system components is consistent with the analytical predictions of the piping system stress analyses.

Description

Observations and/or recordings of the thermal expansion movements of key points on the piping of the NSSS and related auxiliary systems are made as the piping systems are brought initially from ambient to operational temperature. The points ordinarily chosen to be monitored will be those points in each piping system that are expected to exhibit relatively large thermal deflections and/or experience large thermally induced stresses, as predicted by the piping system stress analysis.

Pipe position will be recorded or logged at the ambient, intermediate, and maximum expected temperature points described above.

One or more of the following methods of monitoring piping system thermal movement will be employed, depending on practicality and accessibility limitations:

a. Actual observation of piping system thermal behavior by a member or delegate of the Edison Startup Group

b. Installation of local mechanical recording devices (scratch or dial gages)

c. Installation of remote-indicating movement measuring devices (linear variable differential transformers and Lanyard potentiometers) used in conjunction with suitable indicating/recording instruments installed in accessible locations.

Extent of Testing

The piping systems subjected to thermal expansion test verification are listed in Table 3.9-1. Detailed discussion concerning thermal expansion testing is presented in Subsection 3.9.1.1.

Criteria

Acceptance criteria for this test are presented in Subsection 3.9.1.1.5.

14.1.4.8.16 (Not Applicable)

14.1.4.8.17 Core Performance

Purpose

a. To evaluate the core thermal power

b. To evaluate the following core performance parameters:

   1. Maximum linear heat generation rate (MLHGR)

   2. Minimum critical power ratio (MCPR)

   3. Maximum average planar linear heat generation rate (MAPLHGR).

Description

The core performance evaluation is employed to determine the principal thermal and hydraulic parameters associated with core behavior. These parameters are

a. Core flow rate

b. Core thermal power level

c. MLHGR

d. MCPR

e. MAPLHGR.

Those core performance parameters listed are evaluated as described below.

a. Core flow rate is read from the total core flow recorder in the control room, and a correction curve is used if necessary. During some transients, core DP will be used as an indication of core flow

b. Core thermal power is determined from a detailed reactor heat balance

c. The MLHGR is determined using the LPRM system, axial power distribution information, and calculated fuel assembly local power distribution information

d. The value of MAPLHGR in the core shall be restricted to the limits given in the Technical Specifications

e. The MCPR of a fuel assembly depends on the fuel assembly flow, the total fuel assembly power, the fuel assembly average exposure, the core inlet subcooling, and the fuel assembly peak axial power factor and location.

Criteria

Level 1

The MLHGR during steady-state conditions shall not exceed the allowable heat flux as specified in the Technical Specifications.

The steady-state MCPR shall be maintained greater than, or equal to, the value specified in the Technical Specifications.

The MAPLHGR shall not exceed the limits given in the Technical Specifications.

Steady-state reactor power shall be limited to full rated maximum values on or below the design flow control line.

Core flow should not exceed its rated value.

Level 2

Not applicable.

14.1.4.8.18 Steam Production (Deleted)

This subsection has been deleted because the test is performed only for warranty demonstration purposes unrelated to safety. The test will be conducted as a demonstration test.

14.1.4.8.19 (Not Applicable)

14.1.4.8.20 Pressure Regulator

Purpose

a. To determine the optimum settings for the pressure control loop by analysis of the transients induced in the reactor pressure control system by means of the pressure regulators

b. To demonstrate the takeover capability of the backup pressure regulator on failure of the controlling pressure regulator and to set spacing between the setpoints at an appropriate value

c. To demonstrate smooth pressure control transition between the control valves and bypass valves when the reactor generates more steam than is used by the turbine.

Description

The pressure setpoint is decreased rapidly and then increased rapidly by up to 10 lb/in.^{2}, and the response of the system will be measured in each case. It is desirable to accomplish the setpoint change in less than 1 sec. At specified test conditions, the load limit setpoint is set so that the transient is handled by control valves, bypass valves, or both. The backup regulator is tested by simulating a failure of the operating pressure regulator so that the backup regulator takes over control. The response of the system is measured and evaluated and regulator settings are optimized. The matrix of test mode and conditions is tabulated below.

		Test Condition Number				
Mode	Input	1	2	3	5	6
CV	Setpoint	No	Yes	Yes	Yes	Yes
CV	Fail to back up	No	Yes	Yes	No	Yes
BPV	Setpoint	Yes	Yes	No	Yes	Yes
BPV	Fail to back up	Yes	Yes	No	No	Yes
	Recirc. modes	Manual	Manual	Manual	Manual	Manual

Criteria

Level 1

The decay ratio must be less than 1.0 for each process variable that exhibits oscillatory response to pressure regulator changes.

Level 2

In all tests the decay ratio must be less than or equal to 0.25 for each process variable that exhibits oscillatory response to pressure regulator changes when the plant is operating above the lower limit setting of the master flow controller.

Pressure control deadband, delay, etc., shall be small enough for steady-state limit cycles, if any, to produce turbine steam flow variations no larger than 0.5 percent of rated flow.

During the simulated failure of the controlling pressure regulator along the 100 percent rod line (Figure 14.1-2), if the setpoint of the backup pressure regulator is optimally set, the backup regulator shall control the transient so that the peak neutron flux or peak vessel pressure remains below the scram settings by 7.5 percent and 10 lb/in.^{2}, respectively.

After a pressure setpoint adjustment, the time between the setpoint change and the occurrence of the pressure peak shall be 10 sec or less. (This applies to pressure setpoint changes made with the recirculation system in the master or local manual control mode.)

14.1.4.8.21 Feedwater System

Purpose

a. To adjust the feedwater control system for acceptable reactor water level control

b. To demonstrate stable reactor response to subcooling changes

c. To demonstrate the capability of the automatic core flow runback feature to prevent low water level scram following the trip of one feedwater pump

d. To demonstrate adequate response to feedwater heating loss

e. To determine the maximum feedwater runout capability.

Description

Reactor water level setpoint changes of approximately 3 to 6 in. will be used to evaluate and adjust the feedwater control system settings for all power and feedwater pump modes. The level setpoint changes will also demonstrate core stability to subcooling changes. One of two operating feedwater pumps will be tripped and the automatic flow runback circuit will act to drop power to within the capacity of the remaining pump. The worst single- failure case of feedwater temperature loss will be performed and the resulting transients recorded between 80 and 90 percent power and near full core flow rate. Data will be taken between 50 and 100 percent power to allow determination of the maximum feedwater runout capability.

Criteria

Level 1

The response of any level-related variable to any test input change, or disturbance, must not diverge during the setpoint changes.

For the feedwater temperature loss test, the maximum feedwater temperature decrease due to a single-failure case must be less than or equal to 100°F. The resultant MCPR must be greater than the fuel thermal safety limit.

For the feedwater temperature loss test, the increase in simulated heat flux cannot exceed the predicted Level 2 value by more than 2 percent. The predicted value will be based on the actual test values of feedwater temperature change and power level.

The feedwater flow runout capability must not exceed the assumed value in the FSAR.

Level 2

Level control system-related variables may contain oscillatory modes of response. In these cases, the decay ratio for each controlled mode of response must be less than or equal to 0.25, as a result of the setpoint change testing.

A scram must not occur from low water level following a trip of one of the operating feedwater pumps. There should be a greater than 3-in. water-level margin to scram for the feedwater pump trip.

For the feedwater temperature loss test, the increase in simulated heat flux cannot exceed the predicted value referenced to the actual feedwater temperature change and power level, which will be taken from the Transient Safety Analysis Design Report.

The average rate of response of the feedwater actuator to large (>20 percent of pump flow) step disturbances shall be between 10 to 25 percent of pump rated feedwater flow per second. This average response rate will be assessed by determining the time required to pass linearly through the 10 percent and 90 percent response points of the flow transient.

The dynamic flow response of each feedwater actuator (turbine or valve) to small (<10 percent) step disturbances shall be the following:

a. Maximum time to 10 percent of a step disturbance ≤1.1 sec

b. Maximum time from 10 to 90 percent of a step disturbance ≤1.9 sec

c. Peak overshoot (percentage of step disturbance) ≤15 percent.

14.1.4.8.22 Turbine Valve Surveillance

Purpose

To demonstrate acceptable procedures and maximum power levels for surveillance testing of the main turbine control and stop valves without producing a reactor scram.

Description

Individual main turbine control and stop valves are tested routinely during plant operation as required for turbine surveillance testing. At several test points, the response of the reactor is observed and the maximum possible power level for performance of these tests along the 100 percent load line established.

First actuation should be between 45 and 65 percent power, and be used to extrapolate to the next test point between 70 and 95 percent power and, ultimately, to the maximum power test condition, with ample margin to scram. Note proximity to APRM flow bias scram point. Each valve test is manually initiated and reset. The rate of valve stroking and the timing of the close-open sequence is such that the minimum practical disturbance is introduced.

If it is later decided to do bypass valve surveillance testing at power (present plans are to test these valves only when the plant is shut down), then these valves will be tested in the same manner as described above for control and stop valves.

Criteria

Level 1

Not applicable.

Level 2

Peak neutron flux must be at least 7.5 percent below the scram trip setting. Peak vessel pressure must remain at least 10 $lb/in.^2$ below the high-pressure scram setting. Peak heat flux must remain at least 5.0 percent below its scram trip point.

Peak steam flow in the high-flow lines must remain 10 percent below the high-flow isolation trip setting.

14.1.4.8.23 Main Steam Isolation Valves

Purpose

a. To check functionally the main steam line isolation valves (MSIVs) for proper operation at selected power levels

b. To determine reactor transient behavior during and after simultaneous full closure of all MSIVs

c. To determine isolation valve closure time.

Description

At selected power levels, both slow and fast single-valve closure is performed. A test of the simultaneous full closure of all MSIVs is performed at a level greater than or equal to 95 percent of rated thermal power. Should an inadvertent full closure of the MSIVs occur at a lower power level (≥70 percent), credit may be taken for this test if supporting analysis shows that the results can be extrapolated to the higher power condition. Correct performance of the RCIC (if L2 is reached) and relief valves is shown. Reactor process variables are monitored to determine the transient behavior of the system during and following the main steam line (MSL) isolation.

The MSIV closure times are determined from the MSL isolation data by multiplying the time increment between deenergizing the solenoids and actuation of the MSIV closed light by an extrapolation factor. The extrapolation factor will correct the time obtained to that of full closure and will be calculated for each MSIV based on previous, direct measurement data of valve full stroke length and actual position indicating switch actuation points.

The times to be determined are (a) the time from deenergizing the solenoids until the valve is 100 percent closed (t_{sol}) and (b) the valve stroke time (t_s). Time t_{sol} equals the interval from deenergizing the solenoids until the valve reaches 90 percent closed plus 1/8 times the interval from 10 to 90 percent closure. Time t_s equals the interval from when the valve starts to move until it is 100 percent closed and is based on the interval from 10 to 90 percent closure and linear valve travel from 0 to 100 percent closure.

Criteria

Level 1

The MSIV stroke time (t_s) shall be no faster than 3.0 sec (average of the fastest valve in each steam line) and for any individual valve 2.5 sec $\leq t_s \leq$ 5 sec. Total effective closure time for any individual MSIV shall be t_{sol} plus the maximum instrumentation delay time and shall be ≤5.5 sec.

The positive change in vessel dome pressure occurring within 30 sec after the simultaneous full closure of all MSIVs must not exceed the Level 2 criteria by more than 25 psi. The positive change in simulated heat flux shall not exceed the Level 2 criteria by more than 2 percent of rated value.

Flooding of the main steam lines shall not occur following the full MSIV closure test.

The reactor must scram during the full simultaneous MSIV closure test to limit the severity of the neutron flux and simulated fuel surface heat flux transient.

Level 2

During full closure of individual valves, peak vessel pressure must be at least 10 psi below scram, peak neutron flux must be at least 7.5 percent below scram, and steam flow in individual lines must be at least 10 percent below isolation trip setting. The peak heat flux must be at least 5 percent less than its trip point. The reactor shall not scram or isolate as a result of individual valve testing.

The relief valves must reclose properly (without leakage) following the pressure transient resulting from the simultaneous MSIV full closure.

The positive change in vessel dome pressure and simulated heat flux occurring within the first 30 sec after the closure of all MSIV valves must not exceed the predicted values in the Transient Safety Analysis Design Report. Predicted values will be referenced to actual test conditions of initial power level and dome pressure and will use beginning of life nuclear data. The predicted values will be corrected for the appropriate measured parameters.

After the full MSIV closure, the initial action of the RCIC and HPCI shall be automatic if L2 is reached, with RCIC capable of establishing an average pump discharge flow equal to or greater than 600 gpm within the first 50 sec after automatic initiation and HPCI capable of establishing an average pump discharge flow equal to or greater than 5000 gpm with a system response time of less than or equal to 30 sec as defined in the Technical Specifications.

If the low-low set pressure relief logic functions after the simultaneous full MSIV closure test, the open/close actions of the safety/relief valves (SRVs) shall occur within ±20 psi of the low-low set design setpoints. The total number of opening cycles, for the SRVs opening on low-low setpoint, after initial blowdown is not to exceed four times during the initial 5 minutes following isolation. If any SRVs open as a result of this test, only one valve may reopen after the first blowdown.

Recirculation pump trip shall be initiated if L2 is reached after the MSIV full closure test.

14.1.4.8.24 Relief Valves

Purpose

The purposes of this test are (a) to verify that the relief valves function properly (can be opened and closed manually), (b) to verify that the relief valves reseat properly after operation, and (c) to verify that there are no major blockages in the relief valve discharge piping.

Description

A functional test of each SRV shall be made as early in the startup program as practical. This is normally the first time the plant reaches 250 psig. The test is then repeated at rated reactor pressure. Bypass valve response is monitored during the low-pressure test, and the electrical output response is monitored during the rated pressure test. The test duration will be about 10 sec to allow turbine valves and tailpipe sensors to reach a steady state.

The tailpipe sensor response will be used to detect the opening and subsequent closure of each SRV. The bypass valve and MWe responses will be analyzed for anomalies indicating a restriction in an SRV tailpipe.

Valve capacity will be based on certification by ASME code stamp and the applicable documentation being available in the onsite records. Note that the nameplate capacity/pressure rating assumes that the flow is sonic. This will be true if the back-pressure is less than 55 percent of inlet pressure. The GE design specification requires the backpressure to be less than 40 percent of the inlet pressure, and present designs have backpressures on the order of 30 percent of the inlet pressures. The methods of calculating line losses and pressure drops are reliable enough to ensure that the 15 to 25 percent conservatism in the design more than offsets any slight inaccuracies in the calculation. A major blockage of the line would not necessarily be offset, and it should be determined that none exists through the bypass valve response signatures.

Vendor bench test data of the SRV opening responses will be available onsite for comparison with design specifications.

Criteria

Level 1

There should be a positive indication of steam discharge during the manual actuation of each valve.

Level 2

Variables related to the pressure control system may contain oscillatory modes of response. In these cases, the decay ratio for each controlled mode of response must be less than or equal to 0.25.

The temperature measured by thermocouples on the discharge side of the valves shall return to within 10°F of the temperature recorded before the valve was opened. If pressure sensors are available, they shall return to their initial state on valve closure.

During the 250 psig functional test, the steam flow through each relief valve, as measured by the initial and final bypass valve position, shall not differ by more than 10 percent from the average relief valve steam flow as measured by bypass valve position.

During the rated pressure test, the steam flow through each relief valve as measured by change in MWe is not to differ by more than 0.5 percent of rated MWe from the average of all the valve responses.

14.1.4.8.25 Turbine Stop Valve and Control Valve Fast Closure Trips

Purpose

To demonstrate the response of the reactor and its control systems to protective trips in the turbine and generator.

Description

The turbine stop valves and the main generator breakers are tripped at selected reactor power levels. Several reactor and turbine operating parameters are monitored to evaluate the response of the bypass valves, the relief valves, and the reactor protection system (RPS). In addition, the peak values and change rates of reactor steam pressure and heat flux are determined. The ability to ride through a load rejection within bypass capacity without a scram is demonstrated.

A turbine/generator trip is performed at Test Condition 6. Should an inadvertent turbine/generator trip occur at a lower power level (≥70 percent), credit may be taken for this test if supporting analysis shows that the results can be extrapolated to the higher power condition. Both line circuit breakers and the generator field breaker will open, and all the turbine valves will close at the maximum rate.

Criteria

Level 1

For turbine/generator trips, there should be a delay of no more than 0.1 sec following the beginning of control or stop valve closure before the beginning of bypass valve opening. The bypass valves should be opened to a point corresponding to greater than or equal to 80 percent of their capacity within 0.3 sec from the beginning of control or stop valve closure motion.

Flooding of the main steam lines shall not occur following the turbine/generator trips.

The positive change in vessel dome pressure occurring within 30 sec after either generator or turbine trip must not exceed the Level 2 criteria by more than 25 psi.

The positive change in simulated heat flux shall not exceed the Level 2 criteria by more than 2 percent of rated value.

Level 2

There shall be no MSIV closure in the first 3 minutes of the transient, and operator action shall not be required in that period to avoid the MSIV trip.

The positive change in vessel dome pressure and in simulated heat flux that occur within the first 30 sec after the initiation of either generator or turbine trip must not exceed the predicted values in the Transient Safety Analysis Design Report.

For the turbine/generator trip within the bypass valves capacity, the reactor shall not scram for initial thermal power values less than or equal to 25 percent of rated.

If the low-low set pressure relief logic functions, the open/ close actions of the SRVs shall occur within +20 psi of their design setpoints. If any SRVs open, only one valve may reopen after the first blowdown.

14.1.4.8.26 Shutdown From Outside the Control Room

Purpose

To demonstrate that the reactor can be brought from a normal, initial, steady-state power level to the hot shutdown condition and to verify that the plant has the potential for being safely cooled from hot shutdown to cold shutdown conditions from outside the control room using the remote shutdown panel.

Description

Hot Shutdown Demonstration:

The reactor will be shut down following a simulated main control room evacuation. The reactor will be scrammed, from outside the main control room, from a power level sufficiently high for the plant systems to be in normal operating configurations with the turbine generator in operation.

Reactor vessel water level and pressure will be controlled from a location outside the main control room. All other non-safety- related activities that would not be required during an actual remote shutdown will be performed from the main control room.

Data will be obtained at locations outside the control room to verify that the plant has achieved hot standby status and that the plant can be maintained in the stable hot standby condition.

This portion of the test will be performed with the minimum shift complement.

Cold Shutdown Demonstration:

The potential capability for cold shutdown will be demonstrated by partially cooling down the plant in the hot standby condition using controls and instrumentation located outside the control room. Cooldown can then proceed using normal procedures and operating modes from the control room to the point at which the shutdown cooling mode of residual heat removal (RHR) can be initiated. Operation of the RHR system in the shutdown cooling mode will then be initiated and controlled from outside the control room. Reactor coolant temperature will be partially reduced at a rate that will not exceed Technical Specifications limits. This demonstration will use additional personnel who can be made available to the plant before cooldown is initiated.

Approved operating procedures will be available for performance of a remote shutdown, including procedures for conducting all portions of the startup test.

Criteria

Level 1

Not applicable.

Level 2

During the cold shutdown demonstration, the reactor must be brought to the point where cooldown is initiated and under control.

During the simulated control room evacuation and hot shutdown demonstration, the reactor vessel pressure and water level are controlled using equipment and controls outside the control room.

14.1.4.8.27 Flow Control

Purpose

a. To determine the correct gain settings for the individual recirculation controllers

b. To demonstrate plant response to changes in circulation flow in both local manual and master manual mode

c. To set the limits of range of operation for the recirculation pumps.

Description

The testing of the recirculation flow control system follows a "building block" approach while the plant is ascending from low to high power levels. The time responses of the individual pump flow loops and speed loops will be optimized by adjusting the gains of the controllers. By far, the most extensive testing will be performed along the mid-power load line where most of the systems' final adjustments are determined.

Criteria

Level 1

The transient response of any variable related to the recirculation system to any test input must not diverge.

Level 2

The decay ratio of the speed loop response shall be <0.25 at any speed.

Flow control system limit cycles (if any) must produce a turbine steam flow variation no larger than ±0.5 percent of the rated steam flow value.

The APRM neutron flux trip avoidance margin shall be ≥7.5 percent, and the heat flux trip avoidance margin shall be ≥5.0 percent as a result of the recirculation flow control maneuvers.

14.1.4.8.28 Recirculation System

Purpose

a. To verify that the feedwater control system can satisfactorily control the water level without a resulting turbine trip/scram and obtain actual pump speed/flow

b. To verify recirculation pump startup under pressurized reactor conditions

c. To obtain recirculation system performance data

d. To verify that no recirculation system cavitation occurs in the operable region of the power flow map.

Description

The reactor coolant recirculation system consists of the reactor vessel and two piping loops. Each loop contains a centrifugal recirculation pump and two isolation valves located in the drywell and 10 jet pumps in parallel situated in the reactor downcomer. Each recirculation pump takes suction from the reactor downcomer and discharges through a manifold system to the nozzles of the 10 jet pumps. Here the flow is augmented by suction flow from the downcomer and delivered to the reactor inlet plenum.

A potential threat to plant availability is the high water level turbine trip scram caused by the level upswell that results after an unexpected trip of one recirculation pump. The change in core flow and resultant power decrease causes void formation, which the level-sensing system senses as a rise in water level. The one pump trip test is to prove that the water level will not rise enough to threaten a high-level trip of the main turbine or the feedwater pumps, while the pump restart demonstrates the adequacy of the restart procedure at the highest possible reactor power level.

Steady-state data will be collected several times during the startup test program in order to obtain a complete record of recirculation system performance.

Both the jet pumps and the recirculation pumps will cavitate at conditions of high flow and low power, where net positive suction head (NPSH) demands are high and little feedwater subcooling occurs. However, the recirculation pumps will automatically run back to minimum speed when feedwater flow decreases to 20 percent and the maximum recirculation flow is normally limited by the upper limit of the master flow controller which corresponds to the pump speed for rated flow at rated power. It will be verified that these limits are sufficient to prevent operation where recirculation pump or jet pump cavitation occurs.

Criteria

Level 1

The response of any level-related variables during pump trips must not diverge.

Level 2

The simulated heat flux margin to avoid a scram shall be greater than or equal to 5.0 percent during the one pump trip recovery.

The APRM margin to avoid a scram shall be greater than or equal to 7.5 percent during the one pump trip recovery.

During the noncavitation verification, runback logic shall have settings adequate to prevent operation in areas of potential cavitation.

During the one pump trip, the reactor water level margin to avoid a high-level trip (L8) shall be greater than or equal to 3.0 in.

14.1.4.8.29 Loss of Turbine Generator and Offsite Power

Purpose

a. To determine the reactor transient performance during the loss of the main generator and all offsite power

b. To demonstrate acceptable performance of the station electrical supply system.

Description

The loss-of-auxiliary-power test will be performed with the generator at least l0 percent of rated electrical output. The proper response of reactor plant equipment and automatic switching equipment, as well as the proper switching of loads to the diesel generator, will be checked.

Suitable provisions are made to facilitate continuous indicating and recording capability throughout the duration of the test (variables of interest are power, core flow, vessel pressure, and reactor water level).

The transient is extended for a minimum of 30 minutes.

Criteria

Level 1

The RPS, the diesel generator, RCIC, and HPCI must function properly without manual assistance. The HPCI and/or RCIC system action, if necessary, shall keep the reactor water level above the initiation level of low-pressure core spray, low pressure coolant injection (LPCI), and automatic depressurization systems.

Level 2

If the low-low set pressure relief logic functions, the open/ close actions of the SRVs shall occur within ±20 psi of their design setpoints. If any SRVs open, only one may reopen after the first blowdown.

14.1.4.8.30 Steady-State Vibration

Purpose

To determine the vibration characteristics of the primary pressure boundary piping (NSSS) and engineered safety feature (ECCS) piping systems for vibrations induced by recirculation flows, hot two-phase forces, and hot hydrodynamic transients; and to demonstrate that flow-induced vibrations, similar in nature to those expected during normal and abnormal operation, will not cause damage and excessive pipe movement and vibration.

Description

The systems subjected to the piping vibration testing during the startup test phase are listed in Table 3.9-1.

A complete, detailed discussion of the piping vibration and dynamic effect test program is presented in Subsection 3.9.1.1.

Criteria

Acceptance criteria for this test are presented in Subsection 3.9.1.1.5.

14.1.4.8.31 Recirculation System Flow Calibration

Purpose

To perform a complete calibration of the installed recirculation system flow instrumentation.

Description

During the testing program at operating conditions that allow the recirculation pumps to be operated at the speeds required for rated flow at rated power, the jet pump flow instrumentation is adjusted to provide correct flow indication based on the jet pump flow. After the relationship between drive flow and core flow is established, the flow-biased APRM/RBM system will be adjusted to match this relationship.

Criteria

Level 1

Not applicable.

Level 2

Jet pump flow instrumentation is adjusted so that the jet pump total flow recorder provides a correct core flow indication at rated conditions.

The APRM/RBM flow-bias instrumentation is adjusted to function properly at rated conditions.

The flow control system shall be adjusted to limit maximum core flow to 102.5 percent of rated flow by limiting motor-generator (M-G) set scoop tube position.

14.1.4.8.32 Reactor Water Cleanup System

Purpose

To demonstrate specific aspects of the mechanical operability of the reactor water cleanup (RWCU) system.

Description

With the reactor at rated temperature and pressure, process variables are recorded during steady-state operation in three modes as defined by the system process diagram: blowdown, hot standby, and normal. A comparison of the bottom head flow indicator and the RWCU inlet flow indicator will be made.

Criteria

Level 1

Not applicable.

Level 2

The temperature at the tube side outlet of the nonregenerative heat exchangers shall not exceed 130°F in the blowdown mode and shall not exceed 120°F in the normal mode.

The pump available NPSH is 13 ft or greater during the hot shutdown with loss of RPV recirculation pumps mode defined in the process diagrams.

The bottom head flow indicator will be recalibrated against the RWCU flow indicator if the deviation is greater than 25 gpm.

The cooling water supplied to the nonregenerative heat exchangers shall be less than 6 percent above the flow corresponding to the heat exchangers' capacity (as determined from the process diagram) and the existing temperature differential across the heat exchangers. The outlet temperature shall not exceed 180°F.

14.1.4.8.33 Residual Heat Removal System

Purpose

To demonstrate the ability of the RHR system to remove residual and decay heat from the nuclear system so that refueling and nuclear servicing can be performed.

Description

During the first suitable reactor cooldown, the shutdown cooling mode of the RHR system will be demonstrated. The torus cooling mode will also be demonstrated, if necessary.

Criteria

Level 1

Not applicable.

Level 2

The RHR system is capable of operating in the suppression pool cooling and shutdown cooling modes at the flow rates and temperature differentials indicated on the process diagrams.

14.1.4.8.34 Piping System Dynamic Response Testing

Purpose

To verify that piping system structural behavior under probable transient loadings is acceptable and within the limit predicted by analytical investigations.

Description

The following piping systems and dynamic transient events are evaluated by test during the startup testing sequence:

a. Behavior of the feedwater system piping from the feedwater pump discharge to the containment penetration following a trip of a feedwater pump

b. Behavior of the HPCI system piping from the HPCI pump discharge to the feedwater system tee connection in the steam tunnel after a rapid start of the HPCI pump turbine

c. Behavior of the main steam piping from the turbine stop valve to the containment penetration after a turbine stop valve and control valve fast closure trip. This test will be conducted during an inadvertent turbine trip after the startup test program is completed

d. Selected main steam SRV discharge piping during SRV operation

e. Recirculation piping for a pump trip at 100 percent-rated flow.

The tests described above have been selected for the following reasons:

a. The transient phenomena identified are normal/upset transients that may be reasonably expected to occur during the life of the plant

b. The transients described are already planned during the system's tests to confirm system and equipment behavior in accordance with design

c. Evaluation of the results of these tests will aid in confirming that use of present design rules and stress analysis requirements produces system designs that are adequate for anticipated transient events.

The vibration surveys conducted during these transient events make up one portion of the piping vibration test program presented in Subsection 3.9.1.1.

Criteria

Acceptance criteria for this test are presented in Subsection 3.9.1.1.5.

TABLE 14.1-1 STARTUP TEST PROGRAM

Test No.	Test Name	Open Vessel or Cold Test	Heatup	Test Conditions[a] 1	2	3	4[b]	5	6	Warranty
1	Chemical and Radiochemical	X	X	X		X		X	X	
2	Radiation Measurements	X	X		X	X			X	
3	Fuel Loading	X								
4	Full Core Shutdown Margin		X							
5	CRD	X	X	X					X	
6	SRM Performance and Control Rod Sequence		X	X						
7	Water Level Measurements		X							
8	IRM Performance		X	X						
9	LPRM Calibration		X	X		X			X	
10	APRM Calibration		X	X	X	X		X	X	X
11	Process Computer	X		X[c]		X		X	X	
12	Reactor Core Isolation Cooling System		X	X	M					
13	High Pressure Coolant Injection System		X			M				
14	Selected Process Temperatures		X				X		X	
15	System Expansion	X	X						X	
16	(Deleted)									
17	Core Performance			X	X	X	X	X	X	X
18	(Deleted)									
19	(Deleted)									
20	Pressure Regulator - Setpoint Changes			M,BP	M	M		M	M	
	- Backup Regulator			M,BP	M	M			M	
21	Feedwater System - Feedwater Pump Trip								M(SP)	
	- Water Level Setpoint Changes		X	X	M	M		M	M	
	- Heating Loss							M[d]		
	- Maximum Runout Capability							M[d]		
22	Turbine Valve Surveillances							M[d],SP	M[e,f],SP	
23	MSIVs - Each Valve		X[g]	M[h],SP		X[g]			X[g]	
	- Full Isolation								M,SD[k]	
24	Relief Valves		X		M[i]					
25	Turbine Stop Valve and Control Valve Fast Closure Trips				M,SP[j]				M,SD[k,l]	
26	Shutdown from Outside Control Room			(SD)X[l]					X[m]	
27	Flow Control				M	M		M[d]		
28	Recirculation System - Trip One Pump								M(SP)	
	- System Performance				X	X	X		X	
	- Noncavitation Verification					M				
29	Loss of T-G Offsite Power				M,SD[l]					
30	Vibration Measurements		X		X	X			X	

TABLE 14.1-1 STARTUP TEST PROGRAM

Test No.	Test Name	Open Vessel or Cold Test	Heatup	Test Conditions[a] 1	2	3	4[b]	5	6	Warranty
31	Recirculation System Flow Calibration					X			X	
32	Reactor Water Cleanup System	X					X			
33	Residual Heat Removal System	X							X	
34	Piping Systems Dynamic Response	X		X		X			X	

Key: M = manual flow control mode; X = test independent of flow control; SP = scram possibility; SD = scram definite; BP = bypass valve response.

[a] See Figure 14.1-2 for test conditions region map.

[b] Testing at natural circulation on 100 percent load line can be done anytime following Test Condition 3.

[c] Between Test Conditions 1 and 3.

[d] Between Test Conditions 5 and 6.

[e] Determine maximum power without scram.

[f] Future maximum power test point.

[g] 10 percent slow closure-slow mode.

[h] Full closure-fast mode.

[i] Between Test Conditions 2 and 3.

[j] Within bypass valve capability.

[k] If an inadvertent full MSIV isolation or turbine/generator trip occurs at between 70 percent and 100 percent of core thermal power, credit may be taken for this test if supporting analysis shows that the results can be extrapolated to the higher power condition.

[l] Perform Test 5, timing four slowest control rods in conjunction with these scrams.

[m] RHR shutdown cooling mode demonstration.

TABLE 14.1-2 CONTROL ROD DRIVE SYSTEM TESTS

Test Description	Accumulator Pressure	Preop Tests	Reaction Pressure With Core Loaded (psig) 0	600	800	Rated
Position indication		All	All			
Normal stroke times insert/withdraw		All	All			4[a]
Coupling		All	All			
Friction			All			4[a]
Scram	Normal	All	All	4[a]	4[a]	All
Scram	Minimum		4[a]			4[a]
Scram	Zero					4[a]
Scram (scram discharge volume high level)[b]	Normal					
Scram	Normal					4[c]

[a] Refers to four CRDs selected for continuous monitoring based on slow normal accumulator pressure scram times, or unusual operating characteristics, at zero reactor pressure. The four selected CRDs must be compatible with rod worth minimizer, RSCS systems, and CRD sequence requirements.

[b] The scram discharge volume fill time will be determined at Test Conditions 1 and 6 during planned reactor scrams.

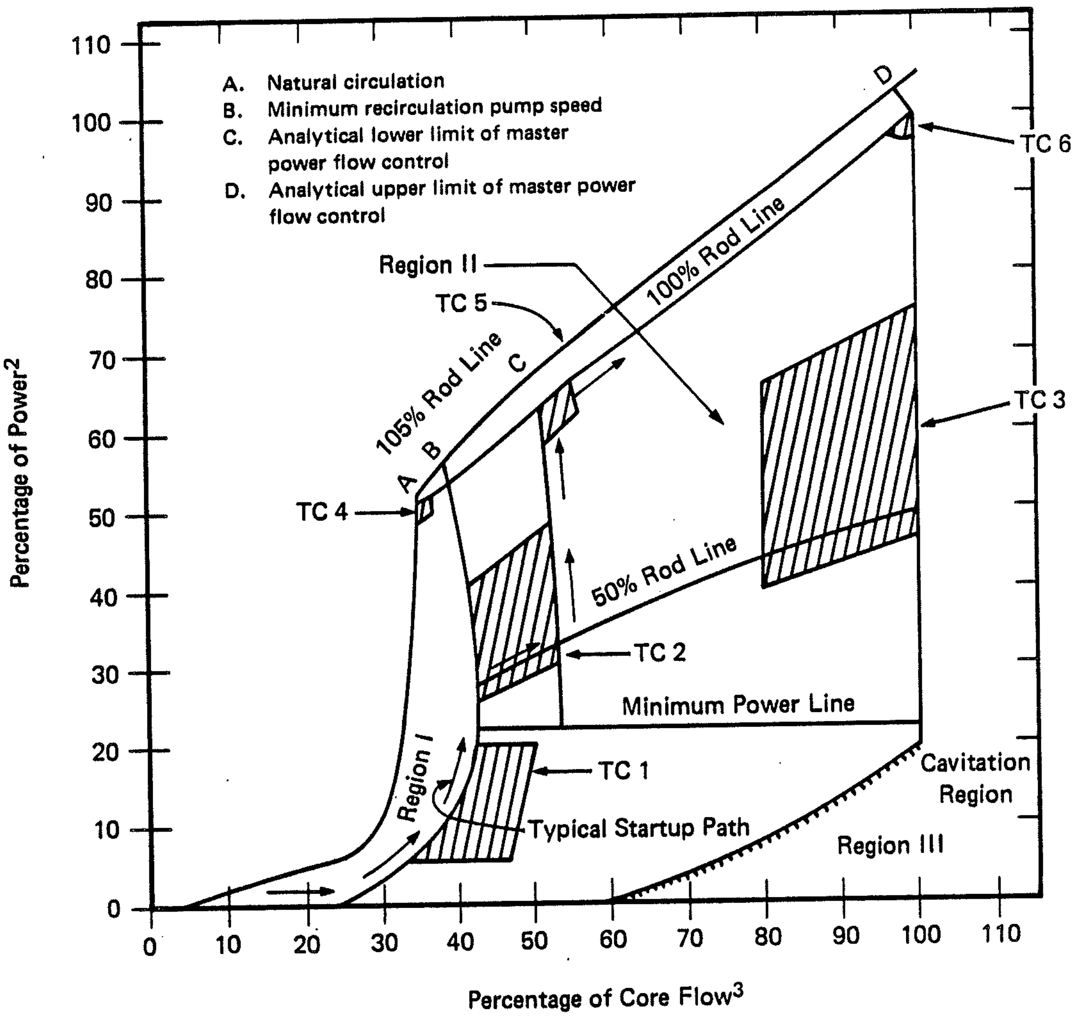
[c] Scram times of the four slowest CRDs will be determined at Test Conditions 1 and 6 during planned reactor scrams.

Note: Single CRD scrams should be performed with the charging valve closed (do not ride the charging pump head).

PROGRAM PHASE	RESPONSIBILITIES	MAJOR ACTIVITIES
Construction Test Phase Construction Complete and Equipment and System Jurisdictional Transfer	Detroit Edison Company — Primary Responsibility Surveillance Function Daniel International Corporation Performing Agent	1. Structures, Components, Systems Erected 2. Mechanical and Electrical Checks To Determine Equipment and Systems Installed as Designed 3. Review and Approve Tests and Check Results 4. System Hydro Tests
Checkout and Initial Operations Test Phase Checkout and Initial Operations Test Phase Complete	Detroit Edison Company — Primary Responsibility and Performing Agent SCO, GE, Consultants, Vendors as Necessary for Assistance	1. Initial Equipment Energization 2. Flushing and Cleaning 3. Initial Calibration of Instrumentation 4. Electrical Wiring and Equipment Tests 5. Valve and Mechanical Equipment Tests 6. Initial Equipment Operation 7. Equipment and System Maintenance 8. Review and Approve Test Results 9. Refurbishment of Equipment 10. System Hydro Tests
Preoperational Test Phase Preoperational Test Phase Complete; System Turnover to Nuclear Production	Detroit Edison Company — Primary Responsibility and Performing Agent SCO, GE, Consultants as Necessary for Assistance	1. Approve Prerequisites for Preop Testing 2. Perform Preop Tests 3. Return Systems to Normal Status 4. Review and Approve Preop Tests Results
Startup Test Phase Fuel Load	Detroit Edison Company — Primary Responsibility and Performing Agent GE, Consultants as Necessary for Assistance	1. Approve Readiness for Fuel Loading 2. Load Fuel 3. Perform Startup Tests From Initial Criticality to Full Power 4. Review and Approve Startup Test Results
Warranty Demonstration Phase Commercial Operation	Detroit Edison Company — Primary Responsibility and Performing Agent GE, Vendors, Consultants as Necessary for Assistance	1. Approve Readiness for Warranty Tests 2. Perform Warranty Tests 3. Review and Approve Warranty Test Results

FIGURE 14.1-1

TEST PROGRAM OUTLINE



Notes:

1. See Table 14.1-1 for startup test titles.
2. Power in percentage of rated thermal power, 3292 MWT.
3. Core flow in percentage of rated core recirculation flow, 100.0 X 10^6 lb/hr.
4. TC = test condition.

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FIGURE 14.1-2

APPROXIMATE POWER FLOW MAP
SHOWING STARTUP TEST CONDITIONS

14.2 AUGMENTATION OF STAFF IN INITIAL TESTS AND OPERATIONS

14.2.1 Description of Augmented Staff

Since the normal complement of plant operating personnel was insufficient in number to staff the initial test and operation program, Edison augmented the staff for this initial test period, primarily with General Electric and English Electric test personnel.

The responsibility for the completion of the startup test program lies with the Edison Startup Test Phase Group, which is part of the Nuclear Production Organization. The detailed description of the organization, personnel qualifications, and responsibilities for the Startup Test Phase Group is covered by plant administrative procedures.

CHAPTER 15: ACCIDENT ANALYSIS

15.0 GENERAL

The original Final Safety Analysis Report (FSAR) was submitted in support of the Detroit Edison Company's (Edison) application for a license to operate Fermi 2, a 3293-MWt nuclear power plant, at the Enrico Fermi Atomic Power Plant site on the western shore of Lake Erie, at Lagoona Beach, Monroe County, Michigan. The Updated Final Safety Analysis Report (UFSAR) was prepared in response to 10 CFR 50.71(e).

The design power rating (emergency core cooling system [ECCS] design basis) for Fermi 2 is 3486 MWt, with a turbine-generator design gross electrical output at the generator terminals of 1235 MWe and a net electrical output of approximately 1170 MWe.

On September 9, 1992, the NRC issued Amendment 87 to the Fermi 2 operating license authorizing a change in the thermal power limit from 3293 MWt to 3430 MWt, a 4.2 percent increase in thermal power (References 1 and 2). This changed the new electrical capacity from 1093 MWe to 1139 MWe, or an increase of 46 MWe.

During RF05 the LP Steam Path was replaced by a GE designed LP Steam Path with a higher efficiency. This changed the designed net electrical capacity from 1139 MWe to 1150 MWe, or an increase of 11 MWe.

During RF07, the HP Steam Path was replaced by a GE designed HP Steam Path with a higher efficiency. However, the gross generator output will not exceed the present 1217 MWe.

The Fermi Power Uprate Program followed the GE Nuclear Energy guidelines and evaluations for BWR power plants (References 3, 4 and 5).

Fermi 2 specific analyses and evaluations were performed, consistent with the generic guidelines, for systems and components that might be affected to ensure their capability to support the increase in power output and steam flow. Since the analyses are described in detail in the UFSAR, revisions have been made to reflect power uprate, as appropriate.

Cycle 3 was used as the representative fuel cycle for power uprate. The radiological consequences were calculated for the transient and accident analyses as applicable. Direct or statistical allowance for 2 percent power uncertainty was included in the analysis. The data has been updated for Cycle 7 fuel. Since the radiological consequences for Cycle 3 are bounding, the base calculations remain unchanged.

For Fermi 2, the limiting events for each limiting transient category were analyzed to determine their sensitivity to core flow, feedwater temperature, and cycle exposure. The results of these analyses developed the new licensing basis for transient analyses at uprated power. No changes to the basic characteristics for any of the limiting events were caused by power uprate.

The radiological doses resulting from several postulated accidents were reanalyzed for uprated conditions using methods recommended in the NRC Standard Review Plan (NUREG-0800, Chapter 15). The whole body dose and thyroid dose at the exclusion area, low population zone and, where appropriate, for the main control room were calculated.

In addition, feedwater line break, Section 15.6.6, air ejector line break, Section 15.7.1, liquid and solid radwaste system failure, Section 15.7.3, and gaseous radwaste failure, Section 15.11 were evaluated for impact due to power uprate. The feedwater line break is not affected by power uprate since it was analyzed based upon Technical Specification radiation levels which are not changing. The other accidents (originally analyzed based on a reactor thermal power level of 3430 MWt) were conservatively reanalyzed assuming a 2 percent increase in radiation releases which results in only minor increases in dose.

The results from all the reanalyses are significantly below the 10 CFR 100 guidelines and confirm the validity of the generic evaluation conclusions in Reference 3.

Fermi 2 has chosen to reanalyze the radiological consequences associated with a control rod drop accident, Section 15.4.9, a fuel handling accident, Section 15.7.4, and the design basis loss of coolant accident, Section 15.6.5, utilizing the guidance in Regulatory Guide 1.183, *Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors*. The guidelines of 10 CFR 50.67 are applicable to the radiological consequences of these accidents. The results from these analysis are below the 10 CFR 50.67 guidelines.

On February 10, 2014, the NRC issued Amendment 196 to the Fermi 2 operating license authorizing a change in the thermal power limit from 3430 MWt to 3486 MWt, a 1.64 percent increase in thermal power and a 1.88 percent increase in steam flow. This changed the net electrical capacity from 1150 MWe to approximately 1170 MWe (Reference 13). This power uprate was performed in accordance with 10 CFR 50, Appendix K and reflects the improvement in feedwater flow measurement. The Fermi 2 Measurement Uncertainty Recapture (MUR) power uprate followed the GE generic guidelines and evaluations for BWR plants provided in GEH Topical Report NEDC-32938P-A, "Generic Guidelines and Evaluations for General Electric Boiling Water Reactor Thermal Power Optimization," Revision 2, May 2003 (Reference 18). The analyses performed at 102% of the pre-MUR licensed thermal power (3430 MWt) remain applicable at the MUR uprated thermal power (3486 MWt) because the 2% uncertainty factor discussed in Regulatory Guide 1.49 is effectively reduced by the improvement feedwater flow measurements.

In general, the Hydrogen Water Chemistry (HWC) system does not affect any of the events analyzed in chapter 15. It is not an initiator for these events, nor is it required to mitigate any of these events or to shut down the reactor or any systems. Any accident or transient which results in a reactor scram, offgas flow restriction (valves not fully open), or a loss of power, will automatically shut down the HWC system. Once the HWC system is stopped, then the rest of the event proceeds as described in the following sections of chapter 15. The presence of the HWC system will not affect the offsite radiological consequences of any of the analyzed events primarily due to the short half-life of isotope N-16. After two minutes (approximately 15 half lives), any potential N-16 source will have decayed to insignificant levels. Since the transport time out to a building stack and then to the site boundary is typically greater than two minutes, the offsite dose consequences are negligible, when compared to the other potentially-released isotopes. Therefore, the increased N-16 levels caused by HWC operation will not affect any of the accidents described herein.

Chapter 15 through Section 15.8 is presented in the format of Regulatory Guide 1.70, Revision 2 (Reference 6). This was the standard method chosen by GE to present the accident analysis for all safety analysis reports circa 1975. The analyses included in Sections 15.9 through 15.16, with the exception of 15.11, were not reanalyzed for power uprate because they were no longer required by Revision 2/3 of the Regulatory Guide, nor are they presently required by the Standard Review Plan, NUREG-0800.

The safety analysis is based on the General Electric (GE) report, General Electric Standard Application for Reactor Fuel (GESTAR II), described in Reference 7. GESTAR II represents generic information relative to the GE fuel design and analysis and consists of a description of the fuel design and fuel thermal-mechanical, nuclear, and thermal-hydraulic analyses bases. It provides information and methods used to determine reactor limits that are independent of a plant-specific application. Plant-specific information and the transient and accident methods used are given in the United States supplement. Proposed changes to GESTAR II are submitted to the appropriate regulatory body for review and approval. A listing of NRC approved amendments are provided in GESTAR II. All approved changes are incorporated as a revision to the text.

The postulated most limiting transients and accidents were analyzed, consistent with the fuel design, as described in Chapter 4. This Chapter examines the effects of anticipated process disturbances and postulated component failures to determine their consequences and to evaluate the capability built into the plant to control or accommodate such failures and events.

The scope of the situations analyzed includes anticipated operational occurrences (AOOs) (expected) (e.g., loss of electrical load), off-design abnormal (unexpected) transients that induce system operations condition disturbances, postulated accidents of low probability (e.g., the sudden loss of integrity of a major component), and finally hypothetical events of extremely low probability (e.g., an anticipated transient without the operation of the entire control rod drive system).

The Fermi 2 design is intended to be valid for the licensed life of the plant. The supplemental cycle-specific safety analysis assures that the plant can be operated safely and not pose any undue risk to the health and safety of the public. This is accomplished by demonstrating that radioactive releases from the plant for normal operation, AOOs, and postulated accidents meet applicable regulations.

Fermi 2 plant operation must meet various safety requirements defined in the Code of Federal Regulations. To evaluate the safety impact, fuel lattice physics calculations and 3-D simulation, transient, and accident evaluations were performed. The NRC approved methodologies described in GESTAR II were used to license the following combination of operating states (References 2 and 8 through 13):

a. Operation in the maximum extended operating domain with both the turbine bypass and moisture separator reheater in service

b. Operation in the maximum extended operating domain with either the turbine bypass or moisture separator reheater out-of-service

c. Operation in the maximum extended operating domain with both the turbine bypass and moisture separator reheater out-of-service.

d. Operation in the maximum extended operating domain with pressure regulator out-of-service.

Operation in the extended domain includes the maximum extended load line limit region and increased core flow with flow between 83 percent and 105 percent of rated flow at rated power (3486 MWth); feedwater heaters out-of-service and final feedwater temperature reduction with feedwater temperature between -50°F and +5°F of rated; and single loop operation.

The core-wide nuclear and thermal reactivity characteristics when combined with the rest of the plant systems and equipment determines the normal steady-state operation, transient and accident performance of the plant.

The performance of the anticipated operational occurrences (moderate frequency events) were evaluated with the methodologies described in GESTAR II. The limiting events analyzed are determined by a sensitivity study described in Reference 7 that examines the impact of minimum critical power ratio (MCPR) due to the change in fuel design. Based on results of the study, several limiting events have been identified and analyzed using the appropriate input parameters. The MCPR results of these limiting transients form the basis of the MCPR operating limits. Implementation of these MCPR operating limits in the Core Operating Limits Report ensures that the MCPR safety limit for normal conditions (dual loop operation) and for single loop operation will not be exceeded during the most severe anticipated operational occurrences.

15.0.1 Analytical Objective

The spectrum of postulated initiating events is divided into categories based on the type of disturbance and the expected frequency of the initiating occurrence; the limiting events in each combination of category and frequency are quantitatively analyzed. The plant safety analysis evaluates the ability of the plant to operate within regulatory guidelines, without undue risk to the public health and safety.

15.0.2 Analytical Categories

Transient and accident events contained in this report are discussed in individual categories as required by Reference 6. The cycle-specific input parameters and results of the events are summarized in Tables 15.0-1, 15.0-2, 15.0-3, and Reference 15. Each event evaluated is assigned to one of the following applicable categories.

a. Decrease in Core Coolant Temperature

   Reactor vessel water (moderator) temperature reduction results in an increase in core reactivity. This could lead to fuel cladding damage

b. Increase in Reactor Pressure

   Nuclear system pressure increase threatens to rupture the reactor coolant pressure boundary (RCPB). Increasing pressure also collapses the voids in the core moderator, thereby increasing core reactivity and power level which threaten fuel cladding due to overheating

c. Decrease in Reactor Core Coolant Flow Rate

A reduction in the core coolant flow rate threatens to overheat the cladding as the coolant becomes unable to adequately remove the heat generated by the fuel

d. Reactivity and Power Distribution Anomalies

Transient events included in this category are those that cause rapid increases in power due to increased core flow disturbance events. Increased core flow reduces the void content of the moderator, increasing core reactivity and power level

e. Increase in Reactor Coolant Inventory

Increasing coolant inventory could result in excessive moisture carryover to the main turbine, feedwater turbines, etc.

f. Decrease in Reactor Coolant Inventory

Reductions in coolant inventory could threaten the fuel as the coolant becomes less able to remove the heat generated in the core

g. Radioactive Release From a Subsystem or Component

Loss of integrity of a radioactive containment component is postulated

h. Anticipated Transients Without Scram (ATWS)

Anticipated transient without scram (ATWS) means an anticipated operational occurrence (e.g., loss of power to all recirculation pumps, tripping of the turbine generator set, isolation of the main condenser, loss of all offsite power, etc.) followed by the failure of the reactor trip portion of the protection system. The systems used to mitigate the postulated ATWS events are recirculation pump trip (RPT), alternate rod insertion (ARI), and standby liquid control (SLC). These systems are required to meet 10 CFR 50.62.

15.0.3 Event Evaluation

15.0.3.1 Identification of Causes and Frequency Classification

Situations and causes that lead to the analyzed initiating events are described within the categories designated above. The frequency with which each event occurs is summarized on the basis of available operating plant history for the transient event. Events for which inconclusive data exist are discussed separately within each event section.

Each initiating event within the major groups is assigned to one of the following frequency groups:

a. Incidents of moderate frequency - incidents that may occur during a calendar year to once per 20 years for a particular plant. These events are referred to as anticipated (expected) operational transients

b. Infrequent incidents - incidents that may occur during the life of the particular plant (spanning once in 20 years to once in 100 years). These events are referred to as abnormal (unexpected) operational transients

c. Limiting faults - occurrences that are not expected to occur but are postulated because their consequences may result in the release of significant amounts of radioactive material. These events are referred to as design basis (postulated) accidents.

15.0.3.1.1 Unacceptable Results for Incidents of Moderate Frequency (Anticipated [Expected] Operational Transients)

The following are considered unacceptable safety results for incidents of moderate frequency (anticipated operational transients):

a. A release of radioactive material to the environs that exceeds the limits of 10 CFR 20

b. Reactor operation induced fuel cladding failure

c. Nuclear system stresses in excess of those allowed for the transient classification by applicable industry codes

d. Containment stresses in excess of those allowed for the transient classification by applicable industry codes.

15.0.3.1.2 Unacceptable Results for Infrequent Incidents (Abnormal [Unexpected] Operational Transients)

The following are considered unacceptable safety results for infrequent incidents (abnormal operational transients):

a. Release of radioactivity that results in dose consequences that exceed a small fraction of 10 CFR 100

b. Fuel damage that would preclude resumption of normal operation after a normal restart

c. Generation of a condition that results in consequential loss of function of the reactor coolant system

d. Generation of a condition that results in a consequential loss of function of a necessary containment barrier.

15.0.3.1.3 Unacceptable Results for Limiting Faults (Design Basis [Postulated] Accidents)

The following are considered unacceptable safety results for limiting faults (design basis accidents):

a. Radioactive material release that results in dose consequences that exceed the guideline values of 10 CFR 100 or 10 CFR 50.67 for DBA-LOCA and fuel handling accident

b. Failure of fuel cladding that cause changes in core geometry, such that core cooling would be inhibited

c. Nuclear system stresses in excess of those allowed for the accident classification by applicable industry codes

d. Containment stresses in excess of those allowed for the accident classification by applicable industry codes when containment is required

e. Radiation exposure for limiting faults other than DBA-LOCA or fuel handling accident to plant operations personnel in the main control room in excess of 5 rem whole body, 30 rem inhalation, and 75 rem skin

f. Radiation exposure to operations personnel in the main control room in excess of 5 rem TEDE.

15.0.3.2 Sequence of Events and Systems Operations

Each transient or accident is discussed and evaluated in terms of the following.

a. A step-by-step sequence of events from initiation to final stabilized condition

b. The extent to which normally operating plant instrumentation and controls are assumed to function

c. The extent to which plant and reactor protection systems are required to function

d. The credit taken for the functioning of normally operating plant systems

e. The operation of engineered safety systems that are required.

In analyzing anticipated operational transients, some non safety grade pieces of equipment are assumed to operate. The most limiting transient that takes credit for this equipment is the excess feedwater event. The plant operating equipment that plays a significant role in mitigating this event (feedwater controller failure, open to maximum demand; Subsection 15.1.2) is the turbine bypass system and the Level 8 high water level trip (closes turbine stop and control valves). To ensure an acceptable level of performance for Fermi 2, surveillance requirements for both the bypass valves and feedwater Level 8 trip are included in the Technical Specifications.

15.0.3.2.1 Single Failures or Operator Errors

This subsection discusses a very important concept pertaining to the application of single failure and operator error analyses of the postulated events. Single active component failure criteria have been required and successfully applied on past NRC approved docket applications to design basis accident categories <u>only</u>. Reference 6 implies that a single failure and operator error requirement should be applied to transient events (high, moderate, and low probability occurrences) as well as accident (very low probability) situations.

Although Fermi 2 may well be able to tolerate the application of single failures or operator errors to transient events, this analysis does not consider such failures. At the time the construction permit for Fermi 2 was issued, such analyses were not a requirement.

The transients and accidents in this Chapter have been evaluated by the more restrictive old allowances and limits than those of the event categorization presently in effect. Most events postulated for consideration are the results of single equipment failures <u>or</u> single operator errors that have been postulated during any normal or planned mode of plant operation. The types of operational single failures and operator errors considered as initiating events are identified in Subsection 15.0.3.2.2.

Accidents Events. For accidents analyzed, all immediate short term functions are automatic. No operator action is therefore required to mitigate the event consequences for the first 10 minutes. Ten minutes has been judged to be ample time for an operator to assess the situation, determine trends of temperature and pressure, and decide whether containment cooling or suppression pool cooling should be initiated, or whether some other action is more appropriate.

For ECCS evaluation, the post accident period during which no credit is taken for operator action was selected to be 20 minutes, because 20 minutes allows more than enough time for the automatic emergency core cooling systems to have initiated their design function. Specific operator actions would depend on the extent of the primary system break, but in no case is action required in less than 10 minutes, and in general, a longer time (20 minutes or more) would likely be available (Subsection 6.3.2.15.1).

The possible variables that must be considered after the reactor water level has been automatically restored to a safe condition can best be judged and acted upon by trained, licensed operators using information displayed in the control room in conjunction with symptom oriented emergency procedures and guidelines. Because of the large number of variables to be considered, the operator should not be bound to respond to prescriptive instructions, but will respond to the symptoms as they exist.

Operational Transient Events. For all operational transients, no operator action is required to prevent the fuel from exceeding safety design basis limits.

Operator action is expected and used in order to

a. Maintain the plant in a steady-state condition

b. Initiate safe and orderly shutdown.

If the operator is unsuccessful in achieving normal plant status, he will be guided by the symptom oriented emergency procedures that are developed from the BWR Owners Group generic guidelines submitted to the NRC.

Effect of Single Failures or Operator Errors

Accident Events. The effect of single failures or operator errors has been considered in analyzing postulated accidents. Accidents involving an entire spectrum of primary system breaks are covered in Section 6.3.

Operational Transient Events. The use of the single failure or operator error criteria has not been a design basis requirement for Fermi 2. However, information provided to address Item II.K.3.44 of NUREG-0737 demonstrates that, for Fermi 2, adequate core cooling is maintained for any operational transient with the worst single failure.

The generic analysis performed by GE (Reference 14) for the BWR Owners Group of the adequacy of core cooling for transients with single failure is applicable to Fermi 2.

The anticipated transients in Regulatory Guide 1.70, Revision 3, were reviewed from a core cooling viewpoint. The loss of feedwater event was identified to be the most limiting transient that would challenge core cooling. The BWR is designed so that the high pressure makeup or inventory maintenance systems or heat removal systems are independently capable of maintaining the water level above the top of the active fuel given a loss of feedwater. The detailed analyses showed that even with the worst single failure in combination with the bounding loss of feedwater event, the core still remains covered.

Even with more degraded conditions involving four stuck open relief valves in addition to the worst transient with the worst single failure, studies showed that the core remains covered and adequate core cooling is available during the whole course of the transient. It has been concluded that for Fermi 2 anticipated transients (including transients that result in a stuck open relief valves) combined with the worst single failure and assuming proper operator actions, the core remains covered.

15.0.3.2.2 Initiating Events

The following types of operational single failures and operator errors are considered as initiating events.

a. The undesired opening or closing of any single valve (a check valve is not assumed to close against normal flow)

b. The undesired starting or stopping of any single component

c. The malfunction or maloperation of any single control device

d. Any single electrical component failure

e. Any single operator error.

Operator error is defined as an active deviation from written operating procedures or nuclear plant standard operating practices. A single operator error is the set of actions that is a direct consequence of a single erroneous decision. The set of actions is limited as follows:

a. Those actions that could be performed by one person

b. Those actions that would have constituted a correct procedure had the initial decision been correct

c. Those actions that are subsequent to the initial operator error and have an effect on the designed operation of the plant, but are not necessarily directly related to the operator error.

Examples of single operator errors are as follows:

a. An increase in power above the established flow control power limits by control rod withdrawal in the specified sequences

b. The selection and complete withdrawal of a single control rod out of sequence

c. An incorrect calibration of an average power range monitor

d. Manual isolation of the main steam lines as a result of operator misinterpretation of an alarm or indication.

15.0.3.3 Core and System Performance

15.0.3.3.1 Introduction

Section 4.4, Thermal and Hydraulic Design, is a description of the various fuel failure mechanisms. Avoidance of unacceptable results 1 and 2 for incidents of moderate frequency is verified statistically with consideration given to data, calculation, manufacturing, and operating uncertainties. An acceptable criterion was determined to be that 99.9 percent of the fuel rods in the core would not be expected to experience boiling transition (see Reference 1). This criterion is met by demonstrating that transients do not result in a minimum critical power ratio (MCPR) of less than the Safety Limit Minimum Critical Power Ratio (SLMCPR) as stated in the Core Operating Limits Report. (Initial core SLMCPR was 1.06)

The steady-state operating limit is determined as follows:

a. The change in the critical power ratio, ΔCPR, that would result in the safety limit CPR value is calculated for each event. These calculations use the most limiting axial power shape and the results represent the most limiting ΔCPRs for the allowable operating range (e.g. maximum extended load line limit analysis, increased core flow, partial feedwater heating, single loop operation, and various equipment out of service). The results are exposure and fuel type dependent.

b. For nonpressurization events, the ΔCPR value is added to the safety limit CPR value to obtain the event based minimum CPR, MCPR.

c. For pressurization events the MCPR is determined by the safety limit CPR and the ΔCPR in conjunction with correction factors. The correction factors are explained in Subsection 4.4.4.1.

The results are given in Reference 15 for the limiting transients.

The operating limit MCPR is the maximum value of the event based MCPRs calculated from the transient analysis. Maintaining the MCPR operating limit at or above this operating limit ensures that the safety limit CPR is never violated.

Section 4.4 describes the various fuel failure mechanisms and establishes fuel damage limits for various plant conditions. Avoidance of fuel cladding damage and release of radioactive material in excess of 10 CFR 100 or 10 CFR 50.67 (as applicable) limits during or as a result of abnormal operational transients is verified by demonstrating that abnormal operational transients do not result in a MCPR of less than safety limit CPR. If the MCPR remains above the safety limit CPR, no fuel failures result from the transient, and thus the radioactivity released from the plant cannot be increased over the operating conditions existing prior to the transient. Maintaining a MCPR greater than safety limit CPR is a sufficient but not a necessary condition to ensure that no fuel damage occurs. This is discussed in Section 4.4.

Avoidance of catastrophic failure of fuel cladding in design basis accidents is shown by demonstrating that fuel cladding temperatures remain below the fragmentation temperature of 2200°F or fuel enthalpies remain below 280 cal/g (Subsection 4.3.3).

For situations in which fuel damage is sustained, the extent of damage is determined by correlating fuel energy content, cladding temperature, fuel rod internal pressure, and cladding mechanical characteristics.

These correlations are substantiated by fuel rod failure tests and are discussed in Section 4.4, Thermal and Hydraulic Design, and Section 6.3, Emergency Core Cooling Systems.

15.0.3.3.2 Input Parameters and Initial Conditions for Analyzed Events

In general, the events analyzed have values for input parameters and initial conditions as specified in Table 15.0-1. Analyses which assume data inputs different than these values are designated accordingly in the appropriate event discussion.

15.0.3.3.3 Initial Power/Flow Operating Constraints

The analyses basis for most of the transient safety analyses is the rated thermal power at 105 percent rated core flow. This operating point is the apex of a bounded operating power/flow map which, in response to classified anticipated operational occurrences (AOOs), will yield the minimum thermal margins of any operating point within the bounded map.

Any other constraint which may truncate the bounded power/flow map must be observed, such as the recirculation valve and pump cavitation regions, the licensed power limit and other restrictions such as pressure and thermal margin criteria.

The upper operating power/flow limit of a reactor is predicated on the operating basis of the analysis and the corresponding constant rod pattern line. This boundary may be truncated by the licensed power and the MCPR operating limit.

Certain localized events are evaluated at other than the above mentioned conditions. These conditions are discussed as they pertain to the appropriate event.

15.0.3.3.4 Evaluation of Results

The results of the transient analyses are provided for each event and the critical parameters are shown in Reference 15 (peak neutron flux, heat flux, and MCPR responses). The transient responses for these events are presented in figures of Reference 15. The MCPR values provided in Reference 15 are used to generate the operating limit MCPR values for the licensed operating states in the Core Operating Limits Report (COLR). COLR presents these limits as a function of assumed scram speed.

In order to address all of the credible transient events in these eight analytical categories (refer to Subsection 15.0.2), the transients were based on the analysis of a spectrum of approximately 25 events, assignable to one of these categories. The relative and absolute severity of the consequences of the events are generally plant-specific and often cycle-specific as well. Most of the events result in fairly mild plant disturbances. Thus, only a few events are severe enough to be potentially limiting. Furthermore, although the most limiting event may differ from plant to plant and reload to reload, it is General Electric's experience that the most limiting transients can always be expected to come from the same selected group of transient events. Therefore, most of the events analyzed need not be reanalyzed or reassessed for cycle-specific core licensing application. The selected group of limiting events consists of:

a. Generator Load Rejection (without bypass),

b. Turbine generator trip (without bypass),

c. Feedwater controller failure,

d. Pressure Regulator Failure – Closed (when backup pressure regulator is out of service),

e. Loss of Feedwater Heating, and

f. Rod Withdrawal Error at Power

Subsequent AOO analyses verified the results of the above sensitivities. Descriptions of the typical analyses performed for the above limiting events are discussed in the following subsections.

15.0.3.3.4.1 Analysis Uncertainties

Model uncertainties are documented in Chapter 4, Subsection 4.4.4.1.2.6.

15.0.3.4 Barrier Performance

This section primarily evaluates the performance of the reactor coolant pressure boundary (RCPB) and the containment system during transients and accidents. During transients that occur with no release of coolant to the primary containment, only RCPB performance is considered. If release to the primary containment occurs, as in the case of limiting faults, then challenges to the primary containment are evaluated as well. Similarly, if the release occurs outside the primary containment, as in the case of limiting faults, then the challenges to the secondary containment (reactor building) are evaluated (Subsection 3.6.2).

Avoidance of excessive RCPB stresses during abnormal operational transients and accidents is assessed by comparing peak internal pressure with the overpressure transient allowed by the applicable industry code. The only significant areas of interest for internal pressure damage are the high pressure portions of the nuclear system primary barrier (the reactor pressure vessel (RPV) and the high pressure pipelines attached to the RPV). The overpressure, below which no damage can occur, is taken as the pressure increase over design pressure allowed by the ASME Boiler and Pressure Vessel (B&PV) Code Section III, Class 1. This code permits pressure transients up to 10 percent over design pressure (1375 psig = 110 percent x 1250 psig). It can be concluded that the high pressure portion of the nuclear system process barrier meets the design requirement if peak nuclear system pressure remains below 1375 psig.

An analysis performance measurement, discussed in Subsection 4.3.3, is used to evaluate whether nuclear system process barrier damage occurs as a result of reactivity accidents. If peak fuel enthalpy remains below 280 cal/g, no nuclear system process barrier damage results from nuclear excursion accidents.

Containment Damage

Containment integrity during accidents is maintained by ensuring that containment stresses do not exceed those allowed for accidents by applicable industry codes (ASME B&PV Code Section III, Class B, Nuclear Vessel 1968, including 1969 Summer Addenda).

Radioactive Barrier Mechanical Design

Design basis accidents are used in determining the sizing and strength requirements of many of the essential nuclear system components. Comparing accidents considered in this section with those used in the mechanical design of equipment reveals that either the applicable accidents are the same or that the accident in this section results in less severe stresses than those assumed for mechanical design. Damage to any of the radioactive material barriers, as a result of accident initiated fluid impingement and jet forces, is considered in those parts of the UFSAR that describe the mechanical design features of systems and components.

15.0.3.5 Radiological Consequences

In this Chapter, the consequences of radioactivity release during the three types of events: (a) incidents of moderate frequency (anticipated operational transients), (b) infrequent incidents (abnormal operational transients), and (c) limiting faults (design basis accidents), are considered. For all events whose consequences are limiting, a detailed quantitative evaluation is presented. For nonlimiting events a qualitative evaluation is presented or results are referenced from a more limiting or enveloping case or event.

For limiting faults, 2 hr radiation doses were calculated for the site exclusion area boundary, and 30 day doses were calculated for the low population zone boundary. The calculated doses were compared against the NRC dose criteria set forth in 10 CFR 100 or 10 CFR 50.67, as applicable. All of this work has been done according to guidelines issued over the years by the NRC and contained in various Regulatory Guides (e.g., 1.3, 1.4, 1.5, 1.25, 1.98 and 1.183). The maximum doses would result from a LOCA, and this was therefore the bounding accident (Subsection 15.6.5). Regulatory Guide 1.3 clearly states that its assumptions are acceptable to the NRC for use in evaluating the design basis LOCA for a BWR and in comparing the consequent doses against the 10 CFR 100 guidelines. The release of radioactivity and subsequent sources for the bounding accident are as indicated in Regulatory Guide 1.3. The source of offsite radioactivity for those accidents analyzed in accordance with Regulatory Guide 1.3 is the standby gas treatment system; estimates of releases from this system are based on the postulated primary containment leak rate of 0.5 percent per day.

Regulatory Guide 1.183 provides for selective evaluation of the radiological consequences of design basis accidents given that the accidents that were previously analyzed are completely superceded by the new analysis, completely reanalyzed utilizing the assumptions in Regulatory Guide 1.183, and that the results are within the limits of 10 CFR 50.67. The assumptions pertaining to Regulatory Guide 1.183 and the limits of 10 CFR 50.67 cannot be applied to any existing analysis. Therefore, the discussions of the radiological consequences of the accidents not analyzed in accordance with Regulatory Guide 1.183 remain unchanged. The sources of offsite radioactivity for accidents analyzed in accordance with Regulatory Guide 1.183 are leakage of ECCS piping and components that recirculate suppression pool water outside of primary containment, MSIV leakage, standby gas treatment system, and secondary containment bypass leakage.

The ECCS leakage is limited to a maximum of 5 gpm for the entire 30 days of the DBA LOCA. Two percent of the iodine is assumed to become airborne and is released as 97 percent elemental and 3 percent organic. The drywell and wetwell are projected to leak at their design leakage of 0.5 percent of their atmospheric contents by weight for the first 24 hours and 0.25 percent of their atmospheric contents by weight for the remaining 29 days. No credit is taken for secondary containment draw down for 15 minutes after the 2 minute gap release. Secondary containment bypass leakage is limited to 10 percent of the primary containment leakage and is modeled as a ground release at the TBHVAC stack. Credit is not taken for deposition in the bypass leakage pathway. The MSIVs are projected to leak 250 scfh total (100 scfh maximum in one line) for the first 24 hours and 50 percent of that for the remaining 29 days. A portion of elemental and aerosol iodine is credited to plate out in the main steam piping. However, no credit is taken for deposition in the broken steam line upstream of the inboard MSIV. Credit is taken for the main steam piping to cool to increase the mechanism for iodine plate out.

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TABLE 15.0-1 INPUT PARAMETERS AND INITIAL CONDITIONS FOR CYCLE DEPENDENT TRANSIENT ANALYSIS

1.	Thermal Power Level, MWt	3486
2.	Steam Flow, lb per hr	15.143×10^6
3.	Core Flow, lb per hr	105×10^6
4.	Feedwater Temperature, °F	426.5
5.	Vessel Dome Pressure, psia	1045
6.	Vessel Core Pressure, psia	1061
7.	Turbine Bypass Capacity, % NBR	23.5
8.	Core Coolant Inlet Enthalpy, Btu/lb	529.0
9.	Turbine Inlet Pressure, psia	981
10.	Fuel Lattice	GNF3 and GE14
11.	Required Operating Limit MCPR	Reference 15
12.	MCPR Safety Limit	Tech Spec 2.1.1.2 and COLR
13.	Scram Response, sec at Control Fraction %	
	0	0.2
	5	0.490
	20	0.9
	50	2.0
	90	3.5
14.	Safety/Relief Valve Capacity, PPH at 1090 psig	870000.0
15.	Number of Safety/Relief Valves	
	Installed	15
	Assumed	11
16.	Relief Function Delay, seconds	0.4

TABLE 15.0-1 INPUT PARAMETERS AND INITIAL CONDITIONS FOR CYCLE DEPENDENT TRANSIENT ANALYSIS

17.	Safety Function Stroke Time, seconds	0.10
18.	Setpoints for Safety/Relief Valves Safety/Function, psig	1169.1, 1179.4, 1189.7
19.	High Flux Trip, % NBR	124.4
20.	High Pressure Scram Setpoint, psig	1126
21.	Vessel level Trips, inches above vessel zero	
	Level 8 - (L8), inches	588.3
	Level 3 - (L3), inches	535
	Level 2 - (L2), inches	457.5
22.	APRM Simulated Thermal Power Scram Trip Setpoint, % NBR	119.54
23.	High Pressure Recirculation Pump Trip Pressure Setpoint, psig	1133
24.	Total Steamline Volume, ft^3	4737
25.	Reheater Bypass Flow, % NBR	8.0 (Figures 15.0-2 and 15.0-3)

TABLE 15.0-2 TYPICAL LIMITING TRANSIENTS

Section	Transient Event	Cycle Average Exposure (MWd/st)	Power/Flow (% Rated)	Assumed Out-of-Service Equipment or Offnormal Condition
15.1.1	Loss of Feedwater Heating	PHE	100/83	Feedwater heating reduction of 100F
15.1.2	Feedwater Controller Failure to Maximum Demand	BOC-EOC	100/105	Turbine Bypass Final Feedwater Temperature Reduction -50F
15.1.2	Feedwater Controller Failure to Maximum Demand	BOC-EOC	100/105	Turbine Bypass Moisture Separator Reheater Final Feedwater Temperature Reduction -50F
15.2.1	Pressure Regulator Failure Downscale	BOC-EOC	100/105	One pressure regulator
15.2.2	Generator Load Rejection without Bypass	BOC-MOC1	100/105	Turbine Bypass
15.2.2	Generator Load Rejection Without Bypass	MOC1-MOC2	100/105	Turbine Bypass
15.2.2	Generator Load Rejection Without Bypass	MOC2-EOC	100/105	Turbine Bypass
15.2.2	Generator Load Rejection Without Bypass	BOC-EOC	100/105	Moisture Separator Reheater Turbine Bypass
15.4.2	Control Rod Withdrawal Error	PHE	100/100	RBM setpoint at 111 percent

Notes:

1. PHE is Peak Hot Excess reactivity.
2. Cycle Average Exposure is defined in the Supplemental Reload Licensing Report for BOC, MOC1, MOC2, and EOC. BOC is Beginning of Cycle and EOC is End of Cycle. MOC1 and MOC2 correspond to mid-cycle points where the MCPR operating limits are changed.
3. The Generator Load Rejection without Bypass is more limiting than the Turbine Trip without Bypass and the Feedwater Controller Failure with Bypass. The Feedwater Controller Failure without Bypass and without the Moisture Separator Reheaters is the most limiting pressurization transient.

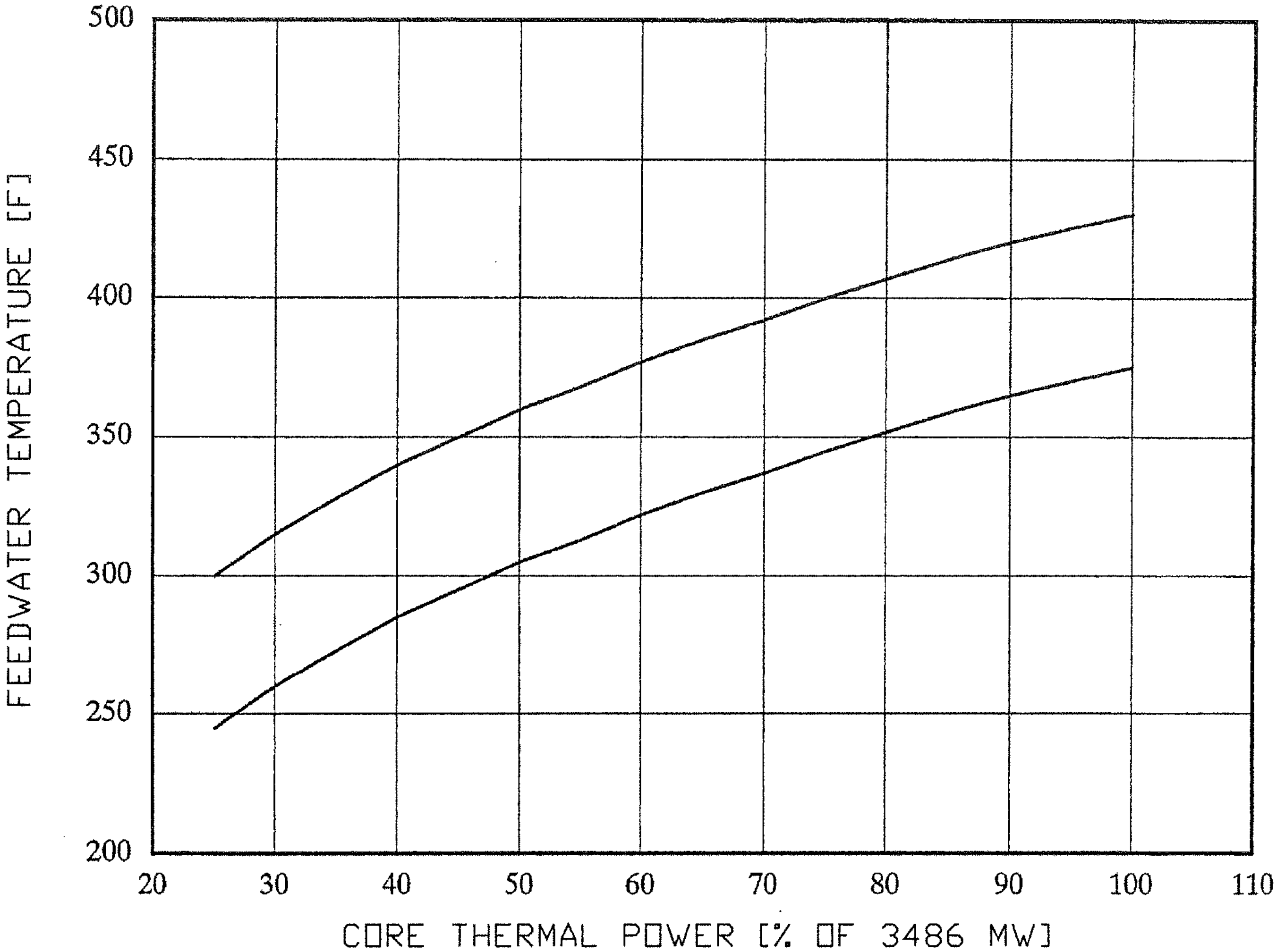
TABLE 15.0-3 TYPICAL OPERATING LIMIT MCPR TRANSIENTS

Transient Event	Applicable Cycle Average Exposure Range (MWd/st)	Applicable Flow at 100 % Power (% Rated)	Applicable Out of Service Equipment[A] and Operating Conditions
Loss of Feedwater Heating	BOC to EOC	83 to 105	Feedwater Heaters Final Feedwater Temperature Reduction – 50F
Feedwater Controller Failure to Maximum Demand	BOC to EOC	83 to 105	Feedwater Heaters Final Feedwater Temperature Reduction – 50F Turbine Bypass
Feedwater Controller Failure to Maximum Demand	BOC to EOC	83 to 105	Feedwater Heaters Final Feedwater Temperature Reduction – 50F Turbine Bypass Moisture Separator Reheaters
Generator Load Rejection without Bypass	BOC to MOC1	83 to 105	Turbine Bypass Feedwater Heaters
Generator Load Rejection without Bypass	MOC1 to MOC2	83 to 105	Turbine Bypass Feedwater Heaters
Generator Load Rejection without Bypass	MOC2 to EOC	83 to 105	Turbine Bypass Feedwater Heaters
Generator Load Rejection without Bypass	BOC to EOC	83 to 105	Turbine Bypass Moisture Separator Reheaters Feedwater Heaters
Control Rod Withdrawal Error	BOC to EOC	83 to 105	This event is independent of equipment out of service options
Pressure Regulator Failure Downscale	BOC to EOC	83 to 105	One Pressure Regulator

Notes

A. The analysis either covers or is independent of the identified out-of-service equipment. The OLMCPR adequately bounds the operating condition with the identified out-of-service equipment. The turbine generator and load rejection events are required to be analyzed without the turbine bypass; therefore, this event still needs to be considered when operating with turbine bypass. Normal operation with or without operation of MEOD and Final Feedwater Temperature Reduction of 50F. The analysis bounds the operation with this out-of-service equipment for a total of 100F feed water temperature reduction.

B. The required OLMCPR values are generated utilizing GE GEMINI or TRACG methods. Statistical mean value distributed control rod scram times are used in the analysis. Event unique adders are used to generate the required OLMCPR for Tau = 0 and Tau = 1 scram times. Tau is defined in the Core Operating Limits Report. OLMCPR values and limiting transients are found in Reference 15.

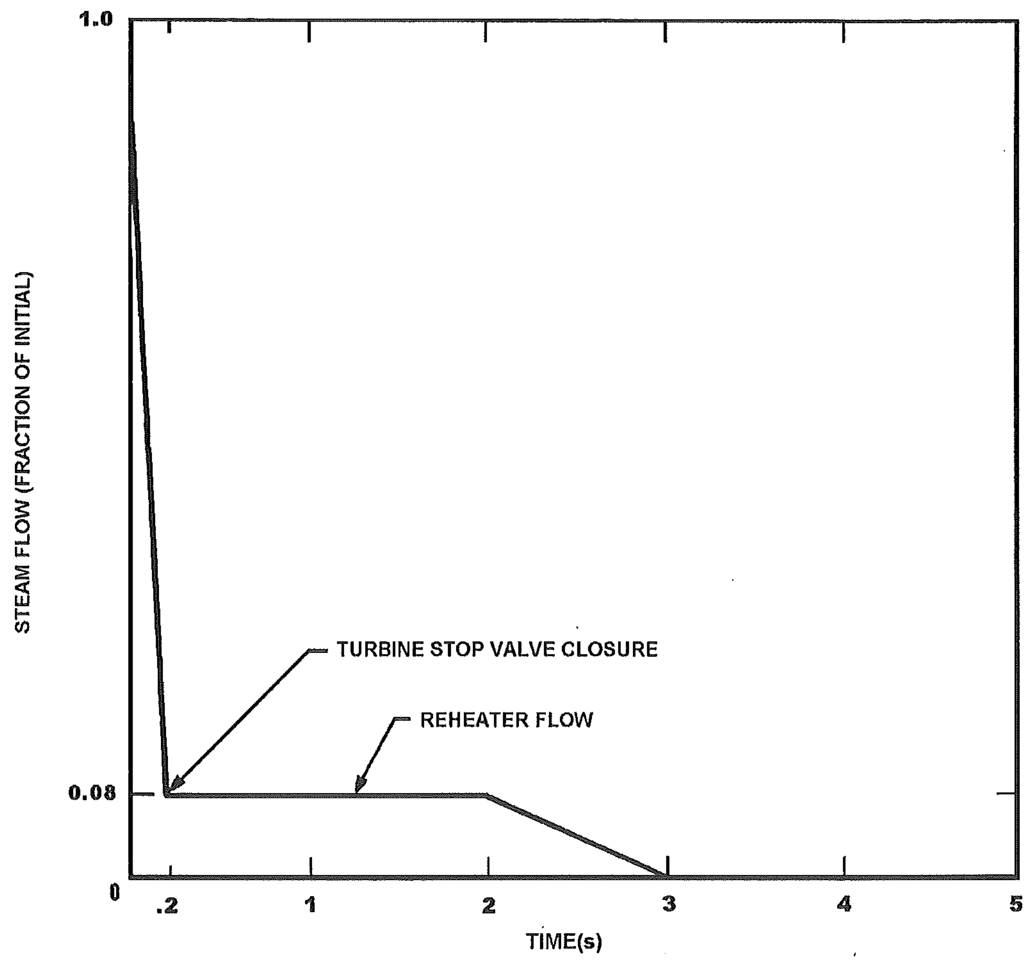


Fermi 2

UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 15.0-1

TYPICAL FEEDWATER TEMPERATURE VERSUS POWER



NOTE: The above reheater steam flow to the Moisture Separator Reheater (MSR) is conservatively estimated based on MSR effectiveness of 90% and 37°F temperature terminal difference (TTD) across the reheater.

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FIGURE 15.0-2

MAIN STEAM FLOW AFTER TURBINE TRIP
ALLOWING NO FLOW THROUGH BYPASS VALVES

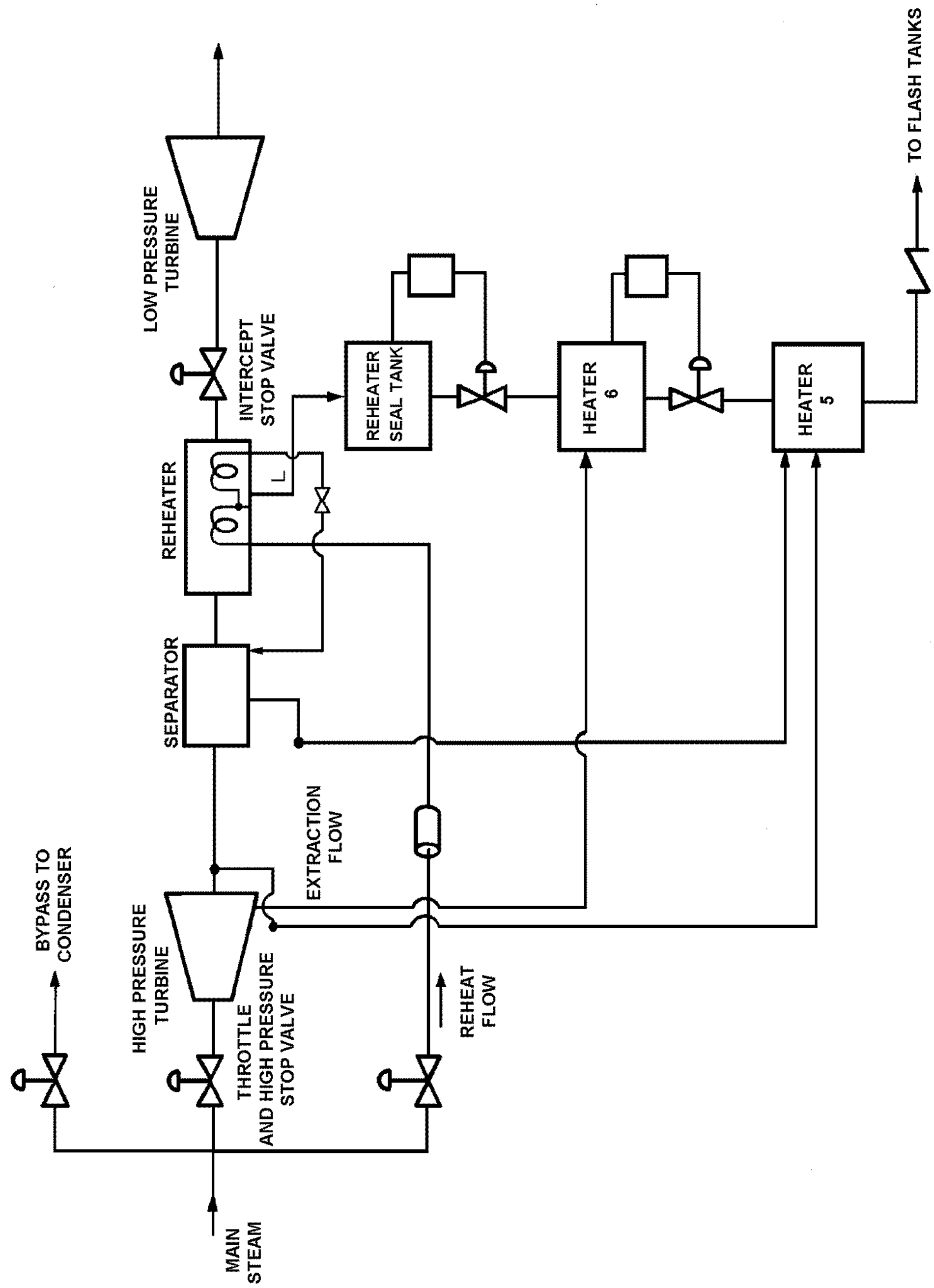

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FIGURE 15.0-3

REHEATER AND DRAINS SYSTEM

15.1 DECREASE IN REACTOR COOLANT TEMPERATURE

Four transients are evaluated under the decrease in reactor coolant temperature analytical category:

a. Loss of feedwater heating

b. Feedwater controller failure

c. Pressure regulator failure

d. Inadvertent safety relief valve opening.

Of the above identified transients, only feedwater controller failure and loss of feedwater heating transients have cycle specific analyses performed. A qualitative prescription of results is described for those events determined to be nonlimiting from a core performance standpoint.

15.1.1 Loss of Feedwater Heating

15.1.1.1 Identification of Causes and Frequency Classification

15.1.1.1.1 Identification of Causes

A feedwater heater can be lost in at least two ways:

a. Steam extraction line to the heater is closed

b. Feedwater is bypassed around the heater.

The first case produces a gradual cooling of the feedwater. In the second case, the feedwater bypasses the heater and no heating of the feedwater occurs. In either case, the reactor vessel receives cooler feedwater. The maximum number of feedwater heaters that can be tripped or bypassed by a single event represents the most severe transient for analysis considerations. This event has been conservatively estimated to incur a loss of up to 100°F of the feedwater heating capability of the plant and causes an increase in core inlet subcooling. This increases core power due to the negative void reactivity coefficient.

The design basis of the loss of feedwater heating event requires that no single failure or operator action can result in a loss of more than 100°F in feedwater inlet temperature. Therefore, the existing transient is conservative for Fermi 2.

The single failure or operator error event that could cause the greatest reduction in feedwater temperature is the inadvertent bypassing of half the feedwater flow around Heaters 3, 4, and 5. There are two separate parallel strings of Heaters 3, 4, and 5, each sized to handle half the total feedwater flow, and a bypass line also sized to limit flow to half capacity. A 100 percent feedwater flow can be maintained by opening the bypass line and then shutting off the flow through one of the half sized heater strings. Such an action would cause a reduction in the final feedwater temperature that is significantly less than the 100°F design criterion established for this system.

In the unlikely event that a drop in feedwater temperature in excess of 100°F occurs, and assuming no operator action, the decrease in the minimum critical power ratio (MCPR) and increase in reactor power would be limited, because a scram would occur from high thermal power and thus no significant reductions in fuel thermal margin would occur. The scram might occur marginally sooner for greater temperature drops. After scram, no further increases in power occur.

The effects of this transient have been reviewed within the maximum extended operating domain described in Section 15.0. The most limiting loss of feedwater heating transient with respect to MCPR is performed at 100 percent rated power, minimum core flow at rated power and a 100ºF reduction in inlet feedwater temperature. The analysis at rated power does not credit the simulated thermal power scram.

The above discussion concerns a transient with a sudden feedwater temperature drop of 100°F. Steady-state operation with partial feedwater heating should also be considered because such operation might occur during maintenance or as a result of a decision to operate with lower feedwater temperature near end-of-cycle (EOC).

There are two distinct periods of concern when operating with partial feedwater heating:

a. Before EOC. Reducing the feedwater temperature before EOC may occur during routine maintenance. The peak pressures will be lower because of the reduced steam production. However, the magnitudes of the DCPR are still transient event dependent and, therefore, evaluation is conducted to ensure that the licensing bases are bounded. The plant is licensed to operate with a 50°F reduction in feedwater temperature.

b. After EOC. Operating with reduced feedwater temperature may occur as a result of an extended fuel cycle. The basis for the plant safety analysis has covered this operating condition. The plant is licensed to operate with a 50°F reduction in feedwater temperature during cycle extension.

15.1.1.1.2 Frequency Classification

The probability of this event (sudden 50°F drop) is considered low enough to warrant being categorized as an infrequent incident. However, because of the lack of a sufficient frequency data base, this transient disturbance is analyzed as an incident of moderate frequency.

This event is analyzed under worst case conditions of a 100°F loss and at full power. A reduction of feedwater temperature of 100°F at high power has never been reported, although smaller decreases have occurred. The probability of occurrence of this event is, therefore, regarded as small.

15.1.1.2 Sequence of Events and Systems Operation

15.1.1.2.1 Sequence of Events

This slow transient event results in the reactor core receiving colder feedwater up to a reduction of 100°F. This collapses the void content in the core thus increasing the core power due to the negative void coefficient.

15.1.1.2.2 Systems Operation

In establishing the expected sequence of events and simulating plant performance, it was assumed that normal functioning occurred in the plant instrumentation and controls, plant protection, and reactor protection systems.

The simulated thermal power trip (STPT) scram is the primary protection system trip in mitigating the consequences of this event.

Required operation of engineered safeguard features is not expected for either of these transients.

15.1.1.3 Core and System Performance

15.1.1.3.1 Mathematical Model

The quasi-steady-state nature of this transient enables this slow transient to be analyzed using the 3-dimensional, coupled nuclear thermal-hydraulics core simulator computer model as described in detail in Reference 1. This model calculates the changes in power level; power distribution; core flow; exposures; reactor thermal-hydraulic characteristics; and critical power ratio with spatially varying voids, control rods, burnable poisons, and other variables under steady-state conditions. For this transient, the time for reactivity insertion is greater than the fuel thermal time constant and the core hydraulic-transport times. Therefore, the steady-state representation before and after the transient is adequate. This computer model has been qualified and approved by the NRC for application with this transient.

15.1.1.3.2 Input Parameters and Initial Conditions

The 100 percent power, minimum core flow at rated power, and partial feedwater heating represents the bounding conditions for the analysis. The transient is simulated by programming a change in feedwater enthalpy corresponding to a 100°F loss in feedwater heating.

15.1.1.3.3 Qualitative Results

A scram on high thermal power may or may not occur for a 100°F loss event since it has been shown that the power increase for a 100°F loss event is very close to the high thermal power scram setpoint. Vessel steam flow and the initial system pressure remains relatively constant or increases slightly.

The analysis evaluated at 100 percent power, minimum core flow at rated power, and partial feedwater heating bounds all power, flow and feedwater temperature conditions. This subcooling perturbation event is not significantly affected by initial power, flow, and feedwater temperature conditions. The operability of the turbine bypass system and the moisture separator reheater does not affect the results of this event.

For reload cores, an evaluation is performed to determine if this transient could potentially alter the cycle MCPR operating limit. The results are reported in the cycle-specific supplemental reload licensing report.

15.1.1.3.4 Consideration of Uncertainties

Important factors (such as reactivity coefficient, scram characteristics, and magnitude of the feedwater temperature change) are assumed to be at the worst configuration so that any deviations seen in actual plant operation reduce the severity of the event.

15.1.1.4 Barrier Performance

The consequences of this event do not result in any temperature or pressure transient in excess of the criteria for which the fuel, pressure vessel, or containment are designed; therefore, these barriers maintain their integrity and function as designed.

15.1.1.5 Radiological Consequences

Since this event does not result in any fuel failures or any release of primary coolant to either the secondary containment or the environment, there are no radiological consequences associated with this event.

15.1.2 Feedwater Controller Failure, Open to Maximum Demand

The Feedwater Controller Failure, open to maximum demand event represents the most limiting event in this analytical category.

15.1.2.1 Identification of Causes and Frequency Classification

15.1.2.1.1 Identification of Causes

This event is postulated on the basis of a single failure of a control device, specifically one that can directly cause an increase in coolant inventory by increasing the feedwater flow.

The most severe applicable event is a feedwater controller failure during maximum flow demand. The feedwater controller is forced to its upper limit at the beginning of the event.

15.1.2.1.2 Frequency Classification

This event is considered to be an incident of moderate frequency.

15.1.2.2 Sequence of Events and Systems Operation

15.1.2.2.1 Sequence of Events

The excess feedwater flow increases the water level to the high level reference point, at which time the feedwater pumps and the main turbine are tripped and a scram is initiated.

15.1.2.2.2 Systems Operation

To properly simulate the expected sequence of events, the analysis of this event assumes normal functioning of plant instrumentation and controls, plant protection, and reactor protection systems, with the exception of the fact that four Group 1 relief valves are assumed to remain closed. Important system operational actions for this event are the high level tripping of the main turbine, turbine stop valve scram trip initiation, feedwater pump trip, bypass valve opening, and low water level initiation of the reactor core isolation cooling (RCIC) system and the high pressure coolant injection (HPCI) system. Initiation of RCIC and HPCI maintains long term water level control following tripping of feedwater pumps.

In addition to the turbine bypass flow after the turbine trip, the steam flow through the moisture separator reheater line is also available for the first 3 seconds after turbine trip during the transient. The Fermi 2 system is unique in that the main steam flow normally flows to this moisture separator reheater and it is not shut off by the stop or control valves.

The moisture separator reheater and drains system is shown in Chapter 15, Figure 15.0-3. A line carries a portion of the main steam from the main steam manifold to the tube side of two moisture separator reheaters where condensation occurs. The heat given up superheats the shell side fluid, which is the steam source for the low pressure turbine. The condensed fluid passes through the moisture separator reheater seal tank, Heater 6, Heater 5, the flash tanks, the drain pumps, and then is directly injected into the main feedwater line.

Outlet valves on the seal tank and Heater 6 are controlled by their respective levels. High water level in these vessels also opens bypass valves to the condenser.

The moisture separator reheater flow characteristics are modeled as shown in Chapter 15, Figure 15.0-2. The total flow ramps off to about 8.0 percent flow at 200 msec after turbine trip. After reaching about 8.0 percent flow, it becomes constant until 2 seconds have elapsed. After 2 seconds, the flow ramps off linearly to zero at approximately 3 seconds. The analysis of reheater steam flow is discussed in more detail in Chapter 10, Subsection 10.4.4.

15.1.2.3 Core and System Performance

15.1.2.3.1 Mathematical Model

The predicted dynamic behavior of this event is evaluated using the TRACG computer model described in Reference 1.

TRACG is designed to predict the transient behavior associated with a BWR. This model has been qualified by extensive comparison of its predicted results with actual BWR test data. Some of the significant features of the model are:

a. TRACG has a multi-dimensional, two-fluid model for the reactor thermal hydraulics and a three dimensional reactor kinetics model. The models simulate a large variety of test and reactor configurations to allow for detailed, realistic simulation of a wide range of BWR phenomena.

b. TRACG uses a two-fluid model, with six conservation equations for both the liquid and gas phases.

c. The two-fluid conservation equations contain a mixing term to account for turbulent mixing and molecular diffusion.

d. TRACG solves the heat conduction equation for the fuel rods in cylindrical geometry and for structural material in slab geometry TRACG heat conduction modeling uses a gap conductance model and couples the heat transfer between the fuel rod and the coolant.

e. The TRACG code has had the GEXL heat transfer correlation installed.

f. TRACG uses basic component models as building blocks to construct physical models. The components modeled include the pipe, pump, valve, tee, channel, jet pump, steam separator, steam dryer, vessel, upper plenum, heat exchanger, and break and fill as boundary conditions.

g. TRACG uses a first-principle mechanistic model for the steam separator validated against full-scale performance test data for two-stage and three-stage steam separators.

15.1.2.3.2 Input Parameters and Initial Conditions

The transient is simulated by programming an upper limit failure in the feedwater system so that 114.8 percent of nuclear boiler rated (NBR) feedwater flow occurs at the operating pressure. An additional 5 percent higher flow rate conservatism is assumed in the analysis to allow for feedwater flow uncertainty.

The 114.8 percent maximum flow used is a valid input because the Fermi 2 feedwater system is designed to supply 112.8 percent flow to the reactor at design sparger pressure. This flow is basically controlled by changing the speed of the two steam driven feed pump turbines. Each turbine drive has an independent, redundant electrohydraulic speed control system that responds to feedwater demands from the level control logic system (Chapter 7, Subsection 7.7.1.3). The controlled speed range of each feed pump is adjusted during startup such that a maximum flow demand signal to both pumps will produce a maximum flow of 114.8 percent at nominal pressure. The adjustment of each of the pump speed control spans results in an adequate margin for flow control at rated power and also maximizes the resolution of the control system over the control system operating range. Each turbine speed control is redundant, and any internal failure generally causes the turbine to fail to minimum speed by design. If a particular turbine fails to a high speed, the remaining turbine would be controlled to a lower speed and maintained at that level automatically by the level control system.

Thus, a failure of the common feedwater demand signal to the power supply voltage level was assumed to produce a flow of 114.8 percent which was evaluated for this transient. Replacement of the feedwater control system (FWC) with a digital feedwater control system (DFCS) has eliminated this common element whose proposed failure to power supply voltage level could affect both feedwater pumps to create this high flow condition. The DFWC hardware has separate modules for each feed pump drive. However, this transient bounds that created by any credible failure with the DFWC and is therefore a valid analysis of the system's ability to respond to any proposed failure.

Because each of the two feed pump drives has been adjusted to produce a pump speed that delivers 114.8 percent feedwater flow at nominal pressure at maximum feedwater demand, the calibration will preclude the need for any further corrective actions to meet the design value of flow subsequent to a single failure.

Typical, cycle-specific feedwater controller failure cases analyzed include the following:

a. Operation with turbine bypass and moisture separator reheater operable, and feedwater heaters inoperable at 100 percent power, 105 percent core flow

b. Operation with moisture separator reheater operable with turbine bypass and feedwater heaters inoperable at 100 percent power, 105 percent core flow

c. Operation with feedwater heaters, turbine bypass and moisture separator reheater inoperable at 100 percent power, 105 percent core flow.

15.1.2.3.3 Qualitative Results

Results of the cycle-specific analyses are presented in Chapter 15.0 Reference 15. The operating limits for these analyses are presented in Chapter 15.0 Reference 15. The following subsections present qualitative results of the cases described in Subsection 15.1.2.3.2. Tables 15.1.2-1 through 15.1.2-3 list the typical sequence of events for these cases.

15.1.2.3.3.1 100 Percent Power, 105 Percent Core Flow, 50°F Feedwater Temperature Reduction with Bypass and Moisture Separator Reheater Flow

The high water level turbine trip and feedwater pump trip occur at about 16 sec. Scram occurs simultaneously from stop valve closure and limits the neutron flux peak and fuel thermal transient so that no fuel damage occurs. The turbine bypass system opens to limit peak pressure in the steam line, and the nuclear system process barrier pressure limit is not endangered.

The bypass valves subsequently close to reestablish pressure control in the vessel during shutdown. The level will gradually drop to the low level isolation reference point, activating the RCIC and HPCI systems for long term level control.

15.1.2.3.3.2 100 Percent Power, 105 Percent Core Flow, 50°F Feedwater Temperature Reduction Without Bypass and With Moisture Separator Reheater Flow

The high water level turbine trip and feedwater pump trip occur at about 16 seconds. Reactor scram occurs immediately thereafter which limits the peak neutron flux and fuel thermal transient so that no fuel damage occurs. This analysis is also conservatively applied to the operating condition without moisture separator reheater, but with turbine bypass operable and with partial feedwater heating. This analysis represents the limiting transient for the operational condition without turbine bypass or moisture separator reheater flow and with partial feedwater heating, and provides the basis for the Core Operating Limits Report MCPR operating limit curve.

15.1.2.3.3.3 100 Percent Power, 105 Percent Core Flow, 50°F Feedwater Temperature Reduction Without Bypass and Moisture Separator Reheater Flow

The high water level turbine trip and feedwater pump trip occurs at about 16 seconds. Reactor scram occurs immediately thereafter which limits the peak neutron flux and fuel thermal transient so that no fuel damage occurs. This analysis represents the limiting transient for operation without bypass and moisture separator reheater flow and provides the basis for the Core Operating Limits Report MCPR operating limit curve.

15.1.2.3.4 Consideration of Uncertainties

Important analytical factors (such as void and scram reactivity coefficients) have been adjusted statistically so that any deviation in the actual plant parameters will produce a less severe transient.

15.1.2.4 Barrier Performance

The consequences of this event do not result in any temperature or pressure transient in excess of the criteria for which the fuel, pressure vessel, or containment are designed; therefore these barriers maintain their integrity and function as designed.

15.1.2.5 Radiological Consequences

While the consequence of this event does not result in fuel failure, it does result in the discharge of normal coolant activity to the suppression pool through safety relief valve (SRV) operation. Since this activity is contained in the primary containment, there will be no exposure to operating personnel.

Since this event does not result in an uncontrolled release to the environment, the plant operator can choose to leave the activity bottled up in the primary containment or discharge it to the environment under controlled meteorological and release conditions. If purging of the primary containment is chosen, the release will have to be in accordance with the established Technical Specifications; therefore, this event, at the worst, would only result in a small increase in the yearly integrated exposure level.

Table 15.1.2-1 Typical Sequence of Events for Feedwater Controller Failure at 100% Power, 105% Core Flow, 50°F Feedwater Temperature Reduction with Bypass and Reheater Flow[(a)]

Estimated Time (sec)	Event
0	Simulated failure of 114.8 percent upper limit on feedwater flow is initiated.
15.9	L8 vessel level setpoint trips main turbine and feedwater pumps.
15.9	Turbine trip initiates closure of turbine stop valves and fast closure of turbine control valves.
15.9	Turbine trip initiates bypass operation.
15.9	Main turbine stop valves reach 90 percent-open position and initiate a reactor scram trip.

Table 15.1.2-1 Typical Sequence of Events for Feedwater Controller Failure at 100% Power, 105% Core Flow, 50°F Feedwater Temperature Reduction with Bypass and Reheater Flow[(a)]

Estimated Time (sec)	Event
15.9	Fast closure of turbine control valves initiates a reactor scram trip.
16.0	Main turbine bypass valves open.
16.1	Turbine control valves are closed.
16.1	Turbine stop valves are closed.
17.7	High pressure pump trip setpoint is reached.
17.9	Reheater flow starts to decay.
18.0	Recirculation pumps trip because of high pressure.
18.9	Reheater flow decays to zero.

(a) See current Supplemental Reload Licensing Report for detailed cycle specific data.

Table 15.1.2-2 Typical Sequence of Events for Feedwater Controller Failure Event at 100% Power, 105% Core Flow, 50°F Feedwater Temperature Reduction without Bypass and with Reheater Flow[(a)]

Estimated Time (sec)	Event
0	Simulated failure of 114.8 percent upper limit on feedwater flow is initiated.
15.9	L8 vessel level setpoint trips main turbine and feedwater pumps.
15.9	Turbine trip initiates closure of turbine stop valves and fast closure of turbine control valves.
15.9	Main turbine stop valves reach 90 percent open position and initiate a reactor scram trip.

Table 15.1.2-2 Typical Sequence of Events for Feedwater Controller Failure Event at 100% Power, 105% Core Flow, 50°F Feedwater Temperature Reduction without Bypass and with Reheater Flow[a]

Estimated Time (sec)	Event
15.9	Fast closure of turbine control valves initiates a reactor scram trip.
16.1	Turbine control valves are closed.
16.1	Turbine stop valves are closed.
17.3	High pressure pump trip setpoint is reached.
17.6	Recirculation pumps trip because of high pressure.
17.7	Group 1 relief valves are actuated.
17.8	Group 2 relief valves are actuated.
17.9	Reheater flow starts to decay.
18.0	Group 3 relief valves are actuated.
18.9	Reheater flow decays to zero.

(a) See current Supplemental Reload Licensing Report for detailed cycle specific data.

Table 15.1.2-3 Typical Sequence of Events for Feedwater Controller Failure Event at 100% Power, 105% Core Flow, 50°F Feedwater Temperature Reduction without Bypass and without Reheater Flow[a]

Estimated Time (sec)	Event
0	Simulated failure of 114.8 percent upper limit on feedwater flow is initiated.
15.9	L8 vessel level setpoint trips main turbine and feedwater pumps.
15.9	Turbine trip initiates closure of turbine stop valves and fast closure of turbine control valves.

Table 15.1.2-3 Typical Sequence of Events for Feedwater Controller Failure Event at 100% Power, 105% Core Flow, 50°F Feedwater Temperature Reduction without Bypass and without Reheater Flow[a]

Estimated Time (sec)	Event
15.9	Main turbine stop valves reach 90 percent open position and initiate a reactor scram trip.
15.9	Fast closure of turbine control valves initiates a reactor scram trip.
16.1	Turbine control valves are closed.
16.1	Turbine stop valves are closed.
17.1	High pressure pump trip setpoint is reached.
17.4	Recirculation pumps trip because of high pressure.
17.4	Group 1 relief valves are actuated.
17.6	Group 2 relief valves are actuated.
17.7	Group 3 relief valves are actuated.

[a] See current Supplemental Reload Licensing Report for detailed cycle specific data.

15.1.3 Pressure Regulator Failure, Open to Maximum Demand

15.1.3.1 Identification of Causes and Frequency Classification

15.1.3.1.1 Identification of Causes

The total steam flow rate to the main turbine, resulting from a pressure regulator malfunction, is limited by a maximum flow limiter imposed at the turbine controls. This limiter is set to limit maximum steam flow to approximately 112.8 percent nuclear boiler rated.

If either the controlling pressure regulator or the backup regulator fails to the open position, the turbine admission valves can be fully opened, and the turbine bypass valves can be partially opened until the maximum steam flow is established.

15.1.3.1.2 Frequency Classification

This transient disturbance is categorized as an incident of moderate frequency.

15.1.3.2 Sequence of Events and Systems Operation

15.1.3.2.1 Sequence of Events

Table 15.1.3-1 lists the typical sequence of events. Section 15.1.3.3.3 describes the potential for an alternate sequence of events that is also considered.

15.1.3.2.2 Systems Operation

To properly simulate the expected sequence of events, the analysis of this event assumes normal functioning of plant instrumentation and controls, plant protection, and reactor protection systems except as described below.

Initiation of high pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) system functions will occur when the vessel water level reaches the L2 setpoint. Normal startup and actuation can take approximately 30 sec (up to 60 sec) before effects are realized. If these events occur, they will follow some time after the primary concerns of fuel thermal margin and overpressure effects have occurred and are expected to be less severe than those already experienced by the system.

15.1.3.3 Core and System Performance

15.1.3.3.1 Mathematical Model

Only a qualitative evaluation is provided.

15.1.3.3.2 Input Parameters and Initial Conditions

This transient is simulated by setting the controlling regulator output to a high value, which causes the turbine admission valves to open fully and the turbine bypass valves to open partially. Since the controlling and backup regulator outputs are gated by a high value gate, the effect of such a failure in the backup regulator would be exactly the same. A regulator failure with 127.6 percent steam flow was simulated as a worst case, since 112.8 percent is the normal maximum flow limit.

15.1.3.3.3 Qualitative Results

For the pressure regulator failure (open) transient, the water level rises to the high level trip setpoint in 2.1 sec and initiates trip of the main turbine and feedwater turbines. Closure of the turbine stop valves initiates scram.

Reactor high level trip limits the duration and severity of the depressurization so that no significant thermal stresses are imposed on the nuclear system process barrier. No significant reductions in fuel thermal margins occur. Because the rapid portion of the transient results in only momentary depressurization of the nuclear system, the nuclear system process barrier is not threatened by high internal pressure for this pressure regulator malfunction.

These qualitative evaluations were performed using the REDY model which predicted that reactor water level would swell during the pressure regulator failure (open) transient. As described in Reference 2, more recent evaluations with improved transient models (e.g., ODYN and TRACG) have determined that the reactor water level swell may not be sufficient to reach the high water level setpoint. In this case, the depressurization would be terminated by main steam isolation valve (MSIV) closure at the low pressure isolation setpoint. Reactor scram would then occur due to MSIV closure. There is no challenge to fuel cladding integrity as the critical power ratio increases during the transient. However, to avoid the potential for reactor steam dome pressure to decrease below the range associated with the Technical Specification Safety Limits prior to the reactor power level decrease due to reactor scram, a methodology was developed in Reference 3 to address this issue. This methodology was adopted, and in Reference 4 the reactor steam dome pressure associated with the Technical Specification Safety Limits was reduced and the low pressure isolation setpoint was increased. With these changes, fuel cladding integrity is ensured and Technical Specification Safety Limits are maintained regardless of whether the pressure regulator failure (open) transient is terminated by the water level increase or by the low pressure isolation setpoint being reached.

15.1.3.3.4 Consideration of Uncertainties

If the maximum flow limiter is set higher or lower than normal, faster or slower loss in nuclear steam pressure will result. The rate of depressurization may be limited by the bypass capacity, but it is unlikely that this will happen. For example, the turbine valves will open to the valves wide open state, admitting slightly more than the rated steam flow; and with the limiter in this analysis set to fail at 127.6 percent, it is expected that something less than 23.5 percent would be bypassed. Therefore, this is not a limiting factor on this plant. If the rate of depressurization does change, it will be terminated by the low turbine inlet pressure trip setpoint.

For the pressure regulator failure (open) transient, depressurization occurs after initiation of the event, which results in voiding action of the core and then reduces the core power, maintaining high thermal margin. The impact on the minimum critical power ratio (MCPR) and peak vessel pressure for the case with a scram from low turbine inlet pressure (a scram caused by main steam isolation valve (MSIV) closure) due to a lower depressurization rate is insignificant. Because this is a relatively mild transient, an opening to maximum (127.6 percent) is assumed.

If the depressurization rate is not large enough, the sensed vessel water level trip setpoint (L8) may not be reached, and a turbine feedwater pump trip will not occur in the transient. In this case the turbine inlet pressure will drop below the low pressure isolation setpoint, and the expected transient signature will conclude with an isolation of the main steam lines. The reactor will be shut down by the scram initiated from main steam isolation valve closure. Therefore, the plant response to a less limiting depressurization is addressed by the alternate sequence of events described in Section 15.1.3.3.3.

15.1.3.4 Barrier Performance

The consequences of this event do not result in any temperature or pressure transient in excess of the criteria for which fuel, pressure vessel, or containment are designed; therefore, these barriers maintain their integrity and function as designed.

15.1.3.5 Radiological Consequences

The consequences of this event do not result in any fuel failure.

Table 15.1.3-1 Typical Sequence of Events for Pressure Regulator Failure, Open To Maximum Demand*

Estimated Time (sec)	Event
0	Simulate maximum limit on steam flow to main turbine.
0.1	Main turbine bypass starts to open.
2.1	L8 vessel level setpoint trips main turbine and feedwater pumps.
2.1	Reactor scram trip is actuated from main turbine stop valve position switches.

* See Section 15.1.3.3.3 for description of a potential alternate sequence of events that is also considered.

15.1.4 Inadvertent Safety/Relief Valve Opening

Inadvertent opening of an SRV can lead to two possible events. First, the valve may open and reclose. This event has no significant effect on plant operation. Second, the valve may open and stick in the open position. This is the more limiting case and results in the plant transient discussed below.

15.1.4.1 Identification of Causes and Frequency Classification

15.1.4.1.1 Identification of Causes

Cause of inadvertent opening is malfunction of the valve or an operator initiated opening. Opening and closing circuitry at the individual valve level (as opposed to groups of valves) is subject to a single failure impact. It is therefore simply postulated that a failure occurs and the event is analyzed accordingly. Detailed discussion of the valve is provided in Chapter 5.

15.1.4.1.2 Frequency Classification

This transient disturbance is categorized as an infrequent incident, but because of the lack of a comprehensive data base, it is being analyzed as an incident of moderate frequency.

15.1.4.2 Sequence of Events and Systems Operation

15.1.4.2.1 Sequence of Events

Table 15.1.4-1 lists the sequence of events for this transient.

15.1.4.2.2 Systems Operation

In this transient, the analysis assumes normal functioning of plant instrumentation and controls, specifically, the relief valve discharge line temperature sensors, suppression pool temperature sensors, and the level control systems. Additionally, minimum reactor and plant protection systems, emergency core cooling system (ECCS) flow, and residual heat removal (RHR) pool cooling are required. No credit is taken for the functioning of normal operation plant systems other than as defined above.

15.1.4.3 Core and System Performance

15.1.4.3.1 Mathematical Model

Only a qualitative evaluation is provided.

15.1.4.3.2 Input Parameters and Initial Conditions

It is assumed that the reactor is operating at an initial power level corresponding to 105 percent of rated steam flow conditions when an SRV is inadvertently opened. Flow through the valve at normal plant operating conditions stated above is approximately 870,000 lb/hr. Table 5.2-5 contains SRV set pressures and capacities.

15.1.4.3.3 Qualitative Results

The opening of an SRV allows steam to be discharged into the suppression pool. The sudden increase in the rate of steam flow leaving the reactor vessel causes a mild depressurization transient.

The pressure regulator senses the nuclear system pressure decrease; within a few seconds it closes the turbine control valve far enough to stabilize reactor vessel pressure at a slightly lower value, and reactor power settles at nearly the initial power level. Thermal margins decrease only slightly through the transient, and no fuel damage results from the transient. The MCPR is essentially unchanged; therefore, the safety limit margin is unaffected.

The analysis assumed the initial suppression pool temperature is 95°F, maximum.

a. For a fully stuck open SRV, the suppression pool temperature Technical Specifications limit of 110°F is reached in about 6 minutes. Thus, the operator would be required to initiate a reactor scram approximately 6 minutes after the occurrence of the stuck open relief valve

b. If the plant shutdown is delayed, the suppression pool temperature would continue to rise at a rate of about 2°F/minute. At 10 minutes after the occurrence of the stuck open relief valve, the reactor is assumed to be scrammed. The suppression pool temperature would be less than 120°F. Fermi 2 has T-quenchers; therefore, no adverse effect on safety is expected

   The maximum allowable suppression pool temperature is limited by the net positive suction head for ECCS pumps and is discussed in Subsection 6.3.2.14

15.1.4.4 Barrier Performance

As discussed above, the transient resulting from a stuck open relief valve is a mild depressurization within the range of normal load following and therefore without significant effect on reactor coolant pressure boundary (RCPB) and containment design pressure limits.

15.1.4.5 Radiological Consequences

While the consequence of this event does not result in fuel failure, it does result in the discharge of normal coolant activity to the suppression pool via SRV operation. Since this activity is contained in the primary containment, there will be no exposure to operating personnel. Since this event does not result in an uncontrolled release to the environment, the plant operator can choose to leave the activity bottled up in the containment or discharge it to the environment under controlled meteorological and release conditions. If purging of the primary containment is chosen, the release will have to be in accordance with the established Technical Specifications; therefore, this event, at the worst, would result in only a small increase in the yearly integrated exposure level.

Table 15.1.4-1 Typical Sequence of Events for Inadvertent Safety/Relief Valve Opening

Estimated Time (min)	Event
0	Initiate opening of one SRV, which remains open throughout the event.
6	Operator actuates scram on high suppression pool temperature.
10	Operator attempts to close valve unsuccessfully.
15	The reactor pressure vessel (RPV) water level reaches L2; the HPCI and RCIC systems are actuated.
20	Operator activates RHR and initiates normal plant shutdown.
300	Shutdown is completed.

15.1 DECREASE IN REACTOR COOLANT TEMPERATURE

REFERENCES

1. General Electric Co., "General Electric Standard Application for Reactor Fuel, GESTAR II," NEDE-24011-P-A, (Latest Approved Revision as identified in the COLR).
2. Letter from Jason Post (GE Energy Nuclear) to U.S. NRC, “10CFR21 Reportable Condition Notification: Potential to Exceed Low Pressure Technical Specification Safety Limit,” dated March 29, 2005 (ML050950428).
3. GE-Hitachi Nuclear Energy (GEH), “BWR Owners Group Reload Analysis and Core Management Committee SC05-03 Analysis Report,” NEDC-33743P, Revision 0, dated April 2012 (Edison File No. R1-8159).
4. NRC Letter to DTE, “Fermi2 – Issuance of Amendment No. 216 – Revision to Technical Specifications in Response to GE Energy-Nuclear’s 10 CFR Part 21 Safety Communication SC05-03 (EPID L-2019-LLA-200),” dated October 5, 2020 (ML20233A838 and ML20282A230).

15.2 INCREASE IN REACTOR PRESSURE

Seven transients are evaluated under the increase in reactor pressure analytical category:

a. Pressure regulator failure - closed

b. Generator load rejection

c. Turbine generator trip

d. Main steam isolation valve closure

e. Loss of condenser vacuum

f. Loss of alternating current power

g. Loss of feedwater flow

Only the turbine generator trip, generator load rejection, and pressure regulator failure – closed with backup pressure regulator out of service transients in this analytical category are analyzed for cycle-specific analysis. A qualitative prescription of results is described for those events determined to be nonlimiting from a core performance standpoint.

15.2.1 Pressure Regulator Failure - Closed

15.2.1.1 Identification of Causes and Frequency Classification

15.2.1.1.1 Identification of Causes

Two identical pressure regulators are provided to maintain primary system pressure control. They independently sense pressure just upstream of the main turbine stop valves and compare it with two separate setpoints to create proportional error signals that produce each regulator output. The regulator with the highest output controls the main turbine control valves. (Note: The lowest pressure setpoint gives the largest pressure error and thereby the largest regulator output.) The backup regulator is set 5 psi higher, giving a slightly smaller error and a slightly smaller effective output of the controller.

It is assumed for the purposes of this transient analysis that a single failure occurs that erroneously causes the controlling regulator to close the main turbine control valves and thereby increases reactor pressure. If this occurs, the backup regulator is ready to take control.

15.2.1.1.2 Frequency Classification

This event is treated as a moderate frequency event.

15.2.1.2 Sequence of Events and Operator Actions

15.2.1.2.1 Sequence of Events

Postulating a failure of the primary or controlling pressure regulator in the closed mode, as discussed in Subsection 15.2.1.1.1, will cause the valves to close momentarily. The pressure will increase because the reactor is still generating the initial steam flow. The backup regulator will reopen the valves and reestablish steady-state operation above the initial pressure equal to the setpoint difference of 5 psi.

15.2.1.2.1.1 Identification of Operator Actions

The operator will verify that the backup regulator assumes proper control.

15.2.1.2.1.2 The Effect of Single Failures and Operator Errors

The nature of the first assumed failure produces a slight pressure increase in the reactor until the backup regulator gains control. Because no other action is significant in restoring normal operation if the backup regulator fails at this time (the second assumed failure), the control valves will start to close, raising reactor pressure to the point where a flux or pressure scram trip will be initiated to shut down the reactor. At rated power, this event is less severe than the turbine trip where stop valve closure occurs.

For the pressure controller failure - closed transient, a single failure is assumed to occur that erroneously causes the main controlling regulator to close the main turbine control valves, thereby increasing reactor pressure. If this occurs, the backup regulator is ready to take control. The probability of the concurrent failure of the backup regulator and the primary regulator is low enough such that the event combination is classified as an infrequent event. Nevertheless, a quantitative evaluation of this assumed transient (failure of the backup regulator) at rated power was made using TRACG.

15.2.1.3 Core and System Performance

The disturbance is mild, similar to a pressure setpoint change, and no significant reductions in fuel thermal margins occur. This transient is much less severe than the generator and turbine trip transients described in Subsections 15.2.2 and 15.2.3. However, the pressure regulator failure – closed event with backup pressure regulator out of service is potentially limiting for reloads and plant modifications. During this event, pressure regulator demand is forced to zero, which causes the full closure of turbine control valves at the normal servo rate as well as inhibit the opening of the turbine bypass valves; thereby increasing reactor power and pressure. The event is terminated when the reactor scrams on high pressure or high neutron flux.

15.2.1.3.1 Mathematical Model

Only a qualitative evaluation is provided except TRACG methodology is used for the backup pressure regulator out of service analysis (see Section 15.1.2.3.1).

15.2.1.3.2 Input Parameters and Initial Conditions

Only a qualitative evaluation is provided.

15.2.1.3.3 Qualitative Results

The response of the reactor during this regulator failure is such that the pressure at the turbine inlet increases quickly, less than 2 sec or so, because of the sharp closing action of the turbine control valves that reopen when the backup regulator gains control. This pressure disturbance in the vessel is not expected to exceed flux or pressure scram trip setpoints.

15.2.1.4 Barrier Performance

As noted above, the consequences of this event do not result in any temperature or pressure transient in excess of the criteria for which the fuel, pressure vessel, or containment are designed; therefore, these barriers maintain their integrity and function as designed.

15.2.1.5 Radiological Consequences

Because this event does not result in any additional fuel failures or any release of primary coolant to either the secondary containment or to the environment, there are no radiological consequences associated with this event.

15.2.2 Generator Load Rejection

Either the generator load rejection without bypass event or the turbine generator trip without bypass event (Subsection 15.2.3) are the most limiting events in this analytical category.

15.2.2.1 Identification of Causes and Frequency Classification

15.2.2.1.1 Identification of Causes

The turbine control valves (TCVs) will close under servo action initiation as a result of turbine shaft acceleration whenever electrical grid disturbances occur that result in significant loss of electrical load on the generator. The turbine control valves are required to close as rapidly as possible to prevent excessive overspeed of the turbine generator rotor. Closure of the main turbine control valves will cause a sudden reduction in steam flow, which in turn will result in an increase in system pressure and reactor shutdown.

15.2.2.1.2 Frequency Classification

This transient is categorized as an incident of moderate frequency. Fermi 2 has an uncommon bypass system because of its English Electric turbine. Additional information on the Fermi 2 bypass system is provided in Subsection 10.4.4.

15.2.2.2 Sequence of Events and Systems Operation

15.2.2.2.1 Sequence of Events

A loss of generator electrical load from high power conditions initiates a fast closure of the turbine control valves which results in a rapid pressurization in the reactor vessel, causing a collapse of steam voids that rapidly increases the neutron flux. The fast closure of the turbine control valves initiates the reactor scram and terminates the event.

15.2.2.2.2 Systems Operation

The TCV fast closure signal is generated independently in each valve control logic and wired directly into the reactor protection system (RPS). The signal to the RPS is generated simultaneously with the de-energizing of the solenoid dump valves, which produces control valve fast closure. Therefore, when TCV fast closure occurs, a scram trip signal is initiated.

The pressure relief system, which operates the relief valves independently when system pressure exceeds relief valve instrumentation setpoints, is assumed to function normally during the time period analyzed with the exception of the fact that four Group 1 relief valves are assumed to remain closed.

All plant control systems maintain normal operation unless specifically designated to the contrary. The steam flow through the moisture separator reheater line as described in Subsection 15.1.2.2.2, is included in the analysis, except as noted.

15.2.2.3 Core and System Performance

15.2.2.3.1 Mathematical Model

The predicted dynamic behavior of this event is evaluated using the TRACG computer model described in Reference 1 (see details in Subsection 15.1.2.3.1).

15.2.2.3.2 Input Parameters and Initial Conditions

These analyses are evaluated, unless otherwise noted, with the plant conditions in Table 15.0-1.

The turbine control system power/speed acceleration rate detects load rejection before a measurable speed change takes place.

The closure characteristics of the TCVs are assumed such that the valves operate in the full arc (FA) mode and have a full stroke closure time, from fully open to fully closed, of 0.220 seconds. The valves are assumed to be at an intermediate position at 100 percent power so they close faster than 0.220 seconds causing a more severe pressure transient.

Fermi 2 valves have a near linear flow versus stroke characteristic. In sensitivity studies the initial control valve position at less than wide open and the reactor operating at full power were considered. These studies indicate that the smaller control valve opening does not result in a significant increase change in CPR.

Auxiliary power would normally be independent of any turbine generator overspeed effects.

A reactor scram is initiated simultaneously with the de-energizing of the solenoid dump valves. This produces the TCV fast closure.

When comparing a lower power case with a full power case for generator load rejection transient with a full stroke TCV closure, the severity of the event remains relatively unchanged. This is because the pressurization effect of reduced steam flow rate and shorter

TCV closure time balance each other. Consequently, ΔMCPR and peak vessel pressure during a load rejection transient at low power are expected to be about the same as during a full power transient.

For the Fermi 2 turbine design, the control valves are at an intermediate position at rated reactor pressure and a steam flow equivalent to rated nuclear boiler rating (NBR). In the case of the TRACG analysis, evaluated for the turbine generator trip transient, an intermediate position of the control valves is assumed to exist initially and corresponds to an actual valve travel time of less than 0.220 seconds.

In the evaluation of the generator load rejection transient, the closure characteristics of the TCVs are assumed to be in the full arc mode. That is, the valves operate in the full arc mode and have a full stroke closure time of 0.220 seconds from fully open to fully closed. Sensitivity studies show that TCV closure times less than the assumed 0.220 sec do not result in unacceptable increases in delta CPR or reactor peak pressure. For example, if the TCV closure time were 0.15 sec, the peak surface heat flux would increase by approximately 1 percent and the peak vessel pressure by only about 1 psi. The change in CPR for the turbine trip transient and the generator load rejection transient are close with the generator load rejection transient normally being more severe. However, this transient is confirmed each fuel cycle so the results of the analysis can be found in the most current Supplemental Reload Licensing Report.

The following generator load rejection without bypass cases are typically analyzed for cycle-specific analysis:

a. Operation with moisture separator reheater and feedwater heaters operable at 100 percent power, 105 percent flow at EOC.

b. Operation without moisture separator reheater and with feedwater heaters operable at 100 percent power, 105 percent flow, at EOC.

15.2.2.3.3 Qualitative Results

Because of Fermi 2 special design features, (Chapter 10, Subsection 10.4.4) the turbine generator trip transient is typically bounded by this transient.

A generator load rejection with failure of the bypass system typically bounds the corresponding turbine trip transient due to the following Fermi 2 specific design features:

a. Recirculation pumps are powered through auxiliary transformers from outside power sources and are independent of turbine generator overspeed effects

b. A reactor scram is initiated simultaneously with the de-energizing of the solenoid dump valves, which produces the TCV fast closure. The TCVs are at an intermediate position so they close faster than the full open closure time of 0.220 seconds. Therefore, the pressure transient is larger.

Therefore, the generator load rejection transient bounds the turbine trip transient discussed in Subsection 15.2.3 typically. However, this transient is confirmed each fuel cycle so the results of the analysis can be found in the most current Supplemental Reload Licensing Report.

15.2.2.3.4 Consideration of Uncertainties

Important analytical factors, such as void and scram reactivity coefficients, have been adjusted statistically at a given cycle exposure so that any deviation in the actual plant parameter will produce a less severe transient.

15.2.2.4 Barrier Performance

The consequences of the analyzed events do not result in any temperature or pressure transient in excess of the criteria for which the fuel, pressure vessel, or containment are designed; therefore, these barriers maintain their integrity and function as designed.

15.2.2.5 Radiological Consequences

While the consequence of this event does not result in fuel failures, it does result in the discharge of normal coolant activity to the suppression pool via safety/relief valve (SRV) operation. Since this activity is contained in the primary containment, there will be no exposure to operating personnel. Since this event does not result in an uncontrolled release to the environment, the plant operator can choose to leave the activity bottled up in the containment or discharge it to the environment under controlled meteorological and release conditions. If purging of the containment is chosen, the release will have to be in accordance with established Technical Specifications; therefore, this event, at the worst, would result in only a small increase in the yearly integrated exposure level.

Table 15.2.2-1 TYPICAL SEQUENCE OF EVENTS FOR GENERATOR LOAD REJECTION, WITHOUT TURBINE BYPASS AND WITH MOISTURE SEPARATOR REHEATER FLOW AT MOC[(a)]

Estimated Time (sec)	Event
(-)0.015	Turbine generator detects loss of electrical load when CM and CF open.
0	Turbine generator trip logic initiates turbine control valve (TCV) fast closure.
0	Turbine bypass valves fail to operate.
0	TCV Fast control valve closure logic simultaneously initiates scram trip.
0.2	Turbine control valves are fully closed.
1.2	High pressure pump trip setpoint is reached.
1.5	Recirculation pumps trip because of high pressure.

Table 15.2.2-1 TYPICAL SEQUENCE OF EVENTS FOR GENERATOR LOAD REJECTION, WITHOUT TURBINE BYPASS AND WITH MOISTURE SEPARATOR REHEATER FLOW AT MOC[(a)]

Estimated Time (sec)	Event
1.6	Group 1 relief valves are actuated.
1.7	Group 2 relief valves are actuated.
1.9	Group 3 relief valves are actuated.
2.0	Reheater flow starts to decay.
3.0	Reheater flow decays to zero.

[(a)] See current Supplemental Reload Licensing Report for detailed cycle specific data.

Table 15.2.2-2 TYPICAL SEQUENCE OF EVENTS FOR GENERATOR LOAD REJECTION, WITHOUT TURBINE BYPASS AND WITH MOISTURE SEPARATOR REHEATER FLOW AT EOC[(a)]

Estimated Time (sec)	Event
(-)0.015	Turbine generator detects loss of electrical load.
0	Turbine generator protective logic initiates turbine control valve fast closure.
0	Turbine bypass valves fail to operate.
0	Fast control valve closure initiates scram trip.
0.2	Turbine control valves are fully closed.
1.3	High pressure pump trip setpoint is reached.
1.6	Recirculation pumps trip because of high pressure.
1.7	Group 1 relief valves are actuated.
1.8	Group 2 relief valves are actuated.
2.0	Group 3 relief valves are actuated.
2.0	Reheater flow starts to decay.
3.0	Reheater flow decays to zero.

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[a] See current Supplemental Reload Licensing Report for detailed cycle specific data.

Table 15.2.2-3 TYPICAL SEQUENCE OF EVENTS FOR GENERATOR LOAD REJECTION, WITHOUT TURBINE BYPASS AND WITHOUT MOISTURE SEPARATOR REHEATER FLOW AT EOC[(a)]

Estimated Time (sec)	Event
(-)0.015	Turbine generator detects loss of electrical load.
0	Turbine generator protective logic initiates turbine control valve fast closure.
0	Turbine bypass valves fail to operate.
0	Fast control valve closure initiates scram trip.
0.2	Turbine control valves are fully closed.
1.1	High pressure pump trip setpoint is reached.
1.4	Recirculation pumps trip because of high pressure.
1.4	Group 1 relief valves are actuated.
1.5	Group 2 relief valves are actuated.
1.7	Group 3 relief valves are actuated.

(a) See current Supplemental Reload Licensing Report for detailed cycle specific data.

15.2.3 Turbine Generator Trip

Either the generator load rejection without bypass event (Subsection 15.2.2) or the turbine generator trip without bypass event are the most limiting events in this analytical category.

15.2.3.1 Identification of Causes and Frequency Classification

15.2.3.1.1 Identification of Causes

A variety of turbine or nuclear system malfunctions will initiate a turbine trip. Some examples are low condenser vacuum and reactor high water level. Both turbine generator trip and load rejection will initiate the closure of turbine stop valves and the fast closure of the turbine control valves (TCV).

15.2.3.1.2 Frequency Classification

This transient is categorized as an incident of moderate frequency. In defining the frequency of the this event, turbine generator trips that occur as a by product of other transients, such as loss of condenser vacuum or reactor high level trip events, are not included. However, spurious low vacuum or high level trip signals that cause an unnecessary turbine generator trip are included in defining the frequency. To get an accurate event-by-event frequency breakdown, this type of division of initiating causes is required.

15.2.3.2 Sequence of Events and Systems Operation

15.2.3.2.1 Sequence of Events

This event results in a rapid pressurization in the reactor vessel causing a collapse of steam void that rapidly increases the neutron flux. The fast closure of the turbine control/stop valve initiates the reactor scram and terminates the event.

15.2.3.2.2 Systems Operation

All plant control systems maintain normal operation unless specifically designated to the contrary. The steam flow through the moisture separator reheater line as described in Subsection 15.1.2.2.2, is included in this analysis with the reheater operational. The turbine bypass is assumed to be out-of-service for all the analyses.

A turbine generator trip signal closes both the stop and control valves at the maximum closure rate of 0.220 sec for full valve travel. Each set of valves is wired in a preassigned logic to cause a reactor scram upon closure. For the stop valve function, a limit switch at a valve position of 10 percent closed from full open is used. A control valve fast closure signal is generated independently in each valve control logic and wired directly into the reactor protection system (RPS). The signal to the RPS is generated simultaneously with the de-energizing of the solenoid dump valves, which produce the control valve fast closure.

In the analyses, it is assumed that both sets of turbine valves are closed on turbine generator trip demand, but as an added conservatism the scram is assumed to occur as a result of the stop valve closure. The trip, which is anticipated by the control valve fast closure signal to the RPS, has been considered. For analytical purposes, the reactor trip occurs 0.02 seconds after the turbine generator trip as the stop valve reaches the 10 percent closed position. Credit is taken for successful operation of the RPS.

The pressure relief system, which operates the relief valves independently when system pressure exceeds relief valve setpoints, is assumed to function normally during the time period analyzed with the exception of the fact that four Group 1 relief valves are assumed to remain closed.

15.2.3.3 Core and System Performance

15.2.3.3.1 Mathematical Model

The predicted dynamic behavior of this event is evaluated using the TRACG computer model described in Reference 1 (see details in Subsection 15.1.2.3.1).

15.2.3.3.2 Input Parameters and Initial Conditions

These analyses are evaluated, unless otherwise noted, with the plant conditions in Table 15.0-1.

Turbine stop valve full stroke closure time is assumed to be 0.220 sec.

A reactor scram is initiated by position switches on the stop valves when the valves are less than 90 percent open. This stop valve scram trip signal is automatically bypassed when the reactor is below 29.5 percent NBR power level.

A reactor scram signal is also initiated by the fast closure of turbine control valves. A 30-msec delay of this scram signal is conservatively assumed.

The following turbine generator trip without bypass cases are typically analyzed for cycle-specific analysis:

a. Operation with moisture separator reheater and feedwater heaters operable at 100 percent power, 105 percent flow at EOC.

b. Operation without moisture separator reheater and with feedwater heaters operable at 100 percent power, 105 percent flow, at EOC.

15.2.3.3.3 Qualitative Results

Results of the cycle-specific analyses are presented in Chapter 15.0 Reference 15. The MCPR operating limits for these analyses are presented in Chapter 15.0 Reference 15. The following subsections present the results of the cases described above. Tables 15.2.3-1, 15.2.3-2 and 15.2.3-3 list the typical sequence of events for these cases.

15.2.3.3.3.1 100 Percent Power, 105 Percent Flow with Moisture Separator Reheater and Feedwater Heaters Operable at MOC

This analysis typically represents a non-limiting transient for normal operation early in the cycle. The Core Operating Limits Report and Table 15.0-3 describe the limiting transients for each operating cycle.

15.2.3.3.3.2 100 Percent Power, 105 Percent Flow with Moisture Separator Reheater and Feedwater Heaters Operable at EOC

This transient is typically bounded by the generator load rejection without bypass with moisture separator reheater and feedwater heaters operable at EOC. The Core Operating Limits Report and Table 15.0-3 describe the limiting transients for each operating cycle.

15.2.3.3.3.3 100 Percent Power, 105 Percent Flow with Moisture Separator Reheater Inoperable and Feedwater Heaters Operable at EOC

This transient is more severe than the turbine generator trip without bypass since no credit is taken for the passive steam bypass flow through the moisture separator reheater. The high pressure pump trip setpoint is reached and the recirculation pumps trip about 0.1 seconds earlier, and the Group 1, 2 and 3 relief valves are actuated about 0.2 seconds earlier than in the turbine generator trip without bypass transient. The Core Operating Limits Report and Table 15.0-3 describe the limiting transients for each operating cycle.

15.2.3.3.4 Consideration of Uncertainties

Important analytical factors, such as void and scram reactivity coefficients, have been adjusted statistically at a given cycle exposure so that any deviation in the actual plant parameter will produce a less severe transient.

15.2.3.4 Barrier Performance

The consequences of the analyzed events do not result in any temperature or pressure transient in excess of the criteria for which the fuel, pressure vessel, or containment are designed; therefore, these barriers maintain their integrity and function as designed.

15.2.3.5 Radiological Consequences

While the consequences of this event do not result in fuel failure, there is discharge of normal coolant activity to the suppression pool via SRV operation. Since this activity is contained in the primary containment, there will be no exposure to operating personnel. Since this event does not result in an uncontrolled release to the environment, the plant operator can choose to leave the activity bottled up in the containment or discharge it to the environment under controlled meteorological and release conditions. If purging of the primary containment is chosen, the release will have to be in accordance with established Technical Specifications; therefore, this event, at the worst, would result in only a small increase in the yearly integrated exposure level.

Table 15.2.3-1 TYPICAL SEQUENCE OF EVENTS FOR TURBINE GENERATOR TRIP WITHOUT BYPASS AT 100% POWER, 105% FLOW, RATED FEEDWATER TEMPERATURE WITH REHEATER FLOW AT MOC[(a)]

Estimated Time (sec)	Event
0	Turbine generator trip initiates fast closure of turbine control valves.
0	Turbine generator trip of load rejection initiates closure of main stop valves.
0	Turbine bypass valves fail to operate.

Table 15.2.3-1 TYPICAL SEQUENCE OF EVENTS FOR TURBINE GENERATOR TRIP WITHOUT BYPASS AT 100% POWER, 105% FLOW, RATED FEEDWATER TEMPERATURE WITH REHEATER FLOW AT MOC[(a)]

Estimated Time (sec)	Event
0.02	Main turbine stop valves reach 90 percent open position and initiate reactor scram trip.
0.03	Fast closure of turbine control valves initiaties a reactor scram trip.
0.2	Turbine control valves are fully closed.
1.3	High pressure pump trip setpoint is reached
1.6	Recirculation pumps trip because of high pressure.
1.7	Group 1 relief valves are actuated.
1.9	Group 2 relief valves are actuated.
2.0	Reheater flow starts to decay.
2.1	Group 3 relief valves are actuated.
3.0	Reheater flow decays to zero.

(a) See current Supplemental Reload Licensing Report for detailed cycle specific data.

Table 15.2.3-2 TYPICAL SEQUENCE OF EVENTS FOR TURBINE GENERATOR TRIP WITHOUT BYPASS AT 100% POWER, 105% FLOW, RATED FEEDWATER TEMPERATURE WITH REHEATER FLOW AT EOC

Estimated Time (sec)	Event
0	Turbine generator trip initiates fast closure of turbine control valves.
0	Turbine generator trip or load rejection initiates closure of main stop valves.
0	Turbine bypass valves fail to operate.

Table 15.2.3-2 TYPICAL SEQUENCE OF EVENTS FOR TURBINE GENERATOR TRIP WITHOUT BYPASS AT 100% POWER, 105% FLOW, RATED FEEDWATER TEMPERATURE WITH REHEATER FLOW AT EOC

Estimated Time (sec)	Event
0.02	Main turbine stop valves reach 90 percent open position and initiate reactor scram trip.
0.03	Fast closure of turbine control valves initiaties a reactor scram trip.
0.2	Turbine control valves are fully closed.
0.2	Turbine stop valves are fully closed.
1.3	High pressure pump trip setpoint is reached
1.6	Recirculation pumps trip because of high pressure.
1.7	Group 1 relief valves are actuated.
1.8	Group 2 relief valves are actuated.
2.0	Group 3 relief valves are actuated.
2.0	Reheater flow starts to decay.
3.0	Reheater flow decays to zero.

Table 15.2.3-3 TYPICAL SEQUENCE OF EVENTS FOR TURBINE GENERATOR TRIP WITHOUT BYPASS AT 100% POWER, 105% FLOW, RATED FEEDWATER TEMPERATURE WITHOUT REHEATER FLOW AT EOC

Estimated Time (sec)	Event
0	Turbine generator trip initiates fast closure of turbine control valves.
0	Turbine generator trip or load rejection initiates closure of main stop valves.
0	Turbine bypass valves fail to operate.

Table 15.2.3-3 TYPICAL SEQUENCE OF EVENTS FOR TURBINE GENERATOR TRIP WITHOUT BYPASS AT 100% POWER, 105% FLOW, RATED FEEDWATER TEMPERATURE WITHOUT REHEATER FLOW AT EOC

Estimated Time (sec)	Event
0.02	Main turbine stop valves reach 90 percent open position and initiate reactor scram trip.
0.03	Fast closure of turbine control valves initiaties a reactor scram trip.
0.2	Turbine control valves are fully closed.
0.2	Turbine stop valves are fully closed.
1.1	High pressure pump trip setpoint is reached
1.4	Recirculation pumps trip because of high pressure.
1.5	Group 1 relief valves are actuated.
1.6	Group 2 relief valves are actuated.
1.7	Group 3 relief valves are actuated.

15.2.4 Main Steam Isolation Valves Closure

15.2.4.1 Identification of Causes and Frequency Classification

15.2.4.1.1 Identification of Causes

Various steam line and nuclear system malfunctions, or operator actions, can initiate main steam isolation valves (MSIV) closure. Examples are low steam line pressure, high steam line flow, high steam line radiation, low water level, or manual action.

15.2.4.1.2 Frequency Classification

15.2.4.1.2.1 Closure of All Main Steam Isolation Valves

This event is categorized as an incident of moderate frequency. To define the frequency of this event as an initiating event and not the by product of another transient, only the following contribute to the frequency: manual action (purposely or inadvertently); spurious signals, such as low pressure, low reactor water level, low condenser vacuum, and the like; and finally, equipment malfunctions, such as faulty valves or operating mechanisms. Depending on reactor conditions, a closure of one MSIV may cause an immediate closure of all the other MSIVs. If this occurs, it is also included in this category. During the MSIV closure, position switches on the valves provide a reactor scram if the valves in three or more main steam lines are less than 90 percent open (except for interlocks which permit proper plant startup). Protection system logic, however, permits the test closure of one valve without initiating scram from the position switches.

15.2.4.1.2.2 Closure of One Main Steam Isolation Valve

This event is categorized as an incident of moderate frequency. One MSIV at a time may be manually closed for testing purposes. Operator error or equipment malfunction may cause a single MSIV to be closed inadvertently. If reactor power is greater than about 80 percent when this occurs, a high flux or high steam line flow scram may result (if all MSIVs close as a result of the single closure, the event is considered a closure of all MSIVs).

15.2.4.2 Sequence of Events and Systems Operation

15.2.4.2.1 Sequence of Events

Table 15.2.4-1 lists the typical sequence of events.

15.2.4.2.2 Systems Operation

15.2.4.2.2.1 Closure of All Main Steam Isolation Valves

The MSIV closures initiate a reactor scram trip via position signals to the protection system. Credit is taken for successful operation of the protection system. The pressure relief system, which initiates opening of the relief valves when system pressure exceeds relief valve setpoints, is assumed to function normally during the time period analyzed. All plant control systems maintain normal operation, unless specifically designated to the contrary.

15.2.4.2.2.2 Closure of One Main Steam Isolation Valve

A closure of a single MSIV at any given time will not initiate a reactor scram. This is because the valve position scram trip logic is designed to accommodate single valve operation and testability during normal reactor operation at limited power levels. Credit is taken for the operation of the pressure and flux signals to initiate a reactor scram. All plant control systems maintain normal operation, unless specifically designated to the contrary.

15.2.4.3 Core and System Performance

15.2.4.3.1 Mathematical Model

Only a qualitative analysis is provided.

15.2.4.3.2 Input Parameters and Initial Conditions

Only a qualitative evaluation is provided.

The MSIVs close in 3 to 5 sec. The worst case, the 3-sec closure time, is assumed in this analysis.

Position switches on the valves initiate a reactor scram when the valves are less than 90 percent open. Closure of these valves inhibits steam flow to the feedwater turbines terminating feedwater flow.

Valve closure indirectly causes a trip of the main turbine and generator. Because of the loss of feedwater flow, water level within the vessel decreases sufficiently and initiates the high pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) systems.

15.2.4.3.3 Qualitative Results

15.2.4.3.3.1 Main Steam Isolation Valves, Position Scram

For the simultaneous isolation of all main steam lines while the reactor is operating at rated NBR, the neutron flux reaches a peak, then drops below its initial power value.

15.2.4.3.3.2 Closure of One Main Steam Isolation Valve

Only one isolation valve is permitted to be closed at a time for testing purposes to prevent scram. Normal test procedure requires an initial power reduction to approximately 80 to 90 percent of design conditions to avoid high flux scram, high pressure scram, or full isolation from high steam flow in the live lines. With a 3-sec closure of one main steam isolation valve during rated power conditions, the steam flow disturbance raises vessel pressure and reactor power enough to initiate a high neutron flux scram. This transient is considerably milder than the full power case. No quantitative analysis is furnished for this event. However, no significant change in thermal margins is experienced, and no fuel damage occurs. Peak pressure remains below SRV setpoints.

Inadvertent closure of one or all of the isolation valves while the reactor is shut down will produce no significant transient. Closures during plant heatup (operating state D) will be less severe than the maximum power cases (maximum stored and decay heat) discussed in Subsection 15.2.4.3.3.1.

15.2.4.3.4 Consideration of Uncertainties

Uncertainties in these analyses involve protection system settings, system capacities, and system response characteristics. In all cases, the most conservative values are used in the analyses.

a. Slowest allowable control rod scram motion is assumed

b. Scram worth shape for all-rod-out conditions is assumed

c. Minimum specified valve capacities are utilized for overpressure protection

d. Setpoints of the SRVs are assumed to be at least 1 percent higher than the valve's nominal setpoint.

15.2.4.4 Barrier Performance

15.2.4.4.1 Closure of All Main Steam Isolation Valves

The nuclear system relief valves begin to open at approximately 2.7 sec after the start of isolation. The valves close sequentially as the stored heat is dissipated, but continue to discharge the decay heat intermittently.

15.2.4.4.2 Closure of One Main Steam Isolation Valve

No significant effect is imposed on the reactor coolant pressure boundary (RCPB) since, if closure of the valve occurs at an unacceptably high operating power level, a flux or pressure scram will result. The main turbine bypass system will continue to regulate system pressure via the other three live steam lines.

15.2.4.5 Radiological Consequences

While the consequences of this event do not result in fuel failures, there is discharge of normal coolant activity to the suppression pool via SRV operation. Since this activity is contained in the primary containment, there will be no exposure to operating personnel. Since this event does not result in an uncontrolled release to the environment, the plant operator can choose to leave the activity bottled up in the primary containment or discharge it to the environment under controlled meteorological and release conditions. If purging of the primary containment is chosen, the release will have to be in accordance with established Technical Specifications; therefore, this event, at the worst, would result in only a small increase in the yearly integrated exposure level.

Table 15.2.4-1 TYPICAL SEQUENCE OF EVENTS FOR MAIN STEAM ISOLATION VALVES, POSITION SCRAM

Estimated Time (sec)	Event
0	Initiate closure of all MSIVs.
0.3	MSIVs reach 90 percent open.[a]
0.3	MSIV position trip scram is initiated.
2.7	Group 1 relief valves open due to pressure relief setpoint action.[b]
2.8	High pressure pump trip setpoint is reached.
3.1	Recirculation pumps are tripped due to high pressure.
11.5	Group 1 pressure relief valves close.
15+	Relief valves open and close as required for pressure relief.
53	HPCI/RCIC systems flow enters vessel to maintain water level (not simulated). Note HPCI rated flow may occur later if the maximum analyzed response time of 60 sec is assumed.

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[a] The change in position scram setpoint to 85 percent open has no significant impact on delta CPR or peak pressure.

[b] The change in allowable SRV setpoint tolerances from ±1% to ±3% has no impact on delta CPR because minimum MCPR occurs before SRV opening.

15.2.5 Loss of Condenser Vacuum at Two Inches per Second

15.2.5.1 Identification of Causes and Frequency Classification

15.2.5.1.1 Identification of Causes

Various system malfunctions that can cause a loss of condenser vacuum through some single equipment failure are designated in Table 15.2.5-1.

15.2.5.1.2 Frequency Classification

This event is categorized as an incident of moderate frequency.

15.2.5.2 Sequence of Events and Systems Operation

15.2.5.2.1 Sequence of Events

Table 15.2.5-2 lists the typical sequence of events.

15.2.5.2.2 Systems Operation

In establishing the typical sequence of events, it was assumed that normal functioning occurred in the plant instrumentation and controls, and in plant protection and reactor protection systems. Tripping functions incurred by sensing main turbine condenser vacuum pressure are designated in Table 15.2.5-3.

15.2.5.3 Core and System Performance

15.2.5.3.1 Mathematical Model

Only a qualitative analysis is provided.

15.2.5.3.2 Input Parameters and Initial Conditions

Only a qualitative evaluation is provided.

A reactor scram is initiated by position switches on the stop valves when the valves are less than 90 percent open. This stop valve scram trip signal is automatically bypassed when the reactor is below 29.5 percent NBR power level.

The analysis presented here is a hypothetical case with a conservative 2-in. Hg/sec vacuum decay rate. Thus, the bypass system is available for several seconds, since the bypass is signaled to close at a vacuum level of about 10 in. Hg less than the stop valve closure.

15.2.5.3.3 Qualitative Results

Under this hypothetical 2-in. Hg/sec vacuum decay condition, the turbine bypass valve and MSIV closure will follow main turbine and feedwater turbine trips about 5 sec after they initiate the transient. For Fermi 2, the minimum period of time (5 sec) between the turbine trip and the isolation of MSIV is based on the maximum rate of vacuum loss in Table 15.2.5-1 (24-in. Hg/min or 0.4 in. Hg/sec) that was estimated at the time of the original licensing of the plant. This transient, therefore, is similar to a normal turbine trip with bypass. The effect of MSIV closure tends to be minimal, since the closure of main turbine stop valves and subsequently the bypass valves has already shut off the main steam line flow. It is assumed that the plant is initially operating at rated NBR power conditions. Safety relief valves open to limit the pressure rise, then sequentially reclose as the stored energy is dissipated.

15.2.5.3.4 Consideration of Uncertainties

The reduction or loss of vacuum in the main turbine condenser will sequentially trip the main and feedwater turbines and close the MSIVs and bypass valves. While these are the major events occurring, other resultant actions will include scram (from stop valve closure) and bypass opening with the main turbine trip. Because the protective actions are actuated at various levels of condenser vacuum, the severity of the resulting transient is directly dependent upon the rate at which the vacuum pressure is lost. Normal loss of vacuum due to loss of cooling water pumps or steam jet air ejector problems produces a very slow rate of loss of vacuum: minutes, not seconds (see Table 15.2.5-1). If corrective actions by the reactor operators are unsuccessful, then simultaneous trips of the main and feedwater turbines, and ultimately complete isolation by closing the bypass valves (opened with the main turbine trip) and the MSIVs, will occur.

A faster rate of loss of the condenser vacuum will reduce the anticipatory action of the scram and the overall effectiveness of the bypass valves, since they will be closed more quickly.

Other uncertainties in these analyses involve protection system settings, system capacities, and system response characteristics. In all cases, the most conservative values are used in the analyses.

a. Slowest allowable control rod scram motion is assumed

b. Scram worth shape for all-rod-out conditions is assumed

c. Minimum specified valve capacities are utilized for overpressure protection

d. Setpoints of the SRVs are assumed to be at least the upper limit of Technical Specifications for all valves.

15.2.5.4 Barrier Performance

The overpressure transient is below the reactor coolant pressure boundary transient pressure limit of 1375 psig. A comparison between the turbine trip with bypass failure at high power shows the similarities between these two transients. The prime differences are the loss of feedwater and main steam isolation, and the resulting low water level trips.

15.2.5.5 Radiological Consequences

While the consequence of this event does not result in fuel failures, it does result in the discharge of normal coolant activity to the suppression pool via SRV operation. Since this activity is contained in the primary containment, there will be no exposure to operating personnel. Since this event does not result in an uncontrolled release to the environment, the plant operator can choose to leave the activity bottled up in the primary containment or discharge it to the environment under controlled meteorological and release conditions. If purging of the primary containment is chosen, the release will have to be in accordance with established Technical Specifications; therefore, this event, at the worst, would result in only a small increase in the yearly integrated exposure level.

TABLE 15.2.5-1 TYPICAL RATES OF DECAY FOR CONDENSER VACUUM

Cause		Estimated Vacuum Decay Rate
1.	Failure or isolation of steam-jet air ejectors	<1 in. Hg/minute
2.	Loss of sealing steam to shaft gland seals	≈1 to 2 in. Hg/minute
3.	Opening of vacuum breaker valves	≈2 to 12 in. Hg/minute
4.	Loss of one or more circulating water pumps	≈4 to 24 in. Hg/minute

TABLE 15.2.5-2 TYPICAL SEQUENCE OF EVENTS FOR LOSS OF CONDENSER VACUUM AT 2 INCHES PER SECOND

Estimated Time (sec)	Event
-2.5	Initiate simulated loss of condenser vacuum at 2 in. Hg per sec.
0.0	Low condenser vacuum main turbine trip is actuated.
0.0	Low condenser vacuum feedwater trip is actuated.
0.02	Main turbine trip initiates reactor scram.
2.0	Moisture separator reheater flow starts to decay.
2.9	Group 1 relief valves' setpoints are actuated.
5.0	Reheater flow decays to zero.
5.0	Low condenser vacuum initiates MSIV closure.

TABLE 15.2.5-2 TYPICAL SEQUENCE OF EVENTS FOR LOSS OF CONDENSER VACUUM AT 2 INCHES PER SECOND

Estimated Time (sec)	Event
5.0	Low condenser vacuum initiates bypass valve closure.
9.8	Group 1 relief valves close.
15.0	Water level drops to L2 initiating recirculation pump trip and the startup sequence for HPCI/RCIC.
20+	Relief valve opens and closes as required to maintain pressure relief.
45	HPCI/RCIC system flow enters vessel to maintain water level (not simulated). Note: HPCI injection will take longer assuming the maximum analyzed response time of 60 sec.

TABLE 15.2.5-3 TRIP SIGNALS ASSOCIATED WITH LOSS OF CONDENSER VACUUM

Vacuum (in. Hg)	Protective Action Initiated
27 to 28	Normal vacuum range
20	Main turbine trip and feedwater turbine trip (stop valve closures)
10	MSIV closure and bypass valve closure

15.2.6 Loss of Alternating Current Power

15.2.6.1 Identification of Causes and Frequency Classification

15.2.6.1.1 Identification of Causes

Loss of all grid connections can result from major shifts in electrical loads, loss of loads, lightning, storms, wind, and the like, which contribute to electrical grid instabilities. These instabilities will cause equipment damage if unchecked. Protective relay schemes automatically disconnect electrical sources and loads to mitigate damage.

15.2.6.1.2 Frequency Classification

This transient disturbance is categorized as an incident of moderate frequency.

15.2.6.2 Sequence of Events and Systems Operation

15.2.6.2.1 Sequence of Events

Table 15.2.6-1 lists the typical sequence of events.

15.2.6.2.2 Systems Operation

This event, unless otherwise stated, assumes and takes credit for normal functioning of plant instrumentation and controls, and plant protection and reactor protection systems.

The reactor is subjected to a complex sequence of events when the plant loses all external ac power. Estimates of the responses of the various reactor systems (assuming loss of all grid connections) provide the following simulation sequence:

a. The recirculation pumps are tripped at a reference time, t = 0, with normal coastdown times. Also, at t = 0 a generator load rejection is initiated. This load rejection immediately causes the TCVs to close and causes a scram

b. At approximately 2 sec, independent MSIV closure and scram are initiated due to loss of power to the respective solenoids

c. At approximately 4 sec, feedwater pump trips are initiated.

Operation of the HPCI and RCIC system functions is not simulated in this analysis. Their operation occurs at some time beyond the primary concerns of fuel thermal margin and overpressure effects of this analysis.

Fermi 2 has no direct isolation signal derived from the loss of all grid connections. However, the MSIV closure analysis assumes that the valves start to close 2 sec after the loss of offsite power.

The MSIV isolation logic is supplied with 120-V ac power derived from the RPS motor generator (MG) sets. Because the drive motor of each MG set is de-energized when there is a loss of offsite power, each MG set output will trip as the output voltage and/or the frequency decays. This trip occurs approximately 2 sec after the initial loss of power to the MG set. Each MSIV actuator is equipped with ac- and dc-operated solenoid valves to prevent the inadvertent closure of an isolation valve on the loss of a single ac-power feed and to permit online testing of the isolation logic.

15.2.6.3 Core and Systems Performance

15.2.6.3.1 Mathematical Model

Only a qualitative analysis is provided.

15.2.6.3.2 Input Parameters and Initial Conditions

Only a qualitative evaluation is provided.

15.2.6.3.3 Qualitative Results

Loss of all grid connections essentially takes on the characteristic response of a full load rejection with turbine bypass operable. The generator load rejection wihout turbine bypass operable is discussed in Subsection 15.2.2.

15.2.6.3.4 Consideration of Uncertainties

The most conservative characteristics of protection features are assumed. Any deviations in actual plant performance are expected to make the results of this event less severe.

Following main steam line isolation, the reactor pressure is expected to increase until the SRV setpoint is reached. At this time the valves operate in a cyclic manner to discharge the decay heat to the suppression pool.

15.2.6.4 Barrier Performance

Safety/relief valves open in the pressure relief mode of operation as the pressure increases beyond their setpoints. The pressure in the dome is well below the vessel pressure limit of 1375 psig.

15.2.6.5 Radiological Consequences

While the consequences of this event do not result in fuel failure, the event does result in the discharge of normal coolant activity to the suppression pool via SRV operation. Since this activity is contained in the primary containment, there is no exposure to operating personnel. Since this event does not result in an uncontrolled release to the environment, the plant operator can choose to leave the activity bottled up in the primary containment or discharge it to the environment under controlled meteorological and release conditions. If purging of the primary containment is chosen, the release will have to be in accordance with established Technical Specifications; therefore, this event, at the worst, will result in only a small increase in the yearly integrated exposure level.

Table 15.2.6-1 TYPICAL SEQUENCE OF EVENTS FOR LOSS OF ALL GRID CONNECTIONS

Estimated Time (sec)	Event
(-)0.01	Loss of grid causes turbine generator to detect a loss of electrical load.
0	Control valve fast closure is initiated.

Table 15.2.6-1 TYPICAL SEQUENCE OF EVENTS FOR LOSS OF ALL GRID CONNECTIONS

Estimated Time (sec)	Event
0	Turbine generator power load unbalance trip initiates main turbine bypass system operation.
0	Recirculation system pump motors are tripped.
0.03	Fast control valve closure initiates a reactor scram trip.
0.1	Turbine bypass valves open.
0.2	Turbine control valves are fully closed.
2.0	MSIVs start to close.
2.6	Group 1 SRVs actuate.
2.8	Group 2 SRVs actuate.
3.0	Emergency diesel generator (EDG) starts.
4.0	Feedwater turbine trips off.
10.5	Group 1 SRVs close.
12.0	Sensed water level reaches Level 3. Containment isolation is initiated.
13.0	EDG breaker close.
60	Sensed water level reaches Level 2. HPCI/RCIC systems are initiated.
120	Core water level is reestablished.

15.2.7 Loss of Feedwater Flow

15.2.7.1 Identification of Causes and Frequency Classification

15.2.7.1.1 Identification of Causes

A loss of feedwater flow could occur from pump failures, feedwater controller failures, operator errors, or reactor system variables, such as high vessel water level (L8) trip signal.

15.2.7.1.2 Frequency Classification

This transient disturbance is categorized as an incident of moderate frequency.

15.2.7.2 Sequence of Events and Systems Operation

15.2.7.2.1 Sequence of Events

Table 15.2.7-1 lists the typical sequence of events.

15.2.7.2.2 Systems Operation

Loss of feedwater flow results in a reduction of vessel inventory, which causes the vessel water level to drop. The first corrective action is the low level (L3) scram trip actuation. The RPS responds within 1 sec after this trip to scram the reactor. The low level (L3) scram trip function meets single failure criterion.

Containment isolation, when it occurs, also initiates a main steam isolation valve position scram trip signal as part of the normal isolation event. The reactor, however, is already scrammed and shut down by this time.

Credit is taken for operation of the SRV (low setpoint) to remove decay heat, since the bypass becomes ineffective due to main steam line isolation.

15.2.7.3 Core and System Performance

15.2.7.3.1 Mathematical Model

Only a qualitative analysis is provided.

15.2.7.3.2 Input Parameters and Initial Conditions

Only a qualitative evaluation is provided.

15.2.7.3.3 Qualitative Results

Feedwater flow terminates in approximately 5 seconds and subcooling decreases, causing a reduction in core power level and pressure. As power level is lowered, the turbine steam flow starts to drop off because the pressure regulator is attempting to maintain pressure for the first 7 sec or so. Water level continues to drop until the vessel level (L3) scram trip setpoint is reached, whereupon the reactor is shut down. As the vessel water level drops to the L2 trip setpoint, the recirculation system is tripped, and HPCI and RCIC operation is initiated (not simulated). Minimum critical power ratio remains considerably above the safety limit, since increases in heat flux are not experienced.

15.2.7.3.4 Consideration of Uncertainties

End-of-cycle scram characteristics are assumed. This transient is most severe from high power conditions because the rate of level decrease is greatest and the amount of stored and decay heat to be dissipated is highest.

Operation of the RCIC or HPCI systems is not included in the simulation of the first 50 sec of this transient, since startup of these pumps occurs in the latter part of this time period; therefore, these systems have no significant effects on the results of this transient.

15.2.7.4 Barrier Performance

The consequences of this event do not result in any temperature or pressure transient in excess of the criteria for which the fuel, pressure vessel, or containment are designed; therefore, these barriers maintain their integrity and function as designed.

15.2.7.5 Radiological Consequences

The consequences of this event do not result in any fuel failure.

TABLE 15.2.7-1 TYPICAL SEQUENCE OF EVENTS FOR LOSS OF ALL FEEDWATER FLOW

Estimated Time (sec)	Event
0	Trip of all feedwater pumps is initiated.
3.6	Recirculation flow is run back to the low end of the flow control range.
5.0	Feedwater flow decays to zero.
6.8	Vessel water level (L3) trip initiates scram trip.
25.5	Vessel water level (L2) trip initiates containment isolation. (The low water level MSIV closure setpoint is at L1).
25.5	Vessel water level (L2) trip initiates HPCI and RCIC operation (not simulated, however).
28.5	The MSIVs are fully closed.[a]

[a] The low water level MSIV closure has been changed from L2 to L1. However, no significant impact on peak pressure and thermal margin will result from the change. Therefore, no reanalysis is required.

15.2 INCREASE IN REACTOR PRESSURE

REFERENCES

1. General Electric Co., "General Electric Standard Application for Reactor Fuel, GESTAR II," NEDE-24011-P-A, (Latest Approved Revision as identified in the COLR).

15.3 DECREASE IN REACTOR COOLANT SYSTEM FLOW RATE

Three transients are evaluated under this analytical category:

a. Recirculation pump trip

b. Recirculation flow control failure

c. Recirculation pump seizure

None of these transients are analyzed on a cycle-specific basis. A qualitative description of results is provided for each event determined to be nonlimiting with respect to core performance.

15.3.1 Recirculation Pump Trip

15.3.1.1 Identification of Causes and Frequency Classification

15.3.1.1.1 Identification of Causes

Recirculation pump motor operation can be tripped off by design for intended reduction of other transient core and reactor coolant pressure boundary effects as well as randomly by unpredictable operational failures. Intentional tripping will occur in response to the following:

a. Reactor vessel water level L2 setpoint trip

b. Failure to scram high pressure setpoint trip

c. Motor branch circuit overcurrent protection

d. Motor overload protection

e. Suction block valve not fully open.

Random tripping will occur in response to the following:

a. Operator error

b. Loss of electrical power source to the pumps

c. Equipment or sensor failures and malfunctions which initiate the above intended trip response.

15.3.1.1.2 Frequency Classification

The trip of one or two recirculation pump(s) is categorized as one of moderate frequency.

15.3.1.2 Sequence of Events and Systems Operation

15.3.1.2.1 Sequence of Events

15.3.1.2.1.1 Trip of One Recirculation Pump

Table 15.3.1-1 lists a typical sequence of events.

15.3.1.2.1.2 Trip of Both Recirculation Pump Motors

Table 15.3.1-2 lists a typical sequence of events.

15.3.1.2.2 Systems Operation

Analysis of these events assumes normal functioning of plant instrumentation and controls and of plant protection and reactor protection systems. Specifically, these transients take credit for vessel level (L8) instrumentation to trip the turbine. Reactor scram is tripped from the turbine stop valves. High system pressure is limited by operation of the pressure relief valve system.

15.3.1.3 Core and System Performance

15.3.1.3.1 Mathematical Model

Only a qualitative evaluation is provided.

15.3.1.3.2 Input Parameters and Initial Conditions

Only a qualitative evaluation is provided.

Pump motors and pump rotors are normally simulated with minimum specified rotating inertias.

The design jet pump efficiency is used in the analysis. However, the minimum pump inertia (lower bound) is used in the analysis for conservatism so that the actual pump flow coastdown rate is slower than the calculated values.

The actual pump motor rotating inertia must meet the inertia requirement in the design specification.

15.3.1.3.3 Qualitative Results

15.3.1.3.3.1 Trip of One Recirculation Pump

No scram is initiated directly by pump trip. The vessel water level swell due to rapid flow coastdown may reach the high level trip, thereby shutting down the main turbine and feed pump turbines and indirectly initiating scrams as a result of the main turbine trip. Thermal-hydraulic instabilities may result from a pump trip and are mitigated by the Oscillating Power Range Monitor (OPRM) or other Operator actions. Subsequent events, such as main steam line isolation and initiation of reactor core isolation cooling (RCIC) and high pressure coolant injection (HPCI) systems occurring late in this event, have no significant effect on the results. This is not a limiting transient and the consequences do not result in any fuel failures.

15.3.1.3.3.2 Trip of Both Recirculation Pumps

No scram is initiated directly by pump trip. The vessel water level swell due to rapid flow coastdown is expected to reach the high level trip, thereby shutting down the main turbine and feed pump turbines and indirectly initiating scrams as a result of the main turbine trip. Subsequent events, such as main steam line isolation and initiation of RCIC and HPCI systems occurring late in this event, have no significant effect on the results. This is not a limiting transient and the consequences do not result in any fuel failures.

15.3.1.3.4 Consideration of Uncertainties

Initial conditions chosen for these analyses are conservative and tend to force analytical results to be more severe than expected under actual plant conditions.

Actual pump and pump motor drive line rotating inertias are expected to be somewhat greater than the minimum design values assumed in this simulation. Actual plant deviations regarding inertia are expected to lessen the severity as analyzed. Minimum design inertias were used as well as the least negative void coefficient, since the primary interest is in the flow reduction.

15.3.1.4 Barrier Performance

15.3.1.4.1 Trip of One Recirculation Pump

The results indicate a final reduction in system pressures from the initial conditions. Therefore, the reactor coolant pressure boundary (RCPB) barrier is not threatened.

15.3.1.4.2 Trip of Both Recirculation Pumps

The results indicate that peak pressures stay well below the 1375 psig limit allowed by the applicable code. Therefore, the RCPB is not threatened.

15.3.1.5 Radiological Consequences

The consequences of this event do not result in any fuel failure.

TABLE 15.3.1-1 TYPICAL SEQUENCE OF EVENTS FOR TRIP OF ONE RECIRCULATION PUMP MOTOR

Estimated Time (sec)	Event
0	Trip of one recirculation pump is initiated.
4.5	Vessel water level (L8) trip initiates turbine trip.[a]
4.5	Feedwater pumps are tripped off.
4.5	Turbine trip initiates bypass operation.
4.5	Reactor scram is initiated.
6.5	Moisture separator reheater flow starts to decay.
9.5	Reheater flow decays to zero.
20.0	Core flow and power level stabilize at new equilibrium conditions.

[a] A level 8 trip is not normally expected after the trip of a single recirculation pump. The table presents the worst-case scenario.

TABLE 15.3.1-2 TYPICAL SEQUENCE OF EVENTS FOR TRIP OF BOTH RECIRCULATION PUMP MOTORS

Estimated Time (sec)	Event
0	Trip of both recirculation pumps is initiated.
3.1	Vessel water level (L8) trip initiates turbine trip.
3.1	Feedwater pumps are tripped off.
3.1	Turbine trip initiates bypass operation.
3.1	Turbine trip initiated reactor scram trip.
5.1	Moisture separator reheater flow starts to decay.
8.1	Moisture separator reheater flow decays to zero.
20.0	Core flow and power level stabilize at new equilibrium conditions.
190.0	Vessel water (L2) setpoint is reached (not simulated).
220.0	The HPCI and RCIC flow enters vessel (not simulated).

15.3.2 Recirculation Flow Control Failure - Decreasing Flow

15.3.2.1 Identification of Causes and Frequency Classification

15.3.2.1.1 Identification of Causes

Failure of an individual recirculation motor generator (MG) set speed control signal (one per loop) or failure of the positioning control of an individual scoop tube positioner can result in a rapid flow decrease in only one recirculation loop.

15.3.2.1.2 Frequency Classification

This transient disturbance is categorized as an incident of moderate frequency.

15.3.2.2 Sequence of Events and Systems Operation

15.3.2.2.1 Sequence of Events

A typical sequence of events for this transient is similar to and can never be more severe than that listed in Table 15.3.1-1 for the trip of one recirculation pump.

15.3.2.2.2 Systems Operation

Normal plant instrumentation and control is assumed to function. Credit is taken for scram in response to vessel high water level (L8) trip if it occurs. This is true for both the single and master controller failure events.

15.3.2.3 Core and System Performance

15.3.2.3.1 Mathematical Model

Only a qualitative evaluation is provided.

15.3.2.3.2 Input Parameters and Initial Conditions

Only a qualitative evaluation is provided. Typically a less negative void coefficient is used for these analyses.

15.3.2.3.3 Qualitative Results

In the case of failure of one control demand signal, the scoop tube positioners are designed so that the flow change rate limit is determined by the individual stroking rate, which is approximately 25 percent/sec. This case is similar to the trip of one recirculation pump, evaluated in Subsection 15.3.1.3.3.1, and is less severe than the transient that results from the simultaneous trip of both recirculation pumps.

15.3.2.3.4 Consideration of Uncertainties

Initial conditions chosen for these analyses are conservative and tend to force analytical results to be more severe than otherwise expected. These analyses, unlike the pump trip series, will be unaffected by deviations in pumps, pump motor, and drive line inertias, since it is the flow demand signal that causes rapid recirculation decrease.

15.3.2.4 Barrier Performance

The barrier performance considerations for these events are the same as those discussed in the section on recirculation pump trips.

15.3.2.5 Radiological Consequences

The consequences of this event do not result in fuel failure.

15.3.3 Recirculation Pump Seizure

15.3.3.1 Identification of Causes and Frequency Classification

The seizure of a recirculation pump is considered in philosophical, probability, and functional senses as a design basis accident event. It has been evaluated as a very mild accident in relation to other design basis accidents, such as the LOCA. The analysis has been conducted with consideration to a single or two loop operation.

The recirculation pump is designed to very rigid standards and codes. It is very well instrumented, monitored, and controlled to ensure safe and orderly operation. It is designed to meet strict seismic and environmental conditions. It is protected from external disturbances that could negate its inherent capabilities to preclude a self destruction (seizure or shaft impairment). Refer to Subsection 5.5.1 for specific mechanical considerations and to Chapter 7 for electrical aspects.

The seizure event postulated certainly would not be the mode failure of such a device. Safe shutdown components (e.g., electrical breakers, protective circuits) would preclude an instantaneous seizure event.

15.3.3.1.1 Identification of Causes

The case of recirculation pump seizure represents the extremely unlikely event of instantaneous stoppage of the pump motor shaft of one recirculation pump. This event produces a very rapid decrease of core flow as a result of the large hydraulic resistance introduced by the stopped rotor.

15.3.3.1.2 Frequency Classification

This event is considered to be a limiting fault in its category but it results in effects that can easily satisfy more frequent event limits (i.e., infrequent incident classification).

15.3.3.2 Sequence of Events and Systems Operation

15.3.3.2.1 Sequence of Events

Table 15.3.3-1 lists the typical sequence of events.

15.3.3.2.2 Systems Operation

To properly simulate the expected sequence of events, the analysis of this event assumes normal functioning of plant instrumentation and controls and plant protection and reactor protection systems. Operation of safe shutdown features, although not included in this simulation, is expected to be utilized to maintain adequate water level.

15.3.3.3 Core and System Performance

15.3.3.3.1 Mathematical Model

Only a qualitative evaluation is provided.

15.3.3.3.2 Input Parameters and Initial Conditions

Only a qualitative evaluation is provided.

For the purpose of evaluating consequences to the fuel thermal limits, this transient event is assumed to occur as a consequence of an unspecified, instantaneous stoppage of one recirculation pump shaft while the reactor is operating at rated NBR power. Also, the reactor is assumed to be operating at thermally limited conditions.

The void coefficient is adjusted to the most conservative value, that is, the least negative value.

15.3.3.3.3 Qualitative Results

Core coolant flow drops rapidly. The MCPR does not decrease significantly before fuel surface heat flux begins dropping enough to restore greater thermal margins. The level swell produces a trip of the main and feedwater turbines, and stop valve closure scram. Since, after MCPR occurs, heat flux decreases much more rapidly than the rate at which heat is removed by the coolant, the scram conditions impose no threat to thermal limits. Additionally, the bypass valves limit the pressure well within the range allowed by the ASME vessel code. Therefore the reactor coolant pressure boundary is not threatened by overpressure. The consequences from the event are rather mild even if this is classified as a moderately frequent event.

15.3.3.3.4 Consideration of Uncertainties

Considerations of uncertainties are included in the GETAB analysis.

15.3.3.4 Barrier Performance

Opening the bypass valves limits the pressure well within the range allowed by the ASME vessel code. Therefore the reactor coolant pressure boundary is not threatened by overpressure.

15.3.3.5 Radiological Consequences

The consequences of this event do not result in fuel failure.

15.3.3.6 Recirculation Pump Seizure With Coincident Loss of Offsite Power

The recirculation pump seizure accident with coincident loss of offsite power is similar to the transient discussed in Subsection 15.2.6 (loss of ac power) except that the feedwater is tripped earlier and the core flow coastdown is faster. Thus, actual expected core power response of this postulated accident is less severe than that evaluated in Subsection 15.2.6 due to the faster core flow coastdown. No fuel failure is expected. Failure of nonsafety grade equipment would not make the core performance and/or radiological consequences of this postulated accident more limiting than the LOCA addressed in the UFSAR. Therefore, no additional evaluations are considered necessary.

The recirculation pump seizure accident was reviewed on a generic basis by the utility Licensing Review Group (LRG) and the NRC as LRG issue RSB-21. The issue was satisfactorily resolved with the commitment to perform Technical Specifications surveillance on the applicable nonsafety grade equipment involved (Level 8 trip and turbine bypass system) and with the knowledge that generic analyses had been performed by GE to show that nonreliance on the nonsafety grade equipment did not significantly affect the overall safety analysis (the postulated accident was still bounded by other analyzed accident scenarios).

TABLE 15.3.3-1 TYPICAL SEQUENCE OF EVENTS FOR SEIZURE OF ONE RECIRCULATION PUMP MOTOR

Estimated Time (sec)	Event
0	Single pump seizure is initiated.
2.6	Vessel level (L8) trip initiates turbine trip.
2.6	Feedwater pumps are tripped off.
2.6	Turbine trip initiates bypass operation.
2.6	Turbine trip initiates reactor scram trip.
4.6	Moisture separator reheater flow starts to decay.
6.4	Vessel water level reaches Level 3 (L3) setpoint.
7.6	Moisture separator reheater flow decays to zero.
65.0	Vessel water reaches Level 2 (L2) setpoint (not simulated).
75.0	The HPCI and RCIC flow enters the vessel (not simulated).

15.4 REACTIVITY AND POWER DISTRIBUTION ANOMALIES

15.4.1 Rod Withdrawal Error - Low Power

15.4.1.1 Control Rod Removal Error During Refueling

15.4.1.1.1 Identification of Causes and Frequency Classification

The event considered here is inadvertent criticality caused by the complete withdrawal or removal of the most reactive rod during refueling. The probability of occurrence of the initial causes alone is considered low enough to warrant the categorization of this event as an infrequent incident, since there is no postulated set of circumstances that results in an inadvertent rod withdrawal error while in the refuel mode.

15.4.1.1.2 Sequence of Events and Systems Operation

15.4.1.1.2.1 Initial Control Rod Removal

During refueling operations, safety system interlocks provide assurance that inadvertent criticality does not occur because a control rod has been removed or is withdrawn in coincidence with another control rod.

15.4.1.1.2.2 Fuel Insertion With Control Rod Removed

To minimize the possibility of loading fuel into a cell containing no control rod, all control rods are required to be fully inserted when fuel is being loaded into the core. This requirement is backed up by refueling interlocks on rod withdrawal and movement of the refueling platform. When the mode switch is in the refuel position, the interlocks prevent the platform from being moved over the core if a control rod is withdrawn and fuel is on the hoist. Similarly, if the refueling platform is over the core and fuel is on the hoist, control rod motion is blocked by the interlocks.

15.4.1.1.2.3 Second Control Rod Removal

When the platform is not over the core (or fuel is not on the hoist), and the mode switch is in the refuel position, only one control rod can be withdrawn. Any attempt to withdraw a second rod results in a rod block by the refueling interlocks. Since the core is designed to meet shutdown requirements with the highest worth rod withdrawn, the core remains subcritical even with one rod withdrawn.

15.4.1.1.2.4 Control Rod Removal Without Fuel Removal

Finally, the design of the control rod, which incorporates the velocity limiter, does not physically permit the upward removal of the control rod without the simultaneous or prior removal of four adjacent fuel bundles. This precludes any hazardous condition.

15.4.1.1.3 Core and System Performance

Since the probability of inadvertent criticality during refueling is precluded, the core and system performance was not analyzed. However, withdrawal of the highest worth control rod during refueling results in a positive reactivity insertion, but not enough to cause criticality. This is verified experimentally by performing shutdown margin checks (see Subsection 4.3.2 for a description of the methods and results of the shutdown margin analysis). Additional reactivity insertion is precluded by interlocks (see Subsection 7.6.1.1). As a result, no radioactive material is ever released from the fuel; it is therefore unnecessary to assess any radiological consequences.

No mathematical models are involved in this event. Input parameters or initial conditions are not required, as there are no results to report. Consideration of uncertainties is not appropriate.

15.4.1.1.4 Barrier Performance

The barrier performance was not evaluated for this event, since it is highly localized and does not result in any change in the core pressure or temperature.

15.4.1.1.5 Radiological Consequences

Radiological consequences were not evaluated for this event, since no radioactive material is released from the fuel.

15.4.1.2 Continuous Rod Withdrawal During Reactor Startup

15.4.1.2.1 Identification of Causes and Frequency Classification

The probability of occurrence of initial causes or errors alone in this event is low enough to warrant its being categorized as an infrequent incident. The probability of further development of this event is extremely low because it is contingent upon the failure of the rod worth minimizer (RWM) concurrent with a high worth, out-of-sequence rod selection contrary to procedure, coupled with lack of operator response to the RWM continuous alarm annunciations prior to safety system actuation.

15.4.1.2.2 Sequence of Events and System Operation

Before the continuous rod withdrawal during reactor startup is possible, the first part of the sequence of events presented in Table 15.4.1.2-1 must occur.

The RWM constraints on the control rod sequences prevent the continuous withdrawal of an out-of-sequence rod during the reactor startup. With the RWM inoperable a second licensed operator or other technically qualified member of the unit technical staff who is present at the reactor control console verifies the control rod movement compliance with the prescribed control rod pattern. The RWM is programmed to the banked position withdrawal sequence (BPWS) to reduce control rod worths to a value that would be acceptable in the event of a control rod drop accident (see Subsection 15.4.9). The generic analyses for the continuous control rod withdrawal transient in the startup range are included in Reference 1.

As generically described in Reference 2, the range of application of BPWS is between 100 percent control rod density (all rods in) and the low power set point, i.e., 10 percent of rated core power. In this low power range the control rods are effectively withdrawn in the form of stepped bank patterns. Because the control rods are withdrawn in the banked patterns, the incremental rod worth is maintained at low values such that the resultant peak fuel enthalpies due to the continuous withdrawal of an out-of-sequence control rod is less than the licensing basis of 170 cal/g.

The generic analysis of the continuous control rod withdrawal transient in the startup range are included in Reference 1. Table 15.4.1.2-1 shows the sequence of events for the continuous rod withdrawal transient considered.

15.4.1.2.3 Core and System Performance

The performance of the RWM forces adherence to the BPWS constraints applied to control rod withdrawals, thus eliminating the rod withdrawal error in the low power range as a transient of any concern.

The methods and design basis used for performing the detailed analyses for this transient are documented in Reference 1.

15.4.1.2.4 Barrier Performance

An evaluation of the barrier performance was not made for this event, since this is a highly localized event with no significant change in core temperature or pressure.

15.4.1.2.5 Radiological Consequences

An evaluation of the radiological consequences is not required for this event, since no radioactive material is released from the fuel.

TABLE 15.4.1.2-1 TYPICAL SEQUENCE OF EVENTS FOR CONTINUOUS ROD WITHDRAWAL DURING REACTOR STARTUP

Estimated Elapsed Time (sec)	Event
-	The reactor is critical and operating in the startup range.
>0	The operator selects and withdraws an out-of-sequence control rod at the maximum normal drive speed of 3.6 ips.
4	Both the RWM and operator check off system fail to block the selection (selection error) and continuous withdrawal (withdrawal error) of the out-of-sequence rod.
4-8	The reactor scram is initiated by the intermediate range monitor (IRM) system or the average power range monitor (APRM) system.
5-9	The prompt power burst is terminated by a combination of Doppler and/or scram feedback.
10	The transient is finally terminated by the scram of all rods, including the control rod being withdrawn.

15.4.2 Rod Withdrawal Error at Power

The control rod withdrawal error at power condition has been identified in GESTAR II (Reference 3) as one of the more likely events to limit operation from MCPR consideration; therefore, it is typically analyzed on a cycle-specific basis.

15.4.2.1 Identification of Causes and Frequency Classification

15.4.2.1.1 Identification of Causes

While operating in the power range in a normal mode of operation, the reactor operator makes a procedural error and withdraws a high worth control rod until the rod block monitor (RBM) system inhibits further withdrawal.

15.4.2.1.2 Frequency Classification

The probability of this event is considered low enough to warrant its categorization as an infrequent incident. However, because of the lack of sufficient frequency data base, this transient disturbance is analyzed as an incident of moderate frequency until its frequency can be further evaluated and justified.

15.4.2.2 Sequence of Events and Systems Operation

15.4.2.2.1 Sequence of Events

The sequence of events for this transient is presented in Table 15.4.2-1. No operator actions are required during this event; however, operator actions expected to occur are shown in the table. This event results in a local power increase due to a reactivity rise from the decrease in control rod poison material. The rod block monitoring system blocks the further withdrawal of the error control rod and terminates the event.

15.4.2.2.2 Systems Operation

This event is localized to a small portion of the core. Therefore, although reactor control and instrumentation is assumed to function normally, credit is taken only for the RBM system. A discussion of the event follows.

While operating in the power range in a normal mode of operation (except as noted in Subsection 15.4.2.3.2), the reactor operator makes a procedural error and withdraws a control rod until the RBM system inhibits further withdrawal.

Under most normal operating conditions, no operator action is required when a rod withdrawal error is made with average rod worth, since the transient that would occur would be very mild. If the local power increase is excessive when a high worth rod is withdrawn, the nearby local power range monitors (LPRM) would detect this phenomenon and sound an alarm. The operator is suppose to acknowledge this alarm and take appropriate action to rectify the situation.

If the rod withdrawal error were severe enough, and the operator continues to withdraw the control rod, the RBM system would block further withdrawal of the control rod before the fuel cladding integrity safety limit is reached.

15.4.2.2.3 Rod Block Monitor System Operation

The RBM system is designed to automatically block control rod withdrawal that could violate the MCPR safety limit during a control rod withdrawal error transient. Upon operator selection of a control rod, the system begins comparing RBM signals to predefined trip levels. The RBM signals consist of the average of selected B, C, and D level local power range monitor (LPRM) in-core signals in the strings immediately surrounding the selected control rod normalized to 100%. An increase in the RBM signal during rod withdrawal indicates a local power increase, and a corresponding local thermal margin decrease. The rod block trip levels are established such that the thermal margin decrease will be less than available margin. If an upscale rod block is received (rod withdrawal permissive removed), the operator verifies that he is in compliance with fuel thermal limits before resetting the rod block trip. Once reset, the RBM system reinitializes and allows further control rod withdrawal consistent with design basis thermal margin reduction increments.

The RBM has three upscale trip levels which vary as a step function of core power. Each trip level is enforced over a range of core power levels, with the highest trip corresponding to the lowest power and the lowest trip corresponding to the highest power. This allows longer withdrawals at low power where thermal margins are high, and only short withdrawals at high power. The trip levels and their corresponding power level ranges can be changed based on the thermal margin reported in the cycle specific Supplemental Reload Licensing Report. The core power input used to automatically select the applicable RBM trip is provided by the Average Power Range Monitoring (APRM) system.

15.4.2.3 Core and System Performance

15.4.2.3.1 Mathematical Model

For this transient, the reactivity insertion rate is very slow; therefore, it is adequate to assume that the core has sufficient time to equilibrate (i.e., that both the neutron flux and heat flux are in phase). With the use of the above assumption, this transient is calculated by using a steady-state, three-dimensional, coupled, nuclear thermal hydraulics computer program. All spatial effects are included in the calculation.

The primary output from this code, in addition to the basic nuclear parameters, is as follows: the variation of the linear heat generation rate (LHGR); the variation of the minimum critical power ratio (MCPR); the total reactor power; and the variation of the in-core instruments during the transient. A detector response code uses the instrument responses to predict the rod block monitor action under the specified condition for the rod withdrawal error.

The analytical methods and assumptions used in evaluating the consequences of this accident are considered to provide a realistic, yet conservative, assessment of the consequences.

15.4.2.3.2 Input Parameters and Initial Conditions

The number of possible rod withdrawal error (RWE) transients is extremely large because of the number of control rods and the wide range of core characteristics and power levels. With the improved RBM system, the RBM response is well correlated to MCPR response. Because of this, a statistical analyses is performed based on the large amount of data available from past reload, and a generic set of bounding values of DCPR as a function of RBM setpoints is established. Also, additional analyses may be supplemented to further assure that the generic statistical result is applicable.

The generic rod withdrawal error database was drawn from actual plant states and covered the spectrum of plant designs, fuel designs and power densities. Relevant cases were selected with minimum margins to MCPR and MAPLHGR limits in bundles near deep control rods to yield meaningful results. For each RWE case, the analytical outputs (MCPR, MAPLHGR, LPRM readings, and gross core power as a function of error rod position) became inputs to the statistical analysis. Furthermore, numerous simulated RWEs were generated from each rod pattern case by randomly varying the initial position of the error rod and the location and number of failed LPRMs. From these simulated RWEs (per each rod pattern case), the mean and standard deviation and components of the standard deviation were calculated for each RBM setpoint. Here the RBM setpoint is the permissible change of local power as computed by the RBM assigned LPRMs for the selected control rod. All these were used to determine the mean and standard deviation of the entire database.

The final RBM setpoints are determined with the requirement that there is 95% confidence that 95% of the RWE consequence will be bounded if the required MCPR is 1.20, 1.25, 1.30, or 1.35. This statistical analyses conclude that the RWE transients can be protected by three RBM protective settings in three power ranges. See Reference 6 for more details on the bounding MCPR value or for more details of this statistical analysis.

This event is localized to a small portion of the core. Therefore, although reactor control and instrumentation is assumed to function normally, credit is taken only for the RBM system. A discussion of the event follows.

While operating in the power range in a normal mode of operation (except as noted in Subsection 15.4.2.3.2), the reactor operator makes a procedural error and withdraws a control rod until the RBM system inhibits further withdrawal.

Under most normal operating conditions, no operator action is required when a rod withdrawal error is made with average rod worth, since the transient that would occur would be very mild. If the local power increase is excessive when a high worth rod is withdrawn, the nearby local power range monitors (LPRM) would detect this phenomenon and sound an alarm. The operator is suppose to acknowledge this alarm and take appropriate action to rectify the situation.

If the rod withdrawal error were severe enough, the RBM system would sound alarms, at which time the operator would acknowledge the alarms and take corrective action. Even for extremely severe (i.e., those involving highly abnormal control rod patterns or operating conditions in which it is assumed that the operator ignores all alarms and warnings and continues to withdraw the control rod), the RBM system would block further withdrawal of the control rod before the fuel reached the point of boiling transition or the 1 percent plastic strain limit imposed on the clad.

15.4.2.3.3 Qualitative Results

To assure the rod withdrawal error transients are acceptable, the RBM setpoints meet the following requirements:

Let required MCPR = 1.25 at rated conditions

Power Range	Analytical Limit	(permissible change of local power)
> 85 – 100%	110.2%	
> 65 - 85%	115.2%	
> 30 – 65%	120%	

15.4.2.3.4 Consideration of Uncertainties

The uncertainties are included in the statistical analyses.

15.4.2.4 Barrier Performance

The barrier performance was not evaluated for this event, since this is a localized occurrence with very little change in the gross core characteristics. Typically, an increase in total core power is less than 5 percent, and the changes in pressure are negligible.

15.4.2.5 Radiological Consequences

An evaluation of the radiological consequences is not required for this event, since no radioactive material is released from the fuel.

TABLE 15.4.2-1 TYPICAL SEQUENCE OF EVENTS - ROD WORTH EVENT IN POWER RANGE

Approximate Elapsed Time (sec)	Event
0	Core is assumed to be operating at rated conditions.
0	Operator selects and withdraws the maximum worth control rod.
1	The total core power and the local power in the vicinity of the control rod increase.
5	The LPRM system indicates excessive localized peaking.
5	The operator ignores warning and continues withdrawal.
15	The RBM system indicates excessive localized peaking.
15	The operator ignores warning and continues withdrawal.
20	The RBM system initiates a rod block inhibiting further withdrawal.

TABLE 15.4.2-1 TYPICAL SEQUENCE OF EVENTS - ROD WORTH EVENT IN POWER RANGE

Approximate Elapsed Time (sec)	Event
40	Reactor core stabilizes at higher core power level.
60	Operator reinserts control rod to reduce core power level.
80	Core stabilizes at rated conditions.

15.4.3 Control Rod Maloperation (System Malfunction or Operator Error)

This event is included in the evaluation cited in Subsections 15.4.1 and 15.4.2.

15.4.4 Abnormal Startup of Idle Recirculation Pump

15.4.4.1 Identification of Causes and Frequency Classification

15.4.4.1.1 Identification of Causes

This action results directly from the operator's manual action to initiate pump operation. It assumes that the remaining loop is already operating.

15.4.4.1.1.1 Normal Restart of Recirculation Pump at Power

This transient is categorized as an incident of moderate frequency.

15.4.4.1.1.2 Abnormal Startup of Idle Recirculation Pump

This transient is categorized as an incident of moderate frequency.

15.4.4.2 Sequence of Events and Systems Operation

15.4.4.2.1 Sequence of Events

Table 15.4.4-1 lists the typical sequence of events.

15.4.4.2.2 Systems Operation

This event assumes and takes credit for normal functioning of plant instrumentation and control as well as plant protection and reactor protection systems. In particular, credit is taken for high flux scram to terminate the transient. No engineered safety feature (ESF) action occurs as a result of the transient.

15.4.4.3 Core and System Performance

15.4.4.3.1 Mathematical Model

Only a qualitative evaluation is provided.

15.4.4.3.2 Input Parameters and Initial Conditions

When starting an idle loop with one pump already running, Technical Specifications require heating the idle recirculation loop to within 50°F of core inlet temperature prior to loop startup, to be consistent with the assumptions of the reactor vessel nozzle and reactor recirculation system ASME Upset category stress analysis and partial power fuel thermal limit analyses.

The idle recirculation pump suction valve is open, but the pump discharge valve is closed. The idle pump fluid coupler is at a setting that approximates 50 percent generator speed demand.

15.4.4.3.3 Qualitative Results

Following the transient response to the incorrect startup of a cold, idle recirculation loop, the pump begins to move and a flow surge from the jet pump diffusers causes the core inlet flow to rise sharply. The neutron flux peak would reach the fixed average power range monitor (APRM) flux setpoint and reactor scram is initiated. Nuclear system pressures do not increase significantly. The water level does not reach either the high or low level setpoints prior to APRM high flux scram.

After the initiation of the startup of the idle recirculation loop pump transient, the core flow increases and thus reduces the void fraction in the core. Because of the negative void reactivity coefficient, the void reactivity increases and causes the neutron flux to increase. The increase of power level then produces more void and reduces the void reactivity and the neutron flux. This is not a limiting transient.

15.4.4.3.4 Consideration of Uncertainties

This transient is evaluated for an initial power level much higher than that expected for the actual event. The much slower thermal response of the fuel mitigates the effects of the rather sharp neutron flux spike; and even in this high range of power, no threat to thermal limits is possible.

15.4.4.4 Barrier Performance

No evaluation of barrier performance is required for this event, because no significant pressure increases are incurred during this transient.

15.4.4.5 Radiological Consequences

An evaluation of the radiological consequence is not required for this event, since no radioactive material is released from the fuel.

TABLE 15.4.4-1 TYPICAL SEQUENCE OF EVENTS FOR STARTUP OF IDLE RECIRCULATION LOOP

Approximate Elapsed Time (sec)	Event
0	Start pump motor.
8	Startup loop flow reverses.
10	Reactor high flux scram is initiated.
13	Turbine control valves start to close upon falling turbine pressure.
20	Turbine control valves fully close. Turbine pressure is below pressure regulator setpoints.
> 45	Core inlet flow and vessel pressure settle at a new steady state.

15.4.5 Recirculation Flow Control Failure With Increasing Flow

15.4.5.1 Identification of Causes and Frequency Classification

15.4.5.1.1 Identification of Causes

Failure of an individual recirculation motor generator (MG) set speed control signal (one per loop) system (maximum demand) or failure of the positioning control of an individual scoop tube positioner can result in a rapid flow increase in only one recirculation loop.

15.4.5.1.2 Frequency Classification

This transient disturbance is classified as an incident of moderate frequency.

15.4.5.2 Sequence of Events and Systems Operation

15.4.5.2.1 Sequence of Events

Table 15.4.5-1 lists the typical sequence of events.

15.4.5.2.2 Systems Operation

The analysis of this transient assumes and takes credit for normal functioning of plant instrumentation and controls and the reactor protection system. Operation of engineered safeguards is not expected.

15.4.5.3 Core and System Performance

15.4.5.3.1 Mathematical Model

Only a qualitative evaluation is provided.

15.4.5.3.2 Input Parameters and Initial Conditions

In each of these transient events, the most severe transient results when initial conditions are established for operation at the low end of the rated flow control rod line.

Maximum change in speed control occurs with failure of one of the MG set speed controllers. A rapid swing of the coupler is simulated at its maximum rate of 25 percent/sec.

15.4.5.3.3 Qualitative Results

Even with the worst recirculation flow control failure, the changes in nuclear system pressure are not significant with regard to overpressure. Pressure decreases over most of the transient. The rapid increase in core coolant flow causes an increase in neutron flux, which initiates a reactor APRM high flux scram. The MCPR remains above the safety limit and no radioactive material is released from the fuel. This is not a limiting event.

15.4.5.3.4 Consideration of Uncertainties

Some uncertainties in void reactivity characteristics, scram time, and worth are expected to have less serious outcomes than those simulated here.

15.4.5.4 Barrier Performance

This transient results in a very slight increase in reactor vessel pressure and therefore represents no threat to the reactor coolant pressure boundary (RCPB).

15.4.5.5 Radiological Consequences

An evaluation of the radiological consequences is not required for this event, since no radioactive material is released from the fuel.

TABLE 15.4.5-1 TYPICAL SEQUENCE OF EVENTS FOR RECIRCULATION FLOW CONTROLLER FAILURE WITH INCREASING FLOW

Approximate Elapsed Time (sec)	Event
0	Simulate failure of single loop control.
1.5	Reactor high flux scram trip is initiated.
5	Turbine control valves start to close upon falling turbine pressure.
14	Turbine control valves fully close. Turbine pressure is below pressure regulator setpoints.

TABLE 15.4.5-1 TYPICAL SEQUENCE OF EVENTS FOR RECIRCULATION FLOW CONTROLLER FAILURE WITH INCREASING FLOW

Approximate Elapsed Time (sec)	Event
55	Vessel water level reaches Level 8 (L8) setpoint.
55	Feedwater pumps are tripped off.
>100	Core inlet flow and vessel pressure settle at a new steady state.

15.4.7 Misplaced Bundle Accident

15.4.7.1 Identification of Causes and Frequency Classification

15.4.7.1.1 Identification of Causes

The event discussed in this section is the improper loading of a fuel bundle and subsequent operation of the core. Analysis is performed for the initial core, and reload cores through Cycle 21, where the resultant CPR response may establish the operating limit MCPR.

Three errors must occur for this event to take place in the initial core loading. First, a bundle must be misloaded into a wrong location in the core. Second, the bundle that was supposed to be loaded where the mislocation occurred also has to be put in an incorrect location. Third, the two misplaced bundles have to be overlooked during the core verification process performed following initial core loading. For reload cores, only two errors must occur.

15.4.7.1.2 Frequency of Occurrence

This unlikely event occurs when a fuel bundle is loaded into the wrong location in the core. It is assumed that the bundle is misplaced to the worst possible location and that the plant is operated with the mislocated bundle. This event is categorized as an infrequent incident on the basis of the following data: expected frequency is 0.004 events per operating cycle.

The above number is based upon past experience. The only misloading events that have occurred in the past were in reload cycles where only two errors are necessary. Therefore, the frequency of occurrence for initial cores is even lower, since three errors must occur concurrently. There has never been a loading error in an initial core.

15.4.7.2 Sequence of Events and Systems Operation

15.4.7.2.1 Sequence of Events

The postulated sequence of events for the misplaced bundle accident is presented in Table 15.4.7-1.

15.4.7.2.2 Systems Operation

A fuel loading error may result in a reduction in thermal margin during power operations. For the analysis reported here, detection occurs when offgas radiation levels rise. No corrective operator action or automatic protection system functioning occurs to prevent the event.

15.4.7.2.3 Effect of Single Failure and Operator Errors

This analysis already represents the worst case (i.e., operation of a misplaced bundle with three single operator errors [SOEs]).

15.4.7.3 Core and System Performance

15.4.7.3.1 Mathematical Model

A three-dimensional BWR simulator model would be used to calculate the core performance resulting from this event. The misplaced bundle accident is a steady-state event, and the BWR simulator easily models this situation. This model is described in detail in Reference 3.

15.4.7.3.2 Input Parameters and Initial Conditions

15.4.7.3.2.1 Initial Core

The initial core consists of three bundle types with average enrichments that are high, medium, or low, with correspondingly different gadolinia concentrations. The fuel bundle loading error involves interchanging a bundle of one enrichment with another bundle of a different enrichment. The following fuel loading errors can be conceived for an initial core:

a. A high enriched bundle is misloaded into a low enriched bundle location

b. A medium enriched bundle is misloaded into a low enriched bundle location

c. A low enriched bundle is misloaded into a high enriched bundle location

d. A low enriched bundle is misloaded into a medium enriched bundle location

e. A medium enriched bundle is misloaded into a high enriched bundle location

f. A high enriched bundle is misloaded into a medium enriched bundle location.

Since all low enriched bundles are located on the core periphery, the two possible fuel loading errors consisting of the misloading of high or medium enriched bundles into a low enriched bundle location (i.e., types 1 and 2) are not significant. In these cases, the higher reactivity bundles are moved to a region of lower importance, resulting in an overall improvement in performance.

The third type of fuel loading error, as identified above, results in the largest enrichment mismatch. However, it does not result in an unacceptable operating consequence. Consider a fuel bundle loading error at beginning of cycle (BOC) with the low enriched bundle (which should be loaded at the periphery) interchanged with a high enriched bundle located adjacent to a local power range monitor (LPRM) and predicted to have the highest LHGR and/or lowest CPR in the core. After the loading error has occurred and has gone undetected, it is assumed, for purposes of conservatism, that the operator uses a control pattern that places the limiting bundle in the four bundle array containing the misplaced bundle on thermal limits as recorded by the LPRM. As a result of loading the low enriched bundle in an improper location, the average power in the four bundles decreases. Normally, the reading of the LPRM will show a decrease in thermal flux due to the decreased power; however, in this case, an increase in the thermal flux occurs due to decreased neutron absorption in the low enriched bundle. The effects of the softer neutron spectrum due to the decreased thermal absorption are larger than the power depression effect of the lower fission rate, resulting in a net increase in instrument reading. Thus, a fuel loading error of this kind does not result in undetected reductions in thermal margins during power operations.

The fourth and fifth types of fuel loading errors are of the same kind (lower enrichment into higher enrichment) as the third type, and also do not result in a nonconservative operating error.

The fuel bundle loading error with greatest impact on thermal margin is of the sixth type, which occurs when a high enriched bundle is interchanged with a medium enriched bundle located away from an LPRM. Since the medium and high enrichment bundles have a corresponding medium and high gadolinia content, the maximum reactivity difference occurs at end of cycle (EOC), where the gadolinia is burned out. After the loading errors are made and have gone undetected, the operator assumes that the mislocated bundle is operating at the same power as the instrumented bundle in the mirror image location and operates the plant until EOC. For the purpose of conservatism, it is assumed that the mirror image bundle is on thermal limits as recorded by the LPRM. As a result of placing the instrumented bundle on limits, the mislocated bundle violates the Technical Specifications operating MCPR limit.

A misoriented bundle loading error, i.e., rotated 180°, is of no consequence for C-lattice BWR plants. The C-lattice configuration has equal size gaps on all four sides of the bundle; thus rotation will have no effect on the maximum R-factor. Similar to the D-lattice, the bundle in a C-lattice configuration will tilt axially due to the channel buttons at the top of the level assembly. Contrary to the D-lattice, where the tilting tends to mitigate the effect of a rotation, the R-factor increases slightly for the C-lattice. The net effect for the C-lattice is a CPR of less than 0.05.

15.4.7.3.2.2 <u>Reload Cores</u>

For reload cores, the loading error involves the mislocation of at least two fuel bundles. One location is loaded with a bundle which would potentially operate at a lower critical power than it would otherwise. The other location would operate at a higher critical power. The low critical power location could have less margin to boiling transition than other bundles in the core.

15.4.7.3.3 <u>Qualitative Results</u>

The generic radiological analysis in GESTAR Amendment 28 (Reference 3) assumes no fuel melt occurs as a result of this event. The incident would be like a fuel assembly operating with one or more leaking fuel rods. However, to bound the consequences for this event, a conservative assumption that all fuel rods in the misplaced fuel assembly and the four face adjacent fuel assemblies will experience instantaneous failure.

15.4.7.3.4 Consideration of Uncertainties

In order to account for any uncertainties, major input parameters of the bounding analysis are taken as the worst case, that is, (a) the bundle is placed in a location with the highest LHGR and/or the lowest CPR in the core, (b) the bundle is assumed to fail and cause 4 four face adjacent bundles to fail, (c) all fuel rods fail in the five failed bundles, and (d) the radial peaking factor is high.

15.4.7.4 Barrier Performance

An evaluation of the barrier performance was not made for this event, since it is a very mild and highly localized event. No perceptible change in the core pressure would be observed.

15.4.7.5 Radiological Consequences

Using the generic guidance of GESTAR Amendment 28, the offsite radiological dose and the control room dose are within Amendment 28 limits. Offsite dose is less than 2.5 Rem TEDE and the control room dose is less than 5 Rem TEDE.

TABLE 15.4.7-1 TYPICAL SEQUENCE OF EVENTS FOR THE MISPLACED BUNDLE ACCIDENT

1. During the core loading operation, a bundle is loaded into the wrong core location.
2. Subsequently, the bundle designated for this location is incorrectly loaded into the location of the previous bundle.
3. During core verification procedure, the two errors are not observed.
4. The plant is brought to full power operation with subsequent failure of a primary fuel assembly and adjacent fuel assemblies.
5. The fuel failure is detected by the offgas radiation monitors.

15.4.9 Control Rod Drop Accident

15.4.9.1 Identification of Causes and Frequency Classification

15.4.9.1.1 Identification of Causes

The control rod drop accident (CRDA) is the result of a postulated event in which a high worth control rod is inserted out-of-sequence into the core. Subsequently, it becomes decoupled from its drive mechanism. The mechanism is withdrawn, but the decoupled control rod is assumed to be stuck in place. At a later optimum moment, the control rod suddenly falls free and drops out of the core. This action results in the removal of large negative reactivity from the core, which in turn results in a localized power excursion.

A more detailed discussion is given in Reference 7 and 8.

15.4.9.1.2 Frequency Classification

The CRDA is categorized as a limiting fault because it is not expected to occur during the lifetime of the plant; if postulated to occur, however, it has consequences that include potential for the release of radioactive material from the fuel.

15.4.9.2 Sequence of Events and Systems Operation

15.4.9.2.1 Sequence of Events

Before the CRDA is possible, the first part of the sequence of events presented in Table 15.4.9-1 must occur.

To limit the worth of the rod that would be dropped in a banked position withdrawal sequence (BPWS) operating mode, the RWM is used below the low power setpoint to enforce the BPWS. The RWM is programmed to follow the BPWS, which are generically defined in Reference 2. For BPWS, the effective withdrawal is in the form of (stepped) defined bank patterns.

15.4.9.2.2 System Operation

The unlikely set of circumstances described above makes possible the rapid removal of a control rod. The dropping of the rod results in high reactivity in a small region of the core. For large, loosely coupled cores, this action should result in a highly peaked power distribution and subsequent operation of shutdown mechanisms. Significant shifts in the spatial power distribution would occur during the course of the excursion.

The rod worth minimizer (RWM) limits the worth of any control rod that could be dropped by regulating the withdrawal sequence. This system prevents the movement of an out-of-sequence rod in the 100 percent control rod density to the preset low power level; the RWM will allow only BPWS mode withdrawals or insertions.

The RWM or second operator check off system is assumed to operate throughout the event. The second operator check off system provides similar protection as the RWM if the RWM was not functioning and the second operator check off system conducted.

This excursion is terminated by automatic safety features of inherent shutdown mechanisms. Therefore, no operator action during the excursion is required. Although other normal plant instrumentation and controls are assumed to function, no credit is taken for their operation in the analysis of this event.

15.4.9.3 Core and System Performance

15.4.9.3.1 Mathematical Model

Techniques and models used to analyze the control rod drop accident (CRDA) are documented in References 1, 7, 8, and 9. The information in these documents has been used for the development of design approaches to make the consequences of CRDA acceptable.

The rod worth and scram worth are determined by using the BWR simulator model described in Chapter 4, Subsection 4.3. The Doppler coefficient is calculated by using the methods described in References 1, 2, and 7.

15.4.9.3.2 Input Parameters and Initial Conditions

The core at the time of the CRDA is assumed to be at the point in cycle that results in the highest control rod worth, to contain no xenon, to be in a hot startup condition, and to have the control rods positioned such that the highest incremental control rod worth encountered occurs next. The removal of xenon, which competes well for neutron absorptions, increases the fractional absorptions, or worth, of the control rods.

15.4.9.3.3 Qualitative Results

Adherence to BPWS reduces control rod worth such that the postulated control rod drop accident is well under the design criterion of 280 cal/gm. Reference 10 provides a statistical evaluation of BPWS control rod accident analyses. The results show that, in all cases, the peak fuel enthalpy in a CRDA would be much less than the 280 cal/gm design limit even with a maximum incremental rod worth corresponding to 95 percent probability at the 95 percent confidence level. Based on these results, it was proposed to the NRC, and subsequently found acceptable, to delete the CRDA from the standard GE BWR reload package for the BPWS plants (References 2 and 11).

15.4.9.4 Barrier Performance

An evaluation for the barrier performance was not made for this accident, since this is a highly localized event with no significant change in the gross core temperature or pressure.

15.4.9.5 Radiological Consequences

The design basis analysis is consistent with the requirements of 10 CFR 50 and in accordance with Regulatory Guide 1.183 (Reference 19). The analytical results were evaluated against the criteria contained in 10 CFR 50.67. Two release paths were considered: the original NRC Standard Review Plan 15.4.9 (Reference 12) condenser release and a forced release via the offgas system (i.e. steam-jet air ejector (SJAE) discharge through a series of sand filters and charcoal beds). Specific parametric values used in the evaluation are presented in Table 15.4.9-2 and Table 15.4.9-3. The specific models, assumptions, and programs used for computer evaluation are described in Reference 18.

The design basis analysis also meets the requirements of NEDO-31400A (Reference 20), which provided a basis for elimination of reactor scram and MSIV closure associated with main steam line high radiation (Reference 23). In addition to the analysis described in this subsection, NEDO-31400A required the alarms associated with the main steam line radiation monitor subsystem (Subsection 11.4.3.8.2.3) and offgas 2-minute delay pipe radiation monitor subsystem (Subsection 11.4.3.8.2.13) to be set at 1.5 times the "full power background." These alarm setpoints allow for prompt sampling of the reactor coolant to determine sources of contamination and the need for corrective actions. Determination of the "full power background" is described in Subsections 15.4.9.5.4 and 15.4.9.5.5 below.

15.4.9.5.1 Fission Product Release From Fuel

Table 15.4.9-4 provides a summary of pre-accident core activities. No credit is assumed for source term decay prior to reactor startup. The number of failed fuel rods is assumed to be 1,200 rods for the bounding case of 10x10 GE14 fuel (Reference 17). The breached fuel gap is assumed to release 10 percent of the core inventory of noble gases and iodine, and 12 percent of the core inventory of alkali metals. The percentage of breached fuel that melts is assumed to be 0.77 percent, releasing 100 percent of the noble gases, 50 percent of the iodine, and 25 percent of the alkali metals contained in the melted fuel fraction.

15.4.9.5.2 Fission Product Transport to the Environment

The activity released from the fuel from either the gap or from fuel pellets is assumed to be instantaneously mixed with the reactor coolant within the pressure vessel and 100 percent of all noble gases, 10 percent of the iodines, and 1 percent of alkali metal nuclides are transported to the turbine/condenser. Of the activity that reaches the turbine and condenser, 100 percent of the noble gases, 10 percent of the iodines, and 1 percent of the alkali metal nuclides are available for release to the environment. The accident release duration is 24 hours and no credit is taken for MSIV closure, nor SJAE shutdown, prior to 24 hours.

Two release paths were considered: delayed release from the main condenser and a forced release from the offgas system due to the continued operation of the SJAEs.

The main condenser is assumed to release the post-CRDA activity to the turbine building at a rate of 1% per day. No credit is taken for dilution or holdup within the turbine building; however, radioactive decay during holdup in the condenser is credited. The condenser activity released to the environment is assumed to exit via the turbine building ventilation stack.

The evaluation of a release via the offgas system from the SJAEs assumes that the MSIVs do not close and that steam flow continues for approximately 24 hours before this path is isolated. The SJAEs are placed into operation once sufficient steam is available above approximately 2.5 percent power. The offgas system delivers noncondensable gases in the main condenser to a series of sand filters which remove particulates and a series of charcoal adsorber beds that retain iodine and holdup the noble gases to allow the natural decay process to significantly reduce activities prior to release to the environment via the reactor building exhaust stack.

Upon detection of high radiation by the main steam line radiation monitors (MSLRM) (see Subsection 11.4.3.8.2.3), the reactor water sample system is automatically isolated, the condenser mechanical vacuum pumps and line valves are automatically tripped, and the gland seal exhausters are automatically tripped. As a result of crediting these automatic trips and isolations, release through these pathways are not considered in the analysis. Above 10 percent reactor power, control rod reactivity worth is reduced such that the effects of a postulated rod drop are not sufficient to cause significant fuel damage (Figure 3-9 of Reference 7) and the automatic trips are not required. To minimize the potential for spurious gland seal exhauster trips that could result in a malfunction of the turbine gland sealing system, the exhauster trip is automatically bypassed above the low power setpoint associated with the rod worth minimizer (see Subsection 7.7.1.3.3.5). No automatic bypass of the condenser vacuum pump trip is provided since vacuum pumps are not operated above 10 percent reactor power.

15.4.9.5.3 Results

The calculated exposures from the Reference 18 design basis analysis are presented in Table 15.4.9-5 and are well within the guidelines of 10 CFR 50.67. Note the design basis analysis is based on an 18-month GE14 fuel cycle. The consequences of this accident have also been evaluated for the GNF3 24-month equilibrium core source term in Reference 14. The GE14 18-month results bound the GNF3 based accident. While the number of damaged rods is the same for both accidents, there are fewer effective rods per bundle for GE14; thus, the fraction of core damage is larger for GE14.

15.4.9.5.4 Evaluation of the Impact of Hydrogen Water Chemistry

The operation with HWC will increase radiation doses in the main steam lines due to carryover of Nitrogen N-16. For a 4 ppm final feedwater dissolved hydrogen concentration, the background radiation levels in the main steam lines may increase by a factor of up to eight (8). Therefore, the MSLRM will see an increase in the normal operating radiation levels while the reactor is at power. The MSLRMs have a high radiation alarm, trip, and isolation functions with setpoints based on an increased radiation level relative to the operating background to provide an early detection of gross release of fission products from fuel failures. Fermi 2 takes credit for the MSLRM initiated trip and isolation functions in the event of a control rod drop accident (CRDA). The MSLRM allowable value is specified in the Fermi 2 Technical Specifications as 3.6 times "full power background" with a nominal setpoint specified in the Technical Requirements Manual of three times "full power background."

As part of the HWC implementation at Fermi 2, it has been decided to keep the MSLRM allowable value at 3.6 times the "full power background" as stated in the Technical Specifications. However, the redefined "full power background" will include the effects of hydrogen injection. By redefining the "full power background" to include the effects of hydrogen injection, the MSLRM setpoint will have to be adjusted due to an increase in the "full power background" radiation levels. An increase in the "full power background" radiation level by a factor of up to eight (8) may thus require an MSLRM setpoint adjustment. However, by redefining the "full power background" to include the effects of hydrogen injection, the wording in the Technical Specifications and Technical Requirements Manual need not be changed.

The MSLRMs provide signals which isolate the reactor water sample system, trip condenser mechanical vacuum pumps, and trip gland seal exhausters when elevated (i.e. high-high) radiation levels are detected in the main steam lines. However, the only accident which takes credit for the MSLRM trip and isolation signals is the Control Rod Drop Accident (CRDA).

During this accident, the primary function of the MSLRM trip and isolation signals is to limit the potential fission product release pathways. During a CRDA, the reactor scram signal would be initiated by the neutron monitoring system.

The evaluation of the proposed MSLRMs setpoint adjustment (to account for background radiation change due to the HWC) from three times the "full power background" without the HWC to three times the "full power background" with HWC performed by GENE (Ref. 15) has concluded that such a change will not affect the radiological consequences of the CRDA, which are given in Table 15.4.9-5. GENE's evaluation of the design basis accident indicates that the adjusted MSLRM setpoint for HWC is still a fraction of the dose rate expected as a result of CRDA. Thus though the adjusted setpoint due to HWC may be higher by a factor of up to eight, a CRDA would still be detected by the MSLRMs, whether HWC is operating or not. Therefore on the basis of this evaluation, it is concluded that plant operation with or without hydrogen injection is justified for a MSLRM setpoint of up to 30 R/hr.

15.4.9.5.5 Evaluation of Impact of On-Line Noble Chem™ and Hydrogen Water Chemistry

On-Line Noble Chem™ (OLNC) injects a noble metal compound into reactor feedwater. This provides a catalytic environment that promotes the recombining of hydrogen and oxygen in the reactor coolant in the reactor and recirculation piping. OLNC works in conjunction with Hydrogen Water Chemistry (HWC) for controlling intergranular stress corrosion cracking (IGSCC). The catalytic nature of the OLNC process allows the use of lower hydrogen injection rates when compared to HWC alone. The lower hydrogen injection rates will result in lower amounts of N-16 being carried over into the main steam lines lowering the "full power background" radiation dose in the vicinity of the lines.

The reactor water sample system isolation, condenser mechanical vacuum pump trip, and gland seal exhauster trip functions of the main steam line radiation monitors (MSLRM) are specified in the Fermi 2 Technical Specifications. The Technical Requirements Manual specifies the setpoint as three times "full power background." The definition of "full power background" at the time of HWC implementation included the effects of hydrogen injection. As hydrogen will continue to be injected, that definition remains valid.

As part of OLNC implementation the MSLRM setpoints are adjusted to reflect the full power background radiation at the new hydrogen injection rates. Reference 15 concludes that plant operation is justified for a MSLRM setpoint of up to 30 R/hr. As the setpoints for OLNC with lower hydrogen injection rates will be lower than the setpoints for HWC alone, the evaluation in Reference 15 bounds the conditions for OLNC with lower hydrogen injection rates.

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19. NRC Regulatory Guide 1.183 Revision 0, "Alternative Radiological Source Terms For Evaluating Design Basis Accidents At Nuclear Power Reactors," July 2000.

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21. Federal Guidance Report No. 11, "Limiting Values of Radionuclide Intake and Air Concentration and Dose Conversion Factors for Inhalation, Submersion, and Ingestion," September 1988.

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23. Amendment 212, "Fermi 2 – Issuance of Amendment Re: Elimination of Main Steam Line Radiation Monitor Trip and Isolation Function," September 2018.

24. NEDC-33879P, Revision 2 "GNF3 Generic Compliance with NEDE-24011-P-A (GESTAR II)", March 2018.

TABLE 15.4.9-1 TYPICAL SEQUENCE OF EVENTS FOR CONTROL ROD DROP ACCIDENT

Approximate Elapsed Time (sec)	Event
-	Reactor is at a control rod pattern corresponding to maximum increment rod worth.
-	The Rod Worth Minimizer or operators are functioning within constraints of banked position withdrawal sequence (BPWS). The control rod that will result in the maximum incremental reactivity worth addition at any time in core life under any operating condition while employing the BPWS becomes decoupled from the control rod drive.
-	Operator selects and withdrawals the drive of the decoupled rod along with the other required control rods assigned to the banked-position group such that the proper core geometry for the maximum incremental rod worth exists.
-	Decoupled control rod sticks in the fully inserted position.
0	Control rod becomes unstuck and drops at the maximum velocity determined from experimental data (3.11 fps).
< 1 sec	Reactor goes on a positive period and initial power burst is terminated by the Doppler reactivity feedback.
-	The average power range monitor system (APRM) 120% power signal scrams reactor (conservative; in startup mode APRM scram would be operative + intermediate range monitor).
< 5 sec	Scram terminates accident.

TABLE 15.4.9-2 CONTROL ROD DROP ACCIDENT: EVALUATION PARAMETERS[a]

Reactor Power		3499 MWt
Radial Power Peaking Factor		1.7
Number of Failed Fuel Rods		1200
Fraction Melted Fuel Rods		0.77%
Fission Product Release Fractions:		
Gap:		
	Noble Gas	10%
	Iodine	10%
	Alkali Metals	12%
Melted Fuel:		
	Noble Gas	100%
	Iodine	50%
	Alkali Metals	25%
Transport Fractions RPV to Condenser:		
	Noble Gas	100%
	Iodine	10%
	Alkali Metals	1%
Transport Fractions Condenser to Environment:		
	Noble Gas	100%
	Iodine	10%
	Alkali Metals	1%
Condenser Release Rate		1% volume/day
Charcoal Bed Holdup for SJAE Release:		
	Krypton	8 hours
	Xenon	4.66 days
	Iodine/Particulate	Infinite
Dose Conversion Factors		FGRs 11 & 12[b]

a See Reference 18
b See References 21 and 22

TABLE 15.4.9-3 CONTROL ROD DROP ACCIDENT: EVALUATION PARAMETERS[a]

MCR Ventilation Parameters:

Emergency Filtration Credit	None
Ventilated Volume	252,731 ft^3
Shine Volume	56,960 ft^3
Normal Makeup Flow Rate	< 4,000 cfm

Atmospheric Dispersion, χ/Q (s/m^3), and Breathing Rate, BR (m^3/s), at EAB and LPZ:

	EAB χ/Q (s/m^3)	LPZ χ/Q (s/m^3)	BR (m^3/s)
0-2 hr	2.09E-4	4.86E-5	3.5E-4
2-8 hr	--	2.17E-5	3.5E-4
8-24 hr	--	1.45E-5	1.8E-4
24-96 hr	--	6.02E-6	2.3E-4
96-720 hr	--	1.71E-6	2.3E-4

Atmospheric Dispersion, χ/Q, Breathing Rate, BR, and Occupancy at MCR (South Intake):

	SJAE Release via RBHVAC Stack χ/Q (s/m^3)	Condenser Release via TBHVAC Stack χ/Q (s/m^3)	BR (m^3/s)	Occupancy
0-2 hr	7.33E-3	1.17E-3	3.5E-4	1.0
2-8 hr	5.59E-3	9.09E-4	3.5E-4	1.0
8-24 hr	2.35E-3	3.41E-4	3.5E-4	1.0
24-96 hr	1.66E-3	2.29E-4	3.5E-4	0.6
96-720 hr	1.26E-3	1.73E-4	3.5E-4	0.4

a See Reference 18

TABLE 15.4.9-4 CONTROL ROD DROP ACCIDENT: CORE ISOTOPIC INVENTORY[a]

Isotope	Inventory (Ci/MWt)	Isotope	Inventory (Ci/MWt)	Isotope	Inventory (Ci/MWt)
Kr-85	3.736E+02	Ru-106	1.558E+04	Ba-139	4.843E+04
Kr-85m	6.693E+03	Rh-105	2.624E+04	Ba-140	4.877E+04
Kr-87	1.343E+04	Sb-127	2.278E+03	La-140	5.079E+04
Kr-88	1.863E+04	Sb-129	8.507E+03	La-141	4.422E+04
Rb-86	4.767E+01	Te-127	2.244E+03	La-142	4.320E+04
Sr-89	2.609E+04	Te-127m	3.799E+02	Ce-141	4.477E+04
Sr-90	3.295E+03	Te-129	8.084E+03	Ce-143	4.142E+04
Sr-91	3.263E+04	Te-129m	1.639E+03	Ce-144	3.790E+04
Sr-92	3.463E+04	Te-131m	5.246E+03	Pr-143	4.041E+04
Y-90	3.405E+03	Te-132	3.823E+04	Nd-147	1.800E+04
Y-91	3.387E+04	I-131	2.657E+04	Np-239	5.051E+05
Y-92	3.497E+04	I-132	3.901E+04	Pu-238	8.162E+01
Y-93	2.656E+04	I-133	5.500E+04	Pu-239	1.041E+01
Zr-95	4.575E+04	I-134	6.078E+04	Pu-240	1.826E+01
Zr-97	4.322E+04	I-135	5.235E+04	Pu-241	3.847E+03
Nb-95	4.609E+04	Xe-133	5.412E+04	Am-241	4.902E+00
Mo-99	4.988E+04	Xe-135	1.451E+04	Cm-242	1.233E+03
Tc-99m	4.428E+04	Cs-134	4.793E+03	Cm-244	5.321E+01
Ru-103	4.183E+04	Cs-136	1.463E+03	Xe-138	4.680E+04
Ru-105	2.826E+04	Cs-137	4.270E+03		

a See Reference 18

TABLE 15.4.9-5 CONTROL ROD DROP ACCIDENT: RADIOLOGICAL EFFECTS[a]

EAB (rem TEDE)	LPZ (rem TEDE)	Control Room (rem TEDE)	Dose Contributor
0.030	0.015	0.250	Condenser release (1% volume per day)
2.770	0.650	2.800	Forced release via steam jet air ejector (SJAE) discharge
2.800	0.665	3.050	Conservative combination of release pathways
6.3	6.3	5.0	Regulatory Limits

EAB – Maximum 2 Hour Accumulated Dose
LPZ, Control Room – 30 Day Accumulated Dose

a See Reference 18

15.5 INCREASE IN REACTOR COOLANT INVENTORY

Only one transient was evaluated under the increase in reactor coolant inventory analytical category. However, this event may not always be analyzed on a cycle-specific basis, since it is normally bounded by the loss of feedwater heater event.

15.5.1 Inadvertent High Pressure Coolant Injection Startup

The inadvertent high pressure coolant injection (HPCI) activation or startup transient behaves similarly to the loss of feedwater heating event (Subsection 15.1.1). The high pressure coolant injection pumps are inadvertently started and the cold water injection results in an increase in inlet subcooling (or decrease in temperature) and a consequent increase in power.

15.5.1.1 Identification of Causes and Frequency Classification

15.5.1.1.1 Identification of Causes

Manual startup of the high pressure coolant injection (HPCI) system is postulated for this analysis; i.e., operator error is postulated.

15.5.1.1.2 Frequency Classification

This transient disturbance is categorized as an incident of moderate frequency.

15.5.1.2 Sequence of Events and Systems Operation

15.5.1.2.1 Sequence of Events

Table 15.5.1-1 lists the typical sequence of events. Similar to the loss of feedwater heating transient, this event results in the reactor core receiving colder water through the feedwater sparger. The reactor vessel initially receives an excess of feedwater flow (as during the feedwater controller failure) until the feedwater flow is reduced by the water level controls. The subcooling of the feedwater along with the excess flow result in an increase in core inlet subcooling which is usually less than that produced by the LFWH event. The increase in core inlet subcooling collapses the void content in the core, thus increasing the core average power due to the negative void coefficient. The increased subcooling also produces a power distribution change, shifting the axial distribution towards the bottom of the core. Because of this axial shift, voids begin to build up at the bottom again which acts as a negative feedback to the void collapsing process. Additional negative reactivity (doppler feedback) is applied when the fuel temperature increases. This feedback moderates the core power increase. This event also tends to flatten the radial power distribution.

The HPCI event is a relatively slow event. The reactor core power is essentially in steady state throughout the transient. The core power typically reaches its maximum value during the first half minute of the transient. This is attributable to the core inlet subcooling transient brought about by the excess feedwater flow.

15.5.1.2.2 Systems Operation

To properly simulate the expected sequence of events, the analysis of this incident assumes normal functioning of plant instrumentation and controls, specifically of the pressure regulator and the vessel level control that respond directly to this event.

Required operation of engineered safeguards, apart from what is described, is not expected for this transient event. The system is assumed to be in the manual flow control mode of operation.

15.5.1.3 Core and System Performance

15.5.1.3.1 Mathematical Model

The quasi-steady-state nature of this transient allows analysis using the 3-dimensional, coupled nuclear thermal-hydraulics core simulator model described in Reference 1. This model calculates changes in power level, power distribution, core flow, exposures, reactor thermal-hydraulic characteristics, and critical power ratio with spatially varying voids, control rods, burnable poisons, and other variables under steady-state conditions. For this transient, the time for reactivity insertion is greater than the fuel thermal time constant and core hydraulic-transport times. Therefore, the steady-state representation of the event's initial, final, and peak power state is adequate.

As described in Reference 2, the loss of feedwater heating event is demonstrated to be bounding by comparing the increase in core inlet subcooling due to feedwater temperature reduction from HPCI plus the increase in core inlet subcooling due to the excess feedwater from HPCI to the increase in core inlet subcooling for the LFWH event. If the HPCI increase is less than the LFWH increase, then the LFWH is bounding.

The enthalpy of the high pressure cold water supplied to the vessel, $h_{sparger}$, is determined by performing an energy balance on the feedwater line just downstream of the point of HPCI injection. Based on $h_{sparger}$, the core inlet subcooling due to feedwater temperature reduction from HPCI can be determined from an energy balance on the reactor vessel. The increase in core inlet subcooling due to the excess feedwater from HPCI is determined using the REDY point dynamic transient model described in Reference 1. The core inlet subcooling due to LFWH can be determined from an energy balance on the reactor vessel based on the post-event feedwater enthalpy.

If the HPCI event is not bounded by the loss of feedwater heating event, the cycle specific results are determined using the REDY point dynamic transient model described in Reference 1.

The REDY model is designed to predict associated transient behavior of this reactor. This model has been improved and verified through extensive comparison of its predicted results with actual BWR test data. Some of the significant features of the model are presented below.

a. A point kinetic model is assumed with reactivity feedbacks from control rods (absorption), voids (moderation), and Doppler (capture) effects.

b. The fuel is represented by three four-node cylindrical elements, each enclosed in a cladding node. One of the cylindrical elements is used to represent core average power and fuel temperature conditions, providing the source of Doppler feedback. The other two are used to represent hot spots in the core, and to simulate peak fuel center temperature and cladding temperature.

c. Four primary system pressure nodes are simulated representing the core exit pressure, vessel dome pressure, steam line pressure (at a point representative of the SRV location), and turbine inlet pressure.

d. The active core void fraction is calculated from a relationship among core exit quality, inlet subcooling, and pressure. This relationship is generated from multi-node core steady-state calculations. A second-order void dynamic model, with the void boiling sweep-time calculated as a function of core flow and void conditions, is also utilized.

e. Principal controller functions, such as feedwater flow, recirculation flow, reactor water level, pressure, and load demand, are represented, together with their dominant nonlinear characteristics.

f. The ability to simulate necessary reactor protection system functions is provided.

15.5.1.3.2 Input Parameters and Initial Conditions

The bounding conditions for this analysis are 100 percent power and maximum subcooling. The transient is simulated by programming a change in feedwater enthalpy corresponding to the maximum subcooling condition.

The water temperature of the HPCI system was assumed to be 40°F. Inadvertent startup of the HPCI system provides the greatest auxiliary source of cold water into the vessel. For the inadvertent HPCI startup transient, the lowest HPCI injection temperature of 40°F and a minimum enthalpy of 8 Btu/lb are used. The lower the HPCI injection temperature, the greater the subcooling increase. To inject at a temperature lower than 40°F, the operator would have to fail to use the heater to maintain the condensate tank temperature above 40°F. This would violate procedural requirements the operator is required to follow.

A higher HPCI temperature would still result in a water level considerably below the setpoint of the Level 8 trip and would result in a lower increase in heat flux.

15.5.1.3.3 Qualitative Results

If the cycle-specific analyses are required to be performed, then the results are documented in the cycle-specific supplemental reload licensing report. Table 15.5.1-1 lists the typical sequence of events.

The simulated transient event begins with the introduction of cold water into the feedwater sparger. Within 5 sec, the full HPCI flow is established at approximately 20 percent of the rated feedwater flow rate. Delays were not considered because they are irrelevant to the analysis.

Addition of cooler water to the core causes the neutron flux to increase. No violation of fuel limits occurs as a result of this event.

15.5.1.3.4 Consideration of Uncertainties

Important analytical factors, such as the feedwater temperature change, have been assumed to be at the worst conditions so that any deviations in the actual plant parameters will produce a less severe transient. Additionally, the HPCI flow rate is assumed to be 10 percent greater than its rated capacity.

15.5.1.4 Barrier Performance

A slight pressure reduction from initial conditions occurs; therefore no further evaluation is required, as reactor coolant pressure boundary (RCPB) margins are maintained.

15.5.1.5 Radiological Consequences

Since no radioactivity is released during this event, a detailed evaluation is not required.

15.5 INCREASE IN REACTOR COOLANT INVENTORY

REFERENCES

1. General Electric Co., "General Electric Standard Application for Reactor Fuel, GESTAR II," NEDE-24011-P-A, (Latest Approved Revision as identified in the COLR).
2. General Electric Co., “Determination of Limiting Cold Water Event,” NEDC-32538-P-A, February 1996.

TABLE 15.5.1-1 TYPICAL SEQUENCE OF EVENTS FOR INADVERTENT HIGH PRESSURE COOLANT INJECTION PUMP START

Estimated Time (sec)	Event
0	The HPCI cold water injection is simulated.
5	Full flow is established for HPCI.

15.6 DECREASE IN REACTOR COOLANT INVENTORY

Four events are evaluated under the decrease in reactor coolant inventory analytical category:

a. Instrument line pipe break

b. Steam system pipe break outside containment

c. Loss of coolant accident inside containment

d. Feedwater line break outside containment

None of these events are analyzed on a cycle-specific basis. A qualitative description of results is provided for those events determined to be nonlimiting from a core performance standpoint.

15.6.2 Instrument Line Pipe Break

There is no specific event or circumstance identified that results in the failure of an instrument line. First, the line is constructed seismically so that it will not fail. Second, if the line did fail, the check valves provided would prevent flow out of the break. However, for the sake of conservatism and for the purpose of evaluating a small line rupture, the failure of an instrument line is assumed to occur between the check valve and the primary containment. This highly unlikely failure is postulated only for the sake of presenting an analysis of the consequences of a small line rupture.

This event involves a postulated small steam line or liquid line pipe break inside or outside primary containment but within a controlled release structure. To bound the event, it is assumed that a small instrument line instantaneously and circumferentially breaks at a location where it may not be possible to isolate it and where immediate detection is not automatic or apparent. This event is far less limiting than the postulated events in Subsections 15.6.4, 15.6.5, and 15.6.6.

This postulated event represents the envelope evaluation for small line failure inside and outside containment, relative to sensitivity to detection.

Though beyond the design basis for Fermi 2, the NRC requested an analysis of an accident scenario that assumed a break of a reactor water level sensing line coincident with a single failure in the remaining instrumentation. The results of such an evaluation concluded that adequate time is available to allow proper mitigating actions to be taken to negate the effects of this scenario.

15.6.2.1 Identification of Causes and Frequency Classification

15.6.2.1.1 Identification of Causes

No specific event or circumstance is identified that results in the failure of an instrument line. These lines are designed to meet high quality engineering standards and strict seismic and environmental requirements. However, for the purpose of evaluating the consequences of a small line rupture, the failure of an instrument line is assumed.

15.6.2.1.2 Event Description

A circumferential rupture of an instrument line that is connected to the primary coolant system is postulated to occur outside the drywell but inside the secondary containment. This failure results in the release of primary system coolant to the secondary containment structure until the reactor is depressurized. This event could conceivably occur also in the drywell. However, the associated effects would not be as significant as those from a failure in the secondary containment.

15.6.2.1.3 Frequency Classification

This event is categorized as a limiting fault.

15.6.2.2 Sequence of Events and Systems Operation

15.6.2.2.1 Sequence of Events

The typical sequence of events for this accident is shown in Table 15.6.2-1.

15.6.2.2.2 Systems Operation

Normal plant instrumentation and controls are assumed to be fully operational during the entire plant transient to ensure positive identification of the break and safe shutdown of the plant. Minimum reactor and plant protection system operations are assumed for the analysis, e.g., minimum emergency core cooling system (ECCS) flow and pool cooling capability. As a consequence of the accident, the reactor is scrammed and the reactor vessel cooled and depressurized over a 5-hr period.

15.6.2.3 Core and System Performance

15.6.2.3.1 Qualitative Summary - Results

Instrument line breaks, because of their small size, are substantially less limiting from a core and system performance standpoint than the events examined in Subsections 15.6.4, 15.6.5, and 15.6.6. Consequently, instrument line breaks are considered to be bounded specifically by the steam line break (Subsection 15.6.4). Details of this calculation, including those pertinent to core and system performance, are discussed in detail in Subsection 15.6.4.

Since instrument line breaks result in a slower rate of coolant loss and are bounded by the calculations referenced above, the results presented here are qualitative rather than quantitative. Since the rate of coolant loss is slow, an orderly reactor system depressurization follows reactor scram, and the primary system is cooled down and maintained without ECCS actuation. No fuel damage or core uncovering occurs as a result of this accident.

15.6.2.3.2 Quantitative Results

Instrument line breaks, because of their small size, are substantially less limiting from a core and system performance standpoint than is the steam line break outside containment. Similarly, instrument line breaks are considered within the spectrum considered in ECCS performance calculations discussed in detail in Subsection 6.3.3. Therefore, all information concerning ECCS models employed, input parameters, and detailed results for a more limiting (steam line break) event may be found in Section 6.3.

15.6.2.3.3 Consideration of Uncertainties

The approach to conservative analysis of this event is discussed in detail for a more limiting case in Section 6.3.

15.6.2.4 Barrier Performance

15.6.2.4.1 General

The release of primary coolant through the orificed instrument line could result in an increase in secondary containment pressure and the potential of isolation of the normal ventilation system. The following assumptions and conditions are the basis for the mass loss during the 5-hr reactor shutdown period of this event.

a. Shutdown and depressurization are initiated 10 minutes after break occurs

b. Normal depressurization and cooldown of reactor pressure vessel occur

c. Line contains a 1/4-inch diameter flow restricting orifice inside the drywell

d. Moody critical blowdown flow model (Reference 1) is applicable, and flow is critical at the orifice.

The total integrated mass of fluid released into the secondary containment via the break during the blowdown is 25,000 lb. Of this total, 6000 lb flashes to steam. Release of this mass of coolant results in a containment pressure that is well below the design pressure.

15.6.2.4.2 Outside Containment Structure Effects

Refer to Subsection 3.6.2, Pipe Break Outside Containment.

15.6.2.5 Radiological Consequences

While the NRC has developed a standard review plan for this event, a specific regulatory guide calculation method has not been issued to specify unique design-basis assumptions. For this reason, only the realistic bases will be provided.

This analysis is bases on a realistic, but still conservative, assessment of this accident. A circumferential rupture of an instrument line that is connected to the primary coolant system is postulated to occur outside of the drywell. Operator action is assumed to occur at 10 minutes. Therefore, for 10 minutes, primary coolant flows into the reactor building at the maximum rate. At 10 minutes the reactor building is isolated, the standby gas treatment system (SGTS) is initiated, and the reactor is taken through a normal shutdown over a 5.4 hr period. It is assumed that saturated water flows into the instrument line, therein resulting in the maximum iodine release to the reactor building. If the water is subcooled, then there will be less flashing; and if the line connects to partially vaporized coolant, the activity level in the fluid will be less than in the saturated liquid due to steam carryover considerations. During the first 10 minutes prior to operator action, the activity releases from the break are based on coolant iodine concentrations which correspond to the Technical Specification maximum equilibrium concentration of 0.2 microcuries/gm dose-equivalent ^{131}I. After 10 minutes the coolant is assumed to contain additional iodine activity as a consequence of the release of "spiking activity" from the fuel during depressurization of the vessel. The specific models, assumptions, and program used for computer evaluation are described in Reference 2. Specific values of parameters used in the evaluation are presented in Table 15.6.2-2. The leakage path used in these calculations is shown in Figure 15.6.2-1.

15.6.2.5.1 Fission Product Release From Fuel

The quantity of activity released as a consequence of reactor scram and vessel depressurization is based in part on measurements during plant shutdowns (Reference 2). These measurements have been used to develop an empirical model that predicts, during the depressurization transient, ^{131}I releases of 0.42 Ci/ bundle for a 50 percent probability value to 2.14 Ci/bundle for the 95 percent probability value. For the purpose of this evaluation, the 95th percentile values are used. The release of other iodine isotopes is considered to be inversely proportional to the fission yields. For example, the 95th percentile spike activity for ^{132}I is:

$$^{132}\mathrm{I} = \frac{(2.14)\left(\mathrm{F}_{\gamma}\ ^{132}\mathrm{I}\right)}{\mathrm{F}_{\gamma}\ ^{132}\mathrm{I}}$$

These releases are assumed to occur from all 764 bundles. It is assumed that when depressurization is initiated at time 10 minutes, 15% of the total available spiking activity is immediately released to the reactor coolant. At any subsequent time, it is assumed that the cumulative fractional release to the coolant of the remaining 85% of spiking activity is equal to the fractional reduction in vessel pressure at that time.

15.6.2.5.2 Fission Product Release to the Environment

Fifty percent of the iodine activity in the coolant which flashes to steam is assumed to be removed by plateout in the reactor building, leaving 50% airborne. The activity airborne in the reactor building is presented in Table 15.6.2-3.

The activity airborne in the reactor building is assumed to be uniformly mixed in the air volume and released unfiltered to the environment through the ventilation system via the roof vent for the first 10 minutes. After initiation of the SGTS (at 10 minutes), flow to the environment is at the rate of 100 percent per day. The integrated isotopic activity released to the environment is presented in Table 15.6.2-4.

15.6.2.5.3 Results

The calculated exposures are presented in Table 15.6.2-5. The results are well below 10 CFR 100 requirements.

15.6.3 DELETED IN PREVIOUS REVISION

15.6.4 Steam System Piping Break Outside Containment

This event involves the postulation of a large steam line pipe break outside primary containment. It is assumed that the largest steam line instantaneously and circumferentially breaks at a location downstream of the outermost isolation valve. The plant is designed to immediately detect such an occurrence, to initiate isolation of the main steam lines, and to actuate the necessary protective features. This postulated event represents the envelope evaluation of steam line failures outside primary containment.

15.6.4.1 Identification of Causes and Frequency Classification

15.6.4.1.1 Identification of Causes

A main steam line break is postulated without identification of the cause. These lines are designed to high quality engineering codes and standards and to restrictive seismic and environmental requirements. However, for the purpose of evaluating the consequences of a postulated large steam line rupture, the failure of a main steam line is assumed to occur.

15.6.4.1.2 Frequency Classification

This event is categorized as a limiting fault.

15.6.4.2 Sequence of Events and Systems Operation

15.6.4.2.1 Sequence of Events

Accidents that result in the release of radioactive materials directly outside the primary containment are the results of postulated breaches in the reactor coolant pressure boundary or the steam power conversion system boundary. A break spectrum analysis for the complete range of reactor conditions indicates that the limiting fault event for breaks outside the containment is a complete severance of one of the four main steam lines. The sequence of events and approximate times required to reach the event are given in Table 15.6.4-1.

15.6.4.2.2 Systems Operation

A postulated guillotine break of one of the four main steam lines outside the primary containment results in mass loss from both ends of the break. The flow from the upstream side is initially limited by the flow restrictor upstream of the inboard isolation valve. Flow from the downstream side is initially limited by the total area of the flow restrictors in the three unbroken lines. Subsequent closure of the MSIVs further limits the flow when the valve area becomes less than the limiter area and finally terminates the mass loss when the full closure is reached. A discussion of plant and reactor protection system action and ESF action is given in Sections 6.3, 7.2, and 7.3. Figure 15.6.4-1 is a schematic of the steam flow system and the location of the break; and Figure 15.6.4-2 is the leakage path for the steam line break.

15.6.4.3 Core and System Performance

Quantitative results for this event (including mathematical models, input parameters, and consideration of uncertainties) are given in Section 6.3. The temperature and pressure transients that result from this accident are insufficient to cause fuel damage.

15.6.4.3.1 Input Parameters and Initial Conditions

Refer to Section 6.3 for initial conditions.

15.6.4.3.2 Results

There is no fuel damage as a consequence of this accident. Refer to Section 6.3 for ECCS analysis.

15.6.4.3.3 Consideration of Uncertainties

Sections 6.3 and 7.3 contain discussions of the uncertainties associated with the ECCS performance and the containment isolation system, respectively.

15.6.4.4 Barrier Performance

Since this break occurs outside the primary containment, barrier performance within the primary containment envelope is not applicable. Details of the results of this event can be found in Subsection 3.6.2, Pipe Break Outside Containment.

15.6.4.5 Radiological Consequences

The design basis analysis is based on NRC Standard Review Plan 15.6.4 and Regulatory Guide 1.5. The specific models, assumptions, and program used for computer evaluation are described in Reference 3. Specific values of parameters used in the evaluation are presented in Table 15.6.4-2. The design basis analysis is documented in Reference 12.

15.6.4.5.1 Fission Product Release From Fuel

There is no fuel damage as a result of this accident. The only activity available for release from the break is that present in the reactor coolant and steam lines prior to the break. In accordance with the Standard Review Plan 15.6.4, two cases have been analyzed. For Case 1, the analysis was performed for continued full power operation with a maximum equilibrium coolant concentration of 0.2 μCi/gm dose equivalent I-131. For Case 2, a maximum coolant concentration of 4.0 μCi/gm dose equivalent I-131 is used. This is based on a preaccident iodine spike caused by power changes. It was also conservatively assumed that the offgas release rate (after 30 minutes decay) was 350,000 μCi/sec (as modified by the methodology in Reference 3), and that noble gas activity was discharged into the environment for 10.5 seconds, up to full MSIV closure. The iodine concentration in the reactor coolant is given by (μCi/gm):

	Case 1	Case 2
^{131}I	0.074	1.47
^{132}I	0.67	13.4
^{133}I	0.49	9.89
^{134}I	1.34	26.8
^{135}I	0.73	14.7

Because of its short half-life, N-16 is not considered in the analysis.

15.6.4.5.2 Fission Product Transport to the Environment

The transport pathway is a direct unfiltered release to the environment. The MSIV detection and closure time of 10.5 sec results in a discharge of approximately 112,000 pounds from the break. Assuming that all the activity in this discharge becomes airborne, the release of activity to the environment is presented in Table 15.6.4-3.

15.6.4.5.3 Results

The calculated exposures for the design-basis analysis are presented in Table 15.6.4-4 and are a small fraction of the guidelines of 10 CFR 100.

15.6.5 Loss-of-Coolant Accidents (Resulting From Spectrum of Postulated Piping Breaks Within the Reactor Coolant Pressure Boundary) Inside Containment

This event involves the postulation of a spectrum of piping breaks inside primary containment varying in size, type, and location. The break type includes steam lines and/or liquid process system lines. This event is also coupled with severe natural environmental conditions, including earthquakes.

The event has been analyzed quantitatively in Sections 6.2, 6.3, 7.1, 7.3, 7.6, and 8.3. Therefore, the following discussion provides only new information not presented in the subject sections. All other information is covered by cross referencing.

The postulated event represents the envelope evaluation for liquid or steam line failures inside containment.

15.6.5.1 Identification of Causes and Frequency Classification

15.6.5.1.1 Identification of Causes

There are no realistic, identifiable events that would result in a pipe break inside the containment of the magnitude required to cause a LOCA coincident with a safe shutdown earthquake (SSE) plus single active component failure criteria requirements. The subject piping is designed to meet strict engineering codes and standards criteria, and to withstand severe seismic and environmental conditions. However, since such an accident provides an upper limit estimate to the resultant effects for this category of pipe break, it is evaluated without identification of the causes.

15.6.5.1.2 Frequency Classification

This event is categorized as a limiting fault.

15.6.5.2 Sequence of Events and Systems Operation

15.6.5.2.1 Sequence of Events

Following the pipe break and scram, the low low water level or high drywell pressure signal will initiate the HPCI system at time 0 plus approximately 30 sec. Note that HPCI injection may take as long as 60 sec assuming the maximum analyzed response time; however, this analysis does not depend on HPCI response time. The MSIV will begin closing on the low

low low level signal at time 0 plus approximately 0.5 sec. Additionally, the low low low water level or high drywell pressure signal will initiate the core spray system at time 0 plus approximately 30 sec and the low pressure coolant injection (LPCI) system at time 0 plus approximately 77 sec.

15.6.5.2.2 Systems Operation

Accidents that could result in the release of radioactive fission products directly into the containment are the results of postulated nuclear system, primary coolant pressure boundary pipe breaks. Sections 6.2 and 6.3 examine the possibilities for all pipe break sizes and locations, including the severance of small process system lines, the main steam lines upstream of the flow restrictors, and the recirculation loop pipe lines. The most severe nuclear system effects and the greatest release of radioactive material to the containment result from a complete circumferential break of one of the two recirculation loop pipe lines. In the case where a recirculation pipe breaks, all of the main steam lines are available for iodine deposition and the dose consequences are not maximized. In order to maximize the potential radioactive consequences, a steamline is assumed to break upstream of an inboard MSIV with a degraded ECCS and the maximum release of radioactive material to the containment. This deterministic sequence of events maximizes the dose consequences of a DBA LOCA and is discussed in Section 15.6.5.5. The minimum required functions of any reactor and plant protection system are discussed in Sections 6.2, 6.3, 7.3, 7.6, and 8.3.

15.6.5.3 Core and System Performance

15.6.5.3.1 Mathematical Model

The analytical methods and associated assumptions used in evaluating the consequences of this accident are considered to provide ultraconservative assessment of the expected consequences of this very improbable event. The details of these calculations, their justification, and bases for the models are developed in Sections 6.2, 6.3, 7.3, 7.6, and 8.3.

15.6.5.3.2 Input Parameters and Initial Conditions

Input parameters and initial conditions used for the analysis of this event are given in Table 6.3-6.

15.6.5.3.3 Results

Results of this event are given in detail in Sections 6.2 and 6.3. The temperature and pressure transients resulting from this accident are insufficient to cause perforation of the fuel cladding. Therefore, no fuel damage results from this accident. The containment integrity is maintained. Postaccident tracking instrumentation and control is ensured. Continued long term core and containment cooling is demonstrated. Radiological effects are minimized and kept within limits. Continued operator control and surveillance are examined and guaranteed.

15.6.5.3.4 Consideration of Uncertainties

This event was conservatively analyzed; see Sections 6.2, 6.3, 7.3, 7.6, and 8.3. In order to account for uncertainties in the accident, additional conservative assumptions were utilized in the analysis to maximize the dose consequences:

a. MSIV leakage is through the three shortest main steam lines. No leakage is assumed in the longest main steam line

b. The outboard steam lines are assumed to be at 554 F for the first 8 hours and decrease in four steps to 289 F at 96 hours

c. The inboard steam piping remains at 554 F through the duration of the accident

d. No hold up or deposition is credited in the secondary containment bypass leakage pathway

e. No mixing or hold up is credited in the secondary containment

f. The release points at the SGTS stack and the TBHVAC stack are modeled as ground level releases.

15.6.5.4 Barrier Performance

The design basis for the containment is to maintain its integrity and to experience normal stresses after the instantaneous rupture of the largest single primary system piping within the structure while also accommodating the dynamic effects of the pipe break at the same time an SSE is occurring. Therefore, any postulated LOCA does not result in exceeding the primary containment design limit. For details and results of the analyses, see Sections 3.6, 3.9, and 6.2.

15.6.5.5 Radiological Consequences

A schematic of the transport pathway is shown in Figure 15.6.5-1.

Edison's analysis of the radiological consequences of the design basis LOCA is consistent with the requirements of 10 CFR 50 and in accordance with Regulatory Guide 1.183. The analytical results were evaluated against the criteria contained in 10 CFR 50.67. Each criterion and fundamental assumption used in the analysis is, in itself, appropriately conservative. These criteria and assumptions, however, are used collectively and will likely result in substantially overestimating the potential exposures.

Among the assumptions that are used is that the primary containment is postulated to leak at a rate of 0.5 percent per day for the first 24 hours after the start of the postulated accident, then at a reduced rate of 0.25 percent per day for the remainder of the 30-day event.

The methods, assumptions, and conditions used to evaluate this accident are in accordance with those guidelines set forth in the NRC Standard Review Plan 15.0.1 and Regulatory Guide 1.183. The specific models, assumptions, and computer code used to evaluate this event on the bases of the above criteria are presented in References 7, 8 and 9. Specific values of parameters used in this evaluation are presented in Table 15.6.5-1.

15.6.5.5.1 Fission Product Release From Fuel

It is assumed, per Regulatory Guide 1.183 guidance, that core fission products are released consistent with the values shown in Table 15.6.5-1. Core activity at the start of the DBA-LOCA is an End-of-Cycle (EOC) condition with a core average burnup of 38.235 GWD/MTU, and based on an average initial enrichment of 4 percent. EOC is conservative in that I-131 is maximized. The powers model for natural deposition (incorporated in the RADTRAD code) is used, consistent with NUREG/CR-6604 and Regulatory Guide 1.183 methodology (Reference 7) to credit post-LOCA plateout in the drywell.

Activity deposited in containment can potentially be carried to the suppression pool. In order to assure that dissolved iodines remain in solution, the suppression pool water pH is maintained above 7 using sodium pentaborate injected into the reactor vessel using the Standby Liquid Control System. The SLCS is manually initiated, and injection is required to be complete within approximately 6 hours. The sodium pentaborate will reach the suppression pool through ECCS injection and spill through the break. The amount of sodium pentaborate solution that is required for the SLCS reactivity control function, and controlled per Technical Specifications, is sufficient to assure that the pH remains above 7 for the 30-day accident duration. For primary containment isolation purposes, the activity from the damaged core is assumed to begin to be released into the containment at 121 sec following the accident. This timing assumption recognizes conclusions derived from the source term studies described in NUREG-1465, Regulatory Guide 1.183 and Reference 4. During a DBA LOCA, the drywell and torus air volumes are uniformly mixed due to steam action driving the drywell volume into the suppression pool. However, for the first 2 hours of this accident it is conservatively assumed that no mixing between the drywell and suppression pool occurs. This concentrates the source term in the drywell air volume increasing the dose consequences to personnel. After 2 hours, the drywell and torus air volumes are modeled to instantaneously and homogeneously mix. Natural deposition of iodine particulate (aerosol) is credited in the primary containment utilizing the Powers natural deposition algorithm. No credit is taken for either suppression pool scrubbing or for the use of containment sprays.

15.6.5.5.2 Fission Product Transport to the Environment

The transport pathway consists of leakage from the primary containment to the secondary containment by several different mechanisms, as well as discharge to the environment through the standby gas treatment system (SGTS) at an elevated location and modeled as a ground level release. The SGTS filter efficiency for iodine removal is assessed as 99 percent. The assumed mechanisms for leakage from the primary containment are discussed below.

a. Containment leakage

The design basis leak rate of the primary containment and its penetrations to the secondary containment is 0.5 percent per day, reduced to 0.25 percent per day at 24 hours for the remaining duration of the accident. Ninety percent of the activity in the secondary containment escapes to the environment via SGTS which has a 99 percent efficiency. Ten percent of the activity in the secondary containment bypasses SGTS. The bypass leakage is released through the TBHVAC stack and modeled as a ground release. The duration of exfiltration during the drawdown of the secondary containment is 15 minutes after the 2-minute gap release. No credit is taken for mixing and holdup within the secondary containment structure. Figure 15.6.5-1 is an illustration of the release path to the environment.

b. Leakage from engineered safety feature (ESF) components outside the primary containment, which is filtered by the SGTS. The ECCS leakage is limited to 5 gpm for the 30-day duration of the accident. Two percent of the iodine is assumed to become airborne and is released as 97 percent elemental and 3 percent organic.

c. An MSIV leakage rate totaling 250 scfh, with a maximum of 100 scfh in one main steam line. The worst case single failure is a failure of an outboard MSIV to close in the broken line with the highest flow and shortest length outside primary containment. To credit activity removal in a main steam line, a steam line is modeled as two well mixed deposition nodes, as the formulations in AEB 98-03, Appendix A (Reference 8) are used. The settling velocity for aerosol particulate nuclides is a median velocity based on a Monte Carlo analysis; only horizontal piping is credited, and the aerosol settling area is assumed to be only the bottom half of this piping. For elemental iodine, the entire volume and inside surface area is available for deposition, the deposition velocity from the Cline report of Reference 9 was used because gravitational settling is not an applicable transport mechanism. No organic iodine removal is credited. There is no iodine removal credited in the broken steam line upstream of the inboard MSIV. Time dependent pipe wall temperatures are applied to the piping downstream of the inboard MSIV.

Shutdown cooling operation during the 30-day period after a LOCA would involve recirculation of the emergency core coolant water stored in the suppression pool. The emergency core cooling systems used would be the core spray system to cool the reactor core and the RHR system to remove the heat from the emergency coolant. Reactor core cooling with the core spray system is described in Subsection 6.3.2.2.3. Containment cooling with the RHR system is described in Subsection 5.5.7.3.3.

There is no storage of emergency coolant in these systems except in the suppression pool.

The two redundant core spray loops are not connected. The redundant RHR divisions are cross connected for LPCI injection with an isolation valve.

Non seismic piping systems connected to the core spray or RHR systems are seismically qualified up to the first seismic constraint beyond the isolation valve that separates the safety related and non seismic portions of the piping system, as discussed in Section 3.7.3.13. Relief valves on both the RHR and core spray systems discharge back to the suppression pool. The RHR heat exchanger vent lines also drain back to the suppression pool.

The ECCS pump manufacturer's design criteria and technical manuals state that expected leakage for the pump seals is essentially zero. Experience has shown that occasionally seals have a slight leakage when first started; after a short period, this leakage usually ceases.

Edison believes the leakage from the ECCS pump seals to be essentially zero. Industry-wide experience has shown no significant leakage through such pump seals. In spite of this experience and the pump manufacturer's design criteria, which strongly indicate the expected leakage through the seals to be insignificant, the radiological consequences of leakage of water from the emergency cooling water systems have been examined. Hence, in accordance with Appendix B of NRC Standard Review Plan 15.6.5, leakage of ECCS was assumed and a conservative leakage rate of 5-gpm was assigned. It was further assumed that 98 percent of ECCS coolant remains in an unflashed state and that SGTS filter efficiency is 99 percent. The resulting activity in the secondary containment thus undergoes reduction by a factor of five thousand before its release to the environment.

The iodine released to the primary containment includes 95 percent cesium iodine, 4.85 percent elemental iodine, and 0.15 percent organic forms. The assumption of this specification is predicated on maintaining the suppression pool pH 7.0 or higher. At pH below 7.0, elemental iodine may evolve from the water pool and invalidate this specification. The standby liquid control system (SLC) will be used to establish and maintain the pH of the suppression pool at 7.0 or higher. Operators will be directed to initiate SLC when high radiation levels and LOCA symptoms are detected in the primary containment. Due to the mixing action of the ECCS in the RPV, the suppression pool pH control will be effective within 6 hours.

15.6.5.5.3 Results

The calculated exposures for the design basis analysis are presented in Table 15.6.5-4 and are well within the guidelines of 10 CFR 50.67. Dose associated with coolant activity release in the first 121 sec of the accident is not included in this table. Its contribution to the accident dose is insignificant (on the order of 2 rem thyroid at the Exclusion Area Boundary). The control room dose analysis is found in Appendix 15A.

15.6.6 Feedwater Line Break Outside Containment

For the purpose of evaluating large liquid process line pipe breaks outside containment, the failure of a feedwater line is assumed to evaluate the response of the plant design to this postulated event. The postulated break of the feedwater line, which is the largest liquid line outside the containment, provides the envelope evaluation relative to this type of occurrence. The break is assumed to be instantaneous, circumferential, and downstream of the outermost isolation valve.

A more limiting event from a standpoint of core performance evaluation, feedwater line break inside containment, has been quantitatively analyzed in Section 6.3, Emergency Core Cooling Systems. Therefore, the following discussion provides only new information not presented in Section 6.3. All other information is covered by cross referencing to appropriate subsections in Chapter 6.

15.6.6.1 Identification of Causes and Frequency Classification

15.6.6.1.1 Identification of Causes

A feedwater line break is assumed without identification of the cause. The subject piping is designed to meet engineering codes and standards and severe seismic environmental requirements.

15.6.6.1.2 Frequency Classification

This event is categorized as a limiting fault.

15.6.6.2 Sequence of Events and Systems Operation

15.6.6.2.1 Sequence of Events

The typical sequence of events is shown in Table 3.6-6.

15.6.6.2.2 Systems Operation

The feedwater system operation is described in Subsection 3.6.2.2.2.

15.6.6.3 Core and System Performance

15.6.6.3.1 Qualitative Summary

The accident evaluation qualitatively considered in this subsection is considered to be a conservative and enveloping assessment of the consequences of the postulated failure (i.e., severance) of one of the feedwater piping lines external to the containment. The accident is postulated to occur at the input parameters and initial conditions given in Table 6.3-6.

15.6.6.3.2 Qualitative Results

The feedwater line break outside containment is less limiting than either the steam line breaks outside containment (analysis presented in Section 6.3 and Subsection 15.6.4) or the feedwater line break inside containment (analysis presented in Subsection 6.3.3). It is far less limiting than the design basis accident (the recirculation line break analysis presented in Subsections 6.3.3 and 15.6.5).

The reactor vessel is isolated on level 1 water level. HPCI, which activates at level 2, restores the reactor water level to normal elevation. The fuel is covered throughout the transient, and there are no pressure or temperature transients sufficient to cause fuel damage.

15.6.6.3.3 Consideration of Uncertainties

This event was conservatively analyzed, and uncertainties were adequately considered (see Section 6.3 for details).

15.6.6.4 Barrier Performance

Accidents that result in the release of radioactive materials outside the primary containment are the results of postulated breaches in the reactor coolant pressure boundary or the steam power conversion system boundary. A break spectrum analysis for the complete range of reactor conditions indicates that the limiting fault event for breaks outside containment is a complete severance of one of the main steam lines as described in Subsection 15.6.4.

15.6.6.5 Radiological Consequences

The analysis is based on a conservative assessment of this accident. The accident evaluation considered is an assessment of the consequences of a failure of the feedwater piping external to containment for the specific Fermi 2 system.

Specific values of parameters used in the evaluation are presented in Table 15.6.6-1. A schematic diagram of the break and the leakage path for this accident is shown in Figures 15.6.6-1 and 15.6.6-2.

15.6.6.5.1 Fission Product Release

There is no fuel damage as a consequence of this accident. In addition, an insignificant quantity of activity (compared to that existing in the main condenser hotwell prior to occurrence of the break) is released from the contained piping system prior to isolation closure.

In order to estimate the upper bounds of the dose consequences, it was assumed that the maximum Fermi Technical Specification limit for the primary coolant iodine concentration (0.2 microcuries per gram of dose equivalent I-131) exists at the time of the accident. In accordance with NUREG-0016 (Revision 1), an iodine carryover factor of 0.004 (0.4 percent carryover) was taken between the reactor coolant and the condenser hotwell. Noble gas activity in the condensate is negligible, since the air ejectors remove essentially all noble gas from the condenser.

15.6.6.5.2 Fission Product Transport to the Environment

The transport pathway consists of liquid release from the break, carryover to the turbine building atmosphere due to flashing and partitioning, and unfiltered release to the environment through the turbine building ventilation system.

Of the 1,484,907 lb of condensate released from the break, 237,779 lb flashes to steam, with an assumed iodine carryover of 100 percent. Of the activity remaining in the unflashed liquid, 5 percent is assumed to become airborne. Normally, all feedwater reaching the break location will have passed through condensate demineralizers that have a 90 percent iodine removal efficiency. However, as a result of the increased feedwater flow caused by the break, differential pressure across the demineralizers is assumed to initiate flow through the demineralizer bypass line. This bypass line then carries 15 percent of the total flow, resulting in an effective iodine removal efficiency for all flow of 76.5 percent.

Taking no credit for holdup, decay, or plate out during transport through the turbine building, the resultant release of dose- equivalent I-131 activity to the environment is 0.026 curie. The entire release is assumed to take place within 2 hr of the occurrence of the break.

15.6.6.5.3 Results

The calculated exposures for the realistic analysis are presented in Table 15.6.6-2 and are a small fraction of 10 CFR 100 guidelines.

15.6 DECREASE IN REACTOR COOLANT INVENTORY

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TABLE 15.6.2-1 TYPICAL SEQUENCE OF EVENTS FOR INSTRUMENT LINE BREAK

Estimated Time (mins)	Event
0	Instrument line fails.
0-10	Identification of break is attempted.
10	Activation of residual heat removal and initiation of orderly shutdown occurs.
300	Reactor vessel is depressurized and break flow is determined.

TABLE 15.6.2-2 INSTRUMENT LINE BREAK ACCIDENT PARAMETERS TABULATED FOR POSTULATED ACCIDENT ANALYSES[b]

Reactor Operating Condition	3499
Time for Operator to Isolate Reactor Building and Initiate Shutdown (min)	10
Time to Depressurize Vessel (hr)	5.0
Iodine Concentration in Coolant Prior to Break (μCi/g dose-equivalent Iodine 131)	0.2
Iodine Activity Available for Spiking during Depressurization (Ci/bundle)	
I-131	2.14
I-132	3.21
I-133	5.03
I-134	5.44
I-135	4.79
Reactor Water Mass (lbm)	6.07E+5
Coolant Release Rate vs. Time (lbm/s)	(a)
Iodine Removal by Plateout (%)	50
Holdup in Reactor Building before Building Isolated	No
Release Filtered before Reactor Building Isolation	No
Removal Rate via SGTS after Reactor Building Isolation (%/day)	100
SGTS Iodine Filter Effic. (%)	99
Release Height (m)	0
χ/Q at EA Boundary (sec/m^3)	1.23E-4
0-2 hours	
χ/Q at LPZ (sec/m^3)	
0-8 hours	9.83E-6
8-24 hours	1.59E-6
24-96 hours	1.18E-6
96-720 hours	5.92E-7

Note (a). NEDO-21142, RELAC Computer Code Manual.

(b) See Reference 10

TABLE 15.6.2-3 INSTRUMENT LINE FAILURE: ACTIVITY AIRBORNE IN THE REACTOR BUILDING (CURIES)

Isotope	10 Min*	1 Hour	2 Hours	8 Hours	1 Day	4 Days	30 Days
I-131	1.0E-20	1.26E+00	2.03E+00	2.74E+00	1.33E+00	5.08E-02	2.84E-14
I-132	1.0E-20	1.69E+00	2.26E+00	6.92E-01	2.76E-03	4.29E-14	1.00E-20
I-133	1.0E-20	2.93E+00	4.63E+00	5.37E+00	1.62E+00	7.24E-03	1.00E-20
I-134	1.0E-20	2.40E+00	2.49E+00	8.21E-02	1.32E-07	1.00E-20	1.00E-20
I-135	1.0E-20	2.72E+00	4.10E+00	3.31E+00	3.16E-01	8.00E-06	1.00E-20
Total	1.0E-20	1.10E+01	1.55E+01	1.22E+01	3.26E+00	5.80E-02	2.84E-14

* No holdup is assumed until reactor building isolation at 10 minutes.

TABLE 15.6.2-4 INSTRUMENT LINE FAILURE: ACTIVITY RELEASED TO THE ENVIRONMENT (CURIES)

Isotope	10 Minutes	1 Hour	2 Hours	8 Hours	1 Day	4 Days	30 Days
I-131	1.06E-02	1.08E-02	1.15E-02	1.87E-02	3.17E-02	4.34E-02	4.39E-02
I-132	9.56E-02	9.59E-02	9.67E-02	1.01E-01	1.02E-01	1.02E-01	1.02E-01
I-133	6.99E-02	7.04E-02	7.20E-02	8.74E-02	1.06E-01	1.17E-01	1.17E-01
I-134	1.91E-01	1.92E-01	1.93E-01	1.96E-01	1.96E-01	1.96E-01	1.96E-01
I-135	1.04E-01	1.05E-01	1.06E-01	1.18E-01	1.26E-01	1.27E-01	1.27E-01
Total	4.71E-01	4.73E-01	4.79E-01	5.21E-01	5.64E-01	5.86E-01	5.86E-01

TABLE 15.6.2-5 INSTRUMENT LINE FAILURE RADIOLOGICAL EFFECTS[b]

	Whole-Body Dose (rem)	Thyroid Inhalation Dose (rem)
Exclusion Area (915 m)	2.9(-5)[a]	1.9(-3)
Low-population zone (4827 m)	2.5(-6)	2.2(-4)

[a] 2.9(-5) = 2.9 x 10^{-5}.
[b] See Reference 10

TABLE 15.6.4.-1 TYPICAL SEQUENCE OF EVENTS FOR STEAM LINE BREAK OUTSIDE OF CONTAINMENT

Estimated Time (sec)	Event
0	Guillotine break of one main steam line occurs outside primary containment.
0.5	High steam line flow signal initiates closure of main steam line isolation valve.
<1.0	Reactor begins scram.
≤10.5	Main steam line isolation valves are fully closed.
15	Safety/relief valves open on high vessel pressure. The valves open and close to maintain vessel bottom pressure less than 1375 psi.
30	The RCIC and HPCI would initiate on low low water level (RCIC is considered unavailable; HPCI is assumed single failure and therefore would not be available).
80	Reactor water level inside shroud begins to drop slowly because of loss of steam through the safety/relief valves. Reactor bottom pressure remains less than 1375 psi.
555	ADS receives signal to initiate on low water level (level 1) signal. ADS bypass timer starts.
1155	All ADS timers timed out. ADS valves actuate. Vessel depressurizes rapidly.
1430	Low pressure ECCS systems are initiated. Reactor fuel is partially uncovered.
1475	Core is effectively reflooded and clad temperature heatup is terminated. There is no fuel rod failure. (Reference to Subsection 6.3.3)

TABLE 15.6.4-2 STEAM LINE BREAK ACCIDENT – PARAMETERS TABULATED FOR ACCIDENT ANALYSIS[a]

Power Level	3499 MWt
Reactor Operating Condition	Hot Standby
Iodine Concentration in Coolant (μCi/g dose-equivalent Iodine 131)	
Case 1	0.2
Case 2	4.0
MSIV Closure Time (sec)	10.5
Coolant Discharged from Break (lbm)	112,000
Fraction of Iodine in Released Coolant Assumed Airborne (%)	100
Noble Gas Release Rate prior to MSIV closure (μCi/sec after 30 min decay)	350,000
Holdup in Turbine Building	No
Release Height (m)	0
χ/Q at EA Boundary (sec/m^3)	
0-2 hours	2.09E-04
χ/Q at LPZ (sec/m^3)	
0-2 hours	4.86E-05

[a] See References 10 and 12

TABLE 15.6.4-3 STEAM LINE BREAK ACCIDENT: ACTIVITY RELEASED TO THE ENVIRONMENT (CURIES)

	Case 1[a]	Case 2[b]
Isotope	Activity	Activity
I-131	3.16	6.29(1)
I-132	2.87(1)	5.73(2)
I-133	2.1(1)	4.23(2)
I-134	5.73(1)	1.15(3)[c]
I-135	3.12(1)	6.29(2)
Total Halogens	1.41(2)	2.83(3)
Kr-83M	1.44(-1)	1.44(-1)
Kr-85M	2.6(-1)	2.6(-1)
Kr-85	7.97(-4)	7.97(-4)
Kr-87	8.41(-1)	8.41(-1)
Kr-88	8.5(-1)	8.5(-1)
Kr-89	3.59	3.59
Xe-131M	6.38(-4)	6.38(-4)
Xe-133M	1.24(-2)	1.24(-2)
Xe-133	3.51(-1)	3.51(-1)
Xe-135M	1.02	1.02
Xe-135	9.4(-1)	9.4(-1)
Xe-137	4.48	4.48
Xe-138	3.46	3.46
Total Noble Gases	1.59(1)	1.59(1)

[a] Case 1: Coolant concentration of 0.2 μCi/gm of I-131 DE.

[b] Case 2: Coolant concentration of 4.0 μCi/gm of I-131 DE.

[c] 1.15(3) = 1.15 x 10^3.

TABLE 15.6.4-4 STEAM LINE BREAK ACCIDENT: RADIOLOGICAL EFFECTS[a]

Case 1: Coolant concentration of 0.2 µCi/gm of I-131 DE

	Whole-Body Dose (rem)	Thyroid Inhalation Dose (rem)
Exclusion area (915 m)	1.53×10^{-2}	9.23×10^{-1}
Low-population zone (4827 m)	3.57×10^{-3}	2.15×10^{-1}

Case 2: Coolant concentration of 4.0 µCi/gm of I-131 DE

	Whole-Body Dose (rem)	Thyroid Inhalation Dose (rem)
Exclusion area (915 m)	2.93×10^{-1}	1.85×10^{1}
Low-population zone (4827 m)	6.82×10^{-2}	4.30×10^{0}

[a] See Reference 12

TABLE 15.6.5-1 LOSS-OF-COOLANT ACCIDENT – PARAMETERS TABULATED FOR POSTULATED ACCIDENT ANALYSIS

Reactor Power	3499
Initial Inventory and Release Fractions in Containment Atmosphere (%)	
Nobel Gases (2 min to 0.5 hrs, Gap Release)	5
Nobel Gases (0.5 hrs to 1.5 hrs, Early In-Vessel Release)	95
Halogens including Iodine (2 min to 0.5 hrs, Gap Release)	5
Halogens including Iodine (0.5 hrs to 1.5 hrs, Early In-Vessel Release)	25
Alkali Metals (2 min to 0.5 hrs, Gap Release)	5
Alkali Metals (0.5 hrs to 1.5 hrs, Early In-Vessel Release)	20
Tellurium Metals (2 min to 0.5 hrs, Gap Release)	0
Tellurium Metals (0.5 hrs to 1.5 hrs, Early In-Vessel Release)	5
Barium & Strontium (2 min to 0.5 hrs, Gap Release)	0
Barium & Strontium (0.5 hrs to 1.5 hrs, Early In-Vessel Release)	2
Noble Metals (2 min to 0.5 hrs, Gap Release)	0
Noble Metals (0.5 hrs to 1.5 hrs, Early In-Vessel Release)	0.25
Cerium Group (2 min to 0.5 hrs, Gap Release)	0
Cerium Group (0.5 hrs to 1.5 hrs, Early In-Vessel Release)	0.05
Lanthanides (2 min to 0.5 hrs, Gap Release)	0
Lanthanides (0.5 hrs to 1.5 hrs, Early In-Vessel Release)	0.02
Primary Containment Leak Rate (%/day)	
0 hrs to 24 hrs	0.5
24 hrs to 720 hrs	0.25
MSIV Leakage Rate (scfh)	
Maximum Allowable per Main Steam Line	100
Total	250
Iodine Species Distribution	
Cesium Iodine (aerosol)	0.95
Elemental	0.0485
Organic	0.0015
Iodine Species Fraction (ECCS Leakage)	
Aerosol	0.00
Elemental	0.97
Organic	0.03
Fraction of Containment Leakage which Bypasses SGTS (%)	10.0
Holdup in Secondary Containment	No
Reactor Building Volume (cu. ft.)	2,800,000

TABLE 15.6.5-1 LOSS-OF-COOLANT ACCIDENT – PARAMETERS TABULATED FOR POSTULATED ACCIDENT ANALYSIS

Duration of Exfiltration during Secondary Containment Drawdown (min) (does not include 2 minute gap release)	15
SGTS Iodine Efficiency (%)	99
ECCS Leakage in Secondary Containment	
Leak Initiation Time (min)	0
Leak Rate (gpm)	5
Fraction Flashed (%)	2
Filtered by SGTS	Yes
ECCS Fluid (gallons)	952,400
Drywell Air Volume (cu. ft.)	163,730
Torus Minimum Water Volume (cu.ft.)	117,160
Torus Air Volume (cu. ft.)	130,900
Reactor Water Mass (lbm) + Credited Portion of ECCS Piping	568,990+60,773
Control Room Intake (cfm)	
Filtered Intake	1800
Unfiltered Inleakage	173
Control Room Effective Intake Filter Efficiency (%)	99.75
Control Room Recirculation Rate (cfm)	1200
Control Room Recirculation Filter Efficiency (%)	95
Control Room Ventilated Volume	
Ventilation Volume (cu.ft.)	252,731
"Shine" Volume (cu.ft.)	56,960
Effective Release Height (m)	
SGTS Release	0
Bypass Leakage	0

TABLE 15.6.5-1 LOSS-OF-COOLANT ACCIDENT – PARAMETERS TABULATED FOR POSTULATED ACCIDENT ANALYSIS

χ/Q at EA Boundary (sec/m3)	
0-2 hours	2.09E-4
χ/Q at LPZ (sec/m3)	
0-8 hours	2.17E-5
8-24 hours	1.45E-5
24-96 hours	6.02E-6
96-720 hours	1.71E-6
Effective SGTS Release χ/Q for Control Room Using Most Favorable (South) Intake	
0-2 hours	6.18E-4
2-8 hours	4.53E-4
8-24 hours	1.88E-4
24-96 hours	1.26E-4
96-720 hours	8.70E-5
Effective TB Stack Release χ/Q for Control Room Using Most Favorable (North) Intake	
0-2 hours	4.75E-4
2-8 hours	3.78E-4
8-24 hours	1.45E-4
24-96 hours	9.80E-5
96-720 hours	7.19E-5
TB Stack ineligible for dual control room inlet credit	
Additional Reduction Factor for Dual Control Room Inlet (included in above SGTS CR χ/Q values)	1/4
Thyroid Inhalation DCF (rem/Ci)	FGR 11 and 12 Reference 5 & 6

TABLE 15.6.5-1 LOSS-OF-COOLANT ACCIDENT – PARAMETERS TABULATED FOR POSTULATED ACCIDENT ANALYSIS

Loss of Coolant Accident – Core Source Terms

Isotopic Nuclide	Decay Constant (hours)$^{-1}$	Release Fractions 0-0.5 hrs	Release Fractions 0.5-2 hrs	Initial Core Activity (Ci)	Isotopic Nuclide	Decay Constant (hours)$^{-1}$	Release Fractions 0-0.5 hrs	Release Fractions 0.5-2 hrs	Initial Core Activity (Ci)
Kr-85	7.376E-06	0.05	0.95	1.551E+06	Co-60	1.500E-05	0.00	0.0025	1.061E+06
Kr-85m	1.547E-01	0.05	0.95	2.337E+07	Mo-99	1,050E-02	0.00	0.0025	1.805E+08
Kr-87	5.451E-01	0.05	0.95	4.440E+07	Tc-99m	1.151E-01	0.00	0.0025	1.577E+08
Kr-88	2.441E-01	0.05	0.95	6.242E+07	Ru-103	7.353E-04	0.00	0.0025	1.525E+08
Xe-133	-5.506E-03	0.05	0.95	1.840E+08	Ru-105	1.561E-01	0.00	0.0025	1.084E+08
Xe-135	7.625E-02	0.05	0.95	7.183E+07	Ru-106	7.844E-05	0.00	0.0025	6.687E+07
I-131	3.592E-03	0.05	0.25	9.517E+07	Rh-105	1.960E-02	0.00	0.0025	1.027E+08
I-132	3.014E-01	0.05	0.25	1.376E+08	Ce-141	8.886E-04	0.00	0.0005	1.557E+08
I-133	3.332E-02	0.05	0.25	1.926E+08	Ce-143	2.100E-02	0.00	0.0005	1.429E+08
I-134	7.907E-01	0.05	0.25	2.109E+08	Ce-144	1.016E-04	0.00	0.0005	1.296E+08
I-135	1.049E-01	0.05	0.25	1.804E+08	Np-239	1.226E-02	0.00	0.0005	2.070E+09
Rb-86	1.548E-03	0.05	0.20	2.658E+05	Pu-238	9.012E-07	0.00	0.0005	6.358E+05
Cs-134	3.835E-05	0.05	0.20	2.933E+07	Pu-239	3.286E-09	0.00	0.0005	5.395E+04
Cs-136	2.205E-03	0.05	0.20	8.775E+06	Pu-240	1.210E-08	0.00	0.0005	7.789E+04
Cs-137	2.636E-06	0.05	0.20	1.761E+07	Pu-241	5.491E-06	0.00	0.0005	2.253E+07
Sb-127	7.502E-03	0.00	0.05	1.073E+07	Y-90	1.083E-02	0.00	0.0002	1.318E+07
Sb-129	1.605E-01	0.00	0.05	3.156E+07	Y-91	4.936E-04	0.00	0.0002	1.087E+08
Te-127	7.413E-02	0.00	0.05	1.073E+07	Y-92	1.958E-01	0.00	0.0002	1.168E+08
Te-127m	2.650E-04	0.00	0.05	1.451E+06	Y-93	6.863E-02	0.00	0.0002	1.368E+08
Te-129	5.975E-01	0.00	0.05	3.105E+07	Zr-95	4.514E-04	0.00	0.0002	1.640E+08
Te-129m	8.596E-04	0.00	0.05	4.608E+06	Zr-97	4.101E-02	0.00	0.0002	1.727E+08
Te-131m	2.310E-02	0.00	0.05	1.400E+07	Nb-95	8.217E-04	0.00	0.0002	1.651E+08
Te-132	8.864E-03	0.00	0.05	1.351E+08	La-140	1.721E-02	0.00	0.0002	1.702E+08
Sr-89	5.719E-04	0.00	0.02	8.342E+07	La-141	1.764E-01	0.00	0.0002	1.554E+08
Sr-90	2.715E-06	0.00	0.02	1.251E+07	La-142	4.496E-01	0.00	0.0002	1.495E+08
Sr-91	7.296E-02	0.00	0.02	1.063E+08	Pr-143	2.130E-03	0.00	0.0002	1.379E+08
Sr-92	2.558E-01	0.00	0.02	1.162E+08	Nd-147	2.630E-03	0.00	0.0002	6.281E+07
Ba-139	5.029E-01	0.00	0.02	1.706E+08	Am-241	1.830E-07	0.00	0.0002	3.516E+04
Ba-140	2.267E-03	0.00	0.02	1.642E+08	Cm-242	1.774E-04	0.00	0.0002	8.209E+06
Co-58	4.079E-04	0.00	0.0025	1.146E+06	Cm-244	4.366E-06	0.00	0.0002	5.826E+05

TABLE 15.6.5-2 HAS BEEN INTENTIONALLY DELETED

TABLE 15.6.5-3 HAS BEEN INTENTIONALLY DELETED

TABLE 15.6.5-4 LOSS-OF-COOLANT ACCIDENT: RADIOLOGICAL EFFECTS

Fermi Unit 2 LOCA

Offsite and Control Room Doses

EAB (rem TEDE)	LPZ (rem TEDE)	Control Room (rem TEDE)	DOSE CONTRIBUTOR
1.834	0.678	0.608	Filtered Primary Containment (PC) Leakage (SGTS Filtration Not Credited for First 15 minutes) [90% of L_A]
7.997	3.946	3.258	MSIV Leakage [250 scfh total all MS lines, 100 scfh max/line] & Unfiltered PC Leakage Bypassing Secondary Containment (SC) [10 % of L_A]
0.122	0.130	0.079	ECCS Leakage in Secondary Containment (SC) [5 gpm; 2% Flashing Fraction]
		0.040	Gamma Shine to Control Room (Direct Dose)
9.96	4.76	3.99*	Total Calculated Doses (173 cfm Unfiltered CR Inleakage)
25	25	5	Regulatory Limits

EAB – Maximum 2 Hour Accumulated Dose

LPZ, Control Room – 30 Day Accumulated Dose

* The total calculated dose reflects 30-day control room occupancy dose only. Control room access dose is computed separately in DC-6133 VOL I to be less than 1 rem TEDE, which is less than the GDC 19 limit of 5 rem that is separately applied to vital area access.

TABLE 15.6.6-1 FEEDWATER LINE BREAK ACCIDENT – PARAMETERS TABULATED FOR POSTULATED ACCIDENT ANALYSES

		Assumptions
I.	Data and assumptions used to estimate radioactive source from postulated accidents	
	A. Power level	3499
	B. Burnup	NA
	C. Fuel damaged	None
	D. Release of activity (dose- equivalent I-131), curies	0.026
	E. Iodine fractions	
	(1) Organic	0
	(2) Elemental	1
	(3) Particulate	0
	F. Reactor coolant activity (dose- equivalent I-131), microcuries per gram	0.2
II.	Data and assumptions used to estimate activity released	
	A. Primary containment leak rate (percent/day)	NA
	B. Secondary containment leak rate (percent/day)	NA
	C. Isolation valve closure time (sec)	NA
	D. Adsorption and filtration efficiencies	
	(1) Organic iodine	NA
	(2) Elemental iodine	NA
	(3) Particulate iodine	NA
	(4) Particulate fission products	NA
	E. Recirculation system parameters	NA
	(1) Flow rate	NA
	(2) Mixing efficiency	NA
	(3) Filter efficiency	NA
	F. Containment spray parameters (flow rate, drop size, etc.)	NA
	G. Containment volumes	NA
	H. All other pertinent data and assumptions	None
III.	Dispersion data	
	A. Boundary and LPZ distance (m)	915/4827
	B. χ/Q's for time intervals of	
	(1) 0 - 2 hr - SB/LPZ	Table 15A-2
IV.	Dose data	
	A. Peak activity concentrations in containment	NA
	B. Doses	Table 15.6.6-2

TABLE 15.6.6-2 FEEDWATER LINE BREAK: RADIOLOGICAL EFFECTS

	Whole-Body Dose (rem)	Thyroid Inhalation Dose (rem)
Exclusion Area (915 m)	4.5(-7)[a]	1.6(-3)
Low-population zone (4827 m)	5.1(-8)	1.8(-4)

[a] 4.5(-7) = 4.5 x 10^{-7}.

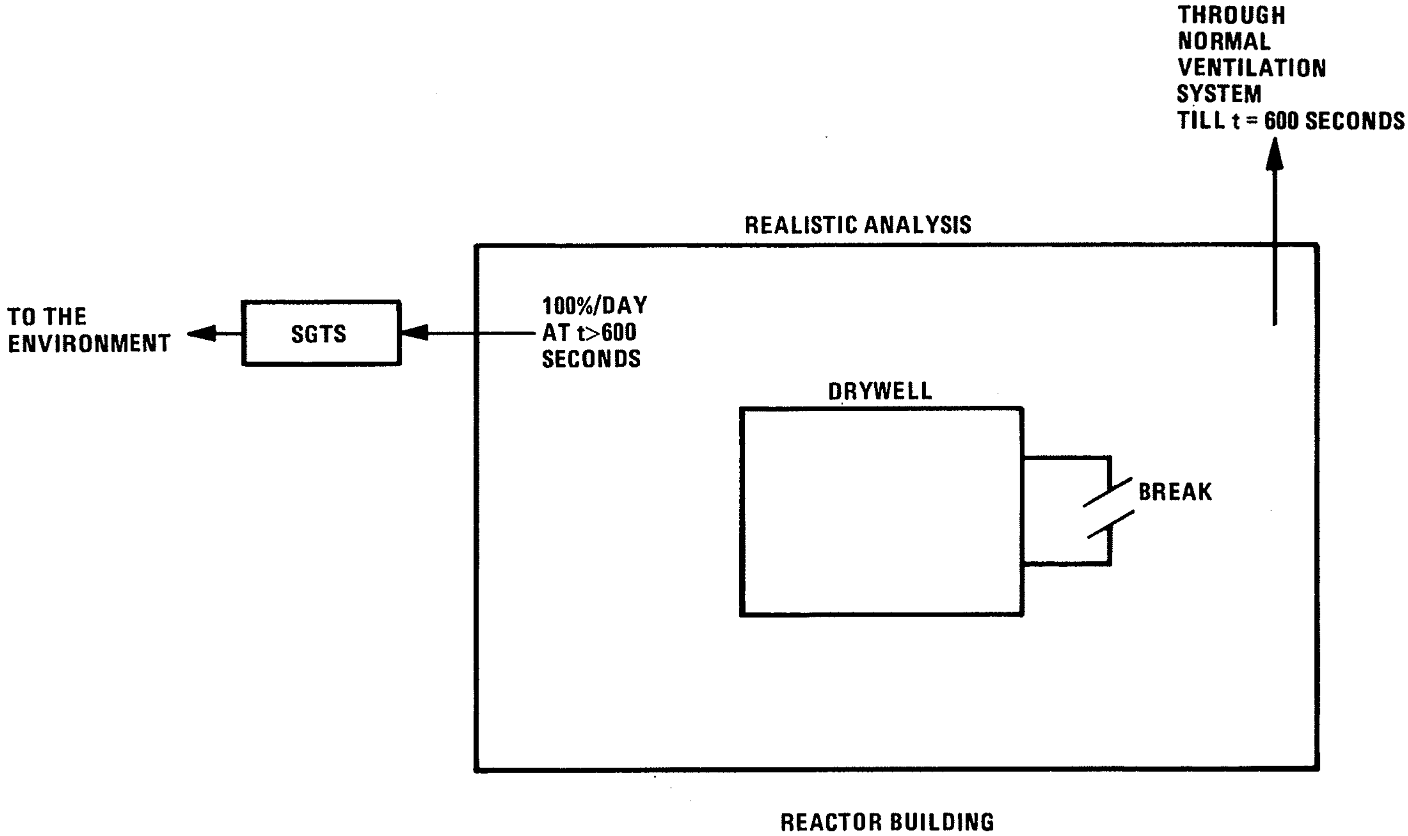

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FIGURE 15.6.2-1

LEAKAGE PATH FOR INSTRUMENT LINE BREAK

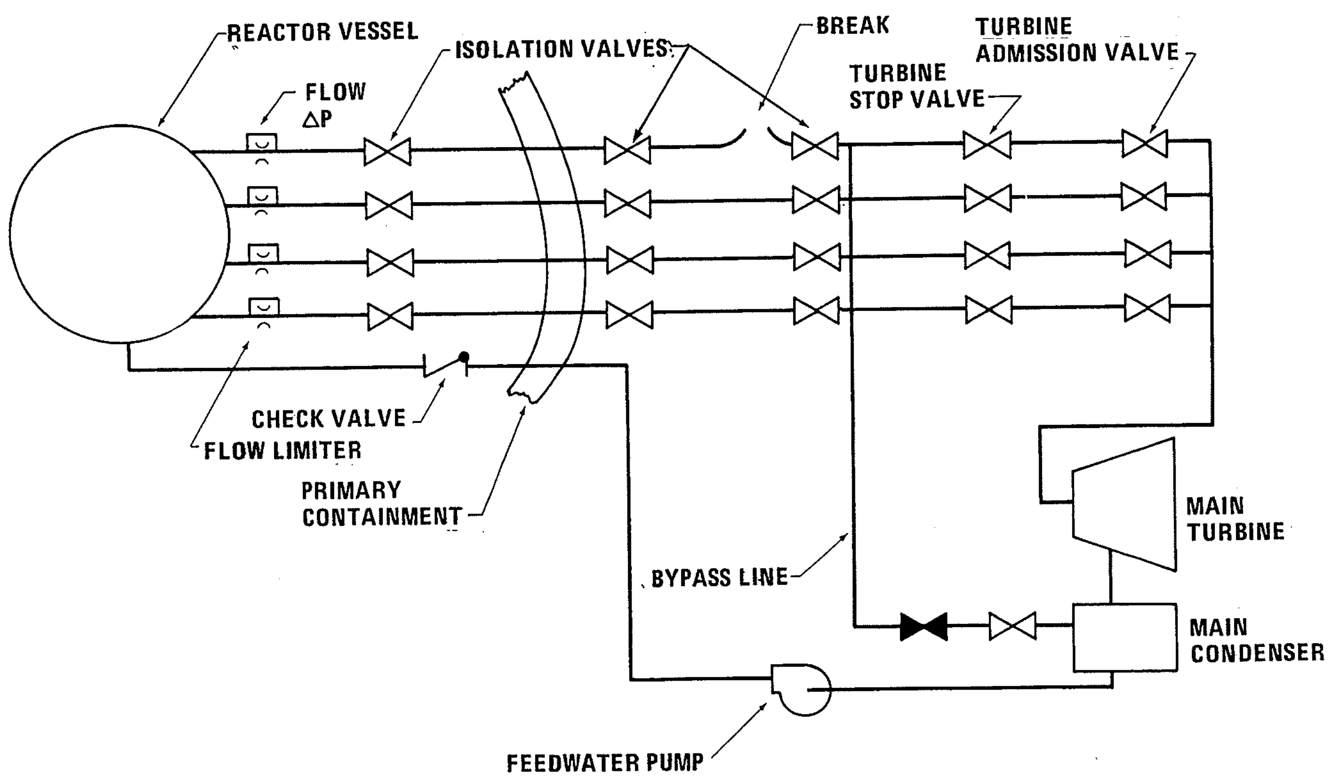

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FIGURE 15.6.4-1

STEAM FLOW SCHEMATIC

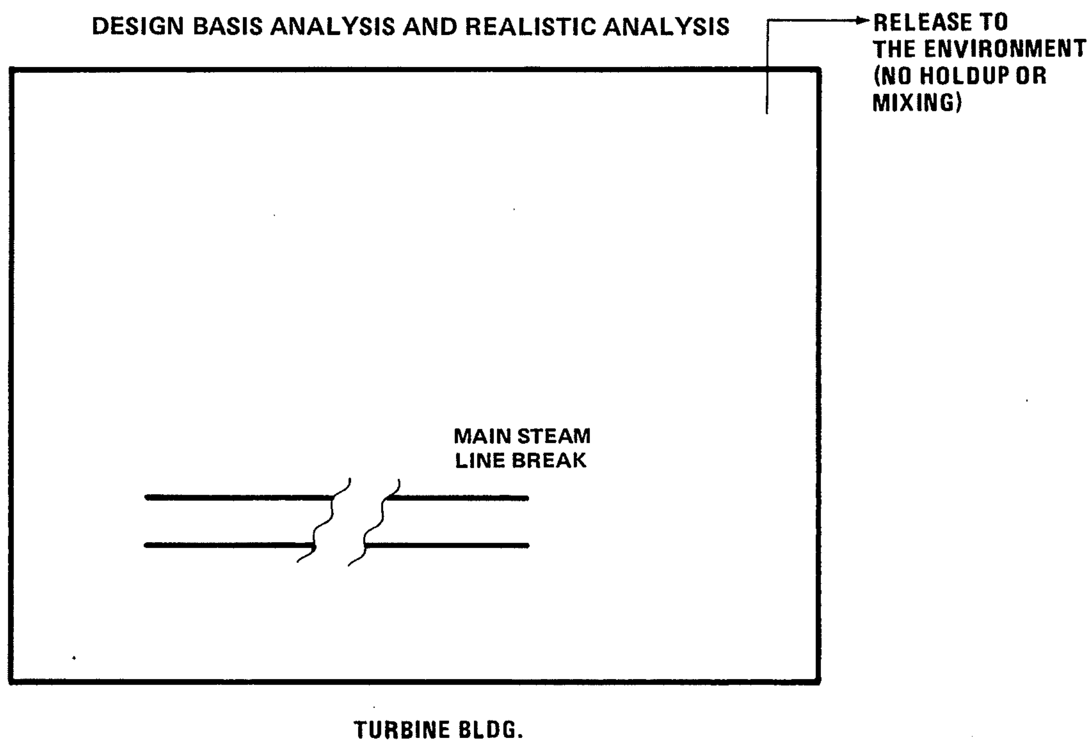

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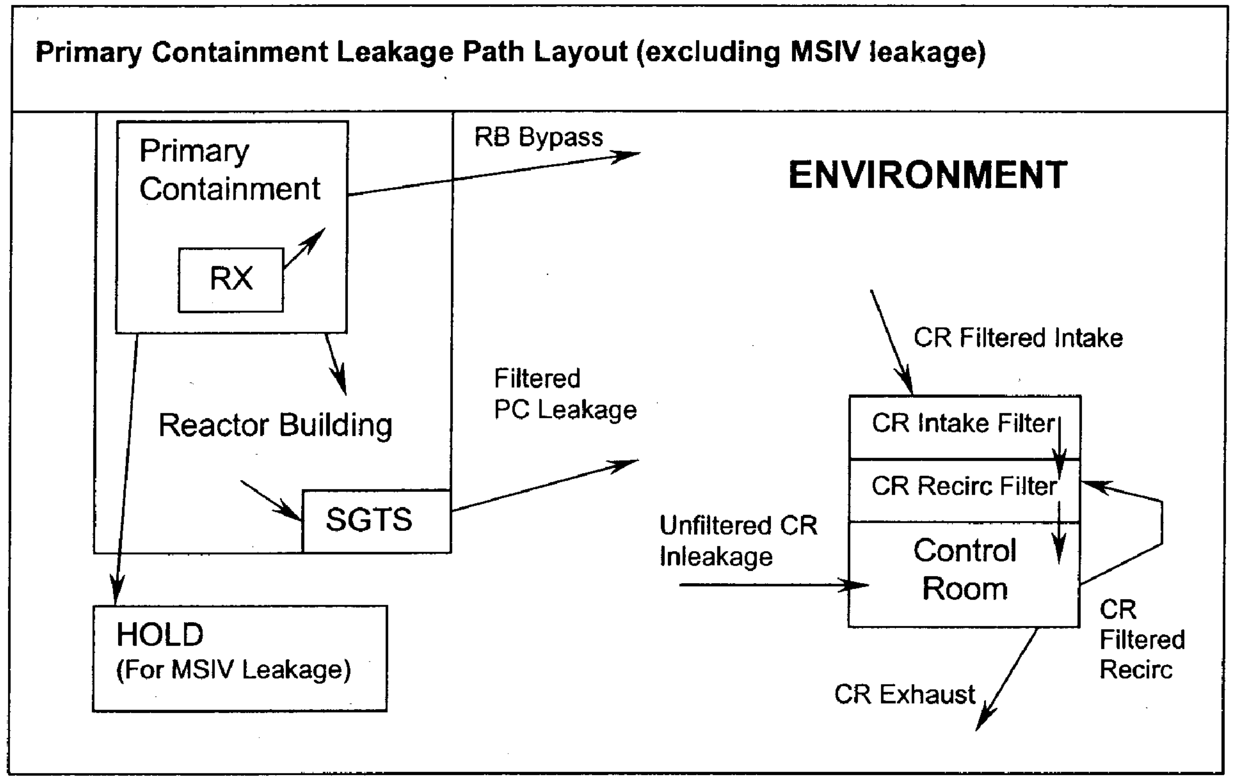
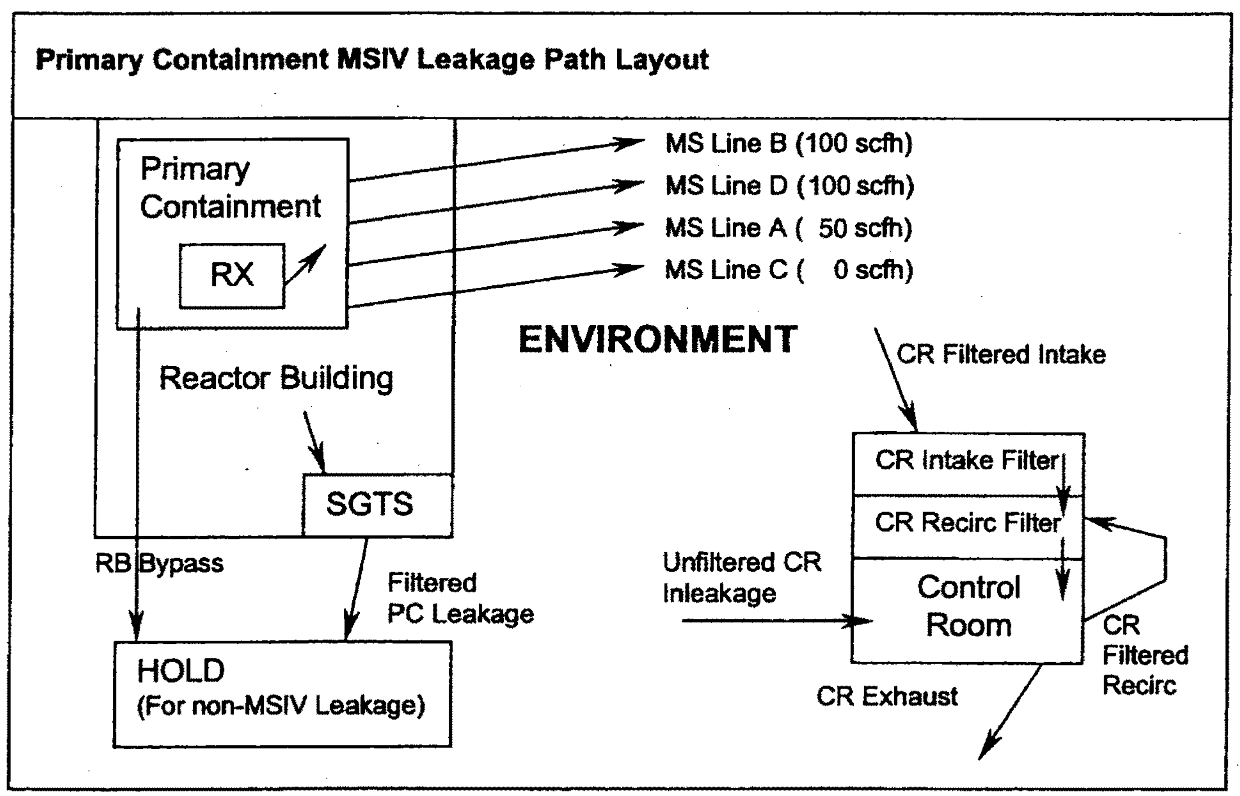
FIGURE 15.6.4-2

LEAKAGE PATH FOR MAIN STEAM LINE BREAK ACCIDENT





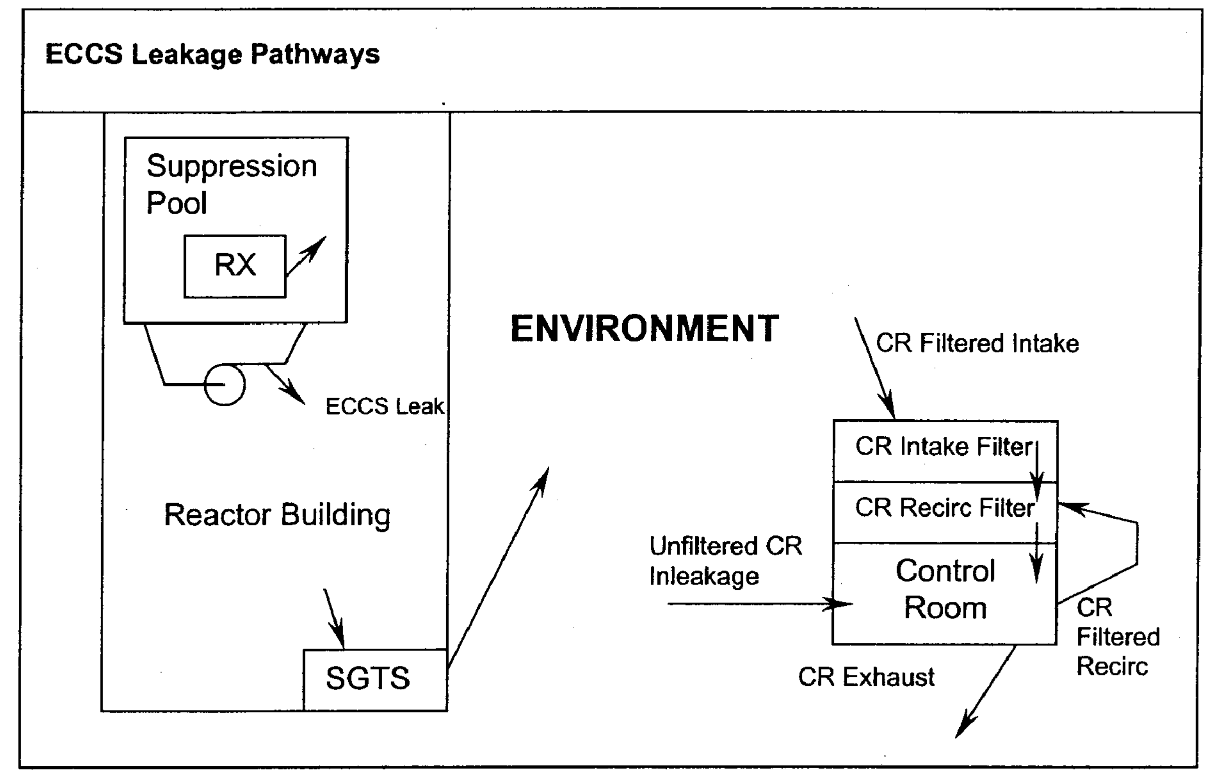


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FIGURE 15.6.5-1

LEAKAGE PATH FOR LOSS-OF-COOLANT ACCIDENT

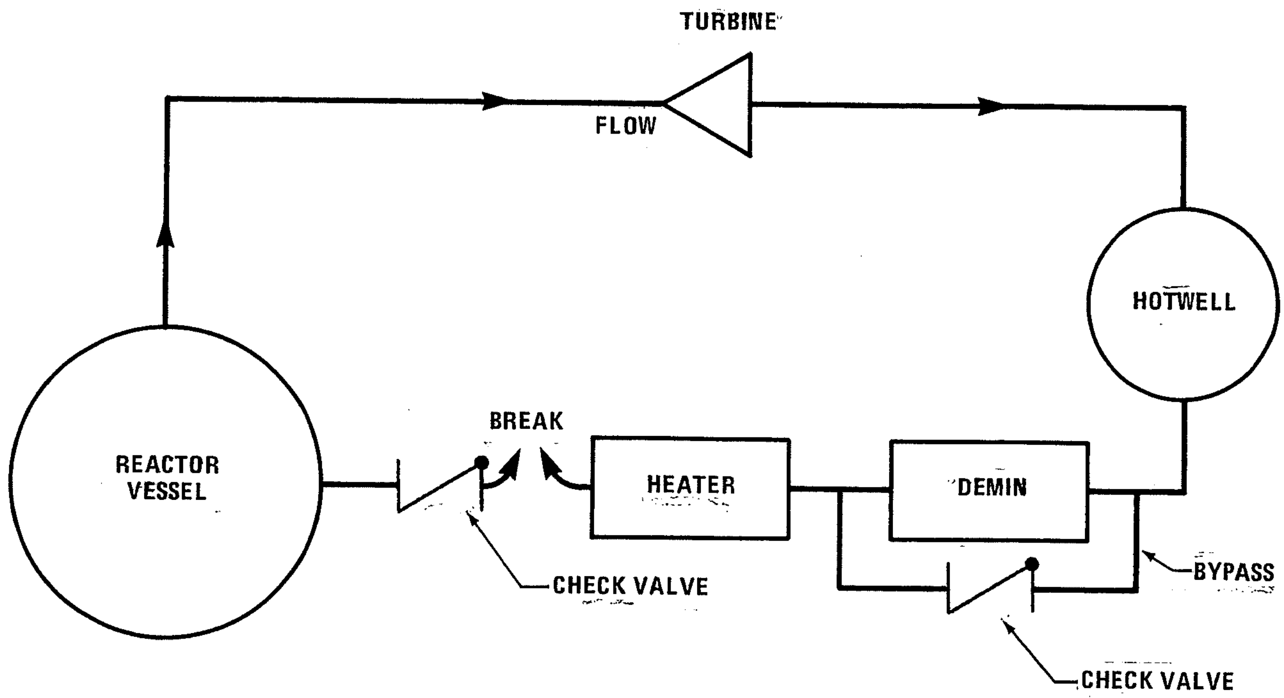

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FIGURE 15.6.6-1

POSTULATED LOCATION FOR FEEDWATER LINE BREAK OUTSIDE CONTAINMENT

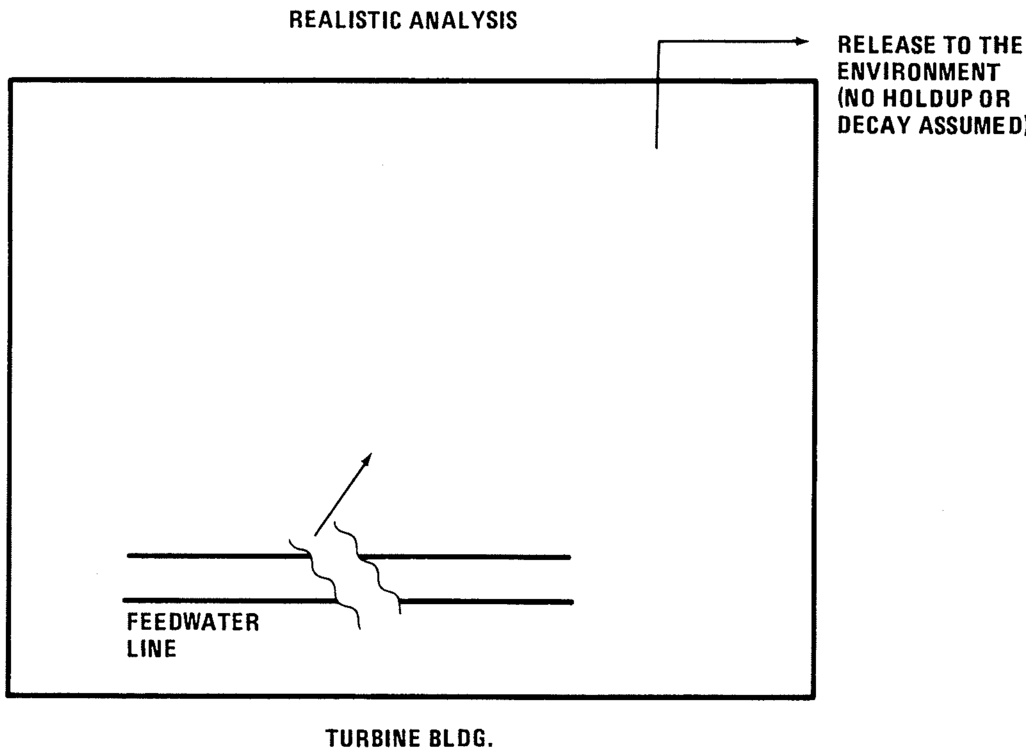

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FIGURE 15.6.6-2

LEAKAGE PATH FOR FEEDWATER LINE BREAK OUTSIDE CONTAINMENT

15.7 RADIOACTIVE RELEASE FROM SUBSYSTEMS AND COMPONENTS

Three events were evaluated under the radioactive release from subsystem and component analytical category:

a. Failure of main turbine steam air ejector lines

b. Hypothetical liquid and solid radwaste system accident

c. Fuel handling accident

None of these events are analyzed on a cycle-specific basis. A qualitative description of results is provided for those events determined to be nonlimiting from a core performance standpoint.

15.7.1 Failure of Main Turbine Steam Air Ejector Lines

This event involves a postulated break in the delay line downstream of the main turbine steam air ejector line.

15.7.1.1 Identification of Causes

An evaluation of those events that could cause a failure of the air ejector line indicates that a seismic event more serious than the system is designed to withstand is the only event that could rupture the lines. The lines are designed to withstand the effects of a hydrogen explosion.

The seismic induced failure is considered the most probable and most severe that the system is designed to prevent or accommodate. The seismic failure is the only conceivable event that could cause significant system damage.

The equipment and piping are designed to contain any hydrogen-oxygen detonation that has a reasonable probability of occurring. A detonation is not considered a possible failure mode.

The system is reasonably isolated from other systems or components that could cause any serious interaction or failure. The only credible event that could result in the release of significant activity to the environment is an earthquake.

An event more severe than the design requirements of the offgas system is arbitrarily assumed to occur, resulting in the failure of the offgas system. The design basis, description, and performance evaluation of the subject system are given in Section 11.3.

15.7.1.2 Sequence of Events and Systems Operation

15.7.1.2.1 Sequence of Events

It is assumed that the incident occurs while the reactor is operating at 3499 MWt. It is assumed that the delay line leading from the steam-jet air ejector to the offgas treatment system fails. This results in activity normally processed by the offgas treatment system being discharged directly to the turbine building and subsequently through the ventilation system to the environment. This failure results in a signal of loss of flow to the offgas system. Table 15.7.1-1 presents the typical sequence of events.

15.7.1.2.2 Systems Operation

In analyzing the postulated steam air ejector line failure, no credit is taken for the operation of plant and reactor protection systems, or engineered safety features. Credit is taken for functioning of normally operating plant instruments and controls and other systems only in assuming the following:

a. Capability to detect the failure itself is indicated by an alarmed increase in radioactivity levels seen by the area radiation monitoring system and in an alarmed loss of flow in the offgas system

b. Capability to isolate the system and shut down the reactor

c. Operational indicator and annunciators in the main control room.

15.7.1.3 Core and System Performance

The postulated failure results in a system isolation necessitating reactor shutdown because of loss of vacuum in the main condenser.

15.7.1.4 Barrier Performance

The postulated failure is the break of the delay line downstream of the steam-jet air ejector. No credit is taken for performance of secondary barriers.

15.7.1.5 Radiological Consequences

The NRC provides specific guidelines for the evaluation of this accident in Regulatory Guide 1.98.

15.7.1.5.1 Fission Product Release

It is assumed that the reactor is operating at 3499 MWt with a steam flow of 1.52 x 10^7 lb/hr. The noble gas release rate at the steam-jet air ejector was assumed to be 350,000 µCi/sec (at 30-minute delay) for a period of 30 days prior to the accident. The reactor water concentrations in mCi/g for iodine were assumed to be the following:

^{131}I	0.047
^{132}I	0.43
^{133}I	0.32
^{134}I	0.86
^{135}I	0.47

The iodine activity per pound of steam is assumed to be 2 percent of the iodine activity per pound of reactor coolant. An additional iodine decontamination factor of 200 is assumed to exist between the condenser water and the offgas piping. No credit for plate-out in the turbine building is assumed.

The design-basis noble gas release rate is 350,000 μCi/sec at 30 minutes. However, for this accident the mix is assumed to be approximately 7 sec old at the time of release. Therefore, the noble gas release rate at the break location is approximately 4.9 x 10^6 μCi/sec.

It is assumed that the steam-jet air ejector continues to operate for a period of 1 hr after the accident. Activation gases are neglected. The total radioactive release from the break is assumed to be released over a 1-hr period. Table 15.7.1-2 presents the parameters used in this analysis. A schematic diagram of the break and the leakage path for this accident is shown in Figure 15.7.1-1.

15.7.1.5.2 Fission Product Release to the Environment

The total activity released to the environment during the 1-hr period is shown in Table 15.7.1-3 and is well below 10 CFR 100 limits.

15.7.1.5.3 Results

The calculated exposures for the design basis analysis are presented in Table 15.7.1-4 and are well below 10 CFR 100 limits.

15.7.3 Hypothetical Liquid and Solid Radwaste System Accident Analysis

15.7.3.1 Problem

The purpose of the accident analysis for the liquid radwaste system is to determine the consequences of a hypothetical uncontrolled release of radioactive liquids from the system. Regulatory Guide 1.143 and Standard Review Plan 15.7.3 require that the analysis assess the effects of this release on the health and safety of the public. It is assumed that the initiating event for the accident is a seismic induced total failure of the liquid radwaste system. This assumption is conservative in comparison with the requirements of Regulatory Guide 1.29. Subsection 15.7.3.2 describes the basic method of the analysis, and Subsection 15.7.3.3 describes the source terms used in the analysis. Subsections 15.7.3.4 and 15.7.3.5 describe the liquid pathway analysis and the atmospheric pathway analysis, respectively. For the power uprates, the data was evaluated at 3499 MWt which resulted in an approximate 2 percent increase in the radiological values.

The pathways considered in evaluating the consequences of the accident are (a) releases to the atmosphere of radioiodines from the spilled liquid and (b) contamination of the potable water supply by transport of radionuclides in the ground water. The sources and characteristics of radioactive contamination of the potable water supply are identified in the analysis and traced through the course of the accidental release to Lake Erie via the site ground water aquifer. The resulting hypothetical radioactivity level was determined at the location of the release to Lake Erie and at the City of Monroe public water supply intake. For the atmospheric release pathway, the controlling dose would be the inhalation thyroid dose to a maximally exposed individual (or a child located at the exclusion radius).

The liquid and solid radwaste system, as described in Chapter 11, is the basis for determining the amounts and types of contaminated liquids contained in the radwaste system at the time of the hypothetical event.

15.7.3.2 Basic Methodology

It is first assumed that all radwaste tanks that contain liquids are filled to full rated capacity (i.e., above the tank overflow point). It is then assumed that an earthquake takes place and that the seismic event causes simultaneous ruptures of all the radwaste tanks, releasing their contents to the basement floor of the radwaste building. A list of these tanks, their volumes, and their contents is given in Table 15.7.3-1.

For the liquid pathway analysis, it is assumed that a massive failure of the basement floor occurs as a result of the seismic event. Since the normal ground water level is above the top of the basement floor of the radwaste building, the initial flow will be into the radwaste building until the water levels are equalized. It is assumed (Subsection 2.4.13.3) that water will enter the radwaste building for a 3- to 4-week period. During this time, equipment can be mobilized for pumping, storage, processing, and disposal of the radioactive liquid. However, credit for these actions is not taken in this analysis. It is also assumed that spilled radwaste liquid will be diluted by at least a factor of 10 to 1 by the incoming ground water. This dilution factor is based on the ratio of the total spilled liquid volume to the available free volume, when considering the radwaste basement as the holding basin.

After the water levels are equalized, it is conservatively assumed that the diluted liquid containing the radwaste will move into and through the aquifer at the same rate of flow and in the same direction as the existing ground water in the aquifer. The direction of movement will be to the east at a rate of 0.24 ft/day, as described in Subsection 2.4.13.2. The length of time required for the liquid to travel the 460-ft distance from the radwaste building to the Lake Erie shoreline is 1920 days.

The total time required for the spilled liquid to reach the water of Lake Erie is calculated as follows:

25.5 days	-	for water levels to equalize
1920.0 days	-	to travel to Lake Erie
40.0 days	-	to move upward through till and lake bottom
1985.5 days		TOTAL

In determining the radionuclide concentration entering Lake Erie, only the credit for dilution occurring in the radwaste building and decay in transit was taken. Although there are other factors that lower the radionuclide concentrations entering the lake, they were not applied to this analysis. These factors are the sorption and ion exchange processes that occur in the soil while the radionuclides in the ground water are transported from the radwaste building to the lake.

For the atmospheric pathway analysis, the inhalation thyroid dose to a maximally exposed individual (or a child located at the exclusion radius) was calculated on the basis of the iodine isotopes released from the failed tanks. It is conservatively assumed that the gaseous iodine partition factor for cold radwaste liquid is 0.01; regulatory guidance allows a partition factor of 0.001 for determining expected releases. The resulting gaseous radioiodine releases are given at the bottom of Table 15.7.3-1. The inhalation thyroid dose was calculated using the

0-1 hr, 5-percentile meteorology, $\chi/Q = 1.52 \times 10^{-4}$ sec/m^3 (see Table 2.3-27), a breathing rate of 1.7×10^{-4} m^3/sec (for a child), and the methodology of Regulatory Guide 1.109.

15.7.3.3 Source Terms

A summary of source-term radionuclides is given in Table 15.7.3-1. It shows the isotopic radioactive source terms in each tank.

15.7.3.3.1 Primary Coolant Activity

The concentrations of the various isotopes in the primary coolant activity (PCA) during normal plant operation are shown in Table 15.7.3-2. These concentrations are based on the data provided in NUREG-0016, Revision 1 (BWR-GALE Code; see Reference 1). The concentrations correspond to a failed fuel level of a noble gas release rate of 50,000 mCi/sec at 30 minutes decay (equivalent to the 15-mCi/sec/MWt value called for in Section 15.7.3 of the Standard Review Plan). The tritium concentration is based on a production rate of 0.03 Ci/MWt, half of which is entrained in the liquid radwaste stream. This rate is also based on data presented in the BWR-GALE Code (Reference 1). The resulting concentrations entering the radwaste system tanks are conservatively assumed to be 0.01 mCi/g.

15.7.3.3.2 Radwaste System Activities

The activities accumulated in the radwaste system inventory at the time of the event are based on the normal operational throughput rates of the radwaste system. The system is assumed to be operating at equilibrium and processing at the normal level. The detailed results described herein assume that the mode of radwaste system operation includes evaporators, the asphalt extruder solidification system, and the etched-disk filter/oil coalescer train are in service. Alternative calculations were made for the overall operational mode of precoat filters in combination with vendor processing and with the evaporators not in service. This latter mode produced airborne and Lake Erie isotopic concentrations which were lower than the first assumed mode. The activities are based on expected normal levels at the particular stage of the tank in the decontamination process. The basic normal radioactivity inputs to the radwaste system (e.g., collector tanks and phase separators) are based on the flow rates listed in the process flow diagram (Figure 11.2-15), along with their corresponding fractions of primary coolant activity (see Table 15.7.3-3). The fractions of primary coolant activity of the effluents from the floor drain collector, waste collector, and chemical waste tanks are determined by the weighted average of the composite streams entering the tanks.

The isotopic concentrations within the radwaste system have been determined on the basis of the normal input streams and the processing equipment decontamination factors listed in Table 15.7.3-4. The computer code CORN (Concentration of Radionuclides; see Reference 2) was used to generate the activity values for the 16 radwaste tanks assumed to fail (see Table 15.7.3-1). This program calculates the specific isotopic concentration in effluent streams and processing equipment by accounting for the buildup and decay of all influent isotopes as they flow through the system, including the contribution of radioactive daughter products. The concentrations of each nuclide vary depending on the various phases of waste processing incurred by the fluids contained in each tank and on the waste retention times. The isotopic concentrations for all powdered and bead resin sludges, etched disk filter backwashes, and evaporator concentrates were calculated on the basis of the buildup and decay of isotopes within the particular piece of process equipment.

The concentrations for the chemical waste tank, condensate phase separators, waste clarifier tank, waste surge tank, spent resin tank, chloride waste tank, centrifuge feed tank, and spent resin slurry feed tank are based on fractions of PCA. The factor of 0.02 for the chemical waste tank and the chloride waste tank is based on guidance from Reference 1 (BWR-GALE Code), Table 1-4. The table specifies this fraction of PCA for the lab drains and chemical lab waste activities, which are the plant input sources of these tanks. The other tank activities derived from PCA use a 0.002 factor, which is also based on Table 1-4 of Reference 2. The table specifies this factor for the cleanup phase separator decant, which is conservatively the highest radioactive input to each of these tanks.

The analysis assumes that all identified radionuclides are soluble in water and that those radionuclides trapped in the process resins by ion exchange remain within the resins and are not available for further transport. The analysis also assumes that for those tanks normally containing bead and powdered resin sludge (e.g., phase separators and feed tanks) the heavy, immobile sludge component is not available for transport to the aquifer. The remaining liquid component is represented by the values in Table 15.7.3-1.

The final source term analysis consisted of computing an average isotopic concentration for the accident (weighted according to each tank volume and concentration). These concentrations are listed in the second from last column of Table 15.7.3-1.

15.7.3.4 Liquid Pathway Analysis

As previously described, the liquid pathway analysis assumes a factor of 10 water dilution before the radioactivity leaves the radwaste basement and enters the aquifer. The resultant average diluted radionuclide concentrations (listed in the last column of Table 15.7.3-1) are, therefore, the aquifer entrance concentrations. Further attenuation through the aquifer is provided by the radioactive decay which occurs during the 1985.5-day travel time.

The concentration of each radionuclide as it enters Lake Erie is therefore calculated as follows:

$$\begin{bmatrix}\text{Concentration}\\ \text{entering Lake Erie}\end{bmatrix} = \begin{bmatrix}\text{Concentration}\\ \text{entering aquifer}\end{bmatrix} \times \exp\left[\frac{-0.693 \times \text{travel time}}{\text{Half-life}}\right]$$

The resultant concentrations from the liquid pathway were calculated at the closest intake of potable water from Lake Erie, which is at Monroe. There are no wells or other intakes for public water consumption between the site and the City of Monroe intake. The radionuclide concentrations attributable to this postulated accident at the potable water intake were assumed to be reduced by a factor of 77 due to dilution by lake water. (See Appendix B-3, Section III, of the Environmental Report.)

The isotopes, along with their half-lives, their average concentrations (C) in the tank before the release, their concentrations upon entering Lake Erie, and their concentrations at the potable water intake, are listed in Table 15.7.3-5. The average concentrations at the Monroe intake are compared with the maximum permissible concentrations (MPC) specified in Appendix B of 10 CFR 20. A summation ratio is obtained of the concentrations of the isotopes considered significant at the Monroe intake to the MPC for that isotope. Only those isotopes with concentrations greater than 10^{-15} $\mu Ci/cm^3$ were considered significant. The results produce a final ratio ($\sum$ C/MPC) of 0.0031, which is well within the NRC requirements in Appendix B of 10 CFR 20. These values are shown in Table 15.7.3-6.

15.7.3.5 Atmospheric Pathway Analysis

The thyroid dose from inhalation by a maximally exposed individual (or a child located at the exclusion radius) was calculated using the methodology of Regulatory Guide 1.109 and a χ/Q value based on the 0-1 hr, 5-percentile meteorology (see Table 2.3-27). The quantity of radioiodine released to the atmosphere was calculated by multiplying the weighted average concentrations by the total tank volume and the conservative partition factor of 0.01.

The inhalation dose to the maximally exposed individual from radioiodines released to the atmosphere by this liquid spill is 5.12 x 10^{-4} rem to the thyroid of a child.

15.7.4 Fuel-Handling Accident

15.7.4.1 Identification of Causes and Frequency Classification

15.7.4.1.1 Identification of Causes

Accidents that result in the release of radioactive materials directly to the containment can occur when the drywell is open. A survey of the various conditions that could exist when the drywell is open reveals that the greatest potential for the release of radioactive material occurs when the drywell head and reactor vessel head have been removed. In this case, radioactive material released as a result of fuel failure is available for transport directly to the containment.

Various mechanisms for fuel failure under this condition have been investigated. With the current fuel design the refueling interlocks, which impose restriction on the movement of refueling equipment and control rods, prevent an inadvertent criticality during refueling operations. In addition, the reactor protection system can initiate a reactor scram in time to prevent fuel damage for errors or malfunctions occurring during planned criticality tests with the reactor vessel head off. It is concluded that the accident that could result in the release of the most significant quantities of fission products to the containment during this mode of operation is the one resulting from the accidental dropping of a fuel bundle onto the top of the core. This accident bounds postulated fuel handling accidents that may occur over the fuel chute, over the spent fuel pool, or over the fuel preparation machine containing a fuel bundle.

This event occurs under non-operating conditions for the fuel. The key assumption of this postulated occurrence is the inadvertent mechanical damage to the fuel rod cladding as a consequence of the fuel bundle being dropped on the core while in the cold condition. Therefore, fuel densification considerations do not enter into or affect the accident results.

15.7.4.1.2 Frequency Classification

This event is categorized as a limiting fault.

15.7.4.2 Sequence of Events and Systems Operation

15.7.4.2.1 <u>Sequence of Events</u>

From a radiological viewpoint, the most severe fuel handling accident is the dropping of a fuel assembly onto the top of the core. The sequence of events is as follows:

	Event	Approximate Elapsed Time
a.	Fuel assembly is being handled by refueling equipment. The assembly and mast drops onto the top of the core	0
b.	Some of the fuel rods in both the dropped assembly and reactor core are damaged, resulting in the release of gaseous fission products to the reactor coolant and eventually to the reactor building atmosphere	0
c.	The reactor building ventilation radiation monitoring system alarms to alert plant personnel, isolates the ventilation system, and starts operation of the SGTS	< 1 Minute
d.	Operator actions begin	< 5 Minute

15.7.4.2.2 <u>Systems Operation</u>

Normally, operating plant instrumentation and controls are assumed to function, but credit is taken only for the isolation of the normal ventilation system and the operation of the SGTS. Operation of other plant or reactor protection systems or ESF systems is not expected.

The radiation monitor provided to detect a fuel-handling accident is described in Subsection 11.4.3.8.2.11. The monitor has a full scale step response of 3 sec or less. Prior to the elimination of response time testing requirements, the Fuel Pool Ventilation Radiation monitor response time requirement was 500 msec or 0.5 sec. An elapsed time of 2 sec from detection of radiation to trip contact operation is included in the analysis.

Following a fuel handling accident, the reactor building ventilation isolation valves are designed to be 90 percent closed in 1 sec and 100 percent or fully closed in 3 sec. A 2-sec margin is judged necessary to account realistically for operating conditions throughout the life of the plant, resulting in an assumed full closure time of 5 sec. Therefore, the elapsed time from detection to valve full-closure is 7 sec.

The transit time from the worst case (shortest path – 153.7 ft long) ventilation exhaust grill to the ventilation inboard isolation valve is 2.7 sec. This time is based on a maximum velocity of 57.6 fps with the isolation valve fully open. This is the highest velocity section of the duct run. The minimum duct transit time predicted, based on actual duct velocities, is 3.5 sec.

Assuming undegraded plant equipment, if a release occurs at the worst case exhaust grill, there is no expected release of the exhaust air to the environment. However, there is conservatism included in the assumed 2-sec detector response time and a 2-sec margin is added to the specified isolation valve stroke time for purposes of accounting for realistic conditions throughout the life of the plant.

The potential 4.3 sec of radioactivity release before SGTS actuation does not appreciably affect the analytical results given in this subsection. Even if no credit is given for isolation of the reactor building and actuation of the SGTS, the resultant calculated offsite doses (thyroid dose only is affected) are still a small fraction of those permitted by 10 CFR 50.67. The initial unfiltered release has a greater potential to affect onsite (operator) dose, however the results presented in this section demonstrate that the GDC19 criteria are still satisfied even without credit for the operation of the CREFS.

15.7.4.3 Core and System Performance

15.7.4.3.1 Mathematical Model

The analytical methods and associated assumptions used to evaluate the consequences of this accident are considered to provide a realistic, yet conservative, assessment of the consequences. The kinetic energy acquired by a falling fuel assembly may be dissi-pated in one or more impacts. To estimate the expected number of failed fuel rods in each impact, an energy approach is used.

The fuel assemblage is expected to impact on the reactor core at a small angle from the vertical, possibly inducing a bending mode of failure on the fuel rods of the dropped assembly. It is assumed that each fuel rod resists the imposed bending load by a couple consisting of two equal, opposite concentrated forces. Therefore, fuel rods are expected to absorb little energy prior to failure as a result of bending.

The energy absorption on successive impacts is estimated by considering a plastic impact. Conservation of momentum under a plastic impact shows that the fractional kinetic energy absorbed during impact is

$$1 - \frac{M_1}{M_1+M_2}$$

where M_1 is the impacting mass and M_2 is the struck mass.

15.7.4.3.2 Input Parameters and Initial Conditions

Three assumptions are used in the analysis of this accident.

a. The assemblage (fuel assembly plus NF-500 mast) is dropped from 34.0 feet (the maximum height allowed by the fuel handling equipment).

b. The entire amount of potential energy, including the energy of the entire assembly falling to its side from a vertical position (referenced to the top of the reactor core), is available for application to the fuel assemblies involved in the accident. This assumption neglects the dissipation of some of the mechanical energy of the falling fuel assembly in the water above the core and requires that the grapple head and three sections of the telescoping mast to remain attached to the falling assembly.

c. None of the energy associated with the dropped fuel assembly is absorbed by the fuel material (UO_2).

d. All fuel rods, including tie rods, were assumed to fail by 1 percent strain in compression, the same mode as ordinary fuel rods. For the fuel designs considered here, there is no propensity for preferential failure of tie rods.

15.7.4.3.3 Results

Because of the complex nature of the impact and the resulting damage to fuel assembly components, a rigorous prediction of the number of failed rods is not possible. For this reason, a simplified energy approach was taken and numerous conservative assumptions were made to assure a conservative estimate of the number of failed rods. The approach, which is described in NEDE-24011-P-A (Reference 13) is demonstrated below for the 9x9 fuel rod array bundle.

The number of failed rods was determined by balancing the energy of the dropped assemblage against the energy required to fail a rod. The wet weight of the dropped bundle is 562 pounds for the 9x9 fuel rod array bundle (617 pounds for the 7x7 fuel rod array bundle) and the wet weight of the grapple mast and head is 619 pounds. The drop distance is 34 feet. The total energy to be dissipated by the first impact is

$$E = (562 \text{ lb} + 619 \text{ lb}) (34 \text{ ft}) = (40{,}154 \text{ ft-lb}).$$

One half of the energy was considered to be absorbed by the falling assembly and one half by the four impacted assemblies.

No energy was considered to be absorbed by the fuel pellets (i.e., the energy was absorbed entirely by the non-fuel components of the assemblies). The energy available for clad deformation was considered to be proportional to the mass ratio:

$$\frac{\text{mass of cladding}}{(\text{mass of assembly} - \text{mass of fuel pellets})}$$

and is equal to a maximum of 0.510 for the fuel designs considered here.

The energy absorbed by the cladding of the four impacted assemblies is therefore

$$(20{,}077 \text{ ft} - \text{lbs})(0.510) = 10{,}239 \text{ ft} - \text{lbs}$$

Each rod that fails is expected to absorb approximately 200 ft-lb before cladding failure, based on uniform 1 percent plastic deformation of the cladding.

The number of rods failed in the four impacted assemblies is

$$N_F = \frac{(10{,}239 \text{ ft}-\text{lb})}{(200 \text{ ft}-\text{lb})} = 51 \text{ rods}$$

The dropped assembly was considered to impact at a small angle from vertical, subjecting all the fuel rods in the dropped assembly to bending moments. The fuel rods are expected to absorb little energy prior to failure as a result of bending. For this reason, it was assumed that all the rods in the dropped assembly fail. The total number of failed rods on <u>initial</u> impact was 74 + 51 = 125.

The assembly was assumed to tip over and result in a second impact horizontally on the top of the core from a height of one bundle length, approximately 160 inches. The remaining available energy was used to predict the number of additional rod failures. The available energy was calculated by assuming a linear weight distribution in the assembly with a point load at the top of the assembly to represent the fuel grapple weight.

$$
\begin{aligned}
E_2 &= W_G\,H_G + \int_0^{H_B} (W_B/H_B)\,y\,dy \\
&= W_G\,H_G + (0.5)\,W_B\,H_B \\
&= (619\text{ lb})(160/12) + (0.5)(562)\,(160/12) \\
&= 12{,}000\text{ ft-lb}
\end{aligned}
$$

As before, the energy was considered to be absorbed equally by the falling assembly and the impacted assemblies and the fraction available for clad deformation was 0.510. The energy available to deform clad in the impacted assemblies was

$$E_C = (0.5)(12{,}000\ ft-lb)\,(0.510) = 3{,}060\text{ ft}-\text{lb}$$

and the number of failures in the secondarily-impacted assemblies was

$$N_F = \frac{(3{,}060\text{ ft}-\text{lb})}{(200\text{ ft}-\text{lb})} = 15\text{ rods}$$

Since the rods in the dropped assembly were considered to have failed in the initial impact, the total failed rods in both impacts is 125 + 15 = 140.

Similar calculations can be performed for both the 7x7 and 8x8 fuel rod array bundles. The corresponding results indicate 111 failed rods for the 7x7 fuel rod array bundle and 117 failed rods for the 8x8 fuel rod array bundle.

Applied to the 10x10 fuel designs currently used in the Fermi 2 fuel cycle, the number of failed rods associated with a 34-ft drop is less than 166 fuel pins for a drop of a GE14 assembly (Reference 14) and less than 169 pins for a GNF3 bundle.

15.7.4.4 Barrier Performance

The reactor coolant pressure boundary and primary containment are assumed to be open. The transport of fission products from the secondary containment is discussed in Subsections 15.7.4.5.1 and 15.7.4.5.2 below.

15.7.4.5 Radiological Consequences

The original Fermi 2 design basis analysis evaluated drops of 7x7, 8x8, and 9x9 fuel types based on the guidance in the NRC Standard Review Plan 15.7.4 and Regulatory Guide 1.25. The Fermi 2 Fuel Handling Accident was subsequently re-analyzed in accordance with the methods and assumptions of NRC Regulatory Guide 1.183, Alternate Source Term, in order to establish a basis for distinguishing between secondary containment and control room isolation and filtration system operability requirements during the movement of irradiated fuel depending on whether or not the fuel is considered recently irradiated. The operability of ESF systems and subsystems previously required to mitigate the radiological consequences of fuel handling accidents is not necessary after a sufficient post-shutdown decay period has elapsed. Prior to this decay period, the fuel is classified as recently irradiated and operability requirements for systems and subsystems supporting secondary containment and control room integrity and filtration apply to the movement of fuel over the spent fuel pool and reactor vessel.

The analysis documented in Reference 8 evaluates the radiological consequences associated with the drop of a recently irradiated fuel bundle and also determines the duration of the post-shutdown decay period after which GNF3 and GE14 10x10 fuel bundle types would no longer be considered as recently irradiated. Dose calculations defining the required delay period for the 7x7, 8x8, and 9x9 fuel bundle types are not performed. These bundle designs have been long since retired hence their source terms have decayed sufficiently that their associated consequences are bounded by the 10x10 bundle design currently used in the Fermi 2 fuel cycle. As a result, the discussion of the radiological consequences associated with the 7x7, 8x8, and 9x9 fuel types hereafter has been deleted from Section 15.7.4.

The re-analysis of the Fermi Fuel Handling Accident provided an opportunity to take advantage of the Alternate Source Term (AST) as defined in NRC Regulatory Guide 1.183 (Reference 7). This regulatory guide contains a set of assumptions, methodologies, and acceptance criteria (different from Regulatory Guide 1.25) that may be used to evaluate the radiological consequences associated with the Chapter 15 design basis accidents. Concerning the Fuel Handling Accident, the new guidance has the advantage of smaller gap fractions, and larger pool decontamination factor (DF), and dose criteria that replace both the 10 CFR 50.100 whole body and thyroid dose limits with a limit on Total Effective Dose Equivalent (TEDE) based on 10 CFR 50.67.

The ability to credit the new AST assumptions depends on the burnup and operating history of the fuel. Specifically, use of the AST non-LOCA gap fractions is predicated on the assumptions of a peak rod average burnup up to 62 GWD/MTU and a peak rod average Linear Heat Generation Rate (LHGR) not exceeding 6.3 kW/ft for exposures above 54 GWD/MTU (Reference 7, Table 3). Thus, the ability of the fuel in a given cycle to meet the Reference 7 criteria is required to be verified prior to applying the definition of recently irradiated during refueling operations.

Reference 8 determines the radiological consequences associated with fuel handling accidents where the AST assumptions are valid considering both the drop of a recently irradiated fuel bundle 24 hours following a plant shutdown, and at a later time when the fuel is considered to be no longer recently irradiated. Based on the damage estimates for GE14 and GNF3 described in Subsection 15.7.4.3.3 above, the drop of the GE14 fuel type results in damage to a larger fraction of the core: 1.93 assembles for GE14 vs 1.91 assemblies for GNF3.

Since the GE14 fuel is still present while the fuel cycle is transitioned to a full core of GNF3, the analysis of consequences is conservatively based on the GE14 damage estimate and a common source term that is bounding for both fuel types (Reference 15). In addition, the core source term has been determined conservatively using a cycle exposure corresponding to a 24-month cycle.

The specific models, assumptions, and program used for computer evaluation are described in References 7 through 11. Specific values of parameters used in the evaluation are presented in Table 15.7.4-1.

15.7.4.5.1 Fission Product Release From Fuel

The core fission product inventory for the bounding (GNF3) fuel design has been determined by GEH (Reference 15) for each isotope (i) of interest in units of Curies per

Megawatt using an ORIGEN 2 based approach as specified in Regulatory Guide 1.183. The source term associated with the fuel damaged in a drop is determined as follows:

$$S_i\left(\frac{Ci}{MW}\right) x\ Core\ Power\ (MW)\ x\ \frac{\#\ Fuel\ Pins\ Damaged}{\#\ Fuel\ Pins\ in\ Core}$$

The fission product inventory of a core average rod is adjusted by the radial peaking factor to establish the inventory of each damaged rod. Only the fraction of the source term located inside the "gap" region of each rod is assumed to be released to the pool. The specific fractions applied are stipulated by Regulatory Guide 1.183 (AST) for fuel that has been confirmed to satisfy the AST limits on LHGR versus fuel exposure.

15.7.4.5.2 Fission Product Transport to the Environment

For fuel handling accidents involving recently irradiated fuel, the transport pathway is assumed to consist of mixing in the fuel pool, migration from the pool to the secondary containment atmosphere, and release to the environment through the SGTS. (It is possible for a slight amount of radioactivity to escape to the environment before initiation of the SGTS if no credit is given for nonsafety related dampers and the outboard safety related damper is assumed to fail open. See Subsection 15.7.4.2.2.) All of the noble gas and 0.5 percent of the iodines in the fuel gap released to the pool are assumed to become airborne in the secondary containment.

The airborne activity is released from the refuel floor to the environment over a 2-hr period after filtration by the SGTS (99 percent removal efficiency for iodine). The release of activity to the environment is presented in Table 15.7.4-2. The analyses that define when irradiated fuel becomes no longer "recently irradiated", assume no credit for SGTS, CCHVAC makeup filtration, or CREF recirculation filtration of iodine species. The analysis does assume that the source term on the refuel floor is released to the outside environment and enters the control room via the more limiting of the normal or emergency makeup air intakes, not via building internal ducts and pathways. The most likely release point is the RBHVAC exhaust stack. However, the Reference 8 analysis established a bounding secondary containment-to-control room atmospheric dispersion factor that did not correspond to a release via the RBHVAC exhaust stack. The analysis conservatively assumed the release is from the reactor building, south side ground level doors.

When the CREF and CCHVAC ductwork is breached in support of maintenance, the assumptions on the transport path of the source term are preserved through the application of administrative controls that are implemented prior to creating a breach to ensure that the transport of the fuel handling accident source term into the control room via the breach is not a credible possibility.

15.7.4.5.3 Results

The calculated exposures for the re-analyzed original design basis analysis (i.e., a drop of recently irradiated fuel 24-hours post-shutdown) presented in Table 15.7.4-3 are well below the guidelines of 10 CFR 50.67. Refueling procedures have been updated in accordance with License Amendment 141 to require the reactor to have been subcritical for at least 60 hours prior to movement of irradiated fuel. Consequently, the analysis based on 24 hours post-shutdown remains conservative. The calculated exposures for the design basis accident which defines the required post-shutdown delay period after which irradiated fuel is no longer considered recently irradiated presented in Table 15.7.4-4 establish a required post-shutdown delay after which irradiated GE14 and GNF3 fuel may be declared no longer recently irradiated to be approximately 6.3 days (151 hours), based on a maximum control room operator 30-day integrated dose of 5 rem TEDE. The Table 15.7.4-4 results show that the control room operator dose consequences associated with drops of fuel that is not recently irradiated fuel without secondary containment and control room isolation and filtration bound those of the original design basis accident.

15.7.4.5.4 Evaluation of the Impact of Uprated Power Operation and Extended Fuel Burnup

The analysis of the radiological consequences of the Fuel Handling Accident involving recently irradiated 9x9 fuel, which is no longer used at Fermi, that does not meet the AST burnup specifications are based on NRC Standard Review Plan 15.7.4 and Regulatory Guide 1.25. The assumptions given in Regulatory Guide 1.25 related to the release of radioactive material from the fuel and fuel storage facility as a result of a fuel handling accident, however, are only valid for fuel with an average burnup for the peak assembly of 25000 MWD/MTU or less (which corresponds to a peak local burnup of about 45000 MWD/MTU).

In a report prepared for the NRC by Pacific Northwest Laboratory (PNL) entitled "Assessment of the Use of Extended Burnup Fuel in Light Water Power Reactors," NUREG/CR-5009, dated February 1988, PNL examined the changes that could result in the NRC design-basis accident (DBA) assumptions contained in various Standard Review Plan Sections and Regulatory Guides as a result of extended fuel burnup (up to 60,000 MWD/MTU). PNL concluded, and the NRC Staff subsequently agreed, that the only DBA which could be affected by the extended fuel burnup would be the potential thyroid doses that could result from a fuel handling accident. The PNL report estimated that the calculated iodine gap-release fraction for fuel with extended burnup would be 20 percent greater for some high power fuel designs than the assumed value of 0.10 stated in Regulatory Guide 1.25. Thus, the calculated thyroid doses resulting from a fuel handling accident with extended burnup fuel could be 20 percent higher than those estimated using Regulatory Guide 1.25. The results of this report were later used as the basis for an NRC Environmental Assessment published in the Federal Register (53 FR 6040).

In response to an NRC Staff question concerning Detroit Edison's submittal for Power Uprate (License Amendment 87), Detroit Edison noted in a February 24, 1992 letter to the NRC its plans to use fuels enriched to a maximum of 5.0 percent by weight of Uranium-235 and fuel burnup levels not exceeding a maximum rod average burnup of 60,000 MWD/MTU. The letter also stated that these values of fuel enrichment and burnup were bounded by the NRC Environmental Assessment and that the conclusions made in the Environmental Assessment were applicable to Fermi 2. The NRC Staff subsequently agreed with Detroit Edison's statement that the conclusions of the Environmental Assessment published in the Federal Register (53 FR 6040) are applicable to Fermi 2, and that the use of extended burnup fuels within the limit specified above will have no significant adverse radiological or non-radiological impacts, and will not significantly affect the quality of the human environment.

During the course of its review of the Detroit Edison submittal for Power Uprate (License Amendment 87), the NRC Staff reevaluated the fuel handling accident for Fermi 2 using the uprated power level. The calculated 2-hour thyroid dose at the exclusion boundary was determined to remain less than 1 rem. Similarly, the low population zone thyroid and whole-body doses would be expected to remain less than 0.1 rem for the fuel handling accident. The staff concluded that the potential increased doses resulting from DBA with extended burnup levels of up to 60,000 MWD/MTU, met the acceptance criteria provided in Standard Review Plan Section 15.7.4, and will remain within the dose guidelines described in 10 CFR Part 100. Consequently, the staff concluded that the changes proposed by Detroit Edison with respect to the use of fuel with Uranium-235 enrichments up to 5 percent and burnup not exceeding 60,000 MWD/MTU were acceptable.

The Alternate Source Term described in Regulatory Guide 1.183, considers fuel burnup up to 62,000 MWD/MTU peak rod average. Thus, the AST assumptions on peak rod average exposure bound the Fermi 2 extended burnup granted in License Amendment 87; however, the Regulatory Guide 1.183 (Table 3 Footnote 11) also places a restriction on Linear Heat Generation Rate that must also be satisfied in order for the non-LOCA AST gap fractions to be valid. GE 10x10 fuel types are not expected to challenge the burnup limitations specified in Regulatory Guide 1.183 and the AST gap fractions are applied. GE11 9x9 and prior fuel types, which are no longer present in the active Fermi 2 fuel cycle, have resided in the spent fuel pool sufficiently long that these designs are no longer formally evaluated for drop consequences.

15.7 RADIOACTIVE RELEASE FROM SUBSYSTEMS AND COMPONENTS

REFERENCES

1. U.S. Nuclear Regulatory Commission, Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents From Boiling Water Reactors (BWR-GALE Code), PB-291025, NUREG-0016, Revision 1, January 1974.

2. S. J. Nathan, CORN Users' Manual, NUS-TM-34, NUS Corporation, Rockville, MD, April 1981.

3. P. P. Stancavage and E. J. Morgan, Conservative Radiological Accident Evaluation - The CONACO1 Code, NEDO-21143, March 1976.

4. Harold A. Careway and Elbyrne G. Thacker, A Sensitivity Study on Fuel Handling Accidents for Fermi 2, Detroit Edison Company, GE-NE-B13-01920-45, Rev 1, April 1998.

5. NUREG/CR-5009, “Assessment of the Use of Extended Burnup Fuel in Light Water Reactors”, January 1998, Pacific Northwest Laboratory.

6. Safety Evaluation By The Office Of Nuclear Reactor Regulation Related To Amendment No. 87 to Facility Operating License No. NPF-43, Detroit Edison Company Fermi-2, Docket No. 50-341, September 9, 1992.

7. NRC Office of Nuclear Reactor Regulation, "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors”, NRC Regulatory Guide 1.183 July 2000.

8. Fermi Design Calculation DC-6086, Volume I "Reanalysis of Fuel Handling Accident Using the Alternate Source Term".

9. “RADTRAD: A Simplified Model for Radionuclide Transport and Removal and Dose Estimation,” NUREG/CR-6604, December 1997.

10. Pacific Northwest National Laboratory, ARCON96 User's Guide, "Atmospheric Dispersion in Building Wakes", NUREG/CR-6331, May 1997.

11. United States Environmental Protection Agency, "Limiting Values of Radionuclide Intake and Air Concentration and Dose Conversion Factors for Inhalation, Submersion, and Ingestion", Federal Guidance Report No. 11, September 1988.

12. United States Environmental Protection Agency, "External Exposure to Radionuclides in Air, Water, and Soil", Federal Guidance Report No. 12, September 1993.

13. General Electric Co., "General Electric Standard Application for Reactor Fuel, GESTAR II," NEDE-24011-P-A, Latest Approved Revision as identified in the COLR.

14. TRVEND 002N2104, Revision 1, “Generic Resolution for the Overestimate in Number of Fuel Rods per Bundle of GE14 Fuel,” General Electric Co. 002N2104-R1, November 2014. Edison File#: R1-8464.

15. TRVEND 24MCGNF3FTRT0802, Revision 1, Core Source Terms.

TABLE 15.7.1-1 TYPICAL SEQUENCE OF EVENTS FOR MAIN TURBINE STEAM AIR EJECTOR LINE FAILURE

Approximate Elapsed Time	Events
0 sec	Event begins. System fails.
0 sec	Noble gases are released.
<1 minute	Area radiation alarms alert plant personnel.
<1 minute	Operator actions begin with
	(a) Initiation of appropriate system isolations
	(b) Manual scram actuation
	(c) Assurance of reactor shutdown cooling.
60 minute	Release to the environment is terminated.

TABLE 15.7.1-2 FAILURE OF MAIN TURBINE STEAM AIR EJECTOR LINES - PARAMETERS TABULATED FOR POSTULATED ACCIDENT ANALYSES

				Assumptions
I.	Data and assumptions used to estimate radioactive source from postulated accidents			
	A.	Power level		3499 MWt
	B.	Burnup		NA
	C.	Fuel damage		None
	D.	Release of activity by nuclide		Table 15.7.1-3
	E.	Iodine fractions		
		(1)	Organic	0
		(2)	Elemental	1.0
		(3)	Particulate	0
	F.	Reactor coolant activity before the accident		Subsection 15.7.1.5
II.	Data and assumptions used to estimate activity released			
	A.	Containment leak rate (percent/day)		NA
	B.	Secondary containment leak rate (percent/day)		NA
	C.	Valve movement times		NA
	D.	Adsorption and filtration efficiencies		NA
		(1)	Organic iodine	NA
		(2)	Elemental iodine	NA
		(3)	Particulate iodine	NA
		(4)	Particulate fission products	NA
	E.	Recirculation system parameters		
		(1)	Flow rate	NA
		(2)	Mixing efficiency	NA
		(3)	Filter efficiency	NA
	F.	Containment spray parameters (flow rate, drop size, etc.)		NA
	G.	Containment volumes		NA
	H.	All other pertinent data and assumptions		None
III.	Dispersion data			
	A.	Boundary and LPZ distances (m)		915
	B.	χ/Q's for SB/LPZ		Table 15A-2
IV.	Dose data			
	A.	Peak activity concentrations in containment		NA
	B.	Doses		Table 15.7.1-4

TABLE 15.7.1-3 FAILURE OF MAIN TURBINE STEAM AIR EJECTOR LINES - FISSION PRODUCT RELEASE TO THE ENVIRONMENT

Isotope	Activity Released (Ci)
I-131	3.20(-2)[a]
I-132	2.95(-1)
I-133	2.19(-1)
I-134	5.91(-1)
I-135	3.20(-1)
Kr-83m	4.47(1)
Kr-85	2.63(-1)
Kr-85m	8.03(1)
Kr-87	2.63(2)
Kr-88	2.63(2)
Kr-89	1.67(3)
Xe-131m	1.97(-1)
Xe-133	1.08(2)
Xe-133m	3.81
Xe-135	2.89(2)
Xe-135m	3.41(2)
Xe-137	1.93(3)
Xe-138	1.17(3)

[a] 3.20(-2) = 3.20 x 10^{-2}.

TABLE 15.7.1-4 FAILURE OF MAIN TURBINE STEAM AIR EJECTOR LINES – RADIOLOGICAL EFFECTS

	Whole-Body Dose (rem)	Thyroid Inhalation Dose (rem)
Exclusion Area (915 m)	3.4(-1)[a]	8.8(-3)
Low-population zone (4827 m)	3.9(-2)	1.0(-3)

[a] 3.4(-1) = 3.4 x 10^{-1}.

TABLE 15.7.3-1 RADIONUCLIDE INVENTORY USED IN ANALYSIS OF LIQUID AND SOLID RADWASTE SYSTEM FAILURE

	Tanks existed prior to 2005																Pre 2005 Concentration #		Tanks installed in 2005			Post 2005 Concentrations	
	FLR.DRAIN COLLECTOR TANK	EVAP. FD SURGE TANK	WASTE OIL TANK	DISTILLATE SURGE TANK	CHEMICAL WASTE TANK	EVAP. DRAINS TANK	WASTE COLLECTOR TANK	WASTE SAMPLE TANK	COND. PHASE TANK	WASTE CLARIFIER TANK	WASTE SURGE TANK	SPENT RESIN TANK	CHLORIDE WASTE TANK	CONC. FEED TANK	SP. RESIN SLURRY TANK	CENTRIF. FEED TANK			DIST INLET BATCH TANK	POST TREATMENT INLET BATCH TANK	SAMPLE BATCH TANK		
No. of Tanks:	1	1	1	2	1	1	1	3	2	1	1	1	1	1	1	1			1	1	1		
Tank Vol. (gal)	19,900	25,000	1,000	5,100	5,200	1,500	23,400	**	11,800	16,500	65,700	1,400	250	1,500	1,500	6,000			800	800	1000		
Total Vol. (gal)	19,900	25,000	1,000	10,200	5,200	1,500	23,400	69,700	23,600	16,500	65,700	1,400	250	1,500	1,500	6,000			800	800	1,000		
ISOTOPE	ACTIVITY CONC. in uCi/cc	ACTIVITY CONC. in uCi/cc	ACTIVITY CONC. in uCi/cc	ACTIVITY CONC. in uCi/cc	ACTIVITY CONC. in uCi/cc	ACTIVITY CONC. in uCi/cc	ACTIVITY CONC. in uCi/cc	ACTIVITY CONC. in uCi/cc	ACTIVITY CONC. in uCi/cc	ACTIVITY CONC. in uCi/cc	ACTIVITY CONC. in uCi/cc	ACTIVITY CONC. in uCi/cc	ACTIVITY CONC. in uCi/cc	ACTIVITY CONC. in uCi/cc	ACTIVITY CONC. in uCi/cc	ACTIVITY CONC. in uCi/cc	Average Activity Concentration After Assumed Failure, in uCi/cc	Activity Concentration of Released Liquid After Dilution With Groundwater Entering the Radwaste Bldg. in uCi/cc	ACTIVITY CONC uCi/cc	ACTIVITY CONC uCi/cc	ACTIVITY CONC uCi/cc	Average Activity Concentration After Assumed Failure, in uCi/cc	Activity Concentration of Released Liquid After Dilution With Groundwater Entering the Radwaste Bldg., in uCi/cc
Br-83	8.826E-06	3.927E-06	1.706E-03	1.727E-09	1.200E-04	6.416E-06	2.067E-03	7.892E-07	1.200E-05	1.200E-05	1.200E-05	1.200E-05	1.200E-04	6.416E-06	1.200E-05	1.200E-05	1.926E-04	1.926E-04	1.200E-04	1.200E-04	1.200E-04	1.919E-04	1.919E-05
Kr-83m	2.786E-09	3.680E-06	1.071E-05	2.897E-09	0.0	1.730E-05	6.40E-06	3.634E-07	0.0	0.0	0.0	0.0	0.0	1.730E-05	0.0	0.0	1.216E.06	1.216E.06	0.0	0.0	0.0	1.205E-06	1.205E-07
Br-84	1.029E-05	2.668E-07	1.958E-03	6.560E-12	1.400E-04	7.902E-11	2.392E-03	3.333E-07	1.400E-05	1.400E-05	1.400E-05	1.400E-05	1.400E-04	7.902E-11	1.400E-05	1.400E-05	2.223E-04	2.223E-04	1.400E-04	1.400E-04	1.400E-04	2.214E-04	2.214E-05
Br-85	4.362E-06	1.768E-23	6.792E-04	0.0	6.000E-05	0.0	9.225E-04	8.653E-09	6.000E-06	6.000E-06	6.000E-06	6.000E-06	6.000E-05	0.0	6.000E-06	6.000E-06	8.580E-05	8.580E-05	6.000E-05	6.000E-05	6.000E-05	8.551E-05	8.551E-06
Kr-85m	5.646E-10	3.125E-08	1.922E-06	2.016E-11	0.0	1.643E-07	1.224E-06	5.087E-09	0.0	0.0	0.0	0.0	0.0	1.643E-07	0.0	0.0	1.182E-07	1.182E-07	0.0	0.0	0.0	1.171E-07	1.171E-08
Kr-85	5.141E-18	1.644E-13	3.422E-13	2.757E-16	0.0	8.005E-11	1.078E-14	1.481E-14	0.0	0.0	0.0	0.0	0.0	8.005E-11	0.0	0.0	9.028E-13	9.028E-13	0.0	0.0	0.0	8.943E-13	8.943E-14
Rb-89	7.340E-06	3.527E-09	1.366E-03	1.516E-15	1.000E-04	5.873E-18	1.688E-03	1.106E-07	1.000E-05	1.000E-05	1.000E-05	1.000E-05	1.000E-04	5.873E-18	1.000E-05	1.000E-05	1.568E-04	1.568E-04	1.000E-04	1.000E-04	1.000E-04	1.563E-04	1.563E-05
Sr-89	1.471E-07	1.484E-07	2.863E-05	1.482E-10	2.000E-06	2.393E-05	3.454E-05	2.027E-08	2.000E-07	2.000E-07	2.000E-07	2.000E-07	2.000E-06	2.393E-05	2.000E-07	2.000E-07	3.490E-06	3.490E-06	2.000E-06	2.000E-06	2.000E-06	3.476E-06	3.476E-07
Sr-90	1.030E-08	1.030E-08	2.008E-06	1.030E-11	1.400E-07	1.761E-06	2.418E-06	1.441E-09	1.400E-08	1.400E-08	1.400E-08	1.400E-08	1.400E-07	1.761E-06	1.400E-08	1.400E-08	2.453E-07	2.453E-07	1.400E-07	1.400E-07	1.400E-07	2.443E-07	2.443E-08
Y-90	3.302E-13	3.073E-10	7.144E-09	6.085E-13	0.0	1.077E-06	2.215E-10	6.998E-11	0.0	0.0	0.0	0.0	0.0	1.077E-06	0.0	0.0	1.195E-08	1.195E-08	0.0	0.0	0.0	1.184E-08	1.184E-09
Sr-91	5.885E-06	4.801E-06	1.143E-03	3.904E-09	8.000E-05	5.954E-05	1.381E-03	7.132E-07	8.000E-06	8.000E-06	8.000E-06	8.000E-06	8.000E-05	5.954E-05	8.000E-06	8.000E-06	1.295E-04	1.295E-04	8.000E-05	8.000E-05	8.000E-05	1.291E-04	1.291E-05
Y-91m	2.338E-09	2.643E-06	8.975E-06	2.405E-09	0.0	3.717E-05	5.416E-06	2.684E-07	0.0	0.0	0.0	0.0	0.0	3.717E-05	0.0	0.0	1.219E-06	1.219E-06	0.0	0.0	0.0	1.208E-06	1.208E-07
Y-91	5.886E-08	6.455E-08	1.147E-05	7.067E-11	8.000E-07	1.564E-05	1.382E-05	8.526E-09	8.000E-08	8.000E-08	8.000E-08	8.000E-08	8.000E-07	1.564E-05	8.000E-08	8.000E-08	1.464E-06	1.464E-06	8.000E-07	8.000E-07	8.000E-07	1.458E-06	1.458E-07
Sr-92	1.471E-05	7.202E-06	2.847E-03	3.489E-09	2.000E-04	1.575E-05	3.446E-03	1.378E-06	2.000E-05	2.000E-05	2.000E-05	2.000E-05	2.000E-04	1.575E-05	2.000E-05	2.000E-05	3.212E-04	3.212E-04	2.000E-04	2.000E-04	2.000E-04	3.201E-04	3.201E-05
Y-92	8.829E-06	9.398E-06	1.718E-03	7.506E-09	1.200E-04	6.895E-05	2.074E-03	1.280E-06	1.200E-05	1.200E-05	1.200E-05	1.200E-05	1.200E-04	6.895E-05	1.200E-05	1.200E-05	1.946E-04	1.946E-04	1.200E-04	1.200E-04	1.200E-04	1.938E-04	1.938E-05
Y-93	5.885E-06	4.868E-06	1.143E-03	4.015E-09	8.000E-05	6.472E-05	1.381E-03	7.184E-07	8.000E-06	8.000E-06	8.000E-06	8.000E-06	8.000E-05	6.472E-05	8.000E-06	8.000E-06	1.296E-04	1.296E-04	8.000E-05	8.000E-05	8.000E-05	1.291E-04	1.291E-05
Zr-95	1.175E-08	1.173E-10	2.359E-08	1.171E-14	1.600E-07	1.917E-08	2.744E-06	1.640E-10	1.600E-08	1.600E-08	1.600E-08	1.600E-08	1.600E-07	1.917E-08	1.600E-08	1.600E-08	2.469E-07	2.469E-07	1.600E-07	1.600E-07	1.600E-07	2.461E-07	2.461E-08
Nb-95m	7.888E-14	2.558E-12	9.106E-10	5.092E-16	0.0	1.000E-08	1.788E-10	8.202E-12	0.0	0.0	0.0	0.0	0.0	1.000E-08	0.0	0.0	1.312E-10	1.312E-10	0.0	0.0	0.0	6.819E-09	6.819E-10
Nb-95	1.175E-08	1.172E-10	2.407E-08	1.169E-14	1.600E-07	1.909E-08	2.744E-06	1.672E-10	1.600E-08	1.600E-08	1.600E-08	1.600E-08	1.600E-07	1.909E-08	1.600E-08	1.600E-08	2.469E-07	2.469E-07	1.600E-07	1.600E-07	1.600E-07	2.461E-07	2.461E-08
Zr-97	8.812E-09	7.858E-11	1.701E-08	6.996E-15	1.200E-07	1.686E-09	2.057E-06	1.113E-10	1.200E-08	1.200E-08	1.200E-08	1.200E-08	1.200E-07	1.686E-09	1.200E-08	1.200E-08	1.850E-07	1.850E-07	1.200E-07	1.200E-07	1.200E-07	1.843E-07	1.843E-08
Nb-97	4.240E-12	6.570E-11	1.641E-10	7.163E-15	0.0	1.812E-09	9.787E-09	6.038E-11	0.0	0.0	0.0	0.0	0.0	1.812E-09	0.0	0.0	8.832E-10	8.832E-10	0.0	0.0	0.0	7.564E-09	7.564E-10
Nb-98	5.871E-06	6.022E-09	1.120E-05	5.974E-14	8.000E-05	1.152E-10	1.363E-03	2.870E-08	8.000E-06	8.000E-06	8.000E-06	8.000E-06	8.000E-05	1.152E-10	8.000E-06	8.000E-06	1.226E-04	1.226E-04	8.000E-05	8.000E-05	8.000E-05	1.222E-04	1.222E-05
Mo-99	2.937E-06	2.652E-08	5.679E-06	2.768E-12	4.000E-05	1.998E-06	6.860E-04	3.888E-08	4.000E-06	4.000E-06	4.000E-06	4.000E-06	4.000E-05	1.998E-06	4.000E-06	4.000E-06	6.170E-05	6.170E-05	4.000E-05	4.000E-05	4.000E-05	6.149E-05	6.149E-06
Tc-99m	2.943E-05	2.134E-05	5.707E-03	1.540E-08	4.000E-04	1.651E-04	6.901E-03	3.358E-06	4.000E-05	4.000E-05	4.000E-05	4.000E-05	4.000E-04	1.651E-04	4.000E-05	4.000E-05	6.455E-04	6.455E-04	4.000E-04	4.000E-04	4.000E-04	6.432E-04	6.432E-05
Tc-101	1.321E-04	3.925E-08	2.452E-02	1.035E-14	1.800E-03	1.522E-17	3.035E-02	1.864E-06	1.800E-04	1.800E-04	1.800E-04	1.800E-04	1.800E-03	1.522E-17	1.800E-04	1.800E-04	2.820E-03	2.820E-03	1.800E-03	1.800E-03	1.800E-03	2.810E-03	2.810E-04
Ru-103	2.937E-08	2.931E-10	5.815E-08	2.925E-14	4.000E-07	4.653E-08	6.860E-06	4.040E-10	4.000E-08	4.000E-08	4.000E-08	4.00E-08	4.000E-07	4.653E-08	4.000E-08	4.000E-08	6.173E-07	6.173E-07	4.000E-07	4.000E-07	4.000E-07	6.152E-07	6.152E-08
Tc-104	1.175E-04	1.853E-07	2.201E-02	2.660E-13	1.600E-03	1132E-14	2.711E-02	2.125E-06	1.600E-04	1.600E-04	1.600E-04	1.600E-04	1.600E-03	1.132E-14	1.600E-04	1.600E-04	2.519E-03	2.519E-03	1.600E-03	1.600E-03	1.600E-03	2.510E-03	2.510E-04
Ru-105	2.937E-06	1.899E-08	5.660E-08	1.220E-12	4.000E-05	9.869E-08	6.851E-04	3.135E-08	4.000E-06	4.000E-06	4.000E-06E	4.000E-06	4.000E-05	9.869E-08	4.000E-06	4.000E-06	6.159E-05	6.159E-05	4.000E-05	4.000E-05	4.000E-05	6.139E-05	6.139E-06
Ru-106	4.407E-09	4.411E-11	9.282E-09	4.408E-15	6.000E-08	7.547E-09	1.029E-06	6.455E-11	6.000E-09	6.000E-09	6.000E-09	6.000E-09	6.000E-08	7.547E-09	6.000E-09	6.000E-09	9.260E-08	9.260E-08	6.000E-08	6.000E-08	6.000E-08	9.229E-08	9.229E-09
Rh-106	2.947E-10	4.411E-11	6.795E-09	4.408E-15	0.0	7.547E-09	4.715E-07	6.454E-11	0.0	0.0	0.0	0.0	0.0	7.547E-09	0.0	0.0	4.066E-08	4.066E-08	0.0	0.0	0.0	4.028E-08	4.028E-09
Te-129m	5.886E-08	5.872E-08	1.144E-05	5.895E-11	8.000E-07	9.237E-06	1.381E-05	7.999E-09	8.000E-08	8.000E-08	8.000E-08	8.000E-08	8.000E-07	9.237E-06	8.000E-08	8.000E-08	1.392E-06	1.392E-06	8.000E-07	8.000E-07	8.000E-07	1.386E-06	1.386E-07
Te-129	1.862E-11	3.015E-08	7.653E-08	3.571E-11	0.0	5.827E-06	4.319E-08	2.771E-09	0.0	0.0	0.0	0.0	0.0	5.827E-06	0.0	0.0	7.166E-08	7.166E-08	0.0	0.0	0.0	7.098E-08	7.098E-09
I-129	4.827E-15	1.970E-13	3.157E-13	7.163E-17	0.0	2.922E-11	1.113E-13	2.919E-16	0.0	0.0	0.0	0.0	0.0	2.922E-11	0.0	0.0	3.511E-13	3.511E-13	0.0	0.0	0.0	3.478E-13	3.478E-14
Te-131m	1.471E-07	1.379E-07	2.857E-05	1.292E-10	2.000E-06	5.029E-06	3.453E-05	1.921E-08	2.000E-07	2.000E-07	2.000E-07	2.000E-07	2.000E-06	5.029E-06	2.000E-07	2.000E-07	3.280E-06	3.280E-06	2.000E-06	2.000E-06	2.000E-06	3.268E-06	3.268E-07
I-131	5.444E-06	5.391E-06	1.058E-03	5.338E-09	7.400E-05	6.517E-04	1.278E-03	7.326E-07	7.400E-06	7.400E-06	7.400E-06	7.400E-06	7.400E-05	6.517E-04	7.400E-06	7.400E-06	1.265E-04	1.265E-04	7.400E-05	7.400E-05	7.400E-05	1.260E-04	1.260E-05
Te-131	4.483E-11	3.046E-08	1.708E-07	2.881E-11	0.0	1.122E-06	1.034E-07	3.449E-09	0.0	0.0	0.0	0.0	0.0	1.122E-06	0.0	0.0	2.555E-08	2.555E-08	0.0	0.0	0.0	2.531E-08	2.531E-09
Te-132	1.471E-08	1.435E-08	2.858E-06	1.399E-11	2.000E-07	1.124E-06	3.453E-06	1.962E-09	2.000E-08	2.000E-08	2.000E-08	2.000E-08	2.000E-07	1.124E-06	2.000E-08	2.000E-08	3.349E-07	3.349E-07	2.000E-07	2.000E-07	2.000E-07	3.336E-07	3.336E-08
I-132	8.826E-05	3.777E-05	1.706E-02	1.597E-08	1.200E-03	5.594E-05	2.067E-02	7.752E-06	1.200E-04	1.200E-04	1.200E-04	1.200E-04	1.200E-03	5.594E-05	1.200E-04	1.200E-04	1.926E-03	1.926E-03	1.200E-03	1.200E-03	1.200E-03	1.919E-03	1.919E-04
I-134	1.470E-04	1.576E-05	2.821E-02	1.635E-09	2.000E-03	3.440E-07	3.431E-02	7.345E-06	2.000E-04	2.000E-04	2.000E-04	2.000E-04	2.000E-03	3.440E-07	2.000E-04	2.000E-04	3.190E-03	3.190E-03	2.000E-03	2.000E-03	2.000E-03	3.179E-03	3.179E-04
I-133	7.357E-05	6.706E-05	1.428E-02	6.105E-08	1.000E-03	1.752E-03	1.726E-02	9.453E-06	1.000E-04	1.000E-04	1.000E-04	1.000E-04	1.000E-03	1.752E-03	1.000E-04	1.000E-04	1.631E-03	1.631E-03	1.000E-03	1.000E-03	1.000E-03	1.625E-03	1.625E-04
Xe-133m	2.345E-11	7.366E-08	9.174E-08	1.390E-10	0.0	4.657E-05	5.453E-08	5.569E-09	0.0	0.0	0.0	0.0	0.0	4.657E-05	0.0	0.0	5.262E-07	5.262E-07	0.0	0.0	0.0	5.212E-07	5.212E-08
Xe-133	3.276E-10	1.041E-06	1.315E-06	1.988E-09	0.0	1.111E-03	7.618E-07	7.867E-08	0.0	0.0	0.0	0.0	0.0	1.111E-03	0.0	0.0	1.242E-05	1.242E-05	0.0	0.0	0.0	1.231E-05	1.231E-06
I-135	7.357E-05	6.706E-05	1.428E-02	6.105E-08	1.000E-03	1.752E-03	1.726E-02	9.453E-06	1.000E-04	1.000E-04	1.000E-04	1.000E-04	1.000E-03	1.752E-03	1.000E-04	1.000E-04	1.631E-03	1.631E-03	1.000E-03	1.000E-03	1.000E-03	1.625E-03	1.625E-04
Xe-135m	3.117E-08	1.296E-05	1.177E-04	1.181E-08	0.0	3.389E-04	7.157E-05	1.608E-06	0.0	0.0	0.0	0.0	0.0	3.389E-04	0.0	0.0	1.192E-05	1.192E-05	0.0	0.0	0.0	1.181E-05	1.181E-06
Xe-135	3.779E-09	1.315E-05	1.471E-05	2.303E-08	0.0	1.853E-03	8.815E-06	9.992E-07	0.0	0.0	0.0	0.0	0.0	1.853E-03	0.0	0.0	2.269E-05	2.269E-05	0.0	0.0	0.0	2.247E-05	2.247E-06
Cs-135	1.393E-13	1.552E-12	5.920E-12	5.982E-16	0.0	1.449E-10	3.275E-12	4.762E-15	0.0	0.0	0.0	0.0	0.0	1.449E-10	0.0	0.0	2.053E-12	2.053E-12	0.0	0.0	0.0	2.034E-12	2.034E-13
Cs-134	4.414E-08	4.414E-08	8.603E-06	4.414E-11	6.000E-07	7.519E-06	1.036E-05	6.155E-09	6.000E-08	6.000E-08	6.000E-08	6.000E-08	6.000E-07	7.519E-06	6.000E-08	6.000E-08	1.051E-06	1.051E-06	6.000E-07	6.000E-07	6.000E-07	1.046E-06	1.046E-07
Cs-136	2.943E-08	2.925E-08	5.718E-06	2.907E-11	4.000E-07	4.011E-06	6.907E-06	3.369E-09	4.000E-08	4.000E-08	4.000E-08	4.000E-08	4.000E-07	4.011E-06	4.000E-08	4.000E-08	6.893E-07	6.893E-07	4.000E-07	4.000E-07	4.000E-07	6.866E-07	6.866E-08
Cs-137	1.177E-07	1.177E-07	2.295E-05	1.177E-10	1.600E-06	2.013E-05	2.763E-05	1.646E-08	1.600E-07	1.600E-07	1.600E-07	1.600E-07	1.600E-06	2.013E-05	1.600E-07	1.600E-07	2.803E-06	2.803E-06	1.600E-06	1.600E-06	1.600E-06	2.792E-06	2.792E-07
Ba-137m	1.502E-09	1.114E-07	5.100E-06	1.113E-10	0.0	1.904E-05	3.224E-06	1.539E-08	0.0	0.0	0.0	0.0	0.0	1.904E-05	0.0	0.0	5.197E-07	5.197E-07	0.0	0.0	0.0	5.148E-07	5.148E-08
Cs-138	1.470E-05	3.989E-07	2.799E-03	1.027E-11	2.000E-04	1.355E-10	3.417E-03	4.818E-07	2.000E-05	2.000E-05	2.000E-05	2.000E-05	2.000E-04	1.355E-10	2.000E-05	2.000E-05	3.175E-04	3.175E-04	2.000E-04	2.000E-04	2.000E-04	3.164E-04	3.164E-05
Ba-139	1.471E-05	3.624E-06	2.835E-03	8.746E-10	2.000E-04	9.861E-07	3.439E-03	1.011E-06	2.000E-05	2.000E-05	2.000E-05	2.000E-05	2.000E-04	9.861E-07	2.000E-05	2.000E-05	3.200E-04	3.200E-04	2.000E-04	2.000E-04	2.000E-04	3.189E-04	3.189E-05

TABLE 15.7.3-1 RADIONUCLIDE INVENTORY USED IN ANALYSIS OF LIQUID AND SOLID RADWASTE SYSTEM FAILURE

	Tanks existed prior to 2005																Pre 2005 Concentration #		Tanks installed in 2005			Post 2005 Concentrations	
	FLR.DRAIN COLLECTOR TANK	EVAP. FD SURGE TANK	WASTE OIL TANK	DISTILLATE SURGE TANK	CHEMICAL WASTE TANK	EVAP. DRAINS TANK	WASTE COLLECTOR TANK	WASTE SAMPLE TANK	COND. PHASE TANK	WASTE CLARIFIER TANK	WASTE SURGE TANK	SPENT RESIN TANK	CHLORIDE WASTE TANK	CONC. FEED TANK	SP. RESIN SLURRY TANK	CENTRIF. FEED TANK	Average Activity Concentration After Assumed Failure, in uCi/cc	Activity Concentration of Released Liquid After Dilution With Groundwater Entering the Radwaste Bldg. in uCi/cc	DIST INLET BATCH TANK	POST TREATMENT INLET BATCH TANK	SAMPLE BATCH TANK	Average Activity Concentration After Assumed Failure, in uCi/cc	Activity Concentration of Released Liquid After Dilution With Groundwater Entering the Radwaste Bldg., in uCi/cc
No. of Tanks:	1	1	1	2	1	1	1	3	2	1	1	1	1	1	1	1			1	1	1		
Tank Vol. (gal)	19,900	25,000	1,000	5,100	5,200	1,500	23,400	**	11,800	16,500	65,700	1,400	250	1,500	1,500	6,000			800	800	1000		
Total Vol. (gal)	19,900	25,000	1,000	10,200	5,200	1,500	23,400	69,700	23,600	16,500	65,700	1,400	250	1,500	1,500	6,000			800	800	1,000		
ISOTOPE	ACTIVITY CONC. in uCi/cc	ACTIVITY CONC. in uCi/cc	ACTIVITY CONC. in uCi/cc	ACTIVITY CONC. in uCi/cc	ACTIVITY CONC. in uCi/cc	ACTIVITY CONC. in uCi/cc	ACTIVITY CONC. in uCi/cc	ACTIVITY CONC. in uCi/cc	ACTIVITY CONC. in uCi/cc	ACTIVITY CONC. in uCi/cc	ACTIVITY CONC. in uCi/cc	ACTIVITY CONC. in uCi/cc	ACTIVITY CONC. in uCi/cc	ACTIVITY CONC. in uCi/cc	ACTIVITY CONC. in uCi/cc	ACTIVITY CONC. in uCi/cc			ACTIVITY CONC uCi/cc	ACTIVITY CONC uCi/cc	ACTIVITY CONC uCi/cc		
Ba-140	5.886E-07	5.849E-07	1.143E-04	5.812E-10	8.000E-06	7.980E-05	1.381E-04	7.934E-08	8.000E-07	8.000E-07	8.000E-07	8.000E-07	8.000E-06	7.980E-05	8.000E-07	8.000E-07	1.378E-05	1.378E-05	8.000E-06	8.000E-06	8.000E-06	1.372E-05	1.372E-06
La-140	8.453E-12	2.751E-08	4.299E-08	5.394E-11	0.0	6.125E-05	1.963E-08	2.129E-09	0.0	0.0	0.0	0.0	0.0	6.125E-05	0.0	0.0	6.796E-07	6.796E-07	0.0	0.0	0.0	6.732E-07	6.732E-08
Ba-141	1.469E-05	2.486E-08	2.752E-03	3.835E-14	2.000E-04	1.883E-15	3.389E-03	2.688E-07	2.000E-05	2.000E-05	2.000E-05	2.000E-05	2.000E-04	1.883E-15	2.000E-05	2.000E-05	3.149E-04	3.149E-04	2.000E-04	2.000E-04	2.000E-04	3.138E-04	3.138E-05
La-141	2.176E-09	7.533E-07	8.232E-06	4.565E-10	0.0	3.235E-06	5.002E-06	1.066E-07	0.0	0.0	0.0	0.0	0.0	3.235E-06	0.0	0.0	5.922E-07	5.922E-07	0.0	0.0	0.0	5.866E-07	5.866E-08
Ce-141	4.406E-08	2.384E-09	8.701E-08	1.729E-12	6.000E-07	9.490E-07	1.029E-05	7.413E-10	6.000E-08	6.000E-08	6.000E-08	6.000E-08	6.000E-07	9.490E-07	6.000E-08	6.000E-08	9.358E-07	9.358E-07	6.000E-07	6.000E-07	6.000E-07	9.326E-07	9.326E-08
Ba-142	8.800E-06	1.535E-10	1.608E-03	2.282E-18	1.200E-04	1.104E-23	2.006E-03	8.910E-08	1.200E-05	1.200E-05	1.200E-05	1.200E-05	1.200E-04	1.104E-23	1.200E-05	1.200E-05	1.864E-04	1.864E-04	1.200E-04	1.200E-04	1.200E-04	1.857E-04	1.857E-05
La-142	7.344E-06	3.458E-07	1.420E-05	9.745E-12	1.000E-04	1.493E-07	1.716E-03	1.610E-07	1.000E-05	1.000E-05	1.000E-05	1.000E-05	1.000E-04	1.493E-07	1.000E-05	1.000E-05	1.543E-04	1.543E-04	1.000E-04	1.000E-04	1.000E-04	1.538E-04	1.538E-05
Ce-143	4.406E-08	4.155E-10	8.513E-08	3.915E-14	6.000E-07	1.653E-08	1.029E-05	5.736E-10	6.000E-08	6.000E-08	6.000E-08	6.000E-08	6.000E-07	1.653E-08	6.000E-08	6.000E-08	9.253E-07	9.253E-07	6.000E-07	6.000E-07	6.000E-07	9.222E-07	9.222E-08
Pr-143	5.875E-08	5.865E-10	1.142E-07	5.854E-14	8.000E-08	8.571E-08	1.372E-05	7.935E-10	8.000E-08	8.000E-08	8.000E-08	8.000E-08	8.000E-08	8.571E-08	8.000E-08	8.000E-08	1.234E-06	1.234E-06	8.000E-08	8.000E-08	8.000E-08	1.230E-06	1.230E-07
Ce-144	4.406E-09	4.405E-11	9.144E-09	4.404E-15	6.000E-08	7.462E-09	1.029E-06	6.359E-11	6.000E-09	6.000E-09	6.000E-09	6.000E-09	6.000E-08	7.462E-09	6.000E-09	6.000E-09	9.260E-08	9.260E-08	6.000E-08	6.000E-08	6.000E-08	9.229E-08	9.229E-09
Pr-144	8.817E-12	4.400E-11	9.641E-10	4.404E-15	0.0	7.462E-09	2.017E-08	5.601E-11	0.0	0.0	0.0	0.0	0.0	7.462E-09	0.0	0.0	1.838E-09	1.838E-09	0.0	0.0	0.0	1.820E-09	1.820E-10
Nd-147	4.406E-09	4.374E-11	8.548E-09	4.342E-15	6.000E-08	5.768E09	1.029E-06	5.921E-11	6.000E-09	6.000E-09	6.000E-09	6.000E-09	6.000E-08	5.768E09	6.000E-09	6.000E-09	9.257E-08	9.257E-08	6.000E-08	6.000E-08	6.000E-08	9.227E-08	9.227E-09
Np-239	1.177E-05	1.137E-05	2.287E-03	1.098E-08	0.0	7.088E-04	2.763E-03	1.562E-06	0.0	0.0	0.0	0.0	0.0	7.088E-04	0.0	0.0	2.559E-04	2.559E-04	0.0	0.0	0.0	2.535E-04	2.535E-05
Na-24	1.471E-05	1.294E-05	2.257E-03	1.135E-08	2.000E-04	2.485E-04	3.452E-03	1.856E-06	2.000E-05	2.000E-05	2.000E-05	2.000E-05	2.000E-04	2.485E-04	2.000E-05	2.000E-05	3.250E-04	3.250E-04	2.000E-04	2.000E-04	2.000E-04	3.238E-04	3.238E-05
P-32	2.943E-07	2.926E-07	5.718E-05	2.909E-10	4.000E-06	4.084E-05	6.907E-05	3.971E-08	4.000E-07	4.000E-07	4.000E-07	4.000E-07	4.000E-06	4.084E-05	4.000E-07	4.000E-07	6.901E-06	6.901E-06	4.000E-06	4.000E-06	4.000E-06	6.874E-06	6.874E-07
Cr-51	8.812E-06	8.786E-08	1.729E-05	8.760E-12	1.200E-04	1.352E-05	2.058E-03	1.201E-07	1.200E-07	1.200E-07	1.200E-07	1.200E-07	1.200E-04	1.352E-05	1.200E-07	1.200E-07	1.852E-04	1.852E-04	1.200E-04	1.200E-04	1.200E-04	1.846E-04	1.846E-05
Mn-54	1.028E-07	1.028E-09	2.136E-07	1.028E-13	1.400E-06	1.743E-07	2.401E-05	1.485E-09	1.400E-07	1.400E-07	1.400E-07	1.400E-07	1.400E-06	1.743E-07	1.400E-07	1.400E-07	2.161E-06	2.161E-06	1.400E-06	1.400E-06	1.400E-06	2.153E-06	2.153E-07
Fe-55	1.469E-06	1.469E-08	3.079E-06	1.469E-12	2.000E-05	2.507E-06	3.430E-04	2.141E-08	2.000E-06	2.000E-06	2.000E-06	2.000E-06	2.000E-05	2.507E-06	2.000E-06	2.000E-06	3.087E-05	3.087E-05	2.000E-05	2.000E-05	2.000E-05	3.076E-05	3.076E-06
Mn-56	7.342E-05	3.465E-07	1.412E-04	1.618E-11	1.000E-03	6.784E-07	1.711E-02	6.712E-07	1.000E-04	1.000E-04	1.000E-04	1.000E-04	1.000E-03	6.784E-07	1.000E-04	1.000E-04	1.538E-03	1.538E-03	1.000E-03	1.000E-03	1.000E-03	1.533E-03	1.533E-04
Co-58	2.937E-07	2.934E-09	5.915E-07	2.931E-13	4.000E-06	4.815E-07	6.860E-05	4.111E-09	4.000E-07	4.000E-07	4.000E-07	4.000E-07	4.000E-06	4.815E-07	4.000E-07	4.000E-07	6.173E-06	6.173E-06	4.000E-06	4.000E-06	4.000E-06	6.152E-06	6.152E-07
Fe-59	4.406E-08	4.398E-10	8.752E-08	4.390E-14	1.000E-06	7.043E-08	1.029E-05	6.081E-10	1.000E-07	1.000E-07	1.000E-07	1.000E-07	1.000E-06	7.043E-08	1.000E-07	1.000E-07	9.507E-07	9.507E-07	1.000E-06	1.000E-06	1.000E-06	9.512E-07	9.512E-08
Co-60	5.875E-07	5.874E-09	1.235E-06	5.874E-13	8.000E-06	1.004E-06	1.372E-04	8.589E-09	8.000E-07	8.000E-07	8.000E-07	8.000E-07	8.000E-06	1.004E-06	8.000E-07	8.000E-07	1.235E-05	1.235E-05	8.000E-06	8.000E-06	8.000E-06	1.231E-05	1.231E-06
Ni-63	1.469E-09	1.469E-11	3.094E-09	1.469E-15	2.000E-08	2.515E-09	3.430E-07	2.151E-11	2.000E-09	2.000E-09	2.000E-09	2.000E-09	2.000E-08	2.515E-09	2.000E-09	2.000E-09	3.087E-08	3.087E-08	2.000E-08	2.000E-08	2.000E-08	3.076E-08	3.076E-09
Cu-64	4.406E-05	3.788E-07	8.509E-05	3.249E-11	6.000E-04	6.264E-06	1.029E-02	5.457E-07	6.000E-05	6.000E-05	6.000E-05	6.000E-05	6.000E-04	6.264E-06	6.000E-05	6.000E-05	9.252E-04	9.252E-04	6.000E-04	6.000E-04	6.000E-04	9.221E-04	9.221E-05
Ni-65	4.405E-07	2.044E-09	8.477E-07	9.374E-14	6.000E-06	3.794E-09	1.027E-04	3.996E-09	6.000E-07	6.000E-07	6.000E-07	6.000E-07	6.000E-06	3.794E-09	6.000E-07	6.000E-07	9.233E-06	9.233E-06	6.000E-06	6.000E-06	6.000E-06	9.203E-06	9.203E-07
Zn-65	2.943E-07	2.942E-07	5.733E-05	2.941E-10	4.000E-06	4.971E-05	6.907E-05	4.084E-08	4.000E-07	4.000E-07	4.000E-07	4.000E-07	4.000E-06	4.971E-05	4.000E-07	4.000E-07	7.000E-06	7.000E-06	4.000E-06	4.000E-06	4.000E-06	6.972E-06	6.972E-07
Zn-69	2.941E-06	3.834E-07	5.649E-04	4.851E-11	4.000E-05	1.516E-08	6.866E-04	1.576E-07	4.000E-06	4.000E-06	4.000E-06	4.000E-06	4.000E-05	1.516E-08	4.000E-06	4.000E-06	6.384E-05	6.384E-05	4.000E-05	4.000E-05	4.000E-05	6.362E-05	6.362E-06
Zn-69m	0.0	0.0	2.818E-17	0.0	0.0	0.0	0.0	1.820E-19	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.500E-19	1.500E-19	0.0	0.0	0.0	1.486E-19	1.486E-20
Ag-110m	1.469E-09	1.468E-11	3.043E-09	1.468E-15	2.000E-08	2.483E-09	3.430E-07	2.116E-11	2.000E-09	2.000E-09	2.000E-09	2.000E-09	2.000E-08	2.483E-09	2.000E-09	2.000E-09	3.087E-08	3.087E-08	2.000E-08	2.000E-08	2.000E-08	3.076E-08	3.076E-09
W-187	4.406E-07	4.063E-09	8.511E-07	3.742E-13	6.000E-06	1.204E-07	1.029E-04	5.666E-09	6.000E-07	6.000E-07	6.000E-07	6.000E-07	6.000E-06	1.204E-07	6.000E-07	6.000E-07	9.252E-06	9.252E-06	6.000E-06	6.000E-06	6.000E-06	9.222E-06	9.222E-07
H-3	1.000E-02	1.000E-02	1.000E-02	1.000E-02	2.000E-04	1.000E-02	1.000E-02	1.000E-02	2.000E-05	2.000E-05	2.000E-05	2.000E-05	2.000E-04	1.000E-02	2.000E-05	2.000E-05	5.601E-03	5.601E-03	2.000E-04	2.000E-04	2.000E-04	5.550E-03	5.550E-04

TOTAL CURIES OF IODINE IN THE SPILLED LIQUID:

I-129 = 3.619E-10
I-131 = 1.304E-01
I-132 = 1.985E+00
I-133 = 1.681E+00
I-134 = 3.288E+00
I-135 = 1.681E+00

TOTAL CURIES OF IODINE ASSUMED TO BE RELEASED TO THE ATMOSPHERE:

I-129 = 3.619E-12
I-131 = 1.304E-03
I-132 = 1.985E-02
I-133 = 1.681E-02
I-134 = 3.288E-02
I-135 = 1.681E-02

* Tank is not considered operational per Note in UFSAR Section 11.2.1.
** Two of the Waste Sample Tanks have volume of 24,300 gallons, and the third has volume of 21,100 gallons.
# Pre-2005 values are more limiting than Post 2005 values. For conservatism, Pre-2005 values are continued to be used in dose calculations. As such, the dose calculation for liquid tank failure analysis remains unchanged.

TABLE 15.7.3-2 CALCULATION OF REACTOR COOLANT ACTIVITY DURING NORMAL PLANT OPERATION*

	Reactor Coolant Specific Activity (μCi/cc)	
Isotope	Soluble	Insoluble
Br-83	6.1E-03	
Br-84	7.1E-03	
Br-85	3.1E-03	
Rb-89	5.1E-03	
Sr-89	1.0E-04	
Sr-90	7.1E-06	
Sr-91	4.1E-03	
Sr-92	1.0E-02	
Y-91	4.1E-05	
Y-92	6.1E-03	
Y-93	4.1E-03	
Nb-95		8.2E-06
Nb-98		4.1E-03
Zr-95		8.2E-06
Zr-97		6.1E-06
Mo-99		2.0E-03
Tc-99m	2.0E-02	
Tc-101	9.2E-02	
Tc-104	8.2E-02	
Ru-103		2.0E-05
Ru-105		2.0E-03
Ru-106		3.1E-06
Te-129m	4.1E-05	
Te-131m	1.0E-04	
Te-132	1.0E-05	
I-131	3.8E-03	
I-132	6.1E-02	
I-133	5.1E-02	
I-134	1.0E-01	
I-135	5.1E-02	
Cs-134	3.1E-05	
Cs-136	2.0E-05	
Cs-137	8.2E-05	

TABLE 15.7.3-2 CALCULATION OF REACTOR COOLANT ACTIVITY DURING NORMAL PLANT OPERATION*

	Reactor Coolant Specific Activity (μCi/cc)	
Isotope	Soluble	Insoluble
Cs-138	1.0E-02	
Ba-139	1.0E-02	
Ba-140	4.1E-04	
Ba-141	1.0E-02	
Ba-142	6.1E-03	
La-142		5.1E-03
Ce-141		3.1E-05
Ce-143		3.1E-05
Ce-144		3.1E-06
Pr-143		4.1E-05
Nd-147		3.1E-06
Np-239	8.2E-03	
Na-24	1.0E-02	
P-32	2.0E-04	
Cr-51		6.1E-03
Mn-54		7.1E-05
Mn-56		5.1E-02
Fe-55		1.0E-03
Fe-59		2.0E-05
Co-58		2.0E-04
Co-60		4.1E-04
Ni-63		1.0E-06
Ni-65		3.1E-04
Cu-64		3.1E-02
Zn-65	2.0E-04	
Zn-69	2.0E-03	
Ag-110m		1.0E-06
W-187		3.1E-04
H-3	1.0E-02	
	0.577	0.103
Total	0.681	

* 3499 MWt

TABLE 15.7.3-3 FRACTIONS OF PRIMARY COOLANT ACTIVITY DURING NORMAL PLANT OPERATION FOR RADWASTE SOURCE

Source	Fraction
Equipment drains	
Drywell	1.00
Reactor building	0.1
Radwaste building	0.1
Turbine building	0.001
Floor drains	
Drywell	0.001
Reactor building	0.001
Radwaste building	0.001
Turbine building	0.001
Lab drains, chemical waste	0.02
Cleanup phase separator decantation	0.002
Condensate phase separator decantation[a]	2×10^{-6}

[a] Assumed to be equal to condensate demineralizer backwash water.

TABLE 15.7.3-4 DESIGN-BASIS DECONTAMINATION FACTORS FOR RADWASTE EQUIPMENT

Equipment	Soluble Isotopes	Insoluble Isotopes
Etched-disk filter	1	10
Precoat filter	1	10
Oil coalescers (3 in series)	1	10
Radwaste demineralizer[a]	100(10)	10(10)
Radwaste evaporator	1,000	10,000
Extruder/evaporator	1,000	1,000
Centrifuge	67	67
Phase separators[b] (sludge effluent)	1	1
Reactor water cleanup condensate filter-demineralizers	100	100

[a] Values in parentheses are for the second demineralizer in series.

[b] All activity entering the phase separators has been assumed to exit via the sludge letdown line.

TABLE 15.7.3-5 SUMMARY OF RADIONUCLIDE CONCENTRATION AT VARIOUS POINTS IN THE LIQUID PATHWAY TO THE CITY OF MONROE POTABLE WATER INTAKE

		Concentration (μCi/cm^3)		
Nuclide	Half-Life (days)	In Tanks	Entering Lake	At Intake
Br-83	1.00E-01	1.97E-04	0.00E-01	0.00E-01
Kr-83m	7.92E-02	1.24E-06	0.00E-01	0.00E-01
Br-84	2.21E-02	2.26E-04	0.00E-01	0.00E-01
Br-85	2.08E-03	8.75E-05	0.00E-01	0.00E-01
Kr-85m	1.82E-01	1.20E-07	0.00E-01	0.00E-01
Kr-85	3.95E-03	9.21E-13	0.00E-01	0.00E-01
Rb-89	1.07E-02	1.60E-04	0.00E-01	0.00E-01
Sr-89	5.08E+01	3.56E-06	6.14E-19	7.98E-21
Sr-90	1.05E+04	2.50E-07	2.19E-08	2.85E-10
Y-90	2.68E+00	1.21E-08	0.00E-01	0.00E-01
Sr-91	4.03E-01	1.32E-04	0.00E-01	0.00E-01
Y-91m	3.49E-02	1.24E-06	0.00E-01	0.00E-01
Y-91	5.90E+01	1.49E-06	1.11E-17	1.45E-19
Sr-92	1.12E-01	3.27E-04	0.00E-01	0.00E-01
Y-92	1.50E-01	1.99E-04	0.00E-01	0.00E-01
Y-93	4.33E-01	1.33E-04	0.00E-01	0.00E-01
Zr-95	6.55E+01	2.52E-07	1.90E-17	2.46E-19
Nb-95m	3.75E+00	1.34E-10	0.00E-01	0.00E-01
Nb-95	3.51E+01	2.52E-07	2.38E-25	3.09E-27
Zr-97	7.00E-01	1.89E-07	0.00E-01	0.00E-01
Nb-97	5.01E-02	9.01E-10	0.00E-01	0.00E-01
Nb-98	3.54E-02	1.25E-04	0.00E-01	0.00E-01
Mo-99	2.78E+00	6.29E-05	0.00E-01	0.00E-01
Tc-99m	2.58E-01	6.58E-04	0.00E-01	0.00E-01
Tc-101	9.86E-03	2.88E-03	0.00E-01	0.00E-01
Ru-103	3.98E+01	6.29E-07	6.09E-23	7.92E-25
Tc-104	1.25E-02	2.57E-03	0.00E-01	0.00E-01
Ru-105	1.88E-01	6.28E-05	0.00E-01	0.00E-01
Ru-106	3.68E+02	9.45E-08	2.24E-10	2.92E-12
Rh-106	3.47E-04	4.15E-08	0.00E-01	0.00E-01
Te-129m	3.41E+01	1.42E-06	4.25E-25	5.52E-27
Te-129	5.00E-02	7.31E-08	0.00E-01	0.00E-01
I-129	5.73E+09	3.58E-13	3.58E-14	4.65E-16
Te-131m	1.25E+00	3.35E-06	0.00E-01	0.00E-01
I-131	8.07E+00	1.29E-04	0.00E-01	0.00E-01
Te-131	1.72E-02	2.60E-08	0.00E-01	0.00E-01
Te-132	3.24E+00	3.42E-07	0.00E-01	0.00E-01
I-132	9.52E-02	1.97E-03	0.00E-01	0.00E-01
I-134	3.63E-02	3.25E-03	0.00E-01	0.00E-01
I-133	8.67E-01	1.66E-03	0.00E-01	0.00E-01
Xe-133m	2.30E+00	5.37E-07	0.00E-01	0.00E-01
Xe-133	5.27E+00	1.26E-05	0.00E-01	0.00E-01
I-135	2.79E-01	1.66E-03	0.00E-01	0.00E-01

TABLE 15.7.3-5 SUMMARY OF RADIONUCLIDE CONCENTRATION AT VARIOUS POINTS IN THE LIQUID PATHWAY TO THE CITY OF MONROE POTABLE WATER INTAKE

		Concentration (μCi/cm^3)		
Nuclide	Half-Life (days)	In Tanks	Entering Lake	At Intake
Xe-135m	1.08E-02	1.21E-05	0.00E-01	0.00E-01
Xe-135	3.80E-01	2.32E-05	0.00E-01	0.00E-01
Cs-135	8.40E+08	2.09E-12	2.09E-13	2.72E-15
Cs-134	7.52E+02	1.07E-06	1.72E-08	2.23E-10
Cs-136	1.30E+01	7.03E-07	0.00E-01	0.00E-01
Cs-137	1.10E+04	2.86E-06	2.52E-07	3.27E-09
Ba-137m	1.81E-03	5.30E-07	0.00E-01	0.00E-01
Cs-138	2.24E-02	3.23E-04	0.00E-01	0.00E-01
Ba-139	5.78E-02	3.26E-04	0.00E-01	0.00E-01
Ba-140	1.28E+01	1.41E-05	0.00E-01	0.00E-01
La-140	1.68E+00	6.94E-07	0.00E-01	0.00E-01
Ba-141	1.27E-02	3.21E-04	0.00E-01	0.00E-01
La-141	1.58E-01	6.04E-07	0.00E-01	0.00E-01
Ce-141	3.25E+01	9.55E-07	3.92E-26	5.09E-28
Ba-142	7.43E-03	1.90E-04	0.00E-01	0.00E-01
La-142	5.35E-02	1.57E-04	0.00E-01	0.00E-01
Ce-143	3.30E+01	9.44E-07	7.36E-26	9.56E-28
Pr-143	1.36E+01	1.25E-06	0.00E-01	0.00E-01
Ce-144	2.84E+02	9.45E-08	7.44E-11	9.65E-13
Pr-144	1.20E-02	1.88E-09	0.00E-01	0.00E-01
Nd-147	1.11E+01	9.45E-08	0.00E-01	0.00E-01
Np-239	2.35E+00	2.61E-04	0.00E-01	0.00E-01
Na-24	6.25E-01	3.32E-04	0.00E-01	0.00E-01
P-32	1.43E+01	7.04E-06	0.00E-01	0.00E-01
Cr-51	2.78E+01	1.89E-04	6.04E-27	7.84E-29
Mn-54	3.13E+02	2.20E-06	2.71E-09	3.53E-11
Fe-55	9.49E+02	3.15E-05	7.39E-07	9.60E-09
Mn-56	1.08E-01	1.57E-03	0.00E-01	0.00E-01
Co-58	7.14E+01	6.29E-06	2.69E-15	3.50E-17
Fe-59	4.50E+01	9.70E-07	5.10E-21	6.62E-23
Co-60	1.89E+03	1.25E-05	6.08E-07	7.90E-09
Ni-63	3.50E+04	3.15E-08	3.03E-09	3.93E-11
Cu-64	5.33E-01	9.44E-04	0.00E-01	0.00E-01
Ni-65	1.06E-01	9.42E-06	0.00E-01	0.00E-01
Zn-65	2.44E+02	7.14E-06	2.54E-09	3.29E-11
Zn-69	3.96E-02	6.51E-05	0.00E-01	0.00E-01
Zn-69m	5.71E-01	1.53E-19	0.00E-01	0.00E-01
Ag-110m	2.53E+02	3.15E-08	1.37E-11	1.78E-13
W-187	9.96E-01	9.44E-06	0.00E-01	0.00E-01
H-3	4.47E+03	5.71E-03	4.20E-04	5.46E-06

TABLE 15.7.3-6 RADIONUCLIDE CONCENTRATION ENTERING LAKE ERIE AND MONROE POTABLE WATER INTAKE DUE TO THE POSTULATED FAILURE OF THE LIQUID RADWASTE SYSTEM

Nuclide*	Concentration (μCi/cc) In Tanks	Concentration (μCi/cc) Entering Lake	Concentration (μCi/cc) At Intake	MPC**	C/MPC***
Sr-90	2.50E-07	2.19E-08	2.85E-10	3.00E-07	9.49E-04
Ru-106	9.45E-08	2.24E-10	2.92E-12	1.00E-05	2.92E-07
I-129	3.58E-13	3.58E-14	4.65E-16	6.00E-08	7.75E-09
Cs-135	2.09E-12	2.09E-13	2.72E-15	1.00E-04	2.72E-11
Cs-134	1.07E-06	1.72E-08	2.23E-10	9.00E-06	2.48E-05
Cs-137	2.86E-06	2.52E-07	3.27E-09	2.00E-05	1.64E-04
Ce-144	9.45E-08	7.44E-11	9.65E-13	1.00E-05	9.65E-08
Mn-54	2.20E-06	2.71E-09	3.53E-11	1.00E-04	3.53E-07
Fe-55	3.15E-05	7.39E-07	9.60E-09	8.00E-04	1.20E-05
Co-58	6.29E-06	2.69E-15	3.50E-17	9.00E-05	3.89E-13
Co-60	1.25E-05	6.08E-07	7.90E-09	5.00E-05	1.58E-04
Ni-63	3.15E-08	3.03E-09	3.93E-11	3.00E-05	1.31E-06
Zn-65	7.14E-06	2.54E-09	3.29E-11	1.00E-04	3.29E-07
Ag-110m	3.15E-08	1.37E-11	1.78E-13	3.00E-05	5.92E-09
H-3	5.71E-03	4.20E-04	5.46E-06	3.00E-03	1.82E-03
				TOTAL C/MPC =	3.129E-03

* Only isotopes entering Lake Erie in concentrations greater than 1.0E-15 μCi/cc are listed.

** MPC = maximum permissible concentration (10CFR20, Appendix B, Table 2, column 2)

*** C/MPC = ratio to the concentration of the isotope of interest at Monroe intake to the MPC for that isotope.

TABLE 15.7.4-1 FUEL-HANDLING ACCIDENT PARAMETERS TABULATED FOR POSTULATED ACCIDENT ANALYSIS

FUEL TYPE DEPENDENT FHA INPUTS			
FUEL BUNDLE TYPE	GE14		GNF3
Number Fuel Rods Failed Note 2	165.84		168.3
Number Fuel Rods per Bundle	85.84		88.3
Effective Number of Damaged Bundles	1.932 Note 10		1.906
FUEL & SCENARIO INDEPENDENT FHA INPUTS			
Reactor Power (MWt)		3499	
Number of Assemblies in Core		764	
Fuel Rod Plenum ("Gap") Activity Release Fractions (%)			
Noble gasses (except Kr-85)		5	
Kr-85		10	
Iodine-131 (I-131)		8	
Iodines (other than I-131)		5	
Alkali Metals		12	
Radial Power Peaking Factor		1.7	
RPV Decontamination Factors			
Noble gases		1	
Iodine		200	
Duration of Release of Activity from Reactor Building (hr) Note 6		<2	
Accident Duration		30 days	
χ/Q at EA Boundary (sec/m^3) 0-2 hours Note 11		2.09E-04	
χ/Q at LPZ (sec/m^3) 0-2 hours Note 11		4.86E-05	
Dose Conversion Factors Note 5		FGRs 11 & 12	
Control Room Volume (ft^3) Ventilated Occupied		252,730 56,960	
Breathing Rates (m^3/sec) Note 12		3.47E-04	
Control Room Makeup Air Flow		4000 cfm Note 1	
FUEL CONDITION (SCENARIO) DEPENDENT INPUTS			
	FUEL CONDITION		
Fuel Condition	Recently Irradiated		Non-Recently Irradiated
Decay Time after Shutdown (hr) Note 13	24		151
SGTS Iodine Filter Efficiency (%)	99		0
CREF Initiation Credited?	No		No
Release Height (m) Note 3	54.3 m		0 m
χ/Q main control room (sec/m^3) 0-2 hours Note 11	3.65E-03 Note 4 Note 8		4.25E-03 Note 7

Notes:

1. No credit for reduced CREF filtration and isolation.

2. Fraction accounts for partial length rods in dropped assembly. All impacted rods assumed to be full length. Drop over RPV (approx. 34 ft) bounds drop over spent fuel pool (approx. 6 ft).

3. SGTS exhaust stack-to-control room χ/Q calculated in Reference 8 using ARCON96 (Reference 10) assuming zero-velocity vent release. See Reference 8 for a complete description of the inputs and methodology used to calculate the χ/Q values used in the FHA analysis.

4. This SGTS stack χ/Q value is different than that used to calculate the control room operator dose in UFSAR Section 15.A. Both values were calculated using reviewed and approved methodologies. The value used for the FHA was calculated in Reference 8 using the same methodology used to evaluate other secondary containment release points. No credit assumed for SRP 6.4 factor of 4 reduction in χ/Q for control room dual air inlet configurations.

5. EPA Federal Guidance Reports 11 and 12 (References 11 and 12)

6. Rate of release conservatively based on a refuel floor volume of 950,000 ft^3 and an assumed air removal rate of 95,000 cfm. The normal rate of ventilation supplied by RBHVAC is approximately 33,000 cfm. 95,000 cfm effectively releases the source term within one-hour. (99.75 percent after one hour, >99.99 percent after two hours)

7. Secondary containment-to-control room χ/Q representing releases via locations other than SGTS calculated in Reference 8 using ARCON96 (Reference 10). See Reference 8 for a complete description of the inputs and methodology used to calculate the χ/Q values used in the FHA analysis.

8. The analysis of the 24-hour FHA involving recently irradiated fuel includes the effects of an initial period of unfiltered release via the RBHVAC stack. UFSAR Section 15.7.4.2.2 describes a 4.3 second period of unfiltered release; however, the Reference 8 analysis conservatively evaluated a 7.2 second unfiltered release. The χ/Q assigned to this release path was 4.05E-3 s/m^3 based on a value of 4.03E-3 s/m^3 calculated in the Reference 8 analysis.

9. GE11 9x9 fuel is no longer used in Fermi 2 fuel cycles. All GE11 fuel has been discharged to the spent fuel pool, is no longer recently irradiated, and satisfies the Reference 7 burnup restriction.

10. All analyses of dose consequences are performed based on GE14 Effective Number of Damaged Bundles.

11. The EAB dose is calculated as the worst 2-hour dose at the EAB boundary. The control room and LPZ doses are conservatively computed assuming 0-2 hr χ/Q persists for the 30-day duration of accident.

12 This breathing rate is assigned to the EAB, LPZ, and main control room. In addition, the control room is assigned the following occupancy factors 1.0 (0-24 hrs), 0.6 (24-48 hrs), and 0.4 (48-120 hrs).

13. Accidents involving recently irradiated fuel have been reviewed and approved assuming the FHA drop occurs 24 hours post-shutdown. This is consistent with UFSAR Section 9.1.4.3.2; however, the expanded capacity of the spent fuel pool approved under License Amendment 141 requires the initial removal of fuel from the core to the spent fuel pool to be delayed for 60 hours.

TABLE 15.7.4-2 FUEL-HANDLING ACCIDENT (DESIGN-BASIS ANALYSIS) ACTIVITY RELEASED TO THE ENVIRONMENT (CURIES)

Nuclide	Shutdown Activity (Ci/MWt)	Reference 8 Curies Released to Reactor Building[1] / Environment[2]	
		Non-Recently Irradiated	Recently Irradiated
	(Reference 15)	10 x 10	10x 10
	0 hrs	151 hrs	24 hrs
Xe-131m	305.5	2.499E+02	2.365E+02
Xe-133m	1607	2.669E+02	1.100E+03
Xe-133	52580	2.099E+04	3.819E+04
Xe-135m	10960	9.222E-04	5.605E+02
Xe-135	20530	1.183E+00	1.080E+04
Xe-138	44780		
Kr-83m	3225		2.734E-01
Kr-85	886.8[5]	6.662E+02	6.668E+02
Kr-85m	6680		1.226E+02
Kr-87	12690		1.988E-02
Kr-88	17840		3.843E+01
I-131	27200	9.677E+01	1.513E+02
I-132	39320	3.973E+01	1.225E+02
I-133	55040	1.351E+00	9.301E+01
I-134	60280		
I-135	51570	2.575E-05	1.565E+01
Te-131	24250		
Te-131m	4000		
Te-132	38620		

[1] Initial release from pool to reactor builidng.
[2] Release to Environment following 2-hr if SGTS filtration not credited.
[3] GE11 9x9 fuel is no longer used in Fermi 2 fuel cycles and is not included above. All GE11 fuel has been discharged to the spent fule pool, is no longer recently irradiated, and satisifies the Reference 7 burnup restriction.
[4] With the exception of tellurium, blank entries represent radionuclides considered in source term that decay so rapidly they are essentially not present at the time of the assumed start of the accident. Tellurium is not present because it is assigned a zero gap fraction. (See Table 15.7.4-1).
[5] Kr-85 core source term doubled to enable use of a single value of Noble Gas gap fraction.

TABLE 15.7.4-3 FUEL-HANDLING ACCIDENT (DESIGN-BASIS ANALYSIS) RADIOLOGICAL EFFECTS (DROPS INVOLVING RECENTLY IRRADIATED FUEL 24 HOURS POST-SHUTDOWN[d])

Drop of 10x10 Recently Irradiated Fuel Bundle

	TEDE Dose (rem)	Regulatory Limit
Main Control Room	0.309	(30-day – 5.0 rem)
Exclusion Area (915 m)	0.169	(2-hr – 6.3 rem)
Low-population zone (4827 m)	0.040	(30-day – 6.3 rem)

Drop of 10x10 Fresh Fuel Bundle over Recently Irradiated Fuel

	TEDE Dose (rem)	Regulatory Limit
Main Control Room	4.025	(30-day – 5.0 rem)
Exclusion Area (915 m)	0.028	(2-hr – 6.3 rem)
Low-population zone (4827 m)	0.065	(30-day – 6.3 rem)

[a] 10x10 Recently Irradiated fuel is assumed to meet exposure limitations necessary for use of Reference 7, Table 3 AST non-LOCA gap fractions.

[b] Use of GE11 9x9 fuel was discontinued at the end of Cycle 14 (October 2010). All GE11 fuel has been discharged to the spent fuel pool, is no longer recently irradiated, and satisfies the Reference 7 burnup restriction. In consideration of the significant period of source term decay to which the discharged GE11 (9x9) fuel has been subjected and given the large degree to which the radiological consequences of a drop of GE11 fuel are bounded by those of the 10x10 fuel designs currently in use, GE11 (9x9) results are no longer computed for presentation in this section.

[c] Results above assume no credit for CREF filtration. Credit for SGTS filtration is assumed for the drop of recently irradiated fuel (see Table 15.7.4-1), but is not assumed for the drop of fresh fuel.

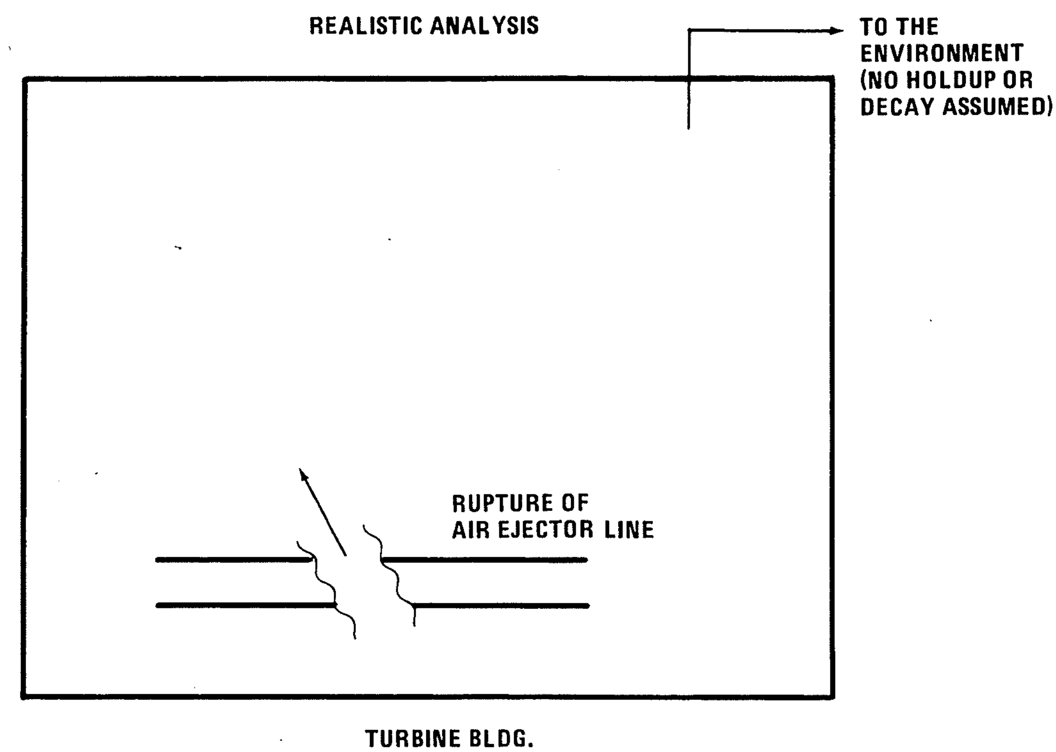
[d] Refueling procedures have been updated in accordance with License Amendment 141 to require the reactor to have been subcritical for at least 60 hours prior to movement of irradiated fuel. Consequently, the analysis based on 24 hours post-shutdown remains conservative.

TABLE 15.7.4-4 FUEL-HANDLING ACCIDENT (ANALYSIS DEFINING "RECENTLY IRRADIATED") RADIOLOGICAL EFFECTS

10 x 10 AST Fuel Rods (6.3 day delay)

	TEDE Dose (rem)	
Main Control Room	4.726	(30-day Reg. Limit 5.0)
Exclusion Area (915 m)	0.267	(2-hr Reg. Limit 6.3)
Low-population zone (4827 m)	0.062	(30-day Reg. Limit 6.3)

Note GE11 9x9 fuel was discontinued at the end of Cycle 14 (October 2010). All GE11 fuel has been discharged to the spent fuel pool, is no longer recently irradiated, and satisfies the Reference 7 burnup restriction. Considering the significant period over which the source term has decayed, consequences associated with the 10x10 fuel types currently in use bound the GE11 consequences to a large degree. For this reason, the results of postulated drops of GE11 fuel type are no longer presented in this chapter.



Fermi 2

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FIGURE 15.7.1-1

LEAKAGE PATH FOR MAIN TURBINE STEAM AIR EJECTOR LINE FAILURE

15.8 ANTICIPATED TRANSIENTS WITHOUT SCRAM (ATWS)

In order to ease the severity of the consequences of the failure of the scram protection system following an anticipated transient, the NRC has imposed 10 CFR 50.62 requirements for all BWR owners.

15.8.1 ATWS Rule 10CFR50.62

Anticipated transients are transients expected to occur during the life of the plant. Anticipated transients without scram (ATWS) are those extremely low probability events in which an anticipated transient occurs and is not followed by an automatic reactor shutdown (scram) when required. The postulation of the "normal scram" failure in ATWS can only be deduced if more than one "single failure criteria" is assumed.

The NRC has since established the requirements to further reduce the risk to the public from such a postulated event. These requirements are specified in 10CFR50.62, "Requirements for Reduction of Risk from Anticipated Transients Without Scram (ATWS) Events for Light Water Cooled Nuclear Power Plants." For the BWR, 10CFR50.62 requires an alternate rod insertion (ARI) system, a manual standby liquid control system (SLCS), and an automatic recirculation pump trip (RPT) function.

The BWR Owners Group had prepared a topical report on the subject of ATWS and discussed the details of the design option how 10CFR50.62 is satisfied. Reference 1 is the NRC approved topical report. Detroit Edison is a member of the Owners Group and the Fermi 2 design is consistent with that discussed in Reference 1. ATWS was previously evaluated at the 3430 MWt power level (Reference 2). ATWS was previously analyzed with a 3% SRV drift and reviewed as acceptable by the NRC in Reference 3. For the GNF3 new fuel introduction and in support of fuel cycle lengths up to 24 months, ATWS was evaluated at current licensed thermal power and found to meet the ATWS acceptance criteria (Reference 4).

Details of the Fermi 2 ARI can be found in Chapters 4 and 7, Subsections 4.5.2.2 and 7.6.1.18; details of the SLCS and enriched boron can be found in Chapter 4, Subsection 4.5.2.4; and details of ATWS-RPT can be found in Chapter 7, Subsection 7.7.1.2.3.1.

15.8 ANTICIPATED TRANSIENTS WITHOUT SCRAM (ATWS)

REFERENCES

1. General Electric Co., "Anticipated Transients Without Scram Response to NRC ATWS Rule 10CFR50.62," NEDE-31096-P-A, February 1987.
2. Letter from the USNRC to Detroit Edison, "Amendment No. 87 to Facility Operating License No. NPF-43 (TAC No. M82102)," September 9, 1992.
3. Letter from USNRC to Detroit Edison, "Fermi 2 – Issuance of Amendment RE: Safety/Relief Valve (SRV) Setpoint Tolerance Change (TAC MA0720)," dated July 31, 1998. (Amendment No. 123).
4. GNF3 Fuel Design Cycle Independent Analyses for Fermi Unit 2, 004N7423 R0, November 2019 (24MCGNF3FTRT1104).

15.9 FAILURE OF THE COOLANT REGULATING INSTRUMENTATION - CORE COOLANT TEMPERATURE INCREASE

This accident was not reevaluated for the Fermi 2 power uprates.

Four coolant regulating instrumentation failures have been identified which can cause a power-coolant mismatch. These events are

a. Core coolant temperature increase

b. Feedwater controller failure

c. Recirculation flow control failure with decreasing flow

d. Recirculation flow control failure with increasing flow.

The analytical methods and assumptions used in evaluating the consequences of these accidents are considered to provide a conservative assessment of the consequences. The NRC has not issued guidelines for evaluating these accidents.

Event a., core coolant temperature increase, is addressed in this section while events b., c., and d. are addressed in Subsections 15.1.2, 15.3.2, and 15.4.5, respectively.

15.9.1 Identification of Causes

15.9.1.1 Starting Conditions and Assumptions

The reactor is going through normal shutdown and cooldown when the residual heat removal (RHR) shutdown cooling system fails.

15.9.1.2 Event Description

Loss of RHR shutdown cooling capability during reactor shutdown and cooldown results in a core coolant temperature increase.

15.9.2 Analysis of Effects and Consequences

15.9.2.1 Methods, Assumptions, and Conditions

An event that can directly cause reactor pressure vessel (RPV) water temperature increase is one in which the energy removal rate is less than the decay heat rate addition. The applicable event is loss of RHR shutdown cooling. This event can occur only during the low pressure portion of a normal reactor shutdown and cooldown when the RHR system is operating in the shutdown cooling mode.

15.9.2.2 Results and Consequences

For most single failures that could result in a loss of shutdown cooling, no unique safety actions are required. In these cases, shutdown cooling is simply reestablished using other normal shutdown cooling equipment. In cases where the RHR system shutdown cooling suction line becomes inoperative, a unique requirement for cooling arises. In operating states in which the RPV head is off, the RHR system LPCI mode can be used to maintain water level. During operating conditions in which the RPV head is on, the system can be pressurized, and the low pressure cooling system, relief valves (manually operated), and RHR system suppression pool cooling mode can be used to maintain water level and remove decay heat.

15.9.2.3 Consideration of Uncertainties

The multiplicity of operator actions available to mitigate the effects of this transient ensure that reactor cooldown can be accomplished.

15.10 INTERNAL AND EXTERNAL EVENTS

These events were not reevaluated for the Fermi 2 power uprates.

The internal accidents to be considered in Subsection 15.10.1 are those that develop from fires in parts of the plant. Specific initiating events are not postulated.

Fires may be initiated from many sources. However, very few flammable materials are used in the plant. Even though fires are postulated to occur for the purpose of accident analysis, the actual probability of a fire is negligible due to both the absence of the combustion process and the low temperatures found in the plant.

External events, such as floods, storms, and earthquakes, are discussed in Subsection 15.10.2. Section 2.4 gives a detailed description of possible floods and storms at the Fermi site. That section also defines the probable maximum flood and the probable maximum meteorological event.

A complete description of the Fermi site seismological characteristics is given in Section 2.5. Response spectra are given for both the operating basis earthquake (OBE) and the safe shutdown earthquake (SSE).

The fire protection system is described in Subsection 9.5.1.

15.10.1 Internal Event Evaluation

A complete description of the Fermi 2 fire protection features is in Subsection 9.5.1, and a fire hazards analysis for safety-related areas is provided in the Fire Protection Program Description/Analysis Program.

15.10.2 External Event Evaluation

Floods, storms, and earthquakes are evaluated in this subsection.

15.10.2.1 Identification of Causes

15.10.2.1.1 Floods

Section 2.4 gives a detailed description of floods, flood parameters, and events concurrent with flooding for the Fermi site. This section also describes the probable maximum flood.

15.10.2.1.2 Storms

Refer to Section 2.3 for a detailed description of storms and other meteorological events concurrent with storms for the Fermi site. Also included in Section 2.4 is a description of the probable maximum flood.

For a description of the wind and tornado design parameters for all Category I structures and components, refer to Section 3.3.

15.10.2.1.3 Earthquakes

Refer to Section 2.5 for a complete description of the Fermi site seismological characteristics and history. Included are the response spectra for both the safe shutdown earthquake (SSE) and the operating basis earthquake (OBE).

15.10.2.2 Analysis of Effects and Consequences

15.10.2.2.1 Floods

Neither the plant ESF systems nor the safe shutdown capability of the reactor will be impaired by flooding of the Fermi site. All Category I structures are conservatively designed to behave elastically and remain functional and watertight under the effects of the probable maximum flood and wind generated waves specified in Sections 2.4 and 3.4. Refer to Section 3.8 for a discussion of the design of Category I structures. As mentioned in Subsection 3.4.1, the design stillwater flood elevation of the probable maximum flood is conservatively increased to 1.1 ft above the predicted probable maximum flood elevation specified in Section 2.4.

The reactor building, auxiliary building, and the RHR complex incorporate the flood protection measures specified in Subsection 3.4.4, to ensure that the effects of the probable maximum flood will not penetrate the exterior boundaries of these structures.

15.10.2.2.2 Storms

All Category I structures and components are designed or suitably protected to remain functional for all credible meteorological events, including the probable maximum meteorological event and the tornado, whose parameters are specified in Subsection 3.3.2.

Superficial damage may be sustained by miscellaneous plant property and nonseismic structures during the postulated tornado. However, this damage will not impair the plant ESF systems nor the safe shutdown capabilities of the reactor.

All roofs are properly sealed, pitched, and drained to prevent water from entering the building. Similarly, the reactor building superstructure siding above the fifth floor has sealed joints. As mentioned in Section 3.3, the metal siding will be assumed to blow away when the wind velocity exceeds 200 mph. However, the superstructure steel framing is designed to behave elastically for the tornado postulated in Subsection 3.3.2. Should this unlikely event occur and expose the refueling floor, the safe shutdown capabilities of the reactor would not be impaired.

A meteorological station has been constructed on the Fermi site and is maintained by Edison. Meteorological data, such as temperature, barometric pressure, and wind velocity and direction, are recorded to keep plant personnel informed of current meteorological conditions.

15.10.2.2.3 Earthquakes

All Category I structures, components, and equipment are designed to remain functional during an SSE. The seismic analysis and design for Category I structures are in accordance with Sections 3.7 and 3.8, respectively. Some cracking of the reactor building exterior walls may occur during an SSE, but large, predominantly open cracks are not expected. Therefore, leakage of water into the reactor building through cracks will not occur.

Active earthquake recording instrumentation (triaxial accelerometers) are provided to measure the basic ground motion time history acceleration, as well as the seismic motion of the primary containment elements (including the base of the RPV pedestal). The recording system will be energized when a seismic trigger senses acceleration above a preset limit. This signal will be sent over shielded cables for permanent recording and data reduction, and will alert facility operators to the fact that an earthquake has occurred.

In addition to active instrumentation, passive sensors (triaxial spectrum recorders) are provided to measure various ground motion and in-structure response spectra.

The recorded data will be examined immediately, and the plant will be evaluated as described in Section 3.7.4.4, and operation will not be resumed until analysis and/or necessary refurbishing of all critical structures, systems, and components is completed. If examination shows that the SSE validation level is exceeded, further rigorous investigation will commence. If permanent deformation or evidence of material yield is encountered, appropriate repairs will be affected before startup.

Refer to Subsection 3.7.4 for a complete description of the seismic instrumentation.

15.11 FAILURE OF THE GASEOUS RADWASTE SYSTEM

15.11.1 Identification of Causes

An evaluation of those events which could cause a gross failure in the offgas system has resulted in the identification of a seismic event more severe than the one for which the system is designed as being the only conceivable event which could cause significant damage.

15.11.2 Starting Conditions and Assumptions

Equipment and piping are designed to contain any explosion which has a reasonable probability of occurring. Therefore, an explosion is not considered a possible failure mode. The equipment vaults are not accessible during normal operation. Therefore, an operator induced failure is not considered reasonable. The only credible event that could result in the release of significant activity to the environment is an earthquake.

15.11.3 Event Description

An event more severe than the design requirements of the offgas system is arbitrarily assumed to occur, resulting in the failure of the offgas system. The sequence of events following this failure is as follows:

	Events	Approximate Elapsed Time
a.	Event begins. System fails	0
b.	Noble gases are released	0
c.	Area radiation alarms alert plant personnel.	< 1 minute

15.11.4 Analysis of Effects and Consequences

15.11.4.1 Realistic Evaluation Methods

The analytical methods and associated assumptions used in evaluating the consequences of this accident are considered to provide a realistic, yet conservative, assessment of the consequences. In some instances very conservative assumptions are made in accordance with Regulatory Guide l.29 to show that the offgas system does not require Category I design.

15.11.4.1.1 Methods, Assumptions, and Conditions

The reactor is assumed to be operating at 3499 MWt for a period of time sufficient to cause an equilibrium inventory to be accumulated in the offgas system.

The activity in the offgas system is based on the following conditions:

a. 40 scfm air inleakage

b. l02,000 μCi/sec noble gas after 30-minute delay

c. Six charcoal beds

d. Removal of daughter products by equipment:

  1. Catalytic recombiner - 100 percent (iodine)

  2. Offgas condenser - l00 percent

  3. Aftercooler - l00 percent

  4. Precooler - l00 percent

  5. Holdup pipe - l00 percent

  6. Chiller - l00 percent

  7. Sandfilter - l00 percent.

e. Operating times

  l. Charcoal beds - l0 years

  2. Afterfilter - l0 years.

The radionuclide inventories for each component in the offgas system, as well as the total system inventories, are listed in Table 11.3-2. Table 15.11-1 presents the parameters used in this accident analysis.

15.11.4.1.2 Results and Consequences

Fuel Damage

There is no fuel damage as a result of this accident.

Fission Product Release From Fuel

There is no fission product release from the fuel as a result of this accident.

Fission Product Release to the Environment

It is conservatively assumed that l00 percent of the iodine and 10 percent of the noble gases in each component of the offgas system are released to the environment. Table 15.11-2 lists the total isotopic releases from this accident. The assumption that 10 percent of the noble gases in the offgas system is released is indeed a conservative one. Approximately 99 percent of the noble gas activity is contained in the charcoal adsorbers. The only credible failure that could result in the release of a significant amount of noble gases would be the loss of carbon from a charcoal adsorber. The circumferential failure of the steel structure surrounding the charcoal bed would be such an accident. However, only 10 to 15 percent of the carbon in the bed would be released.

Measurements made at KRB indicated that the offgas is about 30 percent richer in krypton than air. As a result, when the carbon is exposed to the air, the krypton absorbed by the carbon eventually obtains equilibrium with the noble gases in the air. However, the first few inches of carbon will blanket the underlying carbon from the air. Therefore, a 10 percent loss of noble gases from the beds is conservative because of the small fraction of carbon exposed to the air.

Radiological Effects

The radiological effects for this accident are based on the total system activities summarized in Table 15.11-2. The resultant radiological exposures are presented in Table 15.11-1. These doses are based on conservative dispersion data (5 percentile site meteorology) to conform with Regulatory Guide 1.29 assumptions. The resulting exposures are a small fraction of the guideline values of 10 CFR 100 and the limits for radiation exposure specified in Regulatory Guide 1.29.

TABLE 15.11-1 FAILURE OF GASEOUS RADWASTE SYSTEM - PARAMETERS TABULATED FOR POSTULATED ACCIDENT ANALYSES

		Design-Basis Assumptions	Realistic Assumptions
I.	Data and assumptions used to estimate radioactive source from postulated accidents		
	A. Power level	NA[a]	3499 MWt
	B. Burnup	NA	NA
	C. Fuel damage	NA	None
	D. Release of activity by nuclide	NA	Table 15.11-2
	E. Iodine fractions	NA	
	(1) Organic		0
	(2) Elemental		100 percent
	(3) Particulate		0
	F. Reactor coolant activity before the accident	NA	Subsection 15.7.3.3.1
II.	Data and assumptions used to estimate activity released		
	A. Primary containment leak rate (percent/day)	NA	NA
	B. Secondary containment leak rate (percent/day)	NA	NA
	C. Valve movement times	NA	NA
	D. Adsorption and filtration efficiencies	NA	NA
	(1) Organic iodine		
	(2) Elemental iodine		
	(3) Particulate iodine		
	(4) Particulate fission products		
	E. Recirculation system parameters	NA	NA
	(1) Flow rate		
	(2) Mixing efficiency		
	(3) Filter efficiency		
	F. Containment spray parameters (flow rate, drop size, etc.)	NA	NA
	G. Containment volumes	NA	NA
	H. All other pertinent data and assumptions	NA	None
III.	Dispersion data		
	A. Exclusion area boundary (m)	NA	915
	Low-population zone (m) (from Table 15A-2)		4827

TABLE 15.11-1 FAILURE OF GASEOUS RADWASTE SYSTEM - PARAMETERS TABULATED FOR POSTULATED ACCIDENT ANALYSES

	Design-Basis Assumptions	Realistic Assumptions
B. χ/Q for exclusion area boundary	NA	
(1) 0-2 hr		1.23 x 10-4
C. χ/Q for lowpopulation zone duration of the accident (from Table 15A-2)	NA	
(1) 0-2 hr		1.39 x 10-5
(2) 8-24 hr		NA
(3) 1-4 days		NA
(4) 4-30 days		NA
D. χ/Q for control room (duration of the accident)	NA	NA
(1) 0-8 hr		
(2) 8-24 hr		
(3) 1-4 days		
(4) 4-30 days		
IV. Dose data		
A. Peak activity concentrations in containment	NA	NA
B. Doses (REM)	NA	
(1) 2-hr dose at exclusion area boundary		
(i) Thyroid		4.3 x 10-2
(ii) Whole body		8.6 x 10-3
(2) Dose at low- population zone for duration of the accident	NA	
(i) Thyroid		4.8 x 10-3
(ii) Whole body		9.7 x 10-4
(3) Dose in control room for duration of the accident	NA	NA
(i) Thyroid		
(ii) Whole body		
(iii) Skin		

[a] NA = Not applicable.

TABLE 15.11-2 FAILURE OF GASEOUS RADWASTE SYSTEM - ACTIVITY RELEASED TO THE ENVIRONMENT

(Realistic Analysis)

Isotope	Activity Released (Ci)
I-131	4.8(-1)[a]
I-132	8.9(-2)
I-133	6.0(-1)
I-134	6.9(-2)
I-135	2.9(-1)
Kr-83m	3.6
Kr-85	1.4(-1)
Kr-85m	1.1(1)
Kr-87	1.4(1)
Kr-88	3.0(1)
Kr-89	3.6
Xe-131m	1.6
Xe-133	5.0(2)
Xe-133m	8.3
Xe-135	1.0(2)
Xe-135m	3.7
Xe-137	5.1
Xe-138	1.1(1)

[a] 4.6(-1) = 4.6 x 10^{-1}.

15.12 MALFUNCTION OF TURBINE GLAND SEALING SYSTEM

This malfunction was not reevaluated for the Fermi 2 power uprates:

15.12.1 Loss of Vacuum in the Gland Steam Condenser

The gland steam condenser is self sealing and during normal operation, noncondensables are removed from the gland steam condenser by one of two gland steam condenser blowers. In the event the operating blower malfunctions, the backup blower will automatically assume the gas removal requirements. Assuming loss of both blowers, vacuum will be lost in the gland steam condenser. The pressure in the gland steam exhaust header will increase to greater than atmospheric, allowing sealing steam to escape into the turbine building.

15.12.2 Analysis of Effects and Consequences

In the event of loss of vacuum in the gland steam condenser, the gland sealing steam pressure will begin to increase in the exhaust header. This will result in blowing sealing steam into the atmosphere around the glands (on the third floor of the turbine building). This pressure buildup will be alarmed in the main control room. Main control room personnel will then correct the situation and ensure vacuum is restored in the gland steam condenser. The gland sealing system is not required for a safe reactor shutdown, nor can its failure adversely affect the operation of safety systems required for a safe reactor shutdown. It is an ALARA (as low as reasonably achievable) and a personnel safety concern for personnel near the turbine.

15.13 SHUTDOWN COOLING MALFUNCTION DECREASING TEMPERATURE

This malfunction was not reevaluated for the Fermi 2 power uprates.

At design power conditions, no conceivable single failure type malfunction is possible in the shutdown cooling system that can cause a temperature reduction.

If the reactor were critical or near critical, a very slow increase in reactor power could result. A shutdown cooling malfunction leading to a moderator temperature decrease could result from misoperation of the cooling water controls for the RHR system heat exchangers. The resulting temperature decrease would cause a slow insertion of positive reactivity into the core. If the operator did not act to control the power level, a high neutron flux reactor scram would terminate the transient without fuel damage and without any measurable increase in nuclear system pressure.

15.14 LOSS OF SERVICE WATER SYSTEM

This event was not reevaluated for the Fermi 2 power uprates.

The residual heat removal service water (RHRSW), the emergency equipment service water (EESW), and the emergency diesel generator service water (EDGSW) systems supply cooling water, either directly or indirectly, to all ESF equipment. Subsections 6.3.2.2.6, 9.2.5, and 9.5.5 describe these systems.

15.14.1 Identification of Causes

The loss of the service water systems listed above can be caused by loss of the service water pump, loss of electrical power, loss of the service water piping, loss of the heat exchanger, or loss of control circuits. The EESW system has a temperature regulator valve that fails open. The RHRSW system uses a manually controlled globe valve for flow control. The EDGSW systems do not have regulating valves.

15.14.1.1 Starting Conditions and Assumptions

This accident is analyzed using the following assumptions:

a. Prior to this event the reactor turbine is operating normally at full design reactor power (3292 MWt)

b. The DBA occurs: namely, the circumferential sudden break of a reactor recirculation loop pipe occurs

c. A complete loss of normal power occurs simultaneously with the recirculation pipe break

d. The EDGs start normally

e. The ECCS, HPCI, ADS, LPCI, and core spray systems start and operate normally

f. The RHRSW system is manually started and valved into the RHR heat exchangers between 10 and 30 minutes after ECCS initiation to limit the suppression pool temperature to less than l85°F.

15.14.1.2 Event Description

An individual loss of an EDGSW system will cause loss of only the particular EDG that it cools. The EDG loss will cause loss of only the loads for that particular generator because the Fermi 2 essential power system consists of four independent buses. The loss of the EESW system will cause loss of the emergency equipment cooling water (EECW) system in that division. This loss will cause the eventual loss of the ESF equipment in the particular division cooled by the EECW system.

Loss of the RHRSW system will cause loss of the RHR heat exchanger in that division. For a worst-case assumption, the EDGSW, EESW, and RHRSW systems are assumed to fail simultaneously in the same division coincident with the LOCA. The EDGs will start and load in both divisions. The EDGs without service water will operate approximately 3 minutes before overheating. The remaining division is unaffected.

The EECW system will start and isolate from the nonessential reactor building closed cooling water system (RBCCWS). This system will operate because it is a closed condensate system but will not be able to reject heat to the EESW system. When the EDGs in the division fail (from loss of EDGSW), the equipment serviced by the EECW will stop running. Thus, the EECW will no longer be needed. The remaining division is unaffected.

The RHRSW system failure will not allow the operator to use the RHR heat exchanger in that division. The remaining heat exchanger is unaffected.

15.14.2 Analysis of Effects and Consequences

15.14.2.1 Methods, Assumptions, and Conditions

In analyzing the failure of one division of the RHRSW system, it is assumed that the other division of service water is operable. This meets the single failure criterion (General Design Criterion 44). There are no common mode failures that can cause failure of both divisions of essential service water systems.

15.14.2.2 Results and Consequences

The failure of one divisional service water system results in no effect on the remaining divisional system. No additional operator action is required to initiate the remaining division. The loss of any service water subsystem and a single failure coincident with a LOCA will cause eventual loss of the division, but the effect is not as great as an immediate loss of one emergency power division coincidental with a LOCA. The consequences then reduce to the LOCA accident which assumes one division ESF equipment loss.

15.15 LOSS OF ONE (REDUNDANT) DIRECT CURRENT SYSTEM

This event was not reevaluated for the Fermi 2 power uprates.

15.15.1 Identification of Causes

Loss of one entire redundant dc system would be the result of a total loss of one of the batteries, plus the loss of the full capacity battery chargers or dc distribution panels. This could be due to a fire, hydrogen explosion, or equipment failure. However, the probability of each is very low because of the noncombustible nature of the room and the battery room ventilation requirements of six air changes per hour.

It would be more likely to lose one redundant battery due to the short circuiting of a cell or series of cells, hydrogen explosion within a cell, faulty fuse, or several other possible but rare events. Battery damage would not preclude the use of the charger for handling the normal loads unless it, too, were involved in the event. Any fault in the main distribution cabinet affecting the dc bus would cause the loss of only one division of the dc system.

15.15.1.1 Starting Conditions and Assumptions

The reactor is initially operating at l00 percent of rated power (3292 MWt).

15.15.1.2 Event Description

Loss of the ESF Division I 130/260-V dc battery would result in the loss of availability of the RCIC system and several motor operated containment outboard isolation valves. Loss of the ESF Division II 260-V dc system would eliminate the availability of the HPCI system and also remove motive power from several containment outboard isolation valves.

Since the 130-V dc supply for each ESF is derived from the 260-V dc center tapped battery, loss of the 260-V dc battery would eliminate control power to the ESF division of switchgear serviced from that particular l30-V dc system. Other pertinent effects would be a loss of diesel generator control, loss of control power to dc relays of the RHR and core spray systems, and loss of dc power to one reactor protection system (RPS).

Loss of one 48/24-V dc system would eliminate one redundant system of stack gas monitors, startup range neutron monitors, and process radiation monitors.

15.15.2 Analysis of Effects and Consequences

Assuming that a fire or other event rendered one dc system inoperative, the second redundant system would provide the capability of a safe shutdown.

The operation of the RCIC system is not essential to safe shutdown. Therefore, the loss of the RCIC system, due to the loss of the ESF Division I 260-V dc battery, would not prevent safe shutdown. Loss of motive power to the outboard isolation valves would not be critical, even if they should be needed, since each line is backed up with a redundant ac-operated isolation valve inside the containment.

A loss of an ESF Division II dc power system would remove the HPCI system should an incident occur in which the vessel did not depressurize. The HPCI system is, however, backed up by the automatic depressurization system (ADS), which has its power supply from the ESF Division I l30-V dc system. Thus, in the event of loss of all ESF Division II dc power, the ADS would depressurize the reactor, and the LPCI and core spray systems would provide adequate core cooling. Emergency diesel generators, RHR and core spray pump control, and RPS power are all redundant.

Loss of the 48/24-V dc system would have no significant effect because all indication is backed up with indication from the redundant division.

15.16 LOSS OF INSTRUMENT AIR SYSTEM

This event was not reevaluated for the Fermi 2 power uprates.

15.16.1 Identification of Causes

Equipment malfunctions or operator errors can initiate loss of instrument air supply system pressure.

15.16.1.1 Starting Condition and Assumptions

The station air compressor is loaded automatically to maintain 100 psi in the receiver tanks. The station air header automatic isolation valves are open, and the standby station air compressor is ready to automatically start.

15.16.1.2 Event Description

If the instrument air supply continues to decrease after falling pressure has initiated an automatic start of the standby station air compressor, the main control room will receive an alarm and the third station air compressor will be manually started.

15.16.2 Analysis of Effects and Consequences

15.16.2.1 Effects

Decreasing plant air pressure automatically shuts off plant air supply to equipment requiring station air and starts the control air compressors. An alarm occurs in the control room due to the control air compressor auto start. A sustained decrease in air pressure will cause isolation of both divisions of noninterruptible control air from the nonessential (non safety related) systems and components resulting in their associated equipment and systems being considered inoperative. In such a case, equipment or systems requiring station or interruptible control air go to a fail safe position or have qualified accumulators which automatically isolate to maintain the equipment in a safe condition. Isolation of the noninterruptible control air initiates an alarm in the main control room.

15.16.2.2 Analysis

The safety related portion of the instrument air system is the noninterruptible control air. Noninterruptible control air (NIAS) is supplied through two separate, fully qualified, distribution systems (Division I and II). Each division consists of a compressor, after cooler, filters, dryer, receiver tank, and distribution piping.

Reliability of the system (NIAS) is maintained by the fact that (1) equipment and piping is seismically qualified, (2) control air compressors and dryers are automatically electrically fed off the emergency diesel generators on loss of offsite power, (3) the system is automatically isolated on low header pressure or loss of offsite power, and (4) receiver tanks are capable of maintaining the system pressure at an acceptable level for the short duration transition period of the loss of offsite power event (See Table 8.3-5) until the compressors' electrical load is picked up by the diesel generators on loss of offsite power.

Based on the above, noninterruptible control air will provide the required instrument air on loss of station and/or interruptible air. Therefore, essential equipment will have the necessary control air available to perform their safety function through NIAS or accumulators.

APPENDIX 15A: DOSE CALCULATION MODELS AND SPECIFIC CALCULATIONAL VALUES

For a LOCA, the dose calculations have been re-evaluated as indicated in Section 15.6.5.5 using Alternative Source Terms (AST). The LOCA atmospheric dispersion factors for AST offsite doses were derived as per Section 2.3.4, with onsite (Main Control Room, modeled as a zero velocity vent release) AST dispersion factors derived as per Notes 4 and 7 to Table 15.7.4-1 for the AST Fuel Handling Accident analyses. The resulting LOCA AST atmospheric dispersion factors are provided in Section 15.6.5, replacing those discussed in Section 15A.1 and Table 15A-2 below. The resulting AST LOCA doses are shown in Section 15.6.5.

15A.1 OFFSITE TOTAL BODY AND THYROID DOSES (PRE-AST TREATMENT)

The whole-body and beta skin doses at the site boundary and low population zone have been calculated by the semi-infinite cloud model

$$D_{WB} = \sum_{i=1}^{n} \sum_{j=1}^{m} R_{ij} \frac{\chi}{Qj} DCF_i \qquad (15A\text{-}1)$$

where

D_{WB} = whole-body dose for time period of interest, rem

R_{ij} = integrated release of i^{th} isotope over j^{th} time interval, curies

$\frac{\chi}{Qj}$ = atmospheric dispersion factor to location of interest for j^{th} time interval, sec/m^3

DCF_i = dose conversion factor for i^{th} isotope, $\left[\frac{rem - m^3}{Ci - s}\right]$

The values of DCF_i has been evaluated in accordance with Regulatory Guide 1.3 as

$$DCF_i \ (0.25\bar{\Sigma}\gamma)_i, \text{for whole body dose} \qquad (15A\text{-}2)$$

$$DCF_i \ (0.23\bar{\Sigma}\beta)_i, \text{for skin dose} \qquad (15A\text{-}2a)$$

where

$\bar{\Sigma}\beta$ = average beta energy

$\bar{\Sigma}\gamma$ = average gamma energy

The values of $\bar{\Sigma}_{\beta}$ and $\bar{\Sigma}_{\gamma}$ used in the calculations are presented in Table 15A-1 (Reference 1).

Fermi site meteorological data collected from the 60-meter tower over the period June 1, 1974, to May 31, 1975, were used to calculate the short-term χ/Q values used in the accident analyses. Values of χ/Q for the site boundary and low-population zone are presented in Table 15A-2. The 5 percentile χ/Q for the appropriate time interval was used for the dose calculations.

Thyroid doses at the site boundary and low-population zone have been calculated by the model

$$D_{TH} = \sum_{i=1}^{n} \sum_{j=1}^{m} R_{ij} \frac{\chi}{Qj} B_j \frac{D\infty}{A} \tag{15A-3}$$

where

D_{TH} = thyroid dose commitment from exposure during time period of interest, rem

B_j = breathing rate during j^{th} time interval, m^3/sec

$\left(\frac{D\infty}{A}\right)_i$ = thyroid dose commitment conversion factor from i^{th} isotope $\left(\frac{rem}{Ci}\right)$

The values of B_j used in the calculations are in accordance with Regulatory Guide 1.3. The values of B_j for the appropriate time intervals are

Time Interval	B_j (m^3/sec)
0-8 hr	3.47×10^{-4}
8-24 hr	1.75×10^{-4}
>24 hr	2.32×10^{-4}

The values of $\left(\frac{D\infty}{A}\right)_i$ are presented in Table 15A-1 (Reference 2).

15A DOSE CALCULATIONAL MODELS AND SPECIFIC CALCULATION VALUES

REFERENCES

1. M. E. Meek and B. F. Rider, Compilation of Fission Product Yields, Vallecitos Nuclear Center, General Electric Co., NEDO-12154, January 1972.
2. Calculation of Annual Doses to Man from Routine Release of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR Part 50, Appendix, USNRC Regulatory Guide 1.109, Revision 1, October 1977.

TABLE 15A-1 DOSE CALCULATION RADIONUCLIDE PARAMETERS PRE-AST TREATMENT

Nuclide	Decay Constant (s^{-1})[a]	$\overline{E}_\gamma$ (MeV/dis)[b]	$\overline{E}_\beta$ (MeV/dis)[b]	D_∞ A (rem/Ci)[c]
I-131	9.98×10^{-7}	0.381	0.1904	1.49×10^{6}
I-132	8.37×10^{-5}	2.28	0.501	1.43×10^{4}
I-133	9.26×10^{-6}	0.60955	0.41	2.69×10^{5}
I-134	2.20×10^{-4}	2.626	0.61	3.73×10^{3}
I-135	2.91×10^{-5}	1.574	0.368	5.60×10^{4}
Kr-83m	1.05×10^{-4}	0.00258	0.0382	
Kr-85m	4.30×10^{-5}	0.158	0.2549	
Kr-85	2.05×10^{-9}	0.00223	0.2505	
Kr-87	1.51×10^{-4}	0.793	1.328	
Kr-88	6.78×10^{-5}	1.98	0.3497	
Kr-89	3.64×10^{-3}	1.87	1.312	
Xe-131m	6.74×10^{-7}	0.0201	0.1422	
Xe-133m	3.67×10^{-6}	0.0415	0.19	
Xe-133	1.53×10^{-6}	0.0461	0.135	
Xe-135m	7.38×10^{-4}	0.431	0.0958	
Xe-135	2.12×10^{-5}	0.248	0.317	
Xe-137	3.02×10^{-3}	0.183	1.78	
Xe-138	8.15×10^{-4}	1.13	0.632	

[a] Nuclear Decay Rate for Radionuclides Occurring in Positive Releases from Nuclear Fuel Cycle Facilities, ORNL/NUREG/TM-102, August 1977.

[b] M.E. Meek and B. F. Rider, Compilation of Fission Product Yields, Vallecitos Nuclear Center, General Electric Company, NEDO-12154, January 1972.

[c] Calculation of Annual Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR Part 50, Appendix I, USNRC Regulatory Guide 1.109, Revision 1, October 1977.

CHAPTER 17: QUALITY ASSURANCE

To ensure that the design and construction of the Enrico Fermi Atomic Power Plant Unit 2 (Fermi 2) were in conformance with applicable regulatory requirements and the established design bases, the Detroit Edison Company (Edison), as plant owner, established and implemented a Quality Assurance (QA) program that satisfied the requirements of Appendix B to 10 CFR 50.

Edison, acting as its own Architect-Engineer (A-E), designed major portions of the plant and procured the nuclear steam supply system (NSSS) and the remainder of the plant structures, systems, and components. Edison was assisted in its design effort by the assignment of certain tasks to qualified engineering firms. Administration and control of site erection and construction contractors were assigned to a Construction Manager.

Edison imposed the applicable requirements of Appendix B to 10 CFR 50 on the NSSS vendor, on the engineering firms involved, on the vendors who supplied plant items, and on the contractors who erected and constructed plant structures, systems, and components.

The Edison QA program and its implementation during the plant design, procurement, construction, and testing phases are described in Section 17.1.

The Edison QA program for plant preoperational testing, startup, operation, maintenance, and modification is described in Section 17.2.

17.1 DETROIT EDISON QUALITY ASSURANCE DURING DESIGN AND CONSTRUCTION

Edison established a QA program to control the design, procurement, manufacturing, installation, construction, inspection, and testing of the safety-related structures, systems, and components of Fermi 2.

The organization and procedures that implemented the program are described herein. Also included is a brief description of the corporate organization.

17.1.1 Organization for Quality Assurance

17.1.1.1 Corporate Organization

That part of Detroit Edison, down to the department level, having corporate responsibilities for quality-related activities for Fermi 2 is shown in Figure 17.1-1. More information on the corporate organization is located in Chapter 13 of the original FSAR.

The President, as chief operating officer, had overall responsibility for engineering, construction, operation, and maintenance of Edison's plants and for system development and interconnection. He was also responsible for establishing corporate policies, goals, and objectives on quality assurance matters. The management functions discussed below reported to him.

A Group Vice President was responsible for those Edison organizational units that provided for the planning, engineering, construction, operation, maintenance, and technical support of the company's power plants and electrical facilities. Vice Presidents of Planning and

Research, Operations, and Engineering and Construction reported to the Group Vice President.

The Vice President - Nuclear Operations, with overall responsibility for the operation, maintenance, and operational quality assurance for the Fermi 2 plant, reported to the President.

A Group Vice President responsible for administrative functions and the division organizations reported to the President.

The Manager - Quality Assurance, who was responsible for quality assurance at the corporate level, reported to the President.

17.1.1.2 Project Organization

The Vice President - Fermi 2 Project reported directly to the President. He had overall responsibility for the completion of construction and startup testing of the Fermi 2 project.

The Manager of the Project was responsible for the design, procurement, and construction activities for the project. He was supported by the Project Management Organization described herein.

The Manager - Startup, who was also Manager - Nuclear Operations, was responsible for the testing activities performed by the Startup Organization, including the checkout and initial operational testing, which was subject to the requirements of the QA program described in this section of the UFSAR.

Project functions were organized into five principal groupings, with the head of each group reporting to the Manager of the Project. The organizational structure of the Project Management Organization is shown in Figure 17.1-2. All groups except Project Engineering were located at the site. Project Engineering maintained an organizational unit at the site.

The Assistant Project Manager - Engineering had overall responsibility for administration and technical direction of the Project Engineering Organization.

The Technical Director provided technical direction to the Fermi 2 project and was assisted by a group of System Engineers and the Project Licensing Engineer in performing his duties, which included

a. Ensuring that safety reviews, safety analyses, and design reviews were conducted

b. Defining and controlling the technical scope of the project

c. Performing licensing activities

d. Ensuring compliance with technical regulatory requirements

e. Ensuring correctness of conceptual design documents and functional system descriptions

f. Ensuring adequacy of test criteria, procedures, and results

g. Identifying safety-related plant structures, systems, and components.

The Director - Project Design had overall responsibility for ensuring the adequacy of design performed by Project Engineering and various design contractors. Among his principal duties were the following:

a. Preparation, review, approval, and control of project design documents, including design instructions, system diagrams, drawings, specifications, design change notices, field modification requests, and purchase requisitions
b. Review and control of design documents produced by design contractors
c. Establishment of requirements and acceptance criteria for testing plant structures, systems, and components
d. Preparation of vendor document lists
e. Technical review of submitted vendor documents.

The Director - Project Engineering Assurance had responsibility for ensuring that the design activities of Project Engineering were adequately controlled and that the design achieved the plant quality objectives. Among his duties were:

a. Ensuring that design control procedures were prepared and implemented
b. Assisting Project QA in audits of Project Engineering activities and design contractors
c. Reviewing design documents for quality criteria
d. Ensuring that Project Engineering personnel were properly trained
e. Ensuring the adequacy of computer codes.

The Director - Project Field Engineering had overall responsibility for design activities performed at the site and for acting as the representative of Project Engineering. His principal duties included:

a. Reviewing and determining disposition of deviation disposition requests, design change requests, and field modification requests
b. Interpreting engineering specifications and drawings
c. Designing electrical conduit, cable trays, and supports
d. Designing small-bore process piping, instrument lines, and supports
e. Verifying or modifying design of large-bore supports
f. Reviewing contractor procedures for technical requirements
g. Providing as-built information for ASME Section III, Class 1, piping systems
h. Reviewing drawings prepared by contractors at the site
i. Interfacing with the Construction Manager's area superintendents through the area engineers.

Project Engineering was assisted by a number of A-Es and engineering consultants, namely:

Sargent & Lundy. Sargent & Lundy (S&L) was contracted to perform the civil, structural, and architectural design of the reactor building, prepare specifications for the primary containment vessel, perform certain electrical design tasks, and conduct piping system analyses. This work was performed as an extension of the Edison design effort and was subject to the same QA procedures and controls as those established for Edison's design efforts, including documented design reviews.

By a second contract, S&L had total responsibility for design of the residual heat removal (RHR) system. This included preparing design documents, procurement documents, and an approved bidders list; reviewing bids received by Edison; recommending contract awards; and reviewing contractor or vendor submittals (e.g., drawings, manufacturing and inspection plans, QA programs, and QA documentation) and recommending that they be approved or revised. S&L's QA program, as described in Topical Report SL-TR-1A, was implemented for this contract.

Stone & Webster. Stone & Webster (S&W) was contracted to assist Edison in the design area. A number of identified tasks were assigned, varying from total engineering responsibility, as in the case of the security system, to supplying personnel to work on Edison premises under direct Edison supervision. Work performed at the S&W offices was in accordance with applicable provisions of the S&W Standard Quality Assurance Program, 1-74A.

Giffels and Associates. Work performed by Giffels and Associates (G&A) was an extension of the Edison design effort. G&A received both design criteria and direction from Edison, and G&A work was subject to review and final approval by Edison.

NUS Corporation. NUS Corporation (NUS) acted as engineering consultant to perform calculations of pressure response in the annular space between the reactor pressure vessel (RPV) and sacrificial shield and for the redesign of the radwaste system. In addition, NUS provided environmental and licensing services for the project. Work was performed under the NUS QA program.

NUTECH. NUTECH acted as engineering consultant and was assigned three tasks: designing torus modifications; performing various tasks associated with the GE Mark I Owners Group; and reviewing the environmental qualifications of electrical equipment. Work was performed in accordance with the requirements of the NUTECH QA program.

The Site Manager, who was also an Assistant Project Manager, had overall responsibility at the site for directing construction activities and for completion and turnover of plant systems to the Startup Organization. Reporting to him were the Project Construction Superintendent; the Daniel International Project Manager; the Bechtel Project Manager; and the Director of System Completion.

The Project Construction Superintendent and his staff assisted the Site Manager in carrying out his duties involving construction activities.

Daniel International Corporation (DIC) was the Construction Manager for the project. The DIC Project Manager reported to the Project Management Organization through the Site

Manager. DIC was responsible for supervision of construction and for administration of the site installation and construction contracts awarded by Edison. In addition, DIC was responsible for construction engineering and implementation of the storage and preservation program for equipment, stored or installed.

Responsibilities of contractors at the site varied from having a complete QA program with an independent QA organization, to providing a work force and a limited-scope QA program.

Contractors providing their own inspection were structured organizationally so as to ensure the independence of inspectors from those directly responsible for the work.

If a contractor was required to provide an individual with responsibility for ensuring effective implementation of its corporate QA program, that individual reported to a responsible offsite corporate management level.

The Bechtel Power Corporation (Bechtel) was contracted as the Maintenance Contractor for the operational phase of the plant but was also assigned certain construction tasks. The Bechtel Project Manager on construction matters reported to the Site Manager. Bechtel's work was performed in accordance with Edison procedures or procedures developed by Bechtel and approved by Edison. Inspection of work was by Project QA.

The Director of Systems Completion was responsible for accomplishing turnover of systems from contractors to Edison, completing punchlist items for each turned-over system, coordinating the checkout and initial operations testing by the Startup Organization of Nuclear Operations, performing system hydros, and finally turning over systems to the Startup Organization for preoperational testing.

The Project Materials Director was the General Purchasing Department's representative on the Project Management Organization. He and his staff were responsible for all contracts, including purchasing and expediting activities for Project Management Organization procurements. Additionally, the Project Materials Director was responsible for purchase of materials for Nuclear Operations and operation of warehousing facilities at the site, including the receipt of materials and equipment purchased by Edison.

The Director of Project Controls was responsible for establishment and administration of project cost and scheduling programs. Activities of his department were not subject to requirements of the QA program.

The Project QA Director reported administratively to the Manager - Quality Assurance, but on project-related matters, he reported to the Manager of the Project. The Project QA Director was responsible for ensuring establishment and effective implementation of the project QA program by Edison and its suppliers and contractors and for coordinating project activities involving the interface with the Region III Office of the NRC. With two Assistant Project QA Directors, he provided administrative and technical direction to Project QA. The Project QA Director had stated authority to initiate action to stop work when significant quality problems existed and to bring about their resolution on a timely basis.

The organizational structure of Project QA is shown in Figure 17.1-3. The organization was located both at the site and at the Engineering Construction Center (ECT) at Troy, Michigan.

The Procurement QA Section of Project QA was responsible for activities associated with procurement of materials and equipment for the project. Included in its activities were the following:

a. Coordination on preparation of source surveillance plans with the General Purchasing Department, Inspection Division
b. Review of Edison procurement documents for items important to safety
c. Acceptance of supplier QA manuals
d. Audit of supplier QA programs
e. Maintenance of the approved suppliers list
f. Receiving inspections and supplier QA records review for procured items
g. Evaluation of vendors'/suppliers' performance
h. Participation in American Society of Mechanical Engineers surveys
i. Surveillance over material control practices in the warehouses.

The Construction QA Section of Project QA was responsible for auditing and surveillance of Edison and contractor activities at the site subject to requirements of the QA program for the project. Among its principal activities were the following:

a. Review and acceptance of contractor QA programs and procedures
b. Audit of onsite contractor QA programs
c. Audit of Edison and Construction Management groups at the site
d. Surveillance of contractor activities for compliance with procedures and quality requirements
e. Coordination of onsite NRC inspections by nonresident inspectors and preparation of responses to inspection reports
f. Reporting 50.55(e) deficiencies to the NRC and coordination and preparation of written reports
g. Review and approval of conditional releases
h. Preparation of management reports
i. Initiation of stop-work action when required
j. Preparation of contractor performance evaluations
k. Audit and surveillance of balance-of-plant construction activities
l. Investigation of significant quality problems and determination of corrective actions
m. Coordination of trend analyses.

The Finish Construction and Maintenance QA Section of Project QA was responsible for the surveillance and inspection of work performed by Bechtel, Plant Maintenance, and contractors who did not furnish inspection personnel. Among its principal activities were

a. Contractor maintenance and construction procedures review
b. Inspection planning
c. Development of inspection procedures and checklists
d. Maintenance and finish construction inspection and surveillance
e. Maintenance nondestructive-examination (NDE) activities
f. System completion and turnover monitoring and documentation review
g. Verification of completion of NRC commitments (hardware)
h. Review of project master punchlist
i. Verification of completion of punchlist items.

Engineering QA, located at Troy, Michigan, was responsible for monitoring and auditing activities associated with Project Engineering. Among its principal activities were the following:

a. Audit and surveillance of Project Engineering activities and support A-Es
b. Review of selected project procedures for offsite activities
c. Review of procurement specifications
d. Review of Edison-ECT procurement documents for QA Level I items
e. Preparation of responses to NRC bulletins, etc.

The Operational Assurance Section of Project QA was responsible for audit, surveillance, and inspection of activities and document review involving systems turned over to the Startup Organization for checkout and initial operations testing, including support activities performed by Nuclear Operations organizations. Among its principal activities were the following:

a. Inspection of startup tests
b. Surveillance of startup activities
c. Review of startup test procedures
d. Review of test results documentation
e. Coordination of nonconformance reports resulting from testing activities
f. Initiation of stop-work action when appropriate
g. Performance of trend analyses.

The Inspection Division of the General Purchasing Department provided qualified personnel to perform vendor surveillance, including inspection of hardware and release of materials and equipment for shipment. They also provided the expertise necessary to perform facilities surveys when potential bidders were being qualified. The participation of Inspection Division personnel in the project was coordinated through Project QA. Certain vendor surveillance and inspection was contracted to qualified outside organizations to augment Edison's vendor surveillance personnel.

Quality Control (QC) and technical specialists, such as metallurgists, NDE specialists, welding engineers, construction inspectors, and others from various Edison departments, were available to the project to participate in evaluation of manufacturing, installation, and construction problems and in audits of vendor and contractor activities. Efforts of QC and technical specialists in the latter role were coordinated through Project QA.

The Startup Organization was responsible for conducting testing of plant equipment and systems, beginning with the checkout and initial operations testing and proceeding through preoperational tests. Managerial and administrative controls for testing programs were prescribed in the Startup Manual.

Nuclear Production was responsible for the tagging of systems and components turned over to Edison jurisdiction from the contractors, for operating such systems and components, and for directing the maintenance and refurbishment programs.

Administration Services of Nuclear Operations was assigned responsibility by the Project Management Organization for the operation of the Document Control Center at the site and the QA records vault.

General Electric Company (GE), as the NSSS supplier, was a major participant in the Fermi 2 project. The official interfaces between the Edison and GE organizations were the GE project managers and Edison's Manager of the Project; at the working level, there were numerous interfaces. Review of designs was coordinated through the Assistant Project Manager - Engineering; audit and surveillance of GE's QA program and related activities were coordinated through the Director of Project QA; GE's involvement with licensing of the plant was coordinated by the Project Licensing Engineer; at the site, GE provided technical consultation and supervision in erection, testing, and operation of the NSSS through its Site Resident Manager and staff of technical and startup specialists and QC representatives. The Site Resident Manager and his staff coordinated their activities through the DIC Project Manager, the Edison Startup Engineer, and Project QA.

17.1.2 The Quality Assurance Program

In order to establish the highest degree of functional integrity and reliability for those structures, systems, and components that prevent or mitigate the consequences of postulated accidents that could cause undue risk to the health and safety of the public, Edison implemented a QA program, either directly or through its vendors and contractors, to meet the requirements of Appendix B to 10 CFR 50.

The objectives of this program were to ensure that:

a. Applicable regulatory criteria, codes, standards, and design bases were correctly translated into drawings, specifications, procedures, and instructions

b. Systems, components, and materials fabricated or tested in a manufacturer's facility conformed to drawings, specifications, procedures, and instructions

c. Structures, systems, and components constructed and tested at the Fermi site conformed to drawings, specifications, procedures, and instructions

d. Provisions were made for documenting and retaining information on quality-related activities performed on those structures, systems, and components whose satisfactory performance was necessary to meet plant safety and availability objectives.

The QA program, as defined in the QA manual, contained established written policies that were intended to (1) aid in achieving the program objectives, and (2) satisfy the requirements of each of the 18 criteria of Appendix B to 10 CFR 50.

In accordance with these policies, written procedures were established and implemented during the design, procurement, manufacturing, installation, construction, inspection, and testing phases of the project to delineate:

a. The structure, responsibilities, and functions of the corporate organization relative to QA

b. The Project Management Organization established by Edison for effective management of the project

c. The project personnel responsible for certain QA functions, and to define the responsibilities, duties, and authorities of persons and organizations performing QA functions

d. The responsibilities and methods to ensure that plant design was appropriately controlled in process and that its adequacy was verified and documented

e. The responsibilities and methods for evaluation and dispositioning of changes, deviations, and incidents affecting the plant configurations as defined in the approved design documents to ensure that such changes, deviations, and incidents were adequately controlled and did not compromise the design intent

f. The responsibilities and methods for receiving, identifying, filing, distributing, maintaining, and reporting status of project documents to ensure that such documents were adequately controlled

g. The control of procurement documents to ensure that requirements referenced or included therein for material, equipment, and services procured by Edison, or by its vendors and contractors, conformed to the requirements of the procurement documents

h. The identification and control of material, parts, and components to ensure the use or installation of only correct and accepted items

i. That the activities affecting quality were prescribed by appropriate written instructions, procedures, or drawings and were accomplished in accordance with these documents

j. That special processes were performed in accordance with qualified procedures and only by qualified personnel

k. That a program for inspection of activities affecting quality was established and executed to verify conformance to the documented instructions, procedures, and drawings prescribing a given activity

l. That a documented test program was established and implemented to demonstrate that structures, systems, and components performed satisfactorily in service

m. The control, calibration, and periodic adjustment of tools, gages, instruments, and other measuring and test equipment used to verify conformance to established requirements

n. Controls for the handling, storage, shipping, cleaning, packaging, and preservation of material and equipment to ensure the maintenance of quality from source through installation or use

o. Requirements, methods, and responsibilities for indicating inspection, test, and operating status of the plant structures, systems, and components

p. Methods of controlling items, services, or activities that do not conform to requirements

q. Methods to ensure that appropriate and prompt corrective action was taken when conditions adverse to quality were identified

r. That sufficient records were provided and maintained to furnish documentary evidence of the quality of items and of those activities affecting quality

s. That a comprehensive system of planned and documented audits was carried out to verify compliance with all aspects of the QA program, and to assess the effectiveness of the program; and further, to require that management review the audit results and take necessary action to correct deficiencies.

Those structures, systems, and components covered by the Edison QA program and the programs of vendors and contractors were indicated in the column titled "Quality Assurance Requirements" in Table 3.2-1 of the original FSAR.

The major organizations participating in the project and involved in the QA program, including their designated functions, are discussed in Subsection 17.1.1 and are summarized in the following paragraphs.

Edison, as plant owner, established and implemented a QA program in accordance with the requirements of Appendix B to 10 CFR 50. Edison performed the major part of the plant design; the preparation of procurement documents; the procurement of systems, materials, equipment, and services exclusive of the scope of supply of the NSSS; source inspection; site receiving inspection; and the site QA and certain QC functions not delegated to contractors.

General Electric, the NSSS supplier, was responsible for the design, procurement, manufacture, inspection, and predelivery testing of the components within its scope of supply and for providing technical direction and instructions for the installation and testing of the NSSS components and systems.

Daniel International Corporation was responsible for construction management at the site.

General Electric Company and the A-Es established and implemented QA programs that satisfied the applicable requirements of Appendix B to 10 CFR 50 as defined in the procurement documents. These programs were reviewed and accepted by Edison. The proper implementation of these programs was ensured by the performance of planned and periodic audits, with reaudits as necessary, by Edison Project QA.

Materials and components that were not supplied by GE were procured by Edison from qualified vendors. These vendors, with varying responsibilities for design, procurement, assembly, manufacture, inspection, and testing, established and implemented QA programs as required by the procurement documents. The QA programs of these vendors were reviewed and accepted by Edison QA, and their implementation was verified by planned and periodic audits.

Site installation and construction contractors established and implemented QA/QC programs commensurate with responsibilities and in accordance with contract requirements. The programs were reviewed and accepted by Edison QA.

The Fermi 2 QA policies, procedures, and instructions were contained in the project QA manual and in the project procedures manual.

The requirements and practices delineated in these manuals applied to the Project Management Organization, Project QA personnel, the Construction Management Organization, and Edison personnel or organizational groups who had any responsibilities for the project. Controlled copies of the manuals were distributed to these organizations and personnel.

Certain procedures in the manuals concerned work activities that were performed by others rather than Edison. In such cases, the requirements delineated in these procedures were imposed on the vendors, contractors, and A-Es performing the activities. The implementation of these requirements was verified by planned and periodic audits conducted by Project QA.

17.1.3 Design Control

Edison established and implemented procedures that delineated the design process from initiation through final approval and release, and determined that design activities were carried out in a planned and controlled manner, and that plant design adequacy was verified and documented.

The established procedures defined for participating design groups were:

a. Responsibilities, authority, reporting paths, and lines and methods of communication

b. Method of identifying and controlling design interfaces, including procedures for review, approval, release, distribution, and revision of documents involving interfaces.

The established procedures also delineated specific requirements and methods to ensure:

a. That applicable regulatory criteria and the design bases including codes and standards, as specified in the Preliminary Safety Analysis Report (PSAR), were correctly translated into design documents

b. That appropriate quality standards were specified and included in design documents. Quality standards include codes and industry standards, and must include appropriate quantitative or qualitative acceptance criteria for determining that activities were satisfactorily accomplished

c. That selection and review for suitability of application of materials, parts, equipment, and processes that are essential to the safety-related functions of items were accomplished

d. That proper attention was given to constructibility, accessibility for inservice inspection, maintenance, repair, and delineation of acceptance criteria for inspections and tests

e. That adequacy of design was verified and documented

f. That adequacy of a design was verified or checked by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program

g. That the verifying or checking process was performed by individuals or groups other than those who performed the original design

h. That, as a minimum, verifying or checking consisted of reviewing the design, spot checking the calculations or analyses, and assessing the results against the original design bases and functional requirements

i. That design verification documents identified the verification method utilized

j. That the method and scope of the design verification selected depended upon:

    1. Importance and complexity of design

    2. Degree of standardization

    3. The state of the art

    4. Similarity with previously proven designs.

k. That standardized or previously proven designs were carefully reviewed for applicability

l. That formal design reviews, normally consisting of a detailed check of the complete design, were performed. Personnel from Edison engineering, QA, operating, and construction departments or from a consulting engineering organization participated in these design reviews

m. That the adequacy and compatibility of the seismic design performed by vendors were evaluated by a third-party reviewer

n. That where necessary the adequacy of the final design was verified by documented qualification testing of the item or part under the most adverse design conditions

o. That design changes, including field changes, and deviations from design requirements were processed in accordance with established configuration control procedures

p. That design review documentation was filed and maintained with the controlled project QA records

q. That errors and deficiencies in the design process were determined, documented, and dispositioned, and that corrective actions were determined and implemented

r. That the applicable QA requirements of Appendix B to 10 CFR 50 were defined in the procurement documents for the NSSS vendor, and for the design tasks delegated to A-Es

s. That Project QA conducted planned and periodic audits of the Edison design process and of the design processes of others.

17.1.4 Configuration Control

Edison established and implemented procedures that delineated the responsibilities and methods for the evaluation and disposition of changes, deviations, and incidents affecting the plant configuration as defined in the approved design documents to ensure that such changes, deviations, and incidents were adequately controlled and did not compromise the design intent.

The established procedures contained provisions to ensure:

a. That Project Engineering was responsible for configuration control and for preparation of the required procedures

b. That changes, deviations, or incidents were classified as Type I or Type II; that configuration control procedures delineated the specific criteria for classifying and the responsibility for processing each type

c. That Type I was assigned to changes, deviations, or incidents that affected a characteristic or process that is essential to the safety-related function of an item. A listing of the systems, structures, and components that have a safety-related function was included in the configuration control procedures

d. That Type I was also assigned to changes, deviations, and incidents that do not involve a safety-related item but would

    1. Involve significant re-engineering of an approved design

    2. Affect a characteristic or process that is essential to the availability of the plant

    3. Have a major impact on plant cost or schedule

    4. Affect in-plant safety of operating personnel.

e. That Type II was assigned to changes, deviations, and incidents that did not meet the criteria for Type I

f. That coordination and implementation of the configuration control procedures at the construction site were the responsibility of Field Engineering

g. That changes to approved design documents initiated within Project Engineering were processed in accordance with the configuration control procedures

h. That changes to Edison-approved design documents by vendors, deviations accepted by vendors, and reported incidents occurring in vendor shops, of the Type I classification, were subject to review and concurrence by Project Engineering in accordance with the configuration control procedures

i. That the dispositioning of Type I changes, deviations, and incidents was by those who approved the original design, or by others to whom the responsibility was delegated; their approval was necessary before the disposition could be implemented. The evaluation and disposition were subject to the same requirements for control and documentation as specified for the original design in the design control procedures

j. That changes, deviations, and incidents occurring at the job site were referred to Field Engineering for review and action

k. That the evaluation and disposition of changes, deviations, and incidents were documented and the records retained in the project file.

17.1.5 Procurement Document Control

Edison, acting as its own Architect-Engineer, prepared the technical requirements for the majority of the procurement documents for materials, equipment, and services for the plant. Edison delegated this function to S&L for the RHR complex and the primary containment vessel.

Edison's established procedures were in effect to implement the preparation, review, approval, and control of procurement documents to ensure that the requirements included and/or referenced therein for material, equipment, and services procured for the plant agreed with the design intent and were sufficient to ensure adequate quality.

The established procedures defined the following responsibilities with respect to procurement documents:

a. The Director of Materials Control had the responsibility to coordinate the preparation and administration of procurement document control procedures

b. Project Engineering had the responsibility to prepare, or to delegate the preparation of, the technical content of procurement documents

c. Project QA had the responsibility to prepare, and ensure the inclusion of, the applicable QA requirement

d. Project QA had the responsibility to review the procurement documents to ensure compliance with the requirements of the procedures

e. Changes and/or deviations must have been approved by Project Engineering and Project QA.

The procedures included provisions to ensure that the procurement documents:

a. Were reviewed and that applicable regulatory requirements, design bases, quality requirements, and other requirements were included and/or referenced therein

b. Included requirements for vendors and contractors to provide QA programs in accordance with the identified requirements for QA and the elements of the program applicable to the items or services to be performed, for review and acceptance by Project QA, prior to the initiation of any activity

c. Included, as applicable, basic technical requirements including drawings, specifications, codes, and industrial standards with applicable revision data, test and inspection requirements, and special instructions and requirements such as for designing, fabrication, cleaning, erecting, packaging, handling, shipping, and field storage conditions

d. Included the right of access to vendor and contractor facilities and records for source inspection and audits by Edison and/or its agent

e. Provided for documentation requirements, identifying the documents to be prepared, submitted, maintained, stored, or made available for review, such as drawings, specifications, procedures, procurement documents, manufacturing and testing plans, inspection and test records, personnel and procedures qualifications records, and material, chemical, and physical test results

f. Included instructions for record retention and storage

g. Provided for extending applicable QA requirements to the vendor's or contractor's lower tier suppliers, and including Edison's or its agent's right of access to lower tier suppliers' facilities and records

h. Provided that changes and/or revisions were subject to the same reviews and approvals as the original document.

17.1.6 Instructions, Procedures, and Drawings

The Edison QA program contained provisions to ensure that activities affecting quality were prescribed by appropriate written instructions, procedures, or drawings and that the activities were accomplished in accordance with these documents.

Instructions, procedures, and/or drawings that prescribed quality-affecting activities delineated the method and sequence by which an activity was to be performed, and included appropriate quantitative or qualitative acceptance criteria for determining that the activity had been satisfactorily performed.

Contractors and/or vendors responsible for an activity were required to provide the necessary instructions, procedures, and/or drawings for the accomplishment of the activity.

These documents included as much detail as necessary to properly supplement information given in approved design documents in order that the quality-affecting activity was appropriately described.

The prepared documents were reviewed and approved by responsible personnel in the contractor's or vendor's organization, in accordance with QA program requirements, prior to performing the activity.

Edison may have required contractors or vendors to submit instructions, procedures, and/or drawings to Edison for review and concurrence prior to undertaking the activity. This requirement was established on the basis of the importance of the activity to plant safety or availability.

Project QA performed audits to ensure that approved and appropriate instructions, procedures, and/or drawings were used by Edison personnel and its vendors and contractors in performing any activity that may have affected quality.

Design control, configuration control, and document control procedures were followed in the preparation, receipt, identification, review, approval, processing of changes and deviations, retention and filing, retrieval, distribution, and control of instructions, procedures, and/or drawings.

17.1.7 Document Control

Edison established and implemented procedures to delineate the responsibilities and methods for receiving, identifying, filing, distributing, maintaining, and reporting the status of project documents to determine that such documents were adequately controlled.

The established procedures contained provisions to ensure:

a. That Edison had the overall responsibilities for document control and was responsible for the preparation of the necessary procedures for such control

b. That Edison had the responsibility for site control of documents and was responsible for the preparation of the necessary procedures for such control

c. That Edison had the responsibility for control of documents that recorded evidence of performance of activities affecting quality

d. That an identification system was established and implemented to permit the identification of documents with plant structures, systems, and components. All technical documents were assigned an identification code within the system

e. That documents were received at a central location at both the Edison office and the job site, and that the receipt was recorded

f. That document filing systems were such as to permit ready retrieval of both current and historical documents by reference to the identification system; and that access to the files was controlled to provide security from fire, water, and other hazards

g. That documentation distribution was made in accordance with distribution lists and controlled so that copies of the latest approved documents were available at the place and time needed

h. That documents superseded by revised issues and preliminary or other status drawings not approved for construction or fabrication, were controlled to prevent their inadvertent use

i. That prior to general distribution or release of a document, it had an identification number assigned to it

j. That distribution was accompanied by a transmittal letter, a copy of which, together with a record copy of the document, was maintained in the file

k. That file maintenance procedures established the retention time and final disposition of project documents

l. That a system of document reporting was established and implemented to provide periodic information about the document file; and that this report contained the following information as a minimum:

   1. Document control identification number
   2. Status
   3. Title or description of document
   4. Originator of document
   5. Status date
   6. Originator's identification number
   7. Originator's revision number.

m. That a master list of the current revision number of approved design documents was distributed periodically to the authorized distribution list

n. That document review and change and configuration controls were performed in accordance with the established procedures for design control, configuration control, and procurement document control

o. That documents controlled included, but were not limited to, design specifications; design instructions; design calculations; bills of materials; design, manufacturing, construction, and installation drawings; QA program manuals; QA procedures and instructions, checklists, and audits; procurement documents; manufacturing inspection and testing instructions; meeting minutes; accident reports; inspection reports; design change notices; deviation disposition reports; and correspondence

p. That the procurement documents delineated the requirements for document control that vendors and contractors must have met.

17.1.8 Control of Purchased Material, Equipment, and Services

Edison established and implemented procedures to ensure that safety-related material, equipment, and services procured by Edison, its vendors, and contractors conformed to the requirements of the approved procurement documents.

The established procedures contained provisions to ensure:

a. That quotations to furnish material, equipment, and services were solicited from qualified bidders

b. That criteria for qualification considered Edison's experience with the bidder, the bidder's reputation and experience in the field and in the nuclear industry, QA capability, and other facts, as appropriate

c. That qualification of bidders not on the approved bidders list was accomplished by a detailed evaluation that included assessment of the bidder's management capability, financial resources, plant facilities, technical capability, and QA program. To assist in the evaluation process, Edison representatives, including QA personnel, visited the contractor's or vendor's facilities, when deemed necessary and appropriate

d. That bidders proposing to furnish items or services important to plant safety or availability submitted their QA manual or an adequate description of their QA plan and procedures for review and concurrence by Edison

e. That the procurement documents delineated the documentation required to be furnished by the successful bidders as objective evidence of compliance with the procurement document requirements

f. That bids that were not responsive to the QA requirements of the procurement documents were rejected

g. That a source surveillance program was established and that this program required that:

    1. Vendors furnished Edison with sufficient information concerning their manufacturing and inspection plans to permit Edison to plan and implement a source surveillance plan

    2. Project QA coordinated establishment of the surveillance plan with the Inspection Division of the General Purchasing Department

    3. The surveillance plan included inspection of items, witnessing of tests or processes, and audits of vendor's QA program

    4. Material or equipment requiring source inspection in accordance with the surveillance plan was inspected for conformance to the procurement requirements

    5. This inspection verified that quality documentation existed and was complete

    6. An item could not be accepted if it did not conform to the procurement document requirements

    7. An item could not be accepted if the quality documentation did not comply with the procurement document requirements.

h. That site-receiving inspection of items was performed upon receipt in accordance with a documented receiving inspection plan

i. That items that had been inspected and accepted at the source were inspected at the site for shipping damage, correctness of identification, and proper quality documentation

j. That items that had not been inspected at the source had their quality verified by the review of submitted test reports, inspection, user tests, or other means as identified in the inspection plan

k. That documentary evidence that safety-related items conformed to procurement document requirements was available at the site prior to use or installation of such items

l. That documentary evidence was sufficient to identify that specific requirements, such as codes, standards, and specifications were met by the procured item. (This requirement could be satisfied by having available at the site copies of the purchase specification, purchase order, and a written certification of conformance to procurement requirements)

m. That Project QA verified the validity of certifications of conformance by vendor audits.

17.1.9 Identification and Control of Material, Parts, and Components

Edison established and implemented procedures to identify and control safety-related materials, parts, and components to ensure the use or installation of only correct and accepted items.

The procedures contained provisions to ensure:

a. That the procurement documents required that equipment and/or components be identified at the source, prior to shipping, in accordance with the plant identification system

b. That the procurement documents specified when there was a requirement for traceability of materials, parts, or components to their quality documentation

c. That the procurement documents required vendors to identify items in accordance with the plant identification system

d. That the procurement documents stated that the verification of the correct identification of items and their records was a condition for acceptance of the item

e. That source and receiving inspection planning included the verification of the correct identification of items and their records

f. That physical identification was used to the greatest extent possible for relating an item at any stage of work to an applicable drawing, specification, and/or other pertinent technical document

g. That where physical identification was impractical, physical separation, procedural control, or other appropriate means were employed

h. That identification could be either on the item or on records traceable to the item, as appropriate

i. That consideration was given to ensure that the location and method of identification did not affect the function or quality of the item being identified

j. That contractors established and implemented onsite procedures for the identification and control of materials, parts, and components.

17.1.10 Control of Special Processes

Edison established and implemented procedures to determine that special processes were performed in accordance with qualified procedures by qualified personnel.

Special processes were defined as those metallurgical, chemical, and other processes where assurance of the process quality was dependent largely on the inherent skill of the operator and on the control of the process parameters, and could not be ensured by direct inspection of the work alone. These included, but were not limited to, welding, heat treating, cadwelding, chemical cleaning, and nondestructive examination.

The established procedures contained provisions to ensure:

a. That Project Engineering, or its agent, established the requirements for special processes and for identifying these processes in drawings, specifications, procedures, and/or instructions, in accordance with applicable codes, standards, specifications, criteria, regulatory requirements, and other special requirements

b. That contractors and vendors, onsite and in manufacturing and production facilities, performed special processes with the use of qualified personnel and procedures that were in accordance with the design documents and applicable codes and standards as defined in the procurement documents

c. That documentation on procedure and personnel qualification was submitted to Edison, or its agent, for review and concurrence when required by the procurement documents

d. That equipment and procedures utilized in the performance, control, and inspection of special processes were qualified prior to use in accordance with approved engineering documents and identified codes and standards

e. That controlled conditions for accomplishing a special process were maintained

f. That personnel performing a special process were qualified by proper training and/or testing prior to performing the task, and that they were certified if so required by code or other requirements

g. That documentation was maintained for currently qualified personnel, processes, or equipment in accordance with the requirements of the design documents, applicable codes and standards, and the procurement documents

h. That the necessary qualifications of personnel, procedures, or equipment were defined in applicable design and procurement documents for special processes not covered by existing codes or standards, or where quality requirements exceeded the requirements of established codes and standards

i. That qualification documentation was made available to Edison, or its agents, and to recognized representatives of regulatory agencies

j. That qualifications documentation was regularly reviewed and audited by Project QA to ensure that personnel qualifications had not expired and that equipment and processes were properly qualified.

17.1.11 Inspection

Edison established and executed a program for inspection activities affecting quality to verify conformance to the approved instructions, procedures, and drawings prescribing a given activity.

The established procedures contained provisions that required:

a. That inspection planning included the identification and responsibility for performing and documenting inspections

b. That inspections were performed by individuals other than those who performed an activity and who were appropriately qualified as prescribed by code, specification, or other applicable document

c. That the current status of the qualifications of those who performed inspections was documented and maintained

d. That audits of inspection equipment were conducted to ensure that the equipment was within calibration to perform inspections requiring such equipment

e. That examination, measurement, or tests of items processed were performed after each work operation if deemed necessary to ensure quality

f. That when samples were used to verify the acceptability of a group of items, the documented sampling procedure was based on recognized standard practices and provided justification for the selected procedure

g. That inspection planning prescribed the need for monitoring processing methods and personnel when inspection of the finished product was impractical or inconclusive; and that both inspection and process monitoring were utilized when necessary for adequate control

h. That vendors maintained integrated manufacturing and inspection plans that were reviewed by Edison to establish an agreed-upon set of notification points, including mandatory inspection hold points, beyond which work could not proceed without acceptance by Edison

i. That Edison's General Purchasing Department Inspection Division, or its agent, was responsible for the inspection of vendor's activities in accordance with an inspection plan developed as a part of an overall vendor surveillance program

j. That when mandatory inspection hold points, beyond which work must not proceed until signed off by Edison or its agent, were required, they were indicated in appropriate vendor documents before work was initiated

k. That site contractors having first-level inspection responsibility prepare their inspection plans for review by Project QA and that Project QA establish notification and mandatory inspection hold points beyond which work could not proceed until approved by Project QA

l. That site contractors who furnished only labor prepare limited-scope QA plans and that inspection of their work was performed by Project QA.

17.1.12 Test Control

Edison established and implemented a documented test program in accordance with written controlled procedures to demonstrate that safety-related structures, systems, and components performed satisfactorily in service.

The procedures contained provisions to ensure:

a. That tests were performed at vendor facilities or at the job site, in accordance with written test procedures that included or referenced the requirements and acceptance limits contained in applicable design documents

b. That Project Engineering and responsible vendors provided test instructions, requirements, and acceptance criteria

c. That vendors and contractors were required to perform acceptance tests, prototype qualification tests, proof tests prior to installation, and performance tests, when prescribed by applicable design and engineering documents referenced in the procurement documents

d. That when tests were conducted in vendor facilities, the vendor prepared the test procedure for review and approval by Edison

e. That the Startup Organization, or its designated agents, prepared the acceptance, preoperational, and startup testing procedures

f. That the test specification and/or procedure included criteria that had been reviewed and found acceptable by the Project QA Organization, and that the Project QA Organization audited the performance of the testing activity to ensure that the established criteria had been satisfied

g. That test procedures included provisions to ensure that:

    1. Prerequisites for the test had been met

    2. Adequate instrumentation was available and used

    3. Necessary monitoring was performed.

h. That test prerequisites included, but were not limited to:

    1. Appropriate checklists and test report forms

    2. Calibrated instrumentation

    3. Adequate and appropriate equipment

    4. Trained, licensed, and/or certified personnel, as appropriate

    5. Test equipment in good condition

    6. Items to be tested that were in good condition

    7. Suitable environmental conditions

8. Mandatory hold points, as appropriate, for witnessing of tests by Edison personnel, or its agents, for tests performed at vendor facilities and at the site

9. Provisions for data acquisition, evaluation, and storage.

i. That test results were documented, reviewed, and evaluated by responsible personnel to establish that the test requirements and acceptance criteria had been satisfied

j. That nonconformances, when they occurred, were documented and resolved by the responsible organization. The resolutions and corrective actions, if required, were approved by the appropriate Edison personnel and the approval documented

k. That the acceptance status of the component or system tested was identified in accordance with established procedures.

17.1.13 Control of Measuring and Test Equipment

Edison established and implemented procedures for the control, calibration, and periodic adjustment of tools, gages, instruments, and other measuring and test equipment used to verify conformance to established requirements.

The established procedures contained provisions to ensure:

a. That vendors and contractors implemented written procedures for the control and calibration of tools, measuring and test equipment, and devices used in the manufacture, fabrication, assembly, and testing of an item

b. That inspection, test, and work procedures included provisions to ensure that tools, gages, instruments, and other measuring and testing equipment and devices used in activities affecting quality were of the proper range, type, and accuracy to verify conformance to established requirements

c. That inspection, measuring, and test equipment was controlled, calibrated, adjusted, and maintained at prescribed intervals, or prior to use, with calibration performed against acceptable standards

d. That qualified contractors calibrated, adjusted, and maintained measuring and testing equipment and instrumentation used during installation, construction, and acceptance testing

e. That the calibration status, date of calibration, and recall date were displayed prominently on each device, wherever possible, or on records traceable to the device

f. That controls were provided that prevent the use, by unauthorized personnel, of calibrated tools, gages, instruments, and other measuring and test equipment

g. That records of the calibration history were maintained and included such information as:

1. Calibration procedures and standards

2. Identification
3. Calibration data
4. Calibration recall date
5. Instrument characteristics condition at calibration
6. Control measures to prevent unauthorized use.

h. That contractors provided and maintained the calibration status and records of tools, gages, and other measuring and testing devices used by them at the job site

i. That when discrepancies in measuring and test equipment were found, a nonconformance report was issued. The report must include complete identification of the equipment and description of the work or item on which the out-of-calibration equipment was used. The recommended corrective action must include the requirement for a review of the materials, fabricated items, and/or components previously checked with the out-of-calibration equipment to determine if applicable quality standards had been met.

17.1.14 Handling, Storage, and Shipping

Edison established and implemented written work instructions and inspection procedures to control the handling, storage, shipping, cleaning, packaging, and preservation of material and equipment, to establish the maintenance of quality from source through installation or use.

The established procedures contained provisions that ensured that:

a. Project Engineering established and included in procurement documents the requirements for handling, cleaning, preservation, packaging, shipping, and storage of materials and equipment in conjunction with vendors and the Construction Manager at the site

b. Instructions were included in the procurement documents concerning marking and labeling for packaging, shipment, and storage of items. Marking must have been sufficient to identify, maintain, and preserve the shipment, including the indication of the presence of special environments or the need for special control

c. Project QA personnel reviewed the procurement documents for the inclusion of instructions to vendors to provide information on handling, cleaning, preservation, marking and labeling, packaging, shipping, and storage of the product supplied

d. Vendors, in their shops, and contractors at the site, provided and controlled special handling tools and equipment necessary to maintain safe and adequate handling of critical, sensitive, perishable, or high-value items. Special handling tools and equipment, including but not limited to lifting devices, cables, hooks, slings, cranes, and their appurtenances such as brakes and safety devices, were inspected and tested by qualified personnel in accordance with written procedures at specified times, to verify that the tools and equipment were adequately maintained and were suitable for the intended use

e. Edison Inspection Division personnel, or its agent, verified that the shipping requirements were met prior to release of an item for shipment

f. The Construction Manager prepared and implemented procedures at the job site in accordance with identified requirements for receiving, storing, and preserving materials and equipment

g. When necessary for particular items at the site, special coverings, special equipment, and special protective environments, such as inert gas, and specific moisture-content levels, were specified through Project Engineering, and were provided by the Construction Manager, and their existence and presence were verified by Project QA

h. Project QA established surveillance plans to assess and document onsite compliance with the handling, cleaning, preserving, and storing procedures

i. Nonconformances were reported, corrective actions specified, and monitoring performed to establish compliance with required corrective actions

j. Project QA reviewed the documentation furnished with items received at the site so that the contractor complied with the requirements noted therein.

17.1.15 Inspection, Test, and Operating Status

Edison procedures were in effect to delineate the requirements, methods, and responsibilities for indicating inspection, test, and operating status of the plant structures, systems, and components during manufacturing, installation, testing, and operation.

The established procedures included provisions to ensure that:

a. The inspection and test status of items in vendor shops or at the site was identified, where practicable, by use of stamps, tags, labels, or other suitable means and on records traceable to the item

b. Vendors implemented, in their shops, a system for indicating the inspection, test, and operating status of an item

c. Stamps, tags, labels, or other means of marking were in an approved format and that they conveyed by their color, shape, design, or other characteristic a uniform, unambiguous message

d. Nuclear Production established procedures for the control of test and operating status indicators including the authority for application and removal of tags, markings, labels, and stamps

e. The operating status of systems and components was clearly indicated by suitable means to prevent inadvertent operation and/or hazard to personnel

f. The status indication system did not allow bypassing of inspections, tests, and other critical operations.

17.1.16 Nonconforming Materials, Parts, Components, Services, and Activities

Edison established and implemented procedures to delineate the methods of controlling materials, parts, components, services, or activities that did not conform to established requirements.

The established procedures contained provisions to ensure that:

a. Vendors had in effect acceptance procedures for the control of nonconforming items that included delineation of the vendor's method of identification, segregation, documentation, and evaluation of nonconforming items

b. Edison approval was required on vendor dispositions that

   1. Accepted the nonconforming item "as is"

   2. Allowed rework or repair by a procedure that had not received prior approval by Edison.

c. Upon identification of a nonconformance, contractors at the site suspended the affected work until the nonconformance was evaluated if

   1. The continuance of the work would cover up the nonconformance and make its correction difficult

   2. The nonconformance was caused by the work procedure and continuing the procedure would increase the extent or severity of the nonconformance.

d. Nonconforming items, where practical, were segregated from acceptable material in a controlled access location; when this was not practicable, control of the nonconforming item was maintained by tagging, marking, or other clear means of identification

e. Reports of nonconforming items, services, or activities were dispositioned in accordance with configuration control procedures

f. Occurrence of nonconforming items, services, or activities was reported to affected organizations

g. Nonconforming items were repaired or reworked in accordance with documented procedures, and that, before the acceptance of such repaired or reworked items, they were reinspected in accordance with documented applicable inspection plans and procedures

h. Nonconforming items that were rejected were removed from the work location in vendor shops, and from the job location during construction

i. Documentation for items that had been repaired, reworked, or accepted "as is" described the change, waiver, or nonconformance that had been accepted and denoted the as-built condition

j. Reports of onsite nonconforming items or services were filed in the Project QA office, with copies forwarded to Field Engineering for disposition.

17.1.17 Corrective Action

Edison established and implemented written procedures to ensure that appropriate and prompt corrective action was taken when conditions adverse to quality were identified.

The established procedures contained provisions to ensure that:

a. QA and QC personnel promptly identified and reported on conditions adverse to quality, such as failures, malfunctions, deficiencies, nonconformances, defective material and/or equipment, and procedural nonconformances

b. The reports on conditions adverse to quality were submitted to Field Engineering for action in accordance with established configuration control procedures

c. Corrective action was taken as soon as practical

d. The technical aspects of conditions adverse to quality were resolved by Project Engineering

e. Project Engineering concurred with or rejected solutions provided by vendors or site contractors

f. Project QA determined the cause of significant conditions adverse to quality and that corrective action was taken to preclude repetition

g. Nonconformances to approved project procedures and instructions were reported to Project QA for action

h. Responsible management of the affected vendor or contractor was promptly notified and made aware of the problem and the required corrective action

i. When conditions adverse to quality existed at the site that required prompt action, and the required corrective measures were not taken by responsible supervision when properly notified, the Project QA Director exercised stop-work authority in the affected area

j. Identification of significant conditions adverse to quality, the cause of the condition, and the corrective action taken were documented and reported to appropriate levels of management by Project QA.

17.1.18 Quality Assurance Records

Edison established and implemented requirements that ensured that sufficient records were provided and maintained to furnish documentary evidence of the quality of items and of those activities affecting quality.

Established procedures contained provisions that ensured that:

a. The Document Control Center had the overall responsibility for receiving, filing, and maintaining QA records during and until completion of construction

b. Project QA was responsible for reviewing QA records generated or received at the site

c. QA record requirements, including type and content, were identified in procurement documents

d. Requirements and responsibilities for record transmittal, retention, and maintenance subsequent to the completion of construction were established and documented by written procedures

e. Required QA records included as-built drawings, operating logs, and the results of reviews, inspections, tests, audits, monitoring of work performances, nonconformances, corrective action reports, and materials analyses

f. QA records contained data on the qualification of personnel, procedures, and equipment involved in the quality-related activity

g. The inspection and test reports included identification of the inspector or data recorder, the type of observation made, the test or measurement equipment used, the results, their acceptability, and the disposition of any deviations found

h. Records were identifiable as to structure, system, component, and/or materials, were retrievable, and were secured against loss by theft, fire, or deterioration

i. Vendors or contractors who retained QA records must have met Edison's requirements on retention, and that the records were made available for use by Edison, or its agent, on demand

j. Procurement documents included the requirement that vendors or contractors notify Edison when they intended to dispose of their retained QA records so that Edison could be permitted to take possession of the records

k. Edison was responsible for all QA records, whether retained by Edison or its vendors or contractors

l. Permanent records, such as as-built drawings, and other records required for the operation, maintenance, inservice inspection, or plant maintenance, were retained and maintained for the life of the plant

m. Planned and periodic audits were conducted by Edison and its vendors and contractors to ensure compliance with the requirements for record maintenance and retention.

17.1.19 Audits

Edison established a comprehensive system of planned and documented audits to verify compliance with all aspects of the Project QA program and to assess its effectiveness. Responsible management had the responsibility to review the audit results and to take necessary action to correct deficiencies.

Audits of the program were performed to:

a. Provide an objective evaluation of compliance with established requirements, methods, and procedures

b. Assess progress in assigned tasks

c. Determine the adequacy of QA program performance

d. Verify the implementation of recommended corrective action.

The Project QA Director was responsible for ensuring that periodic audits of the project QA program or any portion of it, as deemed necessary, were conducted and the findings reported to responsible management.

Project QA conducted planned and periodic audits of the QA programs of vendors and contractors and reported findings to the Manager of the Project, the Project QA Director, and responsible management of the area audited.

Audits were performed in accordance with written procedures and/or checklists by appropriately trained personnel having no direct responsibilities in the area audited. Audits were scheduled and conducted on the basis of the status and safety importance of the activity being performed.

Audits included an objective evaluation of:

a. Quality assurance practices, procedures, and instructions
b. The effectiveness of program implementation
c. Conformance to policy directives.

Audits also included an evaluation of:

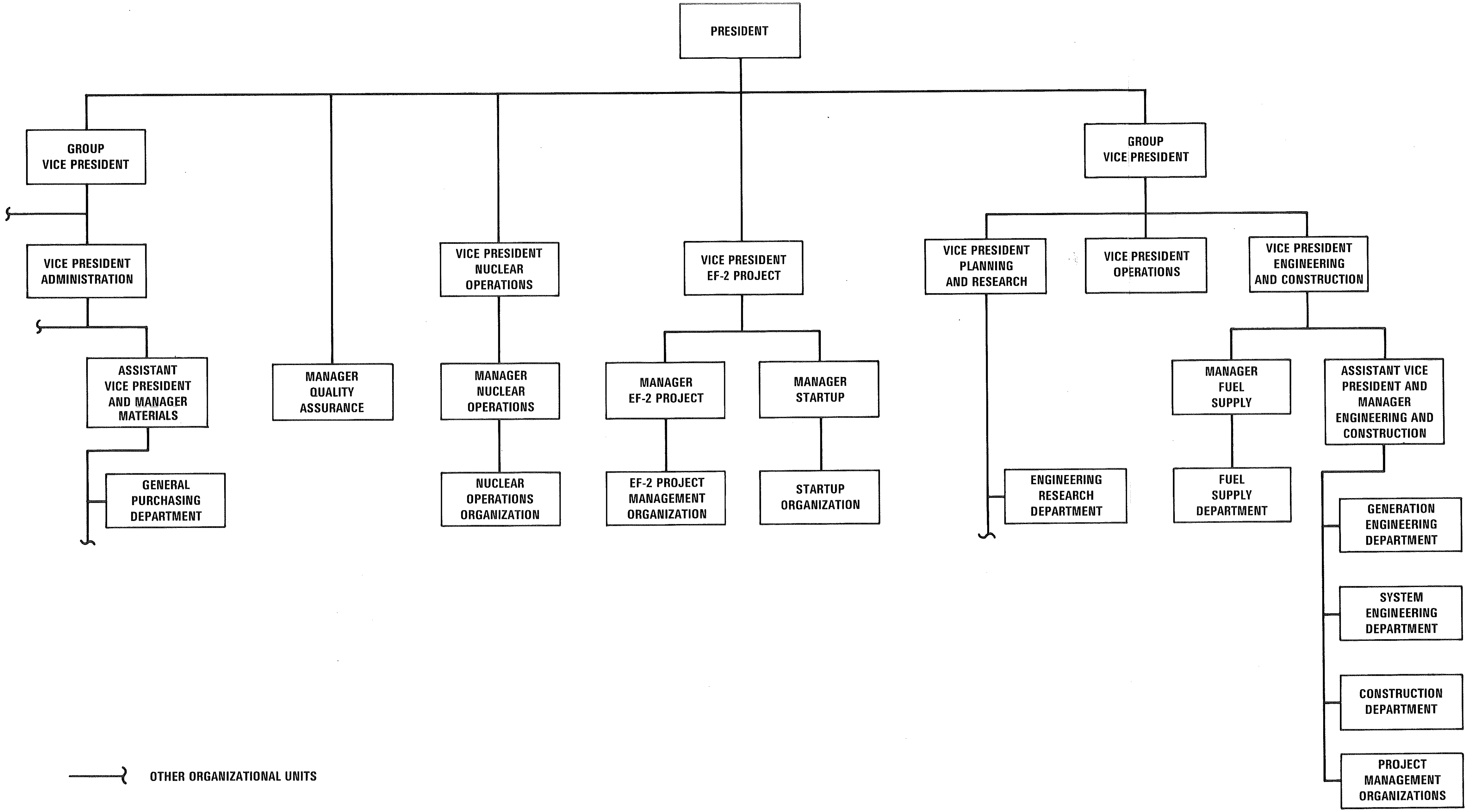
a. Work areas
b. Activities
c. Processes
d. Items
e. Documents and records, and their storage and retrievability.

Audits were initiated early enough to ensure effective implementation of QA programs at the beginning of design, procurement, manufacturing, installation, construction, and testing activities.

Audits were scheduled when one or more of the following conditions existed:

a. When it was necessary to determine the acceptability of a vendor's or contractor's QA program prior to award of a purchase order or contract
b. When, after the award of a purchase order or contract, it was appropriate to determine that a vendor or contractor was implementing his QA program
c. When significant changes were made in functional areas of the QA program, including significant organizational changes and/or procedural revisions
d. When it was suspected that safety, performance, or reliability of the item was in jeopardy because of deficiencies and nonconformances in the QA program
e. When a systematic and independent assessment of program effectiveness or item quality, or both, was considered necessary
f. When it was considered necessary to verify the implementation of required corrective actions.

Suppliers, vendors, and contractors who were providing safety-related materials, components, or services were contractually required to conduct audits as part of their QA programs.



Fermi 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 17.1-1

PORTION OF DETROIT EDISON CORPORATE ORGANIZATION WITH CORPORATE RESPONSIBILITY FOR PROJECT QUALITY-RELATED ACTIVITIES

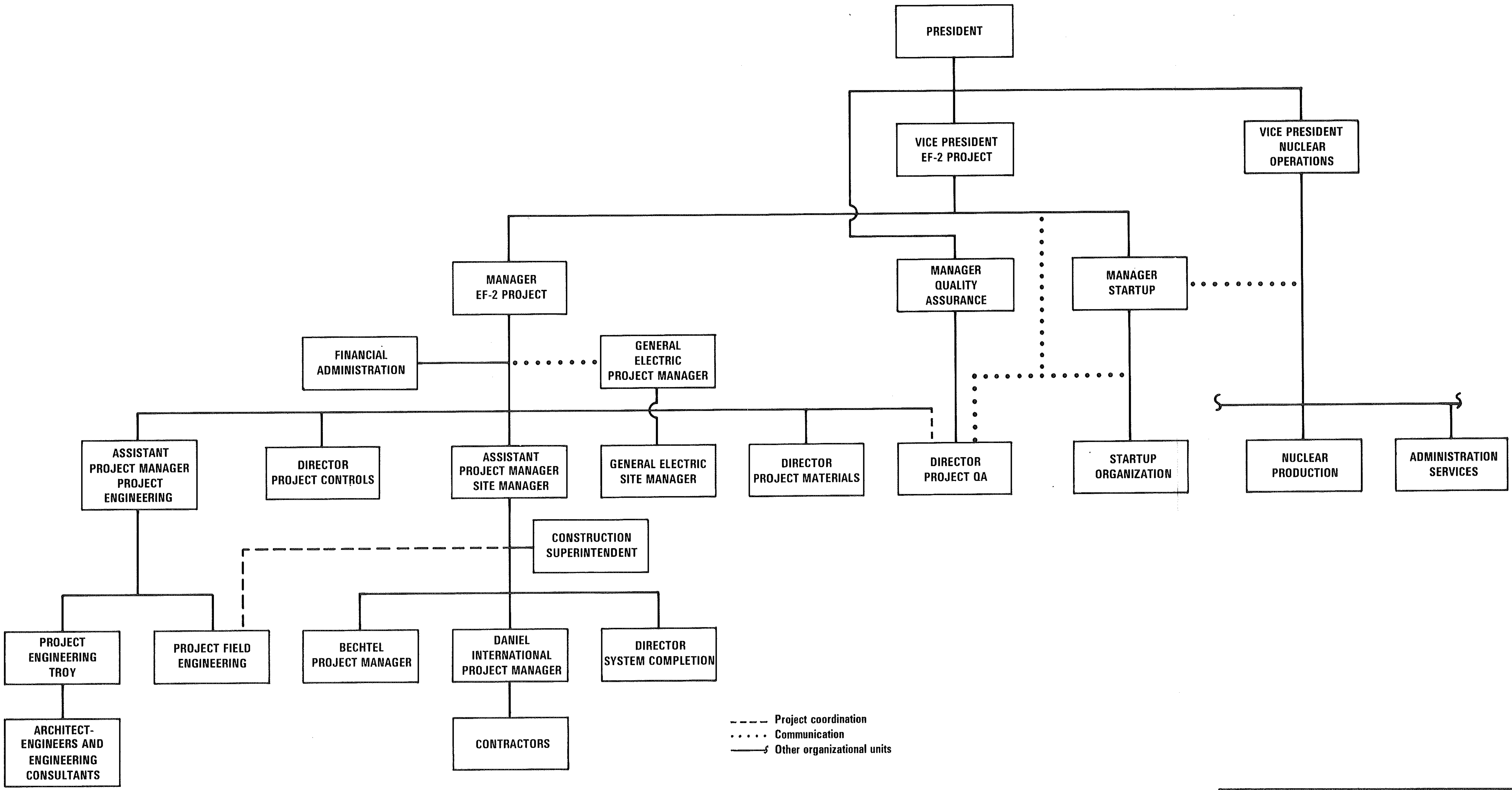


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FIGURE 17.1-2

FERMI 2 PROJECT ORGANIZATIONS

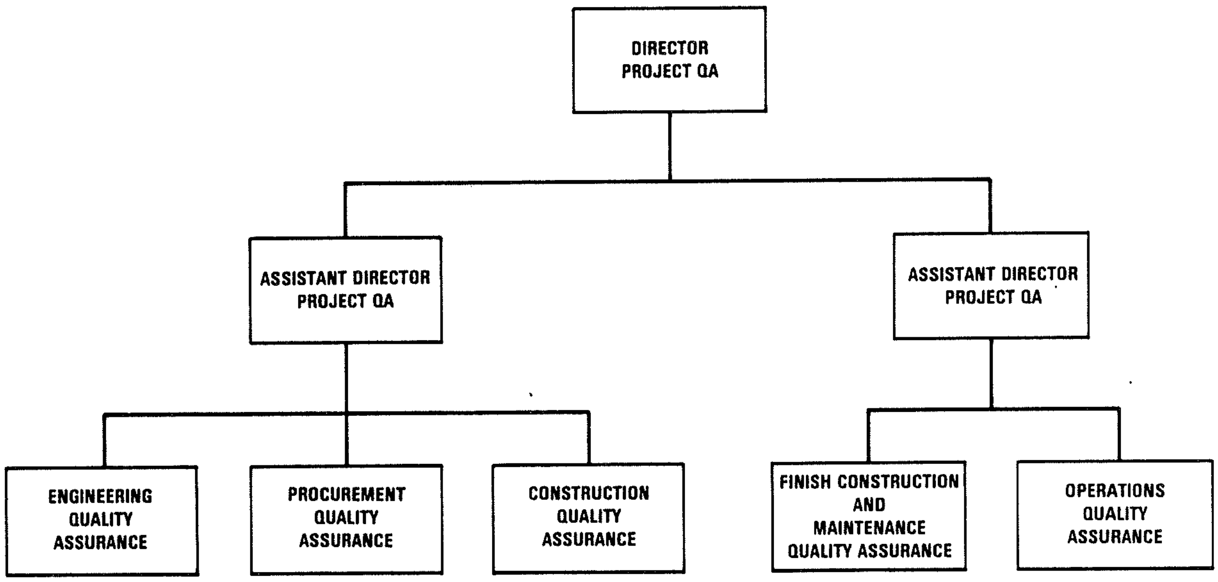

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FIGURE 17.1-3

PROJECT QUALITY ASSURANCE ORGANIZATION

17.2 QUALITY ASSURANCE PROGRAM FOR PLANT OPERATION

The DTE Electric Company (DTE) operational quality assurance (QA) program is based on American National Standards Institute (ANSI) Standard N18.7-1976, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants," as modified by Regulatory Guide 1.33 as addressed in Appendix A of the UFSAR. The program is structured and implemented in accordance with the guidance of the ANSI standards referenced therein and the associated regulatory guides that endorse them. Compliance with this guidance ensures a comprehensive QA program and an effective implementation of that program for compliance with the requirements of Appendix B to 10 CFR 50 and Appendix A to Branch Technical Position (BTP) APCSB 9.5-1, "Guidelines for Fire Protection for Nuclear Power Plants."

NOTE: When a position is not filled, reporting order will be to the next higher position.

17.2.1 Organization

The organizational structure, responsibilities, authorities, and functions of the nuclear organization (Nuclear Generation) are described in this subsection. Those corporate organizational units that support the operation and maintenance of the plant and perform activities subject to the requirements of the QA program are also described. Those organizational units include Supply Chain as discussed in Subsection 17.2.7.

The DTE corporate organization is described in Subsection 13.1.1. That portion of the corporate organization that is involved with activities subject to the QA program is shown in Figure 17.2-1.

17.2.1.1 Senior Vice President and Chief Nuclear Officer (CNO)

The Senior Vice President and Chief Nuclear Officer reports to the President and Chief Executive Officer, DTE Energy. The CNO has responsibility for the overall administration of DTE Nuclear power. The CNO is the ultimate Management Authority for establishing QA Policy and responsibility for the quality assurance function. Reporting to the CNO are the Director – Nuclear Oversight, the Site Vice President – Nuclear Generation, Vice President – Engineering and Technical Support, Director – Strategic Business Operations, and the Nuclear Safety Review Group (NSRG) Chairman. The Senior Vice President and Chief Nuclear Officer is also responsible for the Employee Concerns Program.

17.2.1.1.1 Director – Nuclear Oversight

The Director – Nuclear Oversight is responsible for establishing a sustainable oversight model for Fermi. This includes responsibility for Quality Assurance. Reporting to the Director – Nuclear Oversight is the Manager – Nuclear Quality Assurance.

17.2.1.1.1.1 Manager - Nuclear Quality Assurance

The Manager - Nuclear Quality Assurance is responsible for (1) ensuring the establishment and effective implementation of the Nuclear Generation Quality Assurance Program; (2) monitoring and evaluating the implementation of the Quality Assurance Program within Nuclear Generation by conducting planned and periodic audits; (3) reporting the audit findings to the Site Vice President – Nuclear Generation and Vice President – Engineering and Technical Support; (4) providing direction on Quality Assurance matters to the Executive Director - Nuclear Production; (5) recommending solutions to identified quality problems and verifying implementation of solutions for NQA identified problems which are significant conditions adverse to quality; and (6) issuing action to stop work when appropriate. The Manager - Nuclear Quality Assurance reports to the Director – Nuclear Oversight.

The Manager - Nuclear Quality Assurance has the authority and the responsibility to initiate action to suspend any activity, except reactor operation, if he/she discovers or suspects that a deviation from the QA program has occurred or is developing; nonconformances that appear to warrant suspension of reactor operation, including startup or power generation, will be reported to the Executive Director - Nuclear Production immediately.

The Manager - Nuclear Quality Assurance will meet the following qualifications:

Education: Bachelor Degree in Engineering or related science or the equivalent in practical experience.

Experience: Four years experience in the field of quality assurance, or equivalent number of years of nuclear plant experience in a supervisory or management position preferably at an operating nuclear plant or a combination of the two. At least one year of this four years experience shall be nuclear power plant experience in the implementation of the quality assurance program. Six months of the one year experience shall be obtained within a quality assurance organization.

An additional year of quality assurance program implementation experience may be substituted for six months experience within a quality assurance organization. The equivalent in practical experience to a Bachelor Degree in Engineering or related science is an additional four years experience in the fields of quality assurance, engineering or nuclear plant experience.

The review of implementing QA procedures and the review of nonconformance and corrective action documents covering significant conditions adverse to quality and safety and selected nonsignificant conditions adverse to quality is performed by Nuclear QA.

The NQA organization supports other units within Nuclear Generation to provide the required quality assurance functions.

17.2.1.1.1.1.1 Nuclear Quality Assurance Responsibilities

The Manager - Nuclear Quality Assurance and his/her staff are responsible for the following activities:

a. Performing surveillances of selected plant operations and maintenance and modification activities, Design Engineering, Tactical Engineering and Strategic

Engineering activities, instrument and control activities, transporting of radioactive material, fire protection and other activities which implement the QA program.

b. Review of maintenance and modification procedures, and inspection of maintenance and modification work.

c. Performance of nondestructive testing and examinations or review of its results.

d. Evaluation of inspection and surveillance results.

e. Review of selected engineering related documents.

f. Evaluation of existing and emerging issues and problems having safety significance.

g. Ensuring the content and adequacy of quality program requirements are included in the Fermi Conduct Manuals.

h. Performing audits and surveillances of Nuclear Generation units implementing the QA program.

i. Perform audits and surveillances of the corrective action process.

j. Performing audits and surveillances of onsite and offsite engineering organizations including contractors.

k. Performing supplier audits, source surveillances and commercial grade surveys.

l. Maintenance and issuance of an approved suppliers list.

m. Performing audits and surveillances of the procurement process.

n. Performing special assigned tasks.

17.2.1.1.2 Corporate Support

Corporate Support functions are described in Section 13.1.1.3.2.

17.2.1.1.3 Director – Strategic Business Operations

The functions of the Director – Strategic Business Operations are described in Subsection 13.1.1.3.3.

17.2.1.1.4 Vice President – Engineering and Technical Support

The Vice President – Engineering and Technical Support reports to the Senior Vice President and Chief Nuclear Officer and also has access to the President and Chief Executive Officer, DTE Energy for the reporting of nuclear safety problems. This individual has responsibility for the administration of engineering, including engineering aspects of the fire protection program, and technical support organizations. Reporting to the Vice President – Engineering and Technical Support are the Director – Nuclear Engineering, the Director – Nuclear Technical Support – Project Management, and the Manager – Nuclear Licensing. Supply Chain has a functional relationship to the Vice President – Engineering and Technical

Support. Additional detailed description of those organizations reporting to the Vice President – Engineering and Technical Support is provided in Section 17.2.1.2.

17.2.1.1.5 Site Vice President - Nuclear Generation

The Site Vice President - Nuclear Generation reports to the Senior Vice President and Chief Nuclear Officer and also has access to the President and Chief Executive Officer, DTE Energy for the reporting of nuclear safety problems. The authority and responsibilities of the Site Vice President - Nuclear Generation are discussed in Subsection 13.1.1. He/she has the overall responsibility for the implementation of the QA program and the fire protection program by Nuclear Generation. He/she is assisted by the Executive Director – Nuclear Production, the Manager – Nuclear Security, the Manager – Nuclear Performance Improvement, and the Director – Nuclear Training.

Additional detailed description of those organizations reporting to the Site Vice President – Nuclear Generation is provided in Section 17.2.1.2.

17.2.1.2 Organizations and Positions Reporting to the Site Vice President – Nuclear Generation and the Vice President – Engineering and Technical Support

17.2.1.2.1 Executive Director - Nuclear Production

NOTE: The titles of Plant Manager and Executive Director - Nuclear Production have the same functional responsibility

The Executive Director - Nuclear Production is responsible for the operation, maintenance, and plant administration of Fermi 2 and for the implementation of quality-related procedures and implementing the fire protection program. A detailed description of the Executive Director - Nuclear Production's organization, including responsibilities, authorities, duties, and qualifications for all key staff positions, is given in Subsection 13.1.2.

17.2.1.2.2 Director – Nuclear Technical Support – Project Management

The functions of the Director – Nuclear Technical Support – Project Management are described in Subsection 13.1.2.3.

17.2.1.2.3 Director – Nuclear Engineering

The Director – Nuclear Engineering is responsible for design engineering, including nuclear fuel design and management, strategic engineering, inservice inspection, performance engineering, procurement engineering, and modifications and configuration management in support of plant operations. The Director - Nuclear Engineering is responsible for the formulation and effectiveness of the fire protection program. Reporting to the Director – Nuclear Engineering are Manager – Nuclear Design Engineering, Manager - Nuclear Strategic Engineering, Manager - Nuclear Performance Engineering, and Manager – Nuclear Tactical Engineering.

17.2.1.2.3.1 Manager – Nuclear Design Engineering

The Manager – Nuclear Design Engineering has the overall responsibility for the Fermi 2 plant configuration management program. The Manager – Nuclear Design Engineering is responsible for Engineering Projects and Modifications, and engineering support functions associated with modifications to plant structures, systems and equipment. This responsibility includes the planning and management of the engineering scope and specification, detailed design, procurement, installation and testing phases of the modification. Nuclear Quality Assurance advises the Manager – Nuclear Design Engineering on Quality Assurance matters.

17.2.1.2.3.2 Manager – Nuclear Strategic Engineering

The Manager – Nuclear Strategic Engineering is responsible for strategic engineering.

17.2.1.2.3.3 Manager – Nuclear Performance Engineering

The Manager – Nuclear Performance Engineering is responsible for inservice inspection, including nondestructive examination activities or review of the results, the equipment qualification program, the fire protection program, nuclear fuel, reactor engineering, and probabilistic risk assessment (PSA).

17.2.1.2.3.4 Manager – Nuclear Tactical Engineering

The Manager – Nuclear Tactical Engineering is responsible for Procurement Engineering, including functions of approving procurement documents to ensure that technical and quality requirements are imposed for safety-related or important to safety applications, providing technical support for quality-related supplier oversight, providing evaluations for equivalent part replacements, performing design changes to plant components, and receiving and inspecting safety-related material and supplies.

The Manager – Nuclear Tactical Engineering is also responsible for the Engineering Response Team, including functions of assisting Operations and Maintenance with emergent plant issues, providing technical evaluations for degraded equipment, and performing replacement part evaluations in addition to design changes to plant systems.

The Manager – Nuclear Tactical Engineering has a functional relationship to the Manager – Nuclear Design Engineering, who has overall responsibility for the Fermi 2 plant configuration management program, for the approval of design changes to plant systems and components.

17.2.1.2.4 Director – Nuclear Training

The Director - Nuclear Training is responsible for developing and implementing training programs in support of the safe and efficient operation of the plant. The Director - Nuclear Training also provides the support for licensed operator medical issues.

The training program is described in Section 13.2.

17.2.1.2.5 Other Managers in Figure 17.2-1

17.2.1.2.5.1 Manager – Nuclear Licensing

The Manager - Nuclear Licensing is responsible for nuclear licensing activities, ensuring compliance with regulatory requirements. The Manager or the operating authority is responsible for communications with the NRC regional office on reportable deficiencies for activities covered by the Nuclear QA Program. The Manager – Radiological Emergency Response Preparedness as described in subsection 17.2.1.2.5.4 reports to the Manager – Nuclear Licensing.

17.2.1.2.5.2 Manager – Nuclear Security

The functions of the Manager – Nuclear Security are described in Subsection 13.1.2.5.1.

17.2.1.2.5.3 Manager – Nuclear Performance Improvement

The Manager – Nuclear Performance Improvement is responsible for administration of: 1) the plant Corrective Action Program, including trending and tracking of corrective action documents; 2) the root cause analysis program; 3) benchmarking and self-assessment programs; and 4) internal and external operating experience to provide for early detection of conditions potentially adverse to nuclear safety.

17.2.1.2.5.4 Manager – Radiological Emergency Response Preparedness

The Manager – Radiological Emergency Response Preparedness is responsible for coordinating the activities of Emergency Planning.

17.2.1.3 Review Organizations

The membership, meeting frequency, minutes, quorum, and other details of the NSRG and the OSRO are described in this subsection. These review organizations, which provide a technical review of plant maintenance and operation, have been established in accordance with the criteria listed below. The membership of the NSRG and the OSRO will be supplemented by DTE personnel or consultants as necessary.

17.2.1.3.1 Onsite Review Organization (OSRO)

17.2.1.3.1.1 Function

The OSRO shall function to advise the Executive Director - Nuclear Production on all matters related to nuclear safety as described in Subsection 17.2.1.3.1.6.

17.2.1.3.1.2 Composition

The OSRO membership shall be composed of a minimum of 6 but not more than 11 plant management representatives whose responsibilities include the functional areas of: operations, maintenance, radiation protection, engineering/technical support and quality assurance. All members shall be appointed in writing by the OSRO chairman. The qualifications of each OSRO member shall meet or exceed the requirements and recommendations of Section 4.2 or 4.3 of ANSI N18.1-1971 and the OSRO chairman shall meet or exceed the requirements of Section 4.2.4 of ANSI N18.1-1971.

17.2.1.3.1.3 Alternates

The Chairman may designate in writing other members who may serve as the Vice Chairman of the OSRO. Alternates may be designated for specific OSRO members. No more than two alternates shall participate as voting members in OSRO activities at any one time. All alternate members shall be appointed in writing by the OSRO Chairman.

17.2.1.3.1.4 Meeting Frequency

The OSRO shall meet periodically and as situations demand as convened by the OSRO Chairman or a Vice Chairman.

17.2.1.3.1.5 Quorum

The quorum of the OSRO necessary for the performance of the OSRO responsibility and authority provisions of this section (17.2.1.3.1) shall consist of the Chairman or Vice Chairman and four members including alternates.

17.2.1.3.1.6 Responsibilities

The OSRO shall be responsible for:

a. Review of Plant Administrative Procedures and changes thereto that could affect nuclear safety;

b. Review of all proposed tests and experiments that affect nuclear safety;

c. Review of all proposed changes to Appendix A Technical Specifications;

d. Review of all proposed changes or modifications to unit systems or equipment that affect nuclear safety. OSRO review of plant modifications which require a 10 CFR 50.59 Evaluation meet the requirements for this review;

e. Review of the 10 CFR 50.59 Evaluations for plant procedures and changes thereto completed under the provisions of 10 CFR 50.59;

f. Review of events reportable under 10 CFR 50.73;

g. Review of unit operations to detect potential hazards to nuclear safety;

h. Performance of special reviews, investigations, or analyses and reports thereon as requested by the Executive Director - Nuclear Production or the Nuclear Safety Review Group;

i. Review of every unplanned onsite release of radioactive material to the environs including the preparation and forwarding of reports covering evaluation, recommendations and disposition of the corrective action to prevent recurrence to the Site Vice President - Nuclear Generation and to the Nuclear Safety Review Group;

j. Review of changes to the Process Control Program, the Offsite Dose Calculation Manual, and major modifications to the Radwaste Treatment Systems; and

k. Review of all Licensing Change Requests (LCRs) for proposed changes to the Fire Protection Program, Security Plans and the RERP Plan.

17.2.1.3.1.7 Actions for Events Reportable Under 10 CFR 50.73

Each event reportable under 10 CFR 50.73 shall be reviewed by OSRO, and the results of this review shall be submitted to the NSRG and the Site Vice President - Nuclear Generation.

17.2.1.3.1.8 Written Communication

The OSRO shall:

a. Recommend in writing to the Executive Director - Nuclear Production approval or disapproval of items considered under Subsection 17.2.1.3.1.6.a through d prior to their implementation,

b. Render determinations in writing to the Nuclear Safety Review Group with regard to whether or not each item considered under Subsection 17.2.1.3.1.6.a through e requires a License Amendment prior to implementation,

c. Provide written notification within 24 hours to the Site Vice President - Nuclear Generation and the Nuclear Safety Review Group of disagreement between the OSRO and the Executive Director - Nuclear Production; however, the Executive Director - Nuclear Production shall have responsibility for resolution of such disagreements pursuant to Technical Specification 5.2.1b.

17.2.1.3.1.9 Records

The OSRO shall maintain written minutes of each OSRO meeting that, at a minimum, document the results of all OSRO activities performed under the responsibility provisions of this subsection.

Copies shall be provided to the Site Vice President - Nuclear Generation and the Nuclear Safety Review Group.

17.2.1.3.2 Nuclear Safety Review Group (NSRG)

17.2.1.3.2.1 Function

The NSRG shall function to provide independent review of designated activities in the areas of:

a. Nuclear power plant operations,

b. Nuclear engineering,

c. Chemistry and radiochemistry,

d. Metallurgy,

e. Nondestructive testing,

f. Instrumentation and control,

g. Radiological controls,

h. Mechanical and electrical engineering, and

i. Quality assurance practices.

The NSRG shall report to and advise the Senior Vice President and Chief Nuclear Officer on those areas of responsibility in Subsections 17.2.1.3.2.7 and 17.2.1.3.2.8.

17.2.1.3.2.2 Composition

The Senior Vice President and Chief Nuclear Officer shall appoint members to the NSRG and shall designate from this membership a Chairman and at least one Vice Chairman. The membership shall collectively possess experience and competence to provide independent review in the areas listed in Subsection 17.2.1.3.2.1. The Chairman and Vice Chairman shall have nuclear background in engineering or operations and shall be capable of determining when to call in experts to assist the NSRG review of complex problems. All members shall have at least a bachelor’s degree in engineering or related sciences or at least 10 years of responsible power plant experience of which a minimum of 3 years shall be nuclear power plant experience. The Chairman shall have at least 10 years of professional level management experience in the power field and each of the members shall have at least 5 years of cumulative professional level experience in one or more of the fields listed in Subsection 17.2.1.3.2.1.

17.2.1.3.2.3 Alternates

All alternate members shall be appointed in writing by the NSRG Chairman to serve on a temporary basis; however, no more than two alternates shall participate as voting members in NSRG activities at any one time.

17.2.1.3.2.4 Consultants

Consultants shall be utilized as determined by the NSRG Chairman to provide expert advice to the NSRG.

17.2.1.3.2.5 Meeting Frequency

The NSRG shall meet at least twice per year.

17.2.1.3.2.6 Quorum

The quorum of the NSRG necessary for the performance of the NSRG review functions of this subsection shall consist of the Chairman or his/her designated alternate and at least one half of the remaining NSRG members, with a minimum of four, of whom two may be alternates. No more than a minority of the quorum shall have line responsibility for operation of the unit.

17.2.1.3.2.7 Review

The NSRG shall be responsible for the review of Subsection 17.2.1.3.2.7.a through i:

a. Post facto review of 10 CFR 50.59 Evaluations for (1) changes to procedures, equipment, facilities or systems and (2)tests or experiments completed under the provision of 10 CFR 50.59 to verify that such actions did not require a License Amendment prior to implementation;

b. Proposed changes to procedures, equipment, or systems which involve a License Amendment prior to implementation as defined in 10 CFR 50.59;

c. Proposed tests or experiments which involve a License Amendment prior to implementation as defined in 10 CFR 50.59;

d. Proposed changes to Technical Specifications or the Operating License;

e. Violations of codes, regulations, orders, Technical Specifications, license requirements, or of internal procedures or instructions having nuclear safety significance;

f. Significant operating abnormalities or deviations from normal and expected performance of unit equipment that affect nuclear safety;

g. Events reportable under 10 CFR 50.73;

h. All recognized indications of an unanticipated deficiency in some aspect of design or operation of structures, systems, or components that could affect nuclear safety; and

i. Reports and meeting minutes of the OSRO.

17.2.1.3.2.8 Audits

Audits of unit activities shall be performed under the cognizance of the NSRG. These audits shall encompass topics listed in Subsection 17.2.18.5.

17.2.1.3.2.9 Records

Records of NSRG activities shall be prepared, approved, and distributed as indicated below:

a. Minutes of each NSRG meeting shall be prepared, approved, and forwarded to the Senior Vice President and Chief Nuclear Officer promptly following each meeting.

b. Reports of reviews encompassed by Subsection 17.2.1.3.2.7 shall be prepared, approved, and forwarded to the Senior VicePresident and Chief Nuclear Officer promptly following completion of the review.

c. Audit reports encompassed by Subsection 17.2.1.3.2.8 shall be forwarded to the Senior Vice President and Chief Nuclear Officer and to the management positions responsible for the areas audited within 30 days after completion of the audit by the auditing organization.

17.2.2 Nuclear Quality Assurance Program

The Nuclear QA program established for plant operations applies to all quality-related activities associated with the structures, systems, and components identified as safety related. The QA programs for fire protection and the Independent Spent Fuel Storage Installation (ISFSI) are part of the overall QA program. The program is designed to comply with the requirements of Appendix B to 10 CFR 50, NRC regulatory guides, and the endorsed ANSI standards that are used in structuring the program and in developing procedures to implement it. In all cases the required implementation procedures are established before the initiation of a given activity and must comply with the governing QA program.

Application of the 10 CFR 50, Appendix B QA program to activities conducted under 10 CFR 71 is limited to procurement, maintenance, repair and use of transportation packages for shipment of radioactive materials. Design, fabrication, assembly, and modification of shipping casks will not be conducted under this QA program.

17.2.2.1 Corporate QA Policies, Goals, and Objectives

The Senior Vice President and Chief Nuclear Officer has the ultimate authority for establishing QA policy. He/she is assisted by the Manager - Nuclear Quality Assurance in establishing goals and objectives.

17.2.2.1.1 Policies

QA policies are the following:

a. The operation and maintenance of the power plant shall be managed in accordance with a comprehensive QA program

b. The QA program shall be structured to comply with the requirements of regulations, codes, and company policies

c. Mandatory QA program requirements shall be established for all company and contractor personnel who oversee and/or perform activities that may affect safety or plant availability.

17.2.2.1.2 Goals

QA goals are the following:

a. Achieve safe and efficient operation

b. Achieve maximum plant availability within economic and safety limitations.

17.2.2.1.3 Objectives

QA objectives are to provide assurance that:

a. Plant design modifications are performed in accordance with regulatory requirements, codes, and standards to ensure a safe and reliable plant

b. Materials and services for the plant are procured as specified in design documents

c. Plant structures, systems, and components are constructed, maintained, and repaired to design standards

d. Plant structures, systems, and components are inspected to verify compliance with design requirements

e. Plant structures, systems, and components are tested to verify continued performance to design requirements

f. Adequate documentation is provided as objective evidence of quality and as required for plant operation and maintenance

g. No alterations are made to the facility which constitute a change from the current Technical Specifications except as allowed by 10 CFR 50.54(x) and (y) under emergency conditions. Other necessary alterations are made only after formal revision to the Technical Specifications.

The Fermi Conduct Manuals, approved and made mandatory by management, are the chief means of communicating the policies, goals, and objectives stated above to Nuclear Generation. Indoctrination sessions will also aid in furthering understanding. See Subsection 17.2.2.7 for further details.

17.2.2.2 Program Documentation

The Nuclear QA program is described in this section of the UFSAR (17.2) and is supported by Fermi Conduct Manuals and implementing procedures. QA Program elements applied to ISFSI are described in UFSAR Appendix 17.2A. This quality assurance program description (QAPD) and changes thereto shall be approved by the Senior Vice President and Chief Nuclear Officer after review by the Manager - Nuclear Quality Assurance.

17.2.2.2.1 Fermi Conduct Manuals

The Fermi Conduct Manuals address the QA program and other programs associated with the operation, maintenance, and modification of Fermi 2 and the activities of support organizations. These conduct manuals are organized by function and are divided into chapters which represent administrative implementing procedures.

Fermi Conduct Manuals are endorsed by DTE management in the QA management policy statement, and reflect commitments to meet the applicable regulatory requirements for safe operation, as well as provide for ensuring reliability of operation. These Conduct Manuals are approved by Fermi management and are the basis for the overall management program for Nuclear Generation. The Conduct Manuals are also applicable, as appropriate, to other DTE departments, suppliers, and contractors who furnish materials, equipment, or services that can affect the safe and reliable operation of Fermi 2.

Fermi Conduct Manuals identify the requirements and implementing procedures that management has mandated to be followed. Conduct Manuals applicable to the QA program describe responsibilities and principal duties for the performance of specific quality-related activities and the QA requirements applicable to those activities. These Fermi Conduct Manuals are approved by the Executive Director – Nuclear Production after review by the management of affected organizations. The Executive Director – Nuclear Production may delegate approval authority in writing for specific types of procedures to a management representative responsible for the functional area.

Conduct Manuals are controlled documents and are handled as described in Subsection 17.2.6. Revisions will be made, as appropriate, and will be subject to the same review and approval required for the original issue. Controlled copies of the manual are issued to identified personnel. Holders of the manual are required to keep it updated as revisions are issued and to be familiar with its applicable contents.

A matrix showing the 18 criteria of 10 CFR 50, Appendix B, QA Regulatory Guides and endorsed ANSI standards, and the conduct manuals implementing these criteria is shown in The QA Conduct Manual.

17.2.2.3 Program Elements

The Nuclear QA program implemented in the Fermi Conduct Manuals has the following major elements:

a. Definition of responsibility and authority of those involved in the implementation of the QA program during maintenance, modification, and operation of the plant

b. Identification of items and activities covered by the program and the extent of the applicability of the program, based on the safety-related importance of the item or activity

c. Verification and documentation of quality by personnel with sufficient independence and organizational freedom to effectively control quality

d. Performance of activities affecting quality in accordance with written instructions, procedures, or drawings

e. Indoctrination and training of personnel performing activities affecting quality to the extent required to ensure their proficiency

f. Identification and verification of compliance with requirements of applicable codes, standards, design documents, and regulations

g. Performance of activities affecting quality under suitably controlled conditions

h. Documentation of the satisfactory completion of activities and of the quality of an item

i. Regular review by management, outside of Nuclear QA, as directed by the Site Vice President – Nuclear Generation, to assess the status and adequacy of the QA program

j. Review of proposed changes to the QA program to determine if the proposed change requires prior review and acceptance by the NRC.

17.2.2.4 Program Applicability

The requirements of the Nuclear QA program are to be applied to quality-related activities involving safety-related structures, systems, and components. The safety-related structures, systems, and components are identified in Table 3.2-1 of the UFSAR and in the Central Component Computer Data Base (CECO). Procedures describe how changes are made to CECO.

The requirements of the QA program are applicable to the fire protection program and are applied to the extent consistent with safety. Therefore, Sections 17.2.6, 17.2.8, 17.2.9, 17.2.12 and 17.2.13 are not applicable to the fire protection program.

The requirements of the QA program are applicable to the ISFSI program and are applied to the extent consistent with safety. Elements of the QA program applicable to the ISFSI program are delineated in Appendix 17.2.A.

QA program procedures require that the development, control, and use of computer programs are performed in accordance with implementing procedures that incorporate applicable QA requirements to ensure the adequacy of the design and use of these programs.

17.2.2.5 QA Programs of Others

The QA program for Nuclear Generation includes requirements that a contractor providing items, work, or services involving safety-related structures, systems, or components must establish and maintain a prescribed QA program in compliance with the applicable requirements of Appendix B to 10 CFR 50. The specific QA requirements that the contractor program must satisfy are specified in the procurement documents. The program is subject to review and concurrence by Nuclear QA before work is started. The program may be reviewed by another utility provided that an agreement has been established to ensure that DTE's QA requirements have been satisfied. The results of the review will be provided to DTE.

17.2.2.6 Resolution of Disputes

Disputes between Nuclear QA personnel and others are to be referred for resolution to personnel who have the responsibility and authority to make the final decision. On technical matters, the dispute is referred to those in the organization who have the responsibility and expertise to make the decision; e.g., on problems involving the welding process, the Welding Engineer is the arbiter. Disputes involving operating procedures that cannot be resolved with the responsible organization are to be referred to the OSRO for resolution. In the event the OSRO and the Executive Director - Nuclear Production are in disagreement, resolution shall be obtained as described in Subsection 17.2.1.3.1.8.c. Disputes on QA program requirements specified in the Fermi Conduct Manuals are to be referred through the Manager - Nuclear Quality Assurance to the Senior Vice President and CNO as necessary.

17.2.2.7 Indoctrination and Training of Personnel

Personnel whose responsibilities and duties involve quality- related activities will participate in formal indoctrination and training programs conducted by Nuclear Training. These programs, in conjunction with training provided within the plant organizations, are designed to make personnel knowledgeable of the requirements of the Nuclear QA program, including purpose and scope, and the implementing procedures applicable to their work.

Periodic reviews will be scheduled to maintain a high level of understanding and knowledge of the Nuclear QA program. Special training sessions will be established for personnel requiring specialized skills in the performance of their work. The proficiency of such personnel will be established by appropriate examination, reexamination, and certification as required by codes, standards, and regulations. Files for formal training programs will include the objective, the content of training, the list of attendees, the date of attendance, and records of satisfactory completion. See Subsection 13.2.1 for further details.

17.2.2.8 Regulatory Guides and ANSI Standards

The operational QA program is intended to comply with the requirements of 10 CFR 50.55a, Part g; 10 CFR 50, Appendix B; Branch Technical Position (BTP) APCSB 9.5-1, Appendix A; 10CFR72, Subpart G and appropriate regulatory guides as addressed in Appendix A. The program is structured and implemented in accordance with ANSI N18.7-1976, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants," the ANSI standards referenced therein, and the regulatory guides that endorse them as addressed in Appendix A.

Those structures, systems, and components that are addressed by regulatory guides endorsing American Society of Mechanical Engineers (ASME) codes are listed in Section 3.2.

17.2.3 Design Control

Technical Organization is responsible for the engineering scope of modifications to plant structures, systems, and equipment. Design documents (e.g., drawings, calculations, specifications, procedures, and instructions) originating from or released for review by this group will contain the required regulatory requirements, quality standards, and design bases in accordance with NRC licensing requirements. Design activities may include calculations, analysis, materials selection, equipment arrangement and layout, and specification of test and inspection criteria essential to the safety-related functions of structures, systems, and components. Those design activities performed by individuals within DTE organizations are controlled by design control procedures.

Design control procedures satisfy the applicable QA requirements for design activities as specified in ANSI N45.2.11-1974 and as modified by Regulatory Guide 1.64 as addressed in Subsection A.1.64. Any organization performing design work for DTE must have similar requirements in its procedures before its QA program can be accepted.

To ensure that the design is adequate and that the above requirements and procedures are satisfied, designs are internally verified by the originating organization. This internal verification of adequacy may be accomplished either by a design review, by alternative calculation methods, or by the establishment of a suitable test program. Where a test program is used to verify the adequacy of a specific design feature in lieu of other verification or checking processes, it will include suitable qualification testing of a prototype unit under the most adverse design conditions. Those proposed changes in the facility which involve changes to the Technical Specifications or require a License Amendment prior to implementation as defined in 10 CFR 50.59(c)(2) shall also be reviewed by NSRG. Minutes of each NSRG meeting are prepared and approved.

Design controls have been established to assure that applicable fire protection program guidelines and requirements are included in design and procurement documents and that deviations are controlled. Field changes and design deviations that affect the intent of the modification shall be subject to the same level of controls, reviews, and approvals that were applicable to the original document. Quality standards are specified in the design documents such as appropriate fire protection codes and standards. Deviations or changes from these standards are individually approved. New designs and plant modifications, including fire protection systems, are reviewed by qualified personnel to assure inclusion of appropriate fire protection requirements.

All documentary material reviewed is identified. Copies of minutes are distributed to the originating organization.

During the design reviews, particular attention will be given to ensure that:

a. Appropriate quality standards are contained in the documents and clearly delineated

b. The technical information for the materials, components, equipment, and processes is contained in the documents and is suitable for the intended applications. This information will include, as applicable, the physics, seismic, radiation, hydraulics, thermal, strength, and accident analyses used; the compatibility of design for inservice inspection, maintenance, and repair; and the acceptance criteria for inspections and tests. Performance history and failure data on installed components will be considered when similar components are intended for installation as part of a system or structure modification

c. Design interfaces, when more than one organization has participated in the design, are compatible and consistent with the overall design bases and existing systems

d. In the selection of standard commercial or previously approved items with safety-related functions, a review is performed to determine if the characteristics of the item satisfy the requirements of the application

e. The inspection requirements per Subsection 17.2.10 are included and adequate

f. Errors and deficiencies discovered in the design as a result of the reviews are documented and disposition is assigned. A feedback system of corrective action, by distribution of the review comments to the responsible organization, is used to prevent repetitive errors or deficiencies in the design process.

Changes to the basic documents, including field changes as a result of modifications, which affect the technical adequacy of the design, will receive reviews and approvals comparable to the original basic documents. Editorial changes may be made with the approval of the responsible Nuclear Design Engineering Supervisor or other designated persons. Copies of editorial changes will be routed to the participating design organization and the Information & Procedures organization.

17.2.4 Procurement Document Control

17.2.4.1 General

Design documents are used in the procurement of plant materials, equipment, and services to properly define the technical and quality requirements for each procured item. Procurement packages are prepared or initiated by the responsible individual in accordance with established purchase requisition procedures.

The procurement package originator is responsible for ensuring that the applicable specifications, drawings, test requirements, inspection requirements, special process requirements, codes, standards, and regulatory requirements for safety-related items are specified or referenced in the procurement documents. The procurement packages are reviewed by Procurement Engineering to ensure (or provide) inclusion of appropriate technical, QA, and documentation requirements, DTE's right of access, and the control of nonconformances.

The procurement document planning, preparation, review, approval, and control process is performed in accordance with procedures prepared by the responsible organizations. Procurement document control procedures require that changes to procurement documents be subject to the same controls as the original document. Procurement document control procedures satisfy applicable QA requirements described in ANSI N45.2.13-1976 as modified by Regulatory Guide 1.123 as addressed in Subsection A.1.123.

Procurement documents for fire protection materials, equipment, and services are reviewed, approved and documented by qualified personnel to verify the adequacy of fire protection and quality requirements. This review assures that fire protection and quality requirements are correct; that there are adequate acceptance and rejection criteria; and that the procurement document has been properly prepared, reviewed, and approved.

The provisions which ensure that procurement documents contain DTE's right of access to supplier's facilities and records for source inspection and audits are delineated in the Fermi Conduct Manuals.

17.2.4.2 Procurement of Commercial Quality Items

Procurement of safety-related equipment, parts, and materials at Fermi 2 is in compliance with the plant's design requirements and commitments and is consistent with 10 CFR 50, Appendix B. These items may on occasion be procured commercial quality as replacements in safety-related systems. The criteria used for these commercial-quality procurements are consistent with the definition of commercial-grade items for use in safety-related systems contained in 10 CFR 21.

Safety-related items procured as Commercial Quality require specific engineering evaluations to establish engineering criteria and verification requirements prior to hardware acceptance. The development of engineering criteria includes critical performance characteristics and environmental and seismic requirements. Critical performance characteristics evaluate the item's form, fit, and function. Environmental requirements evaluate humidity, temperature, pressure, and radiation fields in which the hardware is expected to function under normal and accident conditions. Seismic requirements necessitate a need to evaluate the items for operation during and after a seismic event. Verification requirements are developed to ensure that established critical performance characteristics and environmental and seismic requirements are met.

Verification of product quality may be accomplished by sampling. The verification process includes visual inspection, analysis/ justification, or testing, either nondestructive or destructive, before release for installation. Other methods that can be used include commercial grade survey of the supplier or source verification. Commercial grade surveys will not be employed as the basis for accepting items from suppliers with undocumented commercial quality control programs or with programs that do not effectively implement their own necessary controls. Commercial grade surveys will not be employed as the basis for accepting items from distributors unless the survey includes the part manufacturer(s) and the survey confirms adequate controls by both the distributor and the part manufacturer (s). Surveys are led by Nuclear QA personnel. Under certain circumstances, equipment, parts, or materials can be verified by post installation testing.

Other verification activities are performed at the direction of Fermi 2 Procurement Engineering and overseen by Nuclear Quality Assurance in accordance with the Fermi 2 Quality Assurance Program with the exception that some source verifications are performed by QA.

Documentation resulting from engineering evaluations and hardware verifications is designed to be auditable and become permanent plant procurement records. It may also be used to replicate generic or specific engineering evaluations during subsequent procurements.

Nuclear QA will ensure that such requirements are included in the detailed procedures. Independent audits by Nuclear QA will ensure compliance with the established procedures.

17.2.5 Instructions, Procedures, and Drawings

Activities affecting quality are performed in accordance with approved instructions, procedures, or drawings. These documents include the necessary limits and tolerances on materials, equipment, processes, and procedures for all activities from design through operation. Also included are qualitative or quantitative acceptance criteria to ensure that important operations have been accomplished satisfactorily. The basis for determining the need for procedures and their content is consistent with the requirements of ANSI N18.7-1976 and Regulatory Guide 1.33 as addressed in Subsection A.1.33.

Documents established to ensure that activities affecting quality are accomplished in accordance with applicable codes, standards, specifications, and drawings include the following:

a. Fermi Conduct Manuals, including administrative implementing procedures and NQA procedures

b. Technical procedures, including, but not limited to: Operating procedures, radiation protection procedures, maintenance and modification procedures, periodic calibration and test procedures, special test procedures, and fuel handling procedures

c. Inspections, tests, administrative controls, fire drills and training that govern the fire protection program are prescribed in instructions, procedures or drawings and accomplished in accordance with these documents.

Nuclear Generation unit supervisors are responsible for ensuring compliance to procedures by personnel under their direction. Independent auditing by Nuclear QA will further ensure and verify onsite compliance with the approved procedures. The activities of DTE support organizations and vendors or contractors are also audited by Nuclear QA to verify compliance with requirements.

17.2.5.1 Technical Review and Control

17.2.5.1.1 Activities

Procedures required by Technical Specification 5.4, and other procedures which affect plant nuclear safety, including those governing the fire protection program, as determined by the Plant Manager, and changes thereto, shall be prepared by a qualified individual/organization.

17.2.5.1.2 Review

17.2.5.1.2.1 Procedure Review

Each procedure or procedure change prepared in accordance with 17.2.5.1.1, and each plant administrative procedure and changes thereto, shall be reviewed for technical adequacy by a qualified individual other than the individual that prepared the procedure or change thereto. Each such review shall include a determination of whether or not additional, cross-disciplinary review is necessary. If deemed necessary, such review(s) shall be performed by personnel of the appropriate discipline. Procedures governed by the fire protection program shall be reviewed to assure proper inclusion of fire protection requirements.

17.2.5.1.2.2 Procedures Required by Technical Specification 5.4.1.c and 5.5.1

Each procedure required by Technical Specification 5.4.1.c and 5.5.1, or changes thereto, shall be reviewed by the Manager -Radiation Protection or his/her designee. The Environmental Program Coordinators (an alternate title may be designated for this position) will review any changes pertaining to Technical Specification 5.4.1.c. These reviews may be performed in lieu of, or in addition to, those required by 17.2.5.1.2.1 above.

17.2.5.1.3 10 CFR 50.59 Evaluations

When required by 10 CFR 50.59, a 10 CFR 50.59 Evaluation to determine whether or not a License Amendment is involved shall be included in the review. Pursuant to 10 CFR 50.59, NRC approval of items requiring License Amendments prior to implementation shall be obtained prior to approval of the procedure or procedure change.

17.2.5.1.4 Qualifications

Individuals performing the reviews and evaluations in accordance with 17.2.5.1.2.1 through 17.2.5.1.3 above shall meet or exceed the qualifications stated in Sections 4.2 or 4.4 of ANSI N18.1-1971 for the appropriate discipline, and shall be members of the plant staff previously designated in writing by the Executive Director - Nuclear Production.

17.2.5.1.5 Records

Written records of reviews and evaluations performed in accordance with items 17.2.5.1.2.1 through 17.2.5.1.3 above, including recommendations for approval or disapproval, shall be prepared and maintained.

17.2.5.2 Review and Approval Process and Temporary Change Process

17.2.5.2.1 Plant Administrative Procedures

Each plant administrative procedure, and changes thereto, shall be reviewed in accordance with 17.2.5.1.2 and 17.2.1.3.1.6 and approved by the Executive Director – Nuclear Production prior to implementation, and shall be reviewed periodically thereafter as set forth in administrative procedures. The Executive Director – Nuclear Production may delegate approval authority in writing for specific types of procedures to a management representative responsible for the functional area.

17.2.5.2.2 Plant Procedures Required by Technical Specification 5.4.1

Each plant procedure required by Technical Specification 5.4.1, other than administrative procedures, and changes thereto, shall be reviewed in accordance with 17.2.5.1 and approved by the Executive Director – Nuclear Production prior to implementation and shall be reviewed periodically thereafter as set forth in administrative procedures. The Executive Director – Nuclear Production may delegate approval authority in writing for specific types of procedures to a management representative responsible for the functional area.

17.2.5.2.3 Temporary Changes

Temporary changes to procedures of Technical Specification 5.4.1 may be made provided:

a. The intent of the original procedure is not altered;

b. The change is approved by two members of the unit management staff, at least one of whom holds a Senior Operator license on Fermi 2; and

c. The change is documented, and reviewed and approved in accordance with either 17.2.5.2.1 or 17.2.5.2.2 above, as appropriate, within 14 days of implementation.

17.2.5.3 Process Control Program (PCP)

The PCP shall be approved by the Commission prior to implementation.

17.2.5.3.1 Changes to the PCP

a. Shall be documented and records of reviews performed shall be retained as required by Subsection 17.2.17.4.3n. This documentation shall contain:

   1. Sufficient information to support the change together with the appropriate analyses or evaluations justifying the change(s) and

   2. A determination that the change will maintain the overall conformance of the solidified waste product to existing requirements of Federal, State, or the applicable regulations.

b. Shall become effective after review and acceptance by the OSRO and the approval of the Executive Director - Nuclear Production.

17.2.6 Document Control

Documents defining the performance of quality-related activities are controlled to ensure that only current and correct information is used at the work location. Such documents include, but are not limited to, the following:

a. Design specifications, calculations, and analyses

b. Design, manufacturing, and construction drawings

c. Procurement documents

d. Fermi Conduct Manuals

e. Technical procedures

f. Nonconformance and design-change documents.

Such documents are drafted, reviewed, and approved by appropriate individuals or groups to ensure that the documents are adequate and that they include appropriate quantitative or qualitative acceptance criteria for determining that prescribed activities have been accomplished satisfactorily. Nuclear QA reviews such documents either directly or by audits and surveillances as appropriate for the type of document to ensure the inclusion of QA program requirements. The appropriate review and approval process is described in administrative procedures. The issuance of approved documents is made in accordance with established distribution lists.

Changes to such documents will meet the same requirements as the original document and will be reviewed and approved by the same organizations that performed the original review and approval, unless this responsibility is specifically delegated by these organizations to another qualified responsible organization.

Supervisors are responsible for ensuring that the correct revisions of necessary documents are being used to accomplish work.

During inspection, surveillance, and audit activities, Nuclear QA will verify that required documents such as drawings, specifications, instructions, or procedures are available at the work location.

The Director – Strategic Business Operations is responsible for maintaining and making available a document control system that identifies the current revision of procedures, specifications, drawings, procurement documents, and other such quality-related documents. The requirements for retaining and storing the quality-related documentation required above and other historical records are described in Subsection 17.2.17.

17.2.7 Control of Purchased Material, Equipment, and Services

Individuals designated by procedure approve the placement of contracts based on the analysis and recommendation of the appropriate Nuclear Generation organizational units. The evaluation of the QA capabilities of such vendors and contractors is the responsibility of Nuclear QA.

Supply Chain is responsible for supplier selection and bid evaluations. Requisitions are routed to Nuclear Generation and/or Supply Chain management personnel responsible for the issuance of purchase orders. The technical and quality requirements are transferred from the requisition to the purchase order. Procurement personnel review the purchase order for correctness prior to releasing the order to the vendor.

Three types of QA evaluation of a contractor or vendor are possible. One of these three may be used as appropriate to the level of quality required. They are as follows:

a. Desk Review - Evaluation of contractor or vendor QA capabilities accomplished by the review of pertinent information submitted by the contractor or vendor; quality history records of previous performance; documented review of audit reports by other utilities, or other similar methods. Included are ASME accreditation of an N Stamp, NA, NPT, and NV Stamps and associated Certificates of Authorization accepting the ASME accreditation of holders of the aforementioned in lieu of a separate evaluation of the programmatic adequacy of a supplier's documented QA program.

b. Facility Evaluation - Evaluation of a vendor's QA capabilities conducted at their facility, including

   1. Preaward evaluation of vendor QA system and implementation

   2. Preaward surveillance of vendor products, processing, or service and related documentation in accordance with requirements of the applicable purchase contract

   3. Inprocess evaluations.

c. Commercial grade calibration and/or testing services may be procured from commercial laboratories based on the laboratory's accreditation to ISO/IEC-17025 by an Accreditation Body (AB) which is a signatory to the International

Laboratory Accreditation Cooperation (ILAC) Mutual Recognition Arrangement (MRA) provided each of the conditions in the following list are met. The ILAC accreditation process cannot be used as part of the commercial grade dedication process of Nondestructive Examination (NDE) or Nondestructive Testing (NDT) services in lieu of performing a commercial grade survey.

1. A documented review of the supplier's accreditation is performed and includes a verification of the following:
   a) The calibration or test laboratory holds accreditation by an accrediting body recognized by the ILAC MRA. The accreditation encompasses ISO/IEC-17025:2017, "General Requirements for the Competence of Testing and Calibration Laboratories."
   b) For procurement of calibration services, the published scope of accreditation for the calibration laboratory covers the needed measurement parameters, ranges, and uncertainties.
   c) For procurement of testing services, the published scope of accreditation for the test laboratory covers the needed testing services including test methodology and tolerances/uncertainties.
   d) The laboratory has achieved accreditation based on an on-site accreditation assessment by the selected AB within the past 48 months. The laboratory's accreditation cannot be based on two consecutive remote accreditation assessments.
2. The purchase documents require that:
   a) The service must be provided in accordance with their accredited ISO/IEC-17025:2017 program and scope of accreditation.
   b) As found calibration data must be reported in the certificate of calibration when calibrated items are found to be out of tolerance (for calibration services only).
   c) The equipment/standards used to perform the calibration must be identified in the certificate of calibration (for calibration services only).
   d) Subcontracting of these accredited services is prohibited.
   e) The customer must be notified of any condition that adversely impacts the laboratory's ability to maintain the scope of accreditation.
   f) Performance of the services listed on this order is contingent on the laboratory's accreditation having been achieved through an on-site accreditation assessment by the AB within the past 48 months.
   g) Additional technical and quality requirements, as necessary, based upon a review of the procured scope of services, which may include,

but are not necessarily limited to, tolerances, accuracies, ranges, and industry standards.

3. It is validated, at receipt inspection, that the laboratory's documentation certifies that:

   a) The contracted calibration or test service has been performed in accordance with their ISO/IEC-17025:2017 program, and has been performed within their scope of accreditation.

   b) The purchase order's requirements are met.

After evaluation, the approved sources are placed on a current list of approved suppliers. Additions and deletions to the list are made by Nuclear QA.

To ensure that material and equipment fabrication is in accordance with procurement requirements, Nuclear Generation or Supply Chain inspection personnel perform source verification of vendor activities, which includes witnessing significant fabrication checkpoints, validity of vendor-supplied documentation, and overall vendor performance as appropriate to the purchased item. The surveillance activities are accomplished in accordance with approved procedures.

Suppliers shall be required, as part of the purchase order, to furnish, as a minimum, a certificate of conformance or compliance that identifies the item provided and specifically itemizes the quality requirements of the procurement documents that it meets. In some instances inspections and audits of records will be used to verify the credibility of the certification.

One of the provisions in the procurement document shall require a supplier to submit to DTE requests for the disposition of all nonconformances to DTE specified requirements. In addition, the supplier shall be required to document the disposition of nonconformances to their own requirements. Those dispositions that resulted in "accept as is" or "repair" shall be described in the submitted documentation. See Subsection 17.2.16 for corrective actions in the case of nonconformances.

After receipt and before the storage of a material, part, or component, inspection is accomplished by qualified personnel as necessary to ensure that the material, equipment, fire protection items, or service is adequately identified and complies with the specifications delineated in the associated procurement documents. These inspections and subsequent identification of status are performed in accordance with material receiving and inspection procedures.

Documentation of the inspection will be prepared. A necessary condition for acceptance is the receipt of the QA records identified in the procurement documents verifying that the specified quality requirements have been met. An item is considered nonconforming until sufficient quality documentation has been provided. Procedures permit the conditional release of material lacking the specified QA records, provided the item can be readily removed if necessary. Functional testing may be performed on materials installed under conditional release; however, these materials are not to be placed in service unless a technical evaluation has been performed and documented in accordance with approved procedures including a 10 CFR 50.59 review.

Following a satisfactory receiving inspection, the receiving inspection report, and required documentation of tests, certificates of conformance or compliance and other specified requirements are retained to provide documentary evidence of compliance. If a nonconforming item is found during the inspection, the item is retained in a hold area or otherwise controlled area pending resolution.

The procurement of spare or replacement parts for structures, systems, and components is subject to QA program controls, codes, and standards and to technical requirements equal to or better than the original technical requirements as necessary to preclude the repetition of defects.

For specific criteria applying to commercial grade items refer to Subsection 17.2.4.2.

17.2.8 Identification and Control of Materials, Parts, and Components

Safety-related materials (including consumables), parts, and components (including partially fabricated subassemblies) are identified in a manner that allows traceability to the documentation that verifies the acceptability of the items to the extent specified in the procurement documents. The identification system is used to preclude the use of nonconforming materials, parts, and components. Identification must not adversely affect the function or quality of the item identified. Vendor-supplied items are identified and documented by the manufacturer in a manner consistent with applicable codes and as specified in the procurement documents. Materials, parts, and components manufactured or modified by DTE are identified, documented, and controlled.

When safety-related items are received, the items are inspected according to inspection procedures. Incorrect or defective materials, parts, and components will be identified with a tag or other appropriate means and handled in accordance with Subsection 17.2.15 to preclude inadvertent use before proper disposition. Identification and control of materials, parts, and components at the site is prescribed by, and implemented in accordance with, approved procedures.

17.2.9 Control of Special Processes

Special processes used in the course of maintenance, modification, and testing of the plant are controlled to ensure that they are accomplished in a satisfactory manner. Examples of special processes include, but are not necessarily limited to, the following:

a. Chemical cleaning

b. Application of protective coatings

c. Plating

d. Heat treatment

e. Metal joining, such as brazing, soldering, and welding

f. Nondestructive examinations.

Implementing procedures establish the methods for controlling and accomplishing the special processes. These procedures include the following:

a. Training, testing, and qualification requirements of onsite personnel engaged in accomplishing or inspecting special process operations

b. Certification or qualification of equipment and procedures used in the performance of special processes at the site

c. Certification and audit of vendor and contractor special fabrication process equipment, procedures, and personnel

d. Documentation of process results, procedures, personnel qualifications, and equipment certifications.

Implementing procedures define the requirements for the control of special processes to ensure that they are accomplished by qualified personnel in accordance with approved procedures, codes, and specifications. These procedures also require the documentation of personnel qualifications, equipment, special process procedures used, and acceptance/rejection criteria. Supervisors are responsible for ensuring that personnel, equipment, and special processes under their supervision, direction, or use are qualified to accomplish a particular onsite activity. These qualifications are established in accordance with the applicable codes, specifications, and standards.

Offsite special process activities will be performed in accordance with approved procedures and procurement document requirements, and by qualified personnel.

Specific procedures for special processes are prepared by the plant personnel or DTE support organizations. Qualification records of all personnel, procedures, and equipment and copies of procedures for special processes are maintained and controlled in accordance with approved procedures. Personnel performing nondestructive examinations will be qualified and certified in accordance with the requirements of ASNT SNT-TC-1A or ANSI/ASNT-CP-189 (applicable year as specified by the ISI-NDE program) and additional requirements set forth in applicable codes, standards, and specifications.

17.2.10 Inspection

Inspections are required to ensure that maintenance, repair, or modification work has been satisfactorily accomplished. Administrative procedures require that maintenance, repair, or modification procedures be submitted for review by Nuclear QA. Nuclear QA, in conjunction with other Nuclear Generation units, establishes the need for inspection, inspection personnel, and documentation and incorporates such information into plans or procedures. Such procedures include criteria for determining which inspections are required and how they are sequenced. Nuclear QA personnel are also required to prepare inspection plans and checklists from information obtained from original design documents to determine which inspections are required and the acceptance and rejection criteria. If the responsible design organization establishes additional requirements or criteria, these must also be included in the inspection checklists. Inspections are accomplished using procedures, instructions, and/or checklists that contain at least the following:

a. Acceptance and rejection criteria

b. Identification of those individuals responsible for performing the inspection activity

c. Description of the method of inspection, examination, measurement, or test of materials or processes necessary to be performed to ensure quality

d. Requirements for inspection equipment and instruments

e. Identification of required witness and/or hold points

f. Results of inspection activity

g. Identification of inspection subject

h. Signoff signature or controlled stamp showing evidence of completion and verification of the inspection

i. Identification of required procedures, drawings, specifications, and revisions.

If inspection of the work is impossible or disadvantageous, indirect control by the monitoring of processing methods, equipment, and personnel is provided. Both inspection and process monitoring are provided when necessary to ensure adequate control.

The inspection program also includes:

a. Periodic inspections of fire protection systems, breathing equipment and emergency lighting to assure the acceptable conditions of these items

b. Periodic inspections of materials subject to degradation such as fire stops, seals and fire retardant coatings to assure that such items have not been damaged or deteriorated.

With the exception of inservice inspection (ISI), receiving inspection, and source inspection inspectors personnel qualified to perform inspections normally will be from Nuclear QA or from onsite support organizations and will be under the control of DTE. Contract inspectors may be used, if required, for special-purpose inspections. Personnel qualified to perform inspections will:

a. Not have performed any of the activities being inspected

b. Have satisfactorily completed the qualification requirements and be certified as specified by procedures that incorporate the requirements of ANSI N45.2.6-1978 as modified by Regulatory Guide 1.58 and Subsection A.1.58 or the requirements of ASNT SNT-TC-1A or ANSI/ASNT CP-189, as applicable per Section 17.2.9

c. Be currently qualified and so designated on a qualified inspectors list approved by management.

If contractors perform special-purpose inspections, such as inservice inspections, they perform such work under the control of onsite supervision. Responsible onsite supervision ensures that contractor personnel, equipment, and procedures are properly qualified and adequate to perform the inspection.

Activities affecting fire protection will be inspected by NQA personnel or other personnel who are independent of the activity being inspected to verify conformance with documented installation drawings and test procedures for accomplishing the activities. Inspection personnel will be knowledgeable in the design and installation requirements for fire protection to the extent necessary to perform the inspection.

If an inspection reveals that a nonconformance has occurred, the inspector has the authority to initiate action to suspend further activity until the nonconformance is resolved. All nonconformances are reported and acted on in accordance with Subsection 17.2.15.

The results of each inspection are documented. The appropriate Nuclear QA Supervisor is responsible for the review of the results following completion of an activity to ensure that inspections were properly performed and documented. Maintenance of inspection records is described in Subsection 17.2.17.

Each vendor is required to establish and implement an inspection program to ensure that requirements of purchase orders are met. DTE personnel perform selective surveillance inspections to evaluate progress, monitor processes, and verify adherence to specifications and codes during fabrication in the vendor's shop. Specific attention is paid to the quality of workmanship, finishes, cleaning procedures and facilities, the interface setup of connections, and the adequacy and cleanliness of shop assembly and test areas. A system of mandatory hold points is established for critical operations and inspections to permit DTE to witness such operations and inspections.

17.2.11 Test Control

Preoperational and startup test programs were established and completed in accordance with the guidance provided in Regulatory Guide 1.68, as described in the Startup Manual.

Onsite test activities following plant startup are controlled by the implementation of approved test procedures. These procedures are prepared by the organization responsible for a given test activity, technically reviewed by Nuclear Generation staff, and approved by the Executive Director - Nuclear Production or designee in accordance with approved administrative procedures. Test control at the plant provides assurance that appropriate tests are conducted on structures, components, systems, or parts of systems in accordance with design documents, codes, and Technical Specifications. Tests within the scope of this subsection include periodic tests and those tests required as a result of modification, maintenance, or repair of safety-related items.

Following modification, repair or replacement, sufficient testing is performed to demonstrate that fire protection equipment in support of nuclear safety-related equipment areas will perform satisfactorily in service and that design criteria are met. Written test procedures for installation tests are prepared by the responsible engineering group and incorporate the requirements and acceptance limits contained in applicable design documents.

Implementing procedures describe the criteria used to determine which systems, structures, and components require testing and when such testing should be performed. When systems, structures, and components have been repaired, modified, or replaced, proof tests, operational tests, or other special tests are performed as required by NRC regulations and other applicable codes and standards to demonstrate satisfactory performance of the affected equipment. The responsible supervisor ensures that test procedures are prepared for the required tests and that each test procedure complies with applicable design documents, codes, and specifications. Nuclear QA reviews test procedures through inspections, surveillances, and audits.

Each test procedure includes the following as applicable:

a. Test procedure approval sheet

b. Purpose or objective

c. References

d. Prerequisites and precautions, such as suitable and controlled plant conditions for testing, adequate test equipment and instrumentation (including accuracy and calibration requirements), and completeness of item to be tested

e. Special test equipment and materials

f. The body of the procedure, including the delineation of test requirements and acceptance criteria contained in applicable design and procurement documents

g. Radiological control requirements

h. Data sheets, including provisions for signoff of prerequisites

i. Valve and electrical system lineup sheets for test and return to normal conditions

j. Hold points for inspection and witnessing.

The responsible section head or supervisor is responsible for the overall conduct and review of onsite tests. He/she assigns a qualified lead person and qualified personnel under the lead person to perform tests.

The lead person makes certain that test equipment has the proper accuracy and is properly calibrated and that each test is conducted under proper environmental conditions. Tests are conducted, documented, and results are reviewed by the lead person/qualified personnel. Additionally, the Shift Manager (SM) reviews tests to ensure that the results meet the requirements and acceptance criteria of the applicable test procedures.

Nuclear QA reviews test results through inspections, surveillances, or audits. Test records are maintained as described in Subsection 17.2.17.

Safety-related components and equipment may be tested in the vendor's shop before shipment, as required, to verify that they meet the contract drawings and specifications, and to ensure that the required quality is achieved. Tests are conducted in an environment in which shop conditions and activities do not interfere with test results. DTE requires that vendor-conducted shop tests be conducted in accordance with written test procedures. These procedures define in detail the step-by-step operations for demonstrating each feature of specified performance and provide such information as measuring and test equipment used, specifying range, accuracy, and type. The test data sheet provides space for actual test results and is traceable to the acceptance criteria. Space is provided for the signature and title of the person performing the test.

When appropriate, DTE personnel may witness the testing of items in a vendor's shop to ensure compliance with test procedures and specification requirements. The opportunity to witness will be established and coordinated with the vendor.

17.2.12 Control of Measuring and Test Equipment

The control of measuring and test equipment is implemented by specific procedures that describe calibration techniques, frequency requirements, and control of all the instruments and standards used in the measurement, inspection, and monitoring of safety-related components, systems, and structures. Control is used to ensure that tools, gages, instruments, and other measuring and test devices are calibrated to required accuracies against reference and transfer standards traceable to nationally recognized standards. Where national standards do not exist, the basis for calibration is documented in accordance with approved procedures. The DTE organization, supplier, or contractor responsible for testing materials, parts, assemblies, and end products ensures that the specified controls are implemented. Frequently used testing and measuring equipment will be checked for accuracy on a specified routine basis. Testing and measuring equipment used only on an infrequent basis will be checked before use.

Procedures require that testing and measuring equipment be stored in suitable locations and environments and be used only by personnel trained in their proper use and care. The calibration control documentation indicates the source and traceability of calibration, including the date of last calibration. The records also provide identification and traceability for all measuring equipment by a serial number or other suitable means. The responsible supervisor ensures the maintenance of records that indicate the complete status of measuring and test equipment under calibration control. Procedures provide for investigations to be conducted and documented to determine the validity of previously made measurements when measuring or test equipment is found to be out of calibration, and also require the repair or replacement of instruments found to be consistently out of calibration.

The section heads or supervisors of the organizations using measuring and test equipment are responsible for the establishment, implementation, and effectiveness of their calibration program. Procedures describe calibration methods, calibration frequencies, and the use of calibration stickers or tags on equipment indicating the next calibration date.

Calibration frequencies are based on required accuracy, purpose, extent of usage, stability characteristics, and other conditions that affect measurement. Calibrating standards have equal or greater accuracy than the equipment being calibrated. Those standards having equal accuracy must be adequate for the requirements, and such determination is documented and authorized by cognizant staff personnel.

17.2.13 Handling, Shipping, and Storage

Requirements for packaging, handling, cleaning, storing, and shipping safety-related materials, components, and systems are specified in procurement, shipping, and design documents in order to prevent damage, loss, or deterioration by environmental conditions such as temperature or humidity. These requirements are in accordance with applicable codes, standards, specifications, and manufacturer's recommendations. The procurement documents include, as applicable, the requirements for the following:

a. Cleaning and preparation of materials

b. Packaging container requirements

c. Identification and cautionary markings

d. Protection against weathering and corrosion

e. Environmental conditions for shipping and storage

f. Safe-handling requirements.

Plant section heads and supervisors are responsible for ensuring that safety-related items are handled, cleaned, stored, preserved, protected, packaged, and shipped by qualified individuals in accordance with specified codes, standards, and procedures. Procedures are established to control the storage (including shelf life) of chemicals, reagents, lubricants, and other consumable materials. Nuclear QA conducts audits to ensure that items are adequately protected and handled.

On receipt of materials and components, special requirements and protective environment, including inert-gas atmospheres, specific moisture content levels, and temperature levels, are verified and documented. During subsequent storage and before installation or use, these special requirements are maintained and will be verified by documented routine inspection in accordance with approved procedures.

Special handling equipment, cranes, and rigging are examined and tested as required by procedures before the handling of important or large items. Detailed handling instructions are prepared for items requiring special handling because of size, weight, susceptibility to shock damage, or importance. Nonconformances concerned with the handling, shipping, and storage of safety-related items will be controlled as described in Subsection 17.2.15.

17.2.14 Inspection, Test, and Operating Status

The QA program requires that contractors, suppliers, and onsite organizations indicate the inspection, test, and operating status of structures, components, systems, or parts of systems by a suitable means of identification and in the plant records. This prevents the inadvertent use of nonconforming, inoperative, or malfunctioning systems, structures, or components, and verifies that required inspections or tests have been performed.

Personnel safety and proper equipment operation are paramount in conducting inspections and tests associated with plant maintenance and operation. Written procedures describe the process for tagging and documenting the status of valves, breakers, and related controls for inspection, test, or maintenance.

Procedures describe methods for altering the sequence of required tests, inspections, and other operations important to safety so that appropriate reviews and approvals are performed.

The Technical Specifications establish the requirements for safety-related items necessary for the safe operation of the plant, including provisions for periodic and nonperiodic tests and inspections of various instruments, structures, components, systems, or parts of systems. Periodic tests may be operational tests or tests following maintenance; nonperiodic tests may be tests following repairs or modifications. The Technical Requirements Manual establishes requirements for fire protection items.

Schedules and methods for periodic testing of fire protection systems and components have been developed and documented. Fire protection equipment in support of nuclear safety related equipment areas is tested periodically to assure that the equipment will properly function and continue to meet the design criteria. Test results are documented, evaluated and reviewed for acceptability.

The Shift Manager is responsible for maintaining sufficient knowledge of the plant status and the status of tests or inspections in progress to ensure safe plant operation. The Shift Manager will ensure that personnel performing onsite tests or inspections keep him/her or the Licensed Nuclear Operator in charge of the main control room advised of the current status of tests or inspections in progress that could affect any safety-related activity.

Supply Chain, assisted by Procurement Engineering as needed, is responsible for correct status indication of equipment and material in storage.

Administrative procedures require that Nuclear QA review maintenance, modification, repair, special tests, and plant technical procedures for performing radwaste processing and shipping as specified by Nuclear QA. Other procedures are reviewed during audits and surveillances as appropriate. Nuclear QA keeps routinely informed of scheduled plant activities to ensure that they can plan to perform and document inspections and be prepared to review, monitor, or audit work and test activities and any critical operations to ensure compliance with specified requirements.

17.2.15 Nonconforming Material, Parts, or Components

Written procedures govern the discovery, identification, documentation, segregation, review, notification, and disposition of nonconforming conditions identified during maintenance and operation. Materials and equipment that deviate from approved specifications, codes, drawings, or other applicable documents are considered nonconforming items. Until proper disposition has been made, Supply Chain, assisted by Procurement Engineering as needed, is responsible for such items in storage being clearly identified with appropriate tags or other appropriate measures to indicate unacceptable status and segregated, if possible, to prevent inadvertent use or installation for maintenance or operation of the plant.

When nonconforming items are found or suspected, the items are controlled to preclude further activity pending resolution of the adverse condition. A nonconformance document is originated and processed to the organization responsible for determining cause and recommending corrective action. Nuclear QA is notified of the condition. The nonconformance document has provisions for identifying and describing the nonconforming item, the cause, when appropriate, proposed corrective action, and approval by responsible supervision, actual corrective action taken and acknowledgment by responsible supervisory personnel, and closeout action, including any required inspections or tests and acknowledgment by Nuclear QA.

Corrective action will be proposed by qualified organizations and approved by supervisory personnel having responsibility for dispositioning the nonconforming item.

Copies of completed nonconformance documents are maintained as described in Subsection 17.2.17.

The acceptability of rework, repair, or replacement of materials, parts, components, systems, and structures is verified by inspecting and testing the item for conformance with its original requirements or acceptable alternatives. The inspection and test records are documented and become part of the QA records for the item.

Nuclear QA periodically analyzes quality data obtained from the review of nonconformance documents including nonconformance documents issued as a result of inspection reports, surveillance reports, and audit reports. This analysis, including the determination of quality trends is reported to appropriate management and supervisory personnel for their review, assessment and appropriate action.

17.2.16 Corrective Action

Measures are established to ensure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances, are promptly identified and corrected. In the case of a significant condition adverse to quality or safety, procedures require that the cause be determined and corrective action be taken to preclude recurrence, and that the significant condition, its cause, and the corrective action be documented. Significant conditions affecting nuclear safety shall be reported to the Executive Director - Nuclear Production and the NSRG Chairman. Nuclear QA reviews all corrective action documents which delineate significant conditions adverse to quality or safety and some corrective action documents for other conditions adverse to quality to determine, when appropriate, that the root cause of the problem is identified and corrective action is adequate.

The QA requirements in procurement documents or contracts require the vendor or contractor not only to identify material or parts that do not conform to the procurement requirements, but also to determine and correct the causes for the condition adverse to quality.

When vendors furnish products that do not conform to the requirements of the applicable purchase contract, Nuclear QA conducts a reappraisal of the vendor's QA program when appropriate. Results of the reappraisal, together with a request for specific corrective actions, are transmitted to the vendor. If the vendor does not improve their QA program and products as requested, Nuclear QA may remove the vendor from the list of approved suppliers.

Licensing or the operating authority as appropriate is responsible for communications with the NRC Regional Office on reportable deficiencies for activities covered by the Nuclear QA program.

17.2.17 Quality Assurance Records

Copies of pertinent documentation, including available design, procurement, fabrication, inspection, deficiencies and corrective action, test, audit, and construction reports; reviews, material analysis, and monitoring of work performance; qualification of personnel, procedures, and equipment; drawings, specifications, calibration procedures, and reports; pertinent operating logs; maintenance and modification procedures and related inspection results; reportable occurrences; and other records required by Subsection 17.2.17.4 are available at the plant. Storage facility environmental conditions will be maintained to protect the records from deterioration. Redundant storage, where practical, is provided offsite to preclude the loss of records through fire, flood, or theft.

17.2.17.1 Plant Records

The Nuclear QA records and documents are filed and maintained by the Director – Strategic Business Operations, who is responsible for maintaining permanent records of the design documents developed during the plant operating, maintenance, and modification phases. These records will provide the historical reference necessary for maintenance, modification, and operation of the plant. Procedures define the necessary practices for the collection, storage, and maintenance of plant Nuclear QA records in accordance with the requirements of ANSI N45.2.9-1974, as endorsed by Regulatory Guide 1.88, and as addressed in Subsection A.1.88.

17.2.17.2 Support Organization Records

Support organizations that perform work for the plant in the areas of design, procurement, maintenance, modification, and testing will document such work and forward records to the Director – Strategic Business Operations for permanent filing and for ensuring that the records are identifiable and retrievable. Records for offsite support organizations are specified in procurement documents.

17.2.17.3 Vendor or Contractor QA Records

Vendors or contractors who exercise the option to retain QA records will comply with the following requirements:

a. Meet DTE's requirements on collection, storage, and maintenance of records

b. Make records available on demand for use by DTE or its agent

c. Inform DTE of any intent to dispose of QA records and permit DTE to take possession of records in accordance with agreed-upon terms.

17.2.17.4 Record Retention

17.2.17.4.1 Minimum Retention Periods

In addition to the applicable record retention requirements of Title 10, Code of Federal Regulations, the following records shall be retained for at least the minimum period indicated.

17.2.17.4.2 Record Retention - Five Years

The following records shall be retained for at least 5 years:

a. Records and logs of unit operation covering time interval at each power level,

b. Records and logs of principal maintenance activities, inspections, repair, and replacement of principal items of equipment related to nuclear safety,

c. All Reportable Events,

d. Records of surveillance activities, inspections, and calibrations required by the Technical Specifications,

e. Records of changes made to the procedures required by Technical Specification 5.4.1,

f. Records of sealed source and fission detector leak tests and results,

g. Records of annual physical inventory of all sealed source material of record.

17.2.17.4.3 Record Retention - Duration of Operating License

The following records shall be retained for the duration of the unit Operating License:

a. Records and drawing changes reflecting unit design modifications made to systems and equipment described in the Final Safety Analysis Report,

b. Records of new and irradiated fuel inventory, fuel transfers, and assembly burnup histories,

c. Records of doses received by all individuals for whom monitoring was required,

d. Records of gaseous and liquid radioactive material released to the environs,

e. Records of transient or operational cycles for those unit components identified in Technical Specification Table 5.5.5,

f. Records of reactor tests and experiments, if applicable.

g. Records of training and qualification for current members of the unit staff,

h. Records of inservice inspections performed pursuant to the Technical Specifications,

i. Records of quality assurance activities required by ANSI N45.2.9-1974.

j. Records of reviews performed for changes made to procedures or equipment or reviews of tests and experiments pursuant to 10 CFR 50.59,

k. Records of meetings of the OSRO and NSRG,

l. Records of the service lives of all hydraulic and mechanical snubbers required by Technical Requirements Manual Sections 3.7.9 and 5.1 including the date at which the service life commences and associated installation and maintenance records,

m. Records of analyses required by the radiological environmental monitoring program that would permit evaluation of the accuracy of the analysis at a later date. This should include procedures effective at specified times and QA records showing that these procedures were followed,

n. Records of reviews performed for changes to the Offsite Dose Calculation Manual and Process Control Program,

o. Records of radioactive shipments.

17.2.18 Audits

Within DTE, the implementation of a comprehensive system of planned and periodic audits is the responsibility of Nuclear QA.

Nuclear QA provides a direct audit function of the implementation of the QA program. These audits are performed to verify compliance with all aspects of the QA program, including audits of vendors and service contractors.

17.2.18.1 Audit Personnel

Audit personnel are qualified in accordance with ANSI N45.2.23-1978 and Regulatory Guide 1.146 (August-1980) and are provided appropriate training to ensure that they are competent to perform the required audits. The proficiency of audit personnel is maintained by active participation in the audit process and/or by participation in training or orientation programs.

Audits and evaluations of selected subjects may be conducted by using technical specialists from outside the NQA organization. Technical specialists, who occasionally serve as audit team members, will receive indoctrination and/or training appropriate for the audit function performed.

17.2.18.2 Vendor and Service Contractor Audits

Nuclear QA, supported by technical specialists when appropriate, performs audits, source verification, and commercial grade surveys of vendors and service contractors to verify and evaluate their QA programs, procedures, and/or activities, to ensure that they are meaningful and are effectively complying with all aspects of the QA program and procurement requirements. Nuclear QA also verifies that the vendors and contractors review and audit the QA programs of their suppliers as required.

Nuclear QA performs audits or surveillances of special-purpose inspections, such as inservice inspections, performed by contractors to ensure that the inspection work is being properly performed.

Audits are conducted in accordance with established procedures and by personnel having no direct responsibilities in the areas being audited. Audits, source verifications, and commercial grade surveys performed by other nuclear utilities may be accepted as satisfying DTE's criteria based on a documented evaluation of the report. Evaluation may be performed and documented by another utility provided that an agreement has been established that DTE’s scope of supply will be included. The results of the evaluation will be provided to DTE.

Source verification (surveillance or source surveillance) shall be commensurate with the relative importance, complexity, and quantity of the items or service procured and the vendor’s quality performance. In-process and final surveillance requirements of vendor products shall be determined in advance and performed to assure conformance with procurement document requirements. Remote source surveillance is allowed as an adequate dedication or acceptance process when a pandemic or similar state of emergency has been declared restricting access or travel to and/or from vendor locations affected by the declaration. The remote source surveillance will be in accordance with EPRI’s April 2020

Final Report 3002019436, “Remote Source Verification During a Pandemic or Similar State of Emergency: Screening Criteria and Process Guidance” to screen for eligibility, plan, perform using real time video, and document.

When purchasing commercial grade calibration or testing services from a laboratory holding accreditation by an Accreditation Body (AB) which is a signatory to the International Laboratory Accreditation Cooperation (ILAC) Mutual Recognition Arrangement (MRA), commercial grade surveys need not be performed provided each of the conditions in the following list are met. The ILAC accreditation process cannot be used as part of the commercial grade dedication process of Nondestructive Examination (NDE) or Nondestructive Testing (NDT) services in lieu of performing a commercial grade survey.

1. A documented review of the supplier’s accreditation is performed and includes a verification of the following:
    a) The calibration or test laboratory holds accreditation by an accrediting body recognized by the ILAC MRA. The accreditation encompasses ISO/IEC-17025:2017, “General Requirements for the Competence of Testing and Calibration Laboratories.”
    b) For procurement of calibration services, the published scope of accreditation for the calibration laboratory covers the needed measurement parameters, ranges, and uncertainties.
    c) For procurement of testing services, the published scope of accreditation for the test laboratory covers the needed testing services including test methodology and tolerances/uncertainties.
    d) The laboratory has achieved accreditation based on an on-site accreditation assessment by the selected AB within the past 48 months. The laboratory’s accreditation cannot be based on two consecutive remote accreditation assessments.
2. It is validated, at receipt inspection, that the laboratory’s documentation certifies that:
    a) The contracted calibration or test service has been performed in accordance with their ISO/IEC-17025:2017 program, and has been performed within their scope of accreditation.
    b) The purchase order’s requirements are met.

Audit results are reported to the Manager - Nuclear Quality Assurance, the management of the organization audited, and the affected DTE organizations. DTE requires written reports from each organization on the measures taken to correct deficiencies and prevent recurrence. Appropriate follow-up, including reaudits, is made to determine that nonconformances are effectively corrected and that the corrective action precludes repetitive occurrences.

17.2.18.3 Nuclear Generation Audits

Nuclear QA is responsible for independent audits of Nuclear Generation unit activities to verify compliance with the QA program and to assess its effectiveness. The activities audited include those described in the governing procedures that apply to the plant and onsite support organizations.

Copies of the audit report are distributed to appropriate Nuclear Generation management, including the CNO, the Site Vice President - Nuclear Generation, Vice President – Engineering and Technical Support, the Manager - Nuclear Quality Assurance and affected organizations. The NSRG receives a copy of reports of audits for which the NSRG has responsibility to review.

If a condition adverse to quality is discovered that may affect the safe operation of the plant, it will be brought to the attention of the Executive Director - Nuclear Production, in accordance with Subsection 17.2.16. After an audit of an organization has been completed, the appropriate Nuclear Generation manager is responsible for a written report of the corrective action taken in response to any nonconforming conditions identified in the audit report. Appropriate follow-up by Nuclear QA, including reaudits, is made to determine that significant conditions adverse to quality and selected nonsignificant conditions adverse to quality are effectively corrected and that corrective action precludes repetitive occurrences. Other nonsignificant conditions adverse to quality identified during audits are followed up during the next audit of the activity.

Nuclear QA will verify that the correct revisions of procedures, drawings, and other documents are being used when performing an activity affecting quality. This will be accomplished during inspections, surveillances, and audits.

17.2.18.4 Nuclear Safety Review Group

The NSRG is responsible for review as specified in Subsections 17.2.1.3.2.7 and 17.2.1.3.2.8. In addition to these activities, the NSRG will review such other activities as have been established in its charter.

17.2.18.5 Scope and Schedule of Audits

The scope and schedule of audits to be performed will be established by Nuclear QA in coordination with the responsible organizations in accordance with the requirements of the Nuclear QA program. Audit schedules will indicate the activity to be audited and the minimum frequency, and will assign the primary responsibility for the performance of the audit. The audit schedule will be reviewed and revised periodically by Nuclear QA in coordination with the responsible organizations to make certain that coverage and schedule reflect current activities.

A prominent factor in developing and revising audit schedules will be performance in the subject area. The audit schedule will be revised so that weak or declining areas get increased audit or surveillance coverage and strong areas receive less coverage. A maximum interval is set to ensure that all areas receive periodic audit coverage.

Audit schedules shall be based on the month in which the audit starts. For audits scheduled once per 24 months, a 25% grace period beyond the original 24-month completion date may be applied. The maximum time between specific 24-month audits shall not exceed 30 months. Likewise, audits on an annual (12 month) frequency shall not exceed 15 months, except for audit frequencies defined by regulation such as the Emergency and Security plans where the audit intervals are defined and use of extension periods is not allowed.

When an audit interval extension greater than one month is used, the next audit for that particular audit area will be scheduled from the original anniversary month rather than the month of the extended audit.

The following internal Nuclear generation areas will be audited at least once per 24 months, except where a specific frequency is specified by regulation:

a. The conformance of unit operation to provisions contained within the Technical Specifications and applicable license conditions.

b. The performance, training and qualifications of the entire unit staff.

c. The results of actions taken to correct deficiencies occurring in unit equipment, structures, systems, or method of operation that affect nuclear safety at least once per 12 months.

d. The performance of activities required by the Operational Quality Assurance Program to meet the criteria of Appendix B, 10CFR Part 50.

e. The fire protection programmatic controls including the implementing procedures by qualified licensee QA personnel.

f. The fire protection equipment and program implementation, utilizing either a qualified offsite licensee fire protection engineer(s) or an outside independent fire protection consultant. An outside independent consultant should have the qualification for membership in the Society of Fire Protection Engineers as the grade of member; an equivalency of an experienced Fire Protection Engineer not employed by the licensee. An outside independent fire protection consultant shall be utilized at least every third year.

g. Any other area of unit operation considered appropriate by the Nuclear Safety Review Group, the CNO or the Site Vice President-Nuclear Generation.

h. The radiological environmental monitoring program and the results thereof.

i. The OFFSITE DOSE CALCULATION MANUAL and implementing procedures.

j. The PROCESS CONTROL PROGRAM and implementing procedures for processing and packaging of radioactive wastes.

k. The performance of activities required by the Quality Assurance Program to meet the provisions of Regulatory Guide 1.21, Revision 1, June 1974 and Regulatory Guide 4.1, Revision 1, April 1975. (Radioactive Effluents and Environmental Monitoring)

l. The Safeguards Contingency Plan and Security Program (as specified by regulation, and the 25% grace period does not apply).

m. Access Authorization (as specified by regulation).

n. Fitness for Duty (as specified by regulation).

o. Emergency Preparedness (as specified by regulation, and the 25% grace period does not apply).

p. Radiological Protection (as specified by regulation).

q. Fitness for Duty Laboratory.

r. Station Blackout.

s. Nonradiological Environmental Protection Program.

t. Independent Spent Fuel Storage Installation (ISFSI)

Audits are initiated as early as practicable in the life of the activity, consistent with the schedule for accomplishing the activity, to ensure the timely implementation of QA requirements. Audit scope and schedules are established based on the status and importance of the activities performed to ensure the adequacy of, and conformance with, the Nuclear QA program.

Regularly scheduled audits are supplemented by audits for one or more of the following conditions:

a. When it is necessary to assess the capability of a contractor's QA program before awarding a contract or purchase order

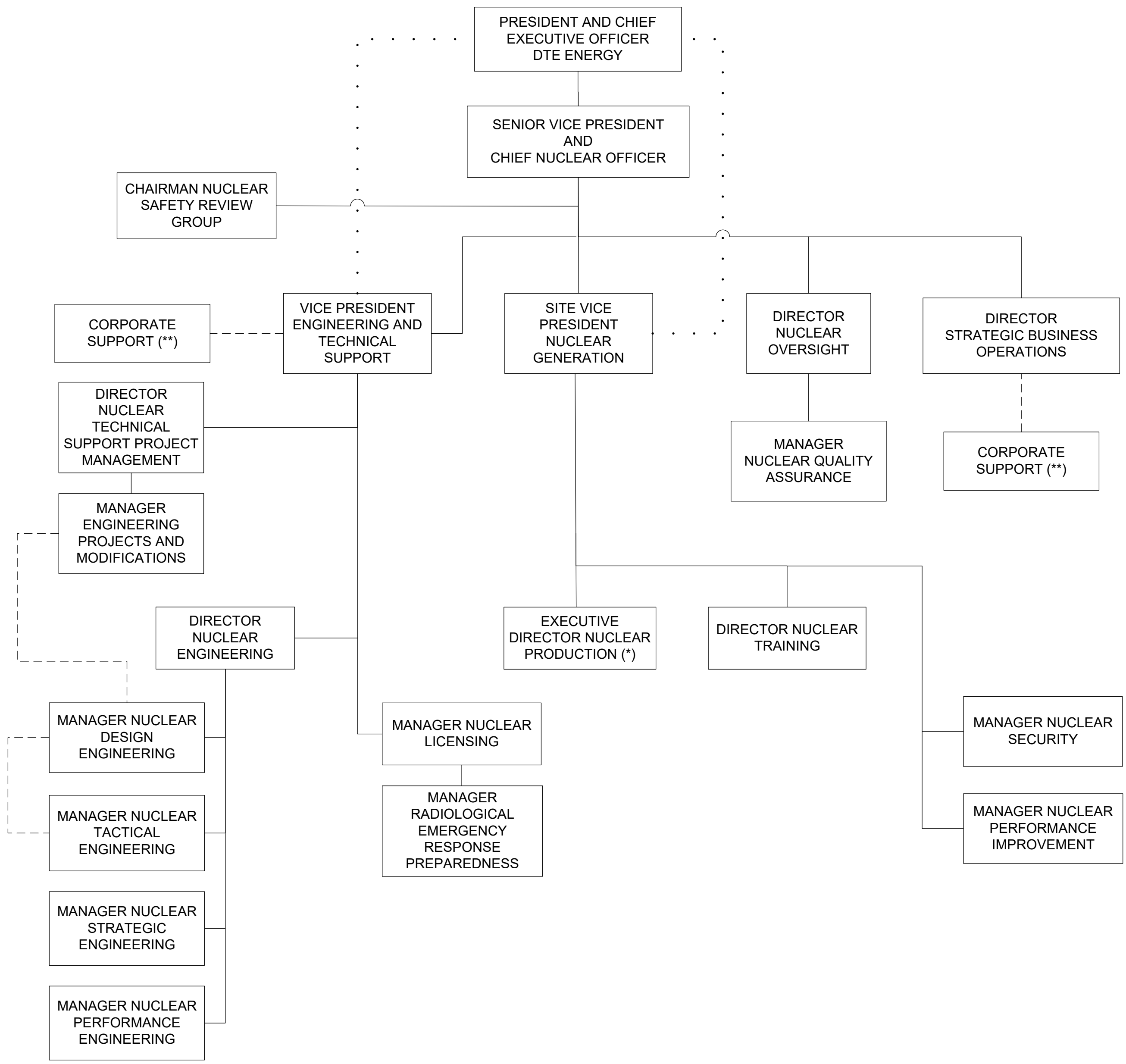
b. When, after the award of a contract, sufficient time has elapsed for implementing the QA program and it is appropriate to determine that the organization is adequately performing the functions as defined in the quality assurance program, codes, standards, and other contract documents

c. When significant changes are made in functional areas of the QA program, such as significant reorganization or procedure revisions

d. When it is suspected that the quality of the item is in jeopardy because of deficiencies in the QA program.

e. When a systematic, independent assessment of program effectiveness is considered necessary

f. When necessary to verify implementation of required corrective action.



. . . . . . Signifies Direct Access

\- - - - - - Signifies Functional Relationship

(*) For details of the Nuclear Production organization, see Figures 13.1-2 and 13.1-3.

(**) When corporate support organizations perform quality-related activities for Fermi 2, such activities are performed under the Fermi 2 Quality Assurance Program.

NOTE: When a position is not filled, reporting order will be the next higher position.

Fermi 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 17.2-1
CORPORATE/NUCLEAR GENERATION ORGANIZATION INVOLVED IN THE QUALITY ASSURANCE PROGRAM FOR OPERATION

17.2A QUALITY ASSURANCE OF THE INDEPENDENT SPENT FUELSTORAGE INSTALLATION

This Appendix describes the administrative controls and the quality assurance (QA) program applied to important-to-safety (ITS) structures, systems and components associated with the Fermi 2 Nuclear Plant Independent Spent Fuel Storage Installation (ISFSI) to assure conformance to regulatory requirements and the design bases. This program is an extension of the quality assurance program described in Section 17.2, modified to address 10 CFR 72 Subpart G items specific to ISFSI and related support activities.

The QA program described in Section 17.2 is applicable to ISFSI items classified as ITS Category A. Specific aspects of the QA program are applied to ITS Categories B and C items as specified in the individual subsections.

The following definitions are applicable to the Fermi 2 Nuclear Plant Quality Assurance Program:

ITS structures, systems, and components are those features of ISFSI whose function is to:

a. Maintain the conditions required to store spent fuel safely,

b. Prevent damage to the spent fuel container during handling, or storage, or

c. Provide reasonable assurance that spent fuel can be received, handled, packaged, stored, and retrieved without undue risk to the health and safety of the public.

The definition of ITS safety categories below are based on NUREG/CR-6407, "Classification of Transportation Packaging and Dry Spent Fuel Storage System Components According to Importance to Safety."

1. Category A – ITS Category A items include structures, components, and systems whose failure could directly result in a condition adversely affecting public health and safety. The failure of a single item could cause loss of primary containment leading to release of radioactive material, loss of shielding, or unsafe geometry compromising criticality control.
2. Category B - ITS Category B items include structures, components, and systems whose failure or malfunction could indirectly result in a condition adversely affecting public health and safety. The failure of a Category B item, in conjunction with failure of an additional item, could result in an unsafe condition.
3. Category C – ITS Category C items include structures, components, and systems whose failure or malfunction would not significantly reduce the packaging effectiveness and would not be likely to create a situation adversely affecting public health and safety.

The QA program, as described in the following identified UFSAR subsections, is applied to ITS Category A, B, and C items unless modified by the description below:

17.2.1 Organization

The corporate organization established to support operation of Fermi 2 Nuclear Plant also functions to support operation of the Fermi 2 Nuclear Plant ISFSI.

Additional offsite support is provided by the storage system vendor.

Some plant personnel who perform 10 CFR 50.59 evaluation reviews also perform the corresponding ISFSI evaluation reviews under 10 CFR 72.48.

17.2.2 Nuclear Quality Assurance Program

QA program requirements are applied to the ISFSI and support structures, systems, and components using a graded approach based on the ISFSI item classification. The program requirements that apply to QA ITS Category A, B and C are identified in table 17.2A-1. Items identified as not important to safety (NITS) are excluded from the QA program.

The plant organization has the same responsibilities as described in paragraph 17.2.1.3 and subsection 17.2.2 for ITS Category A items.

17.2.3 Design Control

Design control measures for ITS Category A and Category B items are applied where appropriate per the controls in subsection 17.2.3. Additional review concerns that are specific to the ISFSI are criticality physics, shielding, and features to facilitate decontamination.

The designs of ITS Category C items specify procurement, inspection, and testing at a level appropriate for the importance of the function performed.

17.2.4 Procurement Document Control

A graded approach is applied through the use of a multi-level procurement classification system based upon the end-use of each item or service. Items procured as ITS Category A items are controlled as described in subsection 17.2.4. ITS Category A items procured as commercial grade are controlled by the existing commercial grade dedication program. ITS Categories B or C items are procured as appropriate for function and safety importance, and are excluded from the provisions of 10 CFR 21.

17.2.5 Instructions, Procedures, and Drawings

17.2.6 Document Control

17.2.7 Control of Purchased Material, Equipment, and Service. (CAT A)

17.2.8 Identification and Control of Materials, Parts, and Components. (CAT A)

17.2.9 Control of Specific Processes. (CAT A & B)

17.2.10 Inspection. (CAT A & B)

17.2.11 Test Control. (CAT A & B)

17.2.12 Control of Measuring and Test Equipment. (CAT A & B)

17.2.13 Handling, Shipping , and Storage, (CAT A)

17.2.14 Inspection, Test, and Operating Status. (CAT A)

17.2.15 Nonconforming Material, Parts, and Components. (CAT A & B)

17.2.16 Corrective Action

17.2.17 QA Records

Records pertaining to design, fabrication, erection, testing, maintenance, and use of ITS items are maintained for the duration of the General License granted under Subpart K of 10 CFR 72 for the specific storage system.

17.2.18 Audits

Audits are performed on a frequency not to exceed 24 months for quality activities related to the operation and maintenance of the ISFSI.

Regarding ISFSI the QA program, as described in the following identified UFSAR subsections, is applied to only ITS Category A and B items as follows.

TABLE 17.2A-1

10 CFR 50 Appendix B Criterion		NUREG/CR-6407 Safety Category A	B	C
I.	Organization	X	X	X
II.	Quality Assurance Program	X	X	X
III.	Design Control	X	X	X
IV.	Procurement Document Control	X		
V.	Instructions, Procedures, and Drawings	X	X	X
VI.	Document Control	X	X	X
VII.	Control of Purchased Material, Equipment, and Services	X		
VIII.	Identification and Control of Materials, Parts, and Components	X		
IX.	Control of Special Processes	X	X	
X.	Inspection	X	X	
XI	Test Control	X	X	
XII.	Control of Measuring and Test Equipment	X	X	
XIII.	Handling, Storage, and Shipping	X		
XIV.	Inspection, Test, and Operating Status	X	X	
XV.	Nonconforming Materials, Parts, or Components	X	X	
XVI.	Corrective Actions	X	X	X
XVII.	Quality Assurance Records	X	X	X
XVIII.	Audits	X	X	X

A.1 DIVISION 1 APPLICABLE REGULATORY GUIDES

A.1.1 REGULATORY GUIDE 1.1 (November 1970), NET POSITIVE SUCTION HEAD FOR EMERGENCY CORE COOLING AND CONTAINMENT HEAT REMOVAL SYSTEM PUMPS

Fermi 2 conforms to the regulatory position in this guide. The net positive suction head (NPSH) margin has been adequately established as being conservative.

The analysis establishing the adequacy of the NPSH margin is found in response to Question 2.8.3f of Amendment 17 to the Fermi 2 FSAR.

For details refer to Subsection 6.3.2.14.

A.1.2 REGULATORY GUIDE 1.2 (November 1970), THERMAL SHOCK TO REACTOR PRESSURE VESSELS

The reactor pressure vessel (RPV) of the Fermi 2 plant will behave in a nonbrittle manner under loss-of-coolant conditions. This position is based on NEDO-10029, "An Analytical Study on Brittle Fracture of GE-BWR Vessel Subject to the Design Basis Accident."

For details refer to Subsection 5.4.4.

A.1.3 REGULATORY GUIDE 1.3 (June 1974, Revision 2), ASSUMPTIONS USED FOR EVALUATING THE POTENTIAL RADIOLOGICAL CONSEQUENCES OF A LOSS OF COOLANT ACCIDENT FOR BOILING WATER REACTORS

Regulatory Guide 1.3 is no longer the basis for Fermi 2 Loss of Coolant Accident radiological consequence analysis. Alternative Source Term (AST) analysis per Regulatory Guide 1.183 has replaced the original Regulatory Guide 1.3 based analysis and discussed in Section 15.6.5 and 15.7.4.

A.1.4 REGULATORY GUIDE 1.4 (June 1974, Revision 2), ASSUMPTIONS USED FOR EVALUATING THE POTENTIAL RADIOLOGICAL CONSEQUENCES OF A LOSS OF COOLANT ACCIDENT FOR PRESSURIZED WATER REACTORS

Regulatory Guide 1.4 does not apply to Fermi 2, which is a BWR.

A.1.5 REGULATORY GUIDE 1.5 (March 1971), ASSUMPTIONS USED FOR EVALUATING THE POTENTIAL RADIOLOGICAL CONSEQUENCES OF A STEAM LINE BREAK ACCIDENT FOR BOILING WATER REACTORS

The analyses of the effects of a steam line break accident are discussed in Subsection 15.6.4. The analysis is in conformance with the regulatory position of this guide.

A.1.6 REGULATORY GUIDE 1.6 (March 1971), INDEPENDENCE BETWEEN REDUNDANT STANDBY (ONSITE) POWER SOURCES AND BETWEEN THEIR DISTRIBUTION SYSTEMS

To provide the assurance of protection from releases of radioactivity by maintenance of fission product barrier integrity under accident conditions, the electrical power supply system to the emergency core cooling systems and operational reactor coolant pressure boundary (RCPB) protection systems must be sufficient in capacity and redundancy to supply service to vital functions at all times from onsite power. In addition, General Design Criterion (GDC) 17 of Appendix A to 10 CFR 50 requires sufficient independence and testability of the onsite electrical power system to perform under single-failure conditions.

The Fermi 2 plant onsite power system consists of four emergency diesel generator (EDG) units separated into two divisions. Each division containing two EDGs will supply power to its own radial load. The capacity of each division (two EDGs; 2850 kW/unit) and required capacities and preoperational design loads are listed in the tables of Subsection 8.3.1.1.8.1. Either divisional pair of diesel generator units will be capable of supplying loads needed for safe reactor shutdown as Position 1 of the guide requires.

To comply with Position 2, each division is connected to an independent offsite power source; Division I through transformers to the 120-kV electrical system grid and Division II through the 345-kV grid.

Fermi 2 has identified the residual heat removal (RHR) system as vital to the protection of the fission product barrier. This system does not comply with Position 1 of the guide. The RHR electrical system automatically transfers loads between divisions (if necessary) during a LOCA. Due to the special nature of the above automatic transfer, all feeds to and from the motor control center (MCC) are run exclusively in conduit in order to maintain divisional integrity.

Position 3 of the guide specifies that dc load groups have battery and battery chargers to energize them. The Fermi 2 dc systems consist of two loads. Within each division are two 130- V dc control batteries in series, thus producing 260-V dc emergency power feed capacity. To provide independence of battery and charger combinations, the system incorporated into the dc system has a charger for each 130-V dc battery and one standby battery charger per division. In conjunction, the dc instrument system consists of one 48/24-V battery per division with two 24-V dc chargers per division and a standby charger. As a result, the battery and charger system combination relies on no automatic connections to other redundant dc loads.

No automatic load transfers are to be performed with the exception of certain RHR-related loads as noted above. There do exist manually operated electrical and physical interlocked maintenance ties between the two ac power supply divisions. During operating conditions, both breakers at each end of the ties are kept open and racked out of their operating position. In compliance with Position 4, this interlock arrangement prevents operator inadvertent error, which might imperil standby power source availability.

The Fermi 2 design uses two divisions of ac sources each with redundant motor-generator sets, i.e., two EDGs per division. This redundancy ensures reliability and satisfies the need for protection against common-mode failures and single failures required in Position 5.

For additional information, refer to Subsections 8.3.1.1.4 and 8.3.1.1.8.1.

A.1.7 REGULATORY GUIDE 1.7 (March 2004, Revision 3), CONTROL OF COMBUSTIBLE GAS CONCENTRATIONS IN CONTAINMENT

Fermi 2 originally complied with the guidance in Regulatory Guide 1.7, Revision 2. The NRC amended 10 CFR 50.44, "Standards for combustible gas control system in lightwater-cooled power reactors" on October 16, 2003 to eliminate the requirements for hydrogen recombiners. The hydrogen recombiner Technical Specification requirements were subsequently removed by License Amendment 159, dated March 15, 2004. Regulatory Guide 1.7, Revision 3, was issued in March 2007 to reflect the amended 10 CFR 50.44.

Fermi 2 complies with guidance set forth in this regulatory guide.

As it is no longer required for compliance with tis regulatory guide, the Combustible Gas Control System (CGCS) has been retired in place with its electrical circuits de-energized and fluid process piping isolated from primary containment with redundant locked-closed isolation valves as described in Subsection 6.2.5. Combustible gas control of the primary containment is provided by inerting the primary containment with nitrogen, see Section 9.3.6. For descriptions of the hydrogen/oxygen monitoring system, see Subsection 7.6.1.

A.1.8 REGULATORY GUIDE 1.8 (September 1975, Revision 1), PERSONNEL QUALIFICATION AND TRAINING

With regard to Revision 1 to Regulatory Guide 1.8 (September 1975), Fermi 2 is in conformance.

A.1.9 REGULATORY GUIDE 1.9 (December 1979, Revision 2), SELECTION, DESIGN, AND QUALIFICATION OF DIESEL GENERATOR UNITS USED AS STANDBY (ONSITE) ELECTRICAL POWER SYSTEMS AT NUCLEAR POWER PLANTS

The guidelines presented in Regulatory Guide 1.9, Revision 2, apply to nuclear power plants whose construction permit applications were docketed after December 1979. Because the application for Fermi 2 was docketed in 1969, the revised versions of the guidelines do not apply to Fermi 2.

The EDGs for Fermi 2 are acceptable as discussed on page 31 of the AEC Staff Safety Evaluation Report of May 17, 1971. The Fermi 2 design conforms to the regulatory guide positions except those in paragraphs C.4, C.5, C.7, C.9, and C.11 of Regulatory Guide 1.9 (December 1979, Revision 2). Exceptions taken to Positions C.4, C.5, C.7, C.9, and C.11 are described below, along with Edison's compliance with Position C.14.

Exception To Position C.4

Preoperational tests have validated the starting and load- accepting capability of the EDGs. Minor deviations from the Regulatory Guide recommendations are noted below but they do not impair the ability of the EDGs to perform their design functions.

System analyses performed by Colt and Detroit Edison produced results close to the recommended limit of 75% in this position. As a result, pre-operational testing was utilized to ensure successful operation in lieu of analytical comparison to the 75% limit. The pre-operational test results, shown in Table 8.3-8, identified that the first voltage dip associated with the RHR pump start did decrease below 75%, but subsequent voltage dips, such as for the CS pump start, did not. The original excitation systems (Portec) were replaced with new excitation systems (Basler). System analysis by Coltec with the new excitation systems predicted voltage dips below 75% for the RHR pump start. Testing performed during refueling outages since the replacement has shown that voltage dips associated with the RHR pump start have sometimes been below the 75% value of this position as well as below those from the pre-operational test results. Similarly, testing has shown that the voltage dip associated with the CS pump start has at times decreased below 75%. The continued successful testing during refueling outages with the identified voltage dips ensures the adequacy of the EDG performance during large-motor starting transients even when voltage dips below the 75% value associated with this position. Voltage dips, while not an acceptance criteria of the testing, are monitored to identify potential for EDG or other equipment degradation. Revision 2 to Regulatory Guide 1.9 maintains the same voltage dip limits of 75 percent and a frequency limit of 95 percent as did Revision 1.

The recovery time of the original regulatory guide was relaxed somewhat in Revision 1. The original regulatory guide required voltage recovery to 10 percent of nominal and frequency to 2 percent of nominal within 45 percent of each load sequence. The revised regulatory guide now allows the recovery in 60 percent of each load sequence. Preoperational test results showed that all loading frequencies, with the exception of the RHR pumps (Table 8.3-8), were within the allowed recovery times.

Fermi 2 is also in compliance with the overspeed trip requirements of this position.

<u>Exception To Position C.5</u>

The Fermi 2 EDGs were purchased to meet IEEE 323-1971, which was acceptable when they were purchased in February 1973.

<u>Exception To Position C.7</u>

Fermi 2 meets most of the requirements of this position. The EDG protective trips are automatically bypassed (except for overspeed and generator differential, in accordance with Position C.7). In addition, the crankcase overpressure and low lube-oil pressure trips, although not bypassed, require coincidental signals to trip, again in accordance with Position C.7. Fermi 2 also has a start failure relay trip which, during the startup of the unit, does not require coincidental signals to trip. (Once the unit is up to speed, two speed contacts bypass the relay.) This approach, as presented in Subsection 8.3.1.1.12.2 and Table 8.3-12 is in compliance with EICSB 17 of the Standard Review Plan (SRP) and was found acceptable in the interim safety evaluation report, NUREG-0314.

The bypass circuits are initiated by either relay ESA or ESB, such that a single failure will not prevent a bypass of the trips.

The bypass function is testable and the emergency mode operation of the EDG is annunciated in the main control room. Any trip that is bypassed will still annunciate in the control room. Fermi 2 does not have manual reset of the trip bypass but the trip bypass automatically resets when the emergency start signals are picked up.

<u>Exception To Position C.9</u>

This position suggests the use of the 1975 version of IEEE 344 for the seismic qualification program. The Fermi 2 seismic qualification followed the 1971 version of IEEE 344, which was current when the equipment was purchased in February 1973.

Exception To Position C.11

Position C.11 suggests that the EDG site-acceptance tests and periodic tests conform with Sections 6.5 and 6.6 of IEEE 387-1977 and be supplemented by Regulatory Guide 1.108. The Fermi 2 EDGs were tested to the performance requirements of Regulatory Guide 1.108, but not necessarily all of the requirements of IEEE 387-1977.

Position C.13

Position C.13 is not applicable to Fermi 2.

Compliance With Position C.14

The Fermi 2 preoperational test procedures were developed to meet Regulatory Guide 1.108, Revision 1. Regulatory Guide 1.108, Section C.2.a.(3), requires a demonstration run of 22 hr at the continuous rating (2850 kW) and 2 hr at the 2-hr rating (3135 kW). Position C.14 in Regulatory Guide 1.9 is basically the same requirement as Regulatory Guide 1.108 except that the test sequence is different and must be continuous. Regulatory Guide 1.9 now calls for a warm-up run at the continuous rating until equilibrium temperatures are reached, then a 2-hr run at the 2-hr load and a subsequent 22-hr run at the continuous rating. Since this position reflects the current NRC position, Edison has run the preoperational test in accordance with Position C.14.

A.1.10 REGULATORY GUIDE 1.10 (January 1973, Revision 1), MECHANICAL (CADWELD) SPLICES IN REINFORCING BARS OF SEISMIC CATEGORY I CONCRETE STRUCTURES

The Fermi 2 procedures are in conformance with the overall objectives and intent in Regulatory Guide 1.10. A minor exception to the detailed practices set forth in the guide is that the Fermi 2 procedures require (1) each splice operator to be qualified by at least one test splice at each anticipated splice position and (2) a test program similar in quality to the one which is specified in the guide. However, it relies heavily on the use of companion or "sister" splicing, rather than "production" splice testing, to qualify the production splices. The procedure requires production testing in the event of companion test failures.

For details refer to Subsection 3.8.4.6.6.

This Regulatory Guide has since been withdrawn (as of July 1981).

A.1.11 REGULATORY GUIDE 1.11 (Supplement, February 1972), INSTRUMENT LINES PENETRATING PRIMARY REACTOR CONTAINMENT

The design of Fermi 2 satisfies GDC 55 and 56 of 10 CFR 50, Appendix A, as well as Regulatory Guide 1.11 and the Supplement to this regulatory guide issued in February 1972. By the use of a single automated excess flow check valve and shutoff valve external to the primary containment wall and a flow restriction orifice, internal to the primary containment wall, the isolation of the penetration line ports takes place. Normally open, the excess flow check valves close automatically and indicate the actuation on the control room panel on occurrence of a line break. These "N" stamp valves are designed to conservative requirements for seismic testing and close with a 2.5-gpm maximum reverse flow rate. Design operating pressure is 1250 psig at 575°F.

For design details refer to Subsection 6.2.4.2.5.

A.1.12 REGULATORY GUIDE 1.12 (April 1974, Revision 1), INSTRUMENTATION FOR EARTHQUAKES

The seismic instrumentation program described in Subsection 3.7.4 meets the intent of Regulatory Guide 1.12, Revision 1. The system conceived and designed for the Fermi facility was documented in January of 1972, prior to the issuance of Regulatory Guide 1.12. In June 1975, the Fermi project reviewed this earthquake recording system for compliance with the requirements of Regulatory Guide 1.12, Revision 1, and concluded that the intent of the requirements was satisfied. In May 1996, the recording system was upgraded with a digital recorder. The upgrade was reviewed for compliance with the requirements of Regulatory Guide 1.12, Revision 1, and concluded that the intent of the requirements was satisfied.

The Fermi 2 earthquake recording system does not contain a triaxial seismic switch, a triaxial response spectrum switch, or any triaxial peak accelerographs. The intent of the Regulatory Guide requirements for this equipment is fulfilled, however, by installed triaxial active time history accelerographs and passive response spectra recorders.

A seismic trigger set at 1/8 of the horizontal operating-basis earthquake (OBE) zero period acceleration level indicates to control room personnel that a seismic event has occurred. Active on-line playback apparatus and extracted triaxial response spectra data provide information allowing a decision to be made expeditiously regarding facility shutdown.

High frequency acceleration data from the 18 response spectrum recorders at the Fermi facility provides significant peak acceleration information for representative reactor equipment, reactor piping, and other Category I equipment and Category I facility structures.

A.1.13 REGULATORY GUIDE 1.13 (December 1975, Revision 1), FUEL STORAGE FACILITY DESIGN BASIS

The design of the Fermi 2 fuel storage facility does not conform fully to certain regulatory positions in this guide. Edison has incorporated alternative solutions to ensure that the design of this facility is adequate. The Fermi 2 reactor building crane meets single-failure criteria and is therefore acceptable by the revised (Revision 1) guide. The design basis of the facility versus the regulatory positions is discussed below.

Edison has done a very careful analysis of the probability of a missile generated by cyclonic winds damaging the pool or the fuel. The results of the study show that in view of the extremely low probability of a tornado-borne missile damaging fuel, neither the added complexity to plant operation nor the cost of a fuel pool cover is warranted. Based on its own independent assessment (AEC letter of June 11, 1974, W. R. Butler (AEC) to H. Tauber (Edison)), the AEC waived the requirement to provide tornado protection of the spent fuel pool on the basis of the low probability of a tornado, the lower likelihood that objects could be lifted to the elevation of the fuel pool and become missiles, and the expectation that where spent fuel damage were to occur, the associated offsite exposure radiological consequences would be likely within 10CFR100 limits.

The reactor building crane is designed to standards of complete redundancy of fail-safe systems. Hooks, cables, brakes, and motors are redundant; drums are fail-safe. Edison takes the position that this solution is superior to the area-interlock method suggested in the regulatory guide. The reactor building crane is described in Subsection 9.1.4.2.2.

Coolant can be added to the pool from the condensate storage tanks (up to 100 gpm), or from the RHR system. The RHR system, including storage, and the cross-tie piping between the RHR system and the fuel pool diffusers, are designed to Category I requirements.

The justification for the design for fuel pool makeup is as follows: the pool, which is a Category I structure, incorporates a very high integrity stainless steel liner; therefore, a large leak is very unlikely. Consequently, the time from initiation of the low-level alarm until the water reaches the top of the fuel is in units of hours. Should the fill line be unusable at this time, numerous alternatives are available to get water into the pool, such as the use of the fire-fighting system or connection of a fire hose to the RHR system. These alternatives can be employed within the time available.

The fuel storage facility is described in Subsections 3.1.2.6, 9.1.1.1, 9.1.2.1, 9.1.3.1, and 9.1.4.1.

A.1.14 REGULATORY GUIDE 1.14 (August 1975, Revision 1), REACTOR COOLANT PUMP FLYWHEEL INTEGRITY

Regulatory Guide 1.14 does not apply to Fermi 2 since BWRs do not use reactor coolant pumps and BWR reactor recirculation coolant pump motors do not have inertia flywheels.

A.1.15 REGULATORY GUIDE 1.15 (December 1972, Revision 1), TESTING OF REINFORCING BARS FOR SEISMIC CATEGORY I CONCRETE STRUCTURES

Fermi 2 is in conformance with the guide except for a departure relating to the requirement to test one bar for each bar size from every 50 tons or fraction thereof from each heat. Edison Specification No. 3071-16, "Concrete Reinforcement," requires that the reinforcing steel conform to ASTM A 615-72, which requires bar testing on a "per heat" basis without regard to heat tonnage.

This Regulatory Guide has since been withdrawn (as of July 1981).

A.1.17 REGULATORY GUIDE 1.17 (June 1973), PROTECTION OF NUCLEAR POWER PLANTS AGAINST INDUSTRIAL SABOTAGE

The Fermi 2 Physical Security Plan is not designed to conform specifically to Regulatory Guide 1.17.

The Fermi 2 Physical Security Plan conforms to 10 CFR 73, Section 73.55, "Requirements for Physical Protection of Licensed Activities in Nuclear Power Reactors Against Industrial Sabotage." The guidelines of NUREG-0908, Acceptance Criteria for the Evaluation of Nuclear Power Reactor Security Plans (August 1982), were used to develop the plan.

A.1.18 REGULATORY GUIDE 1.18 (December 1972, Revision 1), STRUCTURAL ACCEPTANCE TEST FOR CONCRETE PRIMARY REACTOR CONTAINMENTS

Regulatory Guide 1.18 does not apply since Fermi 2 utilizes a steel primary reactor containment.

A.1.19 REGULATORY GUIDE 1.19 (August 1972, Revision 1), NON-DESTRUCTIVE EXAMINATION OF PRIMARY CONTAINMENT LINER WELDS

Regulatory Guide 1.19 does not apply since there is no primary containment liner in the Fermi 2 power plant.

A.1.20 REGULATORY GUIDE 1.20 (May 1976, Revision 2), COMPREHENSIVE VIBRATION ASSESSMENT PROGRAM FOR REACTOR INTERNALS DURING PREOPERATIONAL AND INITIAL STARTUP TESTING

The Fermi 2 vibration program for the reactor internals includes provisions for confirmatory instrumented vibration tests as suggested in this guide. The Tennessee Valley Authority Browns Ferry, Unit 1, reactor was the prototype reactor and was to be tested according to the BWR Prototype Vibrational Testing Program.

Complete details of the program were developed and are available for review by the NRC prior to the performance of scheduled preoperational functional tests.

Refer to Subsection 3.9.1.3 for additional discussion on the testing of reactor internals.

A.1.21 REGULATORY GUIDE 1.21 (June 1974, Revision 1), MEASURING, EVALUATING, AND REPORTING RADIOACTIVITY IN SOLID WASTE AND RELEASES OF RADIOACTIVE MATERIALS IN LIQUID AND GASEOUS EFFLUENTS FROM LIGHT-WATER-COOLED NUCLEAR POWER PLANTS

The Fermi 2 design complied with the first issue of Regulatory Guide 1.21. Changes to the guide in Revision 1 have caused some features of the plant design to be in possible noncompliance.

Areas of possible noncompliance do not affect the ability to safely shut down the reactor. Automatic termination of releases from the condenser offgas system on detection of high activity has not been provided. Edison's reason for noncompliance with this aspect of Regulatory Guide 1.21 is based on Edison's compliance with Appendix I to 10 CFR 50 taking priority. A brief summary of the considerations involved follows.

Paragraph 20.1(c) of 10 CFR 20 states

> Persons engaged in activities under licenses issued by the Nuclear Regulatory Commission . . . make every reasonable effort to maintain radiation exposures, and releases of radioactive materials in effluents to unrestricted areas, as low as is reasonably achievable. The term ‘as low as is reasonably achievable’ means as low as is reasonably achievable taking into account the state of technology, and the

economics of improvements in relation to benefits to the public health and safety, and other societal and socioeconomic considerations, and in relation to utilization of atomic energy in the public interest.

Public use of a dependable energy source, although a seldom- emphasized consideration of the "as low as is reasonably achievable" requirement, is part of the regulation and must receive equal emphasis.

Section IV of Appendix I to 10 CFR 50, which contains numerical guidance for technical specifications and limiting conditions for operation, states that the licensee is permitted the flexibility of operation, compatible with considerations of health and safety, to ensure that "the public is provided a dependable source of power even under unusual operating conditions that <u>may temporarily result in releases higher than such numerical guides</u> for design objectives . . ." (emphasis added). Edison regards this type of operating flexibility to be warranted in light of the restrictive nature of Appendix I. Continued operation of licensed facilities in this manner will <u>not</u> decrease the protection from radiation established by existing regulations. The Commission has clearly emphasized that the Appendix I guides are not radiation protection standards, but are a quantitative expression of meaning of the "as low as is reasonably achievable" requirement. The Commission's standards are in 10 CFR 20 and remain unchanged by Appendix I to 10 CFR 50.

Edison complied with the radiation protection standards for limiting potential doses to the public contained in 10 CFR 20 prior to elaborate additions to the condenser offgas system. It procured the condenser offgas system to satisfy the then proposed Appendix I to 10 CFR 50 to reduce activity releases to the "as low as practicable" level, and not because the health and safety of the public were endangered.

Guidance on technical specifications and limiting condition for operation contained in Appendix I requires (among other things) that the licensee implement a program of corrective action should material actually released during any calendar quarter result in a calculated exposure exceeding twice the annual design objective. This essentially means that a licensee shall take corrective action to limit activity releases well before any individual could receive an exposure above the limiting values of 10 CFR 20. The action taken by a licensee in compliance with Appendix I (and monitored by the Commission) inherently ensures that the limiting doses of 10 CFR 20 will not be exceeded. Automatic isolation of the condenser offgas system would ultimately result in a turbine trip and the potential loss of electrical power to some members of the public. This is not only unnecessary, but should be avoided in order to comply with all aspects of Appendix I.

Clearly, automatic termination of the offgas system operation at the restrictive levels contained in Appendix I is inconsistent with an objective of Appendix I to ensure that the public is provided a dependable source of power even under unusual operating conditions that may temporarily result in releases higher than the design objective.

Automatic termination of offgas system operation required by Regulatory Guide 1.21 is outside the scope of the regulatory guide and inconsistent with the operational flexibility permitted by Appendix I. Compliance with this particular aspect of the regulatory guide should not take priority over the requirements of Appendix I.

In summary, the corrective action the operator would take to comply with the requirements of Appendix I would limit the resultant doses to a value well below the historically accepted safe limits specified in 10 CFR 20. Automatic termination of the condenser offgas system operation would not provide the operator with the option of reducing power nor permit activity releases temporarily higher than those associated with the almost immeasurably small doses of Appendix I, which the Commission expressly expected would be exceeded to permit the necessary flexibility in compliance with Appendix I in its entirety.

The Fermi 2 Technical Specifications and Offsite Dose Calculation Manual implement the intent of this Regulatory Guide.

A.1.22 REGULATORY GUIDE 1.22 (February 1972), PERIODIC TESTING OF PROTECTION SYSTEM ACTUATION FUNCTIONS

The current Fermi 2 provisions for periodic testing of protection system actuation functions conform to the requirements of this guide.

Refer to Subsections 7.2.1.1, 7.2.2.2, 7.3.1.2, 7.6.1.1, 7.6.1.2, 7.6.1.4, 7.6.1.7, 7.6.1.8, 7.6.1.14, 7.6.1.15, 7.6.2.1, 7.6.2.2, 7.6.2.3, 7.6.2.4, 7.6.2.7, 7.6.2.8, 7.6.2.9, 7.6.2.12, 7.6.2.13, and 7.6.2.15.

A.1.23 REGULATORY GUIDE 1.23 (February 1972), ONSITE METEOROLOGICAL PROGRAMS

The Fermi 2 onsite meteorological programs fulfill the requirements of this guide except for the section on instrument accuracy. The Fermi 2 meteorological data acquisition system meets the system accuracy requirements of proposed Revision 1 (September 1980) to Regulatory Guide 1.23.

For details on the Fermi 2 meteorological program, refer to Subsection 2.3.3.6.

A.1.24 REGULATORY GUIDE 1.24 (March 1972), ASSUMPTIONS USED FOR EVALUATING THE POTENTIAL RADIOLOGICAL CONSEQUENCES OF A PRESSURIZED WATER REACTOR RADIOACTIVE GAS STORAGE TANK FAILURE

Regulatory Guide 1.24 does not apply since Fermi 2 is a BWR.

A.1.25 REGULATORY GUIDE 1.25 (March 1972), ASSUMPTIONS USED FOR EVALUATING THE POTENTIAL RADIOLOGICAL CONSEQUENCES OF A FUEL HANDLING ACCIDENT IN THE FUEL HANDLING AND STORAGE FACILITY FOR BOILING AND PRESSURIZED WATER REACTORS

The analysis of the fuel-handling accident, as discussed in Subsection 15.7.4, is in conformance with the regulatory position of this guide. Regulatory Guide 1.25 assumptions regarding the pool iodine decontamination factor and gap fractions (except as modified per License Amendment 87 based on NUREG/CR-5009) apply to the analysis of 9x9 fuel that does not meet the Regulatory Guide 1.183 limitations on fuel burnup. Fuel handling accidents involving fuel that meets the Regulatory Guide 1.183 (Table 3, Footnote 11) burnup specifications are analyzed in accordance with the NRC's Alternate Source Term and; thus, do not conform to this regulatory guide.

A.1.26 REGULATORY GUIDE 1.26 (February 1976, Revision 3), QUALITY GROUP CLASSIFICATIONS AND STANDARDS FOR WATER-, STEAM-, and NUCLEAR POWER PLANTS

The Fermi 2 design is not in full conformance with the requirements of this guide. The design is based on the commitment in the PSAR as accepted by the AEC-DL in the Safety Evaluation Report (SER) Section 3.3.3, page 16. The Fermi 2 project considers the extent to which the design conforms to this guide to be adequate.

For details refer to Subsection 3.2.2.

A.1.27 REGULATORY GUIDE 1.27 (January 1976, Revision 2), ULTIMATE HEAT SINK FOR NUCLEAR POWER PLANTS

The design of the Fermi 2 RHR Complex conforms with the requirements of GDC 44 of 10 CFR 50, Appendix A, by providing assurance of system redundancy for safe removal of reactor decay heat after emergency shutdown and during accident conditions. Fermi 2 meets regulatory guide position 1 by providing 6,598,000 gallons of water at 1 foot below grade level to permit safe cooldown requirements over a 7-day period. This period includes time needed to evaluate the situation and take corrective action to initiate replenishment activities if necessary.

The ultimate heat sink system was originally sized to provide sufficient cooling for 30 days following an accident without make-up water addition to the RHR reservoir. Regulatory Guide 1.27 states that a UHS capacity of less than 30 days may be acceptable if it can be demonstrated that replenishment can be effected to ensure the continuous capability of the sink to perform its safety functions, taking into account the availability of replenishment equipment and the limitations that may be imposed on freedom of movement following an accident.

The Fermi 2 UHS design evolved long before the post-TMI improvements in Emergency Preparedness. These improvements are reflected in the Detroit Edison Radiological Emergency Response Preparedness Plan. One of the objectives of this program is effective and timely implementation of emergency measures. Detroit Edison now has the resources of the Emergency Response Organization to rapidly identify the need for reservoir replenishment and to direct procurement of material and field implementation. This change significantly improves the ability to provide reservoir replenishment within 7 days as it relates to resolving problems associated with freedom of movement following an accident or occurrence of severe natural phenomena.

The 7-day make-up provision for the RHR reservoir is consistent with the 7-day make-up provisions allowed for replenishment of the diesel generator fuel supply. Therefore, this period of time is sufficient to recover from the effects of natural phenomena such as tornado, storm, earthquake or flood and restore site access for replenishment activities.

Make-up will be provided by the normal make-up system or using RHR Complex fire hoses. If these systems are not available, temporary equipment will be used. The necessary pumps and hoses are commercially available from many sources and that seven days is sufficient time to procure and install the equipment. The water source will be either Lake Erie, the Fermi 1 discharge canal, the circulating water reservoir, the on-site Quarry Lake or Swan Creek. The temperature and quality of make-up water is maintained to ensure that the service water systems and cooling towers perform as required. Siphon of the reservoir is prevented by ensuring that hoses are not placed into the reservoir water.

The 7-day supply calculations utilize the Marley design and test data for cooling tower drift and evaporative water losses. As discussed in Section 9.2.5.3.3, water losses due to leakage and EECW makeup from the reservoir are assumed. In addition, both divisions of EDGs, RHR, EECW/EESW, EDGSW, and RHRSW cooling towers are assumed to be operating maximizing heat load to the reservoir and maximizing evaporative and drift losses. Constant historical worst-case meteorological data is used to compute evaporative water losses. The 7-day supply also assumes initial reservoir level at the technical specification limit of 580' - 0" versus the normal operations level of between 582'-0" and 583'-0" which provides additional conservatism.

In regard to Position 2 of the Regulatory Guide, the Fermi 2 RHR heat sink is designed to withstand the most severe natural phenomenon such as the safe-shutdown earthquake (SSE), tornado, hurricane, flood, or drought. In addition, other less severe phenomena and reasonably probable combinations of less severe phenomena have been accounted for in the safety analysis.

The primary components of man-made structures in the RHR heat sink complex are the RHR cooling towers. In the ultimate heat sink design calculations, the 1972 ASHRAE Handbook Fundamentals ambient air wet bulb temperature of 76°F and dry bulb temperature of 92°F are used. These design temperatures represent values that have been equaled or exceeded by only 1% of the total hours of the months of June through September. These conditions are assumed to be continuous over the 7-day period.

The Technical Specification limit for cooling tower reservoir temperature is 80°F. To calculate the peak suppression pool temperature following DBA/LOCA, an energy balance calculation was used to determine the post-LOCA RHRSW temperature increase as a function of time from the initial condition of 80°F to the cooling tower maximum return design temperature of 90°F. The temperature profile, which is nonlinear, was conservatively bounded by a linear profile with the initial temperature of 80°F increasing in a linear way to 90°F over an 8-hour period. Using the conditions outlined in Regulatory Guide 1.1 (November 1970), adequate NPSH margin is provided for pumps taking suction from the suppression pool.

Regulatory Position 3 requires redundant sources of water, both of which must be capable of meeting the requirements of Position 1. In cases where an extremely low probability of failure due to natural phenomena of a single source is demonstrated, this requirement may be waived. In addition, Technical Specifications, including provisions for actions taken in the event of the threat of partial loss of capability of the ultimate heat sink, must be reviewed. The Fermi 2 design of the ultimate heat sink provides a highly reliable single water source of Category I design. This source is located below grade and is composed of two separate reservoirs connected by redundant 10-inch penetrations. The design allows either redundant division of the RHRSW, EESW or EDGSW systems to use the entire volume of water in the two reservoirs. The 7-day water supply is thus met even after considering any single failure. In the event of a seismic disturbance and failure that causes development of a crack, only water stored above ground-water elevation will be lost. The 7-day water supply includes allowance for a below grade crack in both reservoir basins. The RHR complex of diesel generators, cooling towers, RHRSW, EESW and EDGSW systems, and auxiliaries is redundant.

For details refer to Subsection 9.2.5.2.

A.1.28 REGULATORY GUIDE 1.28 (February 1979, Revision 2), QUALITY ASSURANCE PROGRAM REQUIREMENTS (DESIGN AND CONSTRUCTION)

The Fermi 2 quality assurance (QA) program complies with ANSI N45.2-1977 and the requirements of Revision 2 of this regulatory guide.

For details on the QA program, refer to Chapter 17.

A.1.29 REGULATORY GUIDE 1.29 (September 1978, Revision 3), SEISMIC DESIGN CLASSIFICATION

The Fermi 2 design is in conformance with the requirements of Regulatory Guide 1.29. Refer to Subsection 3.2.1 for a listing of safety-related structures, systems, and components that are designed to withstand the effects of an SSE.

A.1.30 REGULATORY GUIDE 1.30 (August 1972), QUALITY ASSURANCE REQUIREMENTS FOR THE INSTALLATION, INSPECTION, AND TESTING OF INSTRUMENTATION AND ELECTRIC EQUIPMENT

The Fermi 2 QA program is in conformance with this guide.

For details refer to Chapter 17.

A.1.31 REGULATORY GUIDE 1.31 (April 1978, Revision 3), CONTROL OF FERRITE CONTENT IN STAINLESS-STEEL WELD METAL

Stainless steel systems and components for Fermi 2 were fabricated by GE or Dravo and include the following:

a. Reactor recirculation system

b. Control rod drive (CRD) hydraulic return

c. CRD housing to flange

d. Reactor core isolation cooling (RCIC) system (suction from condensate storage).

Since these systems and components were ordered prior to the inception of Regulatory Guide 1.31, welds were not specifically tested for delta ferrite. Welds made by GE were made with long- standing procedures that had been proven adequate for consistently producing satisfactory, fissure-free welds. In addition, welds produced in five BWRs using the same procedures as used on Fermi 2 equipment were tested and found to contain a minimum of 3 percent delta ferrite. In addition, stainless steel welds made by Dravo were made using weld filler metal containing 5 to 15 percent delta ferrite. Similar welds made by Dravo using the same procedures were inspected and found to consistently contain a minimum of 3 percent delta ferrite.

In view of the above, Edison does not plan a delta ferrite inspection program on previously fabricated stainless steel components and systems. In addition, since Regulatory Guide 1.31 and Branch Technical Position (BTP) MTEB 5.1 were issued, a considerable amount of attention has been given to delta ferrite control. Programs have been undertaken to determine not only the effects of delta ferrite on fissure sensitivity but also the effects of welding parameters on delta ferrite formation. Programs included analysis of laboratory-produced welds as well as statistical analysis of welds in actual components and systems.

These programs indicated that fissuring is minimized when as little as 3 percent delta ferrite is present. Additional amounts of delta ferrite do not further reduce fissure susceptibility.

It has also been shown that the delta ferrite in a resultant weld can be controlled by controlling the chemistry of the weld metal. Weld metals containing approximately 5 percent delta ferrite will produce welds with a minimum of 3 percent delta ferrite. Accordingly, for all future fabrication and installation of austenitic stainless steel components and systems, Edison will control delta ferrite formation as follows:

a. Each heat of austenitic stainless steel (A-No. 8 analysis of ASME Section IX, QW 442) bare wire and each heat or lot of austenitic stainless steel covered electrodes will be purchased in accordance with the applicable requirements of ASME Code Sections II and III as well as DECo Specification 3071-370

b. All austenitic stainless steel weld materials of the A-No. 8 analysis will also be specified to contain a minimum ferrite number of 8FN. The ferrite number will be determined by both chemical analysis and magnetic measurements performed by the filler metal manufacturer on an undiluted weld pad, with the exception that the ferrite number for A-No. 8 filler metals of SFA Specification 5.9 that are used with the gas tungsten arc welding (GTAW) process need only be determined by chemical analysis. Welding of the coupon shall be as specified in the applicable SFA specification.

c. Completed final welds will not be inspected for ferrite content.

The controls used for Fermi 2 are now consistent with industrial practices and Regulatory Guide 1.31.

A.1.32 REGULATORY GUIDE 1.32 (February 1977, Revision 2), CRITERIA FOR SAFETY RELATED ELECTRIC POWER SYSTEMS FOR NUCLEAR POWER PLANTS

The Fermi 2 design conforms to the requirements of Revision 1 to this guide, with the exception of Parts 1d, 1e, and 2b. These sections required compliance with Regulatory Guides 1.75 and 1.93. For discussions of those guides, see the applicable sections of this appendix.

For details refer to Sections 8.2 and 8.3.

A.1.33 REGULATORY GUIDE 1.33 (February 1978, Revision 2), QUALITY ASSURANCE PROGRAM REQUIREMENTS (OPERATION)

Fermi 2 is in conformance with the requirements of Regulatory Guide 1.33, with the following exceptions:

a. The Quality Assurance program as described in Subsection 17.2.7 permits the conditional release of material lacking the specified quality assurance records, provided the item can be readily removed. The program allows for functional testing on conditionally released materials that have been installed; however, they will not be placed in service unless a technical evaluation has been performed and documented, and appropriate 10 CFR 50.59 review in accordance with 10 CFR 50.59 has been performed.

b. Exception is taken from the audit program scope and frequency of audits described in Regulatory Guide 1.33 and ANSI N18.7-1976 as endorsed by Regulatory Guide 1.33. The provisions in the Quality Assurance Program described in Subsection 17.2.18 govern the audit program. When differences exist between Regulatory Guide 1.33 and the UFSAR, the latter shall take precedence.

c. When purchasing commercial grade calibration or testing services from a laboratory holding accreditation by an Accreditation Body (AB) which is a signatory to the International Laboratory Accreditation Cooperation (ILAC) Mutual Recognition Arrangement (MRA), procurement documents are not required to impose a quality assurance program consistent with ANSI N45.2-1977. Alternative requirements described in UFSAR Appendix A, A.1.123, for Regulatory Guide 1.123 may be implemented in lieu of imposing a quality assurance program consistent with ANSI N45.2-1977. In addition, the following exception will be taken to ANSI N18.7: When purchasing commercial grade calibration or testing services from a laboratory holding accreditation by an accrediting body recognized by the ILAC MRA, the procurement documents are not requires to impose a quality assurance program consistent with ANSI N45.2-1977. Alternative requirements described in UFSAR, Appendix A, for Regulatory Guide 1.123 may be implemented in lieu of imposing a quality assurance program consistent with ANSI N45.2-1977.

An exception is taken to the review of all plant procedures every two years. Instead, non-routine procedures (procedures such as emergency operating procedures, abnormal operating procedures, procedures which implement the emergency plan, and Security and other procedures that are implemented as a result of an event) shall be reviewed at least every two years and revised as appropriate. On a biennial basis, continue to audit a sample of routine procedures and immediately review procedures following an unusual incident or plant modification. Routine plant procedures that are used at least biennially receive scrutiny by knowledgeable individuals during work activities and are updated, as necessary, to assure adequacy of controlled activities. Plant policy requires that the job be stopped and the procedure revised or the situation resolved prior to work continuing if the procedure cannot be implemented as written. Routine plant procedures that have not been used for two years will be reviewed before use to determine if changes are necessary or desirable.

Exception is also taken to full compliance with some of the regulatory guides listed in Section C.2 of Regulatory Guide 1.33. The Fermi 2 position on regulatory guides listed in Section C.2 is stated elsewhere in this appendix.

A.1.34 REGULATORY GUIDE 1.34 (December 1972), CONTROL OF ELECTROSLAG WELD PROPERTIES

Electroslag welding has been performed only on the turbine shielding wall in the field for Fermi 2. Although Edison specifications did not specifically prohibit it, no use of electroslag welding on core support structures or ASME Class 1 or 2 vessels or components can be identified. Most of those components that would be expected to have electroslag welding were completed and fabricated before this guide was issued.

A.1.35 REGULATORY GUIDE 1.35 (January 1976, Revision 2), INSERVICE SURVEILLANCE OF UNGROUTED TENDONS IN PRE- STRESSED CONCRETE CONTAINMENT STRUCTURES

This guide does not apply to Fermi 2, which does not use a concrete containment.

A.1.36 REGULATORY GUIDE 1.36 (February 1973), NONMETALLIC THERMAL INSULATION FOR AUSTENITIC STAINLESS STEEL

The Fermi 2 design is in conformance with the requirements of this regulatory guide.

For details refer to Subsection 5.2.3.3.

A.1.37 REGULATORY GUIDE 1.37 (March 1973), QUALITY ASSURANCE REQUIREMENTS FOR CLEANING OF FLUID SYSTEMS AND ASSOCIATED COMPONENTS OF WATER-COOLED NUCLEAR POWER PLANTS

Fermi 2 is in conformance with the requirements of 10 CFR 50, Appendix B. The plant startup task force is responsible for activities to ensure system cleanliness and flushing with the objective of meeting the intent of ANSI N45.2.1.

For details refer to Subsection 17.1.9 and Chapters 13 and 14.

A.1.38 REGULATORY GUIDE 1.38 (May 1977, Revision 2), QUALITY ASSURANCE REQUIREMENTS FOR PACKAGING, SHIPPING, RECEIVING, STORAGE, AND HANDLING OF ITEMS FOR WATER-COOLED NUCLEAR POWER PLANTS

During the initial design and construction phase, the Fermi 2 project conformed to 10 CFR 50, Appendix B, but not with the measures required to comply with this guide.

The Fermi 2 project procedure was to require each manufacturer to work by written packaging and handling procedures that had been reviewed and approved by Edison, and to supply storage instructions that were followed for onsite storage. These measures are similar to the requirements in ANSI N45.2.2-1972. This standard, however, contained some provisions that were not feasible to implement on Fermi 2 because of the date of issue; specifically,

a. Each specific item covered by the standard (all QA level I items) was required to be classified into one of four levels (A through D). Classification of those items already on order or delivered to the job site prior to issuance of the guide was not feasible for the Fermi 2 project

b. There were numerous minor requirements that would require significant investigation to ensure compliance, both at the job site and at the vendors' facilities. These include, but were not necessarily limited to, the requirement that all tarpaulin be fire retardant, that nonmetallic caps and plugs be brightly colored, and that all hoisting equipment meet the requirements of either ANSI B30.2.0, B30.5, B30.6, or A10.5, as appropriate

c. Inspection, examination, and testing personnel were required to be qualified in accordance with ANSI N45.2.6. The Fermi 2 position on this is stated in the conformance review of Regulatory Guide 1.58.

The operational QA program complies with the requirements of this regulatory guide.

A.1.39 REGULATORY GUIDE 1.39 (September 1977, Revision 2), HOUSEKEEPING REQUIREMENTS FOR WATER-COOLED NUCLEAR POWER PLANTS

The Fermi 2 project was in conformance with the regulatory position of this guide during the construction phase. Procedures were written for the regulation of site area, site preparation, and fire prevention and protection, as required by ANSI N45.2.3-1973. During the operational phase, the Fermi 2 Quality Assurance program is based on ANSI Standard N18.7-1976, “Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants”, as modified by Regulatory Guide 1.33. Housekeeping controls during the operational phase are in conformance with Regulatory Guide 1.33.

A.1.40 REGULATORY GUIDE 1.40 (March 1973), QUALIFICATION TESTS OF CONTINUOUS-DUTY MOTORS INSTALLED INSIDE THE CONTAINMENT OF WATER-COOLED NUCLEAR POWER PLANTS

There are no continuous-duty motors inside the drywell of the Fermi 2 plant to which this guide applies.

A.1.41 REGULATORY GUIDE 1.41 (March 1973), PREOPERATIONAL TESTING OF REDUNDANT ONSITE ELECTRIC POWER SYSTEMS TO VERIFY PROPER LOAD GROUP ASSIGNMENTS

The Fermi 2 testing program, described in Subsection 8.3.1, is in conformance with the requirements of this guide.

A.1.43 REGULATORY GUIDE 1.43 (May 1973), CONTROL OF STAINLESS STEEL WELD CLADDING OF LOW-ALLOY STEEL COMPONENTS

The requirements in this guide primarily concern fabrication of the RPV. Fermi 2 is in conformance with the requirements of this guide.

For details refer to Section 5.4.

A.1.44 REGULATORY GUIDE 1.44 (May 1973), CONTROL OF THE USE OF SENSITIZED STAINLESS STEEL

Fermi 2 is not in complete conformance with the regulatory position as stated in this guide. Intergranular corrosion tests were not performed for each welding procedure to be used for welding material having a carbon content greater than 0.03 percent.

The corrosion tests are not considered necessary because the essential variables used in welding procedures at Fermi 2 were based on recommendations made by GE following extensive research. Furthermore, intergranular stress corrosion cracking (IGSCC) countermeasures have been applied to the extent practical. Steps were taken to minimize sensitization by control of welding procedures and the adverse effects of the limited sensitization offset by IGSCC countermeasures.

For details refer to Subsections 5.2.3 and 5.2.5.

A.1.45 REGULATORY GUIDE 1.45 (May 1973), REACTOR COOLANT PRESSURE BOUNDARY LEAKAGE DETECTION SYSTEMS

To ensure the safety of the public, GDC for Nuclear Power Plants, Criterion 30, Appendix A of 10 CFR 50, requires all plants to provide a means for detecting and identifying the locations of the sources of reactor coolant leakage from the RCPB. The Fermi 2 design, in conformance with Regulatory Position 1 of Guide 1.45, effectively identifies, classifies, and collects sources of leakage to monitor and control individual leakage flow rates, as well as total flow rates.

Sources of leakage can be classified as identified and unidentified. Position 2 of this guide requires that unidentified sources be collected and monitored with a flow rate accuracy of 1 gpm. This sensitivity requirement is attained on the Fermi design by the drywell floor drain sump level rate-of-change monitor.

Regulatory Position 3 requires a minimum of three separate detection systems in the design. These sensing systems must include a sump level and flow monitor and an airborne particulate radioactivity monitor. In addition, either an air cooler condensate flow rate or airborne gaseous radioactivity monitoring system must be included in the design. All global (i.e., general area) systems must use humidity, temperature, or pressure conditions of the containment atmosphere as the alarm setpoint indicator. The Fermi 2 design conforms with these system requirements by providing monitoring of sump level and flow, airborne gaseous radioactivity, and a supplementary drywell floor level monitor. Specific monitored parameters are sump level, sump level flow, airborne particulate matter, airborne gaseous radioactivity, primary containment pressure and temperature, low reactor water level, high steam flow indications, and drywell local temperature.

Regulatory Position 4 requires detection of intersystem leakage utilizing methods of radioactivity monitoring and abnormal water levels or flow in local RCPB regions. Intersystem leakage can be detected in the following systems: RHR service water, general service water, and reactor building closed cooling water systems. With the exception of the general service water, all of these systems use radioactivity level indication as the monitoring parameter. In addition, abnormal water levels or flow are also monitored. Thus Fermi 2 complies with Position 4 of the guide.

The sensitivity and response time for each leakage detection system for unidentified leakage is required by Position 5 to match the 1 gpm-or-less standard of Position 3 in less than 1 hr after the onset of the leak. As stated previously, the Fermi 2 designed detection system guarantees detection of flows with this precise accuracy limit.

Position 6 of the guide specifies that leakage detection systems should be capable of performing their functions during and following seismic events not requiring plant shutdown. The sump level analog monitor will remain functional when exposed to the SSE. In addition, the steam leak detection systems, which utilize temperature detectors and excess steam flow differential pressure measurements, are to withstand SSE conditions. The primary containment pressure and reactor water level systems are also Category I components. Thus, with the exception of the sump level detection (for sump pump control) and the airborne radioactivity monitoring systems, Fermi 2 complies with the intent of Position 6.

Regulatory Position 7 requires that each leakage detection system have a capability for independent activation of response alarms within the control room. In addition, the control room is required to contain indicators from each system. These indicators are required to be calibrated and metered in units that allow operators to convert measurements into common leakage equivalent. Equipment used in the Fermi 2 design provides for control room alarms and indicators. Such design will allow common equivalent leakage procedures to be developed.

Position 8 requires designed equipment to readily permit testing for operability and calibration during plant operation. All leakage detection systems of Fermi 2 except the sump level can be periodically tested and calibrated during plant operation. The reactor level and drywell pressure lines are designed to allow calibration of switch setpoints by application of calibration pressures to switch actuators. The sump level switch operation can be observed during normal operation, and comparison between sets of switches can be used for calibration. The flow within the sumps using differential pressure transmitters can be calibrated. Calibration of the primary containment drain pumps can also be accomplished outside the drywell during operation.

Position 9 states that Technical Specifications with limiting conditions for both identified and unidentified leakage should include the availability of various instrument types during plant operation and the spectrum of coverage each instrument provides. The Fermi 2 Technical Specifications for leakage detection systems include the information necessary to comply with Position 9.

For details on system specifications, refer to Subsection 5.2.7.

A.1.46 REGULATORY GUIDE 1.46 (May 1973), PROTECTION AGAINST PIPE WHIP INSIDE CONTAINMENT

The Fermi 2 design meets the intent of this regulatory guide.

For details, refer to Subsection 3.6.1.

A.1.47 REGULATORY GUIDE 1.47 (May 1973), BYPASSED AND INOPERABLE STATUS INDICATION FOR NUCLEAR POWER PLANT SAFETY SYSTEMS

The Fermi 2 design does not comply with this regulatory guide.

This guide describes an acceptable method of complying with the requirements of Section 4.13 of IEEE 279-1971, and Criterion XIV of Appendix B to 10 CFR Part 50. Fermi 2 implements this requirement of IEEE 279-1971 through the design of subject systems to provide continuous indication in the event that the protective action of some part of the protection system has been bypassed or deliberately rendered inoperative. The conformance of these designs is described in UFSAR Section 1.6, 7.1, 7.2 and 7.3. The requirements of 10 CFR 50, Appendix B, Criterion XIV, are met through proven administrative controls that establish measures for indicating the operating status of structures, systems, and components of the nuclear power plant to prevent inadvertent operation.

A.1.48 REGULATORY GUIDE 1.48 (May 1973), DESIGN LIMITS AND LOADING COMBINATIONS FOR CATEGORY I FLUID SYSTEM COMPONENTS

Fermi 2 does not conform to this regulatory guide.

The Fermi 2 Category I pressure-retaining components are designed pursuant to 10 CFR 50, Paragraph 50.55a, which invokes the compliance with ASME Code Section III.

For details refer to Section 5.5.

A.1.49 REGULATORY GUIDE 1.49 (December 1973, Revision 1), POWER LEVELS OF NUCLEAR POWER PLANTS

Fermi 2 nuclear power plant design is in conformance with Regulatory Guide 1.49. The licensed power level of 3430 MWt for this plant is below the 3800-MWt limit set forth in this guide.

This Regulatory Guide has since been withdrawn (as of June 2007)..

A.1.50 REGULATORY GUIDE 1.50 (May 1973), CONTROL OF PREHEAT TEMPERATURE FOR WELDING OF LOW-ALLOY STEEL

Fermi 2 is in conformance with this guide except for Regulatory Position 2. All low-alloy steel welds, except for ASME Section III, Class 3, 4-in.-and-less diameter piping, are examined by nondestructive testing methods for detection of cracks and other defects prior to or following the application of postweld heat treatment.

A.1.52 REGULATORY GUIDE 1.52 (March 1978, Revision 2), DESIGN, TESTING, AND MAINTENANCE CRITERIA FOR POSTACCIDENT ENGINEERED-SAFETY-FEATURE ATMOSPHERE CLEANUP SYSTEM AIR FILTRATION AND ADSORPTION UNITS OF LIGHT-WATER-COOLED NUCLEAR POWER PLANTS

General Design Criteria 19, 41, 42, 43, and 61 in Appendix A of 10 CFR 50, "General Design Criteria for Nuclear Power Plants," cover the design of atmosphere cleanup systems to safeguard public health and safety. Regulatory Guide 1.52 states acceptable methods for complying with these criteria for the control center and secondary containment filtration systems.

The Fermi 2 control center emergency air filtration system design as described in Section 6.4 conforms to most positions in this guide except for the lack of redundancy of passive components. Other items which do not strictly conform are identified in the following table; overall functional performance is adequate.

The standby gas treatment system (SGTS) design, discussed in Section 6.2 does not strictly conform to all guide positions, but its overall functional performance is adequate. The specific conformances to the positions of Regulatory Guide 1.52 are given in the compliance evaluation for the control center filtration system and SGTS, which follows.

CONFORMANCE OF VENTILATION SYSTEMS WITH RESPECT TO THE POSITIONS OF REGULATORY GUIDE 1.52

Regulatory Position	Control Center Filtration System	Standby Gas Treatment System		
1.0 Environmental Design Criteria				
a. Each ESF atmosphere cleanup system is based on maximum conditions resulting from DBA.	Yes	No. Parameters are listed below:		
			Fermi 2	R.G. 1.52
		Maximum influent temperature	153°F	180°F
		Average radiation levels:		
		Airborne	Not specified	10^5 rads/hr
		Iodine buildup	Not specified	10^9 rads
		Average airborne iodine:		
		Elemental	0.35 mg/m^3	10.0 mg/m^3

CONFORMANCE OF VENTILATION SYSTEMS WITH RESPECT TO THE POSITIONS OF REGULATORY GUIDE 1.52

Regulatory Position	Control Center Filtration System	Standby Gas Treatment System
		Methyl iodine and particulate iodine 0.035 mg/m^3 1.0 mg/m^3
b. System design based on 30-day integrated dose after a DBA in the vicinity of the adsorber section, using Regulatory Guides 1.3, 1.4, and 1.25 radiation source assumptions	Yes	No. A total integrated dose for the charcoal was not used in Fermi 2 SGTS specifications. There are no data for removal efficiency after 10^9 rads exposure. Evans* determined removal efficiency loss is <0.1 percent for KI_3-impregnated carbon. Relative humidity was less than 90 percent for exposure of 10^9 rads from a radiation field of 1.5 x 10^7 rads/hr.
c. Adsorber design based on concentration and relative abundance of iodine as assumed in Regulatory Guides 1.3, 1.4, and 1.25	Yes	Yes. Average airborne elemental and methyl radioiodine release was 1300 g in secondary containment, after DBA. CVI simulation** of SGTS module shows 99.99 percent removal of airborne methyl iodine concentration of 0.035 mg/m^3
d. Compatibility of atmosphere cleanup system with other ESF systems	Yes	System designed to withstand post-LOCA environment and function normally in conjunction with other ESF systems
e. Components of systems designed for both the lowest and highest predicted temperatures	Yes	Yes. All compartments are heated and cooled by Category I equipment during DBA

2.0 System Design Criteria

* A. G. Evans, "Effect of Intense Gamma Radiation on Radioiodine Retention by Activated Carbon," Proceedings of the Twelfth AEC Air Cleaning Conference, pp. 401-414

** D. P. Siegwarth and M. Siegler, Detroit Edison Standby Gas Treatment System Gasketless Filter Test Series, General Electric Company (private), NEDC-12431, Class III, July 1973.

CONFORMANCE OF VENTILATION SYSTEMS WITH RESPECT TO THE POSITIONS OF REGULATORY GUIDE 1.52

	Regulatory Position	Control Center Filtration System	Standby Gas Treatment System
a.	Required redundancy for atmosphere cleanup systems designed and installed to limit doses after DBA. Includes both active and passive components	No. The recirculation and makeup filter system is provided with redundancy of active components only. The recirculation and makeup filter system is provided with redundancy of fans, dampers, heaters, and controls. The passive components, such as ductwork, filter housings, filter, and moisture separator, are not redundant.	No. Previous requirements for SGTS did not specify this feature. Single stacks and ductwork penetrating the reactor building were not associated with any failure mechanisms at that time. Fermi 2 design has common discharge on RB roof and common inlet in secondary containment.
b.	Physical separation of redundant atmosphere cleanup system with missile protection	Yes, except for nonredundant passive components.	Yes. Active components are protected.
c.	Atmosphere cleanup system designed as Category I	Yes	Yes
d.	ACS pressure surge protection	No. Location of the recirculation and makeup air filter system is external to secondary containment. There are no anticipated pressure surges of significant magnitude that could cause damage to any of the filter system components. Thus no pressure relief valves are included in the overall system design.	No. The maximum system pressure is 20.0 in. H_2O. There are no relief valves in the STGS system except in the charcoal adsorber section, which may be overpressurized by CO_2.
e.	Atmosphere cleanup system construction materials must effectively perform under exposure to high radiation levels.	Yes, even though superfluous.	Yes
f.	Limiting flow rate for a single cleanup train of 30,000cfm.	Yes	Yes. Four parallel filter elements, each rated at 1000 scfm, are used.
g.	Atmosphere cleanup system instrumentation to signal, alarm, and record pressure drops, flow rates in the control room	Recirculation and makeup air filter system will be instrumented to alarm in the main control room for large pressure drop. The system flow rate can only be measured locally.	Design provides local signal and alarms for pressure. Flow is recorded, and low flow is alarmed in the main control room.

CONFORMANCE OF VENTILATION SYSTEMS WITH RESPECT TO THE POSITIONS OF REGULATORY GUIDE 1.52

	Regulatory Position	Control Center Filtration System	Standby Gas Treatment System
h.	Electrical distribution and power supply conforming to IEEE standards	Yes	Yes
i.	Automatic activation of ESF atmosphere cleanup systems	Yes	Yes
j.	Unit replacement capability of filter to protect workers from exposure to radiation in accordance with Regulatory Guide 8.8	No. However, unit will be disassembled in largest segments compatible with handling equipment and access availability	Removal of SGTS as a unit is required by the guide. This is impossible for the Fermi SGTS for two reasons: (1) the SGTS fans are mounted separately from the main skid, and (2) the main skid was final assembled on the fifth floor of the auxiliary building from components. Removal as a single unit is not physically possible. Replacement of SGTS is <u>not</u> necessary to remove the SGTS, it can be cut into the segments in which it was shop fabricated for removal.
k.	Protection of outdoor air intakes from weather and contamination.	Yes	Not applicable.
l.	Atmosphere cleanup system housing and ductwork limitations on maximum total leakage rate in accordance with ANSI N509-1976, duct and housing leak tests performed in accordance with ANSI N510-1975	No. Maximum total leakage rate determined in accordance with ANSI N509-1980. Duct and housing leak test developed and implemented using ANSI N510-1980 as guidance.	Fermi 2 criterion for measuring housing integrity is the housing differential pressure. It shall not decrease more than 4 in. H_2O in 5 minutes with initial internal pressure of 20 in. H_2O. In addition, SGTS must maintain the secondary containment at a net negative pressure of 0.25 in. H_2O with respect to the atmosphere.
3.0	<u>Component Design Criteria and Qualification Testing</u>		
a.	Demister performance and qualification requirements to 5.4 ANSI N509-1976	No. Demisters designed in accordance with MSAR 71-45	Fermi 2 SGTS demisters are not designed to ANSI N509. However, they are designed to the functionally similar requirements of Savannah River Laboratory Report DP-812.
b.	Air heaters designed to 5.5 ANSI N509-1976	No. The heaters are designed to reduce the relative humidity to 70 percent.	A prototype heating element will not be qualified under DBA conditions. A heater certified for heating capacity only will be used. The heaters, however, are designed to reduce the relative humidity of the incoming air to 70 percent (maximum) under the worst-expected conditions during postulated accident conditions.

CONFORMANCE OF VENTILATION SYSTEMS WITH RESPECT TO THE POSITIONS OF REGULATORY GUIDE 1.52

	Regulatory Position	Control Center Filtration System	Standby Gas Treatment System
c.	Prefilter material must withstand radiation levels and environmental conditions during a DBA, designed to 5.3 ANSI N509-1976.	No. Materials will withstand the radiation levels and environmental conditions in accordance with ANSI N509-1980.	No. Materials will withstand the radiation levels and environmental conditions in accordance with ANSI N509-1980.
d.	HEPA filter requirements to 5.1 ANSI N509-1976	No. HEPA filter requirements are in accordance with ANSI N509-1980.	No. HEPA filter requirements are in accordance with ANSI N509-1980.
e.	Design and construction requirements and materials for filter and adsorber mounting frames in accordance with 5.6.3 ANSI N509-1976	No. Designed in accordance with 4.3 ORNL-NSIC-65.	Regulatory Guide 1.52 requires HEPA filter separators to be made of corrosion-resistant unpainted steel. Fermi 2 HEPA filters have aluminum separators. HEPA demister, and prefilter frames are made of carbon steel.
f.	Design and construction requirements for filter and adsorber bank arrangements in accordance with 4.4 ERDA 76-21	No. Designed in accordance with 4.4 ORNL-NSIC-65.	No. Designed in accordance with 4.4 ORNL-NSIC-65
g.	Housing steel conformance to 5.6 ANSI N509-1976.	No. Designed in accordance with 4.5 ORNL-NSIC-65	No. Designed in accordance with 4.5 ORNL-NSIC-65
h.	Water drain recommendations in accordance with 4.5.8 ERDA-76-21	No. Designed in accordance with 4.5 ORNL-NSIC-65	No. Designed in accordance with 4.5 ORNL-NSIC-65

CONFORMANCE OF VENTILATION SYSTEMS WITH RESPECT TO THE POSITIONS OF REGULATORY GUIDE 1.52

	Regulatory Position	Control Center Filtration System	Standby Gas Treatment System
i.	Removal of gaseous iodine by adsorber material.	No. Demonstration and certification of the radiation stability of the carbon used in the adsorber will not be performed. Outside air intake radiation levels are low. Thus insignificant loss in carbon performance will take place. Each new replacement batch of impregnated activated carbon used in the adsorber section will meet the qualification and batch test results summarized in Table 5.1 of ANSI/ASME N509-1980- except for Methyl Iodine Penetration at 30°C, 95% RH. ANSI/ASME N509-1980 requires 3% penetration, maximum. Fermi 2's replacement carbon will be tested in accordance with ASTM D3803-1989 to a more stringent acceptance value of 1% penetration, maximum.	No. Seismic efficiency and certification of charcoal for design radiation will not be part of Fermi 2 testing procedures. Seismic analysis will be by calculation only, although some interments will be tested on a shaker table. Past testing experience (see footnote b in 1.0(c.)) will be considered valid for charcoal tests. Testing of new activated carbon will be performed in accordance with ASTM D3803-1989 at 30°C, 95% RH showing less than 1.0% penetration for methyl iodine.
j.	Design of adsorber cells in accordance with 5.2 ANSI N509-1976	No. Gasketless charcoal adsorber design is used in accordance with ANSI N509-1976	No. Gasketless charcoal adsorber design is used in accordance with ANSI N509-1976
k.	Fire prevention in adsorber from auto-ignition by water sprays	No. Entering air into the makeup and recirculation filter is outside air mixed with the discharge from the 99 percent efficiency SGTS, and the resulting radioactivity-induced heat in the adsorbent from this air is not expected to be sufficient for adsorbent auto-ignition	A CO_2 fire protection system is provided instead of the water spray system. Fermi 2 SGTS fire protection system functions to detect and limit charcoal temperatures to values well below the ignition limit and precludes the possibility of charcoal ignition. The ignition temperature of charcoal is 625°F. Fermi 2 CO_2 system will automatically activate at 310°F
l.	System fans provided with rated flow capacity to 5.7 and 5.8 ANSI N509-1976	No. Designed in accordance with 2.7 ORNL-NSIC-65	No. Designed in accordance with 2.7 ORNL-NSIC-65

CONFORMANCE OF VENTILATION SYSTEMS WITH RESPECT TO THE POSITIONS OF REGULATORY GUIDE 1.52

	Regulatory Position	Control Center Filtration System	Standby Gas Treatment System
m.	Atmosphere cleanup system fans on blower designed to operate under environmental conditions postulated	Yes	Yes
n.	Ductwork conformance with 5.10 of ANSI N509-1976	No. Ductwork conforms to the intent of ANSI N509-1980 for all areas of duct construction and testing. The duct construction characteristics are as follows: (1) Transverse companion angles are stitch welded on exterior of the duct, and the duct is bent or formed over the angle. (2) Longitudinal seams are mechanical-lock type and externally brazed with sealant applied to internal duct surfaces. In addition, sealant has been applied externally to the seam to enhance low leakage characteristics	No. The ductwork conforms to the intent of ANSI N509-1980 for all areas of duct construction and testing.
o.	Design configuration to minimize hazards	Yes	Yes
p.	Dampers designed to 5.9 ANSI N509-1976	No	No
4.0	Maintenance		
a.	Easy access to components in accordance with 4.7 ANSI N509-1976 and 23.8 ERDA 76-21.	No. Designed in accordance with 2.5 ORNL-NSIC-65	Fermi 2 SGTS entrance doors are about 5 ft high and probably will require a man to bend over. This is not considered a hindrance for proper maintenance.
b.	Definite mounting frame separation distance (3ft).	No. Minimum 3 ft spacing has not been provided. Components are accessible for maintenance without entering the unit housing by the use of access doors.	Sufficient spacing for component maintenance is provided even though the recommended 3ft is not always provided.
c.	Permanent test probes with external connections in accordance with 4.11 ANSI N509-1976	No. Permanent test probes provided but not necessarily in accordance with ANSI N509-1976.	No. Fermi 2 has no permanent test probes and/or manifolds, only couplings in the doors for DOP and Freon connections.

CONFORMANCE OF VENTILATION SYSTEMS WITH RESPECT TO THE POSITIONS OF REGULATORY GUIDE 1.52

	Regulatory Position	Control Center Filtration System	Standby Gas Treatment System
d.	Periodic operation of standby atmosphere cleanup system	No. Periodic operation is performed in accordance with Regulatory Guide 1.52 Revision 3, Position 6.1, per License Amendment No. 192.	No. Periodic operation is performed in accordance with Regulatory Guide 1.52 Revision 3, Position 6.1, per License Amendment No. 192.
e.	ACS components installed after active construction	Yes	Yes
5.0	In-Place Testing Criteria		
a.	Visual inspection before testing in accordance with 5 ANSI N510-1975	No. Visual inspection in accordance with ANSI N510-1980	No. Visual inspection in accordance with ANSI N510-1980
b.	The airflow distribution should be tested initially and after maintenance that affects distribution	Yes	Yes
c.	The in-place DOP test for HEPA filters should be in accordance with ANSI N510-1975 and occur initially and periodically thereafter	No.* In place DOP test in accordance with ANSI N510-1980 to confirm a penetration of less than 1.0 percent ± 10 percent rated flow. This meets Generic Letter 83-13.	No. In place DOP test in accordance with ANSI N510-1980.
d.	Bypass leakage testing of the activated carbon adsorber section should be in accordance with ANSI N510-1975	No. Bypass leakage testing in accordance with ANSI N510-1980 for a halogenated hydrocarbon refrigerant test gas to confirm a penetration less than 1.0 percent at ± 10 percent rated flow. This meets Generic Letter 83-13.	No. Bypass leakage testing in accordance with ANSI N510-1980 for a halogenated hydrocarbon refrigerant test gas.

* A silicone sealant is used as a permanent seal in HVAC ductwork.

CONFORMANCE OF VENTILATION SYSTEMS WITH RESPECT TO THE POSITIONS OF REGULATORY GUIDE 1.52

Regulatory Position	Regulatory Position	Regulatory Position
6.0 Laboratory Testing Criteria for Activated Carbon	Yes. Both the make-up and recirculation activated carbon adsorbers have been assigned a decontamination efficiency of 95 percent each. This results in a combined efficiency of 99.75 percent for the make-up air supply. Laboratory testing acceptance criteria are based on 95 percent efficient adsorbers. Laboratory testing of used activated carbon will be performed in accordance with ASTM 0383-1989 at 30°C, 70% RH showing a Methyl Iodine penetration of less than 1.0%. This is with a 2-in. bed for the emergency make-up filter train; and a 4-inch bed for the emergency recirculation air filter train. Verification of the above will be done within 31 days after removal.	Yes. (As justified below) A sample of the SGTS charcoal is removed from the adsorber by vertically inserting a “grain thief.” Charcoal removed in this manner will provide a sample possessing essentially the same characteristics of the bed and has advantages over the parallel-canister-type sample arrangement required by Regulatory Guide 1.21. The “grain thief” sample device withdraws a sample that has experienced (1) the same volume, (2) same flow rate, and (3) same exposure to contaminants as the charcoal in the bed. The parallel-canister arrangement has several disadvantages that are avoided by the present design. (1) Air will likely flow through the canister at a different rate than it flows through the bed. This will cause inconsistency in the amount of contamination or loss of efficiency between the sample and the charcol bed; (2) The parallel-canister sample arrangement will require a gasketed seal on the canister that may deteriorate and cause charcoal adsorber bypass; and (3) A parallel-canister sample arrangement will provide the potential for charcoal adsorber bypass if a sample canister is removed and not replaced or if the canister holder is not properly sealed with a cover and gasket. Laboratory testing of used activated carbon will be performed in accordance with ASTM 03803-1989 at 30°C, 70% RH showing a methyl iodide penetration of less than 0.100%. This is in accordance with ASTM 03803-1989 with a 6-inch bed. Verification of the above will be done within 31 days after removal.

The areas of noncompliance do not, either singly or in combination, reduce the high level of reliability of these systems for protecting the health, safety, and welfare of the public. The areas of noncompliance are essentially subjective in nature, and noncompliance does not functionally impair the performance of either system.

A.1.53 REGULATORY GUIDE 1.53 (June 1973), APPLICATION OF THE SINGLE-FAILURE CRITERION TO NUCLEAR POWER PLANT PROTECTION SYSTEMS

Under Section 50.55a, "Codes and Standards," of "Licensing of Production and Utilization Facilities" of 10 CFR 50, the regulatory staff requires the use of IEEE-279-1971 section 4.2 (ANSI N42.7-1972) issued in the Institute of Electrical and Electronic Engineers Criteria for

Nuclear Power Plant Protection Systems. This standard requires that any single failure of a protection system component will not alter proper protective actions at the system level.

The Fermi 2 reactor protection system (RPS) complies with Regulatory Guide 1.53 by meeting the single-failure criterion. In compliance with the positions of the guide the RPS uses redundant sensors and system logic to ensure that failure of a sensing element, decision logic, or an actuator unit will not impair other redundant system functions. Thus any single failure will not prevent or initiate protective action. The RPS employs separate channels in which a fault affecting one channel will not prevent other channels from operating. In addition, facilities exist for testing the RPS so that equipment can be operated in various test modes to confirm operability.

For details refer to Subsection 7.2.2.

A.1.54 REGULATORY GUIDE 1.54 (June 1973), QUALITY ASSURANCE REQUIREMENTS FOR PROTECTIVE COATINGS APPLIED TO WATER-COOLED NUCLEAR POWER PLANTS

The coatings used in the Fermi 2 containment are described in Subsection 6.2.1.6 and are listed in Table 6.2-8. Not all the coatings used on surfaces within the drywell and suppression pool (wetwell) are "qualified" in terms of compliance to the recommendations of Regulatory Guide 1.54. The unqualified coatings, however, have been evaluated and have been determined to have no adverse effect on the reliable performance of the plant under normal or abnormal conditions, and it is considered that the intent of Regulatory Guide 1.54 has been fulfilled.

The Plasite 7155 suppression pool (wetwell) coatings and the coatings applied to the concrete surfaces of the drywell conform to the recommendations of Regulatory Guide 1.54 and are considered fully qualified.

The Carboguard 6250 N suppression pool and torus vent header interior coating conforms to the recommendations of Regulatory Guide 1.54 (1973) with the following exceptions:

- ASTM D5139-10, endorsed by Revision 2 of Regulatory Guide 1.54, was used for surface preparation of test panels instead of ANSI N101.2-1972.
- ASTM D4082-10, endorsed by Revision 2 of Regulatory Guide 1.54, was used for radiation testing instead of ANSI N5.12-1974.
- ASTM D3912-10, endorsed by Revision 2 of Regulatory Guide 1.54, was used for chemical resistance testing instead of ANSI N5.12-1974.
- ASTM D3911-08, endorsed and supplemented by Revision 2 of Regulatory Guide 1.54, was used for evaluation of design basis accident test panels instead of ANSI N101.2-1972.
- ASTM E84, endorsed by Revision 2 of Regulatory Guide 1.54, was used for cure requirements of fire evaluation panels instead of ANSI N101.2-1972.
- There are small areas where Carboguard 6250 N coating was applied to small stainless steel components and welds or where Carboguard 6250 N overlaps Plasite 7155 coating in the suppression pool interior surfaces. These areas are considered

unqualified and tracked as indicated in Table 6.2-8. Additionally, there are small areas in the torus vent header interior vacuum breaker and downcomer penetrations where Carboguard 6250 N coating overlaps Plasite 7155 coating. DBA testing has been performed to simulate this overlap condition in order to provide reasonable assurance that, when properly applied and maintained, the coating will not detach under normal or accident conditions per ASTM D7491-08.

The unqualified Carboguard 6250 N coating areas have been evaluated and have been determined to have no adverse effect on the reliable performance of the plant under normal or abnormal conditions. The alternative standards endorsed by Revision 2 of Regulatory Guide 1.54 have been evaluated relative to the design basis standards. It is concluded that they provide an acceptable qualification basis for the Carboguard 6250 N coating at Fermi 2, and it is considered that the intent of Regulatory Guide 1.54 (1973) has been fulfilled.

Most of the coating on the drywell reactor coolant pressure boundary and the drywell primary structural steel (Carboline Carbozinc 11) was applied prior to the issuance of Regulatory Guide 1.54 and ANSI N101.4, in accordance with the accepted industry standards of that time. This coating system has a long record of reliable service in operating BWRs under a variety of adverse conditions.

The Carbozinc 11 coating has also been subjected to extensive design-basis accident (DBA) testing using a variety of application techniques. The conditions under which failure of the coating could occur and its failure mode have been evaluated (Subsection 6.2.1.6). The coating has been found to present no threat to the reliable performance of the plant under normal or abnormal circumstances.

In 1984, the commercial name of the Carbozinc 11 coating was changed to Carbozinc 11 SG. Consequently, in cases where repairs to the original Carbozinc 11 coating were needed after 1984, Carbozinc 11 SG was used.

A.1.55 REGULATORY GUIDE 1.55 (June 1973), CONCRETE PLACEMENT IN CATEGORY I STRUCTURES

The Fermi 2 procedures conform to the requirements of this guide.

For details refer to Sections 3.8 and 17.1.

A.1.56 REGULATORY GUIDE 1.56 (July 1978, Revision 1 for Comment), MAINTENANCE OF WATER PURITY IN BOILING WATER REACTORS

Fermi 2 chemistry procedures have been developed in conformance with this guide. For details, refer to Subsections 5.5.8, 9.3.2, and 10.4.6.1.2.

A.1.57 REGULATORY GUIDE 1.57 (June 1973), DESIGN LIMITS AND LOADING COMBINATIONS FOR METAL PRIMARY REACTOR CONTAINMENT SYSTEM COMPONENTS

The Fermi 2 containment was purchased, designed, and constructed in accordance with ASME Code Section III, 1968, and is not in conformance with the requirements of this guide, which are based on ASME Code Section III, 1971. Physical changes could not be made without major construction schedule impact.

For details refer to Section 3.8.

A.1.58 REGULATORY GUIDE 1.58 (September 1980, Revision 1), QUALIFICATION OF NUCLEAR POWER PLANT INSPECTION, EXAMINATION, AND TESTING PERSONNEL

The established design and construction QA program, which predates the development of ANSI N45.2.6-1973, was not committed to be in compliance with Regulatory Guide 1.58. Rather, it met the intent of the endorsed ANSI standard.

Inspection and examination personnel of site contractors have been qualified to the requirements of ANSI N45.2.6-1973. Inspection personnel of Project Quality Assurance who performed first-level inspection were also qualified to the same standard.

Edison test personnel, who are part of the Startup Organization and who perform the Checkout and Initial Operations and Preoperational testing, have been qualified to requirements that exceed the requirements of ANSI N45.2.6-1978.

During operations, the provisions of ANSI N45.2.6-1978 apply only to QA/QC inspectors. With two exceptions, the Edison operational QA program conforms to Regulatory Guide 1.58, Revision 1.

(1) For plant inspection, examination, and testing personnel, a grace period of 90 days beyond the maximum one-year cycle is allowed for the completion of at least one inspection or examination.

(2) Edison's exception to NRC Position C.6, regarding the educational requirements, is based on the concern that these requirements, when applied to contractors and vendors, would disqualify fully qualified inspection personnel who have demonstrated the ability to perform but lack the education. The ability to perform should be the only criterion.

A.1.59 REGULATORY GUIDE 1.59 (August 1977, Revision 2), DESIGN BASIS FLOODS FOR NUCLEAR POWER PLANTS

The analytical methods for assessment of design-basis floods at the Fermi 2 site differ in some areas from those presented in Regulatory Guide 1.59, Revision 2. The methods employed for Fermi 2 were reviewed by the NRC staff and were determined to be acceptable. (Refer to NUREG-0314, Sections 2.4 and 3.4.)

A.1.60 REGULATORY GUIDE 1.60 (December 1973, Revision 1), DESIGN RESPONSE SPECTRA FOR SEISMIC DESIGN OF NUCLEAR POWER PLANTS

The Fermi 2 design is not in conformance with the recommendations of this guide. The DBE (now called the SSE) for this plant was defined in 1971; it was reviewed by the AEC/DRL in May 1971, and judged to be reasonable and conservative by the staff and consultants. The seismic environment required in Revision 1 by the AEC sets criteria which in some cases are up to 50 percent more conservative than those used in Fermi 2 design. The following table shows the comparison of design response spectra. Although the Fermi 2 design is not in conformance with the specific numerical requirements of this guide, the discrepancy between recommended response spectra of Revision 1 and the design of Fermi 2 does not have any significant impact on reactor safety.

COMPARISON OF DESIGN RESPONSE SPECTRA

I. Horizontal OBE (2 percent damping)

Parameter	Control Point	Fermi 2	Regulatory Guide 1.60
Acceleration (g)	A	0.08	0.08
Acceleration (g)	B	0.14	0.28
Acceleration (g)	C	0.17	0.34
Displacement (in.)	D	5.0	7.2

II. Horizontal SSE (5 percent damping)

Parameter	Control Point	Fermi 2	Regulatory Guide 1.60
Acceleration (g)	A	0.15	0.15
Acceleration (g)	B	0.18	0.39
Acceleration (g)	C	0.22	0.47
Displacement (in.)	D	7.5	11.0

For details on seismic design bases, refer to Subsections 3.7.1.1, 3.7.1.3, 3.7.2.1, 3.7.2.2, 3.7.2.6, 3.7.3.6, 3.7.3.15, 3.7.3.16, 3.7.4.4, and 3.7.5.2.

In response to a request from the NRC Geosciences Branch, a site-specific earthquake ground response spectrum (essentially per Regulatory Guide 1.60 pegged at 0.15g horizontal) was developed, and structures, systems, and components required for cold shutdown were reassessed for the effect of this site-specific earthquake (see Subsections 2.5.2.11 and 3.7.1.2.1).

A.1.61 REGULATORY GUIDE 1.61 (October 1973), DAMPING VALUES FOR SEISMIC DESIGN OF NUCLEAR POWER PLANTS

The Fermi 2 design conforms to the required damping values for Category I structures, components, and systems. Thus, these structures, components, and systems will remain functional in the event of an SSE as required by Appendix A to 10 CFR 100, "Seismic and Geologic Siting Criteria," and 10 CFR 100, "Reactor Site Criteria." A comparison of model damping values as an analysis of viscous damping for elastic spectral or time-history dynamics has shown that Fermi 2 values are lower than Regulatory Guide 1.61 specifications. Therefore, the Fermi 2 design meets the guide requirements. The following table displays the comparison of guide and Fermi 2 project damping values for each division of structure or component required by the guide except prestressed concrete structures, which Fermi 2 does not have. In addition, specific values of damping are given for the RPV, CRD housing, fuel, and coupling drywell-building values. Fermi 2 damping values are conservatively two to four times lower than the regulatory guide requirements except in the case of bolted steel structures. The comparison shows compliance with Position 1 of the guide.

Therefore due to the lower damping values, Position 2 requiring documented test data of dynamic seismic analysis is not applicable. The use of lower damping values is conservatively incorporated into the Fermi 2 design, thus avoiding an underestimation of vibration amplitudes and dynamic stresses. As a result, Position 3 of the guide has been complied with.

DAMPING VALUES

Item	Percent of Critical: Operating-Basis Earthquake (1/2 SSE)		Safe-Shutdown Earthquake	
	Fermi 2	R.G. 1.61	Fermi 2	R.G. 1.61
General				
Equipment and large (12 in.) diameter piping	0.5	2.0	1.0	3.0
Small-diameter piping (12 in.)	0.5	1.0	1.0	2.0
Welded and H.S. bolted steel framed structures	2.0	2.0	5.0	4.0
Bolted and riveted steel framed structures	5.0	4.0	10.0	7.0
Welded structural assemblies (equipment and supports)	2.0		4.0	
Reinforced concrete structures	2.0	4.0	5.0	7.0
Specific				
Reactor pressure vessel	2.0		2.0	
CRD housing	3.5		3.5	
Fuel	7.0		7.0	
Drywell-building (coupled)	2.0		5.0	

For details on the seismic analysis, refer to Subsections 3.7.3.6 through 3.7.3.16, and 3.7.5.1 through 3.7.5.4.

A.1.62 REGULATORY GUIDE 1.62 (October 1973), MANUAL INITIATION OF PROTECTIVE ACTIONS

The Fermi 2 system design is in partial conformance with this guide.

The isolation system does not have a single manual pushbutton that actuates all valves closed. A manual switch is available to close each individual valve.

The automatic depressurization system (ADS) cannot be actuated manually at the system level. Manual actuation is available at the component level.

Manual initiation of the low pressure coolant injection (LPCI) system is not available at the system level. However, since a low reactor pressure interlock prevents the premature opening of the injection valves from either manual or automatic initiation, actuation at the component level is considered adequate.

The core spray system cannot be actuated by a single manual switch. Manual switches are available in the main control room to actuate the individual system components.

The high pressure coolant injection (HPCI) system cannot be actuated by a single manual switch. Manual switches are available in the main control room to actuate the individual components of the system.

A.1.63 REGULATORY GUIDE 1.63 (July 1978, Revision 2), ELECTRIC PENETRATION ASSEMBLIES IN CONTAINMENT STRUCTURES FOR LIGHT-WATER-COOLED NUCLEAR POWER PLANTS

The guidelines presented in Regulatory Guide 1.63, Revision 2, apply to nuclear power plants for which construction permit applications were docketed after December 30, 1977. The application for Fermi 2 was docketed in 1969 and, as such, is exempt from the guidelines of Regulatory Guide 1.63. However, the Fermi 2 design complies with the intent of Regulatory Guide 1.63 (October 1973, Revision 0). For details, refer to Subsections 6.2.1.2.1.5, 6.2.1.4.1.1, and 8.3.1.3.

A.1.64 REGULATORY GUIDE 1.64 (June 1976, Revision 2), QUALITY ASSURANCE REQUIREMENTS OF THE DESIGN OF NUCLEAR POWER PLANTS

The NRC regulatory staff has accepted ANSI Standard N45.2.11-1974, "Quality Assurance Requirements for the Design of Nuclear Power Plants," as an acceptable method of complying with the Commission's regulations in regard to Design Control. The initial issue of Regulatory Guide 1.64, which endorsed a draft version of ANSI N45.2.11, was published in October 1973, approximately a year after the issuance of the QA Manual. Later revisions of Regulatory Guide 1.64 were published in February 1975, and June 1976. Regulatory Guide 1.64, Revision 1, endorsed the approved ANSI Standard N45.2.11-1974, and was applicable to submittals docketed after April 1, 1975. Regulatory Guide 1.64, Revision 2, clarified the limitations on performance of "independent design verification" by supervisors, and was applicable to submittals docketed after July 15, 1976.

The current Fermi 2 QA Program was planned to meet the requirements of 10 CFR 50, Appendix B. It includes the elements of Design Control necessary for approval at the time it was submitted. To retrofit to the requirements of Regulatory Guide 1.64, Revision 2, was not feasible, and to modify the Design Control program for the remainder of the design and construction phase would have been disruptive.

During the operational phase, design activities will be required to comply with ANSI N45.2.11 as endorsed by Regulatory Guide 1.64, Revision 2.

A.1.65 REGULATORY GUIDE 1.65 (October 1973), MATERIALS AND INSPECTIONS FOR REACTOR VESSEL CLOSURE STUDS

The Fermi 2 design and inspection procedures are in conformance with the requirements of this guide except those in Regulatory Positions 2b, 2e, and 3.

Studs were examined in accordance with the requirements of ASME Boiler and Pressure Vessel Code Section III, N-325 (1968 edition plus 1969 Addendum (Summer) in effect at time of contract). Bored blank nuts were ultrasonically examined by both the longitudinal and shear wave methods. Shear wave examination on the nuts was performed in both the axial and circumferential directions.

Regulatory Position 3 recommends provision for adequate corrosion protection during venting and filling of the vessel, and while the head is removed. General Electric supplies thread protectors that prevent stud damage, but stud holes are not plugged, and neither stud nor flange threads are protected from exposure to water. In practice this has been found to be adequate for studs complying with Regulatory Guide 1.65 Regulatory Position 1 & 2, as exposure to applied loads and operating and servicing environments has not required the replacement of any BWR studs (which were in compliance as stated above) or flange threads. No corrosion protection for studs is proposed.

For details, refer to Section 5.4.

A.1.67 REGULATORY GUIDE 1.67 (October 1973), INSTALLATION OF OVERPRESSURE PROTECTION DEVICES

The guidance provided by this Regulatory Guide has been applied in the installation of the Fermi 2 overpressure protection devices.

A.1.68 REGULATORY GUIDE 1.68 (August 1978, Revision 2), INITIAL TEST PROGRAMS FOR WATER-COOLED REACTOR POWER PLANTS

Compliance with Revision 2 to Regulatory Guide 1.68 is required of applicants for operating licenses docketed after August 15, 1978. Since the docket date for Fermi 2 significantly precedes this effective date, Revision 2 to the Regulatory Guide was not implemented.

The preoperational and initial startup test program were in compliance with those portions of Regulatory Guide 1.68, Revision 0, applicable to BWRs and to Fermi 2 systems, except as noted below:

a. Position D.2.o (Appendix A)

No test of rod pattern exchange was planned. This test has been eliminated from the normal GE prescribed test program and equivalent testing is incorporated in the core performance test

b. Position D.2.r (Appendix A)

No two-pump reactor recirculation pump trip at 100 percent power will be performed. With recent improvement in analytical methods, the two-pump trip at 100 percent power is no longer considered to be a significant fuel thermal transient. The two-pump trip would subject the plant to a large power loss and potential scram. The planned one-pump trip testing will provide adequate plant instability response testing.

Revisions 1 and 2 of Regulatory Guide 1.68 do not affect Edison's position with regard to the Fermi 2 initial test program.

For further details refer to Chapter 14.

A.1.68.1 <u>REGULATORY GUIDE 1.68.1 (January 1977, Revision 1), PREOPERATIONAL AND INITIAL STARTUP TESTING OF FEEDWATER AND CONDENSATE SYSTEMS FOR BOILING WATER REACTOR POWER PLANTS</u>

The Fermi 2 Preoperational and Startup Phase Testing Program for the condensate and feedwater systems meets the intent of Regulatory Guide 1.68.1, Revision 1.

For details refer to Subsections 14.1.3 and 14.1.4.

A.1.68.2 <u>REGULATORY GUIDE 1.68.2 (July 1978, Revision 1), INITIAL STARTUP TEST PROGRAM TO DEMONSTRATE REMOTE SHUTDOWN CAPABILITY FOR WATER-COOLED NUCLEAR POWER PLANTS</u>

Fermi 2 is in compliance with Regulatory Guide 1.68.2. Preoperational testing to demonstrate the remote-shutdown capabiliity of Fermi 2 was conducted in accordance with the requirements of this guide.

For details, refer to Subsection 14.1.4.8.26.

A.1.69 <u>REGULATORY GUIDE 1.69 (December 1973), CONCRETE RADIATION SHIELDS FOR NUCLEAR POWER PLANTS</u>

Regulatory Guide 1.69 cites ANSI N101.6-1972, "Concrete Radiation Shields," as applicable to nuclear power plant shielding. The Fermi 2 plant design meets the intent of this guide.

For details refer to Section 12.1.

A.1.70 REGULATORY GUIDE 1.70 (November 1978, Revision 3), STANDARD FORMAT AND CONTENT OF SAFETY ANALYSIS REPORTS FOR NUCLEAR POWER PLANTS

The Fermi 2 UFSAR is in the format of Revision 1 to this guide, which was the current revision at the time of submittal of the original FSAR. Chapter 15 is in the format of Revision 2.

A.1.71 REGULATORY GUIDE 1.71 (December 1973), WELDER QUALIFICATION FOR AREAS OF LIMITED ACCESSIBILITY

Edison's welding program at Fermi 2 requires qualification of welders as described in this regulatory guide. This requirement applies to both Edison and contractor welders working at Fermi 2. Welds are evaluated individually to determine if testing for compliance with this guide is required.

A.1.72 REGULATORY GUIDE 1.72 (July 1978, Revision 2), SPRAY POND PIPING MADE FROM FIBERGLASS-REINFORCED THERMOSETTING RESIN

This regulatory guide is not applicable to Fermi 2 design and QA requirements. The Fermi 2 plant does not use fiberglass-reinforced thermosetting plastic materials in the construction of ultimate heat sink piping.

A.1.73 REGULATORY GUIDE 1.73 (January 1974) QUALIFICATION TESTS OF ELECTRIC VALVE OPERATORS INSTALLED INSIDE THE CONTAINMENT OF NUCLEAR POWER PLANTS

Regulatory Guide 1.73 pertains to qualification and testing of Class 1 electric valve operators for service within the containment of light-water-cooled nuclear power plants. Based on Section III, "Design Control," of Appendix B to 10 CFR 50, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," this guide requires qualification testing of a prototype unit under conservative design conditions. To guide such testing, the commission has adopted IEEE Standard 382-1972, "IEEE Trial-Use Guide for Type Test of Class 1 Electric Valve Operators for Nuclear Power Generating Stations," as acceptable methods for testing. Review of Fermi 2 electric valve operators considering the criteria of IEEE 382-1972 shows that the valve operators are in compliance with the requirements stated in Position 1 of the guide. Valve operators within containment are provided with NEMA Class H insulation. The insulation as well as the operators are seismic, radiation, and temperature qualified to withstand containment normal operating conditions and the DBA conditions. The test sequence given in IEEE 382-1972 is more conservative than actual operating conditions. Therefore, in compliance with Position 2, Section 4.5.2 of the standard was applied in the test-analysis of the operators. These tests included periodic actuating conditions at 340°F steam atmosphere and radiation testing of 2.0 x 10^8 rads. These conditions simulate the most severe DBA and are thus as conservative as Position 3 of this guide. An exception is valve E11-F608, which has non-Class H insulation. However, this valve is not required to operate during or after an accident to mitigate the consequences of the accident.

A.1.74 REGULATORY GUIDE 1.74 (February 1974), QUALITY ASSURANCE TERMS AND DEFINITIONS

In order to ensure that Fermi 2 has been designed and built in accordance with the commitments made in (1) the Final Safety Analysis Report, (2) a planned and systematic program of Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants, and (3) 10 CFR 50, a documented lexicon of terms and definitions, which describes and characterizes the operating functions of plant structures, systems, and components, which is universal and conforming to common industrial usage, must be devised. To comply with the intent of the recommendations of Regulatory Guide 1.74 and 10 CFR 50, ANSI N45.2.10 was adopted by Fermi 2. This standard of word usage was applied to project contracts, letters of intent, work orders, purchase orders or proposals, and legal authorizations. The recently updated document ANSI N45.2.10-1973 recommended by this guide and the Fermi 2 adopted ANSI N45.2.10 differ insignificantly. Fermi 2 word usage thus conforms generally with QA definitions contained in ANSI N45.2.10. Any changes in usage at the late date within the project would have been detrimental to the continuity of project documentation and personnel communications. Therefore, the changes in the updated revision of ANSI N45.2.10 were not incorporated into Fermi 2 project documents.

A.1.75 REGULATORY GUIDE 1.75 (September 1978, Revision 2), PHYSICAL INDEPENDENCE OF ELECTRIC SYSTEMS

The Fermi 2 plant is not in full compliance with Regulatory Guide 1.75. This guide was issued after the design criteria of Fermi 2 were formulated. Revision 1 of this guide requires application of IEEE Standard 384-1974, "IEEE Trial Use Standard Criteria for Separation of Class 1E Equipment and Circuits." This standard classifies associated circuits as non-Class 1E circuits which share power supplies, enclosures, or raceways with Class 1E circuits or are not separated by distance or barriers from Class 1E components. The Fermi 2 plant does not classify by unique identification or color coding associated circuits.

IEEE Standard 384 also requires a use of isolation devices that do not influence Class 1E equipment during a LOCA. Thus these devices cannot interrupt normal device functions solely by fault current.

In general, the associated circuits must be analyzed to demonstrate no degradation of Class 1E circuit functions. Although identification of associated circuits per se has not been performed, a complete study of Class 1E circuits and their interaction with all other circuits has proved that sufficient isolation and physical separation exist in Fermi 2 design to ensure safe operation.

The comparison of the Fermi 2 design and the regulatory position of Regulatory Guide 1.75, Revision 1, is found in Subsection 3.12.4.

A.1.76 REGULATORY GUIDE 1.76 (April 1974), DESIGN BASIS TORNADO FOR NUCLEAR POWER PLANTS

Under GDC 2, "Design Bases for Protection Against Natural Phenomena," of Appendix A to 10 CFR 50, it is required that structures, systems, and components be able to withstand the effects of natural phenomena. In particular, Regulatory Guide 1.76 cites tornado effects as a concern for design and defines maximum wind conditions. In compliance with Position 1 of this guide, the Fermi 2 plant has been analyzed with conditions defined in a design-basis tornado. The Fermi 2 design-basis tornado is a tornado having a rotational wind velocity of 300 mph, a translational wind velocity of 60 mph and a resultant external pressure drop of 3 psi at the rate of 1 psi/sec.

The Fermi 2 design-basis tornado is virtually identical with the tornado defined in Table 1 of Regulatory Guide 1.76. As described in Subsection 3.3.2.1, the rotational and translational wind velocities given in the guide are slightly different (290 mph/70 mph, respectively); however, the total maximum velocity is the same. Although the rate of pressure drop given in the guide is faster (2 psi/sec) the magnitude of the pressure drop is the same.

Even though the Fermi 2 design-basis tornado was established several years before the issuance of Regulatory Guide 1.76, values were used in the analysis that compare very favorably with the recommendations issued in the guide.

The design of the 4160-V RHR cable vaults and the manholes and ductbanks between these cable vaults and the Reactor/Auxiliary building cable vaults is based on criteria established in Regulatory Guide 1.76, Revision 1 (March 2007) and applicable sections of NUREG-0800, Standard Review Plan 3.5.3 Revision 3 (March 2007).

The Design Basis Tornado wind characteristics are in accordance with Regulatory Guide 1.76 Revision 1 (March 2007) are as follows:

a. A maximum wind velocity of 230 mph

b. A maximum rotational wind velocity of 184 mph

c. A translational wind velocity of 46 mph

d. An external pressure drop of 1.2 psi at the rate of 0.5 psi/sec

For details refer to Subsection 3.3.2.1.

A.1.77 <u>REGULATORY GUIDE 1.77 (May 1974), ASSUMPTIONS USED FOR EVALUATING A CONTROL ROD EJECTION ACCIDENT FOR PRESSURIZED WATER REACTORS</u>

This guide is not applicable to Fermi 2, which is a BWR.

A.1.78 <u>REGULATORY GUIDE 1.78 (Revision 1), ASSUMPTIONS FOR EVALUATING THE HABITABILITY OF A NUCLEAR POWER PLANT CONTROL ROOM DURING A POSTULATED HAZARDOUS CHEMICAL RELEASE</u>

The release of hazardous chemicals presents a potential loss of control room habitability. Criterion 4, "Environmental and Missile Basis," and Criterion 19, "Control Room," of 10 CFR 50 govern the safe operation of a nuclear power plant under normal and abnormal conditions of toxic chemical releases.

Of the toxic chemicals listed in Regulatory Guide 1.78, the following have been identified as present within a 5-mile radius of the plant:

Chemical	Quantity	Location	Distance From Control Center (ft)
Liquid nitrogen	6000 gal	West wall of Reactor building	170

In general, Fermi 2 is in compliance with Regulatory Guide 1.78, Revision 1. However, there are shipments of hazardous chemicals by rail and road routes within a 5-mile radius of the plant. The closest transportation line lies about 3.5 miles from the plant. As discussed in Section 6.4.3.4, at this distance, a release of a hazardous chemical is not considered a threat to Fermi 2 control room habitability.

A.1.79 REGULATORY GUIDE 1.79 (September 1975, Revision 1), PREOPERATIONAL TESTING OF EMERGENCY CORE COOLING SYSTEMS FOR PRESSURIZED WATER REACTORS

This guide is not applicable to Fermi 2, which is a BWR.

A.1.80 REGULATORY GUIDE 1.80 (June 1974), PREOPERATIONAL TESTING OF INSTRUMENT AIR SYSTEMS

Preoperational testing of the control air system was in accordance with this guide.

A.1.81 REGULATORY GUIDE 1.81 (January 1975, Revision 1), SHARED EMERGENCY AND SHUTDOWN ELECTRIC SYSTEMS FOR MULTI-UNIT NUCLEAR POWER PLANTS

This guide is not applicable to Fermi 2 because the current design incorporates only a single nuclear generating unit.

A.1.82 REGULATORY GUIDE 1.82 (May, 1996, Revision 2), WATER SOURCES FOR LONG TERM RECIRCULATION COOLING FOLLOWING A LOSS-OF-COOLANT ACCIDENT

Consistent with Section D, the Detroit Edison response to NRC Bulletin 96-03 committed to replace the original RHR and CS suction strainers with new, larger passive strainers designed to meet the sizing criteria of Revision 2 of this regulatory guide. The new strainers, which were designed and installed in RF06, are of the GE optimized stacked-disk [OSD] design. Whereas the original design sizing was predicated on the deterministic assumption of 50% plugging, the new OSD strainers were designed under the commitment to satisfy the mechanistic design methodology described in Revision 2 of the Regulatory Guide. In their closure of the Fermi response to Bulletin 96-03, the NRC expressed their understanding that the design of the Fermi OSD strainers was performed in accordance with the method provided in NEDO-32686, BWROG Utility Resolution Guidance. The NRC SER that approved the URGs did not accept its proposed analytical methodology for calculating debris head loss and instead stipulated that the calculation of debris head loss were based on vendor supplied analytical correlations developed from tested performance. This requirement is satisfied by utilizing the debris head loss methodology in the NRC-approved GE Licensing

Topical Report NEDO-32721P-A, except as modified to correct elements of the method affected by errors identified in GE Safety Communication 08-02.

A.1.83 REGULATORY GUIDE 1.83 (July 1975, Revision 1), INSERVICE INSPECTION OF PRESSURIZED WATER REACTOR STEAM GENERATOR TUBES

This guide is not applicable to Fermi 2, which is a BWR.

A.1.84 REGULATORY GUIDE 1.84 (September 1983, Revision 21), DESIGN AND FABRICATION CODE CASE ACCEPTABILITY--ASME SECTION III, DIVISION 1

The Fermi 2 plant is in compliance with Regulatory Guide 1.84.

To ensure integrity of the RCPB commensurate with its important safety function, Fermi 2 has applied the code cases of the ASME Boiler and Pressure Vessel Code Section III, to design, fabrication, erection, and testing of Class 1 components within the limitations set forth in 10 CFR 50, Section 50.55(a).

For specific identification of the code cases used, refer to Table 5.2-3.

A.1.85 REGULATORY GUIDE 1.85 (September 1983, Revision 21), MATERIALS CODE CASE ACCEPTABILITY--ASME SECTION III, DIVISION 1

To ensure integrity of the RCPB commensurate with its important safety function, Fermi 2 has applied the code cases of the ASME Boiler and Pressure Vessel Code Section III, to design, fabrication, erection, and testing of Class 1 components within the limitations set forth in 10 CFR 50.55(a) and Regulatory Guide 1.85. Thus the Fermi 2 RCPB is in compliance with the positions of this guide.

For specific identification of the code cases used, refer to Table 5.2-3.

A.1.86 REGULATORY GUIDE 1.86 (June 1974), TERMINATION OF OPERATING LICENSES FOR NUCLEAR REACTORS

This guide is not presently applicable to Fermi 2. At the time of decommissioning and dismantlement of the Fermi 2 plant, Edison intends to follow procedures in compliance with this guide.

A.1.87 REGULATORY GUIDE 1.87 (June 1975, Revision 1), GUIDANCE FOR CONSTRUCTION OF CLASS 1 COMPONENTS IN ELEVATED TEMPERATURE REACTORS (SUPPLEMENT TO ASME SECTION III CODE CASES 1592, 1593, 1594, 1595, and 1596)

This guide is not applicable to the Fermi 2 BWR.

A.1.88 REGULATORY GUIDE 1.88 (October 1976, Revision 2), COLLECTION, STORAGE, AND MAINTENANCE OF NUCLEAR POWER PLANT QUALITY ASSURANCE RECORDS

The guidelines presented in Regulatory Guide 1.88 (Revision 2) apply to nuclear power plants that were issued a construction permit after December 1975. Fermi 2 received its construction permit in September 1972 and is therefore exempt from these guidelines.

The NRC regulatory staff has accepted ANSI Standard N45.2.9-1974, "Requirement for the Collection, Storage, and Maintenance of Quality Assurance Records for Nuclear Power Plants," as an approved method of complying with the Commission's regulations in regard to QA records.

The QA Record System for the initial design and construction phase was based on the requirements in Criterion XVII of 10 CFR 50, Appendix B. To attempt to retrofit the QA records program to conform to all aspects of the ANSI Standard would not have been feasible, and changing the QA record system as it applied to the remaining design and construction work would have been extremely disruptive.

During the operational phase of Fermi 2, the records management operation will be conducted in two stages. From the time the record is generated until it is transmitted to Information Systems for permanent storage, the record will be maintained in an interim storage cabinet with at least 1-hr fire rating. Subsequent storage by Information Systems will comply with Regulatory Guide 1.88. The interim storage in a 1-hr cabinet will not exceed 1 year.

A.1.89 REGULATORY GUIDE 1.89 (June 1984, Revision 1), ENVIRONMENTAL QUALIFICATION OF CERTAIN ELECTRIC EQUIPMENT IMPORTANT TO SAFETY FOR NUCLEAR POWER PLANTS

The guidelines presented in Regulatory Guide 1.89, Revision 1, apply to nuclear power plants which were not previously required, by the NRC, to qualify equipment in accordance with NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety Related Electrical Equipment."

Fermi 2 was required to provide environmental qualification to NUREG-0588 per NRC memorandum and Order CLI-80-21 (see Subsection 3.11.5 for compliance). Therefore, the requirements of Regulatory Guide 1.89, Revision 1, are not applicable to Fermi 2 except for replacement equipment (Section C.6 of Regulatory Guide 1.89, Revision 1).

With regard to replacement equipment, the requirement is to upgrade all replacement equipment, installed subsequent to February 22, 1983, to the provisions of 10 CFR 50.49 unless there are "sound reasons to the contrary." However, the requirements of 10 CFR 50.49 (see Section 3.11), regarding replacement equipment, are such that holders of operating licenses are not required to requalify electrical equipment important to safety in accordance with 10 CFR 50.49 if the NRC had previously required qualification of that equipment in accordance with NUREG-0588.

Since the Fermi 2 Environmental Qualification Program was established based on the requirements of NUREG-0588, the requirements for replacement equipment specified in

NUREG-0588 and NRC Generic Letter 82-09 provide the guidelines to be used for Fermi 2. Certain information contained in Regulatory Guide 1.89, Revision 1, will be used in addition to the above guidelines when further clarifications are required. An exception to these requirements has been taken in that a specific program for addressing equipment upgrade for components being procured was not implemented until April 1985 and that equipment already procured and/or in stock prior to April 1985 was not reevaluated to these equipment upgrade requirements.

The specific replacement equipment requirements applicable to Fermi 2 are as follows:

a. Equipment qualified to NUREG-0588, Category I, requirements is considered qualified to the highest standards required by 10 CFR 50.49. Replacements for this category of equipment are not required to be upgraded

b. Equipment qualified to NUREG-0588, Category II, requirements shall be upgraded to NUREG-0588, Category I, when replacement equipment is procured unless "sound reasons to the contrary," as specified in Generic Letter 82-09 and/or Regulatory Guide 1.89, Revision 1, are established and documented.

A.1.90 REGULATORY GUIDE 1.90 (August 1977, Revision 1), INSERVICE INSPECTION OF PRESTRESSED CONCRETE CONTAINMENT STRUCTURES WITH GROUTED TENDONS

This regulatory guide is not applicable to Fermi 2, which does not use a concrete containment.

A.1.91 REGULATORY GUIDE 1.91 (February 1978, Revision 1), EVALUATION OF EXPLOSIONS POSTULATED TO OCCUR ON TRANSPORTATION ROUTES NEAR NUCLEAR POWER PLANTS

This guide applies to nuclear power plants for which construction permit applications were docketed on or after March 14, 1975. Fermi 2 was docketed in 1969 and is exempt from the guidelines of Regulatory Guide 1.91. However, Fermi 2 has completed review of this guide.

Fermi 2 is located in design-basis tornado region I. This is based on a calculated maximum wind speed of 360 mph and a dynamic wind pressure of 3 psi (see Subsection 3.3.2.1). A survey of transportation routes within 10 miles of Fermi 2 has been made. The results are documented in Subsections 2.2.1 and 2.2.2. As stated in Subsection 2.2.3.3, no conceivable event--including explosions associated with offsite airways, shipping channels, highways, railroads, and pipelines in the area--is expected to influence normal operation of the plant. All transportation routes, "distances of closest approach," are in excess of 4 miles or 21,000 ft from Fermi 2. Figure 2 of Regulatory Guide 1.91 indicates that an explosion in excess of 5000 tons of equivalent TNT would be necessary to affect plant operations. No further consideration of explosion possibilities on transportation routes is warranted. Fermi 2 is thus in compliance with Regulatory Guide 1.91.

A.1.92 REGULATORY GUIDE 1.92 (February 1976, Revision 1), COMBINING MODAL RESPONSES AND SPATIAL COMPONENTS IN SEISMIC RESPONSE ANALYSIS

The guidelines presented in Regulatory Guide 1.92 apply to nuclear power plants for which construction permit applications were docketed after February 1976. The application for Fermi 2 was docketed in 1969 and because of this, Fermi 2 is exempt from the guidelines of Regulatory Guide 1.92. However, Edison has completed review and analysis of the Fermi 2 design with respect to compliance with Regulatory Guide 1.92, Revision 1. Design calculations incorporated in the Fermi 2 vibration-response analysis use spatial component and vibration mode combination by taking the square root of the sum of the squares (SRSS) with due considerations to closely spaced modes in modal combinations as required by Regulatory Guide 1.92, Revision 1. The details of this method are described in Subsection 3.7.3.4. The mathematical analysis in which the resultant modes were evaluated is described in Subsection 3.7.2.1.2.3. It is concluded, therefore, that the Fermi 2 design conforms to the requirements of Regulatory Guide 1.92, Revision 1.

A.1.93 REGULATORY GUIDE 1.93 (December 1974), AVAILABILITY OF ELECTRIC POWER SOURCES

As required by GDC 17, "Electric Power Systems," of Appendix A to 10 CFR 50, two physically independent offsite power and transmission networks along with redundant onsite ac power sources and redundant onsite dc power supplies must be included in the design of each nuclear unit. Limiting conditions for operation (LCO) during the use of emergency electrical power supplies are given in Regulatory Guide 1.93 in accordance with 10 CFR 50, "Licensing of Production and Utilization Facilities," Section 50.36(c)(2).

Regulatory Guide 1.93 is used by the Regulatory Staff in evaluating all construction permit applications for which the issue date of the SER is July 1, 1974, or after. Hence Fermi 2 is not required to comply with this guide, and such compliance is not envisaged. The Fermi 2 project review reveals that the only possible way to fully comply with this guide and still meet the original design intent would be to add a third onsite source (a fifth EDG) that could be used in either division. The plant design and construction had progressed to the point where this change was no longer feasible.

The results of the review that led to these conclusions are summarized below.

The intent of the regulatory positions as stated in Regulatory Guide 1.93 is to implement the safest operating mode whenever the available electric power sources are less than LCO. In the case of Fermi 2, the LCO consists of two offsite sources and two onsite ac power sources. The offsite sources are (1) a 4.16-kV service line stepped down from a 345-kV transmission source by S.S. transformer 65 and (2) a 4.16-kV service line from S.S. transformer 64 stepped down from a 13.2-kV source from the 120-kV transmission bus via switchyard transformer 1. (Refer to Figure 8.3-1.) The two onsite ac sources consist of the four EDGs, two per division. The onsite dc sources consist of dual 130/260-V battery systems, one per division. In the terms of Regulatory Guide 1.93, there are two offsite and two onsite ac sources and two dc sources for LCO.

The regulatory guide's positions describe five levels of degradation of emergency power sources. These levels, the Regulatory Guide compliance position, and the Fermi 2 project position are described on the following pages.

Level of Degradation	Regulatory Guide 1.93 Position	Fermi 2 Project Position
1. The available ac power sources are one less than LCO	Power operation may continue for 72 hr based on system conditions and reserves. If source is restored during this time, unrestricted operation may continue	a. Loss of one offsite source: Fermi 2 would be shut down b. Loss of one onsite source: Fermi 2 must take exception to the Regulatory position. If EDG damage were severe, it could be months before Fermi 2 could return to power under the limits imposed by this regulatory guide. The Fermi 2 design was based on continuous power generating as long as the remaining standby source is verified regularly.
2. The available offsite ac power sources are two less that the LCO	Power operation may continue for 24 hr, pending possibility of restoring circuits.	With loss of both offsite sources, Fermi 2 must shut down.
3. The available offsite and onsite ac power sources are each one less than the LCO	Power operation may continue for 12 hr with limitation based on one source being restored during that time. If either source is restored, operation may continue for 72 hr in accordance with Position 1.	a. Loss of offsite ac power source: Fermi 2 must be shut down. b. Loss of onsite ac power source: if the offsite source is restored, Fermi 2 should be able to return to power based on verification of the remaining onsite source (see Position 1)

Level of Degradation	Regulatory Guide 1.93 Position	Fermi 2 Project Position
4. The available onsite ac power sources are two less than the LCO	Power operation should not exceed 2 hr. If one source is restored within 2 hr, operation may continue for 72hr.	If both onsite sources are lost, Fermi 2 would be shut down. However, if one source were returned, Fermi 2 would continue to operate, as long as that source was verified regularly.
5. The available onsite dc supplies are one less than LCO	Power operation may continue for a period not to exceed 2 hr. If dc power is restored unrestricted, operation may be resumed.	Fermi 2 would comply with this position. The possibility of this occurring considering the Fermi 2 dc system design is extremely remote.

A.1.94 REGULATORY GUIDE 1.94 (April 1976, Revision 1), QUALITY ASSURANCE REQUIREMENTS FOR INSTALLATION, INSPECTION, AND TESTING OF STRUCTURAL CONCRETE AND STRUCTURAL STEEL DURING THE CONSTRUCTION PHASE OF NUCLEAR POWER PLANTS

The implementation of Regulatory Guide 1.94 applies to nuclear power plants submitting applications for construction permits on or after October 15, 1976. The application for Fermi 2 was docketed in 1969. The necessary tests, inspections, records, and data for compliance were not a strict part of Fermi 2 construction procedures. For this reason, records are not in strict compliance with ANSI N45.2.5-1974. Various methods of construction, testing, recording, and material testing have been used during the fabrication of plant structures. As a result, documentation that ensures high quality in materials and workmanship has been retained by the Project's Quality Assurance Group. An outline of these activities as pursued by Fermi 2 is presented in Section 17.1.

A.1.95 REGULATORY GUIDE 1.95 (January 1977, Revision 1), PROTECTION OF NUCLEAR POWER PLANT CONTROL ROOM OPERATORS AGAINST AN ACCIDENTAL CHLORINE RELEASE

Superseded by License Amendment 147

A.1.96 REGULATORY GUIDE 1.96 (June 1976, Revision 1), DESIGN OF MAIN STEAM ISOLATION VALVE LEAKAGE CONTROL SYSTEMS FOR BOILING WATER REACTOR NUCLEAR POWER PLANTS

Superseded by License Amendment 160.

A.1.97 REGULATORY GUIDE 1.97 (December 1980, Revision 2), INSTRUMENTATION FOR LIGHT-WATER-COOLED NUCLEAR POWER

PLANTS TO ASSESS PLANT AND ENVIRONS CONDITIONS DURING AND FOLLOWING AN ACCIDENT

As a result of the post-TMI concerns delineated in NUREG-0737, the postaccident monitoring instrumentation provided for Fermi 2 has been extensively modified.

New channels of instrumentation have been added as described in NUREG-0737, Items II.B.3, II.D.3, II.F.1.1, II.F.1.2, and II.F.1.3. A number of existing instrument channels have been modified to meet new functional requirements specified in NUREG-0737, Items II.F.1.1, II.F.1.4, II.F.1.5, and II.D.3.3.

The subject of instrumentation for the determination of inadequate core cooling was actively pursued by the BWR Owners Group, which developed an industry position on the application of Regulatory Guide 1.97, Revision 2. Edison actively participated in the BWR Owners Group that developed an industry response to more adequately address the subject of postaccident instrumentation for BWR designs. As a consequence of the fairly comprehensive additions and modifications to the Fermi 2 postaccident monitoring system required by NUREG-0737, the modified system is in conformance with Regulatory Guide 1.97 or Edison has provided adequate justification to support an alternative means of meeting the intent of Regulatory Guide 1.97. Edison has submitted reports of compliance with Regulatory Guide 1.97 in References 1 and 2. (Also see Subsection 7.5.1.4.)

Additional references are also provided, which include SER from the NRC, Inspection Report, additional clarification and commitment letters.

A.1.98 REGULATORY GUIDE 1.98 (March 1976), ASSUMPTIONS USED FOR EVALUATING THE POTENTIAL RADIOLOGICAL CONSEQUENCES OF A RADIOACTIVE OFFGAS SYSTEM FAILURE IN A BOILING WATER REACTOR

The analysis of the radiological consequences of a radioactive offgas system failure is presented in Section 15.11.

The analysis of the radiological consequences of the release from continued operation of the steam-jet air ejector after a line break downstream of the steam-jet air ejector is presented in Subsection 15.7.1. The analyses presented in Subsection 15.7.1 follow the Regulatory Guide 1.98 assumptions. (The Regulatory Guide considers only one [lumped] accident, which combines the two events discussed above.)

A few of the assumptions related to the inventories available for release and released from the offgas system differ somewhat from the corresponding assumptions in Regulatory Guide 1.98.

A.1.99 REGULATORY GUIDE 1.99 (May, 1988 Revision 2), RADIATION EMBRITTLEMENT OF REACTOR VESSEL MATERIALS

The Fermi 2 procedures for predicting the effects of neutron radiation on reactor vessel material comply with the requirements of Regulatory Guide 1.99, Revision 2.

For details, refer to Subsection 5.2.4.

A.1.100 REGULATORY GUIDE 1.100 (August 1977, Revision 1), SEISMIC QUALIFICATION OF ELECTRIC EQUIPMENT FOR NUCLEAR POWER PLANTS

The Fermi 2 design is not in conformance with the requirements of Regulatory Guide 1.100, Revision 1. This guide requires the design to conform with the requirements and recommendations specified by IEEE Standard 344-1975 for conducting seismic qualification of Class 1E equipment.

According to the acceptance criteria of SRP 3.10, since the Fermi 2 construction permit application and the preliminary safety analysis report (PSAR) were docketed before October 27, 1972, the seismic qualification of Category I instrumentation, electrical equipment, and supports should meet the requirements of IEEE Standard 344-1971.

As described in Section 3.10 of the UFSAR, the Fermi 2 design complies with the requirements of IEEE Std. 344-1971.

A.1.102 REGULATORY GUIDE 1.102 (September 1976, Revision 1), FLOOD PROTECTION FOR NUCLEAR POWER PLANTS

The Fermi 2 flood protection provisions are in compliance with Regulatory Guide 1.102, Revision 1. (Refer to NUREG-0314, Sections 2.4 and 3.4.)

A.1.103 REGULATORY GUIDE 1.103, (October 1976), POST-TENSIONED PRESTRESSING SYSTEMS FOR CONCRETE REACTOR VESSELS AND CONTAINMENTS

This guide is not applicable to the Fermi 2 plant design.

A.1.105 REGULATORY GUIDE 1.105 (November 1976, Revision 1), INSTRUMENT SETPOINTS

The implementation of Regulatory Guide 1.105, Revision 1, applies to nuclear power plants with construction permit applications docketed after December 15, 1976. The Fermi 2 construction permit application was docketed in April 1969, but Edison has established an acceptable degree of compliance with Regulatory Guide 1.105, Revision 1.

The instrumentation supplied for Fermi 2 complies fully with Regulatory Positions C.1 through C.5 of Regulatory Guide 1.105, Revision 1. The testability option is being implemented on Fermi 2 to ensure this degree of compliance. The documentation required by Regulatory Position C.6 of Regulatory Guide 1.105, Revision 1, has been generated for a specific number of safety system setpoints as part of the BWR generic instrument setpoint methodology response to the NRC staff position on this guide (NRC letter to Edison dated June 14, 1983).

A.1.106 REGULATORY GUIDE 1.106 (March 1977, Revision 1), THERMAL OVERLOAD PROTECTION FOR ELECTRIC MOTORS ON MOTOR-OPERATED VALVES

Two regulatory position options are delineated in Regulatory Guide 1.106, Revision 1. Regulatory Position C.1 is recommended, but Regulatory Position C.2 is allowed as an acceptable degree of compliance.

In complying with Regulatory Position C.2, Fermi 2 established motor-operated valve thermal overload device trip setpoints by considering the following:

a. Variations in ambient temperature at the installed locations of the overloads and the valve motors

b. Variations in motor heating data and the overload's trip characteristics

c. Setpoint drift verification through periodic testing.

A.1.107 REGULATORY GUIDE 1.107 (February 1977, Revision 1), QUALIFICATIONS FOR CEMENT GROUTING FOR PRESTRESSING TENDONS IN CONTAINMENT STRUCTURES

This guide is not applicable to Fermi 2, which is a BWR with a Mark I containment.

A.1.108 REGULATORY GUIDE 1.108 (August 1977, Revision 1), PERIODIC TESTING OF DIESEL GENERATOR UNITS USED AS ONSITE ELECTRIC POWER SYSTEMS AT NUCLEAR POWER PLANTS

The Fermi 2 EDG design and preoperational and periodic testing meet the intent of this Regulatory Guide except where the Technical Specifications surveillance requirements differ. Exceptions are taken to the following regulatory positions:

C.1.b(3) When performing testing of the EDGs in other than the fast (10-sec) start mode, the governor and exciter circuits must be bypassed. Automatic transfer to emergency operation therefore cannot occur without manual action by the testing operator slow starting is allowed in the Technical Specifications to minimize mechanical stress and wear in the diesel engines

C.2.a The testing frequency for diesel generator units is controlled by the Technical Specification Surveillance Frequency Control Program and is not tied to regulatory position C.2.a requirements

C.2.a(3) The 24-hr full-load-carrying test is performed at 2500 to 2600 kW for 22 hr and 2800 to 2900 kW for 2 hr, rather than at the continuous load and 2-hr rating of this regulatory position. The kilowatt load for this test is established in the Technical Specifications

C.2.a(5) The hot-restart test is performed with the loss of offsite power loads only, as established in the Technical Specifications. A demonstration is not performed with design accident loading sequence

C.2.a(8) This test is not performed since position C.1.b(3) is not met

C.2.c(1) The testing frequency for diesel generator units is controlled by the Technical Specification Surveillance Frequency Control Program and is not tied to regulatory position C.2.c requirements

C.2.c(2) The periodic testing load-carrying demonstration is at 2500 to 2600 kW in accordance with the Technical Specifications, rather than at the continuous rating recommended in this position. Also, the Technical Specifications require that the rapid loading (2500 to 2600 kW in less than or equal to 150 sec) only need be demonstrated per the Technical Specification Surveillance Frequency control Program, in conjunction with the 10-sec start test. The testing frequency for diesel generator units is controlled by the Technical Specification Surveillance Frequency Control Program and is not tied to regulatory position C.2.c requirements

C.2.d Test interval of the EDGs is determined in accordance with Technical Specifications and the Corrective Action Program. The testing frequency for diesel generator units is controlled by the Technical Specification Surveillance Frequency Control Program and is not tied to regulatory position C.2.d requirements

C.3.b Reporting requirements were deleted when Technical Specification Amendment 107 was implemented.

A.1.109 REGULATORY GUIDE 1.109 (October 1977, Revision 1), CALCULATION OF ANNUAL DOSES TO MAN FROM ROUTINE RELEASES OF REACTOR EFFLUENTS FOR THE PURPOSE OF EVALUATING COMPLIANCE WITH 10 CFR PART 50 APPENDIX I

Fermi 2 is in conformance with the requirements of this regulatory guide. For details refer to Subsection 11.2.9 and Appendix 11A.

A.1.110 REGULATORY GUIDE 1.110 (March 1976), COST-BENEFIT ANALYSIS FOR RADWASTE SYSTEMS FOR LIGHT-WATER-COOLED NUCLEAR POWER PLANTS

Fermi 2 is in conformance with the requirements of Regulatory Guide 1.110 (refer to NUREG-0389, Cost-Benefit Analysis Requirements of Appendix I to 10 CFR Part 50; Their Application to Certain Nuclear Power Plants Docketed Before January 2, 1971; January, 1978).

A.1.111 REGULATORY GUIDE 1.111 (July 1977, Revision 1), METHODS FOR ESTIMATING ATMOSPHERIC TRANSPORT AND DISPERSION OF GASEOUS EFFLUENTS IN ROUTINE RELEASES FROM LIGHT-WATER-COOLED REACTORS

Fermi 2 is in conformance with the requirements of this regulatory guide. For details refer to Subsection 2.3.5 and Appendix 11A.

A.1.112 REGULATORY GUIDE 1.112 (April 1976), CALCULATION OF RELEASES OF RADIOACTIVE MATERIALS IN GASEOUS AND LIQUID EFFLUENTS FROM LIGHT-WATER-COOLED POWER REACTORS

Fermi 2 is in conformance with the requirements of this regulatory guide. For details refer to Appendix 11A.

A.1.113 REGULATORY GUIDE 1.113 (April 1977, Revision 1), ESTIMATING AQUATIC DISPERSION OF EFFLUENTS FROM ACCIDENTAL AND ROUTINE REACTOR RELEASES FOR THE PURPOSE OF IMPLEMENTING APPENDIX I

Fermi 2 is in conformance with the requirements of this regulatory guide. For details refer to Appendix 11A.

A.1.114 REGULATORY GUIDE 1.114 (November 1976, Revision 1), GUIDANCE ON BEING OPERATOR AT THE CONTROLS OF A NUCLEAR POWER PLANT

Fermi 2 is in conformance with the requirements of this regulatory guide.

A.1.115 REGULATORY GUIDE 1.115 (July 1977, Revision 1), PROTECTION AGAINST LOW-TRAJECTORY TURBINE MISSILES

Fermi 2 is in conformance with the intent of Regulatory Guide 1.115, Revision 1. The Fermi 2 barrier designs for low-trajectory missile protection were evaluated by use of the Modified Petry Formula. For details on missile protection, refer to Section 3.5.

A.1.116 REGULATORY GUIDE 1.116 (June 1976), QUALITY ASSURANCE REQUIREMENTS FOR INSTALLATION, INSPECTION, AND TESTING OF MECHANICAL EQUIPMENT AND SYSTEMS

The NRC regulatory staff has recognized ANSI Standard N45.2.8-1975, "Supplementary Quality Assurance Requirements for Installation, Inspection, and Testing of Mechanical Equipment and Systems for the Construction Phase of Nuclear Power Plants," as an acceptable method of complying with the Commission's regulations in regard to such equipment and systems. Regulatory Guide 1.116, which endorses ANSI N45.2.8 with certain minor exceptions and clarifications, was issued in June 1976. Since the Fermi 2 QA Program for the design and construction phase was established several years before the issuance of ANSI N45.2.8 or Regulatory Guide 1.116, it was based on the requirements of Appendix B to 10 CFR 50. The QA Program included all the elements necessary for NRC approval at that time, and has been followed for all installation, inspection, and testing of mechanical systems so far accomplished. It was not practical to modify the QA Program to include all aspects of the program set forth in ANSI N45.2.8 for the remaining installation, inspection, and testing of mechanical systems as this would have had a disruptive effect on both cost and schedule.

Regulatory Guide 1.116 also states that the requirements of ANSI N45.2.8 are considered to be applicable during the operations phase. Consequently, the requirements of Regulatory

Guide 1.116 will be followed for those applicable operational phase activities that are comparable to activities occurring during the construction phase.

A.1.117 REGULATORY GUIDE 1.117 (April 1978, Revision 1), TORNADO DESIGN CLASSIFICATION

The Fermi 2 construction permit was issued prior to May 30, 1978. Therefore, Regulatory Guide 1.117 does not apply.

A.1.118 REGULATORY GUIDE 1.118 (June 1978, Revision 2), PERIODIC TESTING OF ELECTRIC POWER AND PROTECTION SYSTEMS

Regulatory Guide 1.118 is required only for construction permit applicants under review. Therefore, Fermi 2 is not required to comply. Fermi 2 complies with the intent of Regulatory Guide 1.118 Rev 2 and IEEE 338-1977 to test power (electrical) system in a formal manner. This test requirement was not contained in IEEE 338-1971; Fermi 2 complies with IEEE 338-1971 for all remaining protection system testing. Power system surveillance test procedures have been developed. Reactor protection system test commitments are found in Subsection 7.2.1.1.3.8.

A.1.120 REGULATORY GUIDE 1.120 (November 1977, Revision 1), FIRE PROTECTION GUIDELINES FOR NUCLEAR POWER PLANTS

Regulatory Guide 1.120, Revision 1, was reissued for an extended comment period of 1 year. During this comment period, the existing BTP APCSB 9.5-1, Appendix A, was still the determining guide for fire protection (in accordance with NRC letter dated November 7, 1977, from the Office of Standards Development).

Fermi 2 fire protection follows the intent of BTP APCSB 9.5-1, Appendix A, Construction Permit Received Prior to July 1, 1976. BTP APCSB 9.5-1, Appendix A, is the controlling document for Fermi 2 fire protection. Appendix 9A describes the positions of compliance to the BTP.

A.1.121 REGULATORY GUIDE 1.121 (August 1976), BASES FOR PLUGGING DEGRADED PWR STEAM GENERATOR TUBES

Regulatory Guide 1.121 is not applicable to Fermi 2.

A.1.122 REGULATORY GUIDE 1.122 (February 1978, Revision 1), DEVELOPMENT OF FLOOR DESIGN RESPONSE SPECTRA FOR SEISMIC DESIGN OF FLOOR-SUPPORTED EQUIPMENT OR COMPONENTS

Regulatory Guide 1.122 is required only for construction permit applicants under review. Thus, the Fermi 2 plant is not required to comply.

A.1.123 REGULATORY GUIDE 1.123 (July 1977, Revision 1), QUALITY ASSURANCE REQUIREMENTS FOR CONTROL OF PROCUREMENT OF ITEMS AND SERVICES FOR NUCLEAR POWER PLANTS

The NRC regulatory staff has accepted ANSI Standard N45.2.131976, "Quality Assurance Requirements for Control of Procurement of Items and Services for Nuclear Power Plants," as an acceptable method of complying with the Commission's regulations in regard to control of procurement. The initial issue of Regulatory Guide 1.123 applied to construction permit and operating license applications docketed after June 15, 1977, and Revision 1 is applicable to those docketed after August 1, 1977. The Fermi 2 QA Program for the design and construction phase was established several years before the issuance of either ANSI N45.2.13 or Regulatory Guide 1.123, and is based on the requirements of Appendix B to 10 CFR 50. At the stage of the procurement effort when Regulatory Guide 1.123 was issued, it was not feasible to make any retroactive changes in the system of Procurement Control. The Fermi 2 QA Program already included the basic elements set forth in ANSI Standard N45.2.13. Consequently, a change to the system for control of procurement which could affect only the small fraction of the procurement effort still to be done was impractical as any possible benefits would be far outweighed by the cost and schedule impact.

During the operational phase of Fermi 2, the procurement control program will be conducted in compliance with Regulatory Guide 1.123, with the following exception: With respect to ANSI N45.2.13, Section 3.2, "Control of the Procurement Documents," Subsection 3.2.3, "Quality Assurance Program Requirements," DTE takes the following exception:

When purchasing commercial grade calibration or testing services from a laboratory holding accreditation by an Accreditation Body (AB) which is a signatory to the International Laboratory Accreditation Cooperation (ILAC) Mutual Recognition Arrangement (MRA), commercial grade surveys need not be performed provided each of the conditions in the following list are met. The ILAC accreditation process cannot be used as part of the commercial grade dedication process of Nondestructive Examination (NDE) or Nondestructive Testing (NDT) services in lieu of performing a commercial grade survey.

1. A documented review of the supplier's accreditation is performed and includes a verification of the following:

    a) The calibration or test laboratory holds accreditation by an accrediting body recognized by the ILAC MRA. The accreditation encompasses ISO/IEC-17025:2017, "General Requirements for the Competence of Testing and Calibration Laboratories."

    b) For procurement of calibration services, the published scope of accreditation for the calibration laboratory covers the needed measurement parameters, ranges, and uncertainties.

    c) For procurement of testing services, the published scope of accreditation for the test laboratory covers the needed testing services including test methodology and tolerances/uncertainties.

    d) The laboratory has achieved accreditation based on an on-site accreditation assessment by the selected AB within the past 48 months. The laboratory's accreditation cannot be based on two consecutive remote accreditation assessments.

2. The purchase documents require that:

    a) The service must be provided in accordance with their accredited ISO/IEC-17025:2017 program and scope of accreditation.

    b) As found calibration data must be reported in the certificate of calibration when calibrated items are found to be out of tolerance (for calibration services only).

    c) The equipment/standards used to perform the calibration must be identified in the certificate of calibration (for calibration services only).

    d) Subcontracting of these accredited services is prohibited.

    e) The customer must be notified of any condition that adversely impacts the laboratory's ability to maintain the scope of accreditation.

    f) Performance of the services listed on this order is contingent on the laboratory's accreditation having been achieved through an on-site accreditation assessment by the AB within the past 48 months.

    g) Additional technical and quality requirements, as necessary, based upon a review of the procured scope of services, which may include, but are not necessarily limited to, tolerances, accuracies, ranges, and industry standards.

3. It is validated, at receipt inspection, that the laboratory's documentation certifies that:

    a) The contracted calibration or test service has been performed in accordance with their ISO/IEC-17025:2017 program, and has been performed within their scope of accreditation.

    b) The purchase order's requirements are met.

A.1.124 REGULATORY GUIDE 1.124 (January 1978, Revision 1), SERVICE LIMITS AND LOADING COMBINATIONS FOR CLASS 1 LINEAR-TYPE COMPONENT SUPPORTS

The Fermi 2 construction permit was issued prior to January 10, 1978. Therefore, Regulatory Guide 1.124 does not apply.

A.1.125 REGULATORY GUIDE 1.125 (October 1978, Revision 1), PHYSICAL MODELS FOR DESIGN AND OPERATION OF HYDRAULIC STRUCTURES AND SYSTEMS FOR NUCLEAR POWER PLANTS

Regulatory Guide 1.125 does not apply to Fermi 2 as the construction permit was docketed prior to November 1977.

A.1.126 REGULATORY GUIDE 1.126 (March 1978, Revision 1), AN ACCEPTABLE MODEL AND RELATED STATISTICAL METHODS FOR THE ANALYSIS OF FUEL DENSIFICATION

General Electric Fuel Design Analysis and Manufacturing Procedures as applied to the design and production of the Fermi 2 fuel are in full compliance with Regulatory Guide 1.126.

A.1.127 REGULATORY GUIDE 1.127 (March 1978, Revision 1), INSPECTION OF WATER CONTROL STRUCTURES ASSOCIATED WITH NUCLEAR POWER PLANTS

This guide does not apply to any Fermi 2 structure. As part of the normal maintenance program, the shore barrier will be resurveyed by Edison on an annual basis and after storms in which the crest elevation of incident waves at the shoreline exceeds the top of the shore barrier. (See Subsection 3.4.4.5.) The inspection of the RHR complex reservoir is included in the normal maintenance program.

A.1.128 REGULATORY GUIDE 1.128 (October 1978, Revision 1), INSTALLATION DESIGN AND INSTALLATION OF LARGE LEAD STORAGE BATTERIES FOR NUCLEAR POWER PLANTS

Regulatory Guide 1.128 is required only for construction permit applicants under review. Thus, Fermi 2 is not required to comply.

A.1.129 REGULATORY GUIDE 1.129 (February 1978, Revision 1), MAINTENANCE, TESTING, AND REPLACEMENT OF LARGE LEAD STORAGE BATTERIES FOR NUCLEAR POWER PLANTS

Regulatory Guide 1.129 invokes the use of IEEE Standard 450-1975. Fermi 2 will maintain its present commitment to IEEE 450-1972 and the BWR Standard Technical Specifications with regard to the 130/260-V dc system. See response to Regulatory Guide 1.32 (Subsection A.1.32) for specific compliance.

A.1.130 REGULATORY GUIDE 1.130 (October 1978), SERVICE LIMITS AND LOADING COMBINATIONS FOR CLASS 1 PLATE-AND-SHELL-TYPE COMPONENT SUPPORTS

Regulatory Guide 1.130 applies to construction permit applications docketed after April 1, 1978. It is not applicable to Fermi 2. The Fermi 2 construction permit was docketed April, 1969.

A.1.131 REGULATORY GUIDE 1.131 (August 1977), QUALIFICATION TESTS OF ELECTRIC CABLES, FIELD SPLICES, AND CONNECTIONS FOR LIGHT-WATER-COOLED NUCLEAR POWER PLANTS

Regulatory Guide 1.131 is applicable only for construction permit applications docketed after May 1, 1978; therefore, application of Regulatory Guide 1.131 is not required for Fermi 2. See Subsection 8.3.1.4.2 for cable qualification.

A.1.132 REGULATORY GUIDE 1.132 (March 1979, Revision 1), SITE INVESTIGATIONS FOR FOUNDATIONS OF NUCLEAR POWER PLANTS

Fermi 2 is in compliance with Regulatory Guide 1.132, Revision 0.

Regulatory Guide 1.132, Revision 1, was issued to evaluate investigations submitted in connection with construction permit applications docketed after March 30, 1979. The guide is also applicable for those facilities where the construction permit was issued prior to March 30, 1979, but major changes in plant layout or design took place after this date.

The Fermi 2 construction permit was issued prior to March 30, 1979, and therefore Regulatory Guide 1.132, Revision 1, is not applicable. However, Fermi 2 generally conforms to the requirements presented in the regulatory guide.

The specific item where the Revision 1 guideline differs from the Fermi 2 compliance is as follows:

"Safety-Related Pipelines"--The regulatory guide requires borings at 100-ft intervals, geological sections along the pipelines, and mapping of the excavation, if founded in bedrock. In addition, if the pipeline is soil supported, sophisticated sampling techniques are required. Although sophisticated sampling techniques were not used, the site investigations were performed in accordance with the state of the art at the time.

In conclusion, Fermi 2 site investigations meet the intent, and in most cases the letter, of Regulatory Guide 1.132, Revision 1.

A.1.133 REGULATORY GUIDE 1.133 (May 1981, Revision 1), LOOSE- PART DETECTION PROGRAM FOR THE PRIMARY SYSTEM OF LIGHT-WATER-COOLED REACTORS

Fermi 2 original design was in compliance with the requirements of Regulatory Guide 1.133, Revision 1.

However, the Regulatory Guide is no longer applicable to Fermi as the compliance to the requirements of RG 1.133 is not required per GE Licensing Topical Report NEDC-32975, which has been reviewed and accepted by the NRC SE dated January 25, 2001.

A.1.134 REGULATORY GUIDE 1.134 (September 2014, Revision 4), MEDICAL EVALUATION OF NUCLEAR POWER PLANT PERSONNEL REQUIRING OPERATOR LICENSES

Fermi 2 is in conformance with the requirements of Regulatory Guide 1.134.

A.1.135 REGULATORY GUIDE 1.135 (September 1977), NORMAL WATER LEVEL AND DISCHARGE AT NUCLEAR POWER PLANTS

Under Section D, Implementation of Regulatory Guide 1.135, the NRC states, ". . . the method described herein will be used in the evaluation of submittals for construction permit applications docketed after May 1, 1978. . .." As the construction permit application for Fermi 2 was docketed in 1969, Regulatory Guide 1.135 is not applicable to Fermi 2.

A.1.136 REGULATORY GUIDE 1.136 (October 1978, Revision 1), MATERIAL FOR CONCRETE CONTAINMENTS

Fermi 2 has a steel primary containment; therefore Regulatory Guide 1.136 does not apply.

A.1.137 REGULATORY GUIDE 1.137 (October 1979, Revision 1) FUEL OIL SYSTEMS FOR STANDBY DIESEL GENERATORS

The fuel oil system was designed and installed prior to the issuance of this regulatory guide. However, the Fermi 2 diesel fuel oil system conforms to the basic arrangement, testing, and other requirements of Regulatory Guide 1.137. There are differences in design detail, but overall the intent of the guide is met.

Specific requirements for fuel-oil testing are contained in the Fermi 2 Technical Specifications, and include provisions for testing of delivered fuel oil prior to storage in the tanks and for periodic sampling thereafter. The Technical Specifications requirements satisfy the intent of Regulatory Guide 1.137, Position C.2.

A.1.138 REGULATORY GUIDE 1.138 (April 1978), LABORATORY INVESTIGATIONS OF SOILS FOR ENGINEERING ANALYSIS AND DESIGN OF NUCLEAR POWER PLANTS

The Fermi 2 construction permit was issued prior to December 1, 1978. Therefore, Regulatory Guide 1.138 does not apply.

A.1.139 REGULATORY GUIDE 1.139 (May 1978), GUIDANCE FOR RESIDUAL HEAT REMOVAL

The Fermi 2 plant is in compliance with Regulatory Guide 1.139.

A.1.140 REGULATORY GUIDE 1.140 (October 1979, Revision 1), DESIGN, TESTING, AND MAINTENANCE CRITERIA FOR NORMAL VENTILATION EXHAUST SYSTEM AIR FILTRATION AND ADSORPTION UNITS OF LIGHT-WATER-COOLED NUCLEAR POWER PLANTS

Various discharge filter systems have been provided for Fermi 2 to control the discharge of radioactive material during normal and operational occurrences. The filter and/or radiation monitors are provided for compliance with GDC 60 and 61 of Appendix A, and Appendix I to 10 CFR 50. The filters were purchased in accordance with standards applicable at the time, such as ORNL-NSIC-65.

Fermi 2 is in compliance with the intent of Revision 1 of this regulatory guide. These filters were designed and constructed prior to the issuance of Regulatory Guide 1.140 and ANSI Standards N510 and N509. However, the design and construction of radwaste building ventilation exhaust hood and building exhaust filters do meet the basic intent and performance criteria in these guidelines.

A.1.141 REGULATORY GUIDE 1.141 (October 1979, Revision 1), CONTAINMENT ISOLATION PROVISIONS FOR FLUID SYSTEMS

The Fermi 2 isolation system has been reviewed for compliance with NUREG-0737, Item II.E.4.2. The requirements in NUREG-0737 encompass, expand, and supersede Regulatory Guide 1.141, Revision 1, and the present design of the containment isolation system for Fermi 2, in general, conforms to the requirements of NUREG-0737.

A.1.142 REGULATORY GUIDE 1.142 (April 1978), SAFETY-RELATED CONCRETE STRUCTURES FOR NUCLEAR POWER PLANTS (OTHER THAN REACTOR VESSELS AND CONTAINMENTS)

The Fermi 2 construction permit was issued prior to December 15, 1978. Therefore, Regulatory Guide 1.142 does not apply.

In 2009 a second set of Category I 4160-V ductbanks, manholes and above ground cable vaults were designed and constructed. These Category I structures are in compliance with Regulatory Guide 1.142, Revision 2, with the following exception:

Regulatory Guide 1.142, Rev. 2 cites the use of ACI 349-97, “Code Requirements for Nuclear Safety Related Concrete Structures” along with the 15 Regulatory Positions on the use of ACI 349-97. Fermi used a later ACI Code, 349-01, while still complying with all the applicable 15 Positions of the Reg. Guide for the second set of Category I 4160-V ductbanks, manholes and above ground cable vaults. The requirements in the later ACI code is consistent with ACI 349-97.

Position 15 of Regulatory Guide 1.142, Rev. 2 states that Section 11.6 of ACI 318-99 “…” should be used in lieu of 11.6 of ACI 318-97” … “for evaluating members subject to torsion or combination of shear and torsion”. ACI 349-01 incorporated recent revisions of ACI 318; which includes ACI 318-99 Section 11.6 changes and therefore, is consistent and complies with Position 15.

A.1.143 REGULATORY GUIDE 1.143 (October 1979, Revision 1), DESIGN GUIDANCE FOR RADIOACTIVE WASTE MANAGEMENT SYSTEMS, STRUCTURES, AND COMPONENTS INSTALLED IN LIGHT-WATER-COOLED NUCLEAR POWER PLANTS

Fermi 2 is in compliance with Regulatory Guide 1.143, Revision 1, with the following exceptions:

a. Fermi 2 uses nonconsumable inserts (backing rings) in butt-welded pipes of 2.5 in., or larger, diameter. Edison had previously stated its position on the adequacy of this feature in connection with conformance to Regulatory Guide 1.143, Revision 0

b. Regulatory Guide 1.143, Revision 1, requires that concrete be designed in accordance with ACI 318-77, instead of ACI 349-76 as required by Regulatory Guide 1.143, Revision 0. The Fermi 2 turbine house/ radwaste building was designed in accordance with ACI 318-63 and/or ACI 318-71. Since ACI 318-77 is an updated version of ACI 318-71, without any significant changes to the strength requirements of a structural frame, it is Edison's opinion that the turbine house/radwaste building structure does comply with the requirements of Regulatory Guide 1.143, Revision 1, in this regard. Edison had previously stated the adequacy of the concrete standards associated with radwaste structures in connection with conformance to Regulatory Guide 1.143, Revision 0

c. Regulatory Guide 1.143, Revision 1, calls for hydrotesting of the offgas system and holding pressure for 30 minutes, with no leakage indicated. Fermi 2 piping was tested in full compliance with ASME Section III, ND6000, 1971 winter Addendum, which calls for a 10-minute hold. Edison's justification for a 10-minute hydrotest hold pressure is as follows:

    1. The Fermi 2 offgas piping is already built to more stringent requirements than called for in this regulatory guide

    2. The Fermi 2 offgas system normally operates under a vacuum

    3. The ASME 10-minute requirement is sufficient to detect any defects in the piping system.

    The adequacy of the offgas system test had been previously stated by Edison in connection with the conformance of Fermi 2 to Regulatory Guide 1.143, Revision 0

    A study (Reclassification of the offgas system) was performed, which concluded the Fermi 2 offgas system may be reclassified as non-ASME Code Section III. The code governing the piping and valves is ANSI B31.1.0.

    Modifications made to the offgas piping system subsequent to the code reclassification will be in compliance with ANSI B31.1.0, which is consistent with Regulatory Guide 1.143.

d. Regulatory Guide 1.143, Revision 1, calls for certain portions (primarily charcoal adsorber tank supports) of the offgas system to be designed to specified seismic design criteria. The design of the Fermi 2 offgas system does not conform to the specified seismic design criteria

e. Overflow of the condensate storage or condensate return tank is contained within the containment wall around both tanks. Lost condensate is pumped to the valve pit sumps and then pumped to radwaste. Direct access to Lake Erie by water seeping into the ground is prevented by the clay fill seal beneath the shore barrier. Initial movement of any seepage would be downward to mix and dilute with the ground water from the dolomite aquifer

f. Regulatory Guide 1.143, Revision 1, specifies QA practices appropriate for radwaste systems. The QA practices that were applied consist of measures established to control design activities, the procurement and receiving inspection of pressure boundary items and instrumentation, and the inspection of the installation of pressure boundary items and instrumentation

g. Regulatory Guide 1.143, Revision 1, Section 4.3, states that "process lines should not be less than 3/4-in. (nominal). "The Fermi 2 system contains three process lines (waste slurries and evaporator concentrates) to the extruder which are 1/2-in. Schedule 80 pipe. These pipes have a wall thickness which is actually greater than 3/4-in. Schedule 40 piping. The 1/2-in. piping was needed in these lines to provide and maintain an adequate transport velocity. The lines were specifically designed for slurry service, and feature butt-welded construction, 5-D bends (no elbow fittings), and automatic flushing.

A.1.144 REGULATORY GUIDE 1.144 (September 1980, Revision 1) AUDITING OF QUALITY ASSURANCE PROGRAMS FOR NUCLEAR POWER PLANTS

DTE is in conformance with the requirements and recommendations of this regulatory guide, with the following exceptions:

(1) That a grace period of 25 percent is applied to the completion of annually required documented supplier evaluations and the completion of triennial audits as required by section C.3.b.(2). The total combined time interval for any three consecutive audit intervals should not exceed 3.25 times the specified audit interval.

When procuring commercial grade calibration or testing services from a laboratory holding accreditation by an Accreditation Body (AB) which is a signatory to the International Laboratory Accreditation Cooperation (ILAC) Mutual Recognition Arrangement (MRA), the accreditation process and accrediting body may be credited with carrying out a portion of the purchaser’s duties of verifying acceptability and effective implementation of the calibration or testing service laboratory’s quality assurance program.

In lieu of performing commercial grade survey or accepting a commercial grade survey performed by another licensee, a documented review of the laboratory’s accreditation is performed which includes a verification of each of the conditions in the following list. The ILAC accreditation process cannot be used as part of the commercial grade dedication process of Nondestructive Examination (NDE) or Nondestructive Testing (NDT) services in lieu of performing a commercial grade survey.

1. The calibration or test laboratory holds accreditation by an accrediting body recognized by the ILAC MRA. The accreditation encompasses ISO/IEC-17025:2017, “General Requirements for the Competence of Testing and Calibration Laboratories.”
2. For procurement of calibration services, the published scope of accreditation for the calibration laboratory covers the needed measurement parameters, ranges, and uncertainties.
3. For procurement of testing services, the published scope of accreditation for the test laboratory covers the needed testing services including test methodology and tolerances/uncertainties.

4. The laboratory has achieved accreditation based on an on-site accreditation assessment by the selected AB within the past 48 months. The laboratory's accreditation cannot be based on two consecutive remote accreditation assessments.

(2) DTE will review the information described in the second paragraph of section C.3.b(2) as it becomes available through its ongoing receipt inspection, operating experience and supplier evaluation programs, in lieu of performing a specific evaluation on an annual basis. The results of the reviews are promptly considered for effect on a supplier's continued qualification and adjustments made as necessary (including corrective actions, adjustments of supplier audit plans, and input to third party auditing entities as warranted). In addition, the results are reviewed periodically to determine if, as a whole, they constitute a significant condition adverse to quality requiring additional action.

QA programs of others, that is suppliers, may be audited and evaluated by another nuclear utility provided an agreement has been established to include DTE's scope of supply and for reviews of programs and their changes, DTE's QA requirements.

A.1.145 REGULATORY GUIDE 1.145 (August 1979), ATMOSPHERIC DISPERSION MODELS FOR POTENTIAL ACCIDENT CONSEQUENCE ASSESSMENTS AT NUCLEAR POWER PLANTS

This analysis uses offsite χ/Q determinations based on this regulatory guide.

A.1.146 REGULATORY GUIDE 1.146 (August 1980), QUALIFICATION OF QUALITY ASSURANCE PROGRAM AUDIT PERSONNEL FOR NUCLEAR POWER PLANTS

The established design and construction QA program, which predates the development of ANSI N45.2.23, was not committed to comply with Regulatory Guide 1.146. However, the adopted practices for the training and qualification of auditor personnel met the requirements of the ANSI standard.

The operations QA program complies with the requirements of Regulatory Guide 1.146, except as follows:

(1) Regardless of the methods used for demonstrating proficiency, the prospective lead auditor shall have participated on at least one Nuclear Quality Assurance Audit within the year preceeding the individual's effective date of qualification. Upon successful demonstration of the ability to effectively implement the audit process and effectively lead audits, and having met the other requirements of section 2.3 of ANSI N.45.2.23-1978, the individual may be certified as being qualified to lead audits.

(2) For sections 3.2 and 5.3 of ANSI N45.2.23-1978, a grace period of 90 days is applied to complete the annual assessment of each lead auditor's qualification.

A.1.147 REGULATORY GUIDE 1.147 (latest edition), INSERVICE INSPECTION CODE CASE ACCEPTABILITY--ASME SECTION XI, DIVISION 1

Fermi 2 is in conformance with the requirements of this regulatory guide. Code cases that apply and have been adopted for use are identified in the inservice inspection program.

A.1.148 REGULATORY GUIDE 1.148 (March 1981), FUNCTIONAL SPECIFICATION FOR ACTIVE VALVE ASSEMBLIES IN SYSTEMS IMPORTANT TO SAFETY IN NUCLEAR POWER PLANTS

The Fermi 2 construction permit and licenses to manufacture were issued prior to July 1, 1981. Therefore, Regulatory Guide 1.148 does not apply. However, the intent of this guide will be met for the new equipment ordered for Fermi 2 after July 1, 1981.

A.1.152 REGULATORY GUIDE 1.152 (NOVEMBER 1985), CRITERIA FOR PROGRAMMABLE DIGITAL COMPUTER SYSTEM SOFTWARE IN SAFETY-RELATED SYSTEMS OF NUCLEAR POWER PLANTS

The Fermi 2 procedures conform to the requirements for designing, verifying, and implementing software and validating computer systems as specified in ANSI/IEEE-ANS-7-4.3.2-1982, "Application Criteria for Programmable Digital Computer Systems in Safety Systems of Nuclear Power Generating Stations." In addition, Fermi 2 conforms with IEEE Standard 7-4.3.2-1993, "IEEE Standard Criteria for Digital Computers in Safety Systems of Nuclear Power Generating Stations." The 1993 version provides clarifications and detailed descriptive guidelines without changing the basic technical criteria in the 1982 version.

A.1.155 REGULATORY GUIDE 1.55 (AUGUST 1988), STATION BLACKOUT

The Fermi 2 plant is in compliance with Regulatory Guide 1.155. The compliance of the Fermi 2 plant to the regulatory Guide 1.155 was determined using the NUMARC 87-00 "Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors". The following is a summary of some of the important conclusions from this determination:

a. A minimum emergency diesel generator (EDG) reliability target of .95 per demand for each EDG has been selected and a reliability program is in place to monitor and maintain this reliability level.

b. The Fermi 2 plant minimum acceptable station blackout coping capability was determined to be 4 hours. The Fermi 2 specific plant evaluation determined it is capable of withstanding and recovering from a station blackout event of 4 hour duration.

c. Fermi 2 has an Alternate AC (AAC) power supply available on site that can be started from the Fermi 2 control center and switched to the plant onsite ac power system in less than one (1) hour. The AAC is the 18 MW Combustion Turbine Generator (CTG) 11-1 located near the plant's 120 KV switchyard. The AAC power system is inspected and tested periodically to demonstrate operability and reliability. An alternate to CTG 11-1 is CTG 11-2, 11-3, or 11-4 which can be started with the standby diesel generator.

d. Procedures and training have been established for operator actions necessary to cope with a station blackout event.

e. Quality assurance activities have been implemented as applicable for the non-safety systems and equipment required to support responses to a station blackout event. Further discussion of Station Blackout is provided in Section 8.4, "Station Blackout (SBO)."

A.1.160 REGULATORY GUIDE 1.160 (JANUARY 1995), MONITORING THE EFFECTIVENESS OF MAINTENANCE AT NUCLEAR POWER PLANTS

The Fermi 2 plant is in compliance with Regulatory Guide 1.160. Regulatory Guide 1.160 endorses the use of NUMARC 93-01 as acceptable guidance for implementing the Maintenance Rule (10 CFR 50.65). Regulatory Guide 1.160 states that methods other than those expressed in NUMARC 93-01 may be used to implement the Maintenance Rule. However, the NRC will determine the acceptability of other methods on a case by case basis.

Fermi 2 has utilized NUMARC 93-01 as the base document for implementing the Maintenance Rule. However, after appropriate justification, exceptions were taken. Most of these exceptions were improvements to NUMARC 93-01 guidance.

A.1.163 REGULATORY GUIDE 1.163 (SEPTEMBER 1995), PERFORMANCE-BASED CONTAINMENT LEAK-TEST PROGRAM

By License Amendment 108, the Fermi 2 Plant has implemented the approach as described in Regulatory Guide 1.163 "Performance Based Containment Leak Test Program." This program allows the testing periodicity to be extended from the present two year limit for Type B and C tests up to 120 months for Type B test and up to 60 months for Type C tests. Also, the periodicity for Type A test has been extended from 3 every 10 years to once per 10 years. Regulatory Guide 1.163 approves Nuclear Energy Institute (NEI) 94-01, Revision 0, which provides methods acceptable to the NRC staff for complying with provisions of Option B in Appendix J to 10 CFR 50, subject to four exceptions listed in Regulatory Guide 1.163. By License Amendment No. 153, a one-time extension of the Type A test interval to 15 years was implemented. By License Amendment 205, the program was revised for the permanent extension of the Type A test interval to once every 15 years and extension of the Type C test interval up to 75 months. The program is in accordance with NEI 94-01 Revision 3-A, dated July 2012, and the limitations and conditions specified in NEI 94-01 Revision 2-A, dated October 2008.

A.1.181 REGULATORY GUIDE 1.181 (SEPTEMBER 1999), CONTENT OF THE UPDATED FINAL SAFETY ANALYSIS REPORT IN ACCORDANCE WITH 10 CFR 50.71 (e)

Fermi 2 complies with the general intent of this regulatory guide. Regulatory Guide 1.181 endorses the use of NEI 98-03, "Guidelines for Updating Final Safety Analysis Reports," dated June 1999 as an acceptable method for complying with the provisions of 10 CFR 50.71(e).

A.1.183 REGULATORY GUIDE 1.183 (JULY 2000) ALTERNATIVE RADIOLOGICAL SOURCE TERMS FOR EVALUATING DESIGN BASIS ACCIDENTS AT NUCLEAR POWER REACTORS

The analyses of the control rod drop accident, as discussed in Section 15.4.9, loss of coolant accidents, in general, as discussed in Section 15.6.5, and fuel-handling accidents involving fuel that meets the burnup specification associated with Table 3, Footnote 11 of this regulatory guide, as discussed in Subsection 15.7.4, conform with the regulatory position of this guide.

Analyses of the radiological consequences associated with other Fermi 2 design basis accidents do not conform to the assumptions and methodologies of this regulatory guide.

A.1.196 REGULATORY GUIDE 1.196 (May 2003) CONTROL ROOM HABITABILITY AT LIGHT-WATER NUCLEAR POWER REACTORS

Fermi 2 complies with the guidance set forth in this regulatory guide with the following exceptions:

Positions 2.1 and 2.2: The identification of the licensing bases for CRH and determination of whether CRH is consistent with the licensing bases were completed in the response to Generic Letter 2003-01, “Control Room Habitability.”

The levels of compliance to other Regulatory Guides referenced in Regulatory Guide 1.196 are discussed in applicable sections of UFSAR Appendix A.

A.1.197 REGULATORY GUIDE 1.197 (May 2003) DEMONSTRATING CONTROL ROOM ENVELOPE INTEGRITY AT NUCLEAR POWER REACTORS

Fermi 2 complies with the guidance set forth in this regulatory guide with the following exceptions:

Component Testing described in section C.1.2 and Alternate Test Methods in section C.1.3 are not performed at Fermi 2.

A.4 DIVISION 4 APPLICABLE REGULATORY GUIDES

A.4.1 REGULATORY GUIDE 4.1 (April 1975, Revision 1), PROGRAMS FOR MONITORING RADIOACTIVITY IN THE ENVIRONS OF NUCLEAR POWER PLANTS

Fermi 2's Radiological Environmental Monitoring Program complies with the regulatory guidance of Revision 1 of the NRC Radiological Assessment Branch's Position on the radiological portion of Regulatory Guide 4.8's environmental monitoring program, dated November, 1979.

A.4.2 REGULATORY GUIDE 4.2 (July 1976, Revision 2), PREPARATION OF ENVIRONMENTAL REPORTS FOR NUCLEAR POWER STATIONS

Edison filed an Environmental Report and proposed Technical Specifications - Operating License Stage in April, 1975; Supplement 4 was filed in February 1978. The format of the Environmental Report (OL) does not conform to Revision 2; however, the information contained within the report and its supplements conforms to the requirements of Regulatory Guide 4.2 as it applies to the application for an operating license.

A.4.4 REGULATORY GUIDE 4.4 (May 1974), REPORTING PROCEDURE FOR MATHEMATICAL MODELS SELECTED TO PREDICT HEATED EFFLUENT DISPERSION IN NATURAL WATER BODIES

Fermi 2 conforms to the requirements of this guide. The mathematical models used to analyze the thermal plume from the Fermi 2 discharge into Lake Erie are in accordance with the reporting format as set forth in Regulatory Guide 4.4.

For details refer to Sections 5.1 and 6.1 of the Environmental Report.

A.4.6 REGULATORY GUIDE 4.6 (May 1974), MEASUREMENTS OF RADIONUCLIDES IN THE ENVIRONMENT--STRONTIUM-89 AND STRONTIUM-90 ANALYSIS

Compliance with the intent of Regulatory Guide 4.6 is a component of the Fermi 2 Operational Environmental Radiological Monitoring Program criteria specifications.

A.4.8 REGULATORY GUIDE 4.8 (December 1975), ENVIRONMENTAL TECHNICAL SPECIFICATIONS FOR NUCLEAR POWER PLANTS

Fermi 2's Radiological Environmental Monitoring Program complies with the regulatory guidance of Revision 1 of the NRC Radiological Assessment Branch's Position on the radiological portion of Regulatory Guide 4.8's environmental monitoring program, dated November 1979.

A.4.10 REGULATORY GUIDE 4.10 (June 1976, Revision 1), IRREVERSIBLE AND IRRETRIEVABLE COMMITMENTS OF MATERIAL RESOURCES

The Fermi 2 ER(OL) does not conform to Regulatory Guide 4.10.

A.4.11 REGULATORY GUIDE 4.11 (August 1977, Revision 1), TERRESTRIAL ENVIRONMENTAL STUDIES FOR NUCLEAR POWER STATIONS

The Fermi 2 baseline studies and construction monitoring do not conform to Regulatory Guide 4.11, as they were in effect prior to issuance of the guide. The preoperational and operational programs conform to the intent of Regulatory Guide 4.11 as it applies to the site.

A.4.13 REGULATORY GUIDE 4.13 (July 1977, Revision 1, Issued for Comment), PERFORMANCE, TESTING, AND PROCEDURAL SPECIFICATIONS FOR THERMOLUMINESCENCE DOSIMETRY: ENVIRONMENTAL APPLICATIONS

Compliance with the intent of Regulatory Guide 4.13 is a component of the Fermi 2 Operational Environmental Radiological Monitoring Program criteria specifications.

A.4.15 REGULATORY GUIDE 4.15 (December 1977), QUALITY ASSURANCE FOR RADIOLOGICAL MONITORING PROGRAMS (NORMAL OPERATIONS)--EFFLUENT STREAMS AND THE ENVIRONMENT

Compliance with the intent of Regulatory Guide 4.15 is a component of the Fermi 2 Operational Environmental Radiological Monitoring Program criteria specifications.

A.4.16 REGULATORY GUIDE 4.16 (March 1978), MEASURING, EVALUATING, AND REPORTING RADIOACTIVITY IN RELEASES OF RADIOACTIVE MATERIALS IN LIQUID AND AIRBORNE EFFLUENTS FROM NUCLEAR FUEL PROCESSING AND FABRICATION PLANTS

Regulatory Guide 4.16 is not applicable to electric power production facilities.

A.5 DIVISION 5 APPLICABLE REGULATORY GUIDES

A.5.7 REGULATORY GUIDE 5.7 (May 1980, Revision 1), ENTRY/EXIT CONTROL FOR PROTECTED AREAS, VITAL AREAS, AND MATERIAL ACCESS AREAS

Not applicable.

A.5.12 REGULATORY GUIDE 5.12 (November 1973), GENERAL USE OF LOCKS IN THE PROTECTION AND CONTROL OF FACILITIES AND SPECIAL NUCLEAR MATERIALS

The use of locks at Fermi 2 conforms to the general intent of Regulatory Guide 5.12; however, there are some variations from the criteria contained within the guide. The use of locks at Fermi 2 is described in the Fermi 2 Physical Security Plan.

A.5.15 REGULATORY GUIDE 5.15 (January 1974), SECURITY SEALS FOR THE PROTECTION AND CONTROL OF SPECIAL NUCLEAR MATERIAL

Edison will conform to the requirements of this guide when use of locks and seals is necessary in the Fermi 2 plant.

A.5.17 REGULATORY GUIDE 5.17 (January 1974), TRUCK IDENTIFICATION MARKINGS

This guide does not apply to Edison. When special nuclear material is shipped from Fermi 2 it will be shipped in contractor vehicles to which this guide will apply.

This Regulatory Guide has been withdrawn.

A.5.20 REGULATORY GUIDE 5.20 (January 1974), TRAINING, EQUIPPING, AND QUALIFYING OF GUARDS AND WATCHMEN

Appendix B to 10 CFR 73 was promulgated subsequent to the issuance of this regulatory guide and covers the same subject. Edison will comply with 10 CFR 73, Appendix B.

A.5.29 REGULATORY GUIDE 5.29 (June 1975, Revision 1), NUCLEAR MATERIAL CONTROL SYSTEMS FOR NUCLEAR POWER PLANTS

Edison will provide the control necessary to insure that special nuclear material is properly accounted for in accordance with the applicable sections of 10 CFR 74 and not specifically ANSI N15.8.

A.5.32 REGULATORY GUIDE 5.32 (May 1975, Revision 1), COMMUNICATION WITH TRANSPORT VEHICLES

The requirements of Regulatory Guide 5.32 do not apply to Fermi 2. Regulatory Guide 5.32 references certain paragraphs of 10 CFR 73, specifically 73.1(b)(2), which exempt conformance to this guide.

A.5.43 REGULATORY GUIDE 5.43 (January 1975), PLANT SECURITY FORCE DUTIES

The Fermi 2 Physical Security Plan is not designed to conform specifically to Regulatory Guide 5.43.

The Fermi 2 Physical Security Plan, including security force duties, conforms to 10 CFR 73, Section 73.55, "Requirements for Physical Protection of Licensed Activities in Nuclear Power Reactors Against Industrial Sabotage. NEI 03-12, Revision 1, was used to develop the plan.

For additional information refer to Section 13.7.

This Regulatory Guide has since been withdrawn (as of April 2020).

A.5.44 REGULATORY GUIDE 5.44 (October 1997, Revision 3), PERIMETER INTRUSION ALARM SYSTEMS

The design of the perimeter intrusion detection system at Fermi 2 conforms to the general intent of the suggestions contained in Regulatory Guide 5.44; however, there are some variations from the suggested criteria contained within the guide.

The perimeter intrusion detection system is described in the Fermi 2 Physical Security Plan and Safeguards Contingency Plan. The Physical Security Plan describes what type of sensors were installed, where they were installed, and how the system effectiveness will be evaluated.

For additional information refer to Section 13.7.

A.5.57 REGULATORY GUIDE 5.57 (June 1980, Revision 1), SHIPPING AND RECEIVING CONTROL OF STRATEGIC SPECIAL NUCLEAR MATERIAL

Edison will conform to the requirements of this guide when shipping spent nuclear fuel as required by 10 CFR 73.1(b)(5).

A.5.71 REGULATORY GUIDE 5.71 (January 2010, Revision 0), CYBER SECURITY PROGRAMS FOR NUCLEAR FACILITIES

The Fermi 2 Cyber Security Program and Cyber Security Plan are not designed to conform specifically to Regulatory Guide 5.71. The Fermi 2 Cyber Security Plan was approved by the NRC License Amendment 185. The Fermi 2 Cyber Security Program, including the Cyber Security Plan, conforms to 10 CFR 73, Section 73.54, “Protection of digital computer and communication systems and networks”. NEI 08-09, Revision 6, “Cyber Security Program for Nuclear Power Reactors” was used to develop the Cyber Security Plan.

A.8 DIVISION 8 APPLICABLE REGULATORY GUIDES

A.8.1 REGULATORY GUIDE 8.1 (February 1973), RADIATION SYMBOL

Fermi 2 is in conformance with the requirements of this regulatory guide. For details refer to Subsection 12.1.1.3.

A.8.2 REGULATORY GUIDE 8.2 (February 1973), GUIDE FOR ADMINISTRATIVE PRACTICES IN RADIATION MONITORING

Fermi 2 is in conformance with the requirements of this regulatory guide. For details refer to Chapters 11, 12, and 13.

A.8.3 REGULATORY GUIDE 8.3 (February 1973), FILM BADGE PERFORMANCE CRITERIA

This Regulatory Guide has since been withdrawn (as of January 1998).

A.8.4 REGULATORY GUIDE 8.4 (June 2011, Revision 1), DIRECT READING AND INDIRECT READING POCKET DOSIMETERS

Edison is in conformance with the requirements of this regulatory guide.

A.8.5 REGULATORY GUIDE 8.5 (February 1973), IMMEDIATE EVACUATION SIGNAL

Fermi 2 complies with the intent of this guide. The two systems described below accomplish the objectives of the guide.

Area radiation monitors (ARMs) are provided for the entire plant and include "criticality" monitors for the fuel storage pool and new-fuel vault areas. These two monitors each have a local audible alarm and other features such as control room annunciation and recorder input, fast response time, and seal-in alarm circuitry. Subsection 12.1.4 describes the ARM system in more detail.

Beyond these dedicated ARM channels is the emergency alarm system, which provides a signal to ensure personnel evacuation. The emergency alarm system is described in Subsection 9.5.2 and is discussed in the Radiological Emergency Response Preparedness Plan.

Both the ARM and the emergency alarm systems are subject to initial and periodic tests performed as part of the preoperational test and surveillance programs.

A.8.6 REGULATORY GUIDE 8.6 (May 1973), STANDARD TEST PROCEDURE FOR GEIGER-MUELLER COUNTERS

Fermi 2 is in conformance with the requirements of this regulatory guide.

A.8.7 REGULATORY GUIDE 8.7 (May 1973), OCCUPATIONAL RADIATION EXPOSURE RECORDS SYSTEMS

Fermi 2 is in conformance with the requirements of this regulatory guide. For details refer to Subsection 12.3.4.3.

A.8.8 REGULATORY GUIDE 8.8 (June 1978, Revision 3), INFORMATION RELEVANT TO ENSURING THAT OCCUPATIONAL RADIATION EXPOSURES AT NUCLEAR POWER STATIONS WILL BE AS LOW AS IS REASONABLY ACHIEVABLE

Fermi 2 is in conformance with the requirements of this regulatory guide. For details refer to Subsection 12.3.1.

A.8.9 REGULATORY GUIDE 8.9 (September 1973), ACCEPTABLE CONCEPTS, MODELS, EQUATIONS, AND ASSUMPTIONS FOR A BIOASSAY PROGRAM

Fermi 2 is in compliance with the requirements of this regulatory guide. For details refer to Subsection 12.3.1.

A.8.10 REGULATORY GUIDE 8.10 (September 1975, Revision 1), OPERATING PHILOSOPHY FOR MAINTAINING OCCUPATIONAL RADIATION EXPOSURES AS LOW AS IS REASONABLY ACHIEVABLE

Fermi 2 is in compliance with the requirements of this regulatory guide. For details refer to Subsection 12.3.1.

A.8.12 REGULATORY GUIDE 8.12 (December 1974), CRITICALITY ALARM SYSTEMS

This regulatory guide is based on a combination of 10 CFR 70, Section 70.24, "Criticality Accident requirements," ANS N16.1-1969, "Criticality Accident Alarm System," with Section 70.24 taking precedence. Fermi 2 complies with the regulatory positions as follows:

a. Criticality Monitoring on the Refuel Floor

   The refuel floor is located on the fifth floor of the reactor building. Monitoring for an inadver-tent criticality event on the refuel floor is provided by two redundant detectors (D21-N115 and D21-N117). These detectors are high sensitivity gamma ray detectors (GM tubes) and are located on the east wall approximately 9 ft to 12 ft in the air. The alarm trip setting on these detectors is in the proscribed range of 5-20 mR/hr, which is adequate to detect the minimum accident of concern as described in 10 CFR 70.24 and ANSI/ANS 8.3-1986. The alarm circuitry of these detectors is arranged in a fail safe mode such that any malfunction of the detectors or a loss of power results in an alarm condition. Additionally, the detectors have a meter pegging circuit which precludes a downscale low reading (foldover) during saturation of the GM tube due to high intensity radiation fields. Periodic performance tests are conducted to confirm instrument response to radiation and the operability of the alarm signal generator. The aforementioned design meets the criterion of GDC 63, "Monitoring Fuel and Waste Storage." Moreover, Fermi 2 personnel are instructed to evacuate areas in which radiation or criticality alarms are activated. Evacuation of plant areas is periodically tested by the conduct of emergency response drills.

b. Handling and Transporting New Fuel in the Yard and Reactor Building During Transit to the Refuel Floor

   A criticality safe analysis has been performed for safe storage and transport of GE BWR nuclear fuel shipping containers during new fuel receipt for Fermi 2. The analysis provides assurance that an inadvertent criticality is highly improbable during onsite storage, handling and transportation of new fuel within shipping containers. This meets the criterion of GDC 62, "Prevention of Criticality in Fuel Storage and Handling." The safety analysis is the bases for Fermi 2's exemption from the requirements of 10 CFR 70.24, as granted by the Nuclear Regulatory Commission as identified by reference numbers 9 and 10 herein. The exemption requires criticality monitoring in areas where new fuel is handled outside the inner metal shipping containers. In contrast, the exemption allows administrative controls, such as the use of geometrically safe configurations as bound by the aforesaid safety analysis for areas in which the new fuel remains in the inner metal shipping containers.

c. Criticality Monitoring for the New Fuel Storage Vault

Due to lack of detector redundancy, Fermi 2 does not strictly comply to 10 CFR 70.24 with regard to storage of new fuel in the new fuel storage vault. Accordingly, the fuel pool is used for storage of new fuel rather than the new fuel storage vault. New fuel vault personnel entries require monitoring as governed by plant procedures. The single detector (D21-N116) in the new fuel storage vault is adequate to detect the minimum accident of concern as described in 10 CFR 70.24. This fail safe monitor is located below the 1.5 ft thick concrete floor of the concrete floor of the vault with an alarm trip setting of greater or equal to 5 mR/hr and less than or equal to 20 mR/hr. Calculations indicate this monitor is adequate for the representative critical dose data for a design basis criticality accident. Periodic tests are performed to confirm instrument response to radiation. In addition, a field test of each alarm signal generator is made periodically. During these tests, clarity of the alarm above area background noise will be ascertained.

d. Criticality Monitoring for Calibration Sources and Incore Instrumentation Not in Use

Additionally, the aforementioned NRC exemption states that the quantity of other forms of special nuclear material that is stored onsite in any given location at Fermi 2 (e.g., calibration sources and incore instrumentation that is not in use) is small enough to preclude achieving a critical mass, thus not requiring criticality monitoring.

A.8.13 REGULATORY GUIDE 8.13 (November 1975, Revision 1), INSTRUCTION CONCERNING PRENATAL RADIATION EXPOSURE

Fermi 2 is in conformance with the requirements of this regulatory guide.

A.8.14 REGULATORY GUIDE 8.14 (August 1977, Revision 1), PERSONNEL NEUTRON DOSIMETERS

Fermi 2 is in conformance with the requirements of this regulatory guide. For details refer to Subsection 12.3.4.

A.8.15 REGULATORY GUIDE 8.15 (October 1976), ACCEPTABLE PROGRAMS FOR RESPIRATORY PROTECTION

Fermi 2 is in conformance with the requirements of this regulatory guide. For details refer to Subsection 12.3.2.2.2.

A.8.26 REGULATORY GUIDE 8.26 (September 1980), APPLICATIONS OF BIOASSAY FOR FISSION AND ACTIVATION PRODUCTS

The Fermi 2 bioassay program is in conformance with the requirements of this regulatory guide. For details refer to Subsection 12.3.4.2.

REFERENCES

1. Detroit Edison Letter NRC-89-0148, “Additional Clarification to Fermi 2 Compliance to Regulatory Guide 1.97, Revision 2,” dated June 19, 1989.
2. Detroit Edison Letter NRC-89-0201, “Regulatory Guide 1.97 Revision 2 Design Review”, dated September 12, 1989.
3. NRC Letter, “Emergency Response Capability - Conformance to Regulatory Guide 1.97 Revision 2 - (TAC No. 59620),” dated May 2, 1990.
4. Detroit Edison Letter NRC-90-0095, “Compliance with Regulatory Guide 1.97, Revision 2 (TAC No. 59620),” dated June 6, 1990.
5. NRC Letter, “Inspection Report - Report No. 50-341/91014 (DRS)”, dated July 16, 1991.
6. Detroit Edison Letter NRC-91-0098, Regulatory Guide 1.97 Supplemental Information, dated July 31, 1991.
7. Detroit Edison Letter NRC-93-0105, “Fermi 2 Review of Neutron Monitoring System Against Criteria of NEDO-31558A,” dated September 28, 1993.
8. NRC Letter, “Regulatory Guide 1.97 - Boiling Water Reactor Neutron Flux Monitoring-Fermi 2 (TAC No. M59620),” dated February 17, 1994.
9. Detroit Edison Letter NRC-98-0063, "Request for Exemption from 10 CFR 70.24, Criticality Accident Requirements," dated April 27, 1998.
10. NRC Letter, "Fermi 2 - Issuance of Exemption from the Requirements of 10 CFR 70.24 (TAC No. MA1645)," dated June 2, 1998.
11. NRC Letter, “Fermi 2 - Issuance of Amendment RE: Thermal- Hydraulic Stability, Idle Recirculation Loop Startup, and Post-Accident Monitoring (TAC No. MA0721),” dated September 16, 1998.
12. Fermi 2 Technical Specifications Amendment 159, dated March 15, 2004 with NRC Safety Evaluation.

B. AGING MANAGEMENT PROGRAMS AND ACTIVITIES

The Fermi 2 license renewal application (Reference B.3-1) and information in subsequent related correspondence provided sufficient basis for the NRC to make the findings required by 10 CFR 54.29 (Reference B.3-2). As required by 10 CFR 54.21(d), this UFSAR supplement contains a summary description of the programs and activities for managing the effects of aging (Section B.1) and a description of the evaluation of time-limited aging analyses for the period of extended operation (Section B.2). The period of extended operation is the 20 years after the expiration date of the original operating license for Fermi 2.

B.1 AGING MANAGEMENT PROGRAMS

The integrated plant assessment for license renewal identified aging management programs necessary to provide reasonable assurance that components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis (CLB) for the period of extended operation. This section describes the aging management programs and activities required during the period of extended operation.

Aging management programs will be implemented prior to entering the period of extended operation. For programs requiring enhancements, the programs are described as including the features that will be in place when the enhancements are fully implemented. Each description lists the enhancements required for the program as it existed when the license renewal application was submitted.

Conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment and nonconformances, are promptly identified and corrected. In the case of significant conditions adverse to quality, measures are implemented to ensure that the cause of the condition is determined and that corrective action is taken to preclude recurrence. In addition, the identification and cause of the significant condition adverse to quality and the corrective action implemented is documented and reported to appropriate levels of management. The corrective action controls of the Fermi 2 Quality Assurance Program (10 CFR Part 50, Appendix B) are applicable to all aging management programs and activities required during the period of extended operation.

Corrective actions for systems, structures and components are accomplished per the existing Fermi 2 Corrective Action Program and Fermi 2 procedures. The site Corrective Action Program and procedure control program apply to license renewal aging management activities for both safety-related and nonsafety-related structures and components.

The confirmation process is part of the Corrective Action Program and includes the following:

- Reviews to assure that proposed actions are adequate for conditions adverse to quality.
- Tracking and reporting of open corrective actions.
- Review of corrective action effectiveness for significant conditions adverse to quality.

If the confirmation process leads to a corrective action requiring inspection or testing, the corrective action will be documented in accordance with the Corrective Action Program. The Corrective Action Program constitutes the confirmation process for the Fermi 2 aging management programs and activities.

Fermi 2 quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR 50, Appendix B. The Fermi 2 QA Program applies to safety-related structures and components. The phrase "Administrative Controls" refers to the adherence to the policies, directives, and procedures and includes the formal review and approval process that procedures and manuals undergo as they are issued and subsequently revised. The Fermi 2 QA Program aspects related to procedure controls and administrative controls (document control requirements for procedures and manuals) and retention of records apply to Fermi 2 aging management activities associated with license renewal for both safety-related and nonsafety-related structures, systems, and components.

The Operating Experience program (OEP) at Fermi 2 and the Corrective Action Program help to assure continued effectiveness of aging management programs through evaluations of operating experience. The OEP implements the requirements of NRC NUREG-0737, *Clarification of TMI Action Plan Requirements*, Section l.C.5, and evaluates site and industry operating experience for impact on Fermi 2. The Corrective Action Program implements the requirements of 10 CFR 50, Appendix B, Criterion XVI and is used to evaluate and effect appropriate actions in response to operating experience relevant to Fermi 2 that indicates a condition adverse to quality or a nonconformance.

Revisions to NUREG-1801, *Generic Aging Lessons Learned (GALL) Report*, and other NRC guidance documents on aging management are considered sources of operating experience.

The operating experience program interfaces with and relies on active participation in the Institute of Nuclear Power Operations' operating experience program, as endorsed by the NRC.

In accordance with procedure, incoming operating experience items are screened to identify items that may involve age-related degradation or impact to aging management programs (AMPs), including programs being developed. Items so identified are further evaluated, and AMPs are either enhanced or new AMPs are developed, as appropriate, when it is determined through these evaluations that the effects of aging may not be adequately managed.

Plant-specific operating experience associated with aging management and age-related degradation is reported to the industry in accordance with guidelines established in the operating experience program.

DTE will make the following changes to the process for operating experience review (OER).

- Procedures will be revised to add an aging type code to Corrective Action Program documents that describe either plant conditions related to aging or industry operating experience related to aging.
- Procedures will be revised to provide for training of personnel responsible for submitting, screening, assigning, evaluating, or otherwise processing plant-specific and industry operating experience concerning age-related degradation and aging

management, as well as for personnel responsible for implementing AMPs, based on the complexity of the job performance requirements and assigned responsibilities.

- Procedures will be revised to specify that evaluations of operating experience concerning age-related degradation will include consideration of the affected systems, structures or components, the environments, materials, aging effects, aging mechanisms, and aging management programs.

DTE currently performs periodic self-assessments on many aging management programs. DTE will enhance the Fermi 2 self-assessment process to provide for periodic evaluation of the effectiveness of each aging management program described in the UFSAR supplement. For new aging management programs, the first evaluation will be performed within five years of implementing the program.

B.1.1 ABOVEGROUND METALLIC TANKS PROGRAM

The Aboveground Metallic Tanks Program is a new program that will manage loss of material and cracking for outdoor tanks within the scope of license renewal that are sited on soil or concrete. Preventive measures to mitigate corrosion and cracking were applied during construction, such as using the appropriate materials, protective coatings, and elevation as specified in design and installation specifications. For the insulated aluminum condensate storage tank (CST), the program will monitor the condition of a representative sample of the tank external surface for signs of loss of material, using visual inspections and surface examinations. Internal and external portions of the CST will be inspected in accordance with Table 4a, "Tank Inspection Recommendations," identified in LR-ISG-2012-02. There are no indoor tanks included in this program.

This program will also manage the bottom surface of the CST, which is on a concrete ring foundations and sand. The program will require ultrasonic testing (UT) of the tank bottoms to assess the thickness against the thickness specified in the design specification. UT of the tank bottoms will be performed whenever the tank is drained or at intervals not less than those recommended in Table 4a during the period of extended operation. Caulking or sealant at the concrete/tank interfaces is not credited in the installation and design specifications.

Within the ten years prior to the period of extended operation and every ten years thereafter, a volumetric examination of a minimum 25% of the CST tank bottom interface with the concrete ring foundation will be performed to manage loss of material. The volumetric inspection will be on a 2” grid or less, depending on the technology utilized.

This program will be implemented prior to the period of extended operation, with initial inspections within the ten years prior to the period of extended operation. The combustion turbine generator (CTG) fuel oil tank is in-scope for this program but inspections are not required since the tank was replaced in 2019.

B.1.2 BOLTING INTEGRITY PROGRAM

The Bolting Integrity Program manages loss of preload, cracking, and loss of material for closure bolting for safety-related and nonsafety-related pressure-retaining components using preventive and inspection activities. This program does not include the reactor head closure studs or structural bolting. Preventive measures include material selection (e.g., use of materials with an actual yield strength of less than 150 kilo-pounds per square inch [ksi]), lubricant selection (e.g., restricting the use of molybdenum disulfide), applying the appropriate preload (torque), and checking for uniformity of gasket compression where appropriate to preclude loss of preload, loss of material, and cracking. This program supplements the inspection activities required by ASME Section XI for ASME Class 1, 2, and 3 bolting. For ASME Class 1, 2, and 3 bolting and non-ASME Code class bolts, periodic system walkdowns and inspection (at least once per refueling cycle) ensure identification of indications of loss of preload (leakage), cracking, and loss of material before leakage becomes excessive. Identified leaking bolted connections will be monitored at an increased frequency in accordance with the corrective action process. Applicable industry standards and guidance documents, including NUREG-1339, EPRI NP-5769, and EPRI TR-104213, are used to delineate the program.

The Bolting Integrity Program will be enhanced as follows.

- Revise Bolting Integrity Program procedures to perform opportunistic inspections for Control Center HVAC system safety-related pressure-retaining bolting in a lube oil external environment, including the bolting threads to ensure that loss of material in crevice locations that are not readily visible can be detected.
- Revise Bolting Integrity Program procedures to perform opportunistic inspections for CTG system nonsafety-related pressure-retaining bolting in a lube oil external environment.
- Revise Bolting Integrity Program procedures to ensure consideration of actual yield strength when procuring high-strength bolting material. If procured, closure bolting with actual yield strength greater than or equal to 150 ksi is monitored for cracking.
- Revise Bolting Integrity Program procedures to state that bolting for safety-related pressure-retaining components is inspected for leakage, loss of material, cracking, and loss of preload/loss of prestress. Closure bolting with actual yield strength greater than or equal to 150 ksi is monitored for cracking.
- Revise Bolting Integrity Program procedures to (1) implement applicable recommendations for pressure boundary bolting in NUREG-1339, EPRI NP-5769, and EPRI TR-104213; (2) state both ASME Code class bolted connections and non-ASME Code class bolted connections are inspected at least once per refueling cycle; and (3) include volumetric examination per ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1, for closure bolting with actual yield strength greater than or equal to 150 ksi regardless of code classification.
- Revise Bolting Integrity Program procedures to inspect RHRSW, EESW, and EDGSW systems' pump and valve bolting submerged in the RHRSW reservoir at least once every refueling outage and to opportunistically inspect bolting threads during maintenance activities.
- Revise Bolting Integrity Program procedures to include the additional guidance and recommendations of EPRI NP-5769 for replacement of ASME pressure-

retaining bolts and the guidance provided in EPRI TR-104213 for the replacement of other pressure-retaining bolts.

- Revise Bolting Integrity Program procedures to stipulate that administrative controls are in accordance with the Fermi 2 10 CFR 50 Appendix B Quality Assurance Program.

Enhancements will be implemented prior to the period of extended operation.

B.1.3 BORAFLEX MONITORING PROGRAM

The Boraflex Monitoring Program is an existing program to manage the Boraflex material affixed to the spent fuel storage racks. This program is currently required by Technical Specification 5.5.13 and includes activities implemented in response to NRC GL 96-04 to assure that the required five percent sub-criticality margin is maintained. The Boraflex currently in the spent fuel racks will not be credited for neutron absorption during the period of extended operation and therefore this aging management program will not be relied upon during the period of extended operation. All of the neutron-absorbing material to be credited during the period of extended operation will be managed by the Neutron-Absorbing Material Monitoring Program in Section B.1.27.

B.1.4 BURIED AND UNDERGROUND PIPING PROGRAM

The Buried and Underground Piping Program is a new program that will manage the effects of aging on the external surfaces of buried and underground piping components within the scope of license renewal. The program will manage aging effects of loss of material and cracking for the external surfaces of buried and underground piping fabricated of aluminum, carbon steel, gray cast iron, and stainless steel through preventive and mitigative measures (e.g., coatings, backfill quality, and cathodic protection) and periodic inspection activities during opportunistic or directed excavations. There are no underground or buried tanks for which aging effects would be managed by the Buried and Underground Piping Program. Fermi 2 utilizes a cathodic protection system. Fermi 2 has performed preliminary laboratory soil composition analyses on samples removed from the site to evaluate the potential corrosivity of the soil for use in life cycle management.

Inspections are conducted by qualified individuals. Where the coatings, backfill or the condition of exposed piping does not meet acceptance criteria such that the depth or extent of degradation of the base metal could have resulted in a loss of pressure boundary function when the loss of material rate is extrapolated to the end of the period of extended operation, an increase in the sample size is conducted. Soil testing will be conducted once in each ten-year period starting ten years prior to the period of extended operation, if a reduction in the number of inspections recommended in Table XI.M41-2 of NUREG-1801, is taken based on a lack of soil corrosivity.

When using the 100 mV, -750 mV or -650 polarization criteria as an alternative to the -850 mV criterion, for steel piping, electric resistance probes (ERPs) will be installed in select locations as determined by a Cathodic Protection Specialist. The ERPs will be made of the most anodic metal in the system to ensure adequate protection of the most anodic system metal. Concurrent with the ERPs, permanent reference cells and reference metal will be installed. Installation of the permanent reference cells at pipe depth and near the piping of interest will allow for an accurate measurement of pipe-to-soil potential, minimizing the influence of mixed metals. Where used, the electrical resistance probes will be uncoated and placed in the immediate vicinity of the buried piping it is representing. For each installation application, two probes will be installed; one connected to the cathodic protection system and one left unprotected. The test probe left unprotected (not connected to the pipe) will be free of the mixed metals influence.

This program will be implemented prior to the period of extended operation.

B.1.5 BWR CRD RETURN LINE NOZZLE PROGRAM

The BWR Control Rod Drive (CRD) Return Line Nozzle Program manages cracking of the CRD return line nozzle using preventive, mitigative, and inservice inspection activities, in accordance with Fermi 2 commitments to implement the recommendations in NUREG-0619 and ASME Code Section XI, Subsection IWB, Table IWB 2500-1. Examinations that can detect the presence of cracking are performed to assure detection of cracks before the loss of intended function of the CRD return line nozzle. Cracking found during inservice inspection is evaluated in accordance with ASME Code Section XI requirements. The CRD return line nozzle was capped during construction prior to plant operation.

The BWR CRD Return Line Nozzle Program will be enhanced as follows.

- Revise BWR CRD Return Line Nozzle Program procedures as necessary to ensure that ultrasonic test (UT) examinations will be used to detect applicable aging effects.

Enhancements will be implemented prior to the period of extended operation.

B.1.6 BWR FEEDWATER NOZZLE PROGRAM

The BWR Feedwater Nozzle Program manages cracking of the BWR feedwater nozzles using inspection activities to monitor the effects of cracking due to cyclic loading.

This program augments the examinations specified in the ASME Code, Section XI, with the recommendation and schedule of General Electric NE-523-A71-0594, Revision 1, and NUREG-0619 to perform periodic testing of critical regions of the BWR feedwater nozzles. The feedwater nozzles were never clad and include the improved sparger design. Cracking is evaluated and dispositioned in accordance with the ASME Code.

B.1.7 BWR PENETRATIONS PROGRAM

The BWR Penetrations Program manages cracking due to cyclic loading or stress corrosion cracking (SCC) and intergranular SCC (IGSCC) of BWR instrument penetrations, control rod drive (CRD) housing and incore housing (ICH) penetrations, and standby liquid control (SLC) nozzles/core ΔP nozzles.

Leakage inspections (VT-2) and ultrasonic inspections are scheduled and performed, flaws are evaluated, scope is expanded as required, and acceptance criteria are provided in accordance with the guidelines of the ASME Code Section XI and NRC-approved BWRVIP-49-A, BWRVIP-47-A, and BWRVIP-27-A.

B.1.8 BWR STRESS CORROSION CRACKING PROGRAM

The BWR Stress Corrosion Cracking Program manages intergranular stress corrosion cracking (IGSCC) in stainless steel or nickel alloy reactor coolant pressure boundary piping and piping welds 4 inches or larger in nominal diameter containing reactor coolant at a temperature above 93°C (200°F) during power operation, regardless of code classification.

Scheduled volumetric examinations provide timely detection of IGSCC and leakage of coolant in accordance with the methods, inspection guidelines, and flaw evaluation criteria delineated in the ASME Code; NUREG-0313, Rev. 2; NRC GL 88-01 and its Supplement 1; NRC-approved BWRVIP-75-A; and other requirements specified per 10 CFR 50.55a with NRC-approved alternatives. Ten percent of the feedwater and condensate systems Category D welds are inspected each refueling outage unless 100% of the welds have already been inspected in the Inservice Inspection Interval.

The program includes preventive measures such as induction heating stress improvement, solution annealing, and mechanical stress improvement process to minimize stress corrosion cracking.

B.1.9 BWR VESSEL ID ATTACHMENT WELDS PROGRAM

The BWR Vessel ID [inside diameter] Attachment Welds Program manages cracking in structural welds for BWR reactor vessel internal integral attachments using inspections, scheduling, acceptance criteria, and flaw evaluation in conformance with the requirements of ASME Section XI and guidelines of BWRVIP-48-A. The program includes welds between the vessel wall and vessel ID brackets that attach components to the vessel. The internal attachment weld can be a simple weld or a weld build-up pad on the vessel.

B.1.10 BWR VESSEL INTERNALS PROGRAM

The BWR Vessel Internals Program manages cracking, loss of material due to wear, and reduction of fracture toughness for BWR vessel internal components using inspection and flaw evaluation. The program provides (1) determination of the susceptibility of cast austenitic stainless steel components, (2) accounting for the synergistic effect of thermal aging and neutron irradiation, and (3) implementation of a supplemental examination program, as necessary.

Applicable industry standards and NRC-approved BWRVIP documents provide the basis for scheduling inspections to provide timely detection of aging effects, appropriate NDE inspection techniques, acceptance criteria, flaw evaluation, and repair/replacement, as needed. At Fermi 2, management of the reactor vessel internals is implemented in accordance with ASME Section XI and BWRVIP-94, "BWR Vessel and Internals Project, Program Implementation Guide".

The crack growth rate evaluations and fracture toughness values specified in BWRVIP-14-A, BWRVIP-99-A, and BWRVIP-100-A are used for cracked core shroud welds exposed to the neutron fluence values specified in these BWRVIP reports.

This program also addresses aging degradation of CASS and X-750 alloy. Fermi 2 did not use precipitation-hardened (PH) martensitic stainless steel (e.g., 15-5 and 17-4 PH steel) materials and martensitic stainless steel (e.g., 403, 410, 431 steel) in BWR vessel internal components.

The BWR Vessel Internals Program will be enhanced as follows.

- The susceptibility to neutron or thermal embrittlement for reactor vessel internal components composed of CASS and X-750 alloy will be evaluated.
- BWR Vessel Internals Program procedures will be revised as follows. Portions of the susceptible components determined to be limiting from the standpoint of thermal aging susceptibility, neutron fluence, and cracking susceptibility (i.e., applied stress, operating temperature, and environmental conditions) will be inspected, using an inspection technique capable of detecting the critical flaw size with adequate margin. The critical flaw size will be determined based on the service loading condition and service-degraded material properties. The initial inspection will be performed either prior to or within five years after entering the period of extended operation. If cracking is detected after the initial inspection, the frequency of re-inspection will be justified based on fracture toughness properties appropriate for the condition of the component. The sample size for the initial inspection of susceptible components will be 100 percent of the accessible component population, excluding components that may be in compression during normal operations.
- BWR Vessel Internals Program procedures will be revised as follows. In accordance with an applicant action item for BWRVIP-25 safety evaluation: (a) install core plate wedges prior to the period of extended operation, or (b) complete a plant-specific analysis that justifies no inspections are required, or (c) complete a plant-specific analysis to determine acceptance criteria for continued inspection of core plate hold-down bolts in accordance with BWRVIP-25.

  For Option (b), the analysis will address loss of preload due to stress relaxation in the core plate rim hold-down bolts and quantify the loss of preload/stress relaxation that will occur in these bolts during the period of extended operation. The analysis will be submitted to the NRC two years prior to the period of extended operation. Additionally, the UFSAR will be revised to address the analysis if it is determined to meet the criteria for a TLAA at least two years prior to the period of extended operation.

  For Option (c), the analysis will address loss of preload due to stress relaxation in the core plate rim hold-down bolts and quantify the loss of preload/stress relaxation that will occur in these bolts during the period of extended operation. The analysis, inspection plan with acceptance criteria, and justification for the inspection plan will be submitted to the NRC two years prior to the period of extended operation. Additionally, the UFSAR will be revised to address the analysis if it is determined to meet the criteria for a TLAA at least two years prior to the period of extended operation.
- Revise BWR Vessel Internals Program procedures such that the flaw evaluation methodology for the top guide grid beam will address the following three items if they have not been resolved generically during the NRC review and approval process of BWRVIP-183:

(1) Detected flaws evaluated using the methodology in BWRVIP-183 Section 4 will be demonstrated to be sufficiently far from geometric discontinuities (i.e. notches or slots) such that the stress condition in the vicinity of the flaw is consistent with that for a single edge-crack plate. Appropriately applied K values which account for the effects of geometric discontinuities will be used and justified in the flaw evaluation.

(2) The flaw evaluation methodology in BWRVIP-183 Section 4 will be used to justify continued operation on a cycle-by-cycle basis. Use of the flaw evaluation methodology to justify operation for more than once cycle will require NRC approval and would be based on plant-specific operating experience including crack length measurements of detected top guide grid beam flaws to benchmark the accuracy of the flaw evaluation methodology.

(3) When applying the flaw evaluation methodology in BWRVIP-183 Section 4, a severed beam evaluation consistent with BWRVIP-183 Section 5 will also be performed. The severed beam analysis will demonstrate that even if a beam was completely severed beam, it would not be expected to interfere with the ability of the control rod drive system to insert control rods.

- Revise BWR Vessel Internals Program procedures to perform opportunistic inspections of the differential pressure and standby liquid control line inside the reactor vessel when the line becomes accessible.

Enhancements will be implemented prior to the period of extended operation.

B.1.11 COMPRESSED AIR MONITORING PROGRAM

The Compressed Air Monitoring Program manages loss of material in compressed air systems by periodically monitoring air samples for moisture and contaminants and by opportunistically inspecting internal surfaces within compressed air systems. Air quality is maintained in accordance with limits established by considering manufacturer recommendations, as well as recommendations in EPRI NP-7079 and TR 108147, ASME OM-S/G-1998 (Part 17), ANSI standard ISA-S7.0.01-1996, and ISA-S7.3. Inspection frequency, acceptance criteria, and design and operating reviews are performed in accordance with NRC GL 88-14. The program was developed using applicable industry standards and documents such as ISA-S7.3, Quality Standard for Instrument Air, for guidance on preventive measures, inspection of components, and testing and monitoring air quality.

Periodic internal visual inspections of critical components (compressors, dryers, after-coolers, filters, etc.) are performed to detect signs of corrosion. Air quality is monitored and trended to determine if alert levels or limits are being approached or exceeded. Dew point testing and trending is performed quarterly. Particulates, dew points, hydrocarbon content, and corrosive contaminants are monitored.

The Compressed Air Monitoring Program will be enhanced as follows.

- Revise Compressed Air Monitoring Program procedures to include periodic and opportunistic inspections of accessible internal surfaces of piping, compressors, dryers, aftercoolers, and filters. In addition, include in the Compressed Air Monitoring Program procedures the applicable provisions recommended in EPRI NP

7079, EPRI TR-108147, and ASME OM-S/G-1998, Part 17 for air system contaminants, inspection frequency, inspection methods, and acceptance criteria for components subject to aging management review that are exposed to compressed air in the emergency diesel generator (EDG) starting air system and control air system.

Enhancements will be implemented prior to the period of extended operation.

B.1.12 CONTAINMENT INSERVICE INSPECTION – IWE PROGRAM

The Containment Inservice Inspection (CII) – IWE Program implements the requirements of 10 CFR 50.55a. The regulations in 10 CFR 50.55a impose the inservice inspection (ISI) requirements of the ASME Boiler and Pressure Vessel (B&PV) Code, Section XI, Subsection IWE, for steel containments (Class MC). The Fermi 2 containment design does not include a concrete containment subject to ASME Section XI, Subsection IWL requirements, and therefore the requirements of Class CC are not applicable. There are no tendons associated with Fermi 2's steel containment vessel. The Fermi 2 primary containment is a General Electric Mark I pressure suppression containment and consists of a drywell, a torus (or suppression chamber), and a vent system connecting the drywell and the torus. The scope of the CII-IWE Program includes the steel containment vessel and its integral attachments, containment equipment hatches and airlock and moisture barriers, and pressure-retaining bolting. Visual inspections monitor loss of material of the steel containment vessel surface areas, including welds and base metal and containment vessel integral attachments, metal shell, personnel and equipment access hatches, and pressure-retaining bolting. The CII-IWE Program specifies acceptance criteria, corrective actions, augmented inspections as required and provisions for expansion of the inspection scope when identified degradation exceeds the acceptance criteria. Appendix J, Type A and Type B testing is performed in lieu of surface examinations of dissimilar metal welds of penetration sleeves, penetration bellows, and torus vent line bellows as allowed as an alternative in NUREG-1801, Section XI.S1. The code of record for the examination of the Fermi 2 containment, Class MC components, and related requirements is in accordance with ASME Code Section XI, Subsections IWE, 2001 Edition with the 2003 Addenda, as mandated and modified by 10 CFR 50.55a.

The CII-IWE Program will be enhanced as follows:

- Revise plant procedures to require inspection of the sand cushion drain lines to monitor the internal conditions of the drain lines (e.g. for moisture, sand, blockage) and ensure there is no evidence of blockage at least once prior to the period of extended operation and once every 10 years during the period of extended operation.
- Revise plant procedures to specify the preventive actions delineated in NUREG-1339 and in EPRI NP-5769, NP-5067, and TR-104213 that emphasize proper selection of bolting material, installation torque or tension, and the use of lubricants and sealants for high strength bolting.
- Revise plant procedures to include the preventive actions for storage of ASTM A325 and A490 bolting from Section 2 of Research Council for Structural Connections publication, "Specification for Structural Joints Using ASTM A325 or A490 Bolts."
- Revise plant procedures to determine drywell shell thickness in the sand cushion areas before the period of extended operation and once in each ten year interval

during the period of extended operation. From the results (including prior results), develop a corrosion rate to demonstrate that the drywell shell will have sufficient wall thickness to perform its intended function through the period of extended operation.

- Revise plant procedures to require corrective actions should moisture be detected or suspected in the inaccessible area on the exterior of the drywell shell, including:
  - Identify surfaces requiring augmented inspections for the period of extended operation in accordance with Subsection IWE-1240, as identified in Table IWE-2500-1, Examination Category E-C.
  - Use examination methods that are in accordance with Subsection IWE-2500.
  - Demonstrate through use of augmented inspections performed in accordance with Subsection IWE that corrosion is not occurring or that corrosion is progressing so slowly that the degradation will not jeopardize the intended function of the drywell shell through the period of extended operation.

Enhancements will be implemented prior to the period of extended operation.

B.1.13 CONTAINMENT LEAK RATE PROGRAM

The Containment Leak Rate Program consists of tests performed in accordance with the regulations and guidance provided in 10 CFR Part 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors," Option B; Regulatory Guide 1.163, "Performance-Based Containment Leak-Testing Program"; NEI 94-01, "Industry Guideline for Implementing Performance-Based Options of 10 CFR Part 50, Appendix J"; and ANSI/ANS 56.8, "Containment System Leakage Testing Requirements." The Containment Leak Rate Program does not prevent degradation but provides measures for detection of pressure boundary degradation in various systems penetrating containment. Corrective actions are taken if leakage rates exceed acceptance criteria. The program also provides for detection of age-related degradation in material properties of gaskets, O-rings, and packing materials for the containment pressure boundary access points.

Three types of tests are performed under Option B. Type A tests are performed to determine the overall primary containment integrated leakage rate at the loss of coolant accident peak containment pressure. Performance of the integrated leakage rate test per 10 CFR Part 50, Appendix J, Option B, demonstrates the leak-tightness and structural integrity of the containment. Type B and Type C containment local leak rate tests (LLRT), as defined in 10 CFR 50, Appendix J, are intended to detect local leaks and to measure leakage across each pressure-containing or leakage-limiting boundary of containment penetrations. Containment leakage rate tests are performed at frequencies that comply with the requirements of 10 CFR Part 50, Appendix J, Option B.

B.1.14 DIESEL FUEL MONITORING PROGRAM

The Diesel Fuel Monitoring Program manages loss of material in piping, tanks, and other components exposed to an environment of diesel fuel oil by verifying the quality of the fuel oil source. This is accomplished by limiting the quantities of contaminants in diesel fuel oil. Parameters monitored include water, sediment, total particulate, biodiesel concentration, and levels of microbiological activity. Sampling is performed before the fuel oil is allowed to enter the fuel oil storage tanks. The program also requires periodic multi-level sampling of fuel oil storage tanks, where possible. Where multi-level sampling cannot be performed, a representative sample is taken from the lowest part of the tank. If biological activity is identified, biocides are added to prevent biological activity.

Effectiveness of the program is periodically verified by inspecting low flow areas where contaminants may collect, such as in the bottom of tanks. The tanks are periodically sampled, drained, cleaned, and internally inspected for signs of moisture, contaminants and corrosion. Internal tank inspections will be performed at least once during the ten-year period prior to the period of extended operation, and at least once every ten years during the period of extended operation. Where degradation is observed, a wall thickness determination will be made, and the extent of the condition is determined as a part of the Corrective Action Program. Applicable industry standards and guidance documents are used to establish inspection frequency, if not specified by the Fermi 2 Technical Specifications Surveillance Frequency Control Program.

The One-Time Inspection Program describes inspections planned to verify that the Diesel Fuel Monitoring Program has been effective at managing aging effects.

The Diesel Fuel Monitoring Program will be enhanced as follows.

- Revise Diesel Fuel Monitoring Program procedures to monitor and trend water and sediment, particulates, and levels of microbiological organisms in the EDG fuel oil storage tanks, EDG fuel oil day tanks, diesel fire pump fuel oil tank, and combustion turbine generator (CTG) fuel oil tank quarterly. In addition, revise program procedures to state that biocides or corrosion inhibitors may be added as a preventive measure or are added if periodic testing indicates biological activity or evidence of corrosion, respectively.
- Revise the Diesel Fuel Monitoring Program procedures to include a ten-year periodic cleaning and internal visual inspection of the EDG fuel oil storage tanks, EDG fuel oil day tanks, and diesel fire pump fuel oil tank with the following instructions. The cleanings and internal inspections will be performed at least once during the ten-year period prior to the period of extended operation and at succeeding ten-year intervals. If visual inspection is not possible, perform a volumetric inspection. If evidence of degradation is observed during visual inspection, perform a volumetric examination of the affected area. The CTG fuel oil tank is in-scope for this program but inspections are not required since the tank was replaced in 2019.

  The schedule for the Preventive Maintenance (PM) event to perform diesel fire pump fuel oil tank draining, flushing, and inspection will continue at its frequency at the time of the enhancement implementation, until a PM evaluation of results from fuel oil samples and tank inspections indicates that the system will be capable of continuing to perform its function during the period of extended operation with a lower frequency, not less than once per ten-year interval for cleaning and internal visual inspection consistent with NUREG-1801.

Enhancements will be implemented prior to the period of extended operation.

B.1.15 ENVIRONMENTAL QUALIFICATION (EQ) OF ELECTRIC COMPONENTS PROGRAM

The Environmental Qualification (EQ) of Electric Components Program implements the requirements of 10 CFR 50.49. As required by 10 CFR 50.49, EQ components are refurbished, replaced, or their qualification is extended prior to reaching the aging limits established in the evaluation. The Fermi 2 EQ Program manages component thermal, radiation, and cyclical aging through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. Reanalysis addresses attributes of analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, corrective actions if acceptance criteria are not met, and the period of time prior to the end of qualified life when the reanalysis will be completed.

In accordance with 10 CFR 54.21(c)(1)(iii), implementation of the EQ Program provides reasonable assurance that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.16 EXTERNAL SURFACES MONITORING PROGRAM

The External Surfaces Monitoring Program manages aging effects of components fabricated from metallic, elastomeric, and polymeric materials through periodic visual inspection of external surfaces during system inspections and walkdowns for evidence of leakage, loss of material (including loss of material due to wear), cracking, fouling, and change in material properties. When appropriate for the component and material, physical manipulation, such as touching, pressing, flexing, and bending, is used to augment visual inspections to confirm the absence of hardening and loss of strength in non-metallic materials. The External Surfaces Monitoring Program is also credited for situations where the material and environment combinations are the same for the internal and external surfaces such that the external surfaces are representative of the internal surfaces.

Inspections are performed at a frequency of at least once per refueling cycle by personnel qualified through plant-specific programs. Deficiencies are documented and evaluated under the Corrective Action Program. Surfaces that are not readily visible during plant operations and refueling outages are inspected when they are made accessible and at such intervals that would ensure the components' intended functions are maintained. Inspections of insulated components where the insulation is required to reduce heat transfer will be performed to ensure insulation degradation due to moisture intrusion has not occurred.

Where visual inspection for leakage may not effectively detect cracking in gas-filled stainless steel and aluminum components exposed to outdoor air, alternate detection methods (e.g. performance monitoring or use of a soap solution with the component pressurized) will be employed.

Periodic representative surface condition inspections of the in-scope mechanical indoor components under insulation (with process fluid temperature below the dew point) and outdoor components under insulation will be performed.

For polymeric materials, the visual inspection will include 100 percent of the accessible components. The sample size of polymeric components that receive physical manipulation is at least 10 percent of the available surface area.

Acceptance criteria are defined to ensure that the need for corrective action is identified before a loss of intended function. For stainless steel, a clean shiny surface is expected. For flexible polymers, a uniform surface texture (no cracks) and no change in material properties (e.g., hardness, flexibility, physical dimensions, color unchanged from when the material was new) are expected. For rigid polymers, no surface changes affecting performance, such as erosion, cracking, crazing, checking, and chalking, are acceptable. For insulation, no discoloration, staining, or surface irregularities from moisture intrusion is expected.

The External Surfaces Monitoring Program will be enhanced as follows.

- Revise External Surfaces Monitoring Program procedures to clarify that periodic inspections will be performed of systems in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4 (a)(1) and (a)(3). Inspections shall include areas surrounding the subject systems to identify hazards to those systems. Inspections of nearby systems that could impact the subject systems will include SSCs that are in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(2).
- Revise External Surfaces Monitoring Program procedures to inspect 100 percent of accessible components at least once per refueling cycle and to ensure required walkdowns include instructions to inspect for the following related to metallic components:
  - Corrosion (loss of material).
  - Leakage from or onto external surfaces (loss of material).
  - Worn, flaking, or oxide-coated surfaces (loss of material).
  - Corrosion stains on thermal insulation (loss of material).
  - Protective coating degradation (cracking, flaking, and blistering).
  - Leakage for detection of cracks on the external surfaces of stainless steel components exposed to an air environment containing halides (cracking).
- Revise External Surfaces Monitoring Program procedures to include instructions for monitoring aging effects for flexible polymeric components through physical manipulations of the material, with a sample size for manipulation of at least ten percent of the available surface area. Inspect accessible surfaces for the following:
  - Surface cracking, crazing, scuffing, dimensional changes (e.g., ballooning and necking).
  - Discoloration.
  - Exposure of internal reinforcement for reinforced elastomers.
  - Hardening as evidence by loss of suppleness during manipulation where the component and material are appropriate to manipulation.

- Shrinkage, loss of strength.

- Revise External Surfaces Monitoring Program procedures to specify the following for insulated components:
  - Periodic representative inspections will be conducted during each 10-year period.
  - For a representative sample of insulated indoor components exposed to condensation (because the component is operated below the dew point) and insulated outdoor components, insulation will be removed for visual inspection of the component surface. Inspections include a minimum of 20 percent of the in-scope piping length for each material type (e.g., steel, stainless steel, copper alloy, aluminum), or for components with a configuration which does not conform to a 1-foot axial length determination (e.g., valve, accumulator), 20 percent of the surface area. Alternatively, insulation will be removed and a minimum of 25 inspections performed that can be a combination of 1 foot axial length sections and individual components for each material type.
  - Inspection locations are based on the likelihood of corrosion under insulation (CUI). For example, CUI is more likely for components experiencing alternate wetting and drying in environments where trace contaminants could be present and for components that operate for long periods of time below the dew point. Subsequent inspections will consist of an examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation, if the following conditions are verified in the initial inspection:
    - No loss of material due to general, pitting or crevice corrosion, beyond that which could have been present during initial construction, and
    - No evidence of cracking.

    If the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or there is evidence of water intrusion through the insulation (e.g. water seepage through insulation seams/joints), periodic inspections under the insulation will continue as described above.
  - Removal of tightly adhering insulation that is impermeable to moisture is not required unless there is evidence of damage to the moisture barrier. If the moisture barrier is intact, the likelihood of CUI is low for tightly adhering insulation. Tightly adhering insulation is considered to be a separate population from the remainder of insulation installed on in-scope components. The entire population of in-scope accessible piping component surfaces that have tightly adhering insulation will be visually inspected for damage to the moisture barrier with the same frequency as for other types of insulation inspections. These inspections will not be credited towards the inspection quantities for other types of insulation.

- Revise External Surfaces Monitoring Program procedures to include acceptance criteria for the parameters observed.
  - Metals should not have any indications of relevant degradation.

- Flexible polymers should have a uniform surface texture and color with no cracks and no dimension change, no abnormal surface conditions with respect to hardness, flexibility, physical dimensions, and color.
- Rigid polymers should have no erosion, cracking, crazing, or chalking.
- For insulation, no discoloration, staining, or surface irregularities from moisture intrusion.

- Revise External Surfaces Monitoring Program procedures to stipulate that administrative controls are in accordance with the Fermi 2 10 CFR 50 Appendix B Quality Assurance Program.
- Revise External Surfaces Monitoring Program procedures to include instructions for detection of cracking of gas-filled stainless steel and aluminum components exposed to outdoor air.
- Revise External Surfaces Monitoring Program procedures to:

  a) Visually inspect jacketed and non-jacketed insulation required to reduce heat transfer at a frequency consistent with NUREG-1801 Section XI.M36, as modified by LR-ISG-2012-02, to ensure that insulation degradation due to moisture intrusion has not occurred.

  b) Ensure procedures include instructions to inspect for signs of water intrusion. Inspect accessible surfaces for the following signs of water intrusion: discoloration, staining, or surface irregularities.

Enhancements will be implemented prior to the period of extended operation.

B.1.17 FATIGUE MONITORING PROGRAM

The Fatigue Monitoring Program ensures that fatigue usage remains within allowable limits for components identified to have a TLAA by (a) tracking the number of critical thermal and pressure transients for selected components, (b) verifying that the severity of monitored transients are bounded by the design transient definitions for which they are classified, (c) assessing the impact of the reactor coolant environment on a set of sample critical components including those from NUREG/CR-6260 and those components identified to be more limiting than the components specified in NUREG/CR-6260, and (d) addressing applicable fatigue exemptions. Tracking the number of critical thermal and pressure transients for the selected components ensures a code design usage factor of less than or equal to 1, including environmental effects where applicable. The environmental effects on fatigue for the identified critical components will be evaluated.

The program monitors the number of occurrences for the plant transients that cause significant fatigue usage. The program also provides for updates of fatigue usage calculations on an as-needed basis if an allowable cycle limit is approached or in a case where a transient definition has been changed, unanticipated new thermal events are discovered, or the geometry of components has been modified.

As an alternative to monitoring occurrences of transients, NUREG-1801, Section X.M1, Fatigue Monitoring, also allows more detailed monitoring of local pressure and thermal conditions to be performed to allow the actual fatigue usage for the specified critical locations to be calculated. Therefore the program will include Stress-Based Fatigue (SBF) monitoring. SBF monitoring computes stress history for a given component from transient pressure and temperature data collected from plant instruments, and the corresponding stress history at the critical location in the component. The stress history is analyzed to identify stress cycles and then a cumulative usage factor is computed. The recommendations of NRC Regulatory Issue Summary (RIS) 2008-30 will be applied for any use of SBF. Use of SBF monitoring will appropriately account for environmental effects on fatigue usage.

The Fatigue Monitoring Program will be enhanced as follows.

- Revise Fatigue Monitoring Program procedures to monitor and track critical thermal and pressure transients for components that have been identified to have a fatigue TLAA.
- Develop environmentally assisted fatigue (EAF) usage calculations that consider the effects of the reactor water environment for a set of sample reactor coolant system components. This sample set will include the locations identified in NUREG/CR-6260 and additional plant-specific component locations in the reactor coolant pressure boundary if they are found more limiting than those considered in NUREG/CR-6260. Environmental correction factors will be determined using formulae consistent with those recommended in NUREG-1801, X.M1.
- Revise Fatigue Monitoring Program procedures to provide updates of the fatigue usage calculations on an as-needed basis if an allowable cycle limit is approached, or in a case where a transient definition has been changed, unanticipated new thermal events are discovered, or the geometry of components has been modified. For components with assumed minimal cycle counts, ensure that exemption assumptions are not exceeded.
- After the EAF calculations are completed, revise the Fatigue Monitoring Program procedures to state that the program counting of the cycle limits maintains the cumulative fatigue usage below the design limit through the period of extended operation, with consideration of the reactor water environmental fatigue effects. Revise Fatigue Monitoring Program procedures to allow for use of cycle-based fatigue (CBF) or stress-based fatigue (SBF) monitoring methods (including environmental effects) if a component's CUF value is projected to exceed 1.0 after EAF calculations are completed.
- Revise Fatigue Monitoring Program procedures so that the scope of the program includes monitoring the operating hours for the main steam bypass operation at the 30%-45% valve open position and perform trending to ensure that the operating time for the main steam bypass operation remains below the design limit during the period of extended operation.
- Revise Fatigue Monitoring Program procedures to provide for corrective actions to prevent the operating time for the main steam bypass from exceeding the analysis during the period of extended operation. Acceptable corrective actions include repair of the component, replacement of the component, or a more rigorous analysis of the

component to demonstrate that the service life will not be exceeded during the period of extended operation.

The second enhancement for EAF usage calculations will be implemented at least two years prior to entering the period of extended operation. All other enhancements will be implemented prior to the period of extended operation.

B.1.18 FIRE PROTECTION PROGRAM

The Fire Protection Program manages the following through periodic visual inspection of components and structures with a fire barrier intended function.

- Carbon steel components (loss of material).
- Concrete components (cracking and loss of material).
- Masonry walls (cracking and loss of material).
- Fire resistant materials (loss of material, change in material properties, cracking/delamination, and separation).
- Elastomer components (increased hardness, shrinkage, and loss of strength).

The program includes visual inspections of not less than ten percent of each type of penetration seal at a frequency described in the Technical Requirements Manual (TRM). These inspections examine any sign of degradation, such as cracking, seal separation from walls and components, separation of layers of material, rupture and puncture of seals that are directly caused by increased hardness, and shrinkage of seal material due to loss of material. If any signs of degradation are detected within the sample, the scope of the inspection is expanded to include additional seals.

Visual inspections of the fire barrier walls, ceilings, and floors in structures within the scope of license renewal are performed at a frequency described in the TRM. Inspections of fire barriers include inspections of coatings and wraps. Visual inspection of the fire barrier walls, ceilings, and floors and other fire barrier materials to detect any sign of degradation, such as cracking and loss of material caused by freeze-thaw, chemical attack, and reaction with aggregates, are performed to ensure their intended fire protection functions are maintained.

Periodic visual inspections and functional tests are utilized to manage the aging effects of fire doors. Visual inspections of fire door surfaces and functional testing of fire door closing mechanisms and latches are performed at a frequency described in the TRM.

The Fire Protection Program performs visual periodic inspections and functional tests of the CO2 and Halon systems in accordance with the TRM. These actions verify that the systems actuate correctly and that system integrity is maintained by inspecting for conditions of corrosion that could lead to a loss of material.

The Fire Protection Program will be enhanced as follows.

- Revise Fire Protection Program procedures to perform visual inspections to manage loss of material of the Halon and CO2 fire suppression system.
- Revise Fire Protection Program procedures to require visual inspections of in-scope (a) fire wrap and fire stop materials for loss of material, change in material properties,

cracking/delamination, separation, increased hardness, shrinkage, and loss of strength; (b) carbon steel penetration sleeves for loss of material; (c) steel framing, roof decking, and floor decking for loss of material; (d) concrete fire barriers including manways, manhole covers, handholes, and roof slabs for loss of material and cracking; and (e) railroad bay airlock doors for loss of material. Inspections are performed at a frequency in accordance with the NRC-approved fire protection program or at least once every refueling cycle.

Enhancements will be implemented prior to the period of extended operation.

B.1.19 FIRE WATER SYSTEM PROGRAM

The Fire Water System Program manages loss of material due to general, pitting, and crevice corrosion, microbiologically influenced corrosion, or fouling, and flow blockage due to fouling for in-scope long-lived passive water-based fire suppression system components using periodic flow testing and visual inspections. When visual inspections are used to detect loss of material, the inspection technique is capable of detecting surface irregularities that could indicate wall loss due to corrosion, corrosion product deposition, and flow blockage due to fouling.

Testing or replacement of sprinkler heads that have been in service for 50 years is performed in accordance with the 2011 Edition of NFPA 25. Portions of the water-based fire water system that a) are normally dry, but periodically subject to flow (e.g., dry-pipe or downstream of deluge valve in a deluge system) and b) cannot be drained or allow water to collect are subject to augmented testing beyond that specified in NFPA 25. These augmented inspections include a) periodic full flow tests at the design pressure and flow rate, or internal inspections, and b) volumetric wall thickness evaluations. Applicable industry standards and guidance documents are also used to delineate the program (e.g., insurance loss control manual and INPO operating experience issuances).

Water system pressure is continuously monitored such that loss of pressure is detected and corrective action initiated.

Program acceptance criteria include (a) the water based fire protection system can maintain required pressure, (b) no unacceptable signs of degradation or fouling are observed during nonintrusive or visual inspections, and (c) in the event surface irregularities are identified, testing is performed to ensure minimum design pipe wall thickness is maintained. The Fire Water System Program will be enhanced as follows.

- Revise Fire Water System Program procedures to ensure sprinkler heads are tested or replaced in accordance with NFPA 25 (2011 Edition), Section 5.3.1.
- Revise Fire Water System Program procedures to perform an inspection of wet fire water system piping condition at least once every five years by opening a flushing connection at the end of one main and by removing a sprinkler toward the end of one branch line for the purpose of inspecting the interior for evidence of loss of material and the presence of foreign organic or inorganic material that could result in flow obstructions or blockage of a sprinkler head. Where multiple wet-pipe systems are in a building, every other system shall be inspected in a five year period. Then, in the next five year period, the remaining systems in that building shall be inspected. Refer

to NFPA 25 (2011 Edition) Sections 14.2.1 and 14.2.2) The inspection method used shall be capable of detecting surface irregularities that could indicate wall loss due to corrosion, corrosion product deposition, and flow blockage due to fouling. Ensure procedures require a follow-up volumetric wall thickness evaluation where irregularities are detected.

- Revise Fire Water System Program procedures to ensure a) sprinkler heads are tested or replaced in accordance with NFPA 25 (2011 Edition) Section 5.3.1 and b) the fire protection engineer approves the sprinkler testing laboratory.
- Revise Fire Water System Program procedures to a) specify that in accordance with NFPA Section 13.2.5.2 when there is a 10 percent reduction in full flow pressure when compared to the original acceptance test or previously performed tests, the cause of the reduction shall be identified and corrected as necessary and b) note the time to return to static pressure after performing a main drain test.
- Revise Fire Water System Program procedures to notify the fire protection engineer of test results and deficiencies identified or detected during testing.
- Revise Fire Water System Program procedures to ensure piping is cleaned and sprinklers are replaced if obstructions are identified during internal inspections. Sprinklers loaded with dust may be cleaned using air rather than replaced.
- Revise Fire Water System Program procedures to perform an internal inspection of wet fire water system piping conditions at least once every five years by opening a flushing connection at the end of one main and by removing a sprinkler toward the end of the branch line for the purpose of inspecting the interior for evidence of loss of material and the presence of foreign organic and inorganic material that could result in flow obstructions or blockage of sprinkler heads. Where multiple wet-pipe systems are in a building, every other system shall be inspected in a five year period. Then, in the next five year period, the remaining systems in that building shall be inspected.
- Revise Fire Water System Program procedures to perform at least once every five years either an internal inspection of the dry components downstream of the deluge valves for the hydrogen seal oil unit by removing a sprinkler toward the end of one branch line and inspecting for evidence of loss of material and the presence of foreign organic and inorganic material that could result in flow obstructions or blockage of sprinklers,

  <u>or</u>

  Revise Fire Water System Program procedures to perform at least once every five years an air or smoke test to verify there is no flow obstruction or blockage of sprinklers.
- Revise Fire Water System Program procedures to perform an inspection of the water distribution piping associated with charcoal filters for loss of material and foreign organic or inorganic material when the charcoal beds are replaced.

- Revise Fire Water System Program procedures to perform an obstruction investigation whenever any of the criteria listed in NFPA Section 14.2.1.3 or 14.3.1 are met.
- Perform a fire water system walkdown of the piping and components that are designed to be dry (e.g., downstream of deluge valves or manual isolations of dry fire water piping), but are periodically wetted, to determine if any piping sections are collecting water and are subject to both of the following augmented inspections:
  - In each five year interval, beginning five years prior to the period of extended operation, either a) conduct a flow test or flush sufficient to detect potential flow blockage, or b) conduct a visual inspection of 100 percent of the internal surface of piping segments that cannot be drained or piping segments that allow water to collect.
  - In each five year interval of the period of extended operation, inspect 20 percent of the length of piping segments that cannot be drained or piping segments that allow water to collect using volumetric techniques to measure wall thickness. Measurement points will be obtained so that each potential degraded condition can be identified (e.g., general corrosion, MIC). The 20 percent of piping that will be inspected in each five year interval will be in different locations than previously inspected piping.
- Revise Fire Water System Program procedures to include acceptance criteria that any indication of fouling is evaluated.
- Revise Fire Water System Program procedures to specify that if the presence of sufficient foreign organic or inorganic material to obstruct pipe or sprinklers is detected during pipe inspections, the material is removed and the source and extent of condition determined, corrected, and the condition entered into the Corrective Action Program.
- Revise Fire Water System Program procedures to replace sprinklers associated with representative tested sprinkler, if the representative test sprinkler fails to meet the test requirements.
- Revise Fire Water System Program procedures to replace any sprinkler that shows signs of corrosion.
- If the decreasing trend in fire water system flow tests is not resolved through the Corrective Action Program prior to the period of extended operation, revise Fire Water System Program procedures to continue performing annual fire water system flow tests during the period of extended operation until such a time as trend data from fire water system flow tests indicates that the system will be capable of performing its intended function throughout the period of extended operation and therefore TRM frequency may be resumed.
- Revise Fire Water System Program procedures to include formal documentation of the CCHVAC makeup and recirculation fire water supply drain down inspection for indications of flow blockage.

Enhancements will be implemented prior to the period of extended operation.

B.1.20 FLOW-ACCELERATED CORROSION PROGRAM

The Flow-Accelerated Corrosion (FAC) Program manages loss of material due to wall thinning caused by FAC for carbon steel piping and components through (a) performing an analysis to determine systems susceptible to FAC, (b) conducting appropriate analysis to predict wall thinning, (c) performing wall thickness measurements based on wall thinning predictions and operating experience, and (d) evaluating measurement results to determine the remaining service life and the need for replacement or repair of components.

The program also manages wall thinning due to various erosion mechanisms in treated water and steam systems for all materials that may be identified through industry or plant-specific operating experience.

The program relies on implementation of guidelines published by EPRI in NSAC-202L, Rev. 3, and internal and external operating experience. The program uses a predictive code for portions of susceptible systems with design and operating conditions that are amenable to computer modeling. When field measurements identify that the predictive code is not conservative, the model is recalibrated. The model is also adjusted as a result of any power uprates.

A representative sample of components is selected based on the most susceptible locations for wall thickness measurements at a frequency in accordance with NSAC-202L Rev. 3 guidelines to ensure that FAC degradation is identified and mitigated before the component integrity is challenged. Inspections are performed using ultrasonic or other approved testing techniques capable of detecting wall thickness. Measurement results are used to confirm predictions and to plan long-term corrective action. In the event measurements of wall thinning exceed predictions, the extent of the wall thinning is determined as a part of the Corrective Action Program. Components predicted to reach the minimum allowed wall thickness before the next scheduled outage are isolated, repaired, replaced, or reevaluated under the Corrective Action Program.

The FAC Program will be enhanced as follows.

- Revise procedures to indicate that the FAC Program also manages loss of material due to erosion mechanisms of cavitation, flashing, liquid droplet impingement, and solid particle erosion for any material in treated water or steam environments. Include in program procedures a susceptibility review based on internal operating experience; external operating experience; EPRI TR-1011231, Recommendations for Controlling Cavitation, Flashing, Liquid Droplet Impingement, and Solid Particle Erosion in Nuclear Power Plant Piping; and NUREG/CR-6031, Cavitation Guide for Control Valves. Piping subject to erosive conditions is not excluded from inspections, even if it has been replaced with FAC-resistant material. Periodic wall thickness measurements of such piping should continue until the effectiveness of corrective actions is assured.

- Revise FAC Program procedures to specify that downstream components are monitored for wall thinning when susceptible upstream components are replaced with FAC-resistant materials.

Enhancements will be implemented prior to the period of extended operation.

B.1.21 INSERVICE INSPECTION PROGRAM

The Inservice Inspection (ISI) Program manages loss of material, cracking, and reduction in fracture toughness for ASME Class 1, 2, and 3 pressure-retaining components, including welds, pump casings, valve bodies, integral attachments, and pressure-retaining bolting, using volumetric, surface, and/or visual examination and leakage testing as specified in ASME Code Section XI, 2001 Edition with 2003 Addenda. The examinations, scheduling, acceptance criteria, flaw evaluation, and re-examinations are in accordance with the requirements identified in ASME Section XI with NRC-approved alternatives.

Additional limitations, modifications, and augmentations approved under the provisions of 10 CFR 50.55a with NRC-approved alternatives are included as a part of this program. Every ten years this program is updated to the latest ASME Section XI code edition and addendum approved by the NRC per 10 CFR 50.55a. Repair and replacement activities for these components are covered in Subsection IWA of the ASME code edition of record.

B.1.22 INSERVICE INSPECTION – IWF PROGRAM

The Inservice Inspection (ISI) – IWF Program performs periodic visual examinations of ASME Class 1, 2, 3 and MC piping and component supports to determine general mechanical and structural condition or degradation of component supports such as verification of clearances, settings, physical displacements, loose or missing parts, debris, corrosion, wear, erosion, or the loss of integrity at welded or bolted connections. The ISI-IWF Program is implemented through plant procedures which provide administrative controls, including corrective actions, for the conduct of activities that are necessary to fulfill the requirements of ASME Section XI, as mandated by 10 CFR 50.55a. The monitoring methods are effective in detecting the applicable aging effects, and the frequency of monitoring is adequate to prevent significant degradation.

The ISI-IWF Program will be enhanced as follows.

- Revise plant procedures to specify the preventive actions delineated in NUREG-1339 and EPRI NP-5769, NP-5067, and TR-104213 that emphasize proper selection of bolting material, installation torque or tension, and the use of lubricants and sealants for high-strength bolting.
- Revise plant procedures to require structural bolting replacement and maintenance activities to include appropriate preload and proper tightening (torque or tension) as recommended in EPRI documents, American Society for Testing of Materials (ASTM) standards, American Institute of Steel Construction (AISC) Specifications, as applicable.
- Revise plant procedures to include the preventive actions for storage of ASTM A325 and A490 bolting from Section 2 of Research Council for Structural Connections publication, "Specification for Structural Joints Using ASTM A325 or A490 Bolts."
- Revise plant procedures to include the preventive action of using bolting material that has an actual measured yield strength less than 150 ksi, except in the case of like-for-like replacement of existing bolting material in the reactor pressure vessel skirt to ring girder bolted joint.

- Revise plant procedures to specify that detection of aging effects will include monitoring anchor bolts for loss of material, loose or missing nuts or bolts, and cracking of concrete around the anchor bolts.
- Revise plant procedures to identify the following unacceptable conditions:
  - Debris, dirt, or excessive wear that could prevent or restrict sliding of the sliding surfaces as intended in the design basis of the support.
  - Cracked or sheared bolts, including high-strength bolts, and anchors.
- Revise plant procedures to include assessment of the impact on the inspection sample, in terms of sample size and representativeness, if components that are part of the sample population are re-worked.

Enhancements will be implemented prior to the period of extended operation.

B.1.23 INSPECTION OF OVERHEAD HEAVY LOAD AND LIGHT LOAD (RELATED TO REFUELING) HANDLING SYSTEMS PROGRAM

The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (OVHLL) Program performs periodic visual examinations and preventive maintenance to manage loss of material due to corrosion, loose bolting or rivets, and crane rail wear of cranes and hoists, based on industry standards and guidance documents. The program evaluates the effectiveness of the maintenance monitoring program and the effects of past and future usage on the structural reliability of cranes and hoists. The program includes structural components, including structural bolting, that make up the bridge, the trolley, lifting devices, and rails in the rail system and includes cranes and hoists that meet the provisions of 10 CFR 54.4(a)(1) and (a)(2) as well as NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants." The activities rely on visual examinations and functional testing to ensure that cranes and hoists are capable of sustaining their rated loads, thus ensuring their intended function is maintained during the period of extended operation.

The Inspection of OVHLL Program will be enhanced as follows.

- Revise plant procedures to specify the monitoring of rails in the rail system for loss of material due to wear; monitor structural components of the bridge, trolley and hoists for deformation, cracking, and loss of material due to corrosion; and monitor structural connections/bolting for loose or missing bolts, nuts, pins or rivets and any other conditions indicative of loss of bolting integrity.
- Revise plant procedures to specify inspection frequency requirements will be in accordance with ASME B30.2 or other appropriate standard in the ASME B30 series.
- Revise plant procedures to require that significant loss of material due to wear of rails in the rail system and any sign of loss of bolting integrity will be evaluated in accordance with ASME B30.2 or other appropriate standard in the ASME B30 series.
- Revise plant procedures to specify that maintenance and repair activities will utilize the guidance provided in ASME B30.2 or other appropriate standard in the ASME B30 series.

Enhancements will be implemented prior to the period of extended operation.

B.1.24 INTERNAL SURFACES IN MISCELLANEOUS PIPING AND DUCTING COMPONENTS PROGRAM

The Internal Surfaces in Miscellaneous Piping and Ducting Components Program is a new program that will manage fouling, cracking, loss of material, and change in material properties using representative sampling and opportunistic visual inspections of the internal surfaces of piping and components in environments other than open-cycle cooling water, closed treated water, and fire water. Program periodic surveillances or maintenance activities will be conducted when the surfaces are accessible for visual inspection.

Where practical, the inspections will focus on the bounding or lead components most susceptible to aging because of time in service and severity of operating conditions. At a minimum, in each ten-year period during the period of extended operation, a representative sample of 20 percent of the population (defined as components having the same combination of material, environment, and aging effect) or a maximum of 25 components per population will be inspected. Opportunistic inspections will continue in each period despite meeting the sampling limit.

For metallic components, visual inspection of surface conditions will be used to detect evidence of loss of material and fouling. For non-metallic components, visual inspections and physical manipulation or pressurization will be used to detect evidence of surface discontinuities such as cracking and change in material properties. Visual examinations of elastomeric components will be accompanied by physical manipulation such that changes in material properties are readily observable. The sample size for physical manipulation will be at least ten percent of accessible surface area, including visually identified suspect areas.

Specific acceptance criteria will be as follows:

- Stainless steel: clean surfaces, shiny, no abnormal surface condition.
- Metals: no abnormal surface condition.
- Elastomerics: no change in material properties.
- Rigid polymers: no surface changes affecting performance such as erosion and cracking.

Conditions that do not meet the acceptance criteria will be entered into the Corrective Action Program for evaluation. Any indications of relevant degradation will be evaluated using design standards, procedural requirements, current licensing basis, and industry codes or standards.

This program will be implemented prior to the period of extended operation.

B.1.25 MASONRY WALL PROGRAM

The Masonry Wall Program is based on guidance provided in I.E. Bulletin 80-11, "Masonry Wall Design," and Information Notice (IN) 87-67, "Lessons Learned from Regional Inspections of Licensee Actions in Response to I.E. Bulletin 80-11." The scope of the Masonry Wall Program includes masonry walls within the scope of license renewal as delineated in 10 CFR 54.4. The program manages loss of material and cracking of masonry walls so that the evaluation basis established for each masonry wall within the scope of license renewal remains valid through the period of extended operation. The program will be implemented as part of the Structures Monitoring Program (Section B.1.42).

The program includes visual inspections of masonry walls identified as performing intended functions in accordance with 10 CFR 54.4. Included components are masonry walls required by 10 CFR 50.48, radiation shielding masonry walls, and masonry walls with the potential to affect safety-related components. Structural steel components, steel edge supports, and steel bracing of masonry walls are managed by the Structures Monitoring Program (Section B.1.42).

Enhancements to this program are included in the enhancements to the Structures Monitoring Program (Section B.1.42).

B.1.26 METAL ENCLOSED BUS INSPECTION PROGRAM

The Metal Enclosed Bus Inspection Program is a new condition monitoring program that provides for the inspection of the internal and external portions of metal enclosed bus (MEB) to identify age-related degradation of the bus and bus connections, the bus enclosure assemblies, the bus insulation and the bus insulators. This program will inspect the MEB between combustion turbine generator (CTG) transformer CTG 11 and peaker bus 1-2B located in the 120-kV switchyard, and between CTG11-1 generator and CTG11-1 output breaker A2 in the peaker yard, including the MEB connections to the generator and breaker A2. The MEB associated with CTG 11-1 is utilized as the alternate AC source for a station blackout (SBO) event and to support response by the Dedicated Shutdown Panel to an Appendix R fire.

The program calls for the visual inspection of MEB internal surface (bus enclosure assemblies) to detect age-related degradation, including cracks, corrosion, foreign debris, excessive dust buildup, and evidence of moisture intrusion. MEB insulating material is visually inspected for signs of reduced insulation resistance due to thermal/thermoxidative degradation of organics/thermoplastics, radiation-induced oxidation, moisture/debris intrusion, or ohmic heating, as indicated by embrittlement, cracking, chipping, melting, swelling, discoloration, or surface contamination, which may indicate overheating or aging degradation. The internal bus insulating supports or insulators will be inspected for structural integrity and signs of cracks. MEB external surfaces are visually inspected for loss of material due to general, pitting, and crevice corrosion. Accessible elastomers (e.g., gaskets, boots, and sealants) are inspected for degradation, including surface cracking, crazing, scuffing, and changes in dimensions (e.g., "ballooning" and "necking"), shrinkage, discoloration, hardening, and loss of strength. A sample of accessible bolted connections will be inspected for increased resistance of connection by using thermography or by measuring connection resistance using a micro-ohmmeter. Torque checking will not be used as an alternative test method. Twenty percent of the population with a maximum sample of 25 will constitute a representative sample size. Otherwise, a technical justification of the methodology and sample size used for selecting components should be included as part of the program's site documentation. These inspections are performed at least once every ten years.

As an alternative to thermography or measuring connection resistance of accessible bolted connections covered with heat shrink tape, sleeving, insulating boots, etc., visual inspection of insulation material may be used to detect surface anomalies, such as embrittlement, cracking, chipping, melting, discoloration, swelling, or surface contamination. When this alternative visual inspection is used to check bolted connections, the first inspection is completed prior to the period of extended operation and every five years thereafter.

This program will be used instead of the Structures Monitoring Program (Section B.1.42) for external surfaces of the bus enclosure assemblies.

This program will be implemented prior to the period of extended operation. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.E4, Metal-Enclosed Bus.

B.1.27 NEUTRON-ABSORBING MATERIAL MONITORING PROGRAM

The Neutron-Absorbing Material Monitoring Program provides reasonable assurance that degradation of the neutron-absorbing materials (e.g. Boral) used in spent fuel pools that could compromise the criticality analysis will be detected. The program relies on periodic inspection, testing, and other monitoring activities to assure that the required five percent sub-criticality margin is maintained during the period of extended operation. The program monitors loss of material and changes in dimension, such as blisters, pits, and bulges that could result in a loss of neutron-absorbing capability. The parameters monitored include physical measurements and geometric changes in test coupons. The frequency of testing will be based on the condition of the neutron-absorbing material, justified with plant-specific and industry operating experience, prior to the period of extended operation, at a minimum of once every ten years in the period of extended operation. The approach to relating measurement results of the coupons to the spent fuel neutron-absorber materials considers the spent fuel loading strategy. In the event that a loss of neutron-absorbing capacity is anticipated based on coupon testing, additional testing will be performed to ensure the sub-criticality requirements are met.

The Neutron-Absorbing Material Monitoring Program will be enhanced as follows.

- Prior to the period of extended operation, revise Neutron-Absorbing Material Monitoring Program procedures to establish an inspection frequency, justified with plant-specific operating experience, of at least once every ten years, based on the condition of the neutron-absorbing material.
- Revise Neutron-Absorbing Material Monitoring Program procedures to perform trending of coupon testing results to determine the rate of degradation. Ensure the predicted boron-10 areal density will be sufficient to maintain the subcritical conditions required by technical specifications until the next coupon test.

Enhancements will be implemented prior to the period of extended operation.

B.1.28 NON-EQ CABLE CONNECTIONS PROGRAM

The Non-EQ Cable Connections Program is a new one-time inspection program that consists of a representative sample of electrical connections within the scope of license renewal, which is inspected or tested at least once prior to the period of extended operation to confirm that there are no aging effects requiring management during that period. Cable connections included in this program are those connections susceptible to age-related degradation resulting in increased resistance of connection due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, or oxidation that are not subject to the environmental qualification requirements of 10 CFR 50.49. Inspection methods may include thermography, contact resistance testing, or other appropriate testing methods without removing the connection insulation, such as heat shrink tape, sleeving, insulating boots, etc.. Torque checking will not be used as an alternative test method. The one-time inspection provides additional confirmation to support industry operating experience that shows that electrical connections have not experienced a high degree of failures and that existing installation and maintenance practices are effective.

The factors considered for sample selection will be application (medium and low voltage, defined as < 35 kV), circuit loading (high loading), connection type (crimped, bolted, and tap box), and location (high temperature, high humidity, vibration, etc.). The representative sample size will be based on 20 percent of the connection population with a maximum sample of 25. The technical basis for the sample selections will be documented. If an unacceptable condition or situation is identified in the selected sample, the corrective action program will be used to evaluate the condition and determine appropriate corrective action.

The inspections will be performed prior to the period of extended operation.

B.1.29 NON-EQ INACCESSIBLE POWER CABLES (400 V TO 13.8 KV) PROGRAM

The Non-EQ Inaccessible Power Cables (400 V to 13.8 kV) Program is a new condition monitoring program that will manage the aging effect of reduced insulation resistance on inaccessible power (400 V to 13.8 kV) cables that have a license renewal intended function. The program calls for inaccessible or underground (e.g., in conduit, duct bank, or direct buried) power (greater than or equal to 400 volts) cables exposed to significant moisture, to be tested at least once every six years to provide an indication of the condition of the conductor insulation, with the first tests occurring before the period of extended operation. The specific type of test to be used should be a proven, commercially available test capable of detecting reduced insulation resistance of the cable's insulation system due to wetting or submergence. The applicant can assess the condition of the cable insulation with reasonable confidence using one or more of the following techniques: dielectric loss (dissipation factor/power factor), AC voltage withstand, partial discharge, step voltage, time domain reflectometry, insulation resistance and polarization index, line resonance analysis, or other testing that is state-of-the-art at the time the tests are performed. One or more tests are used to determine the condition of the cables so they will continue to meet their intended function during the period of extended operation.

The program will include periodic inspections for water accumulation in manholes within the scope of this program. The inspection frequency for water collection is established and performed based on plant-specific operating experience with cable wetting or submergence in manholes (i.e., the inspection is performed periodically based on water accumulation over time and event-driven occurrences such as heavy rain or flooding). The periodic inspection should occur at least annually. The inspection should include direct observation that cables are not wetted or submerged, that cables/splices and cable support structures are intact, and dewatering/drainage systems (i.e., sump pumps) and associated alarms operate properly. In addition, operation of dewatering devices should be inspected and operation verified prior to any known or predicted heavy rain or flooding.

This program will be implemented prior to the period of extended operation.

B.1.30 NON-EQ INSTRUMENTATION CIRCUITS TEST REVIEW PROGRAM

The Non-EQ Instrumentation Circuits Test Review Program is a new performance monitoring program that will manage the aging effects of applicable cables in the following systems or sub-systems.

- Neutron monitoring
  - Intermediate range channels (IRMs)
  - Average power range monitors (includes local power range monitors [LPRM] detector strings)
- Process radiation monitoring
  - Control center emergency air inlet radiation monitors
  - Fuel pool ventilation exhaust radiation monitors
  - Main steam line radiation monitors

The Non-EQ Instrumentation Circuits Test Review Program calls for the review of calibration results or findings of surveillance tests on electrical cables and connections used in circuits with sensitive, high-voltage, low-level current signals, such as radiation monitoring and nuclear instrumentation, to provide an indication of the existence of aging effects based on acceptance criteria related to instrumentation circuit performance. By reviewing the results obtained during normal calibration or surveillance, an applicant may detect severe aging degradation prior to the loss of the cable and connection intended function. The review of calibration results or findings of surveillance tests is performed at least once every ten years. In cases where cables are not included as part of calibration or surveillance program testing circuit, a proven cable test (such as insulation resistance tests, time domain reflectometry tests, or other testing judged to be effective in determining cable system insulation condition as justified in the application) is performed. The test frequency is based on engineering evaluation and is at least once every ten years.

For sensitive instrumentation circuit cables that are disconnected during instrument calibrations, testing using a proven method for detecting deterioration for the insulation system (such as insulation resistance tests or time domain reflectometry) will occur at least once every ten years, with the first test occurring before the period of extended operation. Applicable industry standards and guidance documents will be used to delineate the program.

The program will be implemented prior to the period of extended operation.

B.1.31 NON-EQ INSULATED CABLES AND CONNECTIONS PROGRAM

The Non-EQ Insulated Cables and Connections Program is a new condition monitoring program that provides reasonable assurance the intended functions of insulated cables and connections exposed to adverse localized environments caused by heat, radiation[1], moisture, and chemical contamination (i.e. bird droppings) can be maintained consistent with the current licensing basis through the period of extended operation.

The program consists of accessible insulated electrical cables and connections installed in adverse localized environments to be visually inspected at least once every ten years for cable jacket and connection insulation surface anomalies, such as embrittlement, discoloration, cracking, melting, swelling, or surface contamination, that could indicate incipient conductor insulation aging degradation from temperature, radiation, or moisture.

An adverse localized environment is a condition in a limited plant area that is significantly more severe than the plant design environment for the cable or connection insulation materials.

This program will be implemented prior to the period of extended operation with the first inspection prior to the period of extended operation.

B.1.32 OIL ANALYSIS PROGRAM

The Oil Analysis Program ensures that loss of material and fouling are not occurring by maintaining the quality of the lubricating oil. The program ensures that contaminants (primarily water and particulates) are within acceptable limits. Testing activities include sampling and analysis of lubricating oil for detrimental contaminants. Testing results indicating the presence of water in oil samples initiate corrective action that may include evaluating for in-leakage.

The One-Time Inspection Program utilizes inspections or non-destructive evaluations of representative samples to verify that the Oil Analysis Program has been effective at managing the aging effects.

The Oil Analysis Program will be enhanced as follows.

- Revise Oil Analysis Program procedures to identify components within the scope of the program.
- Revise Oil Analysis Program procedures to provide a formalized analysis technique for particulate counting.
- Revise Oil Analysis Program procedures to include the sampling and testing recommendations of equipment manufacturers or industry standards.

Enhancements will be implemented prior to the period of extended operation.

B.1.33 ONE-TIME INSPECTION PROGRAM

The One-Time Inspection Program is a new program that will consist of a one-time inspection of selected components to accomplish the following:

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[1] Reduced insulation resistance from an environment of radiation and air (oxygen) includes radiolysis, photolysis of organics, or radiation induced oxidation. Photolysis is limited to UV sensitive materials.

- Verify the effectiveness of an aging management program that is designed to prevent or minimize aging to the extent that it will not cause the loss of intended function during the period of extended operation. The aging effects evaluated are loss of material, cracking, and fouling.
- Confirm the insignificance of an aging effect for situations in which additional confirmation is appropriate using inspections that verify degradation is not occurring.
- Trigger additional actions that ensure the intended functions of affected components are maintained during the period of extended operation.

The sample size will be 20 percent of the components in each material-environment-aging effect group up to a maximum of 25 components. Identification of inspection locations will be based on the potential for the aging effect to occur. Examination techniques will use established NDE methods with a demonstrated history of effectiveness in detecting the aging effect of concern, including visual, ultrasonic, and surface techniques. Acceptance criteria will be based on applicable ASME or other appropriate standards, design basis information, or vendor-specified requirements and recommendations. Any indication or relevant condition of degradation detected is evaluated. The need for follow-up examinations will be evaluated based on inspection results.

The One-Time Inspection Program will not be used for structures or components with known age-related degradation mechanisms or if the environment in the period of extended operation is not expected to be equivalent to that in the prior 40 years. In these cases, a periodic plant specific inspection will be performed.

The following table identifies potential inspection methods for specific aging effects.

Parameters Monitored and Inspection Methods for Specific Aging Effects			
Aging Effect	Aging Mechanism	Parameters Monitored	Inspection Methods
Loss of material	Crevice corrosion	Surface condition Wall thickness	Visual (VT-1 or equivalent) and/or volumetric (UT)
Loss of material	Galvanic corrosion	Surface condition Wall thickness	Visual (VT-3 or equivalent) and/or volumetric (UT)
Loss of material	General corrosion	Surface condition Wall thickness	Visual (VT-3 or equivalent) and/or volumetric (UT)

Parameters Monitored and Inspection Methods for Specific Aging Effects			
Aging Effect	Aging Mechanism	Parameters Monitored	Inspection Methods
Loss of material	Microbiologically induced corrosion (MIC)	Surface condition Wall thickness	Visual (VT-3 or equivalent) and/or volumetric (UT)
Loss of material	Pitting corrosion	Surface condition Wall thickness	Visual (VT-1 or equivalent) and/or volumetric (UT)
Loss of material	Erosion	Surface condition Wall thickness	Visual (VT-1 or equivalent) and/or volumetric (UT)
Reduction of heat transfer	Fouling	Surface condition	Visual (VT-3 or equivalent)
Cracking	SCC or cyclic loading	Surface condition	Enhanced visual (EVT-1 or equivalent) or surface examination (magnetic particle, liquid penetrant) or volumetric (radiographic testing or UT)

The program will include activities to verify effectiveness of aging management programs and activities to confirm the insignificance of aging effects as described below.

Diesel Fuel Monitoring Program (Section B.1.14)	One-time inspection activity will verify the effectiveness of the Diesel Fuel Monitoring Program by confirming that unacceptable loss of material is not occurring.
Oil Analysis Program (Section B.1.32)	One-time inspection activity will verify the effectiveness of the Oil Analysis Program by confirming that unacceptable loss of material and fouling is not occurring.

Water Chemistry Control – BWR Program (Section B.1.43)	One-time inspection activity will verify the effectiveness of the Water Chemistry Control – BWR Program by confirming that unacceptable cracking, loss of material, and fouling is not occurring.
Stainless steel reactor vessel flange leak off piping and valve body	One-time inspection activity will confirm that cracking is not occurring or is occurring so slowly that the aging effect will not affect the component intended function during the period of extended operation.
A representative sample of internal and external surfaces of core spray piping passing through the waterline region of the suppression pool	One-time inspection activity will confirm that loss of material is not occurring or is occurring so slowly that the aging effect will not affect the component intended function during the period of extended operation.
A representative sample of internal and external surfaces of residual heat removal (RHR) piping passing through the waterline region of the suppression pool	One-time inspection activity will confirm that loss of material is not occurring or is occurring so slowly that the aging effect will not affect the component intended function during the period of extended operation.
A representative sample of internal and external surfaces of high pressure coolant injection (HPCI) turbine exhaust piping passing through the waterline region of the suppression pool and HPCI turbine exhaust drain piping to the suppression pool	One-time inspection activity will confirm that loss of material is not occurring or is occurring so slowly that the aging effect will not affect the component intended function during the period of extended operation.
A representative sample of internal and external surfaces of nuclear pressure relief piping passing through the waterline region of the suppression pool	One-time inspection activity will confirm that loss of material is not occurring or is occurring so slowly that the aging effect will not affect the component intended function during the period of extended operation.
A representative sample of internal and external surfaces of reactor core isolation cooling (RCIC) piping	One-time inspection activity will confirm that loss of material is not occurring or is occurring so slowly that the aging effect will not affect the component intended function during the period of extended operation.

passing through the waterline region of the suppression pool	
A representative sample of internal surfaces of the normally dry suppression chamber spray piping that is periodically wetted by RHR system testing	One-time inspection activity will confirm that loss of material is not occurring or is occurring so slowly that the aging effect will not affect the component intended function during the period of extended operation.
A sample of 25 one-foot long locations of the mechanical draft cooling towers galvanized spray piping will be inspected	One-time inspection activity will confirm that loss of material is not occurring or is occurring so slowly that the aging effect will not affect the component intended function during the period of extended operation.

Inspections will be performed within the ten years prior to the period of extended operation.

B.1.34 ONE-TIME INSPECTION – SMALL-BORE PIPING PROGRAM

The One-Time Inspection – Small-Bore Piping Program is a new program that will augment ASME Code, Section XI (2001 Edition with 2003 Addenda) requirements and be applicable to small-bore ASME Code Class 1 piping and components with a nominal pipe size diameter less than four inches (NPS 4) and greater than or equal to one inch (NPS 1) in systems that have not experienced cracking of ASME Code Class 1 small-bore piping. Fermi 2 has not experienced cracking of ASME Code Class 1 small-bore piping less than NPS 4 and greater than or equal to NPS 1 due to stress corrosion, cyclical (including thermal, mechanical, and vibration fatigue) loading, or thermal stratification and thermal turbulence. The program can also be used for systems that have experienced cracking but have implemented design changes to effectively mitigate cracking.

This program will provide a one-time volumetric or (socket welds only) opportunistic destructive inspection of ASME Class 1 piping butt weld locations and socket weld locations that are susceptible to cracking. Volumetric examinations will be performed using a demonstrated technique that is capable of detecting the aging effect of cracking in the volume of interest. In the event the opportunity arises to perform a destructive examination of an ASME Class 1 small-bore socket weld that meets the susceptibility criteria, then the program will take credit for two volumetric examinations. The program will include pipes, fittings, branch connections, and full and partial penetration welds.

This program will include a sampling approach. Sample selection will be based on susceptibility to stress corrosion, cyclic loading (including thermal, mechanical, and vibration fatigue), thermal stratification and thermal turbulence, and failure history. Since Fermi 2 will not have more than 30 years of operation at the time of submitting the license renewal application, the inspections include ten percent of the weld population or a maximum of 25 welds of each weld type (e.g., full penetration and socket weld).

The program will include measures to verify that degradation is not occurring, thereby either confirming that there is no need to manage aging-related degradation or validating the effectiveness of any existing program for the period of extended operation. If evidence of cracking is revealed by this one-time inspection, it will be entered into the Corrective Action Program to determine extent of condition, and a follow-up periodic inspection will be managed by a plant-specific program. Flaws or indications are evaluated in accordance with the ASME Code.

The inspection will be performed within the six-year period prior to the period of extended operation.

B.1.35 PERIODIC SURVEILLANCE AND PREVENTIVE MAINTENANCE PROGRAM

There is no corresponding NUREG-1801 program.

The Periodic Surveillance and Preventive Maintenance Program manages aging effects not managed by other aging management programs, including loss of material, fouling, loss of material due to wear, and loss of sealing. Any indication or relevant condition of degradation detected is evaluated. Inspections occur at least once every five years during the period of extended operation.

The Periodic Surveillance and Preventive Maintenance Program also manages loss of material in carbon steel components exposed to raw water due to the recurring internal corrosion aging mechanism collectively referred to as multiple corrosion mechanisms (MCM). MCM was identified as a recurring internal corrosion aging mechanism (RICAM) in an operating experience review conducted by DTE in accordance with LR-ISG-2012-02 Section A.

The Fermi 2 aging management review credits the following inspection activities.

- Visually inspect and manually flex the rubber gasket/seal for reactor building spent fuel storage pool gates to verify no loss of sealing.
- Inspect suppression chamber spray nozzles for flow blockage using an air test or by removal and inspection of the nozzles for blockage.
- Determine wall thickness of selected service water system piping components to manage loss of material due to recurring internal corrosion by multiple corrosion mechanisms.
- Perform advanced eddy current testing on a representative sample of emergency diesel generator (EDG) system air coolant, lube oil, and jacket water heat exchanger tubes to manage loss of material due to wear and potential stress corrosion induced circumferential cracking.
- Determine wall thickness of selected EDG system piping components to manage loss of material due to recurring internal corrosion by multiple corrosion mechanisms.
- Use visual or other NDE techniques to inspect internal surfaces to manage fouling of the fire water system heat exchanger tubes exposed to raw water.

- Visually inspect a representative sample of the dry piping downstream of the manual isolation valve for the cable spreading room wet pipe system for flow blockage. The first inspection will be within the five years prior to the period of extended operation.
- Visually inspect a representative sample of combustion turbine generator (CTG) system lube oil heat exchanger tubes to manage loss of material due to wear.
- Visually inspect a representative sample of CTG system atomizing air precooler heat exchanger tubes to manage fouling and loss of material due to wear.
- Visually inspect and clean CTG system atomizing air booster compressor suction filter to manage fouling.
- Visually inspect and clean CTG system compressor extraction air filter to manage fouling.
- Use visual or other NDE techniques to inspect a sample of the containment atmospheric control system recombiner components' internal surfaces to manage loss of material. The area sampled may be outside the recombiner housing.
- Perform thermography on a sample of non-jacketed insulation having an intended function of “insulation” to assess its insulating ability. A sample will consist of at least 20 percent of the available population of non-jacketed insulation where the insulated piping has a heat load and is not located in a high radiation area. The first thermography will be during the five years prior to the period of extended operation.
- Nonsafety-related systems, structures, and components affecting safety-related systems, structures, and components.
  - Determine wall thickness of selected RHR Service Water system (E11) piping components to manage loss of material due to recurring internal corrosion by multiple corrosion mechanisms.
  - Perform visual or ultrasonic inspection of a representative sample of the internal surface of fuel pool cooling and cleanup system (G41) abandoned piping to manage loss of material.
  - Visually inspect the internal surface of a representative sample of condensate system (N20) piping, pump casing, tanks, and valve bodies to manage loss of material.
  - Visually inspect the internal surface of a representative sample of heater drains system (N22) piping, thermowells, and valve bodies to manage loss of material.
  - Visually inspect the internal surface of a representative sample of main turbine generator and auxiliaries system (N30) piping, tanks, and valve bodies to manage loss of material.
  - Visually inspect the internal surface of a representative sample of condenser and auxiliaries system (N61) piping and valve bodies to manage loss of material.
  - Visually inspect the internal surface of a representative sample of process sampling system (P33) chiller and cooler housing to manage loss of material.

- Determine wall thickness of selected general service water system (P41) piping components to manage loss of material due to recurring internal corrosion by multiple corrosion mechanisms.
- Determine wall thickness of selected emergency equipment service water system (P45) piping components to manage loss of material due to recurring internal corrosion by multiple corrosion mechanisms.
- Visually inspect the internal surface of a representative sample of drips, drains and vents system (P95) piping and valve bodies to manage loss of material.
- Determine wall thickness of selected EDG system (R30) piping components to manage loss of material due to recurring internal corrosion by multiple corrosion mechanisms.
- Visually inspect the internal surface of a representative sample of reactor/ auxiliary building HVAC system (T41) piping, strainer housing, tubing, and valve bodies to manage loss of material.
- Visually inspect the internal surface of a representative sample of containment atmospheric control system (T48) piping and valve bodies to manage loss of material.

The Periodic Surveillance and Preventive Maintenance Program will be enhanced as follows.

- Revise the Periodic Surveillance and Preventive Maintenance Program procedures as necessary to incorporate the identified activities.
- Revise Periodic Surveillance and Preventive Maintenance Program procedures to require periodic determination of wall thickness for selected piping components.
- Revise Periodic Surveillance and Preventive Maintenance Program procedures to require wall thickness measurements using UT or other suitable techniques at selected locations be periodically performed to identify loss of material due to MCM in system piping components. The selected locations are based on pipe configuration, flow conditions and operating history to represent a cross-section of potential MCM sites. The selected locations are periodically reviewed to validate their relevance and usefulness, and are modified accordingly. Prior to the period of extended operation, select a method (or methods) from available technologies for inspecting internal surfaces of buried piping that provides suitable indication of piping wall thickness for a representative set of buried piping locations.
- Revise Periodic Surveillance and Preventive Maintenance Program procedures to compare wall thickness measurements to nominal wall thickness or previous measurements to determine rates of corrosion degradation. Compare wall thickness measurements to code minimum wall thickness plus margin for corrosion during the refueling cycle (T_{marg}) to determine acceptability of the component for continued use. Perform subsequent wall thickness measurements as needed for each selected location based on the rate of corrosion and expected time to reach T_{marg}. Perform a minimum of five MCM degradation inspections per year until the rate of MCM corrosion occurrences no longer meets the criteria for recurring internal corrosion.

- Revise the Periodic Surveillance and Preventive Maintenance Program procedures to state that the acceptance criterion is no indication of relevant degradation and to incorporate the following:
  - Examples of acceptance criteria for metallic components
    - No excessive corrosion (loss of material).
    - No leakage from or onto internal surfaces (loss of material).
    - No excessive wear (loss of material).
    - No flow blockage due to fouling.
    - No loss of piping component structural integrity.
  - Examples of acceptance criteria for elastomeric components
    - Flexible polymers should have a uniform surface texture and color with no cracks and no dimension change, no abnormal surface conditions with respect to hardness, flexibility, physical dimensions, and color.

Enhancements will be implemented prior to the period of extended operation.

B.1.36 PROTECTIVE COATING MONITORING AND MAINTENANCE PROGRAM

The Protective Coating Monitoring and Maintenance Program monitors and maintains Service Level I coatings applied to carbon steel and concrete surfaces inside containment (e.g., steel containment vessel shell, structural steel, supports, penetrations, and concrete walls and floors). The program addresses accessible coated surfaces inside containment. The Fermi 2 program will be enhanced to meet the technical basis of ASTM D5163-08. With these enhancements, the program provides an effective method to assess coating condition through visual inspections by identifying degraded or damaged coatings and providing a means for repair of identified problem areas.

Service Level I protective coatings are not credited to manage the effects of aging. Proper monitoring and maintenance of protective coatings inside containment ensures operability of post-accident safety systems that rely on water recycled through the containment. The proper monitoring and maintenance of Service Level I coatings ensures there is no coating degradation that would impact safety functions, for example, by clogging emergency core cooling systems suction strainers and possibly causing unacceptable head loss in the system.

The Protective Coating Monitoring and Maintenance Program will be enhanced as follows.

- Revise plant procedures to include in the program Service Level I coating applied to steel and concrete surfaces of the steel containment vessel (e.g., steel containment vessel shell, structural steel, supports, penetrations, and concrete walls and floors).
- Revise plant procedures to include information and instructions for monitoring Service Level I coating systems to be used for the inspection of coatings in accordance with guidelines identified in ASTM D5163-08.
- Revise plant procedures to specify the parameters monitored or inspected in accordance with subparagraph 10.2 of ASTM D5163-08.

- Revise plant procedures to establish the inspection frequency in accordance with paragraph 6 of ASTM D5163-08.
- Revise plant procedures to develop an inspection plan and specify inspection methods to be used as identified in accordance with subparagraph 10.1 of ASTM D5163-08.
- Revise plant procedures to specify that the nuclear coating specialist qualification recommendations and duties be as defined in ASTM D7108. As a minimum, qualification of inspection personnel (protective coating surveillance personnel) who perform these inspections shall be as specified in ASTM D4537.
- Revise plant procedures to specify a protective coatings program owner (inspection coordinator and inspection results evaluator) or equivalent to nuclear coating specialist defined in ASTM D5163-08 is responsible for the overall plant coatings program and has general duties and responsibilities similar to those defined for a nuclear coating specialist in Section 5 of ASTM D7108-05.
- Revise plant procedures to specify that detection of aging effects will include visual inspections of coatings near sumps or screens associated with the emergency core cooling system (ECCS).
- Revise plant procedures to specify instruments and equipment needed for inspection in accordance with subparagraph 10.5 of ASTM D5163-08.
- Revise plant procedures to specify that upon the completion of a planned refuel outage, a coatings outage summary report will be prepared of the coating work performed in Service Level I areas during the outage. The summary report prioritizes repair areas as areas that must be repaired during the same outage or postponed to future outages, keeping the coatings under surveillance during the interim period.
- Revise plant procedures to specify that the last two performance monitoring reports pertaining to the coating systems will be reviewed prior to the inspection or monitoring process.
- Revise plant procedures to describe the characterization, documentation, and testing of defective or deficient coating surface in accordance with subparagraphs 10.2.1 through 10.2.6, 10.3, and 10.4 of ASTM D5163-08.
- Revise plant procedures to specify that the coatings outage summary report will be evaluated and approved by the protective coatings program owner.

Enhancements will be implemented prior to the period of extended operation.

B.1.37 REACTOR HEAD CLOSURE STUDS PROGRAM

The Reactor Head Closure Studs Program manages cracking due to stress corrosion cracking (SCC) or intergranular stress corrosion cracking (IGSCC) and loss of material due to wear or corrosion for reactor head closure stud bolting (studs, washers, nuts, bushings, and threads in flange) using inservice inspection (ASME Section XI 2001 Edition 2003 Addendum Table IWB-2500-1) and preventive measures to mitigate cracking. The program follows examination and inspection requirements to detect and size cracks and detect loss of material.

Acceptance criteria and evaluation of indications are in accordance with ASME Section XI and other requirements specified per 10 CFR 50.55a with NRC-approved alternatives.

Preventive actions include avoiding the use of metal-plated stud bolting, use of an acceptable surface treatment, use of stable lubricants, and use of bolting materials with low susceptibility to stress corrosion cracking. The program uses visual, surface, and volumetric examinations as required by ASME Section XI. The program also relies on recommendations to address reactor head closure studs degradation listed in NUREG-1339 and NRC Regulatory Guide (RG) 1.65.

The reactor vessel studs, nuts, closure washers, and threaded bushings at Fermi 2 are fabricated from SA-540 Grade B23 and B24 carbon steel. RG 1.65, October 1973, identifies that SA-540 Grades B23 and B24, when tempered to a maximum tensile strength of 170 ksi, are relatively immune to SCC. Nevertheless, since the actual yield strength is not known, the aging management review conservatively identified the stud material as susceptible to cracking.

The Reactor Head Closure Studs Program will be enhanced as follows.

- Revise Reactor Head Closure Studs Program procedures to ensure that replacement studs are fabricated from bolting material with actual measured yield strength less than 150 kilo-pounds per square inch.
- Revise Reactor Head Closure Studs Program procedures to include a statement that excludes the use of molybdenum disulfide (MoS^2) on the reactor vessel closure studs and also refers to recommendations in RG 1.65, Rev. 1.

Enhancements will be implemented prior to the period of extended operation.

B.1.38 REACTOR VESSEL SURVEILLANCE PROGRAM

The Reactor Vessel Surveillance Program manages reduction of fracture toughness of reactor vessel beltline materials due to neutron irradiation embrittlement and monitors reactor vessel long-term operating conditions that could affect neutron irradiation embrittlement of the reactor vessel using material data and dosimetry. The program includes all reactor vessel beltline materials as defined by 10 CFR 50 Appendix G, Section II.F, and complies with 10 CFR 50, Appendix H for vessel material surveillance.

The objective of the reactor vessel material surveillance program is to provide sufficient material data and dosimetry to (a) monitor irradiation embrittlement at the end of the period of extended operation and (b) determine the need for operating restrictions on the inlet temperature, neutron spectrum, and neutron flux.

The original Fermi 2 reactor vessel surveillance program was designed to monitor reactor vessel beltline materials by testing surveillance capsules withdrawn from the Fermi 2 reactor vessel.

The Fermi 2 reactor vessel surveillance program has been integrated into the Boiling Water Reactor Vessel and Internals Project (BWRVIP) Integrated Surveillance Program (ISP). The surveillance sample materials remaining in the Fermi 2 reactor pressure vessel (RPV) are maintained as spares for possible future use. The BWRVIP ISP replaces individual plant reactor pressure vessel surveillance capsule programs with representative weld and base materials data from host reactors. Throughout the term of the ISP, the BWRVIP monitors the progress, coordinates future actions such as withdrawal and testing of future capsules and reporting of surveillance capsule test results, and identifies additional program needs. The BWRVIP will identify and implement changes to the program as the need arises. When specific changes are identified to the ISP testing matrix, withdrawal schedule, or testing and reporting of individual capsule results, these modifications will be submitted to the NRC in a timely manner so that appropriate arrangements can be made for implementation.

The integrated surveillance program for the extended period of operation (ISP(E)), based on BWRVIP document BWRVIP-86, Revision 1, has been approved for use by the NRC. BWRVIP 135 provides reactor pressure vessel surveillance data and other technical material information for the plants participating in the ISP and is revised periodically as additional surveillance data is obtained.

B.1.39 RG 1.127, INSPECTION OF WATER-CONTROL STRUCTURES ASSOCIATED WITH NUCLEAR POWER PLANTS PROGRAM

Fermi 2 is not committed to the requirements of NRC Regulatory Guide (RG) 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants." However, the program at Fermi 2 was developed based on guidance provided in the NRC RG 1.127, Revision 1, and provides an inservice inspection and surveillance program for the Fermi 2 shore barrier and raw water-control structures associated with emergency cooling water systems or flood protection. The scope of the Fermi 2 program includes water-control structures within the scope of license renewal as delineated in 10 CFR 54.4. The program performs periodic visual examinations to monitor the condition of water-control structures and structural components, including structural steel and structural bolting associated with water-control structures, and miscellaneous steel associated with these structures. The program addresses age-related deterioration, degradation due to extreme environmental conditions, and the effects of natural phenomena that may affect water-control structures so that the consequences of age-related deterioration and degradation can be prevented or mitigated prior to loss of intended function. The program will be implemented as part of the Structures Monitoring Program (Section B.1.42).

Enhancements to this program are included in the enhancements to the Structures Monitoring Program (Section B.1.42).

B.1.40 SELECTIVE LEACHING PROGRAM

The Selective Leaching Program is a new program that will demonstrate the absence of selective leaching in a selected sample of components (i.e., 20 percent of the population with maximum of 25 components) fabricated from gray cast iron and copper alloys (except for inhibited brass) that contain greater than 15 percent zinc or greater than 8 percent aluminum exposed to raw water, treated water, waste water, or soil. A sample population is defined as components with the same material and environment combination. Where practical, the sample population will focus on bounding or leading components most susceptible to aging due to time in service, severity of operating condition, and lowest design margin. The program will include a one-time visual inspection of selected components coupled with hardness measurement or other mechanical examination techniques such as destructive testing, scraping or chipping to determine whether loss of material is occurring due to selective leaching that may affect the ability of a component to perform its intended function during the period of extended operation.

Follow-up of unacceptable inspection findings will include an evaluation using the Corrective Action Program and possible expansion of the inspection sample size and location.

This inspection will be performed within five years prior to the period of extended operation.

B.1.41 SERVICE WATER INTEGRITY PROGRAM

The Service Water Integrity Program manages loss of material and fouling for safety-related service water system components fabricated from carbon steel, copper alloys, and stainless steel exposed to service water systems as described in the Fermi 2 response to NRC GL 89-13. The program includes (a) surveillance and control techniques to manage effects of biofouling, corrosion, various erosion mechanisms, and silting; (b) tests to verify heat transfer capability of heat exchangers important to safety; (c) routine inspections and maintenance. System walkdowns are performed.

The Service Water Integrity Program will be enhanced as follows.

- Revise Service Water Integrity Program procedures to include inspection to determine if loss of material due to erosion is occurring in the system.
- Revise Service Water Integrity Program procedures to stipulate that administrative controls are in accordance with the Fermi 2 10 CFR 50 Appendix B Quality Assurance Program.

Enhancements will be implemented prior to the period of extended operation.

B.1.42 STRUCTURES MONITORING PROGRAM

The Structures Monitoring Program provides for aging management of structures and structural components, including structural bolting, within the scope of license renewal. The program was developed based on guidance in Regulatory Guide (RG) 1.160, Revision 2, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," and NUMARC 93-01, Revision 2, "Industry Guidelines for Monitoring the Effectiveness of Maintenance at

Nuclear Power Plants," to satisfy the requirement of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." The scope of the Structures Monitoring Program includes structures within the scope of license renewal as delineated in 10 CFR 54.4. The program performs periodic visual examinations to monitor the condition of structures and structural components, including components such as concrete and steel components, structural bolting, component supports, concrete masonry blocks, and other structures such as earthen structures. Inspections are performed at a frequency to ensure there is no loss of intended function between inspections. The program will be enhanced to perform inspections at least once every five years, with provisions for more frequent inspections, to ensure there is no loss of intended function between inspections. The scope of the program also includes the condition monitoring of masonry walls and water-control structures as described in the Masonry Wall Program and in the NRC RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants," aging management.

The Structures Monitoring Program is augmented by plant procedures to ensure that the selection of bolting material, installation torque or tension, and the use of lubricants and sealants are appropriate for the intended purpose. These procedures will be enhanced to include the guidance of NUREG-1339 and EPRI TR-104213, NP-5067, and NP-5769 to ensure proper specification of bolting material, lubricant, and installation torque.

The Structures Monitoring Program will be enhanced as follows.

- Revise plant procedures to add the following structures to the program.
  - Condensate storage tank and condensate return tank foundations and retaining barrier
  - CTG-11-1 fuel oil storage tank foundation
  - Independent spent fuel storage installation (ISFSI) rail transfer pad
  - Manholes, handholes and duct banks
  - Shore barrier
  - Transformer and switchyard support structures and foundations
- Revise plant procedures to specify that the following in-scope structures are included in the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program:
  - General service water pump house
  - Residual heat removal complex
  - Shore barrier
- Revise plant procedures to ensure that masonry walls located in in-scope structures are in the scope of the Masonry Wall Program.
- Revise plant procedures to include a list of structural components and commodities within the scope of license renewal to be monitored in the program.

- Revise plant procedures to include periodic sampling and chemical analysis of ground water.
- Revise plant procedures to include the following preventive actions:
  - Preventive actions delineated in NUREG-1339 and EPRI NP-5769, NP-5067, and TR-104213 that emphasize the proper selection of bolting material, installation torque or tension, and the use of lubricants and sealants for high-strength bolting.
  - Preventive actions for storage of ASTM A325 and A490 bolting from Section 2 of Research Council for Structural Connections publication, "Specification for Structural Joints Using ASTM A325 or A490 Bolts."
- Revise plant procedures to include the following parameters to be monitored or inspected:
  - For concrete structures, base inspections on quantitative requirements of industry codes (i.e., ACI 349.3R-02), standards and guidelines (i.e., ASCE 11) and consideration of industry and plant-specific operating experience.
  - For concrete structures and components, include loss of material, loss of bond, increase in porosity and permeability, loss of strength, and reduction in concrete anchor capacity due to local concrete degradation.
  - For chemical analysis of ground water, monitor pH, chlorides, and sulfates.
  - Monitor gaps between the structural steel supports and masonry walls that could potentially affect wall qualification.
- Revise plant procedures to include the following components to be monitored for the associated parameters:
  - Structural bolting and anchors/fasteners (nuts and bolts) for loss of material, loose or missing nuts and/or bolts, and cracking of concrete around the anchor bolts.
  - Elastomeric vibration isolators and structural sealants for cracking, loss of material, loss of sealing, and change in material properties (e.g., hardening).
- Revise plant procedures to provide technical guidance for torque value requirements for specified bolting material subject to plant operating environments.
- Revise plant procedures to include the following for detection of aging effects:
  - Personnel (Inspection Engineer and Program Administrator or Responsible Engineer) involved with the inspection and evaluation of structures and structural components, including masonry walls and water-control structures, meet the qualifications guidance identified in ACI 349.3R-02.
  - Visual inspection of elastomeric material should be supplemented by feel or touch to detect hardening if performance of the intended function of the elastomeric material is suspect. Include instructions to augment the visual examination of elastomeric material with physical manipulation of at least ten percent of available surface area.
  - Structures will be inspected at least once every five years.

- Submerged structures will be inspected at least once every five years.
- If normally inaccessible areas become accessible due to plant activities, an inspection of these areas shall be conducted. Additionally, inspections will be performed of inaccessible areas in environments where observed conditions in accessible areas indicate that significant degradation may be occurring in the inaccessible areas.
- Sampling and chemical analysis of ground water at least once every five years. The Structures Monitoring Program owner will review the results and evaluate any anomalies and perform trending of the results.
- Masonry walls will be inspected at least once every five years, with provisions for more frequent inspections in areas where significant aging effects (i.e., missing blocks, cracking, etc.) is observed to ensure there is no loss of intended function between inspections.
- Inspection of water-control structures should be conducted under the direction of qualified personnel experienced in the investigation, design, construction, and operation of these types of facilities.
- Inspections of water-control structures on an interval not to exceed five years.
- Perform special inspections of water-control structures immediately (within 30 days) following the occurrence of significant natural phenomena, such as large floods, earthquakes, hurricanes, tornadoes, and intense local rainfalls.

• Revise plant procedures to prescribe quantitative acceptance criteria based on the quantitative acceptance criteria of ACI 349.3R-02and information provided in industry codes, standards, and guidelines including ACI 318, ANSI/ASCE 11, and relevant AISC specifications. Industry and plant-specific operating experience will also be considered in the development of the acceptance criteria.

• Revise plant procedures to include acceptance criteria for masonry wall inspections that ensure observed aging effects (cracking, loss of material or gaps between the structural steel supports and masonry walls) do not invalidate the wall's evaluation basis or impact its intended function.

• Revise Structures Monitoring Program procedures to include testing and evaluation of water/mineral deposits where in-leakage is observed in concrete elements. Testing and evaluation will determine whether leaching of calcium hydroxide and carbonation are occurring that could impact the intended function(s) of the concrete structure.

• The following testing and evaluation will be performed prior to the period of extended operation to confirm that previously identified conditions are not the result of leaching of calcium hydroxide and carbonation that could impact the intended function(s) of the concrete structure.

  - Available water/mineral deposit samples will be tested for mineral and iron content to assess the effect of the water in-leakage on the reinforced concrete elements involved.

  - The results of the testing and Structures Monitoring Program inspections will be used to determine corrective actions per the Corrective Action Program. Possible corrective actions include, but are not limited to, more frequent inspections, sampling and analysis of the in-leakage water for mineral and iron content, testing core bore samples, and evaluation of the affected area using evaluation and acceptance criteria of ACI 349.3R-02.

Enhancements will be implemented prior to the period of extended operation.

B.1.43 WATER CHEMISTRY CONTROL – BWR PROGRAM

The Water Chemistry Control – BWR Program manages loss of material, cracking, and fouling in components exposed to a treated water environment through periodic monitoring and control of water chemistry. The Water Chemistry Control – BWR Program monitors and controls water chemistry parameters such as pH, chloride, conductivity, and sulfate. EPRI BWR Water Chemistry Guidelines is used to provide guidance.

The One-Time Inspection Program utilizes inspections or non-destructive evaluations of representative samples to verify that the Water Chemistry Control – BWR Program has been effective at managing aging effects. The representative sample includes low flow and stagnant areas.

B.1.44 WATER CHEMISTRY CONTROL – CLOSED TREATED WATER SYSTEMS PROGRAM

The Water Chemistry Control – Closed Treated Water Systems Program manages loss of material, cracking, and fouling in components exposed to a closed treated water environment, through monitoring and control of water chemistry, including the use of corrosion inhibitors, chemical testing, and visual inspections of internal surface condition. The EPRI Closed Cooling Water Chemistry Guideline, industry guidance, and vendor recommendations are used to delineate the program.

The Water Chemistry Control – Closed Treated Water Systems Program will be enhanced as follows.

- Revise the Water Chemistry Control – Closed Treated Water Systems Program procedures to include the following systems.
  - Process sampling system sample cooler loops
  - CCHVAC chill water system
- Revise the Water Chemistry Control – Closed Treated Water Systems Program procedures to provide chemical treatment including a corrosion inhibitor for the following systems in accordance with industry guidelines and vendor recommendations.
  - Process sampling system sample cooler loops
  - CCHVAC chill water system

- Revise Water Chemistry Control – Closed Treated Water Systems Program procedures to specify water chemistry parameters monitored and the acceptable range of values for these parameters in accordance with EPRI Closed Cooling Water Chemistry Guideline, industry guidance, or vendor recommendations.
- Revise Water Chemistry Control – Closed Treated Water Systems Program procedures to inspect accessible components whenever a closed treated water system boundary is opened. Ensure that a representative sample of piping and components is inspected at a frequency of at least once every ten years. These inspections will be conducted in accordance with applicable ASME Code requirements, industry standards, or other plant-specific inspection guidance by qualified personnel using procedures that are capable of detecting corrosion, fouling, or cracking.

  If visual examination identifies adverse conditions, then additional examinations, including ultrasonic testing, are conducted. Components inspected will be those with the highest likelihood of corrosion, fouling, or cracking. A representative sample is 20 percent of the population (defined as components having the same material, environment, and aging effect combination) with a maximum of 25 components.

  Perform treated water sampling and analysis of the closed treated water systems per industry standards and in no case greater than quarterly unless justified with an additional analysis. The process sampling system sample cooler loops will be sampled and tested annually.

Enhancements will be implemented prior to the period of extended operation.

B.1.45 COATING INTEGRITY PROGRAM

The Coating Integrity Program is a new program that will include periodic visual inspections of coatings/linings applied to the internal surfaces of in-scope piping, piping components, heat exchangers, and tanks where loss of coating or lining integrity could prevent accomplishment of a license renewal intended function. Some internally coated components are not managed by the Coating Integrity Program since they are not safety related, leakage through their pressure boundary would not impact a nearby safety-related component and if the coating comes loose, it would not cause a flow blockage that would impact another component's safety related function or function to support a regulated event. For coatings/linings in the program that do not meet the acceptance criteria, physical testing is performed where possible (i.e., sufficient room to conduct testing) in conjunction with visual inspection. Hand tool cleaning and power tool cleaning will be controlled by site procedures that incorporate standards established by the Society of Protective Coatings (SSPC). Specifically, the standards include SSPC-SP 2 Hand Tool Cleaning, SSPC-SP 3 Power Tool Cleaning, and SSPC-SP 11 Power Tool Cleaning to Bare Metal. Further, where applicable, standards for water-jet cleaning will also be incorporated. These would include SSPC-SP WJ-1, 2, 3, and 4. Although there is not an SSPC standard for tap testing, guidance for tap testing is provided in the EPRI Comprehensive Coatings Training Course and other equivalent training. This guidance will also be incorporated into site procedures. The training and qualification of individuals involved in inspections of non-cementitious coatings/linings are in accordance with ASTM standards endorsed in RG 1.54. In addition, the EPRI Comprehensive Coatings Training Course or other equivalent training will be incorporated into site training and qualification requirements for a Coating Specialist. For cementitious coatings, training and qualifications are based on an appropriate combination of education and experience related to inspecting concrete surfaces. Service Level 1 coatings are managed by the Protective Coating Monitoring and Maintenance Program (Section B.1.36).

Baseline coating/lining inspections will occur in the 10-year period prior to the period of extended operation. Subsequent inspections are based on an evaluation of the effect of a coating/lining failure on in-scope component intended functions, potential problems identified during prior inspections, and service life history, but should not exceed the inspection intervals in Table 4a "Inspection Intervals for Internal Coatings/Linings for Tanks, Piping, Piping Components, and Heat Exchangers" identified in LR-ISG-2013-01.

B.2 EVALUATION OF TIME-LIMITED AGING ANALYSES

In accordance with 10 CFR 54.21(c), an application for a renewed license requires an evaluation of time-limited aging analyses for the period of extended operation. The following time-limited aging analyses have been identified and evaluated to meet this requirement.

B.2.1 REACTOR VESSEL NEUTRON EMBRITTLEMENT

The reactor vessel neutron embrittlement time-limited aging analyses, including consideration for measurement uncertainty recapture/thermal power optimization (MUR/TPO) (Refs. DTE Electric Company to NRC, "License Amendment Request for Measurement Un, NRC to DTE Electric, "Fermi 2—Issuance of Amendment re: Measurement Uncertainty Re), either have been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii) or will be managed for the period of extended operation in accordance with 10 CFR 54.24(c)(1)(iii) as summarized below.

Based on the plant operating history, a projected value of 52 EFPY is used to evaluate reactor vessel neutron embrittlement time-limited aging analyses (TLAAs).

B.2.1.1 REACTOR VESSEL FLUENCE

Fluence is calculated based on a time-limited assumption defined by the operating term. Therefore, analyses that evaluate reactor vessel neutron embrittlement based on calculated fluence are time-limited aging analyses.

The reactor vessel fluence has been calculated to include higher power level beginning with cycle 17, when the reactor power increased due to the MUR/TPO uprate. The peak neutron fluence projected for 52 EFPY is 1.03E+18 n/cm^2 at the vessel inner surface. The high energy (> 1 MeV) neutron fluence for the welds and shells of the reactor pressure vessel (RPV) beltline region was determined using the General Electric-Hitachi (GEH) method for neutron flux calculation documented in report NEDC-32983P-A. The method adheres to the guidance prescribed in Regulatory Guide (RG) 1.190.

The neutron fluence calculation results are inputs into fracture toughness analyses. The effects of aging due to neutron irradiation are considered in the neutron embrittlement

TLAAs for the reactor vessel (e.g., upper-shelf energy analysis and P-T limits analysis). The neutron fluence analysis has been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

B.2.1.2 ADJUSTED REFERENCE TEMPERATURE

A key parameter that characterizes the fracture toughness of a material is the reference nil-ductility transition temperature (RT_{NDT}). The effects of neutron radiation on RT_{NDT} are reflected in the reference temperature change (ΔRT_{NDT}). The adjusted reference temperature (ART) is calculated by adding ΔRT_{NDT} to initial RT_{NDT} with an appropriate margin for uncertainties (ΔRT_{NDT} + RT_{NDT} + margin) as defined by RG 1.99 Revision 2.

The method used for the evaluation of the 52 EFPY ART is the same method used by GEH for the MUR/TPO ART evaluation. The ART values for all beltline materials are calculated using fluence values determined with an NRC-approved method that complies with RG 1.190. All projected values are well below the 200°F suggested in Section C.3 of RG 1.99 as an acceptable nominal value of ART for the end of life. The TLAA for ART has been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii). Formal revisions of affected analyses are completed as part of the established process for generation of updated P-T operating limits.

B.2.1.3 PRESSURE-TEMPERATURE LIMITS

Appendix G of 10 CFR 50 requires that the reactor vessel remain within established pressure-temperature (P-T) limits during boltup, hydro-test, pressure tests, normal operation, and anticipated operational occurrences. These limits are calculated using materials and fluence data, including data obtained through the Reactor Vessel Surveillance Program (Section B.1.38).

The P-T limit curves will continue to be updated, as required by Appendix G of 10 CFR Part 50, assuring that limits remain valid through the period of extended operation.

The time-limited aging analyses for reactor vessel pressure-temperature limits will be managed for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

B.2.1.4 UPPER SHELF ENERGY

Upper-shelf energy (USE) is evaluated for beltline materials. Fracture toughness criteria in 10 CFR 50 Appendix G require that beltline materials maintain USE no less than 50 ft-lb during operation of the reactor. The 52 EFPY USE values for the beltline materials were determined using methods consistent with RG 1.99. The determination used the peak ¼T fluence. The re-sults of the evaluation demonstrate that all beltline material remains above 50 ft-lb throughout the period of extended operation.

The time-limited aging analysis for upper shelf energy has been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

B.2.1.5 REACTOR VESSEL CIRCUMFERENTIAL WELD INSPECTION RELIEF

The reactor pressure vessel (RPV) circumferential weld parameters at 52 EFPY will remain within the NRC's (64 EFPY) bounding parameters from the BWRVIP-05 SER. The fact that the values projected to the end of the period of extended operation are less than the 64 EFPY value provided by the NRC leads to the conclusion that the RPV conditional failure probability is less than the conditional failure probability of the NRC analysis. As such, the conditional probability of failure for circumferential welds remains below that determined during the NRC's final safety evaluation of BWRVIP-05.

The reactor vessel circumferential weld inspection relief for the period of extended operation will be submitted to the NRC in accordance with 10 CFR 50.55(a). The effects of aging associated with the time-limited aging analysis for reactor vessel circumferential weld inspection relief will be managed in accordance with 10 CFR 54.21(c)(1)(iii).

B.2.1.6 REACTOR VESSEL AXIAL WELD FAILURE PROBABILITY

The NRC SER for BWRVIP-74-A evaluated the failure frequency of axially oriented welds in BWR reactor vessels. Applicants for license renewal must evaluate axially oriented RPV welds to show that their failure frequency remains below the value calculated in the BWRVIP-74 SER. The SER states that an acceptable way to do this is to show that the mean RT_{NDT} of the limiting axial beltline weld at the end of the period of extended operation is less than the values specified in the SER.

The projected 52 EFPY Fermi 2 mean ART is less than the bounding value shown in the NRC SER for BWRVIP-74. The reactor vessel axial weld TLAA has been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

B.2.1.7 REACTOR PRESSURE VESSEL CORE REFLOOD THERMAL SHOCK ANALYSIS

General Electric Report NEDO-10029 is referenced in UFSAR Section A.1.2 and Table 1.6-1. NEDO-10029 addressed the concern for brittle fracture of the reactor pressure vessel due to reflood following a postulated loss of coolant accident (LOCA). The thermal shock analysis documented in NEDO-10029 assumed a design basis recirculation line break LOCA followed by a low pressure coolant injection, accounting for the full effects of neutron embrittlement at the end of 40 years. Because this analysis bounded only 40 years of operation, reflood thermal shock of the reactor pressure vessel has been identified as a TLAA for Fermi 2 requiring evaluation for the period of extended operation.

A later analysis of the BWR vessels was developed in 1979 (Ranganath, S., "Fracture Mechanics Evaluation of a Boiling Water Reactor Vessel Following a Postulated Loss of Coolant Accident," Fifth International Conference on Structural Mechanics in Reactor Technology, Berlin, Germany, August 1979 (Accession No. 9110110105 in Public Legacy Library)). The Ranganath analysis has been used to evaluate the TLAA through the period of extended operation. The Ranganath analysis which was performed for a 6-inch thick BWR-6 pressure vessel is bounding for the Fermi 2 vessel. The thickness of the lower shell for the Fermi 2 vessel is 7.125 inches; the thickness of the lower-intermediate shell is 6.125 inches.

The Ranganath analysis is bounding for Fermi 2 because (1) the pressure stress (higher for a thinner vessel) is near zero in a thermal shock event and therefore can be neglected, and (2) the difference in temperature and thermal stresses at the ¼T location between a 6-inch thick vessel and a 6.125-inch or 7.125-inch thick vessel (as demonstrated in Figures 3 and 4 of Ranganath) is small. The fluence level and ART values used are specific to Fermi 2, as projected for 52 EFPY. The analysis shows that when the peak stress intensity occurs at approximately 300 seconds after the LOCA, the temperature of the vessel wall at 1.5 inches deep is approximately 400°F.

The maximum ART value calculated for the Fermi 2 RPV beltline material is 102°F. Using the equation for fracture toughness K_{IC} presented in Appendix A of ASME Section XI and the maximum ART value, the material reaches upper shelf at approximately 206°F, which is well below the approximately 400°F temperature predicted for the thermal shock event at the time of peak stress intensity. Therefore, the revised evaluation, using the Ranganath analysis, has projected the TLAA through the period of extended operation. The reactor pressure vessel core reflood thermal shock TLAA has been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

B.2.2 METAL FATIGUE

B.2.2.1 CLASS 1 METAL FATIGUE ANALYSES

Fatigue evaluations were performed in the design of the Fermi 2 Class 1 components. Class 1 fatigue evaluations are contained in analyses and stress reports, and because they are based on a number of transient cycles assumed for a 40-year operating term, these evaluations are considered time-limited aging analyses.

The Fatigue Monitoring Program (Section B.1.17) tracks transient cycles and requires corrective actions, if the numbers of cycles approach analyzed values. It provides for use of cycle-based fatigue or stress-based fatigue monitoring methods if a component's cumulative usage factor based on cycle counting is projected to exceed 1.0 after the environmentally assisted fatigue (EAF) calculations are complete. The Fatigue Monitoring Program will manage the effects of aging due to fatigue in accordance with 10 CFR 54.21(c)(1)(iii).

The following provides additional information for specific Class 1 components.

Reactor Pressure Vessel

As described in UFSAR Section 5.4.6.3.1 and shown in UFSAR Figure 5.4-1, the RPV is a vertical, cylindrical pressure vessel with hemispherical heads of welded construction. Fatigue evaluations for the reactor vessel were performed as part of the vessel design.

Fermi 2 monitors transient cycles using the Fatigue Monitoring Program (Section B.1.17) and assures that action is taken if the actual cycles approach their analyzed numbers. As such, the Fatigue Monitoring Program will manage the effects of aging due to fatigue on the reactor vessel in accordance with 10 CFR 54.21(c)(1)(iii).

Reactor Pressure Vessel Feedwater Nozzle

As described in UFSAR Section 5.2.1.20, Fermi 2 installed a feedwater sparger and thermal sleeve prior to plant operation to eliminate thermal fatigue concerns on the feedwater nozzle.

The vessel was manufactured with unclad feedwater nozzles, so no cladding removal was necessary. The inner thermal sleeve is the feed pipe for the sparger and is sealed against the safe-end with a piston ring. The inner thermal sleeve is welded to the sparger forged tee. As described in UFSAR Section 5.2.1.20, the Fermi 2 feedwater sparger and thermal sleeve design conforms to NUREG-0619.

As a part of the NUREG-0619 review, a plant-specific feedwater nozzle fracture mechanics assessment was completed. The projected number of startup/shutdowns plus scrams is less than the total cycles utilized in this analysis. Therefore, the analysis remains valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

The analysis of the feedwater nozzle includes fatigue from potential rapid cycling behind the thermal sleeves. The feedwater nozzle has fatigue usage contribution from rapid cycling that is part of the total fatigue usage for that location. The usage is calculated based on time and feedwater temperature in order to include the rapid cycling effect.

The effects of fatigue on the feedwater nozzles will be managed for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

Reactor Pressure Vessel Internals

A reactor vessel general assembly drawing is shown in UFSAR Figure 4.5-1, and a cutaway drawing is shown in UFSAR Figure 5.4-1. The Fermi 2 reactor pressure vessel internals are not ASME code pressure boundary components. ASME analyses were completed for some RVI locations. Fermi 2 will monitor transient cycles using the Fatigue Monitoring Program (Section B.1.17) and assure that action is taken before the numbers of accrued cycles exceed their analyzed numbers. As such, the Fatigue Monitoring Program will manage the effects of aging due to fatigue on the reactor vessel internals in accordance with 10 CFR 54.21(c)(1)(iii).

Reactor Recirculation Pumps

As identified in UFSAR Table 3.2-1, the reactor recirculation pumps were designed to the NPVC 1 (NPVC-1, 2, 3 Draft ASME Code for Pumps and Valves for Nuclear Power, Class I, II, III). As identified in Note z of UFSAR Table 3.2-1 and UFSAR Table 3.2-4 Note j, the reactor recirculation pumps were upgraded to the 4th generation design, and the modified components were designed and manufactured to ASME III, 1989. Representative analyses of recirculation pumps are summarized in UFSAR Table 3.9-20.

The Fatigue Monitoring Program (Section B.1.17) will manage the effects of aging due to fatigue on the reactor recirculation pumps in accordance with 10 CFR 54.21(c)(1)(iii).

Class 1 Piping

UFSAR Table 3.2-1 provides a summary of the safety classes for the principal structures, systems, and components of the plant. Components of the reactor coolant pressure boundary whose failure could cause a loss of reactor coolant at a rate in excess of the normal makeup system capability are Class 1 components. Detailed fatigue analyses were generated to analyze multiple locations on each system within the Class 1 boundary.

The Fatigue Monitoring Program (Section B.1.17) will monitor the numbers of cycles incurred to assure that action is taken if the numbers approach the values analyzed. As such, the Fatigue Monitoring Program will manage the effects of aging due to fatigue on the Class 1 piping in accordance with 10 CFR 54.21(c)(1)(iii).

B.2.2.2 NON-CLASS 1 METAL FATIGUE ANALYSES

UFSAR Table 3.2-1 provides a summary of the safety classes for the principal structures, systems, and components of the plant. As identified in UFSAR Table 3.2-1, the non-Class 1 piping within the scope of license renewal is built to ASME III or ANSI B31.1.

The design of ASME III Code Class 2 and 3 or ANSI B31.1 piping systems incorporates a stress range reduction factor for piping design with respect to thermal stresses. In general, a stress range reduction factor of 1.0 in the stress analyses applies for up to 7000 thermal cycles. Fermi 2 evaluated the validity of this assumption for 60 years of plant operation. The results of this evaluation indicate that the 7000 thermal cycle assumption will not be exceeded for 60 years of operation. Therefore, the non-Class 1 piping stress calculations are valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

Non-Class 1 components other than piping require fatigue analyses if they were built to a section of the code such as ASME Section III, NC-3200 or ASME Section VIII, Division 2. A review of the non-Class 1 components identified non-Class 1 fatigue analysis applicable to expansion joints. Fatigue analyses were identified for expansion joints that assumed a bounding number of cycles. These expansion joint fatigue analyses are treated as time-limited aging analyses. Evaluation of these expansion joint analyses determined the number of analyzed cycles was adequate for 60 years of operation. Therefore, these non-Class 1 expansion joint TLAAs are valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

B.2.2.3 EFFECTS OF REACTOR WATER ENVIRONMENT ON FATIGUE LIFE

NUREG/CR-6260 addresses the application of environmental correction factors to fatigue analyses (cumulative usage factors [CUFs]) and identifies locations of interest for consideration of environmental effects. NUREG/CR-6260 identified the following component locations to be the most sensitive to environmental effects for General Electric plants.

(1) Reactor vessel shell and lower head

(2) Reactor vessel feedwater nozzle

(3) Reactor recirculation piping (including inlet and outlet nozzles)

(4) Core spray line reactor vessel nozzles and associated Class 1 piping

(5) Residual heat removal nozzles and associated Class 1 piping

(6) Feedwater line Class 1 piping

Environmentally assisted fatigue (EAF) screening was performed for these NUREG/CR-6260 locations and the remaining ASME Class 1 reactor pressure vessel and piping locations for which fatigue had been assessed that are (1) wetted (in contact with liquid reactor coolant) and (2) form part of the reactor coolant pressure boundary. The components with the highest calculated CUF in each system were evaluated for the effects of EAF. The screening evaluation used guidance in NUREG/CR-6909, as allowed by NUREG-1801, Revision 2. The fatigue curves in NUREG/CR-6909 were applied for all materials. The methodology discussed in EPRI 1024995, "Environmentally Assisted Fatigue Screening: Process and Technical Basis for Identifying EAF Limiting Locations" was used as guidance to determine which locations are bounding. These locations are referred to as Sentinel locations. The Sentinel locations are monitored to manage the effects of aging including EAF in the period of extended operation. This screening has determined there are locations that, when accounting for environmental effects, have projected usage factors greater than 1.0. Additional action will be needed, e.g. more detailed analysis or stress-based or cycle-based fatigue monitoring, as part of the Fatigue Monitoring Program (Section B.1.17) for these locations.

Fermi 2 will manage the effects of fatigue, including environmentally assisted fatigue, under the Fatigue Monitoring Program (Section B.1.17) for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

B.2.3 ENVIRONMENTAL QUALIFICATION OF ELECTRICAL COMPONENTS

All operating plants must meet the requirements of 10 CFR 50.49, which defines the scope of electrical components to be included in a program for qualifying electric equipment important to safety (EQ program) and also sets forth requirements for an EQ program. Qualification is established for the environmental and service conditions expected for normal plant operation and also those conditions postulated for plant accidents. A record of qualification for in-scope components must be prepared and maintained in auditable form. Equipment qualification evaluations for EQ components that result in a qualification of at least 40 years, but less than 60 years, are considered TLAAs for license renewal.

The Fermi 2 Environmental Qualification (EQ) of Electric Components Program (EQ Program) (Section B.1.15) manages component thermal, radiation, and cyclical aging, as applicable, through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. As required by 10 CFR 50.49, EQ components not qualified for the current license term are to be refurbished, replaced, or have their qualification extended prior to reaching the limitations established in the evaluation. The Fermi 2 EQ Program ensures that EQ components are maintained in accordance with their qualification bases.

The Fermi 2 EQ Program is an existing program established to meet Fermi 2 commitments for 10 CFR 50.49. The program is consistent with NUREG-1801, Section X.E1, "Environmental Qualification (EQ) of Electric Components." The Fermi 2 EQ Program will manage the effects of aging on the intended function(s) of EQ components that are the subject of EQ TLAAs for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

B.2.4 FATIGUE OF PRIMARY CONTAINMENT, ATTACHED PIPING, AND COMPONENTS

As described in UFSAR Section 3.8, the primary containment (a Mark I containment) is a leak-tight steel-plate containment vessel consisting of a light-bulb-shaped drywell and a torus-shaped suppression chamber. The Fermi 2 analysis is documented in the Plant Unique Analysis Report (PUAR) for Fermi 2. Fermi 2 will manage the aging effects due to fatigue using the Fatigue Monitoring Program (Section B.1.17) in accordance with 10 CFR 54.21(c)(1)(iii).

The vent line bellows were qualified for bellows expansion from the drywell and torus temperature increase following an accident or from earthquakes. The bellows remain qualified for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

Fermi 2 has a refueling bellows attached to the vessel near the reactor vessel flange and a drywell seal bellows outside of the drywell shell. These bellows remain qualified for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

Fermi 2 has penetration bellows at the traversing incore probe (TIP) penetrations. The fatigue analysis determined the bellows were qualified for many more cycles than they are expected to experience. Therefore, the bellows remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

As described in UFSAR Section 3.8.2.1.3.1, sleeved penetration assemblies with bellows consist of the process pipe, guard pipe, penetration sleeve bellows, and flued head. For Class 1 piping, the design of the flued head meets ASME III Class 1 requirements, which specify a fatigue analysis that determines the cumulative usage factor for the flued head. Fermi 2 will manage the aging effects due to fatigue of these penetrations using the Fatigue Monitoring Program (Section B.1.17) in accordance with 10 CFR 54.21(c)(1)(iii).

The sleeved penetration assembly bellows were determined to be capable of handling the movement from many more cycles than are projected. The sleeved penetration assembly bellows analyses remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

B.2.5 OTHER PLANT-SPECIFIC TLAAs

B.2.5.1 EROSION OF THE MAIN STEAM LINE FLOW RESTRICTORS

UFSAR Section 5.5.4.4 states that the main steam flow restrictors are fabricated from stainless steel and that only very slow erosion will occur with time. The section later postulates that even with an erosion rate of 0.004 inches per year, the increase in choked flow after 40 years would be no more than 5 percent. Analysis of the erosion rate is evaluated as a TLAA.

DTE Electric evaluated the erosion-corrosion rate for the main steam flow restrictors. This evaluation considered the specific material of the Fermi 2 flow restrictors and determined the expected erosion-corrosion rate when operating at the velocities that would be present following an extended power uprate, which is a greater velocity than anticipated following the MUR/TPO uprate. The evaluation determined that the expected erosion-corrosion rate would be much less than the conservative erosion rate provided in the UFSAR. Assuming the expected erosion-corrosion rate for 60 years of operation, the increase in restrictor-choked flow rate will remain no more than five percent as specified in UFSAR Section 5.5.4.4.

This analysis has been projected through the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

B.2.5.2 DETERMINATION OF HIGH-ENERGY LINE BREAK LOCATIONS

UFSAR Sections 3.6.1 and 3.6.2 state that the method used to determine the intermediate locations of pipe breaks in high-energy lines includes an evaluation based on CUFs being less than 0.1 if other stress criteria are also met.

Design criteria for piping between the primary containment and outboard isolation valves provide for maximum stresses considering all normal and upset conditions as calculated by the equations in the ASME Boiler & Pressure Vessel Code Section III Paragraph NB-3653. As identified in UFSAR Section 3.6.2.1.2.2, pipe breaks were not postulated in the high energy piping between the containment penetration and outboard isolation valves since the piping was conservatively designed and restrained. The calculated CUFs for containment penetration piping were also limited to values less than 0.1 if equation 10 of NB-3653 exceeds 2.4 S_m.

The CUFs, as calculated in the design fatigue analyses, are based on the design transients assumed for the original 40-year life of the plant; therefore, the CUF analyses used in the selection of postulated high-energy line break locations are considered TLAAs.

The Fatigue Monitoring Program (Section B.1.17) identifies when the transients affecting high-energy piping are approaching their analyzed numbers of cycles.

DTE Electric will manage the effects of aging associated with the fatigue analyses used in the selection of postulated high-energy line break locations using the Fatigue Monitoring Program in accordance with 10 CFR 54.21(c)(1)(iii).

B.2.5.3 JET PUMP AUXILIARY SPRING WEDGE ASSEMBLY

Auxiliary spring wedges have been installed on jet pumps 1, 2 and 15 at Fermi 2 to maintain continuous three point contact for the inlet mixer to the restrainer bracket. A calculation evaluates relaxation of the spring preload for the jet pump auxiliary spring wedge assemblies. The evaluation considers a neutron fluence of 1.2E+20 n/cm^2 (E > 1 MeV) for a 40-year design life. The relaxation of the spring preload in the spring wedge assembly is a TLAA.

To disposition the TLAA, a fluence analysis was performed to determine the fluence values at the three currently installed wedges on the jet pumps and at the bounding location for possible future installation of wedge assemblies through the period of extended operation. The analysis determined that wedge 1 is the limiting case with the projected neutron fluence for wedge 1 slightly exceeding the design fluence prior to the end of the period of extended operation. An evaluation of the slightly higher fluence for wedge 1 determined that it has no impact on the most limiting stresses that were reported in the original stress report. The slightly higher fluence for wedge 1 has no adverse impact on the structural integrity and functional performance.

The results of the analysis demonstrated that the available preload at the end of period of extended operation is considerably greater than the required preload. Additionally, the auxiliary spring wedge assembly is designed to function independent of the spring preload, i.e. the spring wedge function works at any preload. There will be contact between the belly band, auxiliary spring wedge assembly and the restrainer bracket.

This TLAA has been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

B.2.5.4 JET PUMP SLIP JOINT REPAIR CLAMPS

The jet pump slip joint repair clamp is connected to the diffuser and the mixer. The clamp is installed with a preload that may be relaxed due to neutron fluence. The analysis that evaluated relaxation of the slip joint repair clamp is a TLAA.

To evaluate the TLAA, a fluence analysis including the increased fluence due to the MUR/TPO was performed to determine the fluence at the installed positions on the jet pumps including 52 EFPY. It was determined the neutron irradiation does not impact the amount of expected relaxation. The original relaxation value remains valid for 52 EFPY of operation and the stress report results remain applicable for the period of extended operation.

This TLAA has been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

B.2.5.5 FLAW EVALUATIONS FOR THE REACTOR VESSEL

During refueling outage 9 (RF9) in 2003, new ASME Section XI, Appendix VIII qualified ultrasonic examination procedures were used for the first time on reactor pressure vessel welds. These new techniques employed greatly improved flaw detection and sizing methods and detected several reactor vessel flaws. A reexamination in RF12 used the phased array technique and identified flaws at two additional locations.

A fracture mechanics evaluation was performed to determine the acceptability of the reactor vessel flaw indications. The analysis evaluated the bounding flaw location for consideration of the pressure-temperature analysis. The analysis determined the indications are acceptable for 52 EFPY with consideration of the effects of MUR/TPO.

This TLAA has been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

B.2.5.6 MAIN STEAM BYPASS LINES CUMULATIVE OPERATING TIME

A flaw evaluation concluded that the bypass lines are acceptable for safe operation when operated within the 100 day constraint. The cumulative time the main steam bypass lines are operated with the bypass valves between 30 and 45 percent open will be reported annually. A cumulative value of 100 days is not to be exceeded without prior NRC notification.

Fermi 2 will manage the main steam bypass valves' cumulative usage time using the Fatigue Monitoring Program (Section B.1.17) in accordance with 10 CFR 54.21(c)(1)(iii).

B.2.5.7 CRANE (HEAVY LOAD) CYCLES

UFSAR Section 9.1.4.2.2 states that the reactor building overhead crane meets the structural guidelines of Crane Manufacturers Association of America (CMAA) Specification No. 70. CMAA-70 identifies an allowable stress range based on joint category and service class. The definition of service class considers the load class and the load cycles expected on the crane.

The lowest range of cycles in CMAA-70 is 20,000 to 100,000 for Class A cranes; therefore, the analysis associated with the CMAA-70 lift cycle limit is considered a TLAA.

It is estimated that the number of lifts for the reactor building overhead crane will remain below the 100,000 cycles established in CMAA-70 for a Class A service hoist.

Therefore, the evaluation of lift cycles for the reactor building crane remains valid for the period of extended operation consistent with 10 CFR 54.21(c)(1)(i).

B.2.5.8 CORE SUPPORT PLATE HOLD-DOWN BOLT STRESS RELAXATION

The core support plate is fastened to the core support structure using 34 stainless steel bolting connections. The core plate hold-down bolts are subject to stress relaxation due to thermal and irradiation effects. The BWRVIP determined that all core support bolts will maintain some preload for 40 years of service in BWRVIP-25. Revision 1-A to BWRVIP-25 contains Appendix I, which provides a technical basis justifying no examinations to be performed on core plate bolts provided certain loading and fluence criteria are bounded by plant-specific values.

Plant-specific analysis considering the limiting plant-specific design basis vertical load combinations and fluence projections were used to demonstrate that the Fermi 2 core plate bolts are bounded by the analysis in BWRVIP-25, Revision 1-A, for the period of extended operation. The peak core plate bolt fluence value of 1.06E+20 n/cm^2 at 52 EFPY was used to bound the entire length of the bolt. The use of BWRVIP-25 Revision 1-A to resolve licensee commitments regarding BWRVIP-25 examinations was accepted by the staff by NRC SER (Reference 5), and use of BWRVIP-25 Revision 1-A at Fermi was accepted by NRC SER (Reference 6).

This TLAA has been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

REFERENCES

1. DTE Electric Company to NRC, "Fermi 2 License Renewal Application," NRC-14-0028, letter dated April 24, 2014 (ML14121A554).

2. NRC to DTE Electric, "Safety Evaluation Report Related to the License Renewal of Fermi 2 (TAC No. MF4222)," letter dated July 12, 2016 (ML16179A224). [Re-issued as NUREG-2210 (ML16356A234) in October 2016.]

3. DTE Electric Company to NRC, "License Amendment Request for Measurement Uncertainty Recapture (MUR) Power Uprate," NRC-13-0004, letter dated February 7, 2013 (ML13043A659).

4. NRC to DTE Electric, "Fermi 2—Issuance of Amendment re: Measurement Uncertainty Recapture Power Uprate (TAC NO. MF0650)," letter dated February 10, 2014 (ML13364A131).

5. NRC to BWRVIP, "FINAL PROPRIETARY SAFETY EVALUATION FOR "BWRVIP-25, REVISION 1: BWR VESSEL AND INTERNALS PROJECT, BWR CORE PLATE INSPECTION AND FLAW EVALUATION GUIDELINES" (CAC NO. MF4887; EPID L-2014-TOP-0008)," letter dated March 23, 2020 (ML19290G703).

6. NRC to DTE Energy, "FERMI 2 – REVISED RELIEF REQUEST RR-A39 FOR THE FOURTH 10-YEAR INSERVICE INSPECTION INTERVAL (EPID L-2020-LLR-0161)," letter dated October 15, 2021 (ML21253A010).

TABLE B-1 Fermi 2 License Renewal Commitments

Item Number	Commitment	FSAR Supplement Section/LRA Section	Enhancement or Implementation Schedule	Source
1	DTE will make the following changes to the process for operating experience review. a. Procedures will be revised to add an aging type code to corrective action program documents that describe either plant conditions related to aging or industry operating experience related to aging. b. Procedures will be revised to provide for training of personnel responsible for submitting, screening, assigning, evaluating, or otherwise processing plant-specific and industry operating experience concerning age-related degradation and aging management, as well as for personnel responsible for implementing AMPs, based on the complexity of the job performance requirements and assigned responsibilities. c. Procedures will be revised to specify that evaluations of operating experience concerning age-related degradation will include consideration of the affected systems, structures or components, the environments, materials, aging effects, aging mechanisms, and aging management programs.	A.1	Completed	LRA DTE letter NRC-15-0009 dated 1/15/15 DTE letter NRC-16-0045 dated 7/6/16
2	DTE currently performs periodic self-assessments on many aging management programs. DTE will enhance the Fermi 2 self-assessment process to provide for periodic evaluation of the effectiveness of each aging management program described in the updated final safety analysis report (UFSAR) supplement. For new aging management programs, the first evaluation will be performed within 5 years of implementing the program.	A.1	Within 5 years of implementing the program for new programs.	LRA
3	Implement the new Aboveground Metallic Tanks Program that will manage loss of material and cracking for outdoor tanks within the scope of license renewal that are sited on soil or concrete. Condensate storage tank (CST) internal inspections will be conducted in accordance with Table 4a of LR-ISG-2012-02. This program will also manage the bottom surfaces of the CST. Within the 10 years prior to the period of extended operation and every 10 years thereafter, a volumetric examination of a minimum 25 percent of the CST tank bottom interface with the concrete ring foundation will be performed to manage loss of material. The	A.1.1	Prior to September 20, 2024, or the end of the last refueling outage prior to March 20, 2025, whichever is later. Initial inspections will be performed within the 10 years prior to	LRA DTE letter NRC-15-0005 dated 1/20/15 DTE letter NRC-15-0031 dated 4/10/15

TABLE B-1 Fermi 2 License Renewal Commitments

Item Number	Commitment	FSAR Supplement Section/LRA Section	Enhancement or Implementation Schedule	Source
	volumetric inspection will be on a 2 inch grid or less, depending on the technology utilized.		March 20, 2025.	
4	Enhance the Bolting Integrity Program as follows: a. Revise Bolting Integrity Program procedures to ensure consideration of actual yield strength when procuring bolting material. If procured, closure bolting with actual yield strength greater than or equal to 150 ksi is monitored for cracking. b. Revise Bolting Integrity Program procedures to state that bolting for safety-related pressure-retaining components is inspected for leakage, loss of material, cracking, and loss of preload/loss of prestress. Closure bolting with actual yield strength greater than or equal to 150 ksi is monitored for cracking. c. Revise Bolting Integrity Program procedures to: (1) implement applicable recommendations for pressure boundary bolting in NUREG-1339, Electric Power Research Institute (EPRI) NP-5769, and EPRI TR-104213; (2) state both American Society of Mechanical Engineers (ASME) Code class bolted connections and non-ASME Code class bolted connections are inspected at least once per refueling cycle; and (3) include volumetric examination per ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1, for closure bolting with actual yield strength greater than or equal to 150 ksi regardless of code classification. d. Revise Bolting Integrity Program procedures to inspect residual heat removal service water (RHRSW), emergency equipment service water (EESW), and emergency diesel generator service water (EDGSW) systems' pump and valve bolting submerged in the RHRSW reservoir at least once every refueling outage and to opportunistically inspect	A.1.2	Completed	LRA DTE letter NRC-15-0006 dated 1/20/15 DTE letter NRC-15-0011 dated 2/12/15

TABLE B-1 Fermi 2 License Renewal Commitments

Item Number	Commitment	FSAR Supplement Section/LRA Section	Enhancement or Implementation Schedule	Source
	bolting threads during maintenance activities. e. Revise Bolting Integrity Program procedures to include the additional guidance and recommendations of EPRI NP-5769 for replacement of ASME pressure-retaining bolts and the guidance provided in EPRI TR-104213 for the replacement of other pressure-retaining bolts. f. Revise Bolting Integrity Program procedures to stipulate that administrative controls are in accordance with the Fermi 2 10 CFR Part 50 Appendix B Quality Assurance Program. g. Revise Bolting Integrity Program procedures to perform opportunistic inspections for Control Center HVAC system safety-related pressure-retaining bolting in a lube oil external environment, including the bolting threads to ensure that loss of material in crevice locations that are not readily visible can be detected. h. Revise Bolting Integrity Program procedures to perform opportunistic inspections for CTG system nonsafety-related pressure-retaining bolting in a lube oil external environment.			
5	Implement the Boraflex rack replacement approved in Amendment No. 141 so that the current Boraflex panels in the spent fuel pool will not be required to perform a neutron absorption function during the period of extended operation.	A.1.3	Prior to September 20, 2024, or the end of the last refueling outage prior to March 20, 2025, whichever is later.	LRA DTE letter NRC-15-0081 dated 9/24/15
6	Implement new Buried and Underground Piping Program that will manage the effects of aging on the external surfaces of buried and underground piping within the scope of license renewal. Soil testing will be conducted once in each 10-year period starting 10 years prior to the period of extended operation, if a reduction in the number of inspections recommended in Table XI.M41-2of NUREG 1801 is taken based on a lack of soil corrosivity.	A.1.4	Prior to September 20, 2024, or the end of the last refueling outage prior to March 20, 2025, whichever is later. Initial directed inspections and soil testing (if the reduction in inspections based on soil testing is	LRA DTE letter NRC-15-0002 dated 1/15/15 DTE Letter NRC-16-0027 dated 4/12/16

TABLE B-1 Fermi 2 License Renewal Commitments

Item Number	Commitment	FSAR Supplement Section/LRA Section	Enhancement or Implementation Schedule	Source
			taken) will be performed within the 10 years prior to March 20, 2025.	
7	Enhance the BWR Vessel Internals Program as follows: a. The susceptibility to neutron or thermal embrittlement for reactor vessel internal components composed of cast austenitic stainless steel (CASS) and X-750 alloy will be evaluated. b. BWR Vessel Internals Program procedures will be revised as follows. Portions of the susceptible components determined to be limiting from the standpoint of thermal aging susceptibility, neutron fluence, and cracking susceptibility (i.e., applied stress, operating temperature, and environmental conditions) will be inspected, using an inspection technique capable of detecting the critical flaw size with adequate margin. The critical flaw size will be determined based on the service loading condition and service-degraded material properties. The initial inspection will be performed either prior to or within 5 years after entering the period of extended operation. If cracking is detected after the initial inspection, the frequency of re-inspection will be justified based on fracture toughness properties appropriate for the condition of the component. The sample size for the initial inspection of susceptible components will be 100 percent of the accessible component population, excluding components that may be in compression during normal operations. c. BWR Vessel Internals Program procedures will be revised as follows. In accordance with an applicant action item for BWRVIP-25 safety evaluation: (a) install core plate wedges prior to the period of extended operation, or (b) complete a plant-specific analysis that justifies no inspections are required, or (c) complete a plant-specific analysis to determine acceptance criteria for continued inspection of core plate hold-down bolts in accordance with BWRVIP-25.	A.1.10	Perform initial inspection either prior to March 20, 2025, or before March 20, 2030. Submit analysis and inspection plan to the NRC prior to March 20, 2023. Remaining activities: Prior to September 20, 2024, or the end of the last refueling outage prior to March 20, 2025, whichever is later.	LRA DTE letter NRC-15-0010 dated 2/5/15 DTE letter NRC-15-0044 dated 4/27/15 DTE letter NRC-15-0062 dated 6/9/15 DTE letter NRC-15-0083 dated 8/20/15

TABLE B-1 Fermi 2 License Renewal Commitments

Item Number	Commitment	FSAR Supplement Section/LRA Section	Enhancement or Implementation Schedule	Source
	For Option (b), the analysis will address loss of preload due to stress relaxation in the core plate rim hold-down bolts and quantify the loss of preload/stress relaxation that will occur in these bolts during the period of extended operation. The analysis will be submitted to the NRC 2 years prior to the period of extended operation. Additionally, the UFSAR will be revised to address the analysis if it is determined to meet the criteria for a time-limited aging analysis (TLAA) at least 2 years prior to the period of extended operation. For Option (c), the analysis will address loss of preload due to stress relaxation in the core plate rim hold-down bolts and quantify the loss of preload/stress relaxation that will occur in these bolts during the period of extended operation. The analysis, inspection plan with acceptance criteria, and justification for the inspection plan will be submitted to the NRC 2 years prior to the period of extended operation. Additionally, the UFSAR will be revised to address the analysis if it is determined to meet the criteria for a TLAA at least 2 years prior to the period of extended operation. d. Revise BWR Vessel Internals Program procedures such that the flaw evaluation methodology for the top guide grid beam will address the following three items if they have not been resolved generically during the NRC review and approval process of BWRVIP-183: (1) Detected flaws evaluated using the methodology in BWRVIP-183 Section 4 will be demonstrated to be sufficiently far from geometric discontinuities (i.e., notches or slots) such that the stress condition in the vicinity of the flaw is consistent with that for a single edgecrack plate. Appropriately applied K values which account for the effects of geometric discontinuities will be used and justified in the flaw evaluation. (2) The flaw evaluation methodology in BWRVIP-183 Section 4 will be used to justify continued operation on a			

TABLE B-1 Fermi 2 License Renewal Commitments

Item Number	Commitment	FSAR Supplement Section/LRA Section	Enhancement or Implementation Schedule	Source
	cycle-by-cycle basis. Use of the flaw evaluation methodology to justify operation for more than once cycle will require NRC approval and would be based on plant-specific operating experience including crack length measurements of detected top guide grid beam flaws to benchmark the accuracy of the flaw evaluation methodology. (3) When applying the flaw evaluation methodology in BWRVIP-183 Section 4, a severed beam evaluation consistent with BWRVIP-183 Section 5 will also be performed. The severed beam analysis will demonstrate that even if a beam was a completely severed beam, it would not be expected to interfere with the ability of the control rod drive system to insert control rods. e. Revise BWR Vessel Internals Program procedures to perform opportunistic inspections of the differential pressure and standby liquid control line inside the reactor vessel when the line becomes accessible.			
8	Enhance the Compressed Air Monitoring Program as follows: a. DELETED b. Revise Compressed Air Monitoring Program procedures to include periodic and opportunistic inspections of accessible internal surfaces of piping, compressors, dryers, aftercoolers, and filters. In addition, include in the Compressed Air Monitoring Program procedures the applicable provisions recommended in EPRI NP-7079, EPRI TR- 108147, and ASME OM-S/G-1998, Part 17 for air system contaminants, inspection frequency, inspection methods, and acceptance criteria for components subject to aging management review that are exposed to compressed air and components in the EDG starting air system and control air system.	A.1.11	Completed	LRA
9	Enhance the Containment Inservice Inspection (CII)-IWE Program as follows: a. Revise plant procedures to require inspection of the sand	A.1.12	Prior to	LRA DTE letter

TABLE B-1 Fermi 2 License Renewal Commitments

Item Number	Commitment	FSAR Supplement Section/LRA Section	Enhancement or Implementation Schedule	Source
	cushion drain lines to monitor the internal conditions of the drain lines (e.g., for moisture, sand, blockage) and ensure there is no evidence of blockage at least once prior to the period of extended operation and once every 10 years during the period of extended operation. b. Revise plant procedures to specify the preventive actions delineated in NUREG-1339 and in EPRI NP-5769, NP-5067, and TR-104213 that emphasize proper selection of bolting material, installation torque or tension, and the use of lubricants and sealants for high strength bolting. c. Revise plant procedures to include the preventive actions for storage of American Society for Testing and Materials (ASTM) A325 and A490 bolting from Section 2 of Research Council for Structural Connections publication, "Specification for Structural Joints Using ASTM A325 or A490 Bolts." d. [Deleted] e. [Deleted] f. Revise plant procedures to determine drywell shell thickness in the sand cushion areas before the period of extended operation and once in each 10-year interval during the period of extended operation. From the results (including prior results), develop a corrosion rate to demonstrate that the drywell shell will have sufficient wall thickness to perform its intended function through the period of extended operation. g. Revise plant procedures to require corrective actions should moisture be detected or suspected in the inaccessible area on the exterior of the drywell shell, including: • Identify surfaces requiring augmented inspections for the period of extended operation in accordance with Subsection IWE-1240, as identified in Table IWE-2500-1, Examination Category E-C. • Use examination methods that are in accordance with Subsection IWE-2500.		September 20, 2024, or the end of the last refueling outage prior to March 20, 2025, whichever is later.	NRC-15-0004 dated 1/15/15

TABLE B-1 Fermi 2 License Renewal Commitments

Item Number	Commitment	FSAR Supplement Section/LRA Section	Enhancement or Implementation Schedule	Source
	• Demonstrate through use of augmented inspections performed in accordance with Subsection IWE that corrosion is not occurring or that corrosion is progressing so slowly that the degradation will not jeopardize the intended function of the drywell shell through the period of extended operation.			
10	Enhance Diesel Fuel Monitoring Program as follows: a. Revise Diesel Fuel Monitoring Program procedures to monitor and trend water and sediment, particulates, and levels of microbiological organisms in the EDG fuel oil storage tanks, EDG fuel oil day tanks, diesel fire pump fuel oil tank, and CTG fuel oil tank quarterly. In addition, revise program procedures to state that biocides or corrosion inhibitors may be added as a preventive measure or are added if periodic testing indicates biological activity or evidence of corrosion, respectively. b. Revise the Diesel Fuel Monitoring Program procedures to include a 10-year periodic cleaning and internal visual inspection of the EDG fuel oil storage tanks, EDG fuel oil day tanks and diesel fire pump fuel oil tank with the following instructions. The cleanings and internal inspections will be performed at least once during the 10-year period prior to the period of extended operation and at succeeding 10-year intervals. If visual inspection is not possible, perform a volumetric inspection. If evidence of degradation is observed during visual inspection, perform a volumetric examination of the affected area. The schedule for the Preventive Maintenance (PM) event to perform diesel fire pump fuel oil tank draining, flushing, and inspection will continue at its frequency at the time of the enhancement implementation, until a PM evaluation of results from fuel oil samples and tank inspections indicates that the system will be capable of continuing to perform its	A.1.14	Prior to September 20, 2024, or the end of the last refueling outage prior to March 20, 2025, whichever is later.	LRA DTE letter NRC-15-0056 dated 5/19/15

TABLE B-1 Fermi 2 License Renewal Commitments

Item Number	Commitment	FSAR Supplement Section/LRA Section	Enhancement or Implementation Schedule	Source
	function during the period of extended operation with a lower frequency, not less than once per 10-year interval for cleaning and internal visual inspection consistent with NUREG-1801.			
11	Enhance External Surfaces Monitoring Program as follows: a. Revise External Surfaces Monitoring Program procedures to clarify that periodic inspections will be performed of systems in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4 (a)(1) and (a)(3). Inspections shall include areas surrounding the subject systems to identify hazards to those systems. Inspections of nearby systems that could impact the subject systems will include structures, systems, and components (SSCs) that are in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(2). b. Revise External Surfaces Monitoring Program procedures to inspect 100 percent of accessible components at least once per refueling cycle and to ensure required walk downs include instructions to inspect for the following related to metallic components: • Corrosion (loss of material). • Leakage from or onto external surfaces (loss of material). • Worn, flaking, or oxide-coated surfaces (loss of material). • Corrosion stains on thermal insulation (loss of material). • Protective coating degradation (cracking, flaking, and blistering). • Leakage for detection of cracks on the external surfaces of stainless steel components exposed to an air environment containing halides (cracking). c. Revise External Surfaces Monitoring Program procedures to include instructions for monitoring aging effects for flexible polymeric components through physical manipulations of the material, with a sample size for manipulation of at least 10 percent of the available surface area. Inspect accessible surfaces for the following:	A.1.16	Completed	LRA DTE letter NRC-14-0051 dated 7/30/14 DTE letter NRC-15-0007 dated 1/28/15 DTE letter NRC-15-0032 dated 4/17/15 DTE letter NRC-15-0067 dated 6/18/15

TABLE B-1 Fermi 2 License Renewal Commitments

Item Number	Commitment	FSAR Supplement Section/LRA Section	Enhancement or Implementation Schedule	Source
	• Surface cracking, crazing, scuffing, dimensional changes (e.g., ballooning and necking). • Discoloration. • Exposure of internal reinforcement for reinforced elastomers. • Hardening as evidence by loss of suppleness during manipulation where the component and material are appropriate to manipulation. • Shrinkage, loss of strength. d. Revise External Surfaces Monitoring Program procedures to specify the following for insulated components: • Periodic representative inspections will be conducted during each 10-year period. • For a representative sample of insulated indoor components exposed to condensation (because the component is operated below the dew point) and insulated outdoor components, insulation will be removed for visual inspection of the component surface. Inspections include a minimum of 20 percent of the in-scope piping length for each material type (e.g., steel, stainless steel, copper alloy, aluminum), or for components with a configuration which does not conform to a 1-foot axial length determination (e.g., valve, accumulator), 20 percent of the surface area. Alternatively, insulation will be removed and a minimum of 25 inspections performed that can be a combination of 1-foot axial length sections and individual components for each material type. • Inspection locations are based on the likelihood of corrosion under insulation (CUI). For example, CUI is more likely for components experiencing alternate wetting and drying in environments where trace contaminants could be present and for components that operate for long periods of time below the dew point.			

TABLE B-1 Fermi 2 License Renewal Commitments

Item Number	Commitment	FSAR Supplement Section/LRA Section	Enhancement or Implementation Schedule	Source
	Subsequent inspections will consist of an examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation, if the following conditions are verified in the initial inspection: o No loss of material due to general, pitting or crevice corrosion, beyond that which could have been present during initial construction, and o No evidence of cracking. If the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or there is evidence of water intrusion through the insulation (e.g., water seepage through insulation seams/joints), periodic inspections under the insulation will continue as described above. • Removal of tightly adhering insulation that is impermeable to moisture is not required unless there is evidence of damage to the moisture barrier. If the moisture barrier is intact, the likelihood of CUI is low for tightly adhering insulation. Tightly adhering insulation is considered to be a separate population from the remainder of insulation installed on in-scope components. The entire population of in-scope accessible piping component surfaces that have tightly adhering insulation will be visually inspected for damage to the moisture barrier with the same frequency as for other types of insulation inspections. These inspections will not be credited towards the inspection quantities for other types of insulation. e. Revise External Surfaces Monitoring Program procedures to include acceptance criteria for the parameters observed. • Metals should not have any indications of relevant degradation.			

TABLE B-1 Fermi 2 License Renewal Commitments

Item Number	Commitment	FSAR Supplement Section/LRA Section	Enhancement or Implementation Schedule	Source
	• Flexible polymers should have a uniform surface texture and color with no cracks and no dimension change, no abnormal surface conditions with respect to hardness, flexibility, physical dimensions, and color. • Rigid polymers should have no erosion, cracking, crazing or chalking. • For insulation, no discoloration, staining, or surface irregularities from moisture intrusion. f. Revise External Surfaces Monitoring Program procedures to stipulate that administrative controls are in accordance with the Fermi 2 10 CFR Part 50 Appendix B Quality Assurance Program. g. Revise External Surfaces Monitoring Program procedures to include instructions for detection of cracking of gas-filled stainless steel and aluminum components exposed to outdoor air. h. Revise External Surfaces Monitoring Program procedures to: (a) Visually inspect jacketed and nonjacketed insulation required to reduce heat transfer at a frequency consistent with NUREG-1801 Section XI.M36, as modified by LR-ISG-2012-02, to ensure that insulation degradation due to moisture intrusion has not occurred. (b) Ensure procedures include instructions to inspect for signs of water intrusion. Inspect accessible surfaces for the following signs of water intrusion: discoloration, staining, or surface irregularities.			
12	Enhance the Fatigue Monitoring Program as follows: a. Revise Fatigue Monitoring Program procedures to monitor and track critical thermal and pressure transients for components that have been identified to have a fatigue TLAA. b. Develop environmentally assisted fatigue (EAF) usage calculations that consider the effects of the reactor water environment for a set of sample reactor coolant system components. This sample set will include the locations	A.1.17	Part (b): At least 2 years prior to March 20, 2025. Remainder: Prior to September 20, 2024.	LRA DTE letter NRC-15-0005 dated 1/20/15 DTE letter

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Item Number	Commitment	FSAR Supplement Section/LRA Section	Enhancement or Implementation Schedule	Source
	identified in NUREG/CR-6260 and additional plant-specific component locations in the reactor coolant pressure boundary if they are found to be more limiting than those considered in NUREG/CR-6260. Environmental correction factors will be determined using formulae consistent with those recommended in NUREG-1801, X.M1. c. Revise Fatigue Monitoring Program procedures to provide updates of the fatigue usage calculations on an as-needed basis if an allowable cycle limit is approached, or in a case where a transient definition has been changed, unanticipated new thermal events are discovered, or the geometry of components has been modified. For components with assumed minimal cycle counts, ensure that exemption assumptions are not exceeded. d. After the EAF calculations are completed, revise the Fatigue Monitoring Program procedures to state that the program counting of the cycle limits maintains the cumulative fatigue usage below the design limit through the period of extended operation, with consideration of the reactor water environmental fatigue effects. Revise Fatigue Monitoring Program procedures to allow for use of cycle-based fatigue (CBF) or stress-based fatigue (SBF) monitoring methods (including environmental effects) if a component's cumulative usage factor (CUF) value is projected to exceed 1.0 after EAF calculations are completed. e. Revise Fatigue Monitoring Program procedures so that the scope of the program includes monitoring the operating hours for the main steam bypass operation at the 30%-45% valve open position and perform trending to ensure that the operating time for the main steam bypass operation remains below the design limit during the period of extended operation. f. Revise Fatigue Monitoring Program procedures to provide			NRC-15-0011 dated 2/12/15

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	for corrective actions to prevent the operating time for the main steam bypass from exceeding the analysis during the period of extended operation. Acceptable corrective actions include repair of the component, replacement of the component, or a more rigorous analysis of the component to demonstrate that the service life will not be exceeded during the period of extended operation.			
13	Enhance the Fire Protection Program as follows: a. Revise Fire Protection Program procedures to perform visual inspections to manage loss of material of the Halon and CO2 fire suppression system. b. Revise Fire Protection Program procedures to require visual inspections of in-scope: • Fire wrap and fire stop materials for loss of material, change in material properties, cracking/delamination, separation, increased hardness, shrinkage, and loss of strength. • Carbon steel penetration sleeves for loss of material. • Steel framing, roof decking, and floor decking for loss of material. • Concrete fire barriers including manways, manhole covers, handholes, and roof slabs for loss of material and cracking. • Railroad bay airlock doors for loss of material. Inspections are performed at a frequency in accordance with the NRC-approved fire protection program or at least once every refueling cycle.	A.1.18	Prior to September 20, 2024.	LRA DTE letter NRC-15-0009 dated 1/15/15
14	Enhance the Fire Water System Program as follows: a. Revise Fire Water System Program procedures to ensure sprinkler heads are tested or replaced in accordance with National Fire Protection Association (NFPA) 25 (2001 Edition), Section 5.3.1. b. Revise Fire Water System Program procedures to perform an	A.1.19	Prior to September 20, 2024, or the end of the last refueling outage prior to March 20, 2025, whichever is later, with	LRA DTE letter NRC-14-0051 dated 7/30/14

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	inspection of wet fire water system piping condition at least once every 5 years by opening a flushing connection at the end of one main and by removing a sprinkler toward the end of one branch line for the purpose of inspecting the interior for evidence of loss of material and the presence of foreign organic or inorganic material that could result in flow obstructions or blockage of a sprinkler head. Where multiple wet-pipe systems are in a building, every other system shall be inspected in a 5-year period. Then, in the next 5-year period, the remaining systems in that building shall be inspected. (Refer to NFPA 25 (2011 Edition), Sections 14.2.1 and 14.2.2.) The inspection method used shall be capable of detecting surface irregularities that could indicate wall loss due to corrosion, corrosion product deposition, and flow blockage due to fouling. Ensure procedures require a followup volumetric wall thickness evaluation where irregularities are detected. c. Revise Fire Water System Program procedures to: (a) ensure sprinkler heads are tested or replaced in accordance with NFPA 25 (2011 Edition) Section 5.3.1 and (b) the fire protection engineer approves the sprinkler testing laboratory. d. Revise Fire Water System Program procedures to: (a) specify that in accordance with NFPA 13.2.5.2 when there is a 10 percent reduction in full flow pressure when compared to the original acceptance test or previously performed tests, the cause of the reduction shall be identified and corrected as necessary; and (b) note the time to return to static pressure after performing a main drain test. e. Revise Fire Water System Program procedures to notify the fire protection engineer of test results and deficiencies identified or detected during testing.		the exception that the activities described in this commitment for piping segments designed to be dry but determined to be collecting water shall be conducted within 5 years prior to March 20, 2025.	DTE letter NRC-15-0002 dated 1/15/15 DTE letter NRC-15-0031 dated 4/10/15

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	f. Revise Fire Water System Program procedures to ensure piping is cleaned and sprinklers are replaced if obstructions are identified during internal inspections. Sprinklers loaded with dust may be cleaned using air rather than replaced. g. Revise Fire Water System Program procedures to perform an internal inspection of wet fire water system piping conditions at least once every 5 years by opening a flushing connection at the end of one main and by removing a sprinkler toward the end of the branch line for the purpose of inspecting the interior for evidence of loss of material and the presence of foreign organic and inorganic material that could result in flow obstructions or blockage of sprinkler heads. Where multiple wet-pipe systems are in a building, every other system shall be inspected in a 5-year period. Then, in the next 5-year period, the remaining systems in that building shall be inspected. h. [Deleted] i. Revise Fire Water System Program procedures to perform at least once every 5 years either an internal inspection of the dry components downstream of the deluge valves for the hydrogen seal oil unit by removing a sprinkler toward the end of one branch line and inspecting for evidence of loss of material and the presence of foreign organic and inorganic material that could result in flow obstructions or blockage of sprinklers, or Revise Fire Water System Program procedures to perform at least once every 5 years an air or smoke test to verify there is no flow obstruction or blockage of sprinklers. j. Revise Fire Water System Program procedures to perform an inspection of the water distribution piping associated with charcoal filters for loss of material and foreign organic or inorganic material when the charcoal beds are replaced. k. Revise Fire Water System Program procedures to perform an			

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Item Number	Commitment	FSAR Supplement Section/LRA Section	Enhancement or Implementation Schedule	Source
	obstruction investigation whenever any of the criteria listed in NFPA Section 14.2.1.3 or 14.3.1 are met. l. Perform a fire water system walkdown of the piping and components that are designed to be dry (e.g., downstream of deluge valves or manual isolations of dry fire water piping), but are periodically wetted, to determine if any piping sections are collecting water and are subject to both of the following augmented inspections: • In each 5-year interval, beginning 5 years prior to the period of extended operation, either (a) conduct a flow test or flush sufficient to detect potential flow blockage, or (b) conduct a visual inspection of 100 percent of the internal surface of piping segments that cannot be drained or piping segments that allow water to collect. • In each 5-year interval of the period of extended operation, inspect 20 percent of the length of piping segments that cannot be drained or piping segments that allow water to collect using volumetric techniques to measure wall thickness. Measurement points will be obtained so that each potential degraded condition can be identified (e.g., general corrosion, microbiologically induced corrosion (MIC)). The 20 percent of piping that will be inspected in each 5-year interval will be in different locations than previously inspected piping. m. Revise Fire Water System Program procedures to include acceptance criteria that any indication of fouling is evaluated. n. Revise Fire Water System Program procedures to specify that if the presence of sufficient foreign organic or inorganic material to obstruct pipe or sprinklers is detected during pipe inspections, the material is removed and the source and extent of condition determined, corrected, and the condition entered into the corrective action program. o. Revise Fire Water System Program procedures to replace			

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Item Number	Commitment	FSAR Supplement Section/LRA Section	Enhancement or Implementation Schedule	Source
	sprinklers associated with representative tested sprinkler, if the representative test sprinkler fails to meet the test requirements. p. Revise Fire Water System Program procedures to replace any sprinkler that shows signs of corrosion. q. If the decreasing trend in fire water system flow tests is not resolved through the corrective action program prior to the period of extended operation, revise Fire Water System Program procedures to continue performing annual fire water system flow tests during the period of extended operation until such a time as trend data from fire water system flow tests indicates that the system will be capable of performing its intended function throughout the period of extended operation and, therefore, Technical Requirements Manual (TRM) frequency may be resumed. r. Revise Fire Water System Program procedures to include formal documentation of the Control Center Heating, Ventilation, and Air Conditioning (CCHVAC) makeup and recirculation fire water supply drain down inspection for indications of flow blockage.			
15	Enhance the Flow-Accelerated Corrosion Program as follows: a. Revise procedures to indicate that the Flow-Accelerated Corrosion Program also manages loss of material due to erosion mechanisms of cavitation, flashing, liquid droplet impingement, and solid particle erosion for any material in treated water or steam environments. Include in program procedures a susceptibility review based on internal operating experience, external operating experience, EPRI TR-1011231, and NUREG/CR-6031. Piping subject to erosive conditions is not excluded from inspections, even if it has been replaced with flow-accelerated corrosion-resistant material. Periodic wall thickness measurements of such piping should continue until the effectiveness of corrective actions is assured. b. Revise Flow-Accelerated Corrosion Program procedures to	A.1.20	Completed	LRA

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Item Number	Commitment	FSAR Supplement Section/LRA Section	Enhancement or Implementation Schedule	Source
	specify that downstream components are monitored closely for wall thinning when susceptible upstream components are replaced with resistant materials.			
16	Enhance the Inservice Inspection (ISI)-IWF Program as follows: a. Revise plant procedures to specify the preventive actions delineated in NUREG-1339 and EPRI NP-5769, NP-5067, and TR-104213 that emphasize proper selection of bolting material, installation torque or tension, and the use of lubricants and sealants for high-strength bolting. b. Revise plant procedures to require structural bolting replacement and maintenance activities to include appropriate preload and proper tightening (torque or tension) as recommended in EPRI documents, ASTM standards, American Institute of Steel Construction (AISC) Specifications, as applicable. c. Revise plant procedures to include the preventive actions for storage of ASTM A325 and A490 bolting from Section 2 of Research Council for Structural Connections publication, "Specification for Structural Joints Using ASTM A325 or A490 Bolts." d. Revise plant procedures to specify that detection of aging effects will include monitoring anchor bolts for loss of material, loose or missing nuts or bolts, and cracking of concrete around the anchor bolts. e. Revise plant procedures to identify the following unacceptable conditions: • Debris, dirt, or excessive wear that could prevent or restrict sliding of the sliding surfaces as intended in the design basis of the support. • Cracked or sheared bolts, including high-strength bolts, and anchors. f. Revise plant procedures to include the preventive action of using bolting material that has an actual measured yield strength less than 150 ksi, except in the case of like-for-like	A.1.22	Completed	LRA DTE letter NRC-15-0032 dated 4/17/15 DTE letter NRC-15-0044 dated 4/27/15

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	replacement of existing bolting material in the reactor pressure vessel skirt to ring girder bolted joint. g. Revise plant procedures to include assessment of the impact on the inspection sample, in terms of sample size and representativeness, if components that are part of the sample population are re-worked.			
17	Enhance the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (OVHLL) Program as follows: a. Revise plant procedures to specify the monitoring of rails in the rail system for loss of material due to wear; monitor structural components of the bridge, trolley and hoists for deformation, cracking, and loss of material due to corrosion; and monitor structural connections/bolting for loose or missing bolts, nuts, pins, or rivets, and any other conditions indicative of loss of bolting integrity. b. Revise plant procedures to specify inspection frequency requirements will be in accordance with ASME B30.2 or other appropriate standard in the ASME B30 series. c. Revise plant procedures to require that significant loss of material due to wear of rails in the rail system and any sign of loss of bolting integrity will be evaluated in accordance with ASME B30.2 or other appropriate standard in the ASME B30 series. d. Revise plant procedures to specify that maintenance and repair activities will use the guidance provided in ASME B30.2 or other appropriate standard in the ASME B30 series.	A.1.23	Completed	LRA
18	Implement the new Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage fouling, cracking, loss of material, and change in material properties using representative sampling and opportunistic visual inspections of the internal surfaces of piping and components in environments other than open-cycle cooling water, closed treated water, and fire water. Program periodic surveillances or maintenance activities will be conducted when the surfaces are accessible for visual inspection.	A.1.24	Prior to September 20, 2024.	LRA

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Item Number	Commitment	FSAR Supplement Section/LRA Section	Enhancement or Implementation Schedule	Source
19	Implement the new Metal Enclosed Bus Inspection Program to provide for the inspection of the internal and external portions of metal enclosed bus to identify age-related degradation of the bus and bus connections, the bus enclosure assemblies, the bus insulation and the bus insulators.	A.1.26	Completed	LRA
20	Enhance Neutron-Absorbing Material Monitoring Program as follows: a. Prior to the period of extended operation, revise Neutron-Absorbing Material Monitoring Program procedures to establish an inspection frequency, justified with plant-specific operating experience, of at least once every 10 years, based on the condition of the neutron-absorbing material. b. Revise Neutron-Absorbing Material Monitoring Program procedures to perform trending of coupon testing results to determine the rate of degradation. Ensure the predicted boron-10 areal density will be sufficient to maintain the subcritical conditions required by technical specifications until the next coupon test.	A.1.27	Prior to September 20, 2024.	LRA
21	Implement the new Non-EQ Cable Connections Program, a one-time inspection program that consists of a representative sample of electrical connections within the scope of license renewal, which is inspected or tested at least once prior to the period of extended operation to confirm that there are no aging effects requiring management during that period. Cable connections included in this program are those connections susceptible to age-related degradation resulting in in-creased resistance of connection due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, or oxidation that are not subject to the environmental qualification requirements of 10 CFR 50.49.	A.1.28	Completed	LRA
22	Implement the new Non-EQ Inaccessible Power Cables (400 V to 13.8 kV) Program, a condition monitoring program that will manage the aging effect of reduced insulation resistance on inaccessible power (400 V to 13.8 kV) cables that have a license renewal intended function. The program calls for inaccessible or underground (e.g., in conduit, duct bank, or direct buried) power (greater than or equal to 400 V) cables exposed to significant moisture, to be tested at least once every 6 years to provide an indication of the condition of the conductor insulation, with	A.1.29	Prior to September 20, 2024, or the end of the last refueling outage prior to March 20, 2025, whichever is later.	LRA

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	the first tests occurring before the period of extended operation. The program will include periodic inspections for water accumulation in manholes within the scope of this program.			
23	Implement the new Non-EQ Instrumentation Circuits Test Review Program, a performance monitoring program that will manage the aging effects of applicable cables in the following systems or sub-systems. • Neutron monitoring - Intermediate range channels (IRM) - Average power range monitors (includes local power range monitors [LPRM] detector strings) • Process radiation monitoring - Control center emergency air inlet radiation monitors - Fuel pool ventilation exhaust radiation monitors - Main steam line radiation monitors The Non-EQ Instrumentation Circuits Test Review Program calls for the review of calibration results or findings of surveillance tests on electrical cables and connections used in circuits with sensitive, high-voltage, low-level current signals, such as radiation monitoring and nuclear instrumentation, to provide an indication of the existence of aging effects based on acceptance criteria related to instrumentation circuit performance. The review of calibration results or findings of surveillance tests is performed at least once every 10 years. In cases where cables are not included as part of calibration or surveillance program testing circuit, a proven cable test (such as insulation resistance tests, time domain reflectometry tests, or other testing judged to be effective in determining cable system insulation condition as justified in the application) is performed. The test frequency is based on engineering evaluation and is at least once every 10 years.	A.1.30	Prior to September 20, 2024, or the end of the last refueling outage prior to March 20, 2025, whichever is later.	LRA
24	Implement the new Non-EQ Insulated Cables and Connections Program, a condition monitoring program that provides reasonable assurance that the intended functions of insulated cables and connections exposed to adverse localized environments caused by heat, radiation, moisture, and chemical contamination (i.e., bird droppings) can be maintained consistent with the current licensing basis through the period of extended operation. The program consists of accessible insulated electrical cables	A.1.31	Prior to September 20, 2024, or the end of the last refueling outage prior to March 20, 2025, whichever is later.	LRA DTE letter NRC-15-0056 dated 5/19/15

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	and connections installed in adverse localized environments to be visually inspected at least once every 10 years.			
25	Enhance the Oil Analysis Program as follows: a. Revise Oil Analysis Program procedures to identify components within the scope of the program. b. Revise Oil Analysis Program procedures to provide a formalized analysis technique for particulate counting. c. Revise Oil Analysis Program procedures to include the sampling and testing requirements of equipment manufacturers or industry standards.	A.1.32	Prior to September 20, 2024.	LRA
26	Implement the new One-Time Inspection Program that will consist of a one-time inspection of selected components to accomplish the following: • Verify the effectiveness of an aging management program that is designed to prevent or minimize aging to the extent that it will not cause the loss of intended function during the period of extended operation. The aging effects evaluated are loss of material, cracking, and fouling. • Confirm the insignificance of an aging effect for situations in which additional confirmation is appropriate using inspections that verify degradation is not occurring. • Trigger additional actions that ensure the intended functions of affected components are maintained during the period of extended operation.	A.1.33	Inspections will be performed within the 10 years prior to March 20, 2025.	LRA
27	Implement the new One-Time Inspection – Small-Bore Piping Program that will augment ASME Code, Section XI (2001 Edition with 2003 Addenda) requirements and be applicable to small-bore ASME Code Class 1 piping and components with a nominal pipe size diameter less than 4 inches (NPS 4) and greater than or equal to 1 inch (NPS 1) in systems that have not experienced cracking of ASME Code Class 1 small-bore piping.	A.1.34	The inspection will be performed within the 6-year period prior to March 20, 2025.	LRA
28	Enhance the Periodic Surveillance and Preventive Maintenance Program as follows:	A.1.35	Prior to	LRA

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Item Number	Commitment	FSAR Supplement Section/LRA Section	Enhancement or Implementation Schedule	Source
	a. Revise the Periodic Surveillance and Preventive Maintenance Program procedures as necessary to incorporate the identified activities in LRA Section A.1.35. b. Revise the Periodic Surveillance and Preventive Maintenance Program procedures to state that acceptance criterion is no indication of relevant degradation and to incorporate the following: • Examples of acceptance criteria for metallic components - No excessive corrosion (loss of material) - No leakage from or onto internal surfaces (loss of material) - No excessive wear (loss of material) - No flow blockage due to fouling - No loss of piping component structural integrity • Examples of acceptance criteria for elastomeric components - Flexible polymers should have a uniform surface texture and color with no cracks and no dimension change, no abnormal surface conditions with respect to hardness, flexibility, physical dimensions, and color. c. Revise Periodic Surveillance and Preventive Maintenance Program procedures to require periodic determination of wall thickness for selected piping components. d. Revise Periodic Surveillance and Preventive Maintenance Program procedures to require wall thickness measurements using ultrasonic testing (UT) or other suitable techniques at selected locations to be periodically performed to identify loss of material due to multiple corrosion mechanisms (MCM) in system piping components. The selected locations are based on pipe configuration, flow conditions, and operating history to represent a cross-section of potential MCM sites. The selected locations are periodically reviewed to validate their relevance and usefulness, and are modified accordingly. Prior		September 20, 2024. Initial inspection of cable spreading room dry piping will be performed within the 5 years prior to March 20, 2025.	DTE letter NRC-14-0051 dated 7/30/14 DTE letter NRC-15-0002 dated 1/15/15

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	to the period of extended operation, select a method (or methods) from available technologies for inspecting internal surfaces of buried piping that provide(s) suitable indication of piping wall thickness for a representative set of buried piping locations. e. Revise Periodic Surveillance and Preventive Maintenance Program procedures to compare wall thickness measurements to nominal wall thickness or previous measurements to determine rates of corrosion degradation. Compare wall thickness measurements to code minimum wall thickness plus margin for corrosion during the refueling cycle (Tmarg) to determine acceptability of the component for continued use. Perform subsequent wall thickness measurements as needed for each selected location based on the rate of corrosion and expected time to reach Tmarg. Perform a minimum of five MCM degradation inspections per year until the rate of MCM corrosion occurrences no longer meets the criteria for recurring internal corrosion.			
29	Enhance the Protective Coating Monitoring and Maintenance Program as follows: a. Revise plant procedures to include in the program Service Level I coating applied to steel and concrete surfaces of the steel containment vessel (e.g., steel containment vessel shell, structural steel, supports, penetrations, and concrete walls and floors). b. Revise plant procedures to include information and instructions for monitoring Service Level I coating systems to be used for the inspection of coatings in accordance with guidelines identified in ASTM D5163-08. c. Revise plant procedures to specify the parameters monitored or inspected in accordance with subparagraph 10.2 of ASTM D5163-08. d. Revise plant procedures to establish the inspection frequency in accordance with paragraph 6 of ASTM D5163-08.	A.1.36	Prior to September 20, 2024	LRA

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	e. Revise plant procedures to develop an inspection plan and specify inspection methods to be used as identified in accordance with subparagraph 10.1 of ASTM D5163-08. f. Revise plant procedures to specify that the nuclear coating specialist qualification recommendations and duties be as defined in ASTM D7108. As a minimum, qualification of inspection personnel (protective coating surveillance personnel) who perform these inspections shall be as specified in ASTM D4537. g. Revise plant procedures to specify a protective coatings program owner (inspection coordinator and inspection results evaluator) or equivalent to nuclear coating specialist defined in ASTM D5163-08, is responsible for the overall plant coatings program and has general duties and responsibilities similar to those defined for a nuclear coating specialist in Section 5 of ASTM D7108-05. h. Revise plant procedures to specify that detection of aging effects will include visual inspections of coatings near sumps or screens associated with the ECCS. i. Revise plant procedures to specify instruments and equipment needed for inspection in accordance with subparagraph 10.5 of ASTM D5163- 08. j. Revise plant procedures to specify that upon the completion of a planned refuel outage, a coatings outage summary report will be prepared of the coating work performed in Service Level I areas during the outage. The summary report prioritizes repair areas as areas that must be repaired during the same outage or postponed to future outages, keeping the coatings under surveillance during the interim period. k. Revise plant procedures to specify that the last two performance monitoring reports pertaining to the coating systems will be reviewed prior to the inspection or monitoring process.			

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	l. Revise plant procedures to describe the characterization, documentation, and testing of defective or deficient coating surface in accordance with subparagraphs 10.2.1 through 10.2.6, 10.3, and10.4 of ASTM D5163-08. m. Revise plant procedures to specify that the coatings outage summary report will be evaluated and approved by the protective coatings program owner.			
30	Enhance the Reactor Head Closure Studs Program as follows: a. Revise Reactor Head Closure Studs Program procedures to ensure that replacement studs are fabricated from bolting material with actual measured yield strength of less than 150 kilopounds per square inch (ksi). b. Revise Reactor Head Closure Studs Program procedures to include a statement that excludes the use of molybdenum disulfide (MoS_2) on the reactor vessel closure studs and also refers to recommendations in Regulatory Guide 1.65, Rev. 1.	A.1.37	Completed	LRA
31	[Deleted]			LRA DTE letter NRC-15-0020 dated 3/5/15
32	Implement the new Selective Leaching Program that will demonstrate the absence of selective leaching in a selected sample of components (i.e., 20 percent of the population with maximum of 25 components) fabricated from gray cast iron and copper alloys (except for inhibited brass) that contain greater than 15 percent zinc or greater than 8 percent aluminum exposed to raw water, treated water, waste water, or soil.	A.1.40	Inspection will be performed within 5 years prior to March 20, 2025.	LRA
33	Enhance the Service Water Integrity Program as follows: a. Revise Service Water Integrity Program procedures to include inspection to determine if loss of material due to erosion is occurring in the system. b. Revise Service Water Integrity Program procedures to stipulate that administrative controls are in accordance	A.1.41	Completed	LRA

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	with the Fermi 2 10 CFR Part 50 Appendix B Quality Assurance Program.			
34	Enhance the Structures Monitoring Program as follows: a. Revise plant procedures to add the following structures to the program. • CST and condensate return tank foundations and retaining barrier • CTG-11-1 fuel oil storage tank foundation • Independent spent fuel storage installation (ISFSI) rail transfer pad • Manholes, handholes, and duct banks • Shore barrier • Transformer and switchyard support structures and foundations b. Revise plant procedures to specify that the following in-scope structures are included in the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program (Section A.1.39): • General service water pump house • Residual heat removal complex • Shore barrier c. Revise plant procedures to ensure that masonry walls located in in-scope structures are in the scope of the Masonry Wall Program (Section A.1.25). d. Revise plant procedures to include a list of structural components and commodities within the scope of license renewal to be monitored in the program. e. Revise plant procedures to include periodic sampling and chemical analysis of groundwater. f. Revise plant procedures to include the following preventive actions: • Preventive actions delineated in NUREG-1339 and EPRI NP-5769, NP-5067, and TR-104213 that emphasize the proper selection of bolting material, installation torque or tension, and the use of lubricants and sealants for high-strength bolting.	A.1.42	Prior to September 20, 2024. Testing and evaluation for possible leaching in previously identified conditions will commence in 2015.	LRA DTE letter NRC-14-0070 dated 10/24/14 DTE letter NRC-14-0082 dated 12/26/14 DTE letter NRC-15-0008 dated 1/26/15 DTE letter NRC-15-0030 dated 3/19/15

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	• Preventive actions for storage of ASTM A325 and A490 bolting from Section 2 of Research Council for Structural Connections publication, "Specification for Structural Joints Using ASTM A325 or A490 Bolts." g. Revise plant procedures to include the following parameters to be monitored or inspected: • For concrete structures, base inspections on quantitative requirements of industry codes (i.e., American Concrete Institute (ACI) 349.3R-02), standards and guidelines (i.e., American Society of Civil Engineers (ASCE) 11) and consideration of industry and plant-specific operating experience. • For concrete structures and components, include loss of material, loss of bond, increase in porosity and permeability, loss of strength, and reduction in concrete anchor capacity due to local concrete degradation. • For chemical analysis of groundwater, monitor pH, chlorides, and sulfates. • Monitor gaps between the structural steel supports and masonry walls that could potentially affect wall qualification. h. Revise plant procedures to include the following components to be monitored for the associated parameters: • Structural bolting and anchors/fasteners (nuts and bolts) for loss of material, loose or missing nuts and/or bolts, and cracking of concrete around the anchor bolts. • Elastomeric vibration isolators and structural sealants for cracking, loss of material, loss of sealing, and change in material properties (e.g., hardening). i. Revise plant procedures to provide technical guidance for torque value requirements for specified bolting material subject to plant operating environments. j. Revise plant procedures to include the following for detection of aging effects:			

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Item Number	Commitment	FSAR Supplement Section/LRA Section	Enhancement or Implementation Schedule	Source
	• Personnel (Inspection Engineer and Program Administrator or Responsible Engineer) involved with the inspection and evaluation of structures and structural components, including masonry walls and water-control structures, meet the qualifications guidance identified in ACI 349.3R-02. • Visual inspection of elastomeric material should be supplemented by feel or touch to detect hardening if performance of the intended function of the elastomeric material is suspect. Include instructions to augment the visual examination of elastomeric material with physical manipulation of at least 10 percent of available surface area. • Structures will be inspected at least once every 5 years. • Submerged structures will be inspected at least once every 5 years. • If normally inaccessible areas become accessible due to plant activities, an inspection of these areas shall be conducted. Additionally, inspections will be performed of inaccessible areas in environments where observed conditions in accessible areas indicate that significant degradation may be occurring in the inaccessible areas. • Sampling and chemical analysis of groundwater at least once every 5 years. The Structures Monitoring Program owner will review the results and evaluate any anomalies and perform trending of the results. • Masonry walls will be inspected at least once every 5 years, with provisions for more frequent inspections in areas where significant aging effects (e.g., missing blocks, cracking) is observed to ensure there is no loss of intended function between inspections. • Inspection of water-control structures should be conducted under the direction of qualified			

TABLE B-1 Fermi 2 License Renewal Commitments

Item Number	Commitment	FSAR Supplement Section/LRA Section	Enhancement or Implementation Schedule	Source
	personnel experienced in the investigation, design, construction, and operation of these types of facilities. • Inspections of water-control structures on an interval not to exceed 5 years. • Perform special inspections of water-control structures immediately (within 30 days) following the occurrence of significant natural phenomena, such as large floods, earthquakes, hurricanes, tornadoes, and intense local rainfalls. k. Revise plant procedures to prescribe quantitative acceptance criteria based on the quantitative acceptance criteria of ACI 349.3R-02 and information provided in industry codes, standards, and guidelines including ACI 318, American National Standards Institute (ANSI)/ASCE 11, and relevant AISC specifications. Industry and plant-specific operating experience will also be considered in the development of the acceptance criteria. l. Revise plant procedures to include acceptance criteria for masonry wall inspections that ensure observed aging effects (cracking, loss of material or gaps between the structural steel supports and masonry walls) do not invalidate the wall's evaluation basis or impact its intended function. m. Revise Structures Monitoring Program procedures to include testing and evaluation of water/mineral deposits where in-leakage is observed in concrete elements. Testing and evaluation will determine whether leaching of calcium hydroxide and carbonation are occurring that could impact the intended function(s) of the concrete structure. n. The following testing and evaluation will be performed prior to the period of extended operation to confirm that previously identified conditions are not the result of leaching of calcium hydroxide and carbonation that could impact the intended function(s) of the concrete structure.			

TABLE B-1 Fermi 2 License Renewal Commitments

Item Number	Commitment	FSAR Supplement Section/LRA Section	Enhancement or Implementation Schedule	Source
	• Available water/mineral deposit samples will be tested for mineral and iron content to assess the effect of the water in-leakage on the reinforced concrete elements involved. • The results of the testing and Structures Monitoring Program inspections will be used to determine corrective actions per the corrective action program. Possible corrective actions include, but are not limited to, more frequent inspections, sampling and analysis of the in-leakage water for mineral and iron content, testing core bore samples, and evaluation of the affected area using evaluation and acceptance criteria of ACI 349.3R-02.			
35	Enhance the Water Chemistry Control – Closed Treated Water Systems Program as follows: a. Revise the Water Chemistry Control – Closed Treated Water Systems Program procedures to include the following systems. • Process sampling system sample cooler loops • CCHVAC chill water system b. Revise the Water Chemistry Control – Closed Treated Water Systems Program procedures to provide chemical treatment, including a corrosion inhibitor for the following systems in accordance with industry guidelines and vendor recommendations. • Process sampling system sample cooler loops • CCHVAC chill water system c. Revise Water Chemistry Control – Closed Treated Water Systems Program procedures to specify water chemistry parameters monitored and the acceptable range of values for these parameters in accordance with EPRI Closed Cooling Water Chemistry Guideline, industry guidance, or vendor recommendations. d. Revise Water Chemistry Control – Closed Treated Water	A.1.44	Prior to September 20, 2024.	LRA DTE letter NRC-15-0030 dated 3/19/15

TABLE B-1 Fermi 2 License Renewal Commitments

Item Number	Commitment	FSAR Supplement Section/LRA Section	Enhancement or Implementation Schedule	Source
	Systems Program procedures to inspect accessible components whenever a closed treated water system boundary is opened. Ensure that a representative sample of piping and components is inspected at a frequency of at least once every 10 years. These inspections will be conducted in accordance with applicable ASME Code requirements, industry standards, or other plant-specific inspection guidance by qualified personnel using procedures that are capable of detecting corrosion, fouling, or cracking. If visual examination identifies adverse conditions, then additional examinations, including UT, are conducted. Components inspected will be those with the highest likelihood of corrosion, fouling, or cracking. A representative sample is 20 percent of the population (defined as components having the same material, environment, and aging effect combination) with a maximum of 25 components. Perform treated water sampling and analysis of the closed treated water systems per industry standards and in no case greater than quarterly unless justified with an additional analysis. The process sampling system sample cooler loops will be sampled and tested annually.			
36	Implement the Coating Integrity Program as described in LRA Section B.1.45.	A.1.45	Prior to September 20, 2024, or the end of the last refueling outage prior to March 20, 2025, whichever is later. Initial inspections will be performed within the 10 years prior to March 20, 2025.	DTE letter NRC-15-0021 dated 2/5/15
37	Enhance the BWR CRD Return Line Nozzle Program as follows:	A.1.5	Completed	DTE letter NRC-15-0056 dated 5/19/15

TABLE B-1 Fermi 2 License Renewal Commitments

Item Number	Commitment	FSAR Supplement Section/LRA Section	Enhancement or Implementation Schedule	Source
	a. Revise BWR CRD Return Line Nozzle Program procedures as necessary to ensure that UT examinations will be used to detect applicable aging effects.			

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Figure	3.7-119		1	22
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Figure	3.8-3	Sheet 2	1	0
Figure	3.8-4		1	0
Figure	3.8-5		1	0
Figure	3.8-6		1	0
Figure	3.8-7		1	23
Figure	3.8-8	Sheet 1	1	0
Figure	3.8-8	Sheet 2	1	0
Figure	3.8-9		1	22
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Figure	3.8-16		1	0
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Figure	3.8-19		1	0
Figure	3.8-20		1	0
Figure	3.8-21		1	0
Figure	3.8-22		1	22
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Figure	3.8-25		1	22
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Figure	3.8-28	Sheet 1	1	22
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Figure	3.8-31	Sheet 1	1	22
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Figure	3.9-2		1	0
Figure	3.9-3		1	6
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Figure	3.9-7		1	7
Figure	3.9-8		1	7
Figure	3.9-9		1	6
Figure	3.9-10		1	6
Figure	3.9-11	Through 3.9-13	Deleted	6
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Figure	3.9-20		1	0
Figure	3.9-21		1	0
Figure	3.9-22		1	0
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Figure	3.13-9		1	0

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Figure	3.13-61	1	0
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Figure	3.13-64	1	0
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Table	4.4-1	2	16
Table	4.4-2	1	16
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Table	4.5-1	1	16
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Table	4.5-6	2	16

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Table	4.5-9	1	23

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Figure	4.1-2	1	0
Figure	4.1-3	1	0
Figure	4.1-4	1	0
Figure	4.1-5	1	0
Figure	4.1-6	1	0
Figure	4.1-7	1	0
Figure	4.1-8	1	0
Figure	4.1-9	1	0
Figure	4.1-10	1	0
Figure	4.1-11	1	0
Figure	4.1-12	1	0
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Figure	4.1-22	1	0
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Figure	5.2-9-4		Deleted	19
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Figure	5.2-9-6		Deleted	19
Figure	5.2-10		Deleted	14
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Figure	5.2-12		1	0
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Figure	5.4-2		1	0
Figure	5.5-1		1	0
Figure	5.5-2	Sheet 1	1	22
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Figure	5.5-2	Sheet 3	1	22
Figure	5.5-3		1	0
Figure	5.5-4		1	0
Figure	5.5-5		1	5
Figure	5.5-6		1	22
Figure	5.5-7	Sheet 1	1	22
Figure	5.5-7	Sheet 2	1	22
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Figure	5.5-10		1	22
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Figure	6.2-4	1	22
Figure	6.2-5	1	0
Figure	6.2-6	1	0
Figure	6.2-7	1	0
Figure	6.2-8	1	6
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Figure	6.2-14	Deleted	6
Figure	6.2-15	1	9
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Figure	6.2-17 through 6.2-19	Deleted	6
Figure	6.2-20	1	22
Figure	6.2-21	1	15
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Figure	6.2-23	1	22
Figure	6.2-24	1	23
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Figure	7.3-9	Sheet 10	1	22
Figure	7.3-10		1	11
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Figure	7.3-12	Sheet 1	1	22
Figure	7.3-12	Sheet 2	1	22
Figure	7.3-12	Sheet 3	1	22
Figure	7.3-13	Sheet 1	1	22
Figure	7.3-13	Sheet 2	1	22
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Figure	7.3-13	Sheet 4	1	22
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Figure	7.3-13	Sheet 6	1	22
Figure	7.3-14		1	0
Figure	7.3-15	Sheet 1	1	22
Figure	7.3-15	Sheet 2	1	22
Figure	7.3-15	Sheet 3	1	22
Figure	7.3-15	Sheet 4	1	22
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Figure	7.4-1	Sheet 5	1	22
Figure	7.4-1	Sheet 6	1	22
Figure	7.4-2		1	0
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Figure	7.5-1	Sheet 1	1	22
Figure	7.5-1	Sheet 2	1	22
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Chapter 8 ELECTRIC POWER

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Table	10.4-4		1	16
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Table	10.4-8		1	16
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Figure	10.2-1		1	0
Figure	10.2-2		1	22
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Figure	10.4-1		1	22
Figure	10.4-2		Deleted	16
Figure	10.4-3		1	0
Figure	10.4-4		1	0
Figure	10.4-5		1	22
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Figure	11.3-1	Sheet 1	1	22
Figure	11.3-1	Sheet 2	1	22
Figure	11.3-1	Sheet 3	1	22
Figure	11.3-2		1	0
Figure	11.4-1		1	22
Figure	11.4-2		1	22
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Figure	11.4-4		1	22
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Figure	13.1-4	1	23

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Table	14.1-1	2	16
Table	14.1-2	1	16
Figures:			
Figure	14.1-1	1	0
Figure	14.1-2	1	0

Chapter 15 ACCIDENT ANALYSES

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Section	15.2	27	24
Section	15.3	8	21
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None		

Appendix B AGING MANAGEMENT PROGRAMS AND ACTIVITIES

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Tables:		
B-1	34	24
Figures:		
None		